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ENBRIDGE

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PATOKA ∘ EDMONTON ∘ BARCELONA ∘ NORMAN WELLS ∘ FORT MCMURRAY ∘ INUVIK

CALGARY ∘ REGINA ∘ BOGOTA ∘ SUPERIOR ∘ SARNIA ∘ DAWN ∘ TORONTO ∘ COVEÑAS

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MADRID ∘ OTTAWA ∘ MONTREAL ∘ BUFFALO ∘ ZAMA ∘ TOLEDO ∘ CHICAGO ∘ WOOD RIVER

CUSHING ∘ CASPER ∘ FORT ST. JOHN ∘ SALT LAKE CITY ∘ HOUSTON ∘ MONCTON ∘ HARDISTY

2004 Annual Report

ENBRIDGE*

Earnings for 2004 were **$645.3 million** compared with $667.2 million in 2003. Adjusted operating earnings for 2004 were **$508.4 million, 8% higher** than the prior year, reflecting strong performance in all of the Company's business segments.

Financial *(millions of Canadian dollars, except per share amounts)*	**2004**	2003	2002
Earnings Applicable to Common Shareholders			
Continuing Operations	**645.3**	667.2	330.0
Discontinued Operations	**–**	–	242.3
	645.3	667.2	572.3
Earnings Per Common Share *(dollars per share)*			
Continuing Operations	**3.86**	4.03	2.06
Discontinued Operations	**–**	–	1.51
	3.86	4.03	3.57
Dividends Per Common Share *(dollars per share)*	**1.83**	1.66	1.52
Common Share Dividends Paid	**315.8**	283.9	251.1
Return on Average Common Shareholders' Equity	**17.0%**	19.0%	18.7%
Debt to Debt Plus Shareholders' Equity at Year End	**65.1%**	67.9%	69.4%

Operating	**2004**	2003	2002
Liquids Pipelines [1]			
Deliveries *(thousands of barrels per day)*	**2,138**	2,189	2,088
Barrel miles *(billions)*	**757**	710	705
Average haul *(miles)*	**970**	889	925
Gas Distribution and Services [2]			
Volume of gas distributed *(billion cubic feet)*	**575**	458	410
Number of active customers *(thousands)*	**1,756**	1,679	1,623
Degree day deficiency [3] *(degrees Celsius)*			
Actual	**5,052**	4,029	3,362
Forecast based on normal weather	**4,849**	3,565	3,700

1 *Liquids Pipelines operating highlights include the statistics of the 11.2% owned Lakehead System and wholly owned liquids pipelines operations. Enbridge's interest in the Lakehead System was 11.6% as of December 31, 2004, but was reduced to 11.2% in February 2005.*

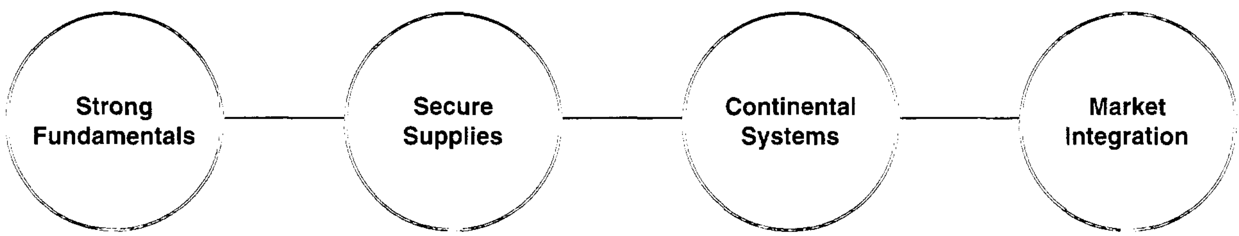
2 *In 2004, Enbridge Gas Distribution (EGD) changed its fiscal year end from September 30 to December 31 to be consistent with Enbridge. Consequently, highlights of Gas Distribution and Services for 2004 include the 15-month period ended December 31 for EGD and other gas distribution operations. Gas Distribution and Services volumes and the number of active customers are derived from the aggregate system supply and direct purchase gas supply arrangements.*

3 *Degree day deficiency is a measure of coldness. It is calculated by accumulating for each day in the period the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Toronto area.*

"As a leader in energy delivery, Enbridge Inc. is an essential link between the energy producer and the consumer – between supply and demand. Our pipeline systems safely and efficiently deliver oil and natural gas throughout North America, to heat homes, power vehicles, fuel industries and sustain the standard of living for millions of people. As energy demand continues to grow and new sources of supply are developed, Enbridge will be there to continue to provide that essential link."

Patrick D. Daniel
President & Chief Executive Officer
Enbridge Inc.

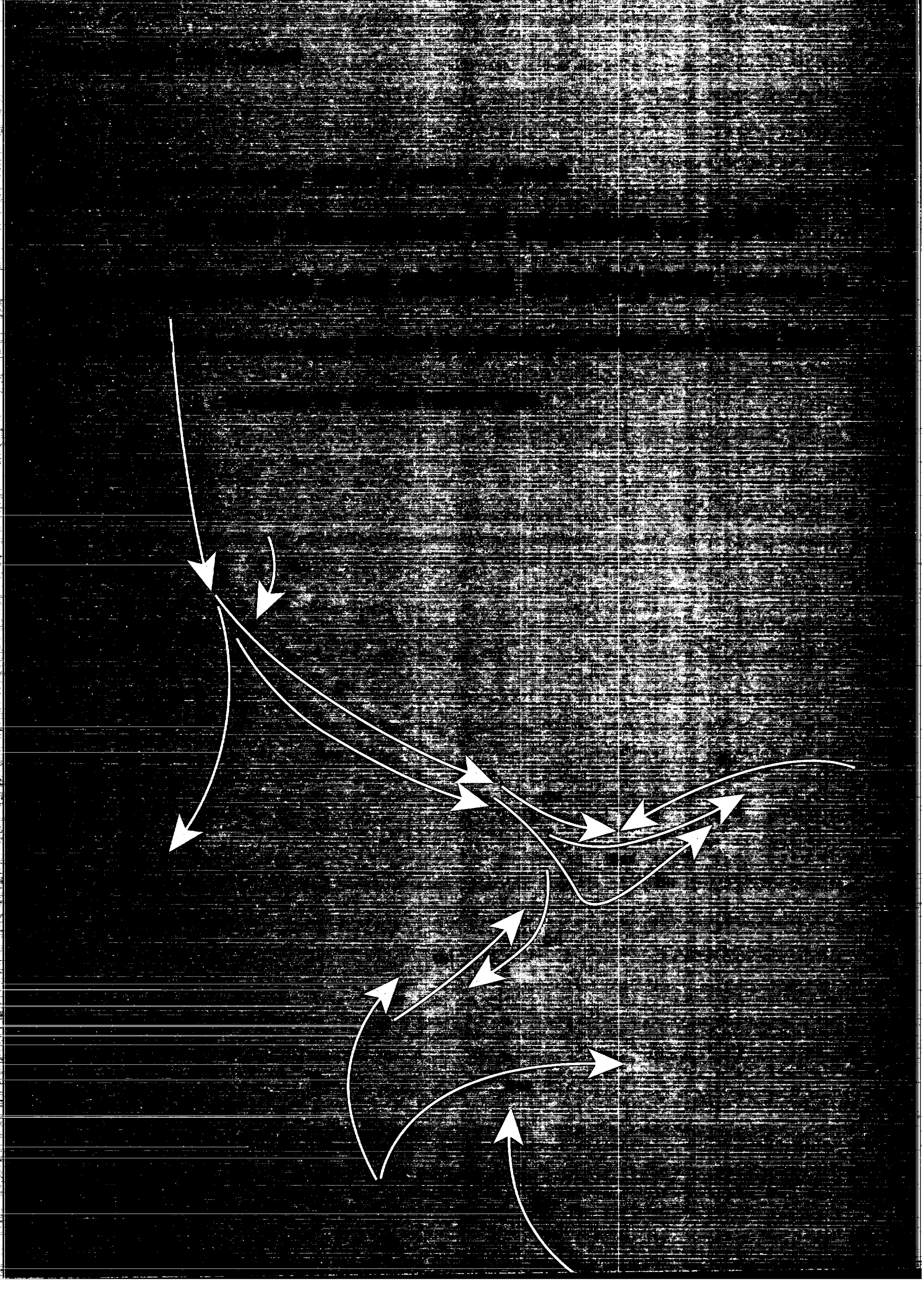
Enbridge has clearly defined strategies for growth – expand existing core asset platforms, develop new growth platforms, capitalize on our Partnership/Trust model, and continue to focus on operational excellence. These strategies, combined with the Company's excellent asset base, strong financial position and proven business model, position us well for the future.

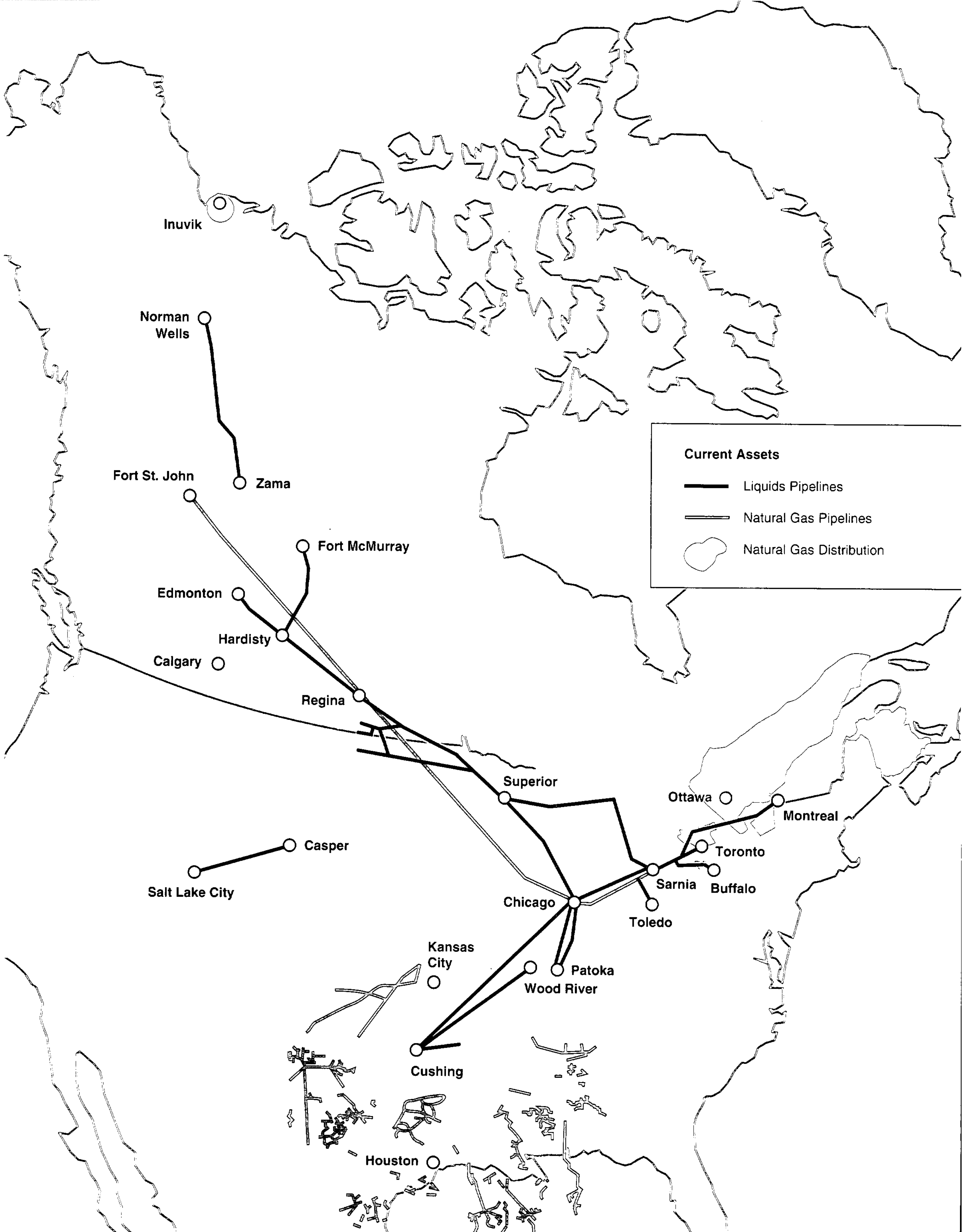


Energy supplies are rarely in close proximity to where they are needed. North America, therefore, relies heavily on its existing energy infrastructure network, and on additional infrastructure capacity being built to address growing demand and depleting supplies.

Enbridge's growth opportunities are built around North America's energy supply/demand fundamentals:

- We're ideally positioned to transport crude oil and natural gas from conventional producing areas in Western Canada and from the continent's largest hydrocarbon play – Alberta's oil sands.
- We're also well positioned to tap some of North America's energy growth hotspots: the Gulf of Mexico, emerging Texas gas plays and the North.
- With the existing integration of markets between Canada and the United States; growing energy demand, particularly in the United States; Canada's history of being a secure source of energy supply; and Enbridge's extensive continental pipeline systems, we are ideally positioned to be a major contributor to meeting continental energy needs.




Current Assets
Liquids Pipelines
Natural Gas Pipelines
Natural Gas Distribution
Inuvik
Norman Wells
Zama
Fort St. John
Fort McMurray
Edmonton
Hardisty
Calgary
Regina
Superior
Ottawa
Montreal
Toronto
Sarnia
Buffalo
Toledo
Chicago
Casper
Salt Lake City
Kansas City
Patoka
Wood River
Cushing
Houston

Donald J. Taylor
Chair

Patrick D. Daniel
President & Chief Executive Officer

Enbridge had a very successful year in 2004, not only in terms of financial and operational results, but also in terms of developing and executing our longer-term strategies.

Earnings were $645.3 million, or $3.86 per common share, including gains on the sale of assets. Removing significant non-operating factors and variances such as the gains, adjusted operating earnings were $508.4 million, 8% higher than a year ago, or $3.04 per common share.

In combination with our growing dividend, the total return to shareholders on the Toronto Stock Exchange was 15.1%, above our 51-year average of 13.1%.

During the year we made good progress in broadening the access to markets for customers of our crude oil pipelines; expanding the North American footprint of our gas pipelines business; expanding our Ontario gas distribution network; growing our sponsored investments (Enbridge Income Fund and Enbridge Energy Partners); and evaluating further opportunities for growth in our International division.

We entered 2005 with the strongest balance sheet, strongest share price and strongest geographic positioning in our history.

2004 accomplishments

We already provide the key link between the rapidly developing oil sands and major U.S. and Canadian markets. Our strategy is to broaden that market, and we made excellent progress in 2004:

- As a result of a successful open season and support from the Canadian Association of Petroleum Producers, we announced that we were proceeding with our Spearhead Pipeline project to transport crude oil from Chicago, Illinois, to Cushing, Oklahoma. We filed applications for the project before year-end.
- We signed preliminary agreements with two more oil sands projects – the sponsors of the Long Lake and Surmont projects in northern Alberta – to build and operate facilities to ship production from those two facilities beginning in 2006. The agreements also supported continued development of our Waupisoo Pipeline project that would transport oil sands production to Edmonton.

- Discussions with Canadian producers and potential customers in Asia for oil sands production were extremely encouraging, as we continued to advance our Gateway project for a crude oil pipeline from Edmonton to the West Coast. We are optimistic about obtaining the contractual agreements we need this year to enable us to file a project application by early 2006 to supply U.S. West Coast and Asian markets.

- We modified our Southern Access pipeline expansion proposal, which will be built and owned by Enbridge Energy Partners, to develop it in a phased manner. We are currently seeking industry support for phased capacity expansion south of Superior, Wisconsin, as early as 2007. Future expansions would involve new market access.

We strengthened our natural gas pipeline presence in 2004, throughout North America:

- At year-end we completed the acquisition of gas gathering and transmission systems in the Gulf of Mexico. The assets, now operated by Enbridge Offshore Pipelines, transport half of all the deepwater production from the Gulf. They provide us with participation in another growing supply basin, and significantly expand our U.S. gas pipeline presence.

- During the year, Vector Pipeline operated at capacity, as did Alliance Pipeline, and we continued to pursue an equity position in an Alaskan natural gas pipeline and an LNG project in Quebec.

Our natural gas franchise continued to grow, with Enbridge Gas Distribution once again adding approximately 60,000 new customers in 2004. We also worked with the Ontario regulator and distribution customers to achieve a number of win/win decisions that benefited all stakeholders.

We continued to capitalize on the success of our two sponsored investments:

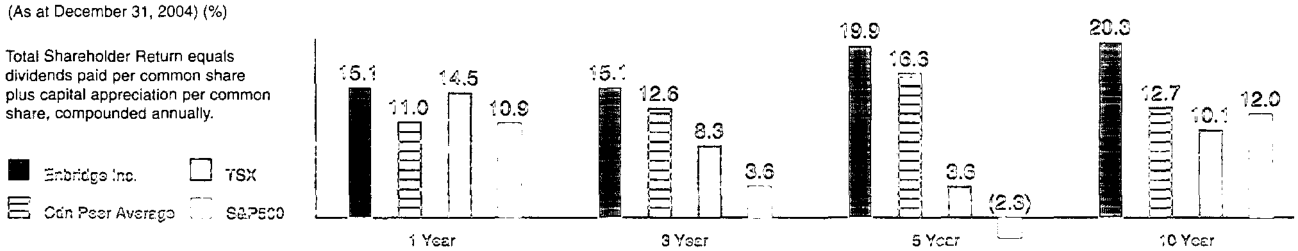
- In the U.S., Enbridge Energy Partners (EEP) had an excellent year, with a number of notable acquisitions – the Palo Duro gas pipeline system in Texas and North Texas gas assets from Devon. EEP began construction in the fall for the East Texas gas expansion pipeline, and also acquired the Mid-Continent liquids system of pipelines and storage terminals, adding a new geographic region to our pipeline system. The Cushing Terminal is currently being expanded to 12.3 million barrels of capacity and will be the largest above-ground crude oil storage facility in North America.

- In Canada, Enbridge Income Fund's increased cash flows from Alliance Canada and the Saskatchewan System led to three increases in the Fund's monthly cash distributions to unitholders. Since inception in mid-2003, cash distributions have increased 10.3%.

Our International investments continued to perform well. Liquids volumes from our CLH investment in Spain were strong, and we continued to evaluate numerous opportunities for further international investment.

Total Shareholder Return
(As at December 31, 2004) (%)

Total Shareholder Return equals dividends paid per common share plus capital appreciation per common share, compounded annually.



Our future

Enbridge is uniquely well positioned for growth. The Company is focused on moving energy from areas where we foresee growing supply to areas of growing demand. For example:

- Our crude oil system is strategically positioned between the oil sands and the U.S. Midwest and Eastern Canadian markets, and our positioning has also led to the initiative to move Canadian crude oil into the growing China and Southeast Asian markets.
- The Alliance and Vector gas pipelines are in a direct line between Alaskan gas and the best gas markets in the U.S.
- Our new U.S. Gulf Coast assets are strategically positioned to transport growing offshore supply and to access key infrastructure into the U.S. northeast.
- Our gas distribution infrastructure serves Canada's fastest growing metropolitan area.
- The investment we have made in Spain is located in one of the fastest growing economies in Europe, with growing need for refined products.
- Our interest in an LNG project in Quebec is intended to provide a new source of supply for that market.
- The investments we have made and our interest in renewable energy and wind power will position Enbridge to meet society's longer term needs for secure supplies of environmentally friendly energy.

In conclusion

Throughout 2004, Enbridge's Board of Directors continued to provide strong guidance and counsel. We thank them for that and for all of their efforts on behalf of shareholders. We would like to thank Richard (Rick) George, who became a Director in 1996 and retired from the Board last year, and to welcome Charles (Chuck) Shultz who joined the Board in 2004.

We also wish to express our deepest thanks to all Enbridge employees who have made this Company one of the world's top 100 sustainable enterprises, as announced earlier this year at the World Economic Forum in Davos, Switzerland. It's an honour all employees can be proud of, and one that all of us will strive to maintain.

On behalf of the Board of Directors,

Donald J. Taylor	**Patrick D. Daniel**
Chair of the Board of Directors	President & Chief Executive Officer
March 1, 2005	

Enbridge's success is built upon the performance of its three strong core businesses:

Liquids Pipelines systems that deliver crude oil and products to customers in Canada, the United States, Colombia and Spain;

Natural Gas Distribution systems serving customers primarily in Central and Eastern Canada;

Natural Gas Pipelines systems that gather and transport gas across Canada and in various parts of the United States.

Enbridge delivers more than **2 million barrels** of liquids per day and transports approximately **60% of the crude oil production** from Western Canada.

Enbridge has interests in **21 000 kilometres** of liquids pipelines in North America.

Enbridge's liquids pipelines business includes the world's longest crude oil and products pipeline system – Enbridge Pipelines in Canada and the Lakehead Pipeline in the United States. The mainline system has been supplying Western Canadian crude oil to Central Canada and the United States Midwest for more than 50 years – in an efficient, low-cost, safe and environmentally responsible manner. Enbridge also has interests in 4000 kilometres of liquids pipelines in Colombia and Spain.

Crude oil from the Northwest Territories, oil sands plants and conventional producing fields in Alberta is delivered to Enbridge's mainline system at points such as Hardisty, Alberta, and Edmonton, Alberta where Enbridge Pipelines employee Jim McCormick works as a Gauger at the Company's Edmonton Terminal (at right).

From points such as these, crude oil is transported to refineries in Central Canada and the Midwest where it is processed into products for consumers – products such as gasoline, heating oil, and aviation fuel. Through its liquids pipelines systems, Enbridge delivers more than 75 unique liquids products for more than 60 different shippers.

As production from the oil sands increases, Enbridge will continue to service current markets, as well as add infrastructure to provide its customers with access to additional markets in eastern and southern states, California and Asia-Pacific countries.


ENBRIDGE

Enbridge delivers natural gas to **1.7 million** customers.

In 2004, Enbridge added approximately **60,000 new customers**

and is well positioned in one of the fastest growing gas markets in North America.

Enbridge distributes approximately **450 billion cubic feet**

of natural gas per year.

Enbridge owns and operates Canada's largest natural gas distribution company, and delivers gas to customers in Ontario, Quebec, New Brunswick and part of New York State. The Company is one of the lowest cost gas distribution operators in North America, and is based in Toronto – where it has provided reliable service to customers for more than 155 years.

Enbridge is focused on being "best in class" in terms of safe and reliable operation of its distribution system. For Enbridge Gas Distribution employees such as Paul Yee (at right), a Technical Expert in the Engineering Materials Evaluation Centre Department in Toronto, ensuring safe and reliable delivery of natural gas to the Company's many residential, commercial and industrial customers is the number one priority.

