

Management's Discussion and Analysis

CONSOLIDATED RESULTS

Financial Highlights¹

(millions of Canadian dollars, except per share amounts)

	2005	2004	2003
Earnings Applicable to Common Shareholders			
Liquids Pipelines	229.1	219.9	213.5
Gas Pipelines	59.8	53.8	70.1
Sponsored Investments	64.8	66.2	234.3
Gas Distribution and Services ^{2,3}	178.8	313.1	153.6
International	87.4	73.6	72.3
Corporate	(63.9)	(81.3)	(76.6)
Earnings Applicable to Common Shareholders	556.0	645.3	667.2
Earnings Per Common Share ⁴	1.65	1.93	2.02
Diluted Earnings Per Common Share	1.63	1.91	2.00
Dividends Per Common Share	1.0375	0.92	0.83
Common Share Dividends	361.1	315.8	283.9
Total Assets	17,210.9	14,905.1	13,945.0
Total Long-Term Liabilities	9,690.7	8,182.5	8,028.2

¹ Financial Highlights have been extracted from financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles.

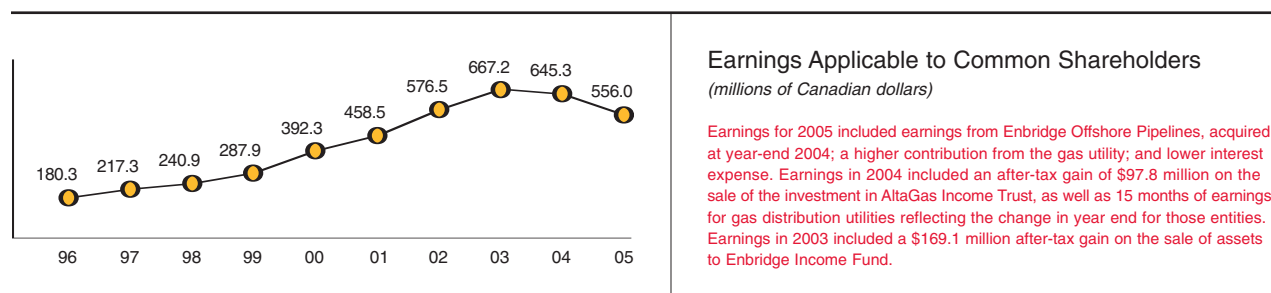
² The reported results for the year ended December 31, 2004, include earnings for the 15 months ended December 31, 2004, for Enbridge Gas Distribution (EGD), Noverco and other gas distribution entities. This resulted from the elimination of the quarter lag basis of consolidation in 2004.

³ The reported results for the year ended December 31, 2003, include earnings for the 12 months ended September 30, 2003, for these entities.

⁴ All per share amounts have been restated to reflect the Company's two-for-one stock split in May 2005.

Earnings applicable to common shareholders are \$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 is primarily the result of the sale of the investment in AltaGas in 2004, which had resulted in an after-tax gain of \$97.8 million as well as the absence of its earnings. 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 include the earnings contribution from the recently acquired Enbridge Offshore Pipelines, higher contribution from the gas distribution utility and lower interest expense.

Earnings applicable to common shareholders for the year ended December 31, 2004, were \$645.3 million, or \$1.93 per share compared with \$667.2 million, or \$2.02 per share, for the year ended December 31, 2003. In addition to the factors noted above, the 2004 results included a full year of incremental earnings from the Terrace Phase III mainline expansion, rate increases and positive variances from forecast costs in Enbridge Gas Distribution, and improved fractionation margins in Aux Sable compared with 2003. These positive factors in 2004 were offset by the absence of earnings from Alliance Pipeline Canada and Enbridge Saskatchewan, which were sold in June 2003 to Enbridge Income Fund for a gain of \$169.1 million.



Significant non-operating factors and variances affecting consolidated earnings are:

<i>(millions of Canadian dollars)</i>	2005	2004	2003
Sponsored Investments			
Dilution gains on the issue of Enbridge Energy Partners (EEP) units	8.9	7.6	20.3
EEP non-cash derivative fair value losses	(5.0)	–	–
Gain on sale of assets to Enbridge Income Fund (EIF)	–	–	169.1
Gas Distribution and Services			
Gain on sale of investment in AltaGas Income Trust	–	97.8	–
Calendar year basis adjustment ¹	–	27.1	–
Calendar year basis adjustment ²	–	–	(4.0)
Colder than normal weather	–	21.3	33.9
Impairment loss on Calmar gas plant	–	(8.2)	–
Regulatory disallowances	–	–	(35.2)
EGD unbilled revenue	–	–	33.6
Dilution gain in Noverco (Gaz Metro unit issuance)	7.3	–	7.1
Dilution gain – AltaGas Income Trust	–	8.0	–
Revalue future income taxes due to tax rate changes	–	0.6	(52.1)
International			
Gain on land sale in CLH	7.6	–	–
Corporate			
Revalue future income taxes due to tax rate changes	–	–	(1.0)
Total significant non-operating factors and variances increasing earnings	18.8	154.2	171.7

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. As a result, this adjustment differs from the adjustment reported in 2004.

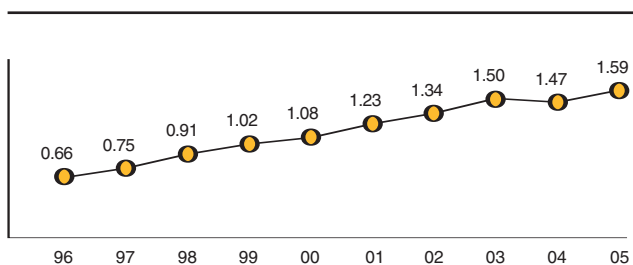
² This adjustment reflects EGD's 2003 earnings on the calendar basis. Prior to EGD's change in fiscal year end in 2004, described above, EGD's earnings were consolidated on a one-quarter-lag basis. As a result, reported consolidated results for the year ended December 31, 2003, included EGD's results for the twelve months ended September 30, 2003. This presentation differs from the presentation in the 2004 Management's Discussion and Analysis.

Significant operating factors affecting earnings in 2005 include:

- Enbridge Offshore Pipelines, acquired December 31, 2004, contributes positive earnings.
- EGD earnings are higher due to higher rate base and a number of smaller favourable variances across the utility.
- There are no earnings from AltaGas in 2005 as the investment was sold in 2004.
- Corporate costs are lower primarily as a result of lower interest expense.

Enbridge completed several strategic initiatives during 2005:

- Negotiated new five year Incentive Tolling Settlement on the Enbridge System.
- Obtained founding shipper agreements underpinning the \$400 million Waupisoo Pipeline and filed an application for regulatory approval.
- Confirmed shipper support for both the Gateway Petroleum Export Pipeline and the Gateway Condensate Import Pipeline, through non-binding open seasons, supporting continued preparations to file a full regulatory application in 2006.



Adjusted Earnings per Common Share (dollars per share)

Adjusted operating earnings represent earnings applicable to common shareholders adjusted for non-operating factors and variances. This is not a measure that has 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. 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.

- Secured the BA Energy Upgrader \$80 million terminaling and pipeline services agreement as the initial customer for our new Stonefell terminal at Fort Saskatchewan, Alberta.
- Substantially completed the US\$190 million Spearhead Pipeline project to deliver Canadian crude oil, for the first time, down to the major hub at Cushing, Oklahoma.
- Secured shipper support and commenced field work for the US\$950 million, 400,000 barrels per day (bpd) Southern Access mainline expansion project being undertaken by Enbridge and Enbridge Energy Partners.
- Entered into a 20-year electricity purchase agreement with the Ontario Power Authority for all of the power to be produced from the \$400 million, 200-megawatt wind power project currently under development by Enbridge on the shores of Lake Huron.
- Entered into an agreement to purchase 65% of the Olympic Pipe Line Company, a refined products pipeline in Washington State, for US\$99.8 million.

Enbridge (the Company) has foreign currency denominated earnings, primarily from U.S. based operations and investments, as well as its Euro investment in Compañía Logística de Hidrocarburos (CLH). The Company uses long-term derivative contracts to economically hedge a significant portion of the cash distributions from these long-term investments. However, this does not eliminate the GAAP earnings volatility caused by exchange rate differences. During the year ended December 31, 2005, the Company received foreign currency denominated cash distributions and settled associated hedge transactions resulting in \$13.0 million (2004 – \$7.5 million) of incremental cash flows, which is not included in reported earnings.

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

Corporate Vision and Objective

Enbridge is an energy delivery company that delivers 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 objective is to generate long-term value for investors. The key elements of this vision are to:

- generate above industry-average annual earnings per share growth;
- maintain a stable, low risk investment profile and strong financial position; and
- deliver superior returns (dividends and capital appreciation) to shareholders.

Core Businesses

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

- Liquids Pipelines, which owns and operates the Canadian portion of the world's longest crude oil pipeline system and includes other common carrier and feeder liquids pipelines, including the Athabasca System;
- Gas Pipelines, which includes the Company's interests in Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines;
- Sponsored Investments, which includes investments in Enbridge Income Fund (EIF) and Enbridge Energy Partners, L.P. (EEP), both managed by Enbridge;
- Gas Distribution and Services, which includes Enbridge Gas Distribution (EGD), the largest gas distribution utility operation in Canada, as well as other gas distribution businesses, CustomerWorks, gas services businesses, Aux Sable and wind power businesses; and
- International, which includes the Company's two energy-delivery investments outside of North America.

Organic Growth Projects

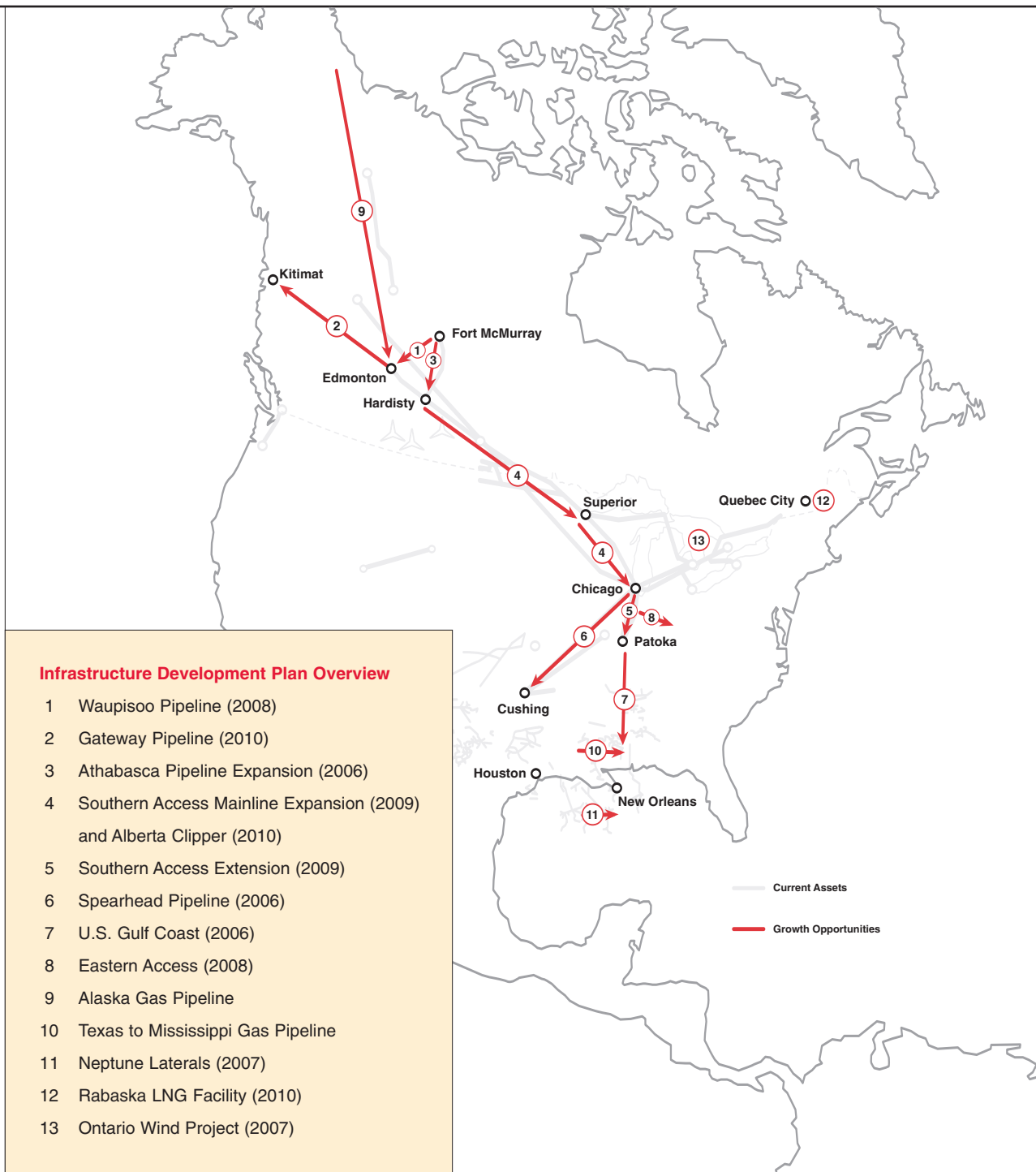
A key focus of the Company's strategy is growth through internally developed organic projects. The Company is targeting organic growth rates averaging 6% over the next five years. The Company is advancing the development of a number of organic growth projects, some of which are summarized below. Enbridge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

Project <i>(Canadian dollars unless otherwise noted)</i>	Estimated Capital Cost	Potential Date of Completion
Liquids Pipelines		
Spearhead Pipeline	US\$190 million	March 2006
Surmont Laterals and Facilities	\$42 million	Mid-2006
Athabasca Pipeline Expansions	\$75 million	Mid-2006
Long Lake Laterals and Facilities	\$45 million	Late 2006
Stonefell Terminal	\$80 million	Late 2007
Upstream Terminaling	\$460 million	2007
Downstream Terminaling	US\$220 million	2007
Waupisoo Oil Pipeline	\$400 million ¹	Mid-2008
Waupisoo Diluent Pipeline	\$200 million ¹	Mid-2008
Southern Access Expansion – Canadian portion	US\$135 million ¹	2009
Southern Access Extension	US\$250-US\$320 million ¹	2009
Gateway Condensate Import Pipeline	\$1,700 million ¹	2010
Gateway Petroleum Export Pipeline	\$2,500 million ¹	2010
Alberta Clipper Pipeline – Canadian Portion	US\$1,020 million ¹	2010
Sponsored Investments (EEP)		
Project Clarity – East Texas	US\$530 million	2007
Southern Access Expansion – U.S. portion	US\$815-US\$980 million ¹	2009
Alberta Clipper Pipeline – U.S. Portion	US\$570 million ¹	2010
Cushing Terminal Expansion	US\$55 million	2006
Gas Pipelines		
Neptune Laterals	US\$125 million	End of 2007
Gas Distribution and Services		
EGD Customer Additions & System Integrity	\$1,500 million	2006-2010
Ontario Wind Project	\$400 million	Early 2007
Rabaska LNG Facility	\$280 million by Enbridge	2010

¹ Estimated capital costs for these projects are reported in 2005 dollars and exclude escalation to the year of expenditure.

There are a number of competing projects, proposed by other companies, which could preclude the Company from developing one or more of these proposed projects.

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



Dividends

The Company has modified its dividend payout ratio to reflect a strong long-term outlook for the business, shareholders' increasing preference for income and a challenging acquisition market, which will create surplus capital in the near term. Starting in the fourth quarter of 2005, the Company is targeting to pay out approximately 60% to 70% of earnings as dividends, an increase from the previous target of 50% to 60% of earnings. The graph below shows dividends per share for the last 9 years and annualized pro-forma dividends for 2006, assuming the Board does not increase the dividend subsequent to the increase announced in November 2005.

Strategy

Enbridge has four key strategies to achieve the overall objective of generating long-term value for shareholders.

1. Expand Existing Core Asset Platforms

The Company will expand its core asset base and existing businesses. Strategies for each core business are included in the sections below.

2. Develop New Growth Platforms

Enbridge believes it is also important to develop new growth platforms that complement the existing core asset base in the following areas:

- Liquefied Natural Gas (LNG) Regasification – Develop LNG regasification projects and related pipeline infrastructure, concentrating on projects that leverage the existing downstream asset base.
- Marketing and Storage – Pursue marketing and storage opportunities to optimize existing assets and stimulate growth initiatives for both oil and gas pipelines.
- Power Generation – Continue to explore gas-fired power generation opportunities that are underpinned by long-term contracts and improve the utilization of existing assets. Also, increase the scale of the wind power business and build in locations near existing Enbridge infrastructure.
- New Energy Technologies – Support development of new technologies that are near commercialization and complement existing businesses. Initiatives will focus on technologies that enhance the economics of oil sands development and thereby ultimately enhance the value of the liquids transportation franchise.

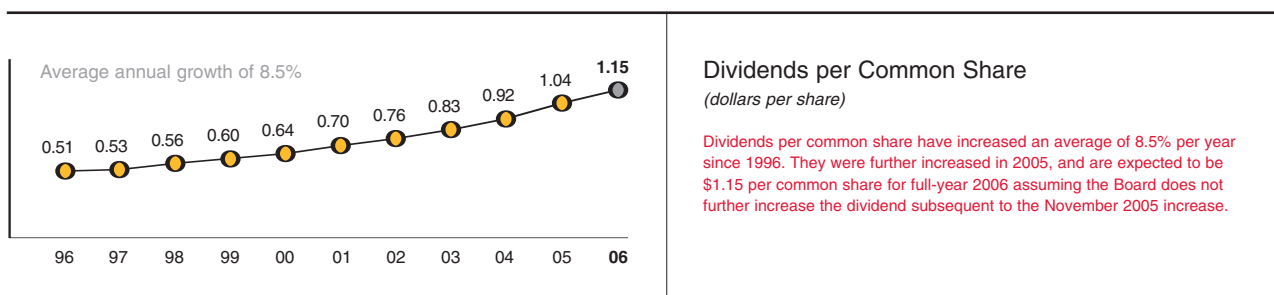
3. Capitalize on the Partnership/Trust Model

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

4. Focus on Operational Excellence

Enbridge will continue its focus on operational excellence, including cost efficiency, safety and reliability, customer relationships, environmental integrity, innovation and effective stakeholder relations.

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".



Corporate Social Responsibility

Enbridge defines Corporate Social Responsibility (CSR) as conducting business in a socially responsible and ethical manner, 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. CSR covers the Company's involvement in areas such as the environment, safety, corporate governance, community investment and stakeholder engagement.

Environmental initiatives include pursuing alternative and renewable energy technologies such as wind power, preventing pipeline leaks by conducting on-going maintenance programs as part of the comprehensive integrity management of pipelines and facilities, and the development of a carbon management strategy to manage the risks from green house gas emissions, such as methane. For example, replacing cast iron pipe with polyethylene mains at EGD is a key factor in reducing fugitive methane emissions. Safety initiatives include regular training and open communication with employees, emphasizing the importance of addressing health and safety risks before serious incidents occur and the establishment of local and regional environmental health and safety committees.

Corporate governance initiatives ensure a comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees. For example, every employee and Director must follow Enbridge's Statement on Business Conduct. Community investment initiatives include funding for the arts and health services, organizing local United Way campaigns and creating innovative partnerships with not-for-profit groups.

Stakeholder engagement means developing positive relationships with employees, suppliers, customers, investors, government agencies, environmental groups, business partners and local communities. Initiatives include early-stage project consultation on organic growth projects; public awareness programs on pipeline safety and regular customer surveys at EGD to better understand customer needs.

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.

LIQUIDS PIPELINES

Earnings

(millions of Canadian dollars)

	2005	2004	2003
Enbridge System	170.1	171.6	162.0
Athabasca System	48.6	42.8	44.8
NW System	7.3	7.8	8.3
Saskatchewan System	—	—	3.1
Feeder Pipelines and Other	3.1	(2.3)	(4.7)
	229.1	219.9	213.5

Business Activities

Liquids Pipelines consists of crude oil, natural gas liquids and refined products pipelines, primarily in Canada.

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). 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.

Tolls on the Enbridge System are governed by various agreements, which are subject to the approval of the National Energy Board (NEB). Significant agreements include the Incentive Tolling Settlement (ITS) applicable to the Enbridge mainline system (excluding Line 8 and Line 9), the Terrace agreement relating to the Terrace Expansion Project completed on April 1, 2003, which added additional capacity of 350,000 bpd and the System Expansion Program (SEP) II Risk Sharing Agreement related to SEP II, a 100,000 bpd expansion completed in 1998. Tolls on the older Mainline System have been governed by incentive tolling settlements since 1995. With the incentive tolling model, Enbridge and shippers share the benefits of cost reductions below agreed levels and the benefits of improvements in reliability and the quality of service. This approach aligns the Company's interests with those of its shippers.

Since Enbridge introduced incentive tolling arrangements in 1995, through the cost performance sharing mechanism, after-tax benefits of \$119.2 million have been shared by Enbridge and its customers, approximately 53% and 47%, respectively. Customers also realized an additional cumulative after-tax benefit of \$16.2 million through the power guarantee mechanism of the ITS.

In 2005, Enbridge and the Canadian Association of Petroleum Producers (CAPP) approved the key terms of a new negotiated ITS, effective for January 1, 2005, to December 31, 2009. In January 2006, the NEB approved the new ITS. The new ITS continues the sharing of earnings in excess of a stipulated threshold and provides a fixed annual mainline integrity allowance. In conjunction with the Terrace Agreement, the new ITS continues the throughput protection provisions ensuring the Company is insulated from negative volume fluctuations beyond its control. In addition to the incentive-based provisions in prior agreements, service and reliability metrics, collectively performance 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.

The service metrics establish financial bonuses and penalties for prescribed performance targets related to crude oil quality management and predictability of scheduled deliveries. The 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 relative to annual capacity targets. If the Company's performance is below the target, it is charged a penalty of \$200,000 after tax per percentage point for each month that performance is below the target. If the Company's performance exceeds the target, it earns \$500,000 per percentage point for each month that performance is above the target. 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.

Athabasca System

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

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 ensuring that the revenue recognized each period is in accordance with the agreement. This receivable is contractually guaranteed by the shipper and will be collected in the later years of the contract.

NW System and Others

Enbridge's NW System is an 870-kilometre (540-mile) pipeline that transports crude oil from Norman Wells, in the Northwest Territories to Zama, Alberta. Earnings are based on an agreement with the primary shipper and are a product of a deemed common equity ratio of 55% (reduced to 50% after 2009) and the NEB multi-pipeline rate of return on common equity, plus any incentive cost savings.

Feeder Pipelines and Other primarily includes a number of liquids pipelines in the United States (Frontier, Toledo, Mustang, Chicap and Spearhead), as well as business development costs related to Liquids Pipelines activities.

Results of Operations

Liquids Pipelines earnings are \$229.1 million in 2005 compared with \$219.9 million in 2004. The increase is 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 and 2003.

Earnings from Liquids Pipelines were \$219.9 million for the year ended December 31, 2004, an increase of \$6.4 million from 2003. The increase resulted from higher earnings from the Enbridge System, which included incremental earnings from Terrace Phase III. The Saskatchewan System was sold to Enbridge Income Fund effective June 30, 2003.

Enbridge System

Enbridge System earnings are \$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 is due to a lower earnings base from the ITS component of the Enbridge System, recently negotiated with the CAPP and approved by the NEB. As well, earnings were negatively impacted by higher taxes within the Terrace component. The decrease has been partially offset with earnings from the service and reliability incentives under the ITS as well as savings from cost management programs.

Enbridge System earnings are higher in 2004 than 2003 as they include incremental earnings from the Terrace Phase III expansion placed into service on April 1, 2003, as well as the increase in Enbridge's share of the Terrace surcharge. This increase is partially offset by a higher oil loss expense and a higher power allowance credit in 2004.

Athabasca System

Earnings for the year ended December 31, 2005, are \$48.6 million, an increase of \$5.8 million from 2004. The increase is consistent with the overall return underpinning the long-term take or pay contract with its major shipper as well as lower operating costs due to leak remediation in the prior year.

The Athabasca System 2004 earnings were \$42.8 million for the year ended December 31, 2004, compared with \$44.8 million for the year ended December 31, 2003. Earnings in 2004 included the contribution from the Hardisty storage caverns, completed in the fourth quarter of 2003. This was more than offset by higher tax expense as 2003 included the utilization of loss carryforwards.

NW System

Earnings in the last three years from the NW System have been consistent and reflect the effect of a declining rate base.

Feeder Pipelines and Other

Earnings in Feeder Pipelines and Other are \$3.1 million for the year ended December 31, 2005, compared with a loss of \$2.3 million for the year ended December 31, 2004. The increase is the result of Gateway condensate pipeline costs being deferred in 2005 whereas in 2004 they were expensed. In addition, Frontier Pipeline earnings were higher due to lower operating costs and the prior year included FERC ordered reparations.

Feeder Pipelines and Other earnings for the year ended December 31, 2004, increased \$2.4 million from 2003 as a result of the Frontier reparations, the majority of which were recorded in 2003.

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. This can be achieved by reducing customers' costs, enhancing their access to premium markets and avoiding restrictions on production volumes caused by limited pipeline capacity.

On existing infrastructure, the Company will maximize cost efficiencies, ensure capacity is reliable and available when required and protect the quality and distinctiveness of the many different batches transported. The new ITS, described above, includes performance metrics which will reward the Company for achieving these goals and penalize the Company if performance in the prescribed areas falls below target levels.

The Company intends to enhance customers' access to favourable markets through ensuring that new transportation and storage infrastructure is developed on a timely basis, to meet customers' needs for expanded capacity in traditional markets and access to new markets with favourable pricing characteristics. There are many organic growth projects underway, described below, driven primarily by forecast increased production from the oil sands. Enbridge will only proceed with projects supported by shippers.

The Liquids Pipelines strategy will focus on: (i) continuing to develop regional Alberta oil sands infrastructure; (ii) enhancing producer access to diluent, which is needed to dilute heavy oils so they can be transported through pipelines; (iii) increasing traditional core PADD II (U.S. Midwest) market penetration; (iv) pursuing new market access initiatives; and (v) continuing to develop customer and stakeholder relationships.

Supply and Reserves

The vast resource of the Western Canadian Sedimentary Basin (WCSB) and its development, create the basis for the Company's growth strategy. Generally, development of the oil sands resource has more than offset declining conventional production. In 2005, due to events such as the Suncor fire, growth in oil sands production did not offset the decline in production from conventional resources. The NEB estimates that total Western Canada 2005 production will be 2.3 million bpd¹ at the end of 2005 (2004 – 2.2 million bpd). At the end of 2004, 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 proven reserves⁴.

¹ National Energy Board 2005 Estimate Production of Canadian Crude Oil and Equivalent Table 1

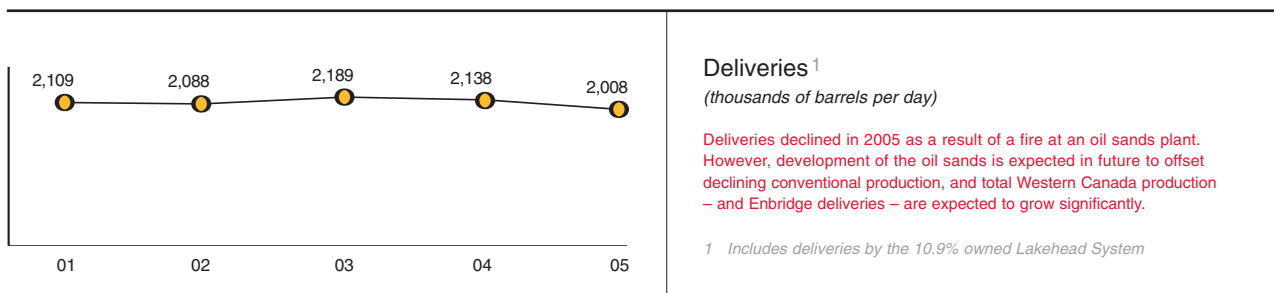
² Canadian Association of Petroleum Producers Statistical Handbook 2005

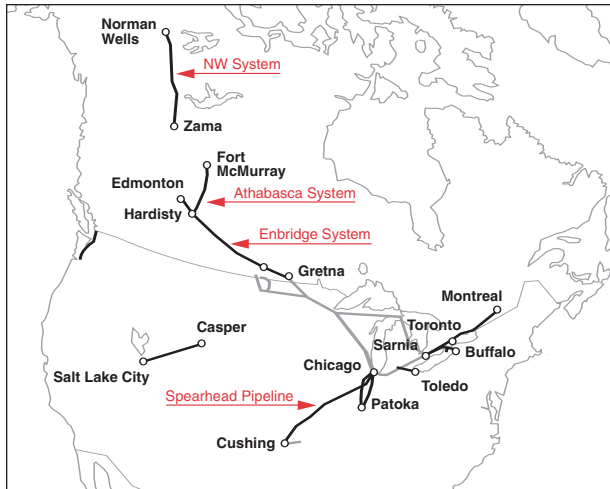
³ Alberta Energy and Utilities Board Alberta's Reserves 2004 and Supply/Demand Outlook

⁴ Oil and Gas Journal's Worldwide Look at Reserves and Production, December 19, 2005

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. Historically, the pipeline system has delivered crude oil to two main markets: Ontario/Quebec, and the Midwest portion of the United States with some volume delivered to Western Canada. Through Company initiatives, crude oil will begin to penetrate southern markets in PADD II with the Spearhead Pipeline as well as the U.S. Gulf Coast (PADD III) via a third party pipeline system.