The Company is also committed to helping its customers use energy wisely. More than 30 demand-side management programs encourage customers to adopt energy-saving equipment and to reduce consumption. Demand-side management programs saved approximately 2.6 billion cubic feet of natural gas in 2004, enough to supply more than 25,000 homes with natural gas for a year.

Natural gas is a clean-burning, environmentally friendly fuel, one that is in demand for electric power generation and which can be used in emerging technologies such as fuel cells. As such, Enbridge is well positioned to continue to deliver this "fuel of choice" to a growing customer base.

Enbridge has interests in more than **25 000 kilometres** of gas pipelines.

Alliance Pipeline transports approximately **9% of all Western Canada gas production.**

The recently acquired Enbridge Offshore Pipelines transports approximately **50% of all deepwater gas** production in the Gulf of Mexico.

Natural gas pipelines have become a strong core business for Enbridge in the last few years, and will continue to be a focus for growth and expansion as the Company is involved [illegible] December 2000.

Enbridge transports natural gas to a variety of North American markets, including the Enbridge Gas Distribution franchise area.

The Alliance and Vector pipelines transport gas from the Western Canadian Sedimentary Basin, and are well positioned to transport future gas volumes from the North. The Enbridge Energy Partners (EEP) pipelines draw from a variety of gas basins in the Gulf Coast and Mid-Continent regions of the United States. And Enbridge Offshore Pipelines (EOP) transports offshore gas from the Gulf of Mexico, a key region for continental supply growth.

EOP is operated, along with Enbridge Energy Partners' gas pipeline businesses, from Enbridge's facilities in Houston, Texas, by U.S. employees such as Angie Morales (at right).

As natural gas demand continues to grow in North America, Enbridge will continue to expand its existing systems, and to pursue other gas pipeline opportunities such as a pipeline from the Rockies region of the United States, and Liquefied Natural Gas regasification and pipeline infrastructure.

Consideration of social and environmental issues is becoming part of mainstream investment analysis and decision making. That's why, in 2004, Enbridge generated a Corporate Social Responsibility policy and aligned the terms of reference of its Environment, Health & Safety Committee of the Board to that of a Corporate Social Responsibility Committee.

Corporate Social Responsibility Policy

At Enbridge, we define Corporate Social Responsibility as follows:

- Conducting business in a socially responsible and ethical manner;
- Protecting the environment and the safety of people;
- Supporting human rights; and
- Engaging, learning from, respecting and supporting the communities and cultures with which we work.

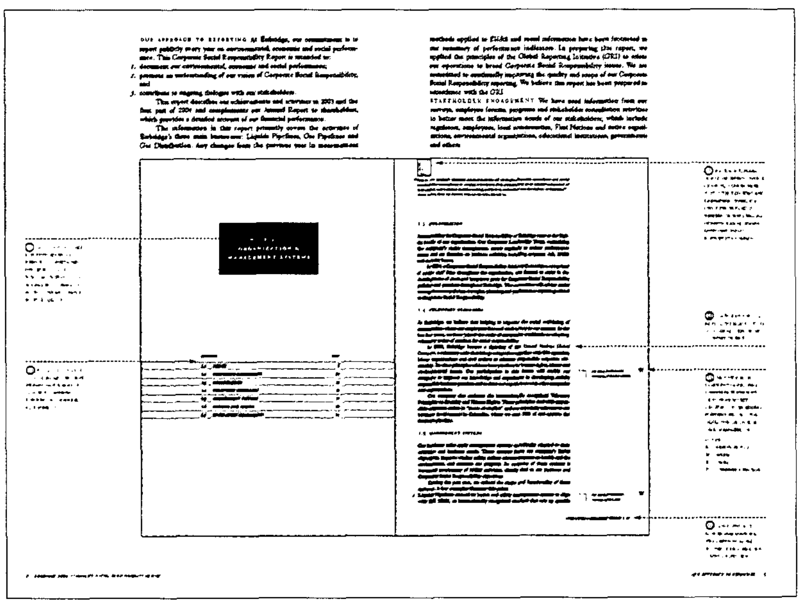
In alignment with our Statement on Business Conduct, Enbridge will ensure that all matters of Corporate Social Responsibility are considered and supported in our operations and administration and are consistent with Enbridge stakeholders' best interests. Enbridge is committed to being recognized as a leader in the field of Corporate Social Responsibility and recognizes that in doing so, we will add significant value for our shareholders.

This Policy applies to activities undertaken by or on behalf of Enbridge Inc. and its controlled subsidiaries anywhere in the world.

All Enbridge employees and contractors will adopt the Corporate Social Responsibility considerations described in this policy into their day-to-day work activities. Enbridge leaders will act as role models by incorporating those considerations into decision-making in all business activities. Enbridge's leaders will ensure that appropriate organizational structures are in place to effectively identify, monitor, and manage Corporate Social Responsibility issues and performance relevant to our businesses.

Excerpt from the Enbridge Inc. Corporate Social Responsibilty Policy

Enbridge contributed **$3.8 million** in **community investments** in Canada in 2004. The Company also produced its first **Corporate Social Responsibility annual report.**



A copy of the CSR annual report, which contains additional information about Enbridge's environment, health, safety, community investment and other CSR activities, is available in the CSR section of Enbridge's website, at ***www.enbridge.com/corporate/.***

Enbridge's first Corporate Social Responsibility (CSR) annual report was published in August 2004 in direct response to the seriousness with which we view the growing demand from stakeholders for corporations to demonstrate greater transparency, environmental and social awareness, and to maintain a more open dialogue with them.

The Enbridge CSR annual report does just that. It's a business-like document that was created in accordance with the internationally recognized standards for CSR reporting – the Global Reporting Initiative's 2002 Sustainability Reporting Guidelines. Enbridge is one of only three Canadian companies whose report is written "in accordance with" these guidelines.

Board of Directors

Standing (left to right)

Louis D. Hyndman, Edmonton, Alberta
Senior Partner, Field Law LLP

Robert W. Martin, Toronto, Ontario
Corporate Director

J. Lorne Braithwaite, Toronto, Ontario
Corporate Director

James J. Blanchard, Beverly Hills, Michigan
Senior Partner, DLA Piper Rudnick Gray Cary U.S., LLP

George K. Petty, San Luis Obispo, California
Corporate Director

Seated (left to right)

Charles E. Shultz, Calgary, Alberta
Chair & Chief Executive Officer, Dauntless Energy Inc.

E. Susan Evans, Calgary, Alberta
Corporate Director

Patrick D. Daniel, Calgary, Alberta
President & Chief Executive Officer, Enbridge Inc.

Donald J. Taylor, Jacksons Point, Ontario
Chair, Enbridge Inc.

William R. Fatt, Toronto, Ontario
Chief Executive Officer, Fairmont Hotels & Resorts Inc.

David A. Arledge, Naples, Florida
Corporate Director

The Board of Directors is responsible for the overall stewardship of Enbridge and, in discharging that responsibility, reviews, approves and provides guidance in respect of the strategic plan of the Company and monitors implementation.

The Board also oversees identification of the principal risks to the Company on an annual basis, monitors the Company's risk management programs, reviews succession planning, and seeks assurance that internal control systems and management information systems are in place and operating effectively.

The Board approves all significant decisions that affect the Company and reviews the results.

Enbridge has a strong corporate governance culture built on integrity, accountability and transparency. It extends from the Board of Directors to management and to all employees of the Company.

Senior Management

Mel F. Belich
Group Vice President,
International &
Corporate Law

J. Richard Bird
Group Vice President,
Transportation North

Patrick D. Daniel
President & Chief
Executive Officer

Bonnie D. DuPont
Group Vice President,
Corporate Resources

Stephen J.J. Letwin
Group Vice President, Gas Strategy
& Corporate Development

Dan C. Tutcher
Group Vice President,
Transportation South

Stephen J. Wuori
Group Vice President &
Chief Financial Officer

Additional information and details about Enbridge's corporate governance policies and practices are available in the Company's annual Management Information Circular, and in the corporate governance section of the Company's website, at ***www.enbridge.com/investor/corporateGovernance.***

A key part of good Corporate Governance is timely, accurate and transparent communication. Enbridge is committed to that, and to making sure that the appropriate internal controls exist to ensure compliance.

Awards and Recognition

Enbridge's financial and operating success is fully documented throughout this annual report. The Company's ability to achieve this success while adhering to its commitments to Corporate Social Responsibility and good Corporate Governance is recognized, in part, by some of the awards and other recognition received from third parties. For example:

2004

- Enbridge was rated 4th best in the Canadian Business Magazine annual listing of Canadian Boards of Directors in terms of Corporate Governance and 5th best in the Globe and Mail annual rankings.
- Enbridge won the Award of Excellence for Corporate Reporting in the Diversified Industries, Industrials and Energy sector in the Canadian Institute of Chartered Accountants' annual awards program for having the highest average scores for four aspects of communications: the annual report, corporate governance disclosure, electronic disclosure, and sustainable reporting.
- Enbridge Inc. was recognized by Corporate Knights Magazine as one of Canada's Best 50 Corporate Citizens: Enbridge was ranked 11th overall and 1st in the gas utility industry.

2005

- At the World Economic Forum at Davos, Switzerland, Enbridge was one of six Canadian companies named to the Global 100 Most Sustainable Corporations in the World listing.

A more complete list of Enbridge awards and recognition is available on the Company's website, at ***www.enbridge.com/about/awards-recognition.php.***

As a foreign private issuer in the U.S., Enbridge is subject to the Sarbanes-Oxley Act being administered the Securities and Exchange Commission. The Company is also subject to companion initiatives by the Canadian Securities Administrators in Canada.

In ensuring that compliance, Enbridge's Chief Executive Officer and Chief Financial Officer sign certificates attesting to the fair presentation of the Company's financial position. Under current rules, the CEO and CFO will also certify as to the effectiveness of internal control over financial reporting under Sarbanes-Oxley for 2005, and for 2006 under the proposed Canadian rules. Enbridge's U.S. affiliates, Enbridge Energy Partners and Enbridge Energy Management, were subject to the Sarbanes-Oxley Act internal certification for 2004 and also received the external auditor's attestation of that certification.

The Enbridge group of companies have expended significant management (24,000 internal audit hours in 2004) and financial resources ($6 million in 2004) to verify compliance, and will sustain these initiatives in future to provide investors with assurance that the Company's financial reporting is accurate and complete.

CONSOLIDATED RESULTS

Financial Highlights[1]

(millions of Canadian dollars, except per share amounts)	**2004**	2003	2002
Earnings Applicable to Common Shareholders			
Liquids Pipelines	**219.9**	213.5	189.6
Gas Pipelines	**53.8**	70.1	47.8
Sponsored Investments	**66.2**	234.3	(51.1)
Gas Distribution and Services[2]	**313.1**	153.6	124.3
International	**73.6**	72.3	68.0
Corporate	**(81.3)**	(76.6)	(48.6)
Earnings from continuing operations	**645.3**	667.2	330.0
Discontinued operations	**–**	–	242.3
	645.3	667.2	572.3
Earnings Per Share			
Earnings – Continuing operations	**3.86**	4.03	2.06
Earnings – Discontinued operations	**–**	–	1.51
	3.86	4.03	3.57
Diluted Earnings Per Share			
Earnings – Continuing operations	**3.83**	4.00	2.03
Earnings – Discontinued operations	**–**	–	1.50
	3.83	4.00	3.53
Total Assets	**14,905.1**	13,945.0	12,987.4
Total Long-Term Liabilities	**8,182.5**	8,028.2	7,972.2
Dividends Per Common Share	**1.83**	1.66	1.52
Common Share Dividends	**315.8**	283.9	251.1

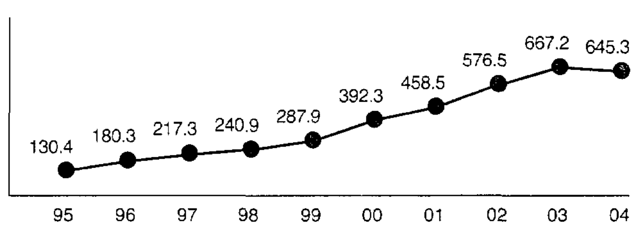
1 *Financial Highlights have been extracted from financial statements prepared in accordance with Canadian Generally Accepted Accounting Principles.*
2 *The year ended December 31, 2004 includes earnings for the 15 months ended December 31, 2004 for Enbridge Gas Distribution (EGD), Noverco and other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

Earnings applicable to common shareholders for the year ended December 31, 2004 are $645.3 million, or $3.86 per share, compared with $667.2 million, or $4.03 per share, in 2003. Significant positive operating factors affecting 2004 earnings include a full year of incremental earnings from Terrace Phase III, rate increases and positive variances from forecast costs in Enbridge Gas Distribution, and improved fractionation margins in Aux Sable. These positive factors are offset by the requirement for Enbridge Gas Distribution to share earnings in excess of a certain threshold and the sale of Alliance Pipeline (Canada) and Enbridge Saskatchewan in 2003 to Enbridge Income Fund.

Earnings for 2004 also include 15 months of earnings for gas distribution utilities, reflecting Enbridge's elimination of the quarter lag basis of consolidation for those entities, and a $97.8 million gain on the sale of the Company's investment in AltaGas Income Trust. Earnings for 2003 included a $169.1 million gain on the sale of assets to Enbridge Income Fund.

Earnings Applicable to Common Shareholders
(millions of dollars)

Earnings for 2004 include a full year of incremental earnings from Terrace Phase III, rate increases and positive variances from forecast costs in Enbridge Gas Distribution, and improved fractionation margins at Aux Sable. These positive factors are offset by the requirement of EGD to share earnings in excess of a certain threshold and the sale of assets in 2003 to Enbridge Income Fund.



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

(millions of Canadian dollars)	**2004**	2003	2002
Sponsored Investments			
Dilution gains on the issue of Enbridge Energy Partners (EEP) units	**7.6**	20.3	6.1
Gain on sale of assets to Enbridge Income Fund (EIF)	**–**	169.1	–
Writedown of Enbridge Midcoast assets	**–**	–	(82.2)
Other	**–**	–	(5.7)
	7.6	189.4	(81.8)
Gas Distribution and Services			
Gain on sale of investment in Altagas Income Trust	**97.8**	–	–
Elimination of quarter lag basis of consolidation[1]	**57.2**	–	–
Colder/(warmer) than normal weather	**23.4**	46.1	(29.3)
Impairment loss on Calmar gas plant	**(8.2)**	–	–
Regulatory disallowances	**(4.6)**	(37.7)	–
Dilution gain in Noverco (Gaz Metro unit issuance)	**1.1**	6.0	–
Dilution gain – AltaGas Income Trust	**8.0**	–	–
Revalue future income taxes due to tax rate changes	**(45.4)**	(6.1)	1.4
	129.3	8.3	(27.9)
Corporate			
Revalue future income taxes due to tax rate changes	**–**	(1.0)	–
Gain on sale of marketable securities	**–**	–	17.8
	–	(1.0)	17.8
Discontinued Operations			
Gain on sale of discontinued operations	**–**	–	240.0
Total significant non-operating factors and variances increasing earnings	**136.9**	196.7	148.1

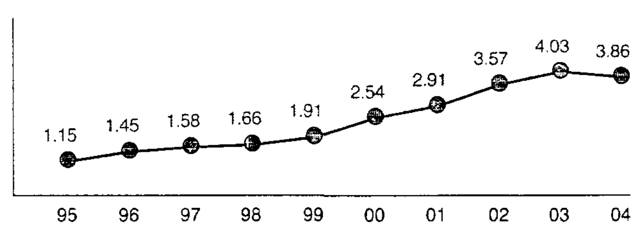
1 Effective December 31, 2004, EGD changed its fiscal year-end for financial reporting purposes from September 30 to December 31 and will be filing financial statements for the 15 months ended December 31, 2004. Consistent with that change, Enbridge will no longer be consolidating gas distribution operations on a quarter lag basis. The quarter lag basis entailed consolidating EGD results for the year ended September 30, the fiscal year-end end prior to the change, with the Enbridge results for the year ended December 31. This caused a quarter lag in the reporting of EGD's results. As an example, when the first quarter of EGD was consolidated with the first quarter of Enbridge, the EGD results were for the three months ended December 31 whereas Enbridge's results were for the three months ended March 31. To eliminate the quarter lag difference it is necessary to record the EGD results for the 15 months ended December 31, 2004 with the Enbridge results for the twelve months ended December 31, 2004. Going forward, management is of the view that this change will provide additional clarity when discussing the gas distribution operations, as the fiscal periods will be consistent.

Enbridge made several strategic acquisitions and divestments during the year.

- Acquired natural gas pipeline systems in the Gulf of Mexico (Enbridge Offshore System) from Shell for approximately $754 million, which closed December 31, 2004, including 11 transmission and gathering pipelines in five major corridors that transport about 3 bcf/d of natural gas, which is approximately half of all deepwater production in the Gulf of Mexico.
- Secured 10-year commitments from shippers on the Spearhead Pipeline (formerly the Cushing to Chicago Pipeline) for initial capacity of 60,000 barrels per day (bpd). In December 2004, Enbridge paid the final installment of US$55.0 million,

Earnings per Common Share
(dollars per share)

Earnings for 2004 also include 15 months of earnings for gas distribution utilities, reflecting Enbridge's elimination of the quarter lag basis of consolidation for those entities, plus a gain on the sale of Enbridge's investment in AltaGas Income Trust. Earnings for 2003 also included some one-time gains.



plus interest of US$4.5 million, on the purchase of a 90% interest in the pipeline. The Company will commence work to reverse the flow of the pipeline and expects it to be in service during the first quarter of 2006.

- Entered into an interim pipeline agreement for a major oil sands project. The Company has signed an interim pipeline agreement for the construction of a pipeline and related facilities required by the Surmont project. The facilities would accommodate an initial contract volume of 50,000 bpd with a planned in-service date of mid-2006.
- Entered into an interim agreement with Nexen Inc. and OPTI Canada Inc. (the Long Lake Shippers) to provide pipeline transportation services for the Long Lake oil sands project. This contract will require capacity expansion on the Athabasca System and has a planned availability for service in late 2006.
- Sold the investment in AltaGas realizing a $97.8 million gain and generating cash proceeds of $346.7 million.

EEP has actively pursued growth through a number of strategic acquisitions, including the acquisition of the Mid-Continent system on March 1, 2004. This system consists of over 480 miles of crude oil pipelines and 9.5 million barrels of storage capacity, primarily located in Cushing, Oklahoma. On January 6, 2005, EEP closed the acquisition of the North Texas Natural Gas System, which consists of approximately 2,200 miles of gas gathering pipelines and three processing plants.

Earnings for the year ended December 31, 2003 were $667.2 million, or $4.03 per share, compared with $572.3 million, or $3.57 per share, in 2002. Growth in earnings was achieved in all core business segments and was further buoyed by the positive effect of colder than normal weather in the Enbridge Gas Distribution franchise area in 2003. Significant incremental earnings were also realized in Gas Pipelines, primarily due to the Company's increased ownership interest in both Alliance Pipeline and Vector Pipeline, and in Liquids Pipelines as a result of the completion of the Terrace Phase III project and the storage cavern project in 2003.

Dividends paid on common shares increased in each of the last five years from growth in the dividend per share and a higher number of outstanding common shares. The quarterly dividend per share increased to $0.4575 in the first quarter of 2004 from $0.415 established in the first quarter of 2003. In the first quarter of 2002, the quarterly dividend was increased to $0.38 per share from $0.35 per share established in the first quarter of 2001. This represents annual increases over the last four years of 10.2%, 9.2%, 8.6% and 8.5%, respectively, and reflects the sustained growth in earnings over the period.

CORPORATE STRATEGY

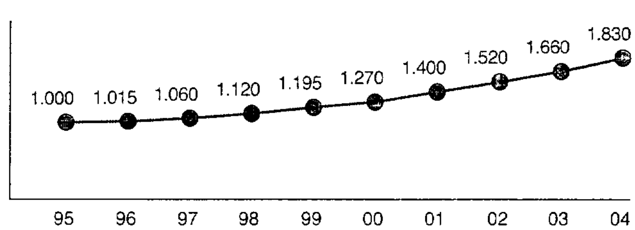
Corporate Vision and Objective

Enbridge is an energy delivery company that delivers crude oil and natural gas 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:

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

Dividends per Common Share
(dollars per share)

The annual growth in dividends per common share in recent years reflects the sustained growth in earnings over the same period, as well as the Company's continued positive outlook.



Strategy

Enbridge has four over-arching corporate strategies to achieve the overall objective of generating long-term value for investors.

1. Expand Existing Core Asset Platforms
   The Company will increase its core asset base through organic growth and asset acquisitions with a particular focus on increasing its U.S. presence. The four platforms will be expanded as follows:
   - *Liquids Pipelines* – Organic growth will come from expanding existing infrastructure and developing new markets to meet the needs of Western Canadian shippers. These opportunities include expansion of the Enbridge System and Athabasca System, as well as the potential construction of pipelines to access new markets.
   - *Gas Pipelines* – The key elements of this strategy centre on significantly increasing the Company's presence in eastern markets and the Gulf Coast area. A continued emphasis will be placed on developing Rockies natural gas. The Company will pursue a phased approach to deliver Alaskan natural gas.
   - *Gas Distribution & Services* – The Company will continue to expand the customer base and Enbridge Gas Distribution (EGD) will seek to implement an alternative rate setting mechanism.
   - *International* – International will focus on the European Union and Latin America while considering opportunistic investments in other regions. Affiliations with key global energy players will be pursued to broaden investment opportunities.
2. Develop New Growth Platforms
   Enbridge will develop several new growth platforms that could include:
   - liquefied natural gas (LNG) regasification;
   - a larger and broader crude oil marketing and storage business;
   - gas-fired power generation projects in Eastern Canada that complement existing gas distribution franchises;
   - wind power projects in Manitoba, Ontario and Quebec; and
   - new technologies including support for a regional bitumen upgrader and development of stationary fuel cells.
3. Capitalize on the Partnership/Trust Model
   Enbridge will utilize EIF and EEP to consolidate mature energy infrastructure assets in North America. EIF intends to maximize the efficiency, and pursue expansions of its existing assets and undertake acquisitions to increase the scale of its operations. EEP will continue to acquire assets that diversify current sources of revenue and will seek to maximize the contribution of its existing assets by acquiring complementary systems.
4. Focus on Operational Excellence
   Enbridge will continue its focus on operational excellence, to reinforce its position as a leader in asset management. This will include cost efficiency, safety and reliability, 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".

Core Businesses

The Company's activities are carried out through five businesses:

- Liquids Pipelines, which owns and operates the Canadian portion of the world's longest crude oil pipeline system and also includes other common carrier and feeder liquids pipelines including the Athabasca System;
- Gas Pipelines, which includes the Company's interests in the Alliance and Vector gas transmission pipelines as well as the recently acquired Enbridge Gulf Offshore System;
- Sponsored Investments, which includes the investments in Enbridge Income Fund (EIF) and Enbridge Energy Partners, L.P. (EEP), both operated 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 and gas service businesses; and
- International, which includes the Company's energy-related investments outside of Canada and the United States.