Liquids Pipelines

Historically, Canada has been the third largest supplier of crude to the U.S. However, for the past two years, Canada has surpassed both Mexico and Saudi Arabia to become the largest crude oil exporter to the U.S. Western Canada demand is served by local supply and has increased by 25,800 bpd over the last two years. During 2005, an equal mix of Western Canadian and Atlantic Basin crude satisfied Ontario's crude oil requirement. Deliveries to Ontario from Western Canada and from Montréal, Quebec declined in 2005 with the closure of Petro-Canada's Oakville refinery. Deliveries of WCSB crude into PADD II (the U.S. Midwest) remained relatively flat over the last two years with reduced WCSB crude oil supply in 2005. U.S. deliveries of Canadian crude grew by 116,400 bpd by December compared to the third quarter of 2005, as Suncor's

recovered production entered the market. Over the same two-year period, deliveries into PADD IV (the U.S. Rocky Mountains) have increased by 30,800 bpd and PADD V (the Western U.S.) deliveries have increased by 25,000 bpd.

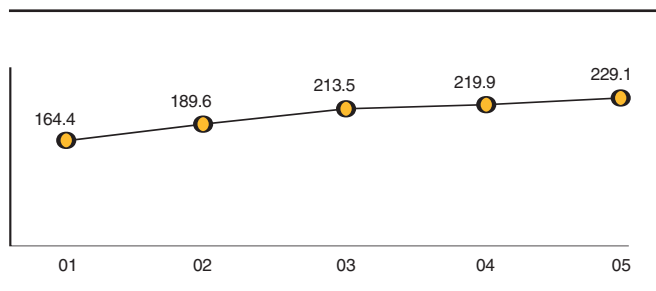
The abundance of established reserves from oil sands, the proximity to the U.S. markets and the relative geopolitical attractiveness of the resource, as well as strong demand, will provide opportunities for the expansion of Enbridge's Athabasca System and the Enbridge System as well as the development of new pipelines.

Alberta Oil Sands Infrastructure

A number of projects are underway to develop oil sands infrastructure including the Gateway, Waupisoo, Surmont and Long Lake projects, described below. Both the Gateway and Waupisoo projects provide for diluent pipelines that would bring needed diluent to the oil sands.

The Gateway Project

The Gateway Project, which includes both a condensate import pipeline and a petroleum export pipeline, continues to progress through the commercial development phase needed to achieve sufficient shipper commitments for each line. Originally, a 16-inch condensate import pipeline was planned at an expected cost of approximately \$1.7 billion on a stand-alone basis. Based on the results of the Open Season, Enbridge expects to increase the diameter of the pipeline from 16 inches to 20 inches. Enbridge has also offered condensate line shippers the option to participate, as partners, in the ownership of the pipeline. Final commitment amounts and transportation agreements, as well as ownership agreements, are nearing the final stages of negotiations. At the same time, updated cost estimates are being prepared for each line. The estimates, along with the respective tolls, will be required prior to execution of shipper agreements for both pipelines.



Liquids Pipelines Earnings
(millions of Canadian dollars)

Liquids Pipelines earnings increased in 2005 due to higher Athabasca System earnings and improved earnings from Feeder Pipelines and Other, primarily Frontier Pipeline.

The petroleum export line, which would transport crude oil from the Edmonton area to the Canadian west coast, closed its Open Season in December 2005 and discussions with interested shippers have commenced with the objective of signing final agreements by the second quarter of 2006, in time for the anticipated regulatory filing. As with the condensate line, interest expressed during the Open Season supports an increase of the pipeline diameter from 30 inches to 36 inches. The petroleum export pipeline is expected to cost approximately \$2.5 billion (in 2005 dollars) on a stand-alone basis and, if both parts of the Project proceed together, total savings of approximately \$550 million could be realized.

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. If the Project proceeds, construction could begin as early as 2008 with a target in-service date early in 2010.

Waupisoo Pipeline Project

During the third quarter of 2005, Enbridge reached agreements with shippers on long-term transportation commitments on the proposed Waupisoo Pipeline. The 30-inch diameter, 380-kilometre long 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 through the addition of pumping units. Enbridge has filed an application for regulatory approval with the Alberta Energy and Utilities Board and other provincial government departments. Pending regulatory approvals, expected in mid-2006, Enbridge will begin construction on the approximately \$400 million pipeline in 2007, with an expected in-service date of mid-2008.

Based on interest expressed by oil sands producers, Enbridge is including a 16-inch, 150,000 bpd diluent return line from the Edmonton area refinery hub north to the oil sands within the scope of the project for regulatory approval and public consultation. The diluent line is expected to cost approximately \$200 million. Shipping commitments on the diluent line have not been finalized.

Surmont Oil Sands Project

Enbridge entered into final agreements with ConocoPhillips Surmont Partnership and Total E&P Canada Ltd. (the Surmont Shippers), to provide pipeline transportation services on the Athabasca Pipeline starting in mid-2006. Enbridge will construct the pipeline and tank facilities required by the Surmont Project at the Cheecham terminal on the Athabasca Pipeline. The estimated cost of these facilities is \$42 million. The agreements provide 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 agreement covering the dedicated Surmont lateral facilities and the agreement for transportation service on the Athabasca Pipeline are both for an initial term of 25 years, with extension provisions. The Athabasca Pipeline agreement also provides flexibility for the Surmont Shippers to transfer their production to the proposed Waupisoo Pipeline to the Edmonton area.

Long Lake Oil Sands Project

During the first quarter of 2005, the Company finalized agreements with Nexen Inc. and OPTI Canada Inc. (the Long Lake Shippers) to provide pipeline transportation services for the Long Lake Project.

Under the terms of the agreements, Enbridge will construct, own and operate the pipeline and tank facilities required by the Long Lake Project, as well as pipeline laterals and tank facilities at the Cheecham terminal on the Athabasca Pipeline. The estimated cost of these facilities is \$45 million with a planned in-service date in late 2006. Enbridge's 545 kilometre Athabasca Pipeline will also require capacity expansion from the Cheecham terminal to its mainline terminal at Hardisty, Alberta.

The agreements provide for an initial contract volume of up to 60,000 bpd of crude oil with provisions for volume increases. The agreement covering the Long Lake lateral facilities 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.

Athabasca Pipeline Expansions

In 2005, the Company initiated several expansion projects on the Athabasca Pipeline. The expansion projects include the addition of two pumping stations, one at Elk Point and one at Cheecham, as well as modifications to existing pumping stations. In addition, the Company is adding three new tanks at the Athabasca Terminal. The projects are scheduled to be completed in mid-2006 at a total cost of approximately \$75 million.

Market Penetration and Access

Three projects currently under consideration which would increase PADD II penetration and would provide improved access to North American markets are the Southern Access Project, which would expand and extend the mainline; the Alberta Clipper Pipeline, the next tranche of mainline capacity; and the Spearhead Pipeline reversal project, which will provide access for Canadian crude to the Cushing refinery hub.

Southern Access Mainline Expansion and Extension Program

On December 23, 2005, EEP, Enbridge's 10.9%-owned affiliate, filed a tolling application with the FERC with respect to the 400,000 bpd Southern Access expansion from the Canada/U.S. border to Griffith, Indiana. The FERC filing is endorsed by CAPP and a FERC decision is expected in the first quarter of 2006. The cost of the expansion is estimated at approximately US\$815 million to EEP. The program is scheduled to be brought into service in stages, with 44,000 bpd in 2007, an additional 146,000 bpd in 2008 and the final 210,000 bpd in 2009. CAPP may request a delay of the target in-service dates if production growth is slower than forecast, but in such case EEP can recover any costs incurred to the date of notification.

Enbridge has also negotiated the Canadian expansion agreement with CAPP for the Southern Access Expansion between Hardisty, Alberta and the Canada/U.S. border. Enbridge intends to file for NEB approval of the Canadian expansion in 2006, the cost of which is estimated at US\$135 million to Enbridge. The Canadian facilities can also be staged, and the in-service dates will be timed to coincide with the U.S. facilities.

Enbridge continues to discuss the extension of the mainline from Flanagan, IL to Patoka, IL or potentially Wood River, IL with shippers. The extension would involve the construction of a new 30-inch diameter, 300,000 bpd pipeline, at a cost of approximately US\$250 million to US\$320 million to Enbridge.

Alberta Clipper Pipeline

Enbridge anticipates that additional capacity to the U.S. Midwest, over and above Southern Access, described above, will be required. The Company has been actively developing the next tranche of mainline expansion capacity, the Alberta Clipper Pipeline, with selected shippers. The Alberta Clipper Pipeline project involves a new 36" line from Hardisty, Alberta to Superior, Wisconsin where it will interconnect with the existing mainline system to provide access to Enbridge's full range of delivery points and storage options, including Chicago, Toledo, Sarnia, Patoka, Wood River and Cushing. The line would involve a total investment of US\$1.6 billion (in 2005 dollars) for an initial capacity of 400,000 bpd. Shipper interest to date has been strong, and the Company will expand these discussions during the first quarter of 2006 to seek broad industry support.

Spearhead Pipeline

Enbridge acquired 90% of the Spearhead Pipeline in 2003 and the remaining 10% in 2005. The Company is reversing the flow of the pipeline, which previously operated from Cushing to Chicago, to bring crude oil from Chicago to Cushing. The Spearhead Pipeline project is currently estimated to result in a total investment of \$230 million, of which approximately \$220 million has been spent. The reversed pipeline is expected to be in service in March 2006.

Other Projects

Contract Terminaling

Enbridge directly, and through EEP, has developed a significant position in the contract terminaling business in recent years, with a total of 12 million barrels of storage capacity at six Canadian and U.S. locations. With increasing crude oil production and price volatility, the Company is encountering strong demand from producers, refiners and marketers for

term storage capacity and associated terminaling services. In addition to the \$80 million Stonefell terminal agreement for the BA Energy Upgrader, described below, the Company has numerous other terminaling investment opportunities, aggregating approximately \$460 million in Canada and US\$220 million in the U.S., either secured or well advanced.

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 \$80 million in new facilities to provide storage services at a new satellite terminal it will develop 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 the fourth quarter of 2007.

Olympic Pipe Line

In December 2005, Enbridge announced that it will acquire a 65% interest in the Olympic Pipe Line Company (Olympic) from BP for US\$99.8 million, subject to working capital adjustments. The transaction closed on February 1, 2006. Olympic owns 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 480 kilometres (300 miles) from Blaine, Washington to Portland, Oregon, connecting four Puget Sound refineries to terminals in Washington and Portland and consists of 640 kilometres (400 miles) of 6-to-20 inch diameter pipe, a 500,000-barrel products terminal, 9 pumping stations and 21 delivery points or facilities. Olympic is the sole supplier of jet fuel to the Seattle-Tacoma International Airport and is a major supplier to the Portland International Airport. BP will continue to operate the pipeline system.

Customer and Stakeholder Relationships

To meet the Company's objective of continuing to develop customer and stakeholder relationships, Liquids Pipelines will focus on achieving operational excellence including assuring best practices relative to system reliability, safety, environmental issues and cost efficiency. The Liquids Pipelines business will continue its efforts to maintain a high level of customer satisfaction while striving to meet performance metrics targets in the new ITS.

Capital Expenditures

Liquids Pipelines generally spends \$80 to \$100 million each year on ongoing capital improvements and core maintenance capital projects. This trend is expected to continue in 2006. Expenditures for organic growth projects described above are expected to be approximately \$230 million during 2006 in Canada.

Legal Proceeding – CAPLA Claim

The Canadian Alliance of Pipeline Landowners' Associations (CAPLA) and two individual landowners have commenced an 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 have filed a motion to establish a cause of action, one of the requirements to have the motion certified as a class action under the *Class Proceedings Act* (Ontario). These matters are currently before the Ontario District Court for hearing. Since the outcome is indeterminable, the Company has made no provision 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 consumption, manufacturing, alternative energy sources and global supply disruptions.

Performance Metrics

The new 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 new 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 2006 and 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. For 2006, this rate of return is 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 upon the cost of transportation, access to supply, and proximity to markets. Other common carriers are available to producers to ship Western Canadian crude oil to refineries in either Canada or the United States. Although the Company does not compete directly in the regions served by these other pipelines, producers can elect to have their crude oil refined at delivery points not on the Enbridge System. 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. Also, 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. Available capacity on the Athabasca System is expected to be more competitive than a new pipeline.

Competition also impacts the Company's ability to execute organic growth projects as a number of competing projects, proposed by other companies, could preclude the Company from developing one or more of the proposed projects. The Company also anticipates challenges in securing the labour that would be required to complete the projects.