LIQUIDS PIPELINES

Earnings

(millions of Canadian dollars)	**2004**	2003	2002
Enbridge System	**171.6**	162.0	123.7
Athabasca System	**42.8**	44.8	41.2
NW System	**7.8**	8.3	9.5
Saskatchewan System	**–**	3.1	6.4
Feeder Pipelines and Other	**(2.3)**	(4.7)	8.8
	219.9	213.5	189.6

Business Activities

Liquids Pipelines consists of the Company's pipelines that transport crude oil, natural gas liquids and refined products.

The mainline system, 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), is the world's longest crude oil pipeline system and is the primary transporter of crude oil from Western Canada to the United States. It is the only pipeline that transports crude oil from Western to Eastern Canada and serves all of the major refining centers in the Province of Ontario, as well as the Midwest region of the United States.

Enbridge also owns the Athabasca System, a 545-kilometre (339-mile) pipeline that transports synthetic and heavy oil from north of Fort McMurray, in Northern Alberta, to the pipeline hub at Hardisty, Alberta. It is the only liquids pipeline directly linking both the Athabasca and Cold Lake oil sands deposits with the 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.

Enbridge's NW System is an 864-kilometre (540-mile) pipeline that transports crude oil from Norman Wells, in the Northwest Territories to Zama, Alberta. 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.

In October and November 2004, the Company conducted an Open Season for the Spearhead Pipeline, which is currently primarily idle, acquired in 2003, resulting in 10-year shipping commitments for an initial 60,000 bpd, increasing to 75,000 bpd by 2009. Enbridge expects to have the line in service in the first quarter of 2006. In December 2004, Enbridge made a final payment of $67.5 million (US$55.0 million) plus accrued interest on its 90% interest in the pipeline. The final payment was originally US$65 million, however the Company negotiated a US$10 million reduction in the price. This reduction reflects lower than anticipated shipper support for the project, which has delayed the reversal. The Spearhead Pipeline project is currently estimated to result in a total investment of $230 million, of which, approximately $150 million has been spent.

Results of Operations

Liquids Pipelines earnings are $219.9 million in 2004 compared with $213.5 million in 2003. The increase is primarily the result of higher Enbridge System earnings, which include incremental earnings from the Terrace Phase III expansion placed into service on April 1, 2003, and the earnings contribution from the Hardisty storage caverns completed in the fourth quarter of 2003. These increases are partially offset by higher tax expense in Athabasca due to the utilization of loss carryforwards in 2003 and the sale of the Saskatchewan System to Enbridge Income Fund (EIF) effective June 30, 2003. The Company continues to have an interest in this pipeline through its 41.9% ownership of EIF, included in Sponsored Investments.

Earnings from Liquids Pipelines were $213.5 million for the year ended December 31, 2003, an increase of $23.9 million from 2002. The results reflected higher earnings from the Enbridge and Athabasca Systems, which included incremental earnings from Terrace Phase III, partially offset by a provision for costs associated with toll complaints on the Frontier pipeline. In addition, the Saskatchewan System was sold to Enbridge Income Fund effective June 30, 2003.

Enbridge System

Enbridge System earnings are higher in 2004 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 2003, Enbridge System earnings were higher than 2002 primarily due to full year earnings from the Terrace Phase II expansion, incremental earnings from Terrace Phase III, lower depreciation rates as approved by the National Energy Board (NEB) as well as recognized power cost savings. Also contributing to the year-over-year variance was the negative effect of an adjustment to the power allowance credit due to shippers in 2002 as a result of Terrace operating at less than capacity.

Enbridge System's incentive tolling agreement expired on December 31, 2004. Negotiations on a new incentive tolling agreement are currently underway. In the interim, tolls in effect on December 31, 2004 are continuing to be charged on an interim basis.

Athabasca System

The Athabasca System 2004 earnings include the contribution from the Hardisty storage caverns completed in the fourth quarter of 2003. This is more than offset by higher tax expense as the prior year included the utilization of loss carryforwards.

In 2003, earnings on the Athabasca System were higher than 2002, primarily due to a full year of earnings from the addition of the MacKay River lateral lines in late 2002. This was further enhanced by the development and commencement of operations, in November 2003, of the Hardisty storage cavern facilities.

The Company has a long-term (30 year) take or pay contract with the major shipper on the Athabasca System. Earnings are 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 permit a specified 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 Enbridge for the debt and equity returns, as well as the cost of providing service. Therefore, Enbridge is recording a receivable in these years. This ensures that the revenue recognized each period is in accordance with the specified return. This receivable is contractually guaranteed by the shipper and will be collected in the later years of the contract.

NW System

Earnings in the last three years from the NW System have been consistent and reflect the effect of a declining rate base. The declining rate base was offset by cost savings that generated incentive earnings in 2002. There was no incentive component in 2003 as this was a rebasing year. Earnings are based on an agreement with the primary shipper and are a product of a deemed common equity ratio of 55% and the NEB multi-pipeline rate of return on common equity, plus any incentive cost savings.

Saskatchewan System

This asset was sold to EIF effective June 30, 2003 and is subsequently reflected in the results of EIF, a component of the Sponsored Investments segment.

Feeder Pipelines and Other

The earnings variance in Feeder Pipelines and Other is the result of Federal Energy Regulatory Commission mandated reparations on the Frontier Pipeline.

The earnings decrease in Feeder Pipelines and Other from 2002 to 2003 primarily reflected a provision for costs associated with toll complaints on the Frontier Pipeline. Business development costs were also higher in 2003 due to the continuing review of a number of liquids pipelines opportunities.

Strategy

The Company's strategy for the Liquids Pipelines segment is based on the Company's forecast of supply and demand for crude oil.

Supply and Reserves

Supply of crude oil from the Western Canadian Sedimentary Basin (WCSB) has grown consistently since 1999 particularly in the last two years where production has grown by 170,000 bpd.[1] At the same time, production from Canada's conventional resources declined by 66,000 bpd. Development of Canada's world scale oil sands resource has more than replaced the declining conventional production, growing by 235,000 bpd over the last two years. The NEB estimates 2004 production from the WCSB to exceed 2.2 million bpd. This places the WCSB on a comparable level with production from OPEC members Kuwait and Nigeria.

Remaining established conventional oil reserves in Western Canada were estimated to be 4.7 billion barrels at the end of 2003. Remaining established reserves from oil sands currently stand at 174 billion barrels. Combined conventional and oil sands reserves of 178.7 billion barrels puts Canada second only to Saudi Arabia with 14% of the worldwide estimated proved reserves.[2]

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. Western Canada demand is served by local supply and has increased by 36,000 bpd over the last two years. With the reversal of the Company's Line 9, competition from Atlantic Basin crude oil has decreased deliveries of Canadian crude into the Ontario/Quebec market. During 2004, an equal mix of western Canadian and Atlantic Basin crude satisfied Ontario's demand for crude with demand for WCSB crude down slightly over the last two years. Deliveries of WCSB crude into PADD II (the U.S. Midwest) have increased significantly over the last two years, growing by 80,000 bpd. At the same time, deliveries into PADD IV (the U.S. Rocky Mountains) have increased by 25,000 bpd and PADD V (the Western U.S.) deliveries have increased by 45,000 bpd.

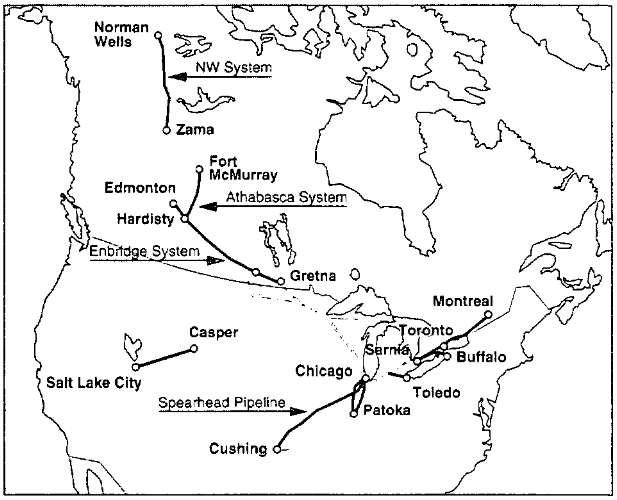
Longer Term Outlook for Supply and Demand for WCSB

The Company has recently completed its annual survey of crude production and demand for WCSB crude. Producers, refiners and provincial/state agencies are surveyed to assist the Company in assessing the future outlook for crude oil supply and demand. Responses indicate a strong supply response to the latest pricing environment. The Company applies judgmental adjustments to the survey results to reflect past experience with the implementation of oil sands projects. The resulting forecast is that by 2010, production could grow to 2.8 to 3.0 million bpd, an increase of up to 800,000 bpd from 2004, consisting of roughly equal parts of upgraded synthetic crude and raw bitumen.

Along with projected growth in supply is growth in demand for oil sands production both at existing connected refineries as well as new market demand. The survey identified a number of existing refineries interested in processing a significantly higher

1 *National Energy Board 2004 Estimate Production of Canadian Crude Oil and Equivalent Table 1*

2 *Oil and Gas Journal's Worldwide Look at Reserves and Production, December 20, 2004*



Liquids Pipelines

volume of heavy crude from Canada than currently received. At the same time, US and foreign refineries not currently receiving Canadian crude have indicated a desire to run significant quantities of oil sands production. The Company continues to develop opportunities to address the transportation needs of producers and refiners, and anticipates that sufficient pipeline capacity and new markets will be available to absorb the growth in supply.

The abundance of established reserves from oil sands will provide opportunities for expansion of Enbridge's Athabasca System and the Enbridge System. During 2004, Enbridge entered into two interim pipeline agreements with shippers for expansion of the Athabasca System and construction of new laterals and tankage facilities. While the Athabasca System, which has a current capacity of 345,000 bpd, has low cost expansion potential to a capacity ultimately of 570,000 bpd, there is insufficient expansion capacity to accommodate all of the planned oil sands developments such that new pipeline capacity is expected to be required by about 2008. Enbridge's Waupisoo Pipeline concept would address this need and would also provide producers with access to Edmonton for a portion of their output.

Enbridge has entered into an interim agreement with ConocoPhillips Surmont Partnership, Total E&P Canada Ltd. and Devon ARL Corporation (the Surmont Shippers) under which Enbridge will undertake preliminary work for the construction of a pipeline and related facilities required by the Surmont Project. Those facilities, which would accommodate an initial contract volume of 50,000 bpd of blended crude, could include one or more diluent lateral pipelines, a blended crude lateral pipeline, as well as blending and tank facilities at Enbridge's proposed Cheecham Terminal on the Athabasca Pipeline. The preliminary agreement will facilitate a planned in-service date of mid-2006.

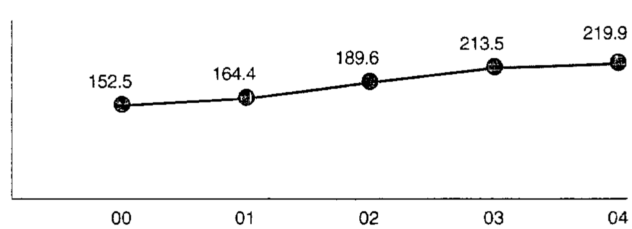
Enbridge has also entered into an interim agreement with Nexen Inc. and OPTI Canada Inc. (the Long Lake Shippers) to provide pipeline transportation services on the Athabasca System for the Long Lake oil sands project. The initial contract volume is for up to 60,000 bpd of crude oil for a 50-month term. This contract will require capacity expansion on the Athabasca System in addition to a new crude oil lateral, one or more diluent laterals, as well as blending and tankage facilities, all with a planned availability for service in late 2006.

Enbridge intends to take advantage of opportunities created by the increasing development of oil sands through securing additional shipper commitments for the Athabasca Pipeline and securing shipping commitments for, constructing, and placing into service the 390-kilometre (245-mile) Waupisoo Pipeline from Fort McMurray to Edmonton. The Waupisoo Pipeline will likely have an initial capacity of 210,000 bpd, expandable to over 300,000 bpd and will provide approximately one million bpd of capacity in total on the Athabasca and Waupisoo System.

Liquids Pipelines Earnings

(millions of dollars)

Liquids Pipelines earnings increased primarily due to higher earnings from the Enbridge System, which include incremental earnings for the Terrace Phase III expansion and the earnings contribution from the Hardisty storage caverns.



Enbridge is also planning capacity expansions on the mainline system in both Canada and the U.S., and expansion of storage facilities, to respond to expected increases in supply.

The Company also sees opportunities in enabling Western Canadian shippers to provide cost-competitive crude oil supplies to key U.S. refinery markets. The Company plans to develop new business initiatives to respond to these opportunities. Major new business initiatives include the reversal of the Spearhead Pipeline to provide access to Cushing, Oklahoma refiners from Chicago. Also under active development is the Gateway Pipeline from Edmonton to the west coast of British Columbia, which would provide crude oil for delivery to Asia Pacific and California markets and multiple alternatives under consideration to provide enhanced access to refineries to the east of Chicago.

Capital Expenditures

Liquids Pipelines expects to spend approximately $83.0 million in 2005 for ongoing capital improvements and core maintenance capital projects. Capital expenditures for 2004 were $83.7 million.

Enbridge System – Tolling Agreements

Negotiations with the Canadian Association of Petroleum Producers (CAPP) towards a new incentive tolling agreement are currently underway. Until a new agreement is signed, tolls in effect on December 31, 2004 are continuing to be charged on an interim basis.

Tolls on the Enbridge System were governed by the provisions of the Incentive Tolling Settlement (ITS), which expired on December 31, 2004. Under the ITS, tolls were determined based on a starting revenue requirement, adjusted each year for 75% of the change in the Gross Domestic Product Implicit Price Index. The ITS allowed the Company and its customers to share in cost savings, protected Enbridge from fluctuations in volumes, and incorporated additional incentive mechanisms for electric power cost savings. Since electricity is used to power the pumping stations, power costs are a significant expense. The Company was allowed to earn a separate return on facilities expansions or additions that qualified as non-routine adjustments.

Since the inception of incentive tolling arrangements in 1995, through the cost performance sharing mechanism of the ITS, after-tax benefits of $107.0 million have been shared by Enbridge and its customers, approximately 53% and 47%, respectively. Customers also realized an additional after-tax benefit of $10.7 million through the power guarantee mechanism of the ITS.

The NEB approved the facilities application for construction of Phase III of the Terrace Expansion Project in Canada in April 2002. Phase III involved construction of 176 kilometres (110 miles) of 36-inch pipeline on the Lakehead System between Clearbrook, Minnesota and Superior, Wisconsin and pumping additions in both Canada and the United States. Phase III increased capacity by approximately 140,000 bpd when it was placed into service on April 1, 2003 and was requested by shippers to handle anticipated increases in oil sands volumes.

Legal Proceeding – CAPLA Claim

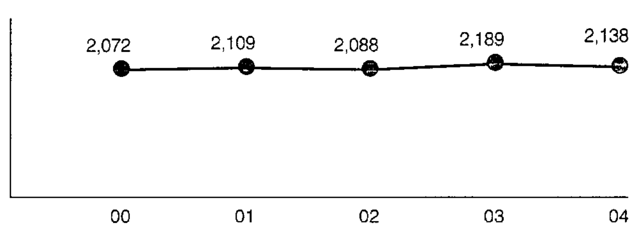
The Canadian Alliance of Pipeline Landowners' Associations and two individual landowners have commenced an action, which they will be applying for certification as a class action, against the Company and TransCanada PipeLines Limited. The claim relates to restrictions in the National Energy Board Act on crossing the pipeline and the landowners' use of land within a 30-metre control zone on either side of the pipeline easements. The Company believes it has a sound defence and intends to vigorously defend the claim. Since the outcome is indeterminable, the Company has made no provision for any potential liability.

Deliveries[1]

(thousands of barrels per day)

Deliveries reflect the growth in oil sands production, which is offsetting conventional crude oil production declines in Western Canada, and which is forecast to continue to increase.

1 Includes deliveries by the 11.6% (at December 31, 2004) owned Lakehead System



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 for oil sands projects, the price of natural gas used for steam production, and the price of crude oil.

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. To the extent the NEB rate of return fluctuates, a portion of the earnings of the Enbridge System and other liquids pipelines changes. The Company believes that regulatory risk can be reduced through the negotiation of long-term agreements, such as the incentive tolling agreement, with its customers.

Competition

Competition among common carrier pipelines is based primarily upon the cost of transportation, access to supply, and proximity to markets. TransMountain Pipeline and Express Pipeline, as well as other common carriers, can be used by 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 elsewhere than delivery points 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.

Increased competition could arise from new feeder systems servicing the same geographic regions as the Company's feeder pipelines. Unused capacity on the Athabasca System should be more competitive than a new pipeline.

GAS PIPELINES

Earnings

(millions of Canadian dollars)	**2004**	2003	2002
Alliance Pipeline (US)	**37.4**	40.3	19.6
Alliance Pipeline (Canada)	**–**	19.6	21.1
Vector Pipeline	**16.4**	10.2	7.1
	53.8	70.1	47.8

Business Activities

Gas Pipelines activities consist of investments in the Alliance and Vector pipelines and the recently acquired Enbridge Offshore System. Enbridge has joint control over these investments with one or more other owners. Enbridge owns a 50.0% interest in Alliance Pipeline (US), the U.S. portion of the Alliance System, a 60% interest in Vector Pipeline and interests ranging from 22% to 80% in the pipelines comprising the Enbridge Offshore System.

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. The Alliance System, which commenced operation in December 2000, 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 (bcfd).

Alliance has firm-service transportation services contracts ending in 2015 to transport 1.325 bcfd of natural gas, on a firm transportation basis, from supply areas in the northwestern Alberta and northeastern British Columbia portions of the WCSB to delivery points near Chicago, Illinois. The transportation service contracts obligate each shipper to pay monthly demand charges based on that shipper's contracted volume, regardless of volumes actually transported on the Alliance System. Each transportation contract may be renewed upon five years notice for successive one-year terms beyond the original 15-year primary term, at the option of the shipper. There is no limitation on the number of times a shipper may renew its transportation contract.

The rates and tariff for Alliance Pipeline (US) are regulated by the Federal Energy Regulatory Commission (FERC) in the United States. All shippers have accepted toll principles negotiated with Alliance and signed transportation contracts incorporating the same toll principles and tariff. The shippers are charged a monthly amount that permits 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 (currently, approximately 10.8% after tax).

The Alliance System connects in the Chicago area with two local natural gas distribution systems and five interstate natural gas pipelines, which provide shippers with access to natural gas markets in the midwestern and northeastern United States and eastern Canada. The Alliance System also connects with a natural gas liquids (NGL) extraction facility (Aux Sable) in Channahon, Illinois near the terminus of the Alliance System, which extracts NGL from the natural gas transported on the Alliance System. It also interconnects with a pipeline in North Dakota.

The Company provides operating services to, and holds a 60% investment in, Vector, which transports natural gas from Chicago to Dawn, Ontario. Vector commenced operations in December 2000. Vector has the capacity to deliver 1.0 bcfd. Vector's primary sources of supply are through interconnections with the Alliance System and the Northern Border Pipeline in Joliet, Illinois. The rates and tariff for Vector are regulated by the FERC in the United States. Approximately 70% of the long haul capacity of Vector is committed to long-term firm transportation contracts at rates negotiated with the shippers and approved by the FERC. The remaining capacity is sold at market rates. Transportation service is provided through a number of different forms of service agreements such as Firm Transportation Service and Interruptible Transportation Service. Vector is currently operating at or near capacity.

Alliance Pipeline (Canada) was sold to the Enbridge Income Fund effective June 30, 2003. Prior to this disposition, the Company had increased its ownership interest from 21.4% in 2001 to 37.1% in late 2002 and up to 50% in 2003.

On December 31, 2004, Enbridge acquired the Enbridge Offshore System, which is comprised of natural gas gathering and transmission pipelines in the Gulf of Mexico. The assets are held primarily through joint ventures with ownership interests ranging from 22% to 80%. The assets were acquired from Shell US Gas & Power LLC for $754.0 million.

Results of Operations

Earnings from Gas Pipelines are $16.3 million lower in 2004 due to the impact of a stronger Canadian dollar and the sale of Alliance Pipeline (Canada) to Enbridge Income Fund on June 30, 2003. The decrease is partially offset by increased ownership interests in both Alliance Pipeline (US) and Vector acquired during 2003 and stronger operating results from Vector in 2004.

Earnings from Gas Pipelines were $70.1 million for the year ended December 31, 2003, an increase of $22.3 million from 2002. The higher earnings were primarily due to additional interests acquired in Alliance and Vector in 2003, partially offset by the sale of the Company's interest in the Canadian portion of Alliance Pipeline in the second quarter of 2003.

Alliance Pipeline (US)

Alliance Pipeline (US) earnings for 2004 reflect the additional ownership interests of 1.1% in March 2003, 10.7% in April 2003 and 1.1% in October 2003, more than offset by the impact of the stronger Canadian dollar in 2004 and the favourable impact, in 2003, of the adjustment recorded in Alliance to reflect a higher rate base.

The increase in earnings of $20.7 million from Alliance Pipeline (US) in 2003, compared with 2002, reflected the acquisition of additional ownership interests and an adjustment to reflect a higher rate base.

Alliance Pipeline (Canada)

Alliance Pipeline (Canada) is included in the results of EIF, in the Sponsored Investments segment, effective June 30, 2003. Prior to its sale to EIF, the Company's ownership interest in Alliance Pipeline (Canada) had increased from 21.4% to 50.0%.

Vector Pipeline

Vector Pipeline earnings in 2004 reflect increased firm transportation commitments and corresponding higher rates as a result of increased demand for service on the pipeline due to new interconnect facilities and customer storage developments, as well as lower interest costs. This is further enhanced by an additional ownership interest of 15% acquired in the fourth quarter of 2003. Vector earnings have also been negatively impacted by the stronger Canadian dollar.

Earnings from Vector were $3.1 million higher in 2003, compared with 2002, as a result of increased volumes and transportation margins, due to both colder than normal weather in Eastern Canada and higher storage injections. This was further enhanced by the additional ownership interest of 15.0% acquired in the fourth quarter of 2003.

Strategy

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 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, Liquefied Natural Gas and the Alaska North Slope/Mackenzie Delta 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 Coast. Alliance's growth strategy will focus on small-scale investments in expansion, efficiency, receipt and delivery facilities and laterals. Alliance is well positioned to participate in the delivery of Alaska/Mackenzie Delta gas to markets in the United States. Vector's growth strategy is to continue to improve margins on capacity not subject to long-term contracts and to firm up long-term contracts at favourable margins. New growth platforms could include significant ownership in a pipeline transporting gas from the 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 a phased approach to deliver Alaska natural gas.