GAS PIPELINES

Earnings

(millions of Canadian dollars)

	2005	2004	2003
Alliance Pipeline US	32.1	37.4	40.3
Vector Pipeline	15.9	16.4	10.2
Enbridge Offshore Pipelines	11.8	—	—
Alliance Pipeline Canada	—	—	19.6
	59.8	53.8	70.1

Business Activities

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 US 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. Alliance Pipeline Canada was sold to EIF effective June 30, 2003. EIF is included in Sponsored Investments.

Alliance Pipeline US

The Alliance System (Alliance), which includes both the Canadian and U.S. portions of the pipeline system, consists of an approximately 3000-kilometre (1,875-mile) integrated, high-pressure natural gas transmission pipeline system and an approximately 700-kilometre (440-mile) lateral pipeline system and related infrastructure. Alliance transports liquids-rich natural gas from Fort St. John, British Columbia to Chicago, Illinois and has the capacity to deliver 1.55 billion cubic feet per day (bcf/d).

Alliance has take-or-pay contracts ending in 2015 to transport 1.325 bcf/d of natural gas. 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 contract may be renewed upon five years notice for successive one-year terms beyond the original 15-year primary term. The rates and tariff for Alliance Pipeline US are regulated by the FERC in the United States.

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. Aux Sable is owned 42.7% by Enbridge and its results are included under Gas Distribution and Services.

Vector Pipeline

The Company provides operating services to, and holds a 60% investment 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.

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. Vector Pipeline has negotiated long-term binding agreements with shippers and initiated the filing process with the FERC. Preliminary engineering and environmental work is underway and the expansion is expected to be in service by the fourth quarter of 2007.

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 kilometres (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 normally transport approximately 2.7 bcf/d.

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 maximum sustainable production that is achievable.

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 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.

Results of Operations

Earnings from Gas Pipelines are \$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.

Earnings from Gas Pipelines were \$53.8 million for the year ended December 31, 2004, a decrease of \$16.3 million from 2003 related primarily to the disposal of Alliance Pipeline Canada to EIF on June 30, 2003.

Alliance Pipeline US

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.

Alliance Pipeline US earnings for the year ended December 31, 2004, were \$2.9 million lower than earnings for the year ended December 31, 2003. The decrease reflected the impact of the stronger Canadian dollar in 2004 compared with 2003, and the favourable impact, in 2003, of the adjustment recorded in Alliance to reflect a higher rate base.

Vector Pipeline

Vector Pipeline earnings are \$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.

Earnings from Vector Pipeline were \$6.2 million more in 2004 compared with 2003, as a result of increased volumes and transportation margins, additional ownership interest of 15.0% acquired in the fourth quarter of 2003 and Canadian dollar effects.

Enbridge Offshore Pipelines

Enbridge Offshore Pipelines contributed \$11.8 million to earnings in 2005. Hurricanes Katrina and Rita negatively affected transmission volumes and the results of this business. The results include property insurance deductibles as well as lost revenue on various systems prior to the commencement of contingent business interruption insurance coverage. The combined effect of the property damage deductibles and the estimated lost revenue reduced expected earnings by approximately \$15 million. In 2006, earnings will likely also be affected, although to a much lesser degree.

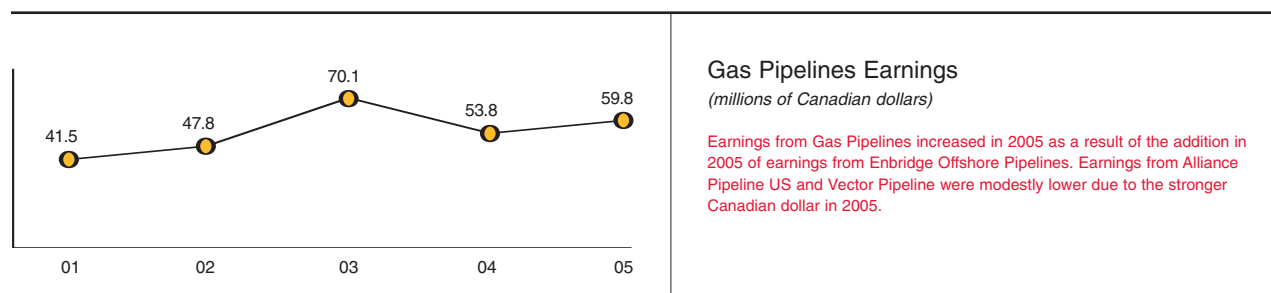
As of December 31, 2005, the pipelines were transporting 90% of pre-hurricane volumes, or approximately 2.4 bcf/d, compared with the pre-hurricane rate of approximately 2.7 bcf/d. The impact on each corridor is described below.

The Mississippi Canyon Corridor was in the direct path of Hurricane Katrina. Minor damage to the Enbridge facilities was isolated primarily to onshore electrical, control and measurement equipment. Two key production source platforms and the Venice gas processing plant, all owned by others, were damaged. Between early September and mid-November 2005, no volumes moved through the Mississippi Canyon Corridor. By year-end, approximately 0.43 bcf/d or 75% of the pre-Katrina throughput level was back on line. Repairs to upstream and downstream infrastructure should allow throughput to fully recover in 2006.

Hurricane Katrina caused modest damage to certain Enbridge assets in the Destin Corridor. However, upstream and downstream oil and natural gas liquids pipelines facilities owned by others experienced damage and were not operational until mid-October. Operations were restored by the end of October with production throughput continuing to increase as repairs of non-Enbridge facilities were completed. As of December 31, 2005, volumes on the Destin Corridor were up to 0.89 bcf/d which is approximately 95% of the pre-hurricane level.

Hurricane Rita caused no material incremental damage to the Mississippi Canyon and Destin Corridors.

Hurricanes Katrina and Rita caused no material damage in the Green Canyon Corridor and volumes were unaffected by the hurricanes.



The Garden Banks and Stingray Corridors were in the direct path of Hurricane Rita. In these corridors, there was minimal damage to the Enbridge owned offshore pipelines and platform facilities. In the Garden Banks Corridor, volumes returned to pre-hurricane levels in mid-November when repairs to an upstream producer gathering line were completed. Volumes on the Stingray pipeline began flowing again in early November at a rate of approximately 0.1 bcf/d and were at 0.325 bcf/d by year-end or 65% of pre-hurricane levels. Volumes are expected to return to pre-hurricane levels in early 2006 following completion of repairs to the Stingray onshore plant facility scheduled for January 2006 and repairs to third party processing facilities.

Strategy

The five main elements of the Gas Pipelines strategy are: (i) continue to expand the existing Alliance and Vector systems and position them for northern gas development; (ii) capitalize on the offshore Gulf of Mexico assets through continued joint venture consolidation, connection of new gas discoveries and acquisition of other deepwater systems; (iii) consolidate Enbridge's assets in the Chicago-to-Dawn corridor and extend its presence downstream of Dawn; (iv) achieve an equity participation in an Alaska-to-Alberta gas pipeline in partnership with producers; and (v) pursue and develop pipeline infrastructure required to move U.S. Rockies gas to the Midwest and northeastern markets. The strategy is based on the Company's assessment of the 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 will mitigate growth in the demand for natural gas in that sector. The development of oil sands projects in Alberta also impacts the demand for natural gas, as various extraction and upgrading processes require the use of natural gas. Demand growth is expected to be constrained by recent strong prices and increased volatility due to supply concerns from traditional sources. Over time, the entry of new supplies from the U.S. Rockies and the Alaska North Slope / Mackenzie Delta as well as Liquefied Natural Gas are expected to alleviate supply concerns and provide opportunities for Enbridge to deliver this natural gas to markets.

To respond to this expected growth in demand, Enbridge will further develop its existing gas pipelines investments and pursue new growth platforms including an increased presence in the Gulf of Mexico. Offshore development is expected to include options that offer both crude oil and natural gas transportation. Alliance will focus on cost-effective optimization, more efficient maintenance practices and increased heating values. Alliance is well positioned to participate in the delivery of Alaska/Mackenzie Delta gas to markets in the United States. Vector's strategy will focus on ensuring a safe and cost-efficient expansion for a late-2007 in-service date. New growth platforms could include significant ownership in a pipeline transporting gas from the U.S. Rockies; ownership in a pipeline connecting Dawn, Ontario, to New York State; storage facilities in Ontario and a significant ownership position in other storage facilities; as well as the pursuit of an equity participation in the Alaska-to-Alberta gas pipeline.

The Company continues to pursue developments in the Gulf of Mexico, building on its initial \$754 million investment in EOP. During 2005, Enbridge increased its interest in Garden Banks Gas Pipeline and Neptune Pipeline Company, two systems within EOP. The Company believes that gas production from the deepwater Gulf of Mexico will increase from pre-Hurricane Katrina flows of 3.5 to 4.0 bcf/d to approximately 8 bcf/d by 2010. Strategically, the Company believes that its status as an independent operator, not a producer, will allow for the further consolidation of joint venture interests across the Gulf of Mexico. Further growth is anticipated from connecting new leases and entry into oil pipelines.

Neptune 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\$125 million and will have the capacity to deliver in excess of 200 mmcf/d of gas and approximately 50,000 bpd of oil. Construction of the Neptune oil and gas laterals is scheduled for the second quarter of 2007 with first throughput expected by year-end 2007.

Capital Expenditures

The Company expects to spend approximately \$100 million in 2006 in the Gas Pipelines segment for on ongoing capital improvements, core maintenance capital projects and expansion, including the Neptune Project described above.

Business Risks

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

Alliance Pipeline US and Vector Pipeline

Supply and Demand

Currently, pipeline capacity out of the WCSB exceeds supply. Alliance Pipeline US and Vector Pipeline have been unaffected by this excess supply environment mainly because of long-term capacity contracts going to 2015. Vector Pipeline 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 the shippers to perform their contractual obligations under the transportation contracts 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 agreed thresholds. Vector Pipeline also has a diverse group of long-term transportation shippers, which includes various gas and energy distribution companies, producers and marketing companies, further reducing the exposure.

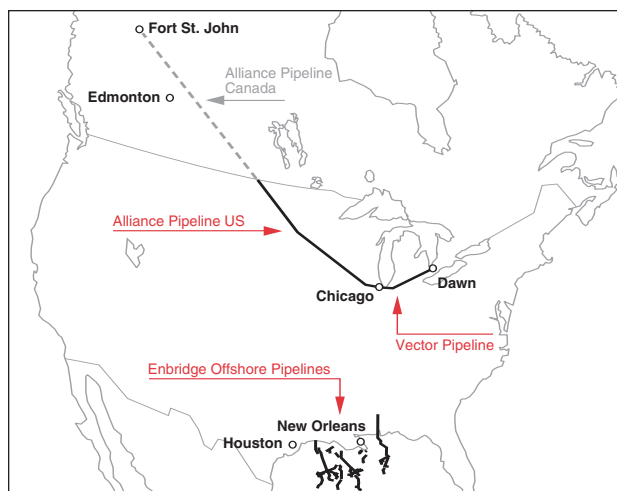
Competition

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 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 penalize early termination if shippers do not extend their contracts beyond the initial term. The effectiveness of these mitigation factors is evidenced by the increase in the utilization of the pipeline since its construction, despite the presence of transportation alternatives.

Regulation

Both Vector Pipeline and Alliance Pipeline US are regulated by the FERC which has the responsibility to ensure that rates charged are not greater than those necessary to enable the pipelines to recover costs prudently incurred and to earn a reasonable return. Under FERC regulations, the FERC, shippers and others have the opportunity to contest rates and the tariff structure.



Gas Pipelines

Enbridge Offshore Pipelines

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 indirectly decrease throughput on EOP systems.

Competition

There is significant competition for new and existing business in the Gulf of Mexico. EOP has been able to capture key opportunities, which extends its footprint, positioning EOP 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, 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.

SPONSORED INVESTMENTS

Earnings

(millions of Canadian dollars)

	2005	2004	2003
Enbridge Income Fund (EIF)	34.2	30.0	17.6
Enbridge Energy Partners (EEP)	21.7	28.6	27.3
Gain on sale of assets to EIF	—	—	169.1
Dilution gains	8.9	7.6	20.3
	64.8	66.2	234.3

Business Activities

Sponsored Investments includes the Company's 10.9% 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.

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 pipelines and a crude oil feeder pipeline in North Dakota.

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:

	Unitholders	Enbridge
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 2005, EEP paid quarterly distributions of \$0.925 per unit (2004 – \$0.925 per unit; 2003 – \$0.925 per unit). Of the \$21.7 million Enbridge recognized as earnings from EEP during 2005, 64.7% (2004 – 50%; 2003 – 49%) were incentive earnings while 35.3% (2004 – 50%; 2003 – 51%) were Enbridge's share of EEP's earnings.

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 Inc.'s mainline pipeline to be transported to the United States.

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 2005, the Company received incentive fees of \$2.1 million (2004 – \$0.8 million, 2003 – nil). The Company is the primary beneficiary of EIF through a combination of the voting units and a preferred units investment and as such EIF is consolidated, starting January 1, 2005, under variable interest entity rules.

Results of Operations

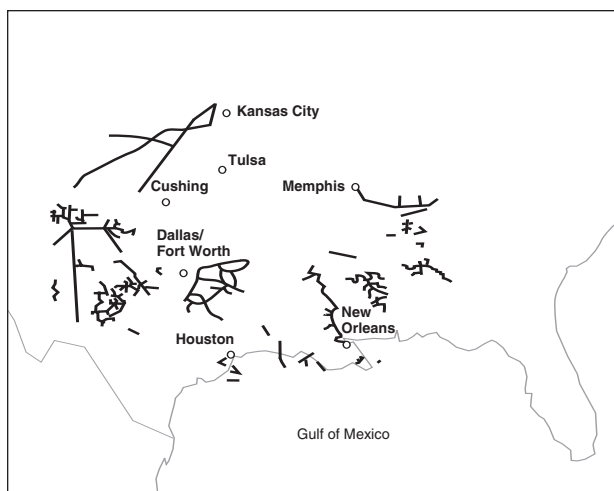
Earnings from Sponsored Investments are \$64.8 million for the year ended December 31, 2005, compared with \$66.2 million in 2004. EIF has increased earnings of \$4.2 million due to allowance oil sales on the Saskatchewan System and collection of a notional tax in tolls on Alliance Canada. This increase is more than offset by EEP's non-cash unrealized mark-to-market losses on derivative instruments that are considered ineffective hedges for accounting purposes.

The decrease in 2004 earnings compared with 2003 stems from the gain of \$169.1 million on the sale of the Company's interests in Alliance Pipeline Canada and Enbridge Pipelines (Saskatchewan) to EIF in 2003.

Enbridge Income Fund

EIF earnings are \$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.

Earnings for 2004 include a full year of operations whereas earnings for 2003 included only the six months from inception of EIF on June 30, 2003.



Enbridge Energy Partners – Gas Pipelines

Enbridge Energy Partners

Earnings of \$21.7 million for the year ended December 31, 2005, are down from 2004 earnings of \$28.6 million due to \$5.0 million (net to Enbridge) of unrealized mark-to-market losses on derivative financial instruments, which do 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 must be accounted for on a mark-to-market basis through earnings. In addition, EEP earnings have been 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's 2004 results reflected higher operating earnings, compared with 2003, partially offset by the

stronger Canadian dollar, a lower ownership interest and the negative effect of a FERC decision requiring a refund to shippers on one of EEP's regulated natural gas pipelines. The higher operating earnings were from increased volumes on the main crude oil liquids pipeline system, as well as increased throughput and higher processing margins on various natural gas assets.

EEP issued partnership units in each of 2005, 2004 and 2003. Because Enbridge did not fully participate in these offerings, dilution gains resulted.

Strategy

Enbridge Energy Partners

EEP intends to grow primarily through organic growth, supplemented by opportunistic acquisitions. Specifically, EEP intends to:

- increase the utilization and productivity of its core assets to meet the supply of and demand for hydrocarbons in the markets EEP serves; and
- develop and acquire complementary energy delivery assets, particularly in the Gulf Coast region of the United States, and improve the financial performance and operating efficiency of these assets.

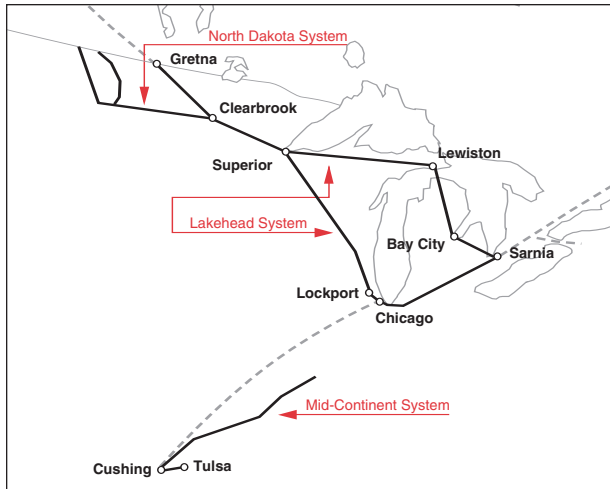
On January 30, 2006, EEP announced that it has received customer commitments to support the construction of a US\$530 million expansion and extension of its East Texas natural gas system (Project Clarity). The Project will handle growing natural gas production in East Texas and will consist of a 36-inch intrastate pipeline with a capacity of approximately 700 mmcf/d, a 250 mmcf/d treating facility and a number of upstream facilities, including gathering pipelines all of which are expected to be fully operational in late 2007.

Enbridge Income Fund

Enbridge Income Fund will continue to position itself as a premier income fund in Canada with a value proposition characterized by a low risk profile with dependable but modest organic growth, long-life assets and potential for further growth through energy infrastructure acquisitions.

Business Risks

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



Enbridge Energy Partners – Liquids Pipelines

Enbridge Energy Partners

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 future 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 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 does business.

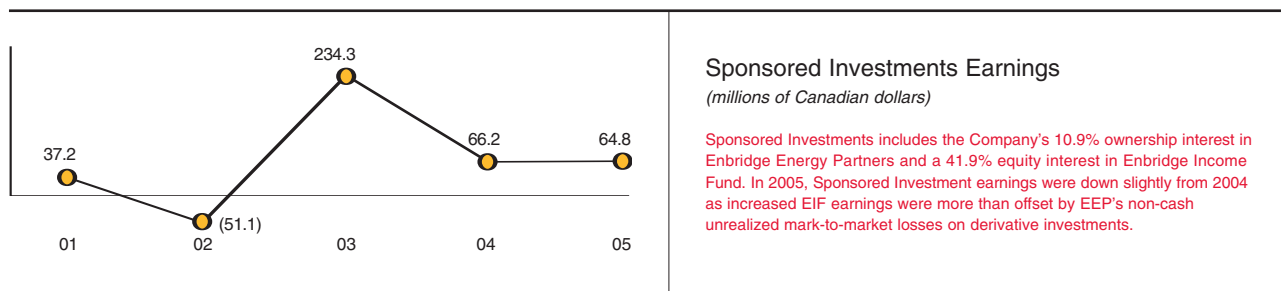
Market Price Risk

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 financial contracts, fixing the prices of natural gas and natural gas liquids. Certain of these 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

Risks for Alliance Pipeline Canada are similar to those identified for the Alliance Pipeline US in the Gas Pipelines segment.

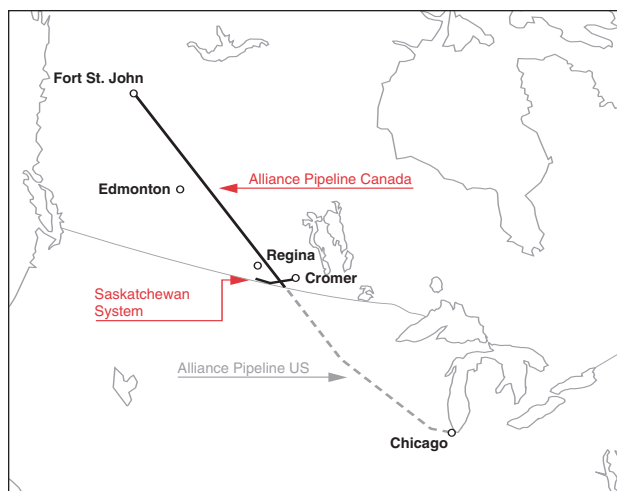
The majority of the volumes shipped on the Saskatchewan and Westspur common carrier pipeline systems, components of the Saskatchewan System, have no specific on-going volume commitments. There is no assurance that shippers will continue to utilize these systems in the future or transport volumes on similar terms or at similar tolls. However, there is limited pipeline competition in this area. The main competition to the pipelines is from trucking.



Sponsored Investments Earnings

(millions of Canadian dollars)

Sponsored Investments includes the Company's 10.9% ownership interest in Enbridge Energy Partners and a 41.9% equity interest in Enbridge Income Fund. In 2005, Sponsored Investment earnings were down slightly from 2004 as increased EIF earnings were more than offset by EEP's non-cash unrealized mark-to-market losses on derivative investments.



Enbridge Income Fund

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

Earnings

(millions of Canadian dollars)

	2005	2004	2003
Enbridge Gas Distribution ¹	111.9	133.1	103.0
Noverco ¹	28.3	32.3	24.2
CustomerWorks/ECS	23.2	20.5	16.9
Other Gas Distribution ¹	6.7	8.5	6.8
Enbridge Gas New Brunswick	6.1	3.7	4.4
Gas Services	0.2	(2.8)	(5.9)
Aux Sable	5.3	7.3	(6.9)
AltaGas Income Trust (AltaGas)	—	21.1	12.3
Gain on sale of investment in AltaGas	—	97.8	—
Impairment loss on Calmar gas plant	—	(8.2)	—
Other	(2.9)	(0.2)	(1.2)
	178.8	313.1	153.6

¹ The year ended December 31, 2004 includes earnings for the 15 months ended December 31, 2004. The year ended December 31, 2003 includes earnings for the year ended September 30, 2003.

Business Activities

The largest portion of Gas Distribution and Services is the gas distribution operations of Enbridge Gas Distribution. This segment also includes Noverco, CustomerWorks, the gas services business, which manages the Company's merchant capacity commitments on Alliance and Vector, and the Company's investment in Aux Sable.

Enbridge Gas Distribution

EGD is Canada's largest natural gas distribution company and has been in operation for more than 150 years. It serves over 1.75 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).

Gas Distribution Rates

In November 2004, EGD received approval from the OEB for its 2005 rates, under a cost of service model. The key elements are summarized below:

Regulatory year	Requested 2006	Approved 2005	Approved 2003
Rate base <i>(millions of Canadian dollars)</i>	\$3,596.2	\$3,422.1	\$3,155.8
Deemed common equity for regulatory purposes	35.00%	35.00%	35.00%
Rate of return on common equity	10.11%	9.57%	9.69%

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 10.11% requested for 2006 was a preliminary calculation based on the forecast yield for long bonds used in the formula at the time the 2006 rate application was made. Subsequent movements in the forecast yield for long bonds have resulted in an updated rate of return on common equity of 8.74% becoming applicable for 2006.

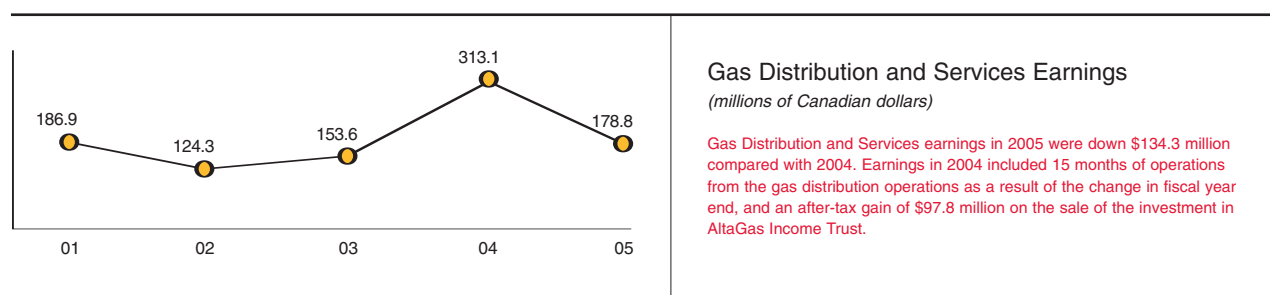
EGD's 2005 and 2003 rates were established pursuant to a cost-of-service methodology that allowed revenues to be set to recover EGD's forecast costs. For 2004, rates were set by increasing 2003 rates by 90 percent of the forecast Ontario consumer price index, resulting in an increase of 1.8 percent. 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 were shared on a 50/50 basis between ratepayers and the Company's shareholders. The 2004 financial results for the fifteen months ended December 31, 2004, include a reduction of \$8.7 million after tax for the earnings sharing with customers.

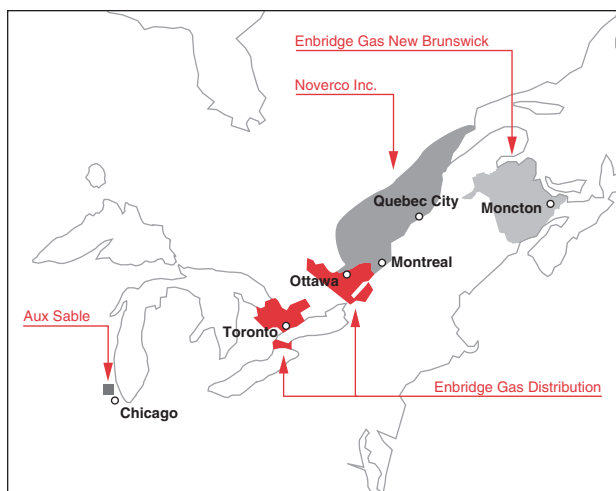
Forecast costs included gas commodity and transportation, operation and maintenance, depreciation, income taxes, and the debt and equity costs of financing the rate base. The rate base is EGD's investment in all assets used in gas distribution, storage and transmission, as well as an allowance for working capital. Under the cost-of-service model, it is EGD's responsibility to demonstrate to the OEB the prudence of the forecast costs. EGD does not earn a profit on the price of natural gas.

The rate base is financed by EGD 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.

Earnings from EGD are impacted to the extent that volumes sold differ from forecasted volumes. There are four key factors that affect the probability that EGD will distribute the forecast volumes. These are 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, earnings will be less than the total revenue requirements established in the ratemaking process due to lower distribution volumes.

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.





Gas Distribution and Services

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.

2006 Rate Application

On March 18, 2005, EGD filed an application with the OEB for approval of the 2006 rates, under a cost-of-service model. A final decision on this rate application is expected from the OEB during the first quarter of 2006.

In 2005, EGD added approximately 50,700 customers (15 months ended December 31, 2004 – 74,500; 12 months ended October 31, 2003 – 54,800). The increased number of customers is due primarily to the strong housing market in EGD’s franchise area driven

by low interest rates, urbanization and immigration patterns. EGD expects to continue to add 45,000 to 55,000 customers per year in the foreseeable future due to continued growth in the greater Toronto area. This level of customer growth would lead to continued growth of EGD’s rate base. EGD serves approximately 95% of the residential homes in its franchise area and, as the price of natural gas continues to be favourable relative to competing energy sources, expects to continue this level of market penetration.

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 (a gas distribution company in British Columbia). ECS owns the customer information services system that CustomerWorks uses under license to provide services to EGD.

Noverco

Enbridge owns an equity interest in Noverco through ownership of 32% of the common shares and a cost investment through ownership of preferred shares. Noverco is a holding company that owns approximately 75% 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.

Noverco also has an investment in the common shares of Enbridge resulting in dividend and earnings 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.

Enbridge Gas New Brunswick

The Company owns 64% 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 4,858 customers. Approximately 470 kilometres (294 miles) of distribution main has been installed with the capability of attaching approximately 20,000 customers. EGNB is regulated by the New Brunswick Board of Commissioners of Public Utilities.

Aux Sable

Enbridge owns 42.7% of Aux Sable, a NGL extraction and fractionation business. Aux Sable owns and operates a plant, attached to 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. The NGL, which include ethane, propane, normal butane, iso-butane and natural gasoline, are resold. Aux Sable's ability to generate earnings is dependent on the difference between the prices of the NGL and natural gas, which Aux Sable must buy to replace the NGL it extracts from the Alliance System. Starting in 2004, heat content requirements were reduced providing increased operating flexibility, largely enabling Aux Sable to operate only when it is economic.