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.

Supply and Demand

Currently, pipeline capacity out of the WCSB exceeds supply. Alliance has been unaffected by this excess supply environment mainly because of long-term capacity contracts going to 2015. Vector 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.

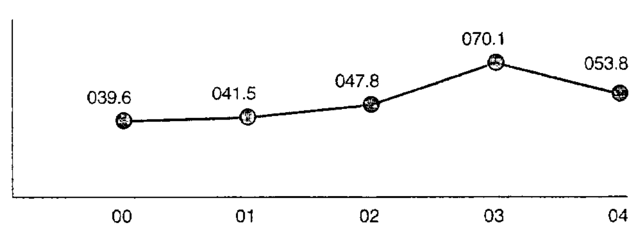
Exposure to Shippers

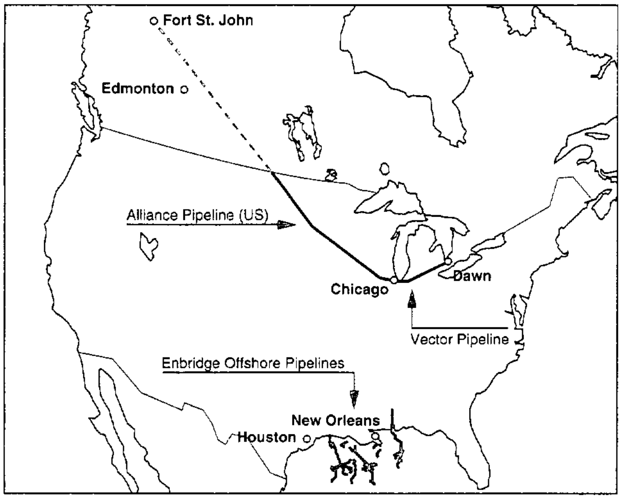
Alliance and Vector are highly dependent on shippers for revenues from contracted transportation capacity. The failure of the shippers to perform their contractual obligations under the transportation contracts could have an adverse effect on the cash flows and financial condition of Alliance and Vector. To reduce this risk, Alliance and Vector monitor the creditworthiness of each shipper and receive collateral for future shipping tolls should a shipper's credit position not meet

Gas Pipelines Earnings

(millions of dollars)

Gas Pipelines earnings reflect strong operating results from the Alliance Pipeline (US) and Vector Pipeline: the decline in 2004 earnings compared with 2003 reflects the sale in 2003 of Alliance Pipeline (Canada) to Enbridge Income Fund.





Gas Pipelines

agreed thresholds. Vector also has a diverse group of long-term transportation shippers, which include various gas and energy distribution companies, producers and marketing companies, further reducing the exposure.

Competition

Alliance faces competition for pipeline transportation services to the Chicago area from both existing and proposed pipeline projects. Existing pipelines, other than Alliance, with a combined transportation capacity of approximately 3.8 bcfd 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 such areas and markets. Any new or upgraded pipelines could either allow shippers and competing pipelines to have greater access to natural gas markets in addition to the markets served by the Alliance System and the pipelines to which it is connected, or offer natural gas transportation services that are more desirable to shippers than those provided by the Alliance System because of location, facilities or other factors. Alliance has the ability to deliver volume in excess of its contracted capacity. Existing shippers on Alliance have access to this additional delivery capacity at no additional cost, other than fuel requirements. This serves to enhance Alliance's competitive position.

Vector faces competition for pipeline transportation services to its delivery points from new or upgraded pipelines, which could allow shippers to have greater access to the markets served by Vector or offer transportation that is more desirable to shippers because of location, facilities or other factors. In addition, these pipelines could charge rates or provide service to locations that result in greater net profit to shippers, forcing Vector to lower its rates and reducing Vector's cash flows. Vector has mitigated this risk by entering into long-term firm transportation contracts for approximately 70% of its capacity. These long-term contracts are not conducive to early termination and provide shippers with financial disincentives if they 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 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.

SPONSORED INVESTMENTS

Earnings

(millions of Canadian dollars)	**2004**	2003	2002
Enbridge Energy Partners	**28.6**	27.3	19.5
Enbridge Income Fund	**30.0**	17.6	–
Enbridge Midcoast Energy	**–**	–	5.5
Gain on sale of assets to Enbridge Income Fund	**–**	169.1	–
Writedown of Enbridge Midcoast Energy assets	–	–	(82.2)
Dilution gains	**7.6**	20.3	6.1
	66.2	234.3	(51.1)

Business Activities

Sponsored Investments includes the Company's ownership interests in EEP and EIF. Enbridge manages the assets of both investments. Enbridge receives management fees for providing day-to-day operation and management services to EEP and EIF including developing acquisition strategies and investigating potential acquisitions. Enbridge also receives incentive fees when cash distributions to unitholders exceed specified levels.

Enbridge Energy Partners (EEP)

Enbridge has an effective 11.6% ownership interest (2003 – 12.2%, 2002 – 14.1%) in EEP. This ownership interest represents the Company's direct investment in EEP of 8.5% and an indirect investment of 3.1% through the Company's 17.2% ownership interest in Enbridge Energy Management (EEM). EEM's business activities are limited to managing the business and affairs of EEP and holding an approximate 18% interest in EEP.

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 east Texas (East Texas System), the mid-continent crude oil system (Mid-Continent System), which was acquired in 2004, a natural gas system in north Texas (North Texas System), which was also acquired in 2004, and a feeder pipeline in North Dakota.

Enbridge, as the general partner of EEP, receives incentive income based on the level of quarterly cash distributions. EEP makes quarterly cash distributions of all of its available cash to the holders of its common units, including Enbridge. Under the Partnership Agreement, Enbridge 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 2004, EEP paid quarterly distributions of $0.925 per unit (2003 – $0.925 per unit; 2002 – $0.90 per unit). Of the $28.6 million Enbridge recognized as earnings from EEP during 2004, 50% (2003 – 49%; 2002 – 48%) were incentive earnings while 50% (2003 – 51%; 2002 – 52%) were Enbridge's share of EEP's earnings.

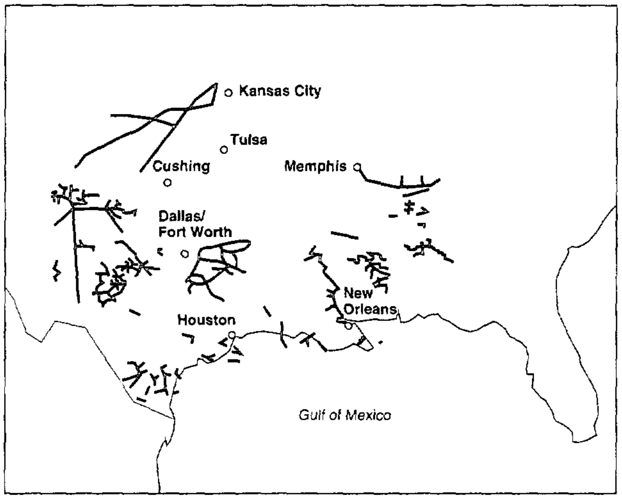
In January 2005, EEP closed the purchase of the North Texas Natural Gas System from Devon Energy Corporation for approximately US$165 million. This system includes approximately 3500 kilometres (2,200 miles) of gas gathering pipelines and three processing plants with aggregate processing capacity of 81 million cubic feet of natural gas per day (mmcfd). The acquired assets serve areas of the Fort Worth Basin, primarily in Jack, Palo Pinto and Parker counties.

EEP acquired the Mid-Continent System in March 2004. This System, which consists of crude oil pipeline and storage systems, was purchased for US$117.0 million. The assets serve refineries in the U.S. mid-continent from Cushing, Oklahoma, and consist of over 768 kilometres (480 miles) of crude oil pipelines and 9.5 million barrels of storage capacity.

Effective December 31, 2003, EEP acquired the North Texas System, a collection of natural gas gathering and processing assets in North Texas. The system primarily serves the Fort Worth Basin, including growing production from the Barnett Shale zone.

Enbridge Midcoast Energy

In October 2002, Enbridge sold the United States assets of Enbridge Midcoast Energy (Midcoast) to EEP. The results of operations of Midcoast, in the preceding Earnings table, relate to the period when the assets were wholly owned.



Enbridge Energy Partners – Gas Pipelines

Enbridge Income Fund (EIF)
Enbridge has a 41.9% voting interest in EIF through the ownership of 14.5 million subordinated units. This interest is accounted for as an equity investment. Enbridge also owns 38 million preferred units of Enbridge Commercial Trust (ECT), a subsidiary of EIF. The preferred units do not have voting rights and are redeemable at the Company's option at a per unit value equal to the price of the publicly traded EIF ordinary units. The preferred units mature on June 30, 2033 at a value of $10 per unit. This interest is accounted for as a cost investment.

Under new accounting rules in effect in Canada on January 1, 2005, EIF is considered a variable interest entity. Enbridge, as the primary beneficiary, will account for EIF as a subsidiary, consolidating the accounts of EIF in Enbridge's financial statements. The impact on Enbridge's 2004 and 2003 financial results is presented in Enbridge's financial statements in Note 22, United States Accounting Principles. Similar accounting rules were adopted in the United States in 2003 and Enbridge has reported the impact of consolidating EIF in the reconciliation to U.S. generally accepted accounting principles in that note. The adoption of the new accounting rules will have no impact on earnings.

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 2004, the Company received incentive fees of $0.8 million (2003 – nil).

Effective June 30, 2003, Enbridge sold its 50% interest in the Canadian portion of Alliance Pipeline and 100% ownership of Enbridge Pipelines (Saskatchewan) Inc. to EIF. For the period prior to this sale, the operating results of Alliance Canada are included in Gas Pipelines and the operating results of Enbridge Pipelines (Saskatchewan) Inc. are included in Liquids Pipelines. Thereafter, the operating results of these assets are included in EIF, which is a component of this segment.

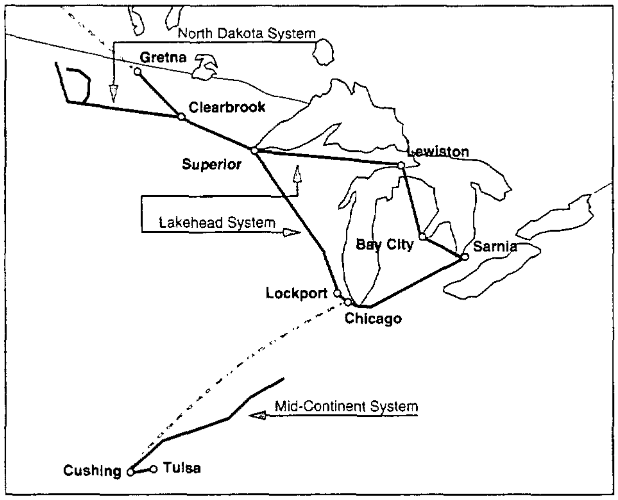
Results of Operations

Earnings from Sponsored Investments are $66.2 million in 2004 compared with $234.3 million in 2003. The decrease results primarily 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. Earnings in 2003 also included dilution gains of $20.3 million, which resulted from two unit issuances by EEP. In 2004, earnings include only one dilution gain of $7.6 million.

For the year ended December 31, 2003, earnings were $234.3 million compared with a loss of $51.1 million for 2002. The 2003 results included the after-tax gain of $169.1 million, as well as, dilution gains of $20.3 million, compared with $6.1 million in 2002. This reflected two unit issuances by EEP in 2003, compared with only one in the prior year.

Excluding the impact of these gains, earnings in this segment in 2003 increased $102.1 million from 2002. A significant portion of this year-over-year change is due to an $82.2 million write down, recorded in 2002, on the sale of the Midcoast assets. The remainder of the $19.9 million increase is attributed to the creation of EIF, effective June 30, 2003, and incremental earnings in EEP from increased throughput on the Lakehead and North Dakota systems.

In October 2002, the Company closed the sale of the United States assets of Midcoast to EEP for consideration of US$820.0 million. Concurrent with the sale transaction, EEM, a subsidiary of Enbridge, completed an initial public offering of common shares and used the net proceeds from the offering to purchase i-units, a new class of limited partnership interests, from EEP. Enbridge purchased 17.2% of the EEM shares.



Enbridge Energy Partners – Liquids Pipelines

Enbridge Energy Partners

EEP's 2004 results reflect higher operating earnings partially offset by the stronger Canadian dollar, a lower ownership interest and the negative effect of a Federal Energy Regulatory Commission decision requiring a refund to shippers on one of EEP's regulated natural gas pipelines. The higher operating earnings are 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 realized incremental earnings from the acquisition of the North Texas assets, for US$249.6 million, which closed on December 31, 2003, and the Mid-Continent assets, for US$117.0 million, which closed on March 1, 2004.

In 2003 EEP issued partnership units twice whereas in 2004 there was only one such issuance. As Enbridge did not participate in these offerings, dilution gains resulted.

Equity earnings in EEP improved in 2003, compared with 2002, due to higher incentive income earned by Enbridge as the general partner and improved results from the Lakehead System. The increased earnings also reflected incremental earnings from EEP's acquisition of the Company's Midcoast assets in October 2002, as well as increased throughput on the Lakehead and North Dakota systems.

Enbridge Income Fund

In June 2003, the Company formed EIF. On formation, EIF acquired the Company's 50% interest in the Canadian segment of Alliance Pipeline together with its 100% interest in the Saskatchewan System.

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

Enbridge Midcoast Energy

Midcoast was sold to EEP in October 2002.

Strategy – EEP

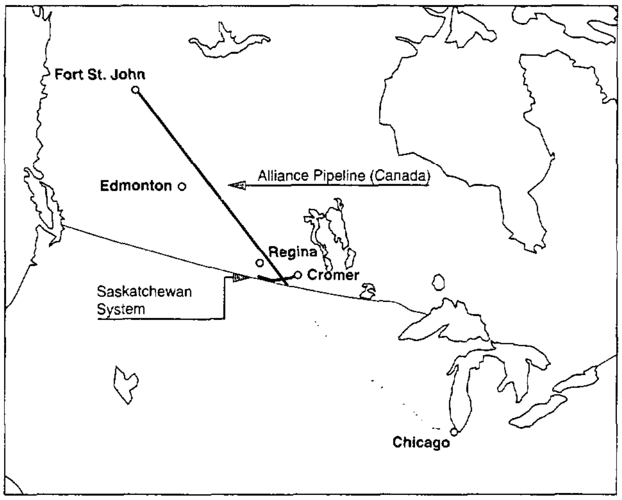
EEP is Enbridge's primary vehicle to own and acquire mature energy infrastructure assets in the United States. In this regard, EEP will continue to grow its geographic footprint through accretive acquisitions and diversification of the revenue stream through a focus on natural gas assets. This strategy will emphasize acquisitions complementary to existing regional assets. EEP will also seek to optimize existing assets through operational efficiency and increased throughput.

Strategy – EIF

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 growth, long-life assets and potential for further growth through energy infrastructure acquisitions.

Business Risks

All of the Company's operations in Sponsored Investments are carried out through EEP and EIF and therefore, the risks are limited to the percentage investment that the Company has in each entity. 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 Income Fund

Enbridge Energy Partners

Supply and Demand

The profitability of the Lakehead System depends to a large extent on the volume of products transported on its pipeline systems. Decreases in the volume of products transported by the Partnership's systems, whether caused by supply or demand factors, can directly affect EEP's revenues and results of operations. The volume of shipments on the 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. EEP expects future increased supplies to come from the oil sands projects in Alberta. In addition, Enbridge's future plans to provide access to new markets in the southern United States would increase demand for Western Canadian crude.

Certain of 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.

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. Gas gathering currently is not subject to active regulation. Several of EEP's assets are regulated by FERC and their revenues could decrease if tariff rates were protested.

Market Price Risk

EEP's gas processing business is subject to commodity price risk for natural gas costs and natural gas liquids. Historically, these risks have been managed by using derivative financial instruments, fixing the prices of natural gas and natural gas liquids.

Enbridge Income Fund

Risks within EIF relate to Alliance Canada and the Saskatchewan System. Risks for Alliance Canada are similar to those identified under Gas Pipelines, which includes the U.S. portion of the Alliance System. Below are risks identified within EIF directly related to the Saskatchewan System.

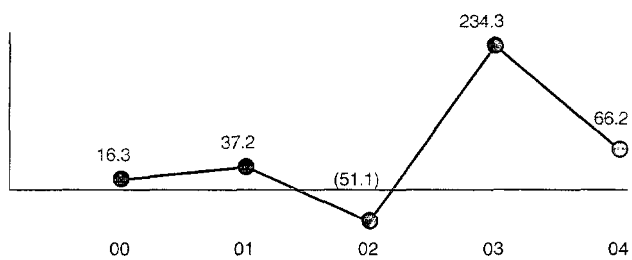
Supply and Demand

The majority of the volumes shipped on the Saskatchewan and Westspur pipeline systems are transported on terms similar to a common carrier basis with 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.

Sponsored Investments Earnings

(millions of dollars)

Sponsored Investments earnings include strong results from Enbridge's investments in Enbridge Energy Partners and Enbridge Income Fund: results in 2003 also included a one-time gain on the sale of assets to Enbridge Income Fund.



GAS DISTRIBUTION AND SERVICES

Earnings

(millions of Canadian dollars)	**2004**	2003	2002
Enbridge Gas Distribution[1]	**133.1**	103.0	85.3
Noverco[1]	**32.3**	24.2	20.6
CustomerWorks/ECS	**20.5**	16.9	10.7
Other Gas Distribution[1]	**8.5**	6.8	6.2
Enbridge Gas New Brunswick	**3.7**	4.4	3.6
Gas Services	**(2.8)**	(5.9)	(7.8)
Aux Sable	**7.3**	(6.9)	(3.1)
AltaGas Income Trust (AltaGas)	**21.1**	12.3	9.4
Gain on sale of investment in AltaGas units	**97.8**	–	–
Impairment loss on Calmar gas plant	**(8.2)**	–	–
Other	**(0.2)**	(1.2)	(0.6)
	313.1	153.6	124.3

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

Business Activities

Gas Distribution and Services primarily includes the gas distribution operations of Enbridge Gas Distribution (EGD), CustomerWorks/ECS, the Company's investment in Noverco and other gas distribution activities in smaller franchise areas. This segment also includes the gas services business, which manages the Company's merchant capacity commitments on Alliance and Vector, and the Company's investment in Aux Sable, which the Company jointly controls with other owners.

EGD is Canada's largest natural gas distribution company and has been in operation for more than 150 years. It serves over 1.7 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).

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 and Terasen. In August 2002, CustomerWorks outsourced the provision of its customer care services to a subsidiary of Accenture Inc. ECS owns the customer information services system that CustomerWorks uses under license to provide services to EGD.

Enbridge owns an equity interest in Noverco through ownership of 32% of the common shares and a cost investment through ownership of preference shares. Noverco is a holding company that owns an approximate 75% interest in Gaz Metro Limited Partnership, a gas distribution company operating in the province of Quebec and the state of Vermont, which has a 50% interest in TQM Pipeline, a pipeline transporting natural gas in Quebec.

The Company owns 63% 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 3,150 customers. Approximately 380 kilometres (238 miles) of distribution main has been installed with the capability of attaching between 14,000 and 15,000 customers. EGNB is regulated by the New Brunswick Board of Commissioners of Public Utilities.

Enbridge owns 42.7% of Aux Sable, a natural gas liquids (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, is 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. When the price of NGL is higher relative to natural gas, there is greater potential for earnings in Aux Sable. Demand for NGL is influenced by overall economic activity and weather 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 has entered into hedge transactions to fix the spread between natural gas and NGL prices. Starting in 2004, downstream heat content requirements were reduced providing improved operating flexibility.

During 2004, Enbridge sold its investment in AltaGas Income Trust (AltaGas) for total cash proceeds of $346.7 million, net of underwriting fees. Enbridge realized a gain on the sale of $97.8 million after tax. Earnings from AltaGas include a dilution gain of $8.0 million (2003 and 2002 – nil).

Results of Operations

Earnings are $313.1 million in 2004 compared with $153.6 million in 2003. The increase is due to the inclusion of a fifth quarter of results for EGD, Noverco and other gas distribution businesses (described below) and a gain on the sale of AltaGas in 2004.

Earnings were $153.6 million for the year ended December 31, 2003, compared with $124.3 million in 2002. Higher earnings were attributable to colder than normal weather experienced in the EGD franchise area in 2003, further aided by a decrease in losses from Gas Services and an increased contribution from CustomerWorks/ECS.

Enbridge Gas Distribution

(millions of Canadian dollars)	**2004**	2003	2002
Enbridge Gas Distribution – as reported	**133.1**	103.0	85.3
Significant non-operating factors and variances:			
Fifth quarter of earnings	**(48.0)**	–	–
Regulatory disallowances	**4.6**	37.7	–
Colder than normal weather	**(23.4)**	(46.1)	29.3
Tax rate adjustments	**47.6**	3.8	–
	113.9	98.4	114.6

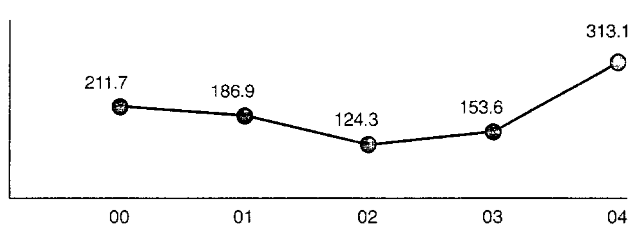
The regulatory disallowance in 2004 relates to outsourcing costs. The 2003 disallowances relate to a $7.1 million gas costs disallowance related to a long-term transportation contract, an outsourcing disallowance, as well as a $26.0 million write-down of a regulatory receivable. The remaining EGD variance, after considering those listed in the above table, is the result of the 2004 rate increase, new customer additions and other positive variances from the forecast cost of service, partially offset by an accrual to share excess earnings, consistent with the 2004 rate filing.

Earnings from EGD for 2003 decreased by $16.2 million to $98.4 million after considering the adjustments listed in the above table. The decrease was primarily due to increased operating and maintenance expenditures in 2003.

Normal weather is the weather forecast by EGD, 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. 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 is the same as the manner in which EGD calculates degree-days for regulatory purposes.

Gas Distribution and Services Earnings
(millions of dollars)

Increased Gas Distribution and Services earnings in 2004 include a fifth quarter of results for gas distribution businesses and a gain on the sale of Enbridge's investment in AltaGas: they also reflect a 2004 rate increase, new customer additions and other positive variances from the forecast cost of service for Enbridge Gas Distribution.