Aux Sable has entered into a binding memorandum of agreement with BP Products North America Inc. to sell all of its NGL production to BP at its facilities near Chicago. In return, BP will pay Aux Sable a fixed annual fee and a share of any net margin generated from the business in excess of specified thresholds. In addition, BP will compensate Aux Sable for all operating, maintenance and capital costs associated with the Aux Sable facilities subject to certain limits on capital costs. BP will supply, at its cost, all make-up gas and fuel supply gas to the Aux Sable facilities and will assume responsibility for the capacity on the Alliance Pipeline held by an Aux Sable affiliate, at market rates. The agreement will be for an initial term of 20 years, commencing December 31, 2005, 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.

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.

Tidal Energy

Tidal Energy (Tidal) provides crude oil marketing services for the Company and its customers in a full range of crude oil types including light sweet, light and medium sour and several heavy grades and natural gas liquids. 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 at low margins. Tidal does not trade on a speculative basis and its business is tightly monitored by, and must comply with, the Company's formal risk management policies. Earnings from Tidal are included in Other.

Results of Operations

Earnings are \$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 include 15 months of operations from the gas distribution operations as a result of the change in EGD's fiscal year end. Also included in the earnings of 2004 is the after-tax gain of \$97.8 million on the sale of the investment in AltaGas Income Trust.

Reported earnings for the year ended December 31, 2003, included EGD's results for the twelve months ended September 30, 2003.

Enbridge Gas Distribution

(millions of Canadian dollars)

	2005	2004	2003
Enbridge Gas Distribution – as reported	111.9	133.1	103.0
Significant non-operating factors and variances:			
Calendar year basis adjustment	–	(11.5)	0.8
Regulatory disallowances	–	–	35.2
Colder than normal weather	–	(21.3)	(33.9)
Unbilled revenue	–	–	(33.6)
Tax rate adjustments	–	–	51.4
	111.9	100.3	122.9

As noted above, earnings for the year ended December 31, 2004, included 15 months of earnings for Enbridge Gas Distribution, as a result of the elimination of the quarter lag basis of consolidation. Earnings for the first quarter, ended December 31, 2003, have been eliminated to adjust 2004 earnings to a calendar basis, making it comparable to 2005. The remaining EGD variance, after considering the items listed above, is the result of a higher rate base and a number of smaller positive variances across the utility.

Earnings for 2003 have also been adjusted to reflect the calendar basis, making them comparable with 2005. The 2003 regulatory disallowances related to gas costs for a long-term transportation contract, an outsourcing disallowance, as well as a \$26.0 million write-down of a regulatory receivable. Unbilled revenue is the difference between amounts charged to customers based on estimated gas consumption and the actual volumes delivered in the reporting period. Starting October 1, 2003, EGD refined its process and began recording unbilled revenue on a quarterly basis using a current estimate of actual volumes delivered. In 2003, the unbilled revenue accrual was based on amounts approved by the OEB for the September 30 year-end. When the 2003 results are adjusted to reflect a calendar year, the quarter added, October 1 to December 31, 2003, has unbilled revenue recorded at the full December 31 amount. The quarter removed, October 1 to December 31, 2002, does not include the full impact of unbilled revenue because EGD was still using its previous estimation process during that period. Therefore, it is necessary to remove the effects of unbilled revenue, recorded in the quarter ended December 31, 2003, from the calendar adjustment to make 2003 comparable with 2004 and 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.

Noverco

(millions of Canadian dollars)

	2005	2004	2003
Noverco – as reported	28.3	32.3	24.2
Significant non-operating factors and variances:			
Calendar year basis adjustment	–	(13.6)	3.4
Dilution gains in Noverco on Gaz Metro issuances	(7.3)	–	(7.1)
Tax rate adjustments	–	–	0.7
	21.0	18.7	21.2

Noverco earnings are \$2.3 million higher for the year ended December 31, 2005 compared with the year ended December 31, 2004, after considering the items listed above. The increase reflects a future income tax recovery related to the receipt of cash dividends net of an adjustment for reciprocal dividends. During the year, the Company received a \$70 million cash dividend from Noverco and recorded a \$50 million adjustment for reciprocal dividends paid to Noverco.

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%.

Other Gas Distribution Operations

<i>(millions of Canadian dollars)</i>	2005	2004	2003
Other Gas Distribution Operations – as reported	6.7	8.5	6.8
Significant non-operating factors and variances:			
Calendar year basis adjustment	–	(2.1)	(0.4)
	6.7	6.4	6.4

Earnings from Other Gas Distribution Operations, after the calendar basis adjustment, are consistent for the three year period.

Enbridge Gas New Brunswick

Enbridge Gas New Brunswick earnings are \$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, resulting in a higher equity base.

Gas Services

Gas Services recorded earnings of \$0.2 million for the year ended December 31, 2005, an improvement of \$3.0 million from 2004. The Gas Services business includes several natural gas related businesses, including U.S. Oil acquired in January 2005.

Gas Services experienced a loss of \$2.8 million for the year ended December 31, 2004, compared with a loss of \$5.9 million in 2003. The improvement from 2003 reflected a continuing increase in the demand for natural gas and associated transmission services, reducing merchant capacity losses on the Alliance System and Vector Pipeline.

Aux Sable

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

The positive earnings from Aux Sable in 2004 compared with 2003 were the result of positive fractionation margins. Enbridge's ownership interest in Aux Sable was also higher in 2004, as an additional 11.8% was acquired in April 2003 resulting in the current ownership of 42.7%. As the acquisition of the additional interest was at a discount to the book value, depreciation expense is lower on that additional interest.

AltaGas

The Company sold its investment in AltaGas in the third quarter of 2004. The earnings contribution from AltaGas in 2004 reflected a number of factors including an \$8.0 million after-tax dilution gain.

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

Strategy

While EGD will continue to be under the cost-of-service model in 2006, EGD will continue to file through the cost-of-service process to ensure a just and reasonable base is in place for a 2008 incentive regulation plan. Enbridge will continue to explore new business opportunities that are complementary to the distribution business, including energy and fuel cell investments. Enbridge will pursue an industry facilitation strategy to make it easier for customers to find, install and finance natural gas appliances. Enbridge is committed to enhancing customer satisfaction by aligning service standards with customer commitment and to ensuring customers have access to a secure gas supply by pursuing new sources of natural gas and storage opportunities.

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,
- pursuing marketing and storage opportunities that optimize existing assets,
- exploring gas-fired generation opportunities that are underpinned by long-term contracts and improve the utilization of existing assets, and
- increasing the scale of the wind power business in locations near existing Enbridge infrastructure.

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 has reversed an earlier decision opposing the project and are now fully supportive. Options for the required land have been secured and environmental filings were filed with federal and Quebec authorities in January 2006. The partners are in the process of developing definitive supply and market agreements. The project is expected to cost approximately \$840 million in total.

Goreway Power Project

The Company, in partnership with Sithe Global Power, L.L.C., has been selected by the Ontario Power Authority (OPA) to enter into negotiations to develop a 880-megawatt gas-fired power generation plant in Brampton, Ontario. The new plant would provide needed electricity to the Western Greater Toronto Area. Enbridge would hold a 25% interest in the project, which would provide the Company with an entry point into the gas-fired power generation business in a geographical area already served by the Company's largest gas distribution business, EGD.

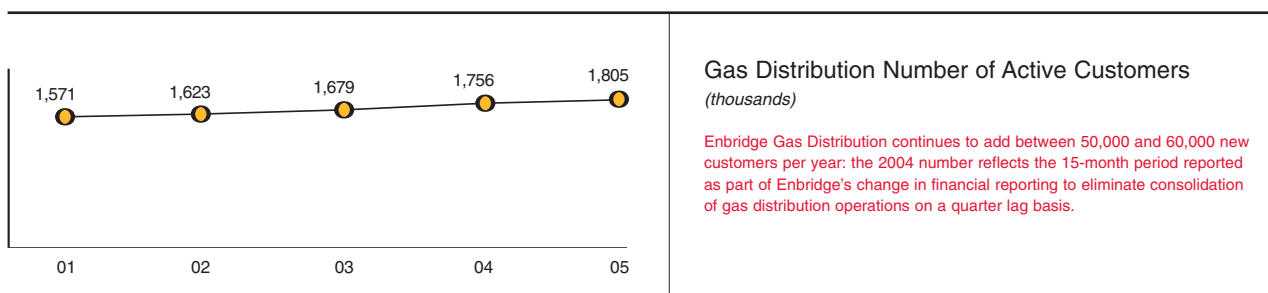
Ontario Wind Project

Enbridge will be developing 200 megawatts of wind power on the eastern shore of Lake Huron in Ontario. Construction will commence in mid-2006 and total capital expenditures are expected to be approximately \$400 million. Enbridge has entered into a 20-year electricity purchase agreement with the OPA for all of the power produced by the project. Enbridge currently has ownership in three wind power projects, which generate over 70 megawatts, in total.

Capital Expenditures

In order to support continuing customer growth, expansion of EGD's network on an ongoing basis is required. In addition, as part of its 2006 rate application, EGD has requested the OEB's approval for an accelerated program to replace the remaining cast iron mains with polyethylene mains. If the OEB approves the request for the accelerated cast iron main replacement program along with certain other requested capital expenditures, total capital expenditures during 2006 will be approximately \$460 million, as compared to the annual capital expenditures in recent years of between \$250 million to \$300 million a year.

Capital expenditures in other Gas Distribution and Services businesses, including the Ontario Wind Project, described above, are expected to be approximately \$240 million in 2006.



Enbridge Gas Distribution Legal Proceedings

Class Action Lawsuit – late payment penalties

On April 22, 2004, the Supreme Court of Canada released its decision in a case commenced against EGD by a customer with respect to late payment penalties. The Supreme Court of Canada determined that EGD would be required to repay a portion of amounts paid to it as late payment penalties from April 1994. The total amount of late payment penalties billed between April 1994 and February 2002 (when EGD's late payment penalty was revised), was approximately \$74 million, of which a portion may be eligible for repayment. The amount payable is not determinable at this time. The Supreme Court has directed that a lower court determine the amount payable. Case conferences were held before a judge of the Ontario Supreme Court in August and December 2004 and March 2005 to discuss the remaining outstanding issues following the Supreme Court's decision. Further court proceedings to determine the amount payable and other related issues are likely to be held in early 2006.

Late payment penalty revenues are included in EGD's estimate of revenues for the year and therefore accrue to the benefit of all customers, reducing the cost of providing distribution services. The OEB approves these estimates and the resulting rates each year. EGD intends to apply to the OEB for recovery of any amount payable that results from this action.

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. EGD does not expect the outcome of these civil actions to result in any material financial impact.

Business Risks

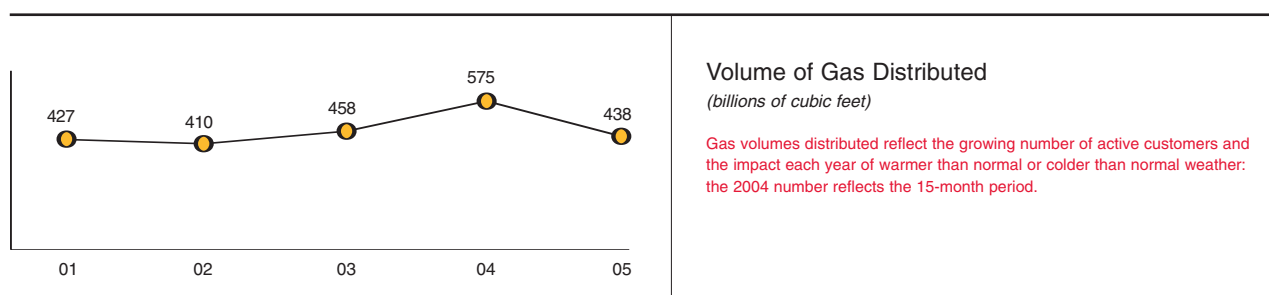
The risks identified below are specific to the Gas Distribution and Services business. General risks that affect the Company as a whole are described under Risk Management.

Enbridge Gas Distribution

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, accuracy in forecasting, and then 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 upon achieving the forecast distribution volume established in the annual ratemaking process. The probability of realizing such volume is contingent upon four key forecast variables: weather; economic conditions; the price of gas and the pricing of 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 78% (2004 – 77%) of total distribution volume. Weather during the year, measured in degree days, has a significant impact on distribution volume as a major portion of the gas distributed to these two markets is used ultimately for space heating. In 2005, degree days closely approximated those forecast, resulting in no weather related volume variance.

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 1.0% per annum over the last 10 years, reflecting consistent customer conservation efforts.

Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volumes distributed to these sectors as some customers have the ability to switch to an alternate fuel. Customer additions are important to all market sectors as continued expansion adds to the total consumption of natural gas.

Even in those circumstances where EGD attains its total forecast distribution volume, it may not earn the approved return on equity due to other forecast variables such as, mix of sales and transportation of gas for customers, the mix between the higher margin residential and commercial sectors, and lower margin industrial sector.

Rate Relief

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.

EGD does not profit from the price of the natural gas commodity nor is it at risk for the difference between the actual cost of gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to ratepayers until the OEB approves its disposition.

Forecasting Accuracy

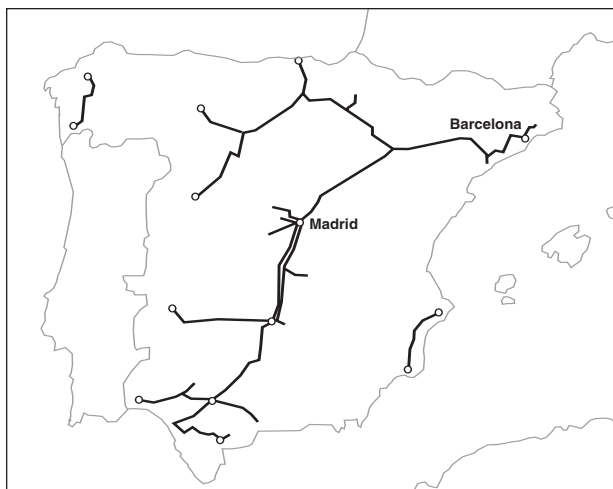
Forecasting accuracy is a risk since rates are established in advance, based on anticipated distribution volume by class of customer. Forecasts are also made for the future cost of capital including the forecast yield rate for long-term Government of Canada Bonds used in the determination of the return 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 approved for that fiscal year based on the anticipated distribution volume.