Earnings from EGD will be impacted to the extent that volumes sold differ from the forecast distribution volume established in the ratemaking process. There are four key factors that affect the probability that EGD will distribute the forecast volumes. These are weather, economic conditions, pricing of competitive energy sources, and the number of customers. To the extent that these factors vary unfavourably as compared with forecasts, earnings will be less than the total revenue requirements established in the ratemaking process.

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.

Over the last three years, EGD added approximately 180,600 customers, including approximately 74,500 customers in the fifteen months ended December 31, 2004. The increased number of customers is due primarily to the strong housing market in EGD's franchise area. EGD expects to continue to add 45,000 to 55,000 customers per year in the foreseeable future.

Noverco

(millions of Canadian dollars)	**2004**	2003	2002
Noverco – as reported	**32.3**	24.2	20.6
Significant non-operating factors and variances:			
Fifth quarter of earnings	**(7.5)**	–	–
Dilution gains on Gaz Metro issuances	**(1.1)**	(6.0)	–
Tax rate adjustments	**(1.6)**	2.3	(2.1)
	22.1	20.5	18.5

Noverco earnings in 2004 and 2003, after considering the items in the above table, reflect growth at Gaz Metro, as well as lower interest expense.

Variations from normal weather 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 preference share investment, which is based on the yield of 10-year Government of Canada bonds plus 4.34%. The weighted average dividend yield on the preference shares, which is reset annually, was approximately 10% for each of the last three years.

CustomerWorks/ECS

Earnings from CustomerWorks/ECS are $3.6 million higher in 2004 due primarily to lower depreciation expense.

The contribution from CustomerWorks/ECS was $16.9 million for the year ended December 31, 2003, an increase of $6.2 million compared with the prior year. The main component of these earnings in 2003 was the contribution from CustomerWorks as the primary operations of ECS were rebundled into EGD at the end of 2002. In 2002, earnings from CustomerWorks were affected by activity levels, including customer service calls, which were lower due to warmer weather. In 2003, earnings reflected higher weather-related customer service call volumes and growth in the customer base of the utilities served by CustomerWorks.

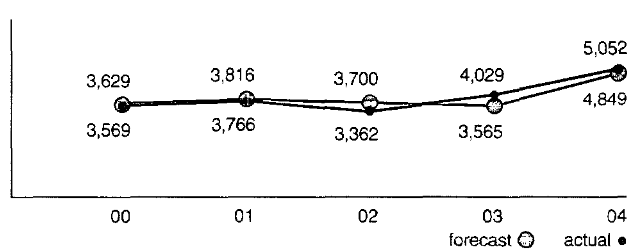
Gas Services

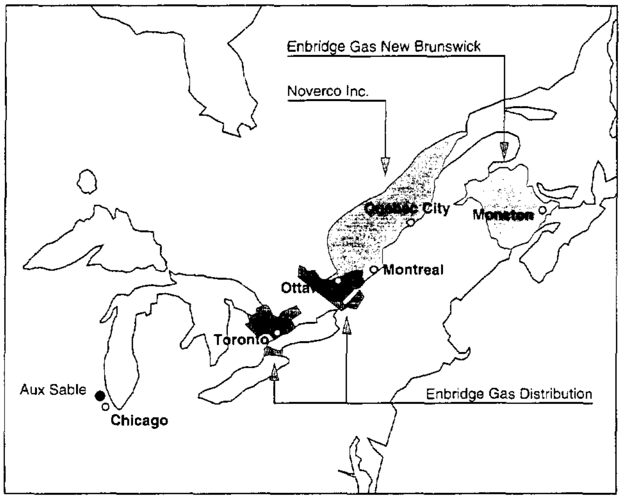
Gas Services recorded a loss of $2.8 million for 2004, an improvement of $3.1 million from 2003. The improvement reflects a continuing increase in the demand for natural gas and associated transmission services, reducing merchant capacity losses on Alliance and Vector.

Energy Distribution Degree Day Deficiency

(degrees Celsius)

Degree day deficiency is a measure of coldness. It is calculated by accumulating for each day in the period the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. The figures given are those accumulated in the Toronto area. Data for 2004 are for 15 months.





Gas Distribution and Services

Gas Services experienced a loss of $5.9 million for the year ended December 31, 2003, compared with a loss of $7.8 million in 2002. The improvement was due primarily to the commencement of fee-based gas service management contracts with certain U.S.-based companies in late 2002 and increased demand for natural gas transmission services.

Aux Sable

The higher earnings from Aux Sable in 2004 are 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.

In 2003, the loss from Aux Sable was $6.9 million, a weakening of $3.8 million from the 2002 loss of $3.1 million. The additional loss reflected the combined effect of higher natural gas prices and lower ethane prices relative to 2002, most significantly during the second quarter of 2003. The results from Aux Sable in 2003 also reflected the increase in ownership interest from 30.9% to 42.7% offset by lower depreciation as the acquisition of the additional interest was at a discount to the book value.

AltaGas

The earnings contribution from AltaGas in 2004 reflects a number of factors including an $8.0 million after-tax dilution gain when AltaGas issued additional trust units and Enbridge did not participate. The revaluation of the future income tax liability related to this investment, primarily as a result of the first quarter Alberta tax rate reductions, also increased earnings. In early August, Enbridge reduced its ownership interest to approximately 10% and cost accounted for this investment thereafter until the ownership position was reduced to nil in September.

Gas Distribution Rates

2005 Rate Application

EGD filed its fiscal 2005 rate application with the OEB in December 2003. Although EGD's long-term objective is to implement an alternative ratemaking model as described below, this rate application was based on the traditional cost of service. The key elements are summarized below:

Year ended September 30,	Approved 2005	Approved 2003
Rate base *(millions)*	$3,422.8	$3,155.8
Rate of return on rate base	8.14%	8.32%
Deemed common equity for regulatory purposes	35.00%	35.00%
Rate of return on common equity	9.57%	9.69%

The fiscal 2004 rate application was not a traditional cost of service application, accordingly no rate base information is provided in the table above.

In May 2004, as a result of settlement negotiations with intervenors, an agreement was reached on the majority of the financial aspects affecting 2005 rates. These primarily included EGD's capital budget, operating and maintenance budget, financing arrangements, and return on common equity. EGD also applied to the OEB for approval to change the regulatory rate-setting cycle to run on a calendar year basis instead of the existing October to September cycle. This was approved by the OEB on November 1, 2004 as part of its final decision on the 2005 rate application.

Discontinuation of Seasonal Rates

Effective October 1, 2004, seasonal rates for delivery charges have been replaced with a uniform rate throughout the year. The impact of this change will result in lower earnings in the winter months, offset by higher earnings in the summer months, causing a shift in earnings between quarters with no earnings impact over 12 consecutive months, mitigating weather risk to some degree. This change did not have a material impact on earnings during the 15 months ended December 31, 2004.

2004 Rates

EGD's 2004 rate application requested that rates for 2004 be set by increasing 2003 rates by 90 percent of the forecast Ontario consumer price index, that being an increase of 1.8 percent. The OEB accepted the proposal for EGD's fiscal 2004 rates on September 4, 2003, thus allowing rates to be in place for the start of the 2004 fiscal year.

The OEB also added a sharing mechanism to fiscal 2004, whereby if earnings on a weather-normalized basis exceed the benchmark ROE, these excess earnings would be shared on a 50/50 basis between ratepayers and the Company's shareholders. The financial results include a charge of $6.3 million after tax for the earnings sharing.

2003 Rates

EGD's 2003 rates were established pursuant to a cost-of-service methodology that allowed revenues to be set to recover EGD's forecast costs. Forecast costs included gas commodity and transportation, operation and maintenance, depreciation, 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 cost-of-service, it is EGD's responsibility to demonstrate to the OEB the prudence of the forecast costs. EGD does not profit from the sale of the natural gas commodity.

The rate base is financed by EGD through a combination of debt and equity. The proportion of debt and equity 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 yield on Canadian government long-term bonds. For 2003, the allowed rate of return was 9.69% (2002 – 9.66%) on a deemed common equity ratio of 35.0%.

2002 Rates

During the fiscal periods 2000 to 2002, EGD operated under a targeted Performance-Based Regulation (PBR) plan. The PBR plan used a formula to calculate the level of operation and maintenance costs recoverable in rates. During the PBR period, EGD was allowed to retain any savings realized if it achieved lower operation and maintenance expenses than those calculated under the formula.

Legislative Change and Future Regulatory Direction

On August 1, 2003, the Ontario Energy Board Consumer Protection and Governance Act, 2003 was proclaimed, providing a new mandate for the OEB. The legislation provides for improved regulatory processes, performance measurement and reporting by the OEB, as well as the establishment of the OEB as a self-financing Crown Agency.

Gas Distribution Access Rule

The Ontario Energy Board (OEB), pursuant to the Energy Competition Act, has undertaken the development of a Gas Distribution Access Rule (GDAR). The stated purpose of the GDAR is to establish rules governing natural gas distributors' conduct in relation to gas marketers and to establish conditions of access to distribution services. The OEB issued the final version of the GDAR in December 2002. Despite EGD's arguments with respect to the GDAR's position on customer mobility and billing options, the GDAR mandates that distributors, including EGD, provide gas marketers with the option to consolidate the gas distribution charges to consumers on the marketers' own bill, forcing the distributor to appoint the marketer as its billing agent. EGD would have to undertake extensive system changes and negotiate new contractual arrangements in order to effect the GDAR directives. Despite appeal by both Union Gas Limited and EGD, on January 11, 2005 the Ontario Court of Appeal dismissed the appeal and upheld the OEB's authority to enact the vendor consolidated billing aspects of the GDAR. EGD is reviewing the decision and considering its options.

Strategy

While EGD will again be under a cost of service regime in 2005 and earnings will be exposed to variances from the components included in the forecast cost of service, it continues to believe that an incentive based regulatory model is advantageous for customers and shareholders. To this end, EGD will be advancing alternate ratemaking models to the OEB through the Natural Gas Forum, which has been initiated for the purpose of exploring options for better regulation of the evolving gas market. EGD will pursue an alternative regulatory model for implementation by 2007 with a focus on growth and customer service and continue to seek improvements in the regulatory process through negotiation with stakeholders and the Ontario Energy Board.

Enbridge Gas New Brunswick plans to increase the customer attachment rate by becoming actively involved in the sale of the natural gas commodity as well as the sale, installation and service of natural gas equipment to the residential and small commercial markets.

The Company's strategies for other gas services businesses are to develop markets downstream of Dawn, Ontario, including support of Enbridge's involvement in power generation in Ontario and position Gas Services to provide marketing, optimization, and other agency services to the proposed LNG regasification facility in Quebec (the proposed LNG facility is described below).

Enbridge intends to pursue gas business development opportunities outside of the existing gas distribution and services businesses through a significant ownership interest in gas-powered co-generation and dedicated electricity generation in Eastern Canada and through significant ownership in at least one LNG project in Canada. To achieve this, Enbridge plans to create a strategic partnership with a large, established company experienced in electricity generation and conclude a partnership with Gaz Metro and Gaz de France to develop a Quebec-based LNG facility.

LNG Facility Update

Enbridge, Gaz Metro and Gaz de France previously announced their intention to build a liquefied natural gas (LNG) terminal in the Levis-Beaumont area of Quebec City. Project "Rabaska" would cost approximately $700 million and is forecast to be put into service in 2008. The Levis municipal council is not in support of the proposed location at this time as evidenced by a majority vote against the proposal. The partners are currently reviewing their options in response to this decision. The terminal would supply regasified LNG primarily to Quebec and Ontario markets and provide diversity of natural gas sources, as well as meet the growing demand for natural gas.

Capital Expenditures

Capital expenditures in 2005, for the Gas Distribution and Services business are expected to be approximately $248 million. The majority of the expenditures relate to expansion of and core maintenance on the EGD system. It is anticipated that these additions will be financed through internal funds, as well as short and medium-term borrowings. Capital expenditures for 2004 were $353 million compared with expected expenditures of $287 million. The difference is due to the inclusion of five quarters of expenditures for EGD. The change in year end from September 30 to December 31 resulted in the consolidation of 15 months of expenditures in the Company's financial results.

Enbridge Gas Distribution Legal Proceedings

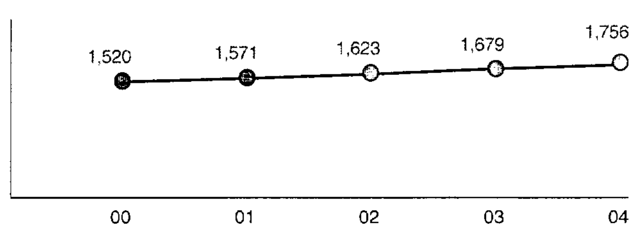
Class Action Lawsuit – late payment penalties

On April 22, 2004, the Supreme Court of Canada released its decision in a case commenced against Enbridge Gas Distribution (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

Gas Distribution Number of Active Customers

(thousands)

Enbridge Gas Distribution continues to add between 50,000 and 60,000 new customers per year: the 2004 number reflects the 15-month period reported as part of Enbridge's change in financial reporting to eliminate the consolidation of gas distribution operations on a quarter lag basis.



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 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 2005.

Late payment penalty revenues are included in EGD's estimate of revenues for the year and therefore offset rates charged to customers. Revenues from late payment penalties accrue to the benefit of all customers, thereby reducing the cost of providing distribution services. The Ontario Energy Board (OEB) approved these estimates and the resulting rates each year, including the years 1994 through 2002. 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 (the TSSA) and the Ontario Occupational Health and Safety Act (the 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 approximately $5.0 million in the aggregate. EGD has also been named as a defendant in a number of civil actions related to the explosion. A Coroner's Inquest in connection with the explosion is also possible. The courts have not yet dealt with 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. EGD does not expect the civil actions to result in any material financial impact.

Remediation of Discontinued Manufactured Gas Plant Sites

The remediation of discontinued manufactured gas plant sites may result in future costs to EGD. In October 2002, a claim was filed for $55 million in damages relating to a certain manufactured gas plant site. EGD filed a statement of defence in June 2003 denying liability. EGD expects that trial scheduling will take place in the summer of 2005 and that a trial date will be fixed for early 2006. Although management believes that it has a valid defence to this claim, certain risks exist. The probable overall cost cannot be determined at this time due to uncertainty about the presence and extent of damage in addition to the potential alternative remediation approaches which vary in cost. EGD expects that costs, if any, not recovered through insurance would be recovered through rates. As such, management does not believe that the outcome will have 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

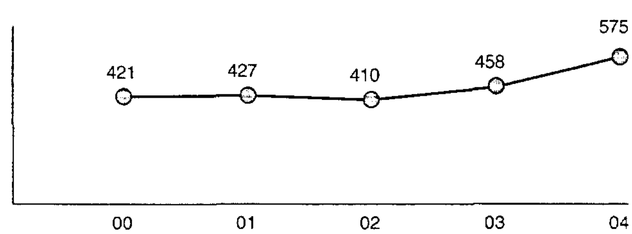
The business risks inherent in the natural gas distribution industry impact the ability of EGD to realize the revenue level required to generate the allowed return on equity. These business risks include timely and adequate rate relief, accuracy in forecasting distribution volume, and most importantly, achieving the forecast natural gas distribution volume.

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; pricing of competitive energy sources; and the number of customers.

Gas Distribution Volume of Gas Distributed
(billions of cubic feet)

Gas volumes distributed reflect the growing number of active customers and the impact each year of warmer than normal or colder than normal weather: the 2004 number reflects the 15-month period.



Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 77% (2003 – 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.

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.

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 also be sought 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 rate applications are made or 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. Consequently, 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 recovered in new rates approved for that fiscal year based on the anticipated distribution volume.

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.

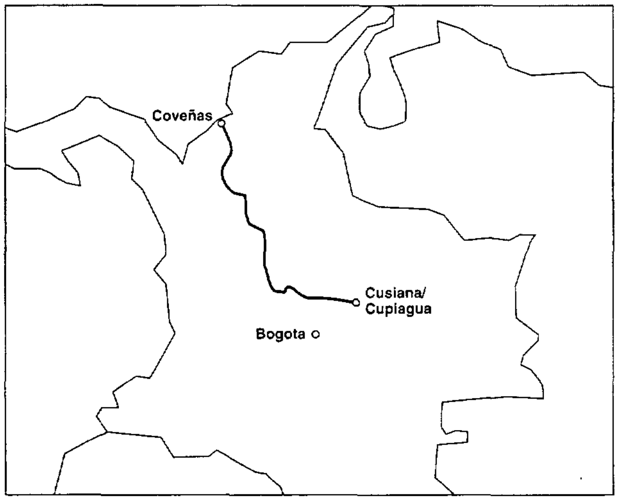
Aux Sable

Earnings from Aux Sable will continue to be exposed to the effect of spreads between the sale prices of natural gas liquids and the purchase price of replacement natural gas. Earnings would be negatively impacted by a decrease in the spread and positively impacted by an increase in the spread. This risk is mitigated by lower heat content requirements on downstream pipelines, which commenced in 2004, and the use of commodity hedges, which opportunistically lock in positive margins when forward markets allow.

INTERNATIONAL

Earnings

(millions of Canadian dollars)	**2004**	2003	2002
CLH	**48.6**	46.3	33.3
OCENSA/CITCol	**33.0**	32.3	35.3
Other	**(8.0)**	(6.3)	(0.6)
	73.6	72.3	68.0



Colombia – OCENSA

Business Activities

International includes earnings from the investments in Compañia Logistica 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.

The Company owns a 25% interest in CLH of Spain. 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 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 kilometers of pipelines and 40 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's core business is the provision of basic logistics and the company 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 crude oil and refined products are imported.

The Company owns a 24.7% interest in OCENSA, a cost investment on which the Company earns a stated return. The Company also has responsibility for the operations of the pipeline, through a 100% owned entity, CITCol, and earns a fee for this service, which includes incentive earnings for operating performance.

Other is primarily administration and business development costs, as well as the results of Enbridge Technology Inc.

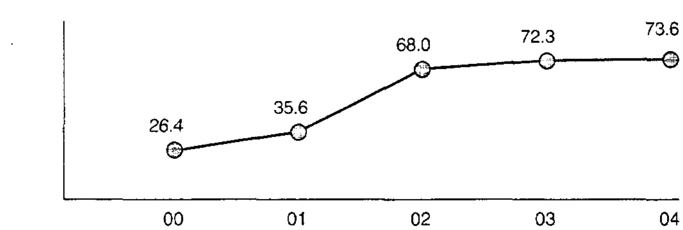
Results of Operations

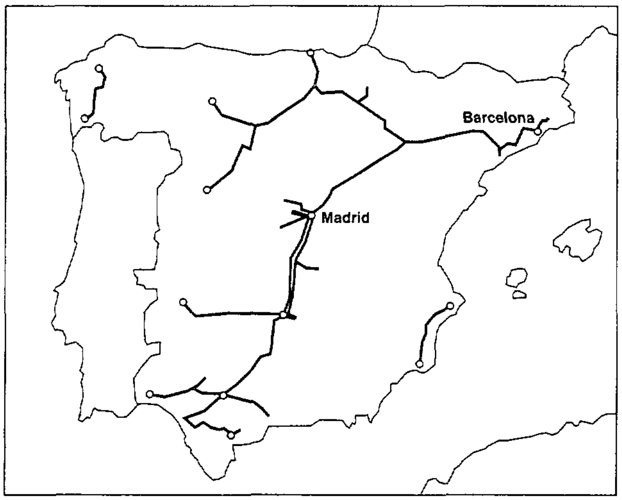
In 2004, increased earnings of $1.3 million from 2003 are due to stronger results from CLH and from CITCol, operator of the OCENSA pipeline, exceeding certain operational performance targets resulting in additional incentive income. Operating results from CLH continue to reflect increased volumes due to greater demand for refined products throughout Spain, lower operating costs and the translation impact of the stronger Euro. Other costs include higher business development costs.

In 2003, earnings increased by $4.3 million from 2002 primarily as a result of higher earnings from CLH, due to increased volumes and the impact of a stronger Euro, partially offset by a reduction in marine fleet revenues due to the scheduled

International Earnings
(millions of dollars)

International earnings in 2004 reflect stronger results from Enbridge's investments in CLH in Spain and OCENSA/CITCol in Colombia.





Spain – CLH

retirement of certain ships. The increased earnings were partly offset by the termination of the Jose Terminal operating agreement in Venezuela and lower incentive earnings from CITCol.

Business Risks

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

CORPORATE

(millions of Canadian dollars)	**2004**	2003	2002
Corporate	**(81.3)**	(76.6)	(48.6)

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

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

Corporate costs amounted to $76.6 million in 2003, an increase of $28.0 million from 2002. During 2003, lower financing costs were more than offset by various negative factors including increased business development costs, an expense for stock-based compensation and other corporate costs primarily relating to prior year business dispositions and final settlements. The Company adopted the fair-value based method of accounting for stock-based compensation effective January 1, 2003.

DISCONTINUED OPERATIONS

In the second quarter of 2002, the Company sold its retail and commercial energy services business for proceeds of $1 billion. Earnings from discontinued operations for the year ended December 31, 2002 were $242.3 million and included a $240.0 million after-tax gain on the sale.

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 their decisions, or grant approval, and involve the timing of revenue and expense recognition to ensure that the actions of the regulatory authorities have been reflected in the financial statements. Assets or liabilities may be created by decisions of regulatory authorities.

The way that these items are reflected in the Company's financial results depends on its expectation of the future actions of the regulatory authorities. For example, 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 System has 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.

Revenue Recognition

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 permit a specific 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 specified 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 in a manner that is 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 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 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. These amounts are expenses or income that would be recognized in the income statement, absent the actions of the regulator. The regulator, through the hearing 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. The difference between the regulatory approved cost of gas and the actual cost of gas 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 through the statement of financial position, at the formal direction of the regulator, with no impact on revenues or expenses in the income statement. Enbridge Gas Distribution (EGD) has no exposure to the cost of gas, as it is a flow through cost that is borne directly by the ratepayer.

LIQUIDITY AND CAPITAL RESOURCES

The Company's cash generated from operations, commercial paper issuances, available capacity under credit facilities, and access to capital markets in Canada and the United States for the issuance of long-term debt, equity, or other securities are expected to be sufficient to satisfy liquidity 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, 2004, including short-term borrowings, but excluding non-recourse short and long-term debt of its joint ventures, was 65.1%, compared with 67.9% at the end of 2003 (restated for the reclassification of preferred securities from equity to debt).

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

Operating Activities

Cash provided by operating activities before changes in operating assets and liabilities, and cash from discontinued operations, was $1,027.8 million for the year ended December 31, 2004, compared with $938.3 million and $699.5 million for 2003 and 2002, respectively.

Although earnings were slightly lower in 2004, non-cash gains included in earnings were lower in 2004, resulting in higher cash from operations. Cash from operations is affected by 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. The variance in changes in operating assets and liabilities is 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.