Franchise Rights

To date, the OEB has upheld the Company's exclusive right to serve all end users within its franchise area, under its franchise agreements. Similar franchise agreements 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 is unprecedented. However, the OEB characterized this decision as transitional, and has set up a rates proceeding to assess the service requirements of gas fired generation in the province of Ontario. At the present time, the Company is unable to assess the possible future financial implications given the recentness of this decision and potential outcomes from the above rates proceeding.

Gas Services

Earnings from Gas Services are dependent upon the basis (location) differentials between Alberta and Chicago and between Chicago and Dawn. To the extent that the difference in the price of natural gas in the various locations is not greater than the cost of transportation between Alberta and Chicago or Dawn, earnings will be negatively affected.



Spain – CLH

Aux Sable

Earnings from Aux Sable were exposed to the effect of spreads between the sale prices of natural gas liquids and the purchase price of replacement natural gas. This risk was mitigated by lower heat content requirements on downstream pipelines, which commenced in 2004, and the use of commodity hedges, which opportunistically locked in positive margins when forward markets allow.

Demand for NGL is influenced by overall weather and economic activity because NGL are used to make energy products for home and industrial heating and as feedstock for the petrochemical industry, among other things. Because Aux Sable's earnings are dependent, to a large degree, on commodity prices, earnings can be volatile. To reduce this volatility,

Aux Sable entered into hedge transactions to fix the spread between natural gas and NGL prices. Starting in 2006, this risk will be eliminated by Aux Sable's contract with BP.

INTERNATIONAL

Earnings

(millions of Canadian dollars)

	2005	2004	2003
CLH	61.6	48.6	46.3
OCENSA/CITCoI	32.8	33.0	32.3
Other	(7.0)	(8.0)	(6.3)
	87.4	73.6	72.3

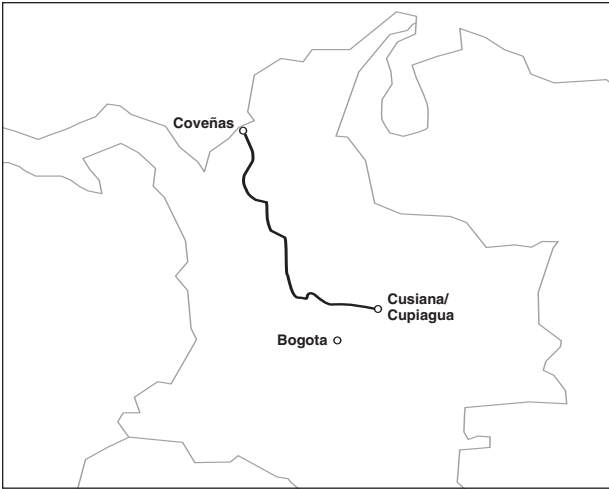
Business Activities

International includes earnings from the Company's 25% interest in Compañía Logística de Hidrocarburos (CLH), Spain's largest refined products transportation and storage business, and OCENSA, a crude oil pipeline in Colombia. Earnings also include fees earned from technology and consulting services provided by 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 non-discriminatory basis. The system consists of over 3,400 kilometres of pipelines and 39 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, 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 of Spain's crude oil and refined products are imported.



Colombia – OCENSA

Earnings from CLH are directly impacted by the demand for refined products including diesel and other fuels for transportation purposes. Economic growth in Spain over the last decade has been one of 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 plans to expand its system over the next several years in order to meet the continued growth expected in this region. This expansion, which includes 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 it and earns a fee for this service, which includes incentive earnings for operating performance.

Results of Operations

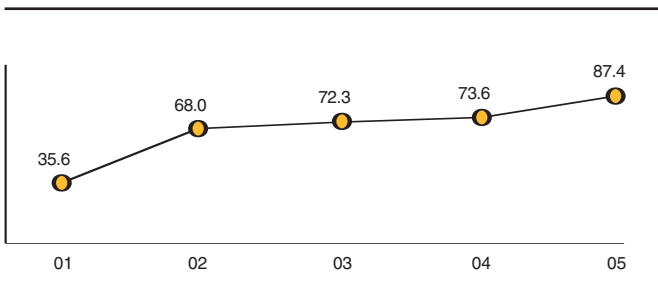
Earnings for the year ended December 31, 2005, are \$87.4 million compared with \$73.6 million for the year ended December 31, 2004. The increase results primarily from a \$7.6 million gain on the sale of land in CLH. Operating results at CLH are also improved due to higher volumes and increased average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

In 2004, increased earnings of \$1.3 million compared with 2003 were due to stronger results from CLH and from CITCol, operator of the OCENSA pipeline, which exceeded certain operational performance targets resulting in additional incentive income. Operating results from CLH reflected increased volumes in 2004 compared with 2003 due to greater demand for refined products throughout Spain, lower operating costs and the translation impact of the stronger Euro.

Other costs include other administration and business development costs.

Strategy

Enbridge plans to increase its business development activity in Europe and Latin America. In Europe, Enbridge will seek opportunities to acquire assets or develop greenfield projects that facilitate expected supply flow through eastern European countries to satisfy growing western European demand. In Colombia, where the Company has substantial expertise, Enbridge will focus on acquiring additional assets.



International Earnings

(millions of Canadian dollars)

International earnings include earnings from the Company's interests in CLH in Spain and OCENSA in Colombia. Earnings in 2005 increased primarily because of improved operating results at CLH and a \$7.6 million gain on the sale of land in CLH.

Business Risks

The International business is subject to risks related to political and economic instability, currency volatility, market and supply volatility, government regulations, foreign investment rules, security of assets and environmental considerations. The Company assesses and monitors international regions and specific countries on an ongoing basis for changes in these risks. Risks are mitigated by a combination of Enbridge's governance involvement, contractual arrangements, influence in operation of the assets, regular analysis of country risk, as well as foreign currency hedging and insurance programs.

CORPORATE

<i>(millions of Canadian dollars)</i>	2005	2004	2003
Corporate	(63.9)	(81.3)	(76.6)

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

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

The 2004 corporate costs include a higher expense for stock-based compensation, compared with 2003, and increased business development activity, partially offset with lower interest expense.

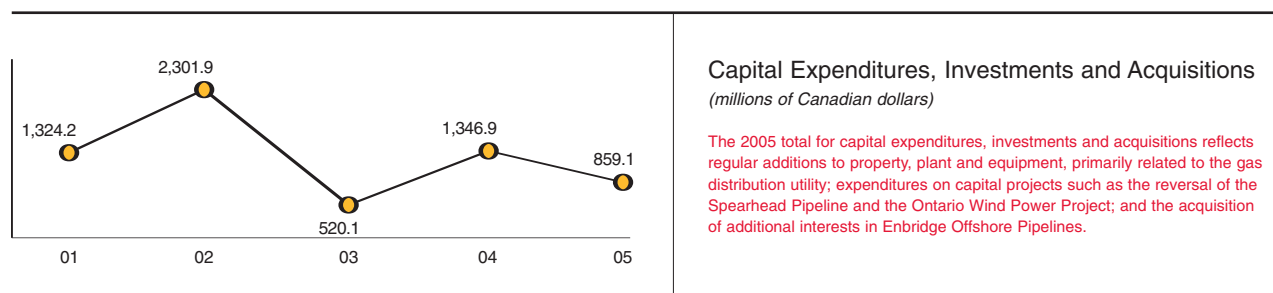
LIQUIDITY AND CAPITAL RESOURCES

The Company's cash generated from operations, commercial paper issuances, available capacity under credit facilities, which totaled \$3,454.8 million on December 31, 2005, 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.

The Company continues to manage its debt to capitalization ratio to maintain a strong balance sheet. The debt to capitalization ratio at December 31, 2005, including short-term borrowings, but excluding non-recourse short and long-term debt, was 64.5%, compared with 65.1% at the end of 2004. The improved debt to capitalization ratio reflects the Company's continuing commitment to maintaining a strong balance sheet.

The Company's current liabilities routinely exceed current assets. This deficit is funded through cash from operations, which are typically about double the balance of the deficit in a given year. For example, at the end of 2003, the working capital deficit was \$270.5 million. During 2004, operations generated \$886.7 million cash which easily funded the deficit. The Company expects this trend to continue.

The Company's cash balance at the end of the year includes \$16.4 million (2004 – \$6.0 million; 2003 – \$18.7 million) held in trust in joint ventures, pursuant to finance agreements within the joint ventures.



Operating Activities

Cash from operating activities increased to \$903.5 million for the year ended December 31, 2005, from \$886.7 million for the year ended December 31, 2004, and \$368.5 million for the year ended December 31, 2003.

<i>(millions of Canadian dollars)</i>	2005	2004	2003
Earnings net of non-cash items	1,300.9	1,027.8	938.3
Changes in operating assets and liabilities	(397.4)	(141.1)	(569.8)
Cash Provided by Operating Activities	903.5	886.7	368.5

Cash provided by earnings net of non-cash items, was \$1,300.9 million for the year ended December 31, 2005, compared with \$1,027.8 million and \$938.3 million for 2004 and 2003, respectively. This \$273.1 million increase in cash from 2004 reflects special dividends from Noverco, cash generated by Enbridge Offshore Pipelines, acquired on December 31, 2004, and increased earnings from EGD.

In 2004 cash from earnings net of non-cash items reflected increased contributions from the Enbridge System, due to the Terrace Phase III expansion placed into service on April 1, 2003, from EGD, due to increased rates in 2004, and from Aux Sable, due to improved fractionation margins in 2004 compared with 2003.

Changes in operating assets and liabilities were \$258.7 million lower in 2005 compared with 2004. The majority of this change is in EGD where higher commodity prices increased accounts receivable and inventory.

The variance in changes in operating assets and liabilities from 2003 to 2004 was due to the draw down of gas in storage in EGD from September 30, 2003, (the prior year end) to December 31, 2004, (the new year end). Gas in storage is typically lower at the end of December as winter demand has drawn down some of the supply.

Since the Company's pension plans are adequately funded, no additional funding above usual levels is anticipated for 2006.

Investing Activities

Cash used for investing activities for the year ended December 31, 2005, was \$833.0 million compared with \$999.7 million in 2004. 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, is due to increased expenditures on capital projects, such as the reversal of the Spearhead Pipeline and the Ontario Wind Power Project.

In 2005, the Company made minor acquisitions throughout the year of \$88.6 million whereas, in 2004, \$833.9 million was used for acquisitions including Enbridge Offshore Pipelines, acquired for \$743.4 million (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.

Also in 2005, the Company made contingent payments to the former owners of the Company's 25% interest in CLH because CLH met cumulative volume targets. These payments make up the majority of the 2005 expenditure on long-term investments. In 2004, the Company also made smaller contingent payments to the former owners of the 25% interest in CLH.

In 2003, investing activities provided \$259.5 million primarily as a result of the proceeds received on the sale of assets to EIF. Also, 2003 reflected the repayment by EEP of short-term loans from the Company. Additions to property, plant and equipment were primarily related to EGD.

Financing Activities

In 2005, financing activities used cash of \$22.1 million compared with a source of \$114.4 million in 2004.

During 2005, the Company issued \$1,020.1 million new long-term debt in the form of medium-term notes and senior notes. 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 uses short-term borrowings to finance working capital, which was higher at the end of 2005 due to increased commodity prices.

Dividends on common shares have increased again in 2005 due to an increased number of common shares outstanding and a higher dividend rate.

In 2004, cash was generated through a net issuance of debt of \$788.0 million, partially offset by the payment of dividends. The Company also repaid \$350.0 million of preferred securities at the end of 2004. Financing activity in 2003 included the payment of dividends and a net reduction in debt through utilization of the cash proceeds from the sale of assets to EIF.

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 \$1,130 million during 2006 on capital projects. The Company expects to finance these expenditures through cash from operating activities 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	6,662.5	400.0	788.4	950.0	4,524.1
Non-recourse long-term debt	1,563.0	66.7	155.7	244.5	1,096.1
Capital and operating leases	85.0	5.1	10.3	11.0	58.6
Long-term contracts	822.5	190.9	217.0	196.4	218.2
Total Contractual Obligations	9,133.0	662.7	1,171.4	1,401.9	5,897.0

RISK MANAGEMENT

The Company's business activities are subject to both financial and operational 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 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 to manage its exposures to within these policy limits. The following summarizes the types of 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. The return of capital on the cost accounted for investment in OCENSA also is hedged with cross currency swaps.

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 it stays within its Board of Directors approved policy limit band of 15% to 25% floating rate debt within the consolidated portfolio. 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 on anticipated fixed rate debt issuances. Also, the Company enters into interest rate derivatives to hedge a portion of the interest cost of future debt issues related to specific capital projects.

Commodity Price Risk

The Company uses natural gas price swaps, futures, options and collars to manage the value of commodity purchases and sales that arise from capacity commitments on the Alliance and Vector pipelines. The Company also uses derivative instruments to fix the value of variable price exposures that arise from commodity storage arrangements and natural gas supply agreements.

As a result of the Company's ownership interest in Aux Sable, it is exposed to the price differential between natural gas and NGL. This risk is hedged through the use of over-the-counter derivatives whereby the forward prices of natural gas and NGL are fixed with swaps, or capped or collared with options. Starting in 2006, Aux Sable's contract with BP will eliminate this risk.

The Company has also entered into over-the-counter swap agreements to convert the price of power in Alberta and Ontario from a floating rate to a fixed rate per megawatt hour (MW/H) or convert fixed rate power to floating rate.

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

Fair Values of Derivative Instruments

The following table summarizes the financial instruments outstanding at year end for the purposes of mitigating the risks as described above. Amounts shown in the table below under Fair Value Receivable/(Payable) represent unrecognized gains/(losses) associated with these instruments.