Cash from operations in 2003 reflected fluctuations due to the higher gas prices and distribution volumes of the Enbridge Gas Distribution business. Temporary differences between accounting and taxable income, driven by changes in gas costs to be settled with ratepayers, have increased the amount of future income taxes in 2003. The significant variance in operating assets and liabilities is due to an increase in accounts receivable and gas in storage resulting from higher gas costs pending recovery from ratepayers, as well as higher equal billing plan balances.

Since the Company's pension plans are adequately funded, no additional funding above usual levels is anticipated for 2005.

Investing Activities

Cash used for investing activities for the year ended December 31, 2004 was $999.7 million. In 2003, investing activities provided $259.5 million and in 2002, investing activities used $251.7 million. In 2004, $833.9 million was used for acquisitions including the $743.4 million Enbridge Offshore System acquisition (net of cash acquired) and the final payment of $73.0 million (including interest) on the 90% interest in the Spearhead Pipeline. Cash proceeds from the sale of the investment in AltaGas partially offset the use of cash for acquisitions.

Investing activities in 2003 represented a source of cash primarily as a result of the proceeds received on the sale of assets to EIF. Both 2003 and 2002 reflected the repayment by EEP of short-term loans required to finance acquisitions with additional amounts received in 2003. The majority of these loans have now been repaid.

Additions to property, plant and equipment are primarily related to the gas distribution utility and are consistent with prior years.

Other investing activity in 2003 was limited to the acquisition of Cushing-to-Chicago Pipeline and additional investments in Alliance and Vector Pipelines, net of cash acquired.

Other investing in 2002 was significantly higher as a result of significant transactions. During 2002, the Company completed the acquisition of the North East Texas assets included in the asset sale to EEP; acquired a 25% equity investment in CLH; and increased its equity ownership of Alliance. These items represent the majority of cash used for investing purposes and more than offset the cash inflows from the sale of the Enbridge Midcoast Energy assets and Energy Services business.

Financing Activities

Over the three-year period, the Company's financing requirements have reflected its growth and investment strategies. 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.

In 2004, financing activities provided cash of $114.4 million. Cash was generated through a net issuance of debt of $438.0 million, partially offset by the payment of dividends. Dividends on common shares have increased again in 2004, due to an increased number of common shares outstanding and a higher dividend rate.

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. Dividends have remained consistent with the prior year with the exception of those on the common shares, which reflects a higher number of common shares, as well as an increase in the dividend rate consistent with the Company's earnings growth.

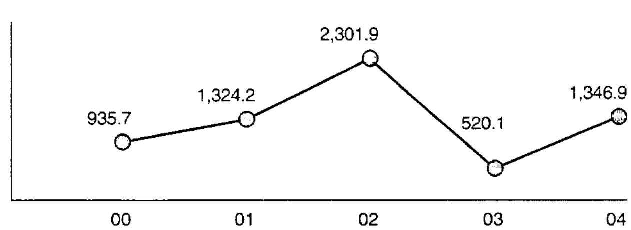
In 2002, cash used for financing activities to reduce short-term debt was partially offset by cash received from the issue of additional common shares and preferred securities. These activities were consistent with the goal of improving the Company's debt to equity ratio and financing the growth in the business. Proceeds from the issuance of shares by EEM were used to invest in i-units of EEP.

Payments due for contractual obligations over the next five years and thereafter are as follows:

(millions of Canadian dollars)	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
Long-term debt	5,222.4	530.2	1,101.9	802.0	2,788.3
Non-recourse long-term debt	695.4	36.4	91.1	88.6	479.3
Long-term contracts	1,563.9	272.8	357.4	304.2	629.5
Other long-term liabilities	44.8	–	44.8	–	–
Total Contractual Obligations	7,526.5	839.4	1,595.2	1,194.8	3,897.1

Capital Expenditures, Investments and Acquisitions
(millions of dollars)

The 2004 total for capital expenditures, investments and acquisitions reflects regular additions to property, plant and equipment, primarily related to the gas distribution utility, and the acquisition of interests in offshore pipelines in the Gulf of Mexico.



CHANGES IN ACCOUNTING POLICIES

Impairment of Long-Lived Assets

A new standard is in effect, for fiscal years beginning on or after April 1, 2003, for recognizing, measuring and disclosing impairment of long-lived assets held for use. The Company adopted this standard effective January 1, 2004 and it has not had a significant impact on the Company's financial statements.

Hedging Relationships

A new guideline is in effect, for fiscal years beginning on or after July 1, 2003, for identifying, designating and documenting hedge relationships, and assessing their effectiveness. The Company adopted the new guideline on January 1, 2004. The new guideline has not had a significant impact on the Company's financial statements.

Generally Accepted Accounting Principles

A new standard is in effect, for all fiscal years beginning on or after October 1, 2003, for identifying appropriate sources of generally accepted accounting principles, and the doctrines that constitute generally accepted accounting principles. At present, the standard has an exemption for rate-regulated operations. As a significant portion of the Company's operations are rate-regulated, this new standard did not have a material impact on the Company's financial statements.

Asset Retirement Obligations

A new standard is in effect, for fiscal years beginning on or after January 1, 2004, for recognizing, measuring and disclosing liabilities for asset retirement obligations and the associated asset retirement costs. The Company adopted the new standard, retroactively, on January 1, 2004. This new standard did not have a material effect on the Company's financial statements.

Consolidation of Variable Interest Entities

A new guideline is in effect, for all annual and interim periods beginning on or after November 1, 2004, for applying consolidation principles to entities subject to control on a basis other than through ownership of voting interests. The new standard must be applied retroactively. This standard will result in the consolidation of the Company's investment in EIF, effective January 1, 2005. A similar standard has been adopted by the Financial Accounting Standards Board in the United States, effective for interim periods commencing after July 15, 2003. As such, the impact of adopting this standard in the current period is disclosed as part of the financial statements in Note 22, United States Accounting Principles.

Preferred Securities

The accounting standard that describes the presentation and disclosure of financial instruments has been amended for fiscal years beginning on or after November 1, 2004. The amendments require that principal or interest payments on preferred securities that may be settled by issuing a variable number of the Company's own shares should be classified as liabilities in the financial statements. The amendments were adopted retroactively and have resulted in a $532.4 million reclassification from equity to long-term debt in the 2003 statements of financial position and the reclassification of preferred security distributions of $26.7 million in 2003 (2002 – $26.7 million), after-tax, to interest expense, for the pre-tax distributions of $41.5 million in 2003 (2002 – $41.9 million), and to income taxes for the related tax expense of $14.8 million in 2003 (2002 – $15.2 million) in the statements of earnings. Preferred security issue costs of $4.2 million net of tax, incurred in 2002, have been reclassified as a $6.6 million increase in interest expense and a $2.4 million decrease in income tax expense. In December 2004, the Company redeemed $350.0 million preferred securities leaving $200.0 million outstanding.

RISK MANAGEMENT

As Enbridge continues to diversify its energy transportation and distribution businesses in North America and internationally, the risk profile of the Company may change. Entry into non-regulated businesses imposes greater economic exposure and requires more "at risk" capital. The Company's expectation of higher returns from these businesses justifies the level of risk. In addition, these operating risks are actively managed through insurance and other programs.

Market Risk
Earnings and cash flows are subject to volatility stemming from movements in interest rates, certain commodity prices and the Canadian dollar exchange rate relative to other currencies. The Company has adopted an earnings at risk methodology to measure its exposure to market risk.

To manage market risk, Enbridge uses derivative financial instruments to create offsetting positions to specific exposures. The Company has established risk management policies, approved by the Board of Directors, covering the use of derivative financial instruments for hedging purposes. Ongoing monitoring and senior management reporting procedures are in place. Derivative financial instruments are not used to create speculative positions. The financial instruments used and outstanding are described below under Derivative Financial Instruments.

Foreign Exchange Risk
The Company has a hedging program to eliminate 80% to 100% of the long-term exposure related to its foreign currency denominated cash flows. The Company also hedges certain of its foreign currency denominated net equity investments. The redemption of the investment in OCENSA also is hedged.

Interest Rate Risk
Enbridge is exposed to interest rate fluctuations on variable rate debt. Floating to fixed interest rate swaps and forward rate agreements are used to manage this exposure. The Company monitors its levels of fixed and variable rate debt instruments and, from time to time, fixed to floating swaps are used to help maintain balances of each commensurate with the Company's financing strategies. The Company also 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 over-the-counter natural gas price swaps and options to manage physical exposures that arise from the merchant capacity commitments on the Alliance and Vector pipelines. The Company also uses these derivative instruments to manage any exposures that may arise from physical asset optimization and natural gas supply agreements.

As a result of the Company's ownership interest in Aux Sable Liquid Products L.P., 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 gas and NGL are fixed with swaps, or capped, or collared with options.

For the period that the Enbridge Midcoast Energy assets were owned, the Company was exposed to the margin between the price of natural gas and NGL. Enbridge used over-the-counter commodity derivatives to fix the selling price of the NGL and the cost of purchasing natural gas to establish the margins. The derivative financial instruments used to manage this exposure were transferred to EEP as part of the sale transaction.

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.

Derivative Financial Instruments Used for Risk Management
The Company uses the following financial instruments to mitigate 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,	2004			2003		
	Notional Principal Quantity	Fair Value Receivable/ (Payable)	Maturity	Notional Principal Quantity	Fair Value Receivable/ (Payable)	Maturity
Foreign exchange						
U.S. cross currency swaps	**535.8**	**(51.1)**	**2005-2022**	535.8	(30.6)	2005-2022
Euro cross currency swaps	**493.5**	**(51.3)**	**2005-2019**	434.7	(46.1)	2004-2019
Forwards (cumulative exchange amounts)	**1,740.3**	**181.0**	**2005-2022**	1,889.5	67.9	2004-2022
Energy commodities						
Natural gas (bcf)	**107.8**	**(1.0)**	**2005-2010**	63.6	12.4	2004-2008
Natural gas supply management (bcf)	**34.9**	**(28.1)**	**2005**	13.1	(3.4)	2004
Interest rates						
Interest rate swaps	**1,069.0**	**1.5**	**2005-2029**	561.0	1.9	2005-2029
Forward interest rate swaps	**200.0**	**–**	**2006**	532.0	(1.0)	2004-2005

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $214.0 million (2003 – $214.0 million), to exchange Canadian for U.S. dollars. The outstanding instruments expire in 2005 and 2007. The contracts are not effective hedges for accounting purposes but offset an exposure related to income taxes on foreign currency gains or losses on Canadian dollar debt of a U.S. subsidiary. These instruments are recorded at fair value and have a fair value payable of $28.8 million as at December 31, 2004 (2003 – $10.5 million payable).

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.

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,	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Liquids Pipelines	**913.4**	**1,037.8**	881.4	990.6
Gas Distribution and Services	**1,823.4**	**2,168.9**	1,674.5	1,972.1
Corporate	**4,020.4**	**4,275.6**	3,855.5	4,089.6
	6,757.2	**7,482.3**	6,411.4	7,052.3

The fair value of debt does not include the effects of hedging. Non-recourse debt of joint ventures has a carrying value of $695.4 million (2003 – $786.6 million) and fair value of $796.4 million (2003 – $845.7 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 federally 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.

QUARTERLY FINANCIAL INFORMATION[1]

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

2004	First	Second	Third	Fourth	Total
Operating revenue from continuing operations	**1,453.2**	**1,843.9**	**1,283.4**	**1,960.0**	**6,540.5**
Operating income from continuing operations	**285.5**	**397.7**	**168.8**	**231.5**	**1,083.5**
Margin	**0.196**	**0.216**	**0.132**	**0.118**	**0.166**
Earnings applicable to common shareholders	**112.4**	**248.4**	**179.7**	**104.8**	**645.3**
Earnings per common share	**0.67**	**1.49**	**1.07**	**0.63**	**3.86**
Dividends per common share	**0.4575**	**0.4575**	**0.4575**	**0.4575**	**1.8300**

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

2003	First	Second	Third	Fourth	Total
Operating revenue from continuing operations	1,045.8	1,887.1	1,068.1	854.3	4,855.3
Operating income from continuing operations	157.2	449.3	182.7	102.2	891.4
Margin	0.150	0.238	0.171	0.120	0.184
Earnings applicable to common shareholders	103.8	445.4	90.7	27.3	667.2
Earnings per common share	0.63	2.70	0.54	0.16	4.03
Dividends per common share	0.415	0.415	0.415	0.415	1.660

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

Operating revenue from continuing operations 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.

The positive effect of colder than normal weather contributed to an increase in revenues and earnings during the second quarter of 2004 and the second and fourth quarters of 2003. Significant items that impacted 2004 and 2003 quarterly earnings are as follows:

- 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 unbilled revenue of $35.0 million consistent with a change in the estimation process in 2004, both within EGD.
- Fourth quarter earnings in 2003 include an $11.1 million dilution gain on an EEP unit issuance, and a $6.0 million dilution gain related to Noverco. Offsetting the gain is a $26.0 million write-down of a regulatory receivable and a $4.6 million regulatory disallowance on outsourcing, both in the Company's gas distribution business.
- Second quarter earnings in 2003 include a $169.1 million after-tax gain on the sale of assets to the Enbridge Income Fund in June 2003 and a $9.2 million dilution gain on an EEP unit issuance.
- First quarter earnings in 2003 include a $7.1 million regulatory disallowance in the Company's gas distribution business.

FOURTH QUARTER 2004 HIGHLIGHTS

Fourth quarter earnings for 2004 are $104.8 million, an increase of $77.5 million from 2003. Included in the 2004 earnings are the extra "fifth quarter" earnings from EGD which are included because of the change in year end. These additional earnings total $57.2 million. Also, in the fourth quarter of 2004, an impairment loss of $8.2 million was recognized on the Calmar gas plant. The fourth quarter of 2003 included a $26.0 million write down of a regulatory receivable related to a prior year.

On December 31, 2004, the Company acquired natural gas pipeline systems in the Gulf of Mexico (Enbridge Offshore System) from Shell for $754 million. Also in December 2004, the Company redeemed $350.0 million of preferred securities.

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)	173,309,559
Total issued and outstanding stock options	5,947,212

Outstanding share data information is provided as at January 17, 2005.

Related Party Transactions

Neither EEP nor EIF have employees and use the services of the Company for managing and operating their businesses. These services, which are charged at cost in accordance with service agreements, amount to $173.0 million (2003 – $128.9 million; 2002 – $97.2 million) for EEP and $9.4 million (2003 – $4.7 million) for EIF, which began operation on June 30, 2003.

The receivable from affiliate of $171.7 million (2003 – $169.8 million) resulted from the sale of Enbridge Midcoast Energy to EEP and the assumption of affiliate debt. The weighted average interest rate is 6.60% for 2004 and 2003. The receivable, which matures in 2007, is denominated in U.S. dollars. The balance on December 31, 2004 was

US$142.1 million (2003 – US$133.1 million). Interest income related to the affiliate receivable was $11.8 million (US$9.0 million), $21.7 million (US$15.5 million), and $7.6 million (US$4.9 million), in 2004, 2003 and 2002, respectively.

The Company provides operation and management services to Vector Pipeline, which is owned 60% by the Company. These services, which are charged at cost in accordance with service agreements, amounted to $4.4 million for 2004 (2003 – $3.3 million; 2002 – $4.1 million).

EGD obtains its customer care services from CustomerWorks Limited Partnership, an affiliate, under an agreement having a five-year term starting January 2002. EGD is charged market prices for these services, which amounted to $127.0 million in 2004 (2003 – $95.5 million; 2002 – $71.8 million).

EGD has contracted for gas transportation services from Alliance Pipeline Limited Partnership and Vector Pipeline Limited Partnership. EGD is charged market prices for these services, which amounted to $50.6 million in 2004 (2003 – $40.7 million; 2002 – $41.3 million) for Alliance Pipeline, and $39.1 million in 2004 (2003 – $23.2 million; 2002 – $25.2 million) for Vector Pipeline.

A subsidiary of the company earns rental revenue from CustomerWorks Limited Partnership for the use of an automated billing system. In 2004, this revenue amounted to $22.5 million (2003 – $25.5 million; 2002 – $35.1 million).

In 2004, Enbridge Gas Services Inc., a subsidiary of the Company, purchased $30.7 million (2003 – $33.6 million; 2002 – $6.3 million) of gas from Enbridge Marketing (US) Inc., a subsidiary of EEP.

The Company also provides consulting and other services to affiliates. 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 trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

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 January 25, 2005

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.

Management's Report

To the Shareholders of Enbridge Inc.

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

Management has established systems of internal control that provide reasonable assurance that assets are safeguarded from loss or unauthorized use and produce reliable accounting records for the preparation of financial information. The internal control system includes an internal audit function and an established code of business conduct.

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

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

Patrick D. Daniel
President & Chief Executive Officer
January 25, 2005

Stephen J. Wuori
Group Vice President & Chief Financial Officer

Auditors' Report

To the Shareholders of Enbridge Inc.

We have audited the consolidated statements of financial position of Enbridge Inc. as at December 31, 2004 and 2003 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and cash flows for each of the years in the three year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada
January 25, 2005

Comments by Auditors for U.S. Readers on Canada-U.S. Reporting Difference

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Corporation's financial statements, such as the changes in stock-based compensation and preferred securities described in Note 2 to the consolidated financial statements. Our report to the shareholders dated January 25, 2005 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

PricewaterhouseCoopers LLP

Chartered Accountants

Calgary, Alberta, Canada
January 25, 2005

Consolidated Statements of Earnings

(millions of Canadian dollars, except per share amounts)

Year ended December 31,	2004	2003	2002
		Restated *(Note 2)*	Restated *(Note 2)*
Revenues			
Gas sales	**4,554.4**	3,061.7	2,987.7
Transportation	**1,695.8**	1,560.6	1,296.6
Energy services	**290.3**	233.0	263.2
	6,540.5	4,855.3	4,547.5
Expenses			
Gas costs	**3,917.0**	2,720.1	2,578.0
Operating and administrative	**1,015.0**	800.8	834.1
Depreciation	**525.0**	443.0	403.9
Writedown of Enbridge Midcoast Energy assets *(Note 4)*	**–**	–	122.7
	5,457.0	3,963.9	3,938.7
Operating Income	**1,083.5**	891.4	608.8
Investment and Other Income *(Note 18)*	**261.7**	208.2	283.1
Gain on Sale of Investment in AltaGas Income Trust *(Note 8)*	**121.5**	–	–
Gain on Sale of Assets to Enbridge Income Fund *(Note 4)*	**–**	239.9	–
Interest Expense *(Note 10)*	**(525.3)**	(492.8)	(468.4)
	941.4	846.7	423.5
Income Taxes *(Note 16)*	**(289.2)**	(172.6)	(86.6)
Earnings From Continuing Operations	**652.2**	674.1	336.9
Earnings From Discontinued Operations *(Note 4)*	**–**	–	242.3
Earnings	**652.2**	674.1	579.2
Preferred Share Dividends *(Note 13)*	**(6.9)**	(6.9)	(6.9)
Earnings Applicable to Common Shareholders	**645.3**	667.2	572.3
Earnings Applicable to Common Shareholders			
Continuing Operations	**645.3**	667.2	330.0
Discontinued Operations	**–**	–	242.3
	645.3	667.2	572.3
Earnings Per Common Share *(Note 13)*			
Continuing Operations	**3.86**	4.03	2.06
Discontinued Operations	**–**	–	1.51
	3.86	4.03	3.57
Diluted Earnings Per Common Share *(Note 13)*			
Continuing Operations	**3.83**	4.00	2.03
Discontinued Operations	**–**	–	1.50
	3.83	4.00	3.53

Consolidated Statements of Retained Earnings

(millions of Canadian dollars, except per share amounts)

Year ended December 31,	2004	2003	2002
			Restated *(Note 2)*
Retained Earnings at Beginning of Year	**1,511.4**	1,128.1	812.3
Earnings Applicable to Common Shareholders	**645.3**	667.2	572.3
Effect of Change in Accounting for Stock-Based Compensation	**–**	–	(5.4)
Common Share Dividends	**(315.8)**	(283.9)	(251.1)
Retained Earnings at End of Year	**1,840.9**	1,511.4	1,128.1
Dividends Paid Per Common Share	**1.83**	1.66	1.52

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

Consolidated Statements of Cash Flows

(millions of Canadian dollars)

Year ended December 31,	**2004**	2003	2002
		Restated *(Note 2)*	Restated *(Note 2)*
Cash Provided By Operating Activities			
Earnings from continuing operations	**652.2**	674.1	336.9
Charges/(credits) not affecting cash			
Depreciation	**525.0**	443.0	403.9
Equity earnings in excess of cash distributions	**(39.2)**	(22.1)	(44.6)
Gain on sale of assets to Enbridge Income Fund	**–**	(239.9)	–
Gain on reduction of ownership interest	**(29.6)**	(50.0)	(10.0)
Gain on sale of investment in AltaGas Income Trust	**(121.5)**	–	–
Gain on sale of securities	**–**	–	(21.4)
Writedown of EGD regulatory receivable	**–**	26.0	–
Writedown of Enbridge Midcoast Energy assets	**–**	–	122.7
Future income taxes	**12.7**	85.8	(77.8)
Other	**28.2**	21.4	(10.2)
Changes in operating assets and liabilities *(Note 19)*	**(141.1)**	(569.8)	151.6
Cash provided by operating activities of discontinued operations	**–**	–	26.3
	886.7	368.5	877.4
Investing Activities			
Acquisitions *(Note 5)*	**(833.9)**	(78.3)	(289.3)
Long-term investments	**(16.9)**	(50.5)	(1,282.7)
Additions to property, plant and equipment	**(496.4)**	(391.3)	(729.9)
Proceeds on redemption of Enbridge Commercial Trust preferred units	**–**	24.9	–
Sale of investment in AltaGas Income Trust	**346.7**	–	–
Sale of assets to Enbridge Income Fund *(Note 4)*	**–**	331.2	–
Proceeds on dispositions	**–**	–	1,706.9
Affiliate loans	**–**	427.2	358.1
Changes in construction payable	**0.5**	(3.7)	(14.8)
	(999.7)	259.5	(251.7)
Financing Activities			
Net change in short-term borrowings and short-term debt	**738.0**	359.8	(1,180.9)
Long-term debt issues	**500.0**	150.0	247.4
Long-term debt repayments	**(450.0)**	(725.0)	(382.7)
Non-recourse long-term debt issued by joint ventures	**–**	538.3	–
Non-recourse long-term debt repaid by joint ventures	**(42.9)**	(663.8)	–
Non-controlling interests	**(2.4)**	(4.0)	0.2
Preferred securities	**(350.0)**	–	200.0
Common shares issued	**44.4**	70.9	293.1
Enbridge Energy Management shares issued *(Note 8)*	**–**	–	421.9
Preferred share dividends	**(6.9)**	(6.9)	(6.9)
Common share dividends	**(315.8)**	(283.9)	(251.1)
	114.4	(564.6)	(659.0)
Increase/(Decrease) in Cash	**1.4**	63.4	(33.3)
Cash at Beginning of Year	**104.1**	40.7	74.0
Cash at End of Year	**105.5**	104.1	40.7

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

Consolidated Statements of Financial Position

(millions of Canadian dollars)

December 31,	**2004**	2003 Restated *(Note 2)*
Assets		
Current Assets		
Cash	**105.5**	104.1
Accounts receivable and other	**1,451.9**	1,120.7
Inventory	**791.6**	827.9
	2,349.0	2,052.7
Property, Plant and Equipment, net *(Note 6)*	**9,066.5**	8,530.9
Long-Term Investments *(Note 8)*	**2,278.3**	2,390.9
Receivable from Affiliate *(Note 20)*	**171.7**	169.8
Deferred Amounts and Other Assets *(Note 9)*	**729.2**	608.2
Intangibles and Goodwill *(Note 5)*	**165.4**	–
Future Income Taxes *(Note 16)*	**145.0**	192.5
	14,905.1	13,945.0
Liabilities and Shareholders' Equity		
Current Liabilities		
Short-term borrowings	**650.6**	649.6
Accounts payable and other	**1,275.9**	906.5
Interest payable	**83.8**	97.0
Current maturities and short-term debt *(Note 10)*	**703.9**	635.9
Current portion of non-recourse long-term debt *(Note 11)*	**30.2**	34.2
	2,744.4	2,323.2
Long-Term Debt *(Note 10)*	**6,053.3**	5,775.5
Non-Recourse Long-Term Debt *(Note 11)*	**665.2**	752.4
Other Long-Term Liabilities	**151.8**	148.3
Future Income Taxes *(Note 16)*	**797.3**	829.0
Non-Controlling Interests *(Note 12)*	**514.9**	523.0
	10,926.9	10,351.4
Shareholders' Equity		
Share capital		
Preferred shares *(Note 13)*	**125.0**	125.0
Common shares *(Note 13)*	**2,282.4**	2,238.0
Contributed surplus	**5.4**	1.9
Retained earnings	**1,840.9**	1,511.4
Foreign currency translation adjustment	**(139.8)**	(147.0)
Reciprocal shareholding *(Note 8)*	**(135.7)**	(135.7)
	3,978.2	3,593.6
Commitments and Contingencies *(Note 21)*	**14,905.1**	13,945.0

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

Approved by the Board:

Donald J. Taylor
Chair

Robert W. Martin
Director

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

Liquids Pipelines
Liquids Pipelines includes the operation of common carrier and feeder pipelines that transport crude oil and other liquid hydrocarbons.