(millions of Canadian dollars unless otherwise noted)

December 31,	2005			2004		
	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity	Notional Principal or Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange						
U.S. cross currency swaps	307.3	(2.9)	2007-2022	535.8	(51.1)	2005-2022
Euro cross currency swaps	447.6	39.6	2006-2019	493.5	(51.3)	2005-2019
Forwards (cumulative exchange amounts)	1,640.1	241.6	2006-2022	1,740.3	181.0	2005-2022
Interest rates						
Interest rate swaps	954.4	(1.1)	2006-2029	1,069.0	1.5	2005-2029
Forward interest rate swaps	150.0	1.2	2007	200.0	–	2006
Energy commodities						
Natural gas (bcf)	130.5	18.1	2006-2011	107.8	(1.0)	2005-2010
Natural gas supply (bcf)	27.3	(6.7)	2006	34.9	(28.1)	2005
Power (MW/H)	28.0	0.8	2006-2017	–	–	–

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian \$91.0 million (2004 – \$214.0 million), to exchange Canadian for U.S. dollars. The outstanding instruments expire in 2007. These instruments are recorded at fair value and have a fair value payable of \$14.3 million as at December 31, 2005 (2004 – \$28.8 million).

The fair values of derivatives have been estimated using year-end market information. These fair values approximate the amount that the Company would receive or pay to terminate the contracts.

Credit risk on derivative financial instruments amounted to \$351.8 million as at December 31, 2005 (2004 – \$211.2 million) with no significant concentration with any single counterparty.

Fair Values of Other Financial Instruments

The fair value of financial instruments, other than derivatives, represents the amounts that would have been received from or paid to counterparties, calculated at the reporting date, to settle these instruments. The carrying amount of all financial instruments classified as current approximates fair value because of the short maturities of these instruments. The estimated fair values of all other financial instruments are based on quoted market prices or, in the absence of specific market prices, on quoted market prices for similar instruments and other valuation techniques.

Total Debt

(millions of Canadian dollars)

December 31,	2005		2004	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liquids Pipelines	1,039.4	1,201.4	913.4	1,037.8
Gas Distribution and Services	1,786.7	2,184.2	1,823.4	2,168.9
Corporate	3,854.2	4,076.3	4,020.4	4,275.6
	6,680.3	7,461.9	6,757.2	7,482.3

The fair value of debt does not include the effects of hedging. Non-recourse debt of joint ventures has a carrying value of \$1,688.1 million (2004 – \$695.4 million) and fair value of \$1,775.1 million (2004 – \$769.4 million).

Operating Risks

Environmental, Health and Safety Risk

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 risks involved in operating a comprehensive pipeline system 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 keep on hand 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, 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.

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.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Rate Regulation

The Company follows generally accepted accounting principles, which may differ for regulated operations from those otherwise expected in non-regulated businesses. In general, these differences occur when the regulatory agencies render decisions that involve the timing of revenue and expense recognition and ensure that the actions of the regulatory authorities, which may create economic assets and liabilities, have been reflected in the financial statements.

The recognition of these items in the Company's financial statements depends on its expectation of the future actions of the regulatory authorities. For example, some of the Company's rate-regulated businesses do not record future income taxes because the regulatory authorities prescribe the use of the taxes payable method for rate-making purposes and there is reasonable expectation that future income taxes will be recovered as they become payable.

If regulatory agencies' future actions are different from the Company's expectations, the timing and amount of the recovery of liabilities or refund of assets, recorded or unrecorded, could be significantly different from that reflected in the financial statements.

The Company's operations are regulated under three main regulatory regimes. Enbridge System negotiates tolls with its shippers under either the ITS or for specific expansions and these agreements are approved by the NEB. EGD files a rate application with the OEB, for its approval. Alliance Pipeline US, Vector Pipeline and Enbridge Offshore Pipelines have negotiated transportation services contracts with shippers that incorporate a FERC-approved toll and tariff structure. Descriptions of each of these regulatory regimes, including how tolls and rates are set, how costs are recovered, and how returns are calculated are included in the sections describing each of these businesses.

In 2005, the Company adopted the new accounting guideline, *Disclosure by Entities Subject to Rate Regulation*. This guideline requires the disclosure of information to facilitate an understanding of the nature and economic effects of rate regulation, as well as additional information on how rate regulation has affected the entity's financial statements.

Revenue Recognition

Generally, revenues are recorded when products have been delivered or services have been performed. Certain of the Liquids Pipelines, Gas Pipelines and gas distribution operations within Gas Distribution and Services are subject to regulation and, accordingly, there are circumstances where revenues recognized do not match the cash tolls or the billed amounts. For rate-regulated operations, revenue is recognized in a manner that is consistent with the underlying rate agreements as approved by the regulatory authority.

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

The recording of revenues under the terms of approved regulatory agreements of the Enbridge System may also not necessarily match the cash tolls. The agreements, and all their terms and conditions, are subject to the review and approval by the pipeline's regulator, the NEB. During their terms, the agreements govern both current and future shippers on the pipeline. The NEB's jurisdiction over the Enbridge System includes statutory authority over matters such as construction, rates and underlying accounting practices, and ratemaking agreements and other contractual arrangements with customers.

Revenues are recognized based on these agreements' definitions of an allowed revenue requirement and are generally not impacted by the level of cash tolls collected. This basis may affect the timing of recognition of revenues from that otherwise expected under generally accepted accounting principles for companies that are not rate-regulated.

Tolls are calculated in accordance with the agreements which stipulate that tolls are to be established each year based on capacity as per the various agreements and/or the allowed revenue requirement. Where actual volumes on the pipeline fall short of 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.

A significant portion of Gas Distribution and Services operations are subject to rate-regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Certain amounts are deferred for recovery with the approval of the regulator and are not included in revenues or expenses that would be recognized in the income statement, absent the actions of the regulator. The regulator, through the rate-making process, allows certain variances between approved and actual expenses or income to be recovered from customers in future periods. The deferred amounts are not included in the calculation of rates to be billed to customers. While there are numerous deferral accounts approved by the regulator, the largest of these typically is the difference between the approved and actual cost of gas, which is not included in the cost of service used to determine rates, and therefore not included in revenues. The recovery of this difference is recognized on the statement of financial position, at the formal direction of the regulator, with no impact on revenues or expenses in the income statement. EGD has no exposure to the cost of gas, as it is a flow through cost that is borne directly by the ratepayer.

CHANGES IN ACCOUNTING POLICIES

Consolidation of Variable Interest Entities

Effective January 1, 2005, the Company adopted, without restatement of prior periods, the new CICA accounting guideline for Consolidation of Variable Interest Entities. This new standard requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. The Company is the primary beneficiary of EIF through a combination of a 41.9% equity interest as well as a preferred unit investment that has no voting rights, a stated par value and a 30-year maturity. The preferred units earn a return that is equivalent to the cash distributions per unit to the equity unit holders and are classified as a liability in EIF's financial statements.

Financial Instruments, Hedging Relationships and OCI

New accounting standards will be in effect for fiscal years beginning on or after October 1, 2006, for hedge accounting, recognition and measurement of financial instruments and disclosure of comprehensive income. The Company is currently investigating the impact of these new standards.

EITF 04-5 – Partnership Consolidation

In June 2005, the U.S. Emerging Issues Task Force (EITF) reached a consensus on EITF issue 04-5, *Determining Whether a General Partner, or the General Partners as a Group, Controls a Limited Partnership or Similar Entity When the Limited Partners Have Certain Rights* (EITF 04-5), addressing when a general partner, or general partners as a group, control and should therefore, consolidate a limited partnership. Under EITF 04-5, a sole general partner is presumed to control a limited partnership when certain conditions are met. As a result, for the first reporting period beginning after December 15, 2005, it is expected that the Company will be required to include the accounts of Enbridge Energy Partners, L.P. for U.S. GAAP purposes.

Enbridge continues to equity account for its interest in EEP under Canadian GAAP.

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, 2005, and in respect of the 2005 year end reporting period.

QUARTERLY FINANCIAL INFORMATION ¹

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

2005	First	Second	Third	Fourth	Total
Revenue	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

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

2004	First	Second	Third	Fourth	Total
Revenue	1,709.8	2,158.8	1,615.6	2,323.6	7,807.8
Earnings applicable to common shareholders	112.4	248.4	179.7	104.8	645.3
Earnings per common share	0.34	0.74	0.54	0.31	1.93
Diluted earnings per common share	0.34	0.73	0.54	0.30	1.91
Dividends per common share	0.22875	0.22875	0.22875	0.22875	0.9150

¹ Financial Highlights have been extracted from financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles.

Quarterly operating revenue fluctuates primarily due to the seasonality of the Company's gas distribution business. Prior to October 1, 2004, this business had a September 30 year end, which resulted in consolidation by the Company on a quarter lag basis. Therefore, peak revenues were recorded in the Company's second quarter, which represented Enbridge Gas Distribution's winter months. Starting in October 2004, EGD has changed to a December 31 year end and, as a result, the Company's consolidated fourth quarter results for 2004 include the results of EGD for the six months ended December 31, 2004.

Effective October 1, 2004, EGD's seasonal rates were replaced with a uniform annual rate. The impact of this change has resulted in lower earnings in the winter months (fourth and first quarters), offset by higher earnings in the summer months (second and third quarters), causing a shift in earnings between quarters but no earnings impact on a 12 consecutive month basis.

The positive effect of colder than normal weather contributed to an increase in revenues and earnings during the second quarter of 2004. Significant items that impacted 2005 and 2004 quarterly earnings are as follows:

- 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 earnings in 2004 include the additional "fifth quarter" for EGD and other gas distribution businesses that account for an increase of \$57.2 million. This was partially offset by an impairment loss of \$8.2 million on the Calmar gas plant.
- Third quarter earnings in 2004 include a \$97.8 million gain on the sale of the Company's investment in AltaGas offset by the remaining reversal of \$25.6 million related to unbilled revenue.
- Second quarter earnings in 2004 reflect the \$9.4 million partial reversal of the \$35.0 million of unbilled revenue recorded in the first quarter of 2004 and a dilution gain of \$8.0 million related to AltaGas.
- First quarter earnings in 2004 reflect a \$47.6 million charge to earnings resulting from an increase in the Ontario tax rate and corresponding revaluation of future income taxes, as well as an increase of \$35.0 million for unbilled revenue, consistent with a change in the estimation process in 2004, both within EGD.

FOURTH QUARTER 2005 HIGHLIGHTS

Fourth quarter earnings for 2005 are \$174.0 million, compared with \$104.8 million in 2004. The increase in earnings reflects a higher contribution from the gas distribution utility. Although the prior year quarter includes six months of earnings for the gas distribution utilities, the additional quarter, July 1 to September 30, 2004, is a summer loss quarter and reduced earnings in the fourth quarter of 2004. Also, in the fourth quarter of 2004, an impairment loss of \$8.2 million was recognized on the Calmar gas plant.

SUPPLEMENTARY INFORMATION

Outstanding Share Data	Number of units outstanding
Preferred Shares, Series A (non-voting equity shares)	5,000,000
Common shares – issued and outstanding (voting equity shares)	349,533,852
Total issued and outstanding stock options (6,164,141 vested)	10,994,291

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

RELATED PARTY TRANSACTIONS

Neither EEP nor EIF have employees and use the services of the Company for managing and operating their businesses. Vector Pipeline uses the services of Enbridge to operationally manage its business. Amounts for these services, which are charged at cost in accordance with service agreements are:

(millions of Canadian dollars)

Year ended December 31,	2005	2004	2003
EEP	184.7	173.0	128.9
EIF	–	9.4	4.7
Vector Pipeline	4.1	4.4	3.3
	188.8	186.8	136.9

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

(millions of Canadian dollars)

Year ended December 31,	2005	2004	2003
Alliance Pipeline Canada	40.4	50.6	40.7
Vector Pipeline	29.2	39.1	23.2
	69.6	89.7	63.9

CustomerWorks Limited Partnership, a joint venture, provides customer care services to EGD under an agreement having a five-year term starting January 2002. EGD is charged market prices for these services. CustomerWorks also rents an automated billing system from ECS, a subsidiary of the Company. Amounts charged by (to) CustomerWorks:

(millions of Canadian dollars)

Year ended December 31,	2005	2004	2003
EGD	103.6	127.0	95.5
ECS	(8.7)	(22.5)	(25.5)
	94.9	104.5	70.0

Enbridge Gas Services Inc., a subsidiary of the Company, purchases and sells gas at prevailing market prices with Enbridge Marketing (US) Inc., a subsidiary of EEP.

(millions of Canadian dollars)

Year ended December 31,	2005	2004	2003
Purchases	48.1	30.7	33.6
Sales	(4.7)	(8.8)	(1.3)
	43.4	21.9	32.3

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

(millions of Canadian dollars)

Year ended December 31,	2005	2004	2003
Alliance Pipeline Canada	9.1	8.8	8.4
Vector Pipeline	0.7	0.5	0.6
	9.8	9.3	9.0

Enbridge Gas Services (US) Inc., a subsidiary of the Company, has transportation commitments through 2015 on Alliance Pipeline US and Vector Pipeline:

(millions of Canadian dollars)

Year ended December 31,	2005	2004	2003
Alliance Pipeline US	7.1	7.6	7.8
Vector Pipeline	9.5	9.8	10.5
	16.6	17.4	18.3

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

(millions of Canadian dollars)

Year ended December 31,	2005	2004	2003
Purchases	9.7	–	–
Sales	–	(2.3)	–
	9.7	(2.3)	–

The receivable from affiliate of \$177.0 million (2004 – \$171.7 million) resulted from the sale of Enbridge Midcoast Energy to EEP. The note, denominated in U.S. dollars, bears interest at 6.6% and matures in 2007. The balance on December 31, 2005, was US\$151.9 million (2004 – US\$142.1 million). Interest income related to the affiliate receivable was \$11.7 million (US\$9.4 million), \$11.8 million (US\$9.0 million) and \$21.7 million (US\$15.5 million), in 2005, 2004 and 2003, respectively. The fair value of the receivable at December 31, 2005, is \$176.8 million.

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

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

Dated February 1, 2006

When used in this document, the words “anticipate”, “expect”, “project”, “believe”, “estimate”, “forecast” and similar expressions are intended to identify forward-looking statements, which include statements relating to pending and proposed projects. Such statements are subject to certain risks, uncertainties and assumptions pertaining to operating performance, regulatory parameters, weather and economic conditions and, in the case of pending and proposed projects, risks relating to design and construction, regulatory processes, obtaining financing and performance of other parties, including partners, contractors and suppliers.