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

Sponsored Investments
Sponsored Investments consists of the Company's investments in Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Management, L.L.C. (EEM) (collectively, the Partnership) and Enbridge Income Fund (EIF). The Partnership transports crude oil and other liquid hydrocarbons through common carrier and feeder pipelines and transports, gathers, processes and markets natural gas and natural gas liquids. Enbridge Income Fund is a publicly traded income fund whose primary operations include a 50% interest in a gas transmission pipeline and a 100% interest in a crude oil and liquids pipeline and gathering system.

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

International
The Company's International business consists of investments in energy transportation and related energy projects outside of Canada and the United States. This business also provides consulting and training services related to proprietary pipeline operating technologies and natural gas distribution.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Company are prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP). These accounting principles are different in some respects from United States generally accepted accounting principles (U.S. GAAP) and the significant differences that impact the Company's financial statements are described in Note 22. Amounts are stated in Canadian dollars unless otherwise noted.

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

Basis of Presentation
The consolidated financial statements include the accounts of Enbridge Inc., its subsidiaries and its proportionate share of the accounts of joint ventures. Investments in entities which are not subsidiaries or joint ventures, but over which the Company exercises significant influence, are accounted for using the equity method. Other investments are accounted for at cost.

The Company's gas distribution activities within Gas Distribution and Services are conducted primarily through a wholly-owned subsidiary, Enbridge Gas Distribution Inc. (EGD). Prior to 2004, the fiscal year-end of EGD and certain smaller gas distribution subsidiaries was September 30 and their results were consolidated on a one quarter lag basis. In respect of 2003 and 2002, references to "December 31" mean the financial position of EGD as at September 30 and references to the "year ended December 31" mean the results of EGD for the year ended September 30. Starting in 2004, EGD changed its fiscal year end to December 31. Accordingly, the Company's financial statements for the year ended December 31, 2004 include 15 months of results for EGD and other gas distribution subsidiaries.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

Regulation

The Company's Liquids Pipelines, Gas Pipelines, and certain Gas Distribution and Services businesses are subject to regulation by various authorities, including the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and underlying accounting practices, and ratemaking agreements with customers. In order to recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under generally accepted accounting principles for non rate-regulated entities.

Revenue Recognition

Generally, revenues are recorded when products have been delivered or services have been performed. However, 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.

Certain Liquids Pipelines revenues are recognized under the terms of a committed long-term delivery contract. The Company records revenues based on the terms of the 30-year contract rather than the cash tolls received. On the Company's main Canadian crude oil pipeline system, for rate-regulated operations, revenue is recognized in a manner that is consistent with the underlying agreements as approved by the regulatory authority.

For rate-regulated operations in Gas Pipelines, transportation revenues include amounts related to expenses in the financial statements that are expected to be recovered from shippers in future tolls. No revenue is recognized in a given period for tolls received that do not relate to current period expenses. Differences between the recorded transportation revenue and actual toll receipts give rise to receivable or payable balances.

A significant portion of Gas Distribution and Services operations are subject to rate-regulation and accordingly there are circumstances where the revenues recognized do not match the amounts billed. Revenue is recognized in a manner that is consistent with the underlying rate-setting mechanism as mandated by the regulators. This may give rise to regulatory assets and liabilities on the consolidated statement of financial position pending disposition by a decision of the regulators. Gas distribution revenues are recorded on the basis of regular meter readings and estimates of customer usage since the last meter reading to the end of the reporting period.

Income Taxes

The regulated activities of the Company recover income tax expense based on the taxes payable method when prescribed by regulators for ratemaking purposes or when stipulated in ratemaking agreements. Therefore, rates do not include the recovery of future income taxes related to temporary differences. Consequently, the taxes payable method is followed for accounting purposes as the Company expects that all future income taxes will be recovered in rates when they become payable.

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

Foreign Currency Translation

The Company has U.S. dollar operations which are all self-sustaining except for certain financing and investing operations. The Company also holds a Euro equity investment in a foreign operation in Spain. These operations, which include those of proportionately consolidated U.S. dollar investments and the Euro equity investment, are self-sustaining and are translated into Canadian dollars using the current rate method. Under this method, assets and liabilities are translated using period-end exchange rates, with revenues and expenses translated using average rates for the period. Gains and losses arising on translation of these operations are included as a separate component of shareholders' equity.

The remaining foreign operations of the Company, including certain financing and investing operations, are integrated with those of the parent company and are translated into Canadian dollars using the temporal method. Under this method, monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet date. Non-monetary assets and liabilities denominated in foreign currencies are translated at exchange rates in effect on the dates the assets were acquired or liabilities were incurred. Revenues and expenses are translated at rates of exchange prevailing on the transaction dates. Under this method, gains and losses on translation are reflected in income when incurred.

Cash
Cash is recorded at cost and includes short-term and demand deposits with a term to maturity of three months or less when purchased.

Inventory
Inventory is primarily comprised of natural gas in storage held in EGD. Natural gas in storage is recorded in inventory at the prevailing prices approved by the OEB in the determination of customer sales rates. The actual price of gas purchased may differ from the OEB-approved price and includes the effect of natural gas price risk management activities. The difference between the approved price and the actual cost of the gas purchased is deferred for future disposition by the OEB.

Property, Plant and Equipment
Expenditures for system expansion and major renewals and betterments are capitalized; maintenance and repair costs are expensed as incurred. Interest during the construction period is capitalized. Regulated operations capitalize an allowance for interest during construction and, if approved, an allowance for equity funds used during construction, at rates authorized by the regulatory authorities.

Depreciation
Depreciation of property, plant and equipment generally is provided on a straight-line basis over the estimated service lives of the assets.

Intangibles and Goodwill
Goodwill is not subject to amortization but is tested for impairment at least annually and written down to fair value if the criteria for impairment are met. Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. Intangible assets consist of long-term transportation contracts and are amortized on a straight-line basis over the expected life of the contracts. The depreciation rate for intangibles is 4%.

Asset Retirement Obligations
No material amount has been recorded for asset retirement obligations relating to the Company's assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope of the asset retirements. Management also believes it is reasonable to assume that all retirement costs associated with the regulated pipelines will be recovered through tolls in future periods.

Depreciation expense for Gas Distribution and Services operations includes a provision for asset retirement obligations at rates approved by the regulator. Actual costs incurred are charged to accumulated depreciation.

Deferred Amounts and Other Assets
The Company defers certain charges, which the regulatory authorities permit to be recovered through future rates. Assets are realized and liabilities are settled based on the terms of the regulatory approval once received. Other deferred charges are amortized straight-line over various periods depending on the nature of the charges and include long-term financing and hedging costs, which are amortized over the terms of the related debt or hedged items. Deferred financing charges are amortized on a straight-line basis, which approximates the effective interest method, over the life of the related debt and classified as interest expense. The Company recognizes revenues under the terms of an enforceable, committed long-term delivery contract, which result in a long-term receivable.

Derivative Financial Instruments
Gains and losses on financial instruments used to hedge the Company's net investment in foreign operations are included in the foreign currency translation adjustment in shareholders' equity. Amounts received or paid related to derivative financial

instruments used to hedge the currency risk of cash flows from foreign currency denominated transactions are recognized concurrently with the hedged cash flows. Amounts received or paid related to derivative financial instruments used to hedge the price of energy commodities are recognized as part of the cost of the underlying physical purchases. For other derivative financial instruments used for hedging purposes, amounts received or paid, including any gains and losses realized upon settlement, are recognized over the term of the hedged item.

The Company applies settlement accounting to derivative financial instruments. Under this method, gains and losses on derivative instruments that qualify for hedge accounting are not recorded until they are realized. The notional amounts are not recorded in the financial statements as they do not represent amounts exchanged by the counterparties.

Post-Employment Benefits

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

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

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

The measurement date used to determine the plan assets and the accrued benefit obligation was September 30, 2004.

Stock-Based Compensation

Stock options granted after January 1, 2003 are accounted for under the fair value method. Under this method, compensation expense is measured at fair value at the grant date using the Black-Scholes option pricing model and recognized over the vesting period with a corresponding credit to contributed surplus. Stock options granted prior to January 1, 2003 continue to be accounted for as capital transactions when the options are exercised, which does not give rise to compensation expense.

Performance stock units (PSUs) are accounted for over the three-year term on a mark-to-market basis whereby a liability and expense are recorded based on the number of PSUs outstanding, the current market price of the Company's shares and the Company's current performance relative to the specified peer group.

Comparative Amounts

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

2. CHANGES IN ACCOUNTING POLICIES

Recently Adopted Accounting Standards

Asset Retirement Obligations

Effective January 1, 2004, the Company adopted the new CICA standard for asset retirement obligations. This new standard requires that the fair value of asset retirement obligations associated with the retirement of long-lived assets is recognized in the period incurred. The fair value, which approximates the cost a third party would incur in performing the tasks necessary to retire such assets, is recognized at the present value of expected future cash flows and is added to the carrying value of the associated asset and depreciated over the asset's useful life. The liability is accreted over time through periodic charges to earnings and is reduced by actual costs of decommissioning and reclamation.

No material amount has been recorded for asset retirement obligations relating to the Company's assets as it is not possible to make a reasonable estimate of the fair value of the liability due to the indeterminate timing and scope of the asset retirements. Management also believes it is reasonable to assume that all retirement costs associated with the regulated pipelines will be recovered through tolls in future periods.

Stock-Based Compensation

Effective January 1, 2002, the Company adopted the CICA standard for stock-based compensation. The standard required retroactive application for certain stock compensation awards as a charge to opening retained earnings without restatement of prior periods. Upon adoption, a charge to opening retained earnings of $5.4 million was recorded relating to outstanding stock appreciation rights, which expired in 2004.

Effective January 1, 2003, the Company early adopted revised requirements in the CICA standard for stock-based compensation. The standard requires the Company to apply the fair value based method of accounting for all awards granted. This method has been applied on a prospective basis and resulted in a charge to income, in the year of adoption, of $1.9 million.

Preferred Securities

Effective December 31, 2004, the Company early adopted amendments to the CICA standard on the disclosure and presentation of financial instruments. The amendments require the Company's preferred securities to be classified wholly as debt rather than splitting the principal and payments components of the securities into debt and equity. The amendments were adopted retroactively and have resulted in financial statement impacts summarized in the table below. In December 2004, $350 million of preferred securities were redeemed.

Impairment of Long-lived Assets

Effective January 1, 2004, the Company adopted the new CICA standard for recognizing, measuring and disclosing impairment of long-lived assets held for use. The new standard has not had a significant impact on the Company's financial results.

Hedging Relationships

Effective January 1, 2004, the Company adopted the new guideline for identifying, designating and documenting hedge relationships, and assessing their effectiveness. The guideline provides parameters on the conditions necessary for hedge accounting to be applied, but does not specify the methods to be used in its application. The guideline, however, does require that the Company adopt an accounting policy for assessing the effectiveness of its hedge relationships. Any ineffectiveness related to instruments recorded in the statement of financial position is to be recognized in income for the period. The new guideline has not had a significant impact on the Company's financial results.

Generally Accepted Accounting Principles

A new standard is in effect, for all fiscal years beginning on or after October 1, 2003, for identifying appropriate sources of generally accepted accounting principles. At present, the standard has an exemption for rate-regulated operations and, as a result, has not had a significant impact on the Company's financial results.

2. CHANGES IN ACCOUNTING POLICIES (continued)

Financial Impact of Changes in Accounting Policies

Year ended December 31,	2003			2002		
(millions of dollars)	As Reported	Change	As Restated	As Reported	Change	As Restated
Statements of Earnings						
Interest expense	(451.3)	(41.5)	(492.8)	(422.0)	(46.4)	(468.4)
Income taxes	(187.4)	14.8	(172.6)	(102.1)	15.5	(86.6)
Preferred security distributions	(26.7)	26.7	–	(26.7)	26.7	–
Earnings to common shareholders	667.2	–	667.2	576.5	(4.2)	572.3
Statements of Retained Earnings						
Preferred securities issue costs	–	–	–	(4.2)	4.2	–
Statements of Financial Position						
Liabilities						
Long-term debt	5,243.1	532.4	5,775.5			
Shareholders' Equity						
Preferred securities	532.4	(532.4)				

Change due to retroactive adoption of amendments to the standard on the disclosure and presentation of financial instruments.

New Accounting Standards

Consolidation of Variable Interest Entities

A new guideline is in effect, for all annual and interim periods beginning on or after November 1, 2004, for applying consolidation principles to entities subject to control on a basis other than through ownership of voting interests. As a result, the Company will consolidate EIF, starting January 1, 2005. A similar standard has been adopted by the Financial Accounting Standards Board in the United States (FIN 46R), effective for interim periods commencing after July 15, 2003. The impact on the Company's financial results of consolidating EIF is presented in Note 22, United States Accounting Principles.

3. SEGMENTED INFORMATION

Year ended December 31, 2004

(millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services[2]	International	Corporate[1]	Consolidated
Revenues	**872.7**	**271.7**	**–**	**5,363.8**	**32.3**	**–**	**6,540.5**
Gas costs	**–**	**–**	**–**	**(3,917.0)**	**–**	**–**	**(3,917.0)**
Operating and administrative	**(310.1)**	**(55.1)**	**–**	**(577.0)**	**(38.6)**	**(34.2)**	**(1,015.0)**
Depreciation[3]	**(145.4)**	**(65.7)**	**–**	**(308.4)**	**(1.9)**	**(3.6)**	**(525.0)**
Operating income	**417.2**	**150.9**	**–**	**561.4**	**(8.2)**	**(37.8)**	**1,083.5**
Investment and other income	**1.8**	**0.8**	**112.2**	**50.6**	**81.5**	**14.8**	**261.7**
Gain on sale of investment	**–**	**–**	**–**	**121.5**	**–**	**–**	**121.5**
Interest and preferred share dividends	**(101.4)**	**(65.6)**	**–**	**(211.1)**	**(0.2)**	**(153.9)**	**(532.2)**
Income taxes	**(97.7)**	**(32.3)**	**(46.0)**	**(209.3)**	**0.5**	**95.6**	**(289.2)**
Earnings applicable to common shareholders	**219.9**	**53.8**	**66.2**	**313.1**	**73.6**	**(81.3)**	**645.3**

Year ended December 31, 2003

(millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
Revenues	821.5	222.1	–	3,785.4	26.2	0.1	4,855.3
Gas costs	–	–	–	(2,720.1)	–	–	(2,720.1)
Operating and administrative	(288.8)	(41.2)	–	(415.9)	(30.5)	(24.4)	(800.8)
Depreciation	(142.6)	(56.7)	–	(237.6)	(2.0)	(4.1)	(443.0)
Operating income	390.1	124.2	–	411.8	(6.3)	(28.4)	891.4
Investment and other income	3.4	36.6	113.1	19.8	78.1	(42.8)	208.2
Gain on sale of assets	–	–	239.9	–	–	–	239.9
Interest and preferred share dividends	(102.1)	(58.7)	–	(162.2)	(0.5)	(176.2)	(499.7)
Income taxes	(77.9)	(32.0)	(118.7)	(115.8)	1.0	170.8	(172.6)
Earnings applicable to common shareholders	213.5	70.1	234.3	153.6	72.3	(76.6)	667.2

Year ended December 31, 2002

(millions of dollars)	Liquids Pipelines	Gas Pipelines	Sponsored Investments	Gas Distribution and Services	International	Corporate[1]	Consolidated
Revenues	787.7	–	1,219.0	2,513.5	27.2	0.1	4,547.5
Gas costs	–	–	(1,051.4)	(1,526.6)	–	–	(2,578.0)
Operating and administrative	(282.5)	–	(109.5)	(410.4)	(19.0)	(12.7)	(834.1)
Depreciation	(150.6)	–	(17.3)	(229.5)	(2.9)	(3.6)	(403.9)
Writedown of Enbridge Midcoast Energy Assets	–	–	(122.7)	–	–	–	(122.7)
Operating income	354.6	–	(81.9)	347.0	5.3	(16.2)	608.8
Investment and other income	4.8	66.3	44.8	32.1	64.0	71.1	283.1
Interest and preferred share dividends	(99.8)	–	(28.1)	(161.7)	(1.6)	(184.1)	(475.3)
Income taxes	(70.0)	(18.5)	14.1	(93.1)	0.3	80.6	(86.6)
Earnings applicable to common shareholders	189.6	47.8	(51.1)	124.3	68.0	(48.6)	330.0
Earnings from discontinued operations							242.3
Earnings applicable to common shareholders							572.3

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

2 Gas Distribution and Services includes 15 months of results for EGD and other gas distribution businesses which changed their year end to December 31 in 2004. This change eliminated the quarter lag basis of consolidation and resulted in additional earnings of $57.2 million.

3 Depreciation expense in Gas Distribution and Services includes a $12.4 million impairment loss on the Calmar Gas Plant. The operations of this plant have not improved to a level to enable the recovery of its carrying costs and as a result it has been written down to an estimated fair value of $5 million.

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

3. SEGMENTED INFORMATION (continued)

Total Assets

(millions of dollars)

December 31,	**2004**	2003
Liquids Pipelines	**3,410.7**	3,411.1
Gas Pipelines	**2,310.2**	1,695.0
Sponsored Investments	**1,116.3**	1,394.5
Gas Distribution and Services	**6,599.4**	6,218.8
International	**958.6**	836.1
Corporate	**509.9**	389.5
	14,905.1	13,945.0

Additions to Property, Plant and Equipment

(millions of dollars)

Year ended December 31,	**2004**	2003	2002
Liquids Pipelines	**83.3**	123.4	255.7
Gas Pipelines	**10.6**	11.3	–
Sponsored Investments	**–**	–	128.9
Gas Distribution and Services	**402.1**	249.0	315.0
International and Corporate	**0.4**	7.6	7.4
	496.4	391.3	707.0
Discontinued Operations	**–**	–	22.9
	496.4	391.3	729.9

Geographic Information

Revenues[1]

(millions of dollars)

Year ended December 31,	**2004**	2003	2002
Canada	**5,030.3**	3,739.4	3,102.3
United States	**1,482.6**	1,089.6	1,418.0
Other	**27.6**	26.3	27.2
	6,540.5	4,855.3	4,547.5

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

Property, Plant and Equipment

(millions of dollars)

December 31,	**2004**	2003
Canada	**6,819.2**	6,747.3
United States	**2,241.8**	1,776.6
Other	**5.5**	7.0
	9,066.5	8,530.9

4. DISPOSITIONS

Alliance Pipeline Canada and Enbridge Pipelines (Saskatchewan) Inc.

On June 30, 2003, the Company formed EIF, an unincorporated open-ended trust established under the laws of Alberta. On formation, the Company sold its 50% interest in the Canadian segment of the Alliance Pipeline together with its 100% interest in Enbridge Pipelines (Saskatchewan) Inc. to EIF for total proceeds of $905.0 million before working capital adjustments of $20.6 million and transaction costs of $0.2 million. The Company recorded an after-tax gain on the sale of $169.1 million. Enbridge's net investment in Alliance Canada was $333.6 million at December 31, 2002 and was classified as a long-term investment. The net assets of Enbridge Pipelines (Saskatchewan) Inc. consist primarily of property, plant and equipment and comprised $86.5 million of Enbridge Inc.'s total property, plant and equipment balance at December 31, 2002.

Enbridge Midcoast Energy

In October 2002, the Company closed the sale of the United States assets of Enbridge Midcoast Energy to EEP, including the Northeast Texas assets described in Note 4. The book value of the assets was written down by $82.2 million, after-tax, to reflect fair value based on the proceeds of $1,289.3 million. The Company received cash proceeds of approximately $529.3 million with the remaining consideration in the form of assumed affiliate debt.

Discontinued Operations

In the second quarter of 2002, the Company sold its retail and commercial energy services business. Earnings from discontinued operations for the year ended December 31, 2002 were $242.3 million, which included a $240.0 million gain on the sale. During the year ended December 31, 2002, the discontinued operations earned revenues of $181.9 million, incurred tax expense of $34.6 million and were allocated interest expense of $12.1 million.

5. ACQUISITIONS

Enbridge Offshore System

On December 31, 2004, the Company acquired offshore natural gas pipeline assets located in the Gulf of Mexico, from Shell US Gas & Power LLC for cash consideration of $754.0 million. The assets are held primarily through joint ventures with ownership interests ranging from 22% to 80%. This acquisition expands the Company's natural gas operations. The acquisition has been accounted for using the purchase method with the results of operations included in the consolidated financial statements from December 31, 2004. The value allocated to the assets was determined by an independent appraisal.

(millions of dollars)	
Fair Value of Assets Acquired:	
Property, plant and equipment	591.8
Intangible assets	133.9
Goodwill	31.5
Other assets	22.5
Other liabilities	(25.7)
	754.0
Purchase Price:	
Cash (includes cash acquired of $9.5 million)	752.9
Transaction costs	1.1
	754.0

The intangible assets, which are comprised of transportation contracts, will be amortized on the straight-line basis over their estimated useful life of 20 - 25 years. Factors that contributed to a purchase price that includes goodwill include the retention of key employees, which adds to the Company's industry knowledge, and the potential to use these assets to accommodate the transportation needs of several proposed LNG re-gasification projects.

5. ACQUISITIONS (continued)

Cushing to Chicago Pipeline System

In September 2003, the Company acquired 90% of the outstanding shares of CCPS Transportation L.L.C., owner of the Cushing to Chicago Pipeline System. Of the total purchase price of $145.8 million, $78.3 million was paid on the date of acquisition and $67.5 million, plus interest of $5.5 million, was paid in December 2004. This final payment triggered the vendor's right to sell the remaining 10% to the Company at a cost of US$12.4 million. This right expires on December 31, 2005 and, if exercised, obligates the Company to buy the remaining interest.

The acquisition was accounted for using the purchase method and the results of operations have been included in the consolidated statement of earnings from the date of acquisition. The amount paid was allocated to property, plant and equipment.

Other

In 2004, the Company acquired interests in other businesses for a total of $17.5 million.

Northeast Texas

In March 2002, the Company acquired natural gas gathering and processing facilities in Northeast Texas for cash consideration of $289.3 million. These assets are included in the Enbridge Midcoast Energy sale described in Note 4. The results of operations have been included in the consolidated statement of earnings for the period of ownership.

6. PROPERTY, PLANT AND EQUIPMENT

(millions of dollars) **December 31, 2004**	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	2.4%	2,534.4	1,118.8	1,415.6
Pumping Equipment, Buildings, Tanks and Other	3.8%	2,255.9	730.4	1,525.5
Land and Right-of-Way	2.1%	38.1	17.5	20.6
Under Construction	–	37.4	–	37.4
		4,865.8	1,866.7	2,999.1
Gas Pipelines				
Pipeline	3.8%	1,915.7	239.5	1,676.2
Land and Right-of-Way	3.0%	51.4	5.4	46.0
Metering and Other	5.2%	122.8	13.8	109.0
Under Construction	–	35.8	–	35.8
		2,125.7	258.7	1,867.0
Gas Distribution and Services				
Gas Mains	4.0%	1,920.5	377.0	1,543.5
Gas Services	4.5%	1,759.9	426.4	1,333.5
Regulating and Metering Equipment	3.7%	556.6	118.0	438.6
Storage	2.7%	254.7	44.8	209.9
Computer Technology	16.1%	308.5	164.4	144.1
Other	4.7%	574.8	79.1	495.7
		5,375.0	1,209.7	4,165.3
Other	10.7%	61.2	26.1	35.1
		12,427.7	3,361.2	9,066.5

(millions of dollars) December 31, 2003	Weighted Average Depreciation Rate	Cost	Accumulated Depreciation	Net
Liquids Pipelines				
Pipeline	2.4%	2,453.5	1,038.0	1,415.5
Pumping Equipment, Buildings, Tanks and Other	3.9%	2,215.0	690.7	1,524.3
Land and Right-of-Way	1.9%	34.1	16.0	18.1
Under Construction	–	47.0	–	47.0
		4,749.6	1,744.7	3,004.9
Gas Pipelines				
Pipeline	3.7%	1,544.4	196.6	1,347.8
Land and Right-of-Way	2.9%	36.6	4.5	32.1
Metering and Other	2.9%	85.6	11.6	74.0
Under Construction	–	6.4	–	6.4
		1,673.0	212.7	1,460.3
Gas Distribution and Services				
Gas Mains	4.3%	1,866.4	320.2	1,546.2
Gas Services	4.5%	1,811.1	370.1	1,441.0
Regulating and Metering Equipment	3.7%	581.9	106.2	475.7
Storage	2.7%	283.1	40.7	242.4
Computer Technology	8.0%	124.1	74.5	49.6
Other	5.4%	325.6	58.4	267.2
		4,992.2	970.1	4,022.1
Other	6.6%	66.7	23.1	43.6
		11,481.5	2,950.6	8,530.9

7. JOINT VENTURES

Enbridge has a joint venture interest in the following entities.

(millions of dollars)	Ownership Interest		Net Assets	
December 31,	**2004**	2003	**2004**	2003
Joint Ventures				
Liquids Pipelines				
Mustang Pipeline	**30.0%**	30.0%	**18.8**	19.0
Hardisty Caverns	**50.0%**	50.0%	**35.5**	33.6
Gas Pipelines				
Alliance Pipeline U.S.	**50.0%**	50.0%	**391.3**	385.1
Vector Pipeline	**60.0%**	60.0%	**441.0**	421.6
Enbridge Offshore Pipelines – various joint ventures	**22%-80%**	–	**651.5**	–
Gas Distribution and Services				
Aux Sable	**42.7%**	42.7%	**125.7**	122.6
Alliance Canada Marketing	**42.7%**	42.7%	**0.1**	0.1
CustomerWorks Limited Partnership	**70.0%**	70.0%	**59.9**	51.5
Wind Power Assets	**50.0%**	50.0%	**25.6**	11.2
			1,749.4	1,044.7

In 2003, the Company invested $223.2 million in Alliance Pipeline Canada, Alliance Pipeline U.S., and Aux Sable, increasing the Company's interest from 37.1% to 50.0% in Alliance Pipeline Canada, 37.1% to 50% in Alliance Pipeline U.S. and 30.9% to 42.7% in Aux Sable. The purchase price was $36.9 million less than the underlying net book value of the assets. This amount was allocated to property, plant and equipment and is being amortized over the economic life of the assets.

7. JOINT VENTURES (continued)

On October 1, 2003, the Company invested $97.7 million in Vector, including the assumption of $61.5 million in debt, increasing the Company's ownership interest from 45% to 60%. The purchase price was $36.3 million less than the underlying net book value of the assets. This amount was allocated to property, plant and equipment and is being amortized over the economic life of the assets.

Following is a summary of the Joint Venture impact on the consolidated financial statements of Enbridge Inc.

(millions of dollars)

Year ended December 31	**2004**	2003
Earnings		
Revenues	**989.7**	546.8
Gas sales	**(482.4)**	(168.1)
Operating and administrative	**(241.3)**	(182.1)
Depreciation	**(74.9)**	(63.3)
Interest expense	**(66.6)**	(60.4)
Investment and other income	**2.5**	6.7
Income taxes	**(3.0)**	0.3
Proportionate share of net earnings	**124.0**	79.9
Cash Flows		
Cash provided by operations	**36.8**	128.6
Cash used in investing activities	**(23.4)**	0.7
Cash used in financing activities	**(2.8)**	(218.1)
Proportionate share of increase/(decrease) in cash	**10.6**	(88.8)

(millions of dollars)

December 31,	**2004**	2003
Financial Position		
Current assets	**202.0**	159.3
Property, plant and equipment, net	**2,010.8**	1,642.7
Other long-term assets	**353.5**	109.6
Current liabilities	**(138.7)**	(98.9)
Long-term debt	**(665.2)**	(752.4)
Other long-term liabilities	**(13.0)**	(15.6)
Proportionate share of net assets	**1,749.4**	1,044.7

Included in the Company's proportionate share of cash from joint ventures is $6.0 million (2003 – $18.7 million) held in trust, pursuant to finance agreements held by a joint venture.

8. LONG-TERM INVESTMENTS

(millions of dollars) December 31,	Ownership Interest	**2004**	2003
Equity Investments			
Liquids Pipelines			
Chicap Pipeline	22.8%	**23.0**	25.0
Sponsored Investments			
The Partnership	11.6%	**730.1**	743.6
Enbridge Income Fund	41.9%	**0.1**	–
		730.2	743.6
Gas Distribution and Services			
Noverco	32.1%	**46.0**	36.7
AltaGas Income Trust	–	**–**	210.7
Other		**3.0**	16.0
		49.0	263.4
International			
Compañía Logistica de Hidrocarburos (CLH)	25.0%	**663.6**	531.2
Corporate		**2.6**	17.8
Cost Investments			
Sponsored Investments			
Enbridge Income Fund		**380.2**	380.2
Gas Distribution and Services			
Noverco		**181.4**	181.4
Fuel Cell Energy		**25.0**	25.0
International			
OCENSA Pipeline		**223.3**	223.3
		2,278.3	2,390.9

Equity investments include $543.1 million (2003 – $536.4 million) representing the unamortized excess of the purchase price over the underlying net book value of the investee's assets at the date of purchase. The excess is attributable to the value of property, plant and equipment within the investees based on estimated fair values and is amortized over the economic life of the assets.

AltaGas Income Trust (AltaGas)

During 2004, AltaGas issued additional trust units. Enbridge did not participate in this offering causing a dilution of ownership to approximately 36% and the recognition of an $8.0 million after-tax dilution gain. Enbridge subsequently disposed of its investment in AltaGas. Net of underwriting fees, total cash proceeds from the disposition were $346.7 million, resulting in an after-tax gain of $97.8 million ($121.5 million pre-tax).

The Partnership

The Company owns 17.2% of EEM, which owns i-units, a class of limited partnership interest in EEP representing an 18.1% ownership in EEP. The Company also has a 2% general partner interest in EEP and a 6.5% direct interest for a combined 11.6% effective ownership in EEP. Although 82.8% of EEM is widely held, the Company has voting control of EEM. The Company's statement of financial position includes 100% of EEM's investment in EEP, which totals $480.6 million (2003 – $478.8 million). The Company's net investment in the Partnership, after deducting the non-controlling interest of $398.9 million (2003 – $396.4 million), is $331.3 million (2003 – $347.7 million).

In 2004, EEP completed a public issue of partnership units and in 2003, EEP completed two public issuances of partnership units. As the Company elected not to participate in these offerings, its effective interest in EEP was reduced to 11.6% from 12.2% (2003 – 12.2% from 14.1%). This resulted in recognition of a dilution gain of $7.6 million (2003 – $20.3 million), net of tax and minority interest.

Enbridge Income Fund

The Company has 14,500,000 subordinated trust units of EIF and 38,023,750 preferred units of Enbridge Commercial Trust (ECT), a subsidiary of EIF, at December 31, 2004. The subordinated units result in a 41.9% common equity interest in EIF.

The Company's $145.0 million initial investment in subordinated units of EIF was offset by a $145.0 million unrecognized gain resulting in a book value of nil. The unrecognized gain is being amortized into income over the life of the underlying assets of EIF and is included as a component of equity earnings.

The Company's 38,023,750 preferred units are accounted for as a $380.2 million (2003 – $380.2 million) cost investment at December 31, 2004. At the request of the Company, the ECT preferred units will be repurchased for cancellation in certain specified circumstances by ECT with a repurchase price per ECT preferred unit based on the net issue price realized from the sale (or that could be realized from the sale) of an ordinary trust unit to the public. The ECT preferred units have no voting rights and mature on June 30, 2033 at which time ECT is obligated to redeem all of the outstanding ECT preferred units for a price of ten dollars per unit. The economic terms of these units are comparable to those of ordinary common units. As such, the approximate fair value of these preferred units, valued at the December 31, 2004 closing price of $13.94 per ordinary common unit (2003 – $12.89), is $530.1 million (2003 – $490.1 million).

Noverco

Noverco holds an approximate 10% reciprocal shareholding in the Company. As a result, the Company has a pro-rata interest of 3.2% (2003 – 3.2%) in its own shares. Both the equity investment in Noverco Inc. and shareholders' equity have been reduced by the reciprocal shareholding of $135.7 million (2003 – $135.7 million).

The Company owns a cost investment in Noverco, of $181.4 million (2003 – $181.4 million), which is entitled to a cumulative dividend based on the average yield of Government of Canada bonds maturing in more than 10 years plus 4.34%. The fair value of the investment approximates its carrying value as its return is based on a floating rate.

CLH

In 2002, the Company invested $430.8 million in CLH, a refined products transportation and storage company in Spain. The Company's 25% interest is accounted for by the equity method. The purchase price included $340.9 million representing the excess of purchase price over the underlying net book value of the assets. The excess is attributable to the value of property, plant and equipment within the investment and is being amortized over the economic life of the assets.

Subsequent to the initial purchase, contingent payments of 10.5 million Euros ($16.9 million) were made due to CLH meeting minimum annual and cumulative volume targets. In addition, the remaining contingent consideration that may become payable is 74.3 million Euros ($121.0 million). Of this, 63.4 million Euros ($103.3 million) has been accrued at December 31, 2004.

OCENSA Pipeline

The Company owns a cost investment in the OCENSA Pipeline of $223.3 million (2003 – $223.3 million), which earns a fixed rate of return. The fair value of this investment is approximately $254.3 million (2003 – $270.0 million), estimated using year-end market information.

Income from Equity Investments

(millions of dollars)

Year ended December 31,	**2004**	2003	2002
Liquids Pipelines	**1.1**	1.1	1.0
Gas Pipelines	**–**	31.6	67.1
Sponsored Investments	**79.5**	73.3	40.9
Gas Distribution and Services	**29.4**	19.9	7.7
International	**49.6**	45.7	34.2
Corporate	**0.7**	1.2	–
	160.3	172.8	150.9

Consolidated retained earnings at December 31, 2004 include undistributed earnings from equity investments of $121.8 million (2003 – $130.5 million).

9. DEFERRED AMOUNTS AND OTHER ASSETS

(millions of dollars)

December 31,	**2004**	2003
Regulatory deferrals	**266.8**	218.6
Contractual receivables	**118.6**	100.4
Long-term portion of receivables from hedge counterparty	**179.9**	114.3
Deferred pension funding	**65.0**	66.3
Deferred financing charges	**39.5**	42.2
Other	**59.4**	66.4
	729.2	608.2

At 2004 year-end, a balance of $114.7 million (2003 – $105.1 million) was subject to amortization. Amortization expense of deferred amounts in 2004 was $13.9 million (2003 – $18.4 million; 2002 – $21.7 million). Accumulated amortization at the end of 2004 was $55.6 million (2003 – $38.9 million).

10. DEBT

(millions of dollars)

December 31,	Weighted Average Interest Rate	Maturity	**2004**	2003
Liquids Pipelines				
Debentures	8.20%	2024	**200.0**	200.0
Medium-term notes	6.66%	2005-2029	**622.8**	622.7
Other[1]			**90.6**	58.7
Gas Distribution and Services				
Debentures	10.98%	2009-2024	**585.0**	635.0
Medium-term notes	6.11%	2005-2033	**1,230.0**	1,030.0
Other			**8.4**	9.5
Corporate				
Senior term notes *(US$275.0 million)*	8.08%	2005-2007	**331.0**	397.8
Medium-term notes	6.17%	2005-2032	**1,692.5**	1,790.0
Preferred securities	7.80%	2051	**200.0**	550.0
Other[2]			**1,796.9**	1,117.7
Total Debt			**6,757.2**	6,411.4
Current maturities of long-term debt			**530.2**	450.0
Other short-term debt			**173.7**	185.9
Current Maturities and Short-Term Debt			**703.9**	635.9
Long-Term Debt			**6,053.3**	5,775.5

1 *Primarily commercial paper borrowings.*
2 *Primarily commercial borrowings and drawdowns on credit facilities. Includes US$585.0 million (2003 – US$306.0 million).*

Short-term debt in the amount of $1,361.1 million (2003 – $1,000.0 million) is supported by the availability of long-term committed credit facilities and has been classified as long-term debt.

Long-term debt maturities for the years ending December 31, 2005 through 2009 are $530.2 million, $400.0 million, $340.8 million, $602.0 million and $200.0 million, respectively.

The Company has $200 million of 7.8% Preferred Securities outstanding. The Preferred Securities may be redeemed at the Company's option, in whole or in part, after February 15, 2007, being the fifth anniversary of its issue. The Company has the

10. DEBT (continued)

right to defer, subject to certain conditions, payments of distributions on the securities for up to 20 consecutive quarterly periods. Deferred and regular distribution amounts are payable in cash or, at the option of the Company, in common shares of the Company.

Interest Expense

(millions of dollars)

December 31,	**2004**	2003	2002
Long-term debt	**497.3**	468.1	439.3
Commercial paper and other short-term debt	**21.7**	20.2	29.0
Short-term borrowings	**10.5**	9.6	9.6
Capitalized	**(4.2)**	(5.1)	(9.5)
	525.3	492.8	468.4

In 2004, total interest paid was $549.3 million (2003 – $508.6 million; 2002 – $473.2 million).

Credit Facilities

(millions of dollars)

December 31, 2004	Committed	Uncommitted	Drawdowns
Liquids Pipelines	150.0	–	–
Gas Distribution and Services	658.4	6.0	11.0
Corporate	2,222.2	–	361.1
	3,030.6	6.0	372.1

Committed facilities carry a weighted average standby fee of 0.10% per annum on the unutilized portion. The committed facilities for Liquids Pipelines expire in 2005 and are extendible annually subject to the approval of the lenders. The committed facilities for Gas Distribution and Services expire in 2005 and 2007 and are extendible annually thereafter subject to the approval of the lenders. The committed facilities for Corporate expire in 2005, 2006 and 2009 and are extendible annually thereafter subject to the approval of the lenders. Drawdowns under all of these facilities bear interest at prevailing market rates.

11. NON-RECOURSE DEBT OF JOINT VENTURES

(millions of dollars)

December 31,	**2004**	2003
Credit Facilities of Alliance Pipeline U.S. (US$8.9 million, 2003 – US$21.7 million)	**10.6**	28.0
Senior Notes of Alliance Pipeline U.S.:		
7.770% due 2015 (US$134.7 million, 2003 – US$140.0 million)	**162.1**	180.9
6.996% due 2019 (US$143.2 million, 2003 – US$153.4 million)	**172.3**	198.3
7.877% due 2025 (US$100.0 million, 2003 – US$100.0 million)	**120.4**	129.2
4.591% due 2025 (US$140.6 million, 2003 – US$146.2 million)	**169.3**	189.0
Obligations under capital leases (US$50.5 million, 2003 – US$47.4 million)	**60.7**	61.2
	695.4	786.6
Less current portion of long-term debt (US$25.1 million, 2003 – US$26.5 million)	**(30.2)**	(34.2)
	665.2	752.4

The debt of joint ventures is non-recourse to Enbridge. Security provided by the joint ventures is limited to all of the rights and assets of the individual joint venture and does not extend to the rights and assets of Enbridge.

The Senior Notes may be redeemed by Alliance Pipeline U.S. at any time, at a price equal to the outstanding principal plus accrued but unpaid interest and a make-whole premium. Alliance Pipeline U.S. may be required to redeem the Senior Notes, in whole or in part, from proceeds received under insurance claims for damages if the proceeds are not applied to repair or rebuild the Alliance pipeline system.

Interest and principal repayments on the Senior Notes are payable semi-annually each June 30 and December 31; principal repayments on the 7.877% Senior Notes commence June 2019. Principal repayments are closely tied to the recovery rates for capital depreciation and deferred income taxes contained in the transportation agreements.

Long-term debt maturities on joint venture borrowings for the years ending December 31, 2005 through 2009 are $30.2 million, $43.4 million, $35.5 million, $36.1 million and $41.2 million, respectively.

12. NON-CONTROLLING INTERESTS

(millions of dollars)

December 31,	**2004**	2003
EEM	**369.8**	377.0
Enbridge Gas Distribution preferred shares	**100.0**	100.0
Other	**45.1**	46.0
	514.9	523.0

Non-controlling interests in EEM include third party interest in the investment of $398.9 million (2003 – $396.4 million) plus third party interests in distributions received from, and earnings of, EEM.

The 4,000,000 4.82% Cumulative Redeemable Enbridge Gas Distribution Preferred Shares, Group 3 Series D are entitled to fixed, cumulative, preferential dividends. Subsequent to July 1, 2009, the Company may, at its option, redeem all or a portion of the outstanding preferred shares, equal to 500,000 or more, for $25.50 if the preferred shares are listed or $25.00 in all other circumstances in each case with all accrued and unpaid dividends to the redemption date. On July 1, 2009, and every five years thereafter, the preferred shares are convertible into cumulative, redeemable preference shares, Group 2, Series D. The Series D preferred shares would pay fixed cumulative dividends quarterly at rates selected with reference to the Government of Canada yield.

13. SHARE CAPITAL

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

Common Shares

(millions of dollars; number of common shares in millions)

December 31,	**2004**		2003		2002	
	Number of Shares	**Amount**	Number of Shares	Amount	Number of Shares	Amount
Balance at beginning of year	**171.9**	**2,238.0**	169.7	2,169.0	162.9	1,875.9
Dividend Reinvestment and Share Purchase Plan	**0.2**	**11.0**	0.4	17.1	0.2	8.3
Issued to Noverco	**–**	**–**	–	–	0.5	23.1
Public issue	**–**	**–**	–	–	5.0	225.4
Exercise of stock options and other	**1.0**	**33.4**	1.8	51.9	1.1	36.3
Balance at end of year	**173.1**	**2,282.4**	171.9	2,238.0	169.7	2,169.0

Contributed Surplus

(millions of dollars)

December 31,	**2004**	2003
Balance at beginning of year	**1.9**	–
Stock-based compensation	**3.7**	1.9
Option exercises	**(0.2)**	–
Balance at end of year	**5.4**	1.9

The fair value based method to expense stock options has been applied on a prospective basis since January 1, 2003. Stock-based compensation expense from fixed stock options and performance-based options is recognized in earnings over the vesting period with a corresponding increase in contributed surplus. Contributed surplus is decreased and share capital is increased upon the exercise of these options.

Preferred Shares

The 5,000,000 5.5% Cumulative Redeemable Preferred Shares, Series A are entitled to fixed, cumulative, preferential dividends of $1.375 per share per year, payable quarterly. Subsequent to December 31, 2004, the Company may, at its option, redeem all or a portion of the outstanding preferred shares for $25.75 if redeemed on or prior to December 1, 2005; $25.50 if redeemed on or prior to December 1, 2006; $25.25 if redeemed on or prior to December 1, 2007; and $25.00 if redeemed thereafter, in each case with all accrued and unpaid dividends to the redemption date.

Earnings Per Common Share

Earnings per common share is calculated by dividing earnings applicable to common shareholders by the weighted average number of common shares outstanding. The weighted average number of shares outstanding has been reduced by the Company's pro-rata weighted average interest in its own common shares of 5.3 million shares (2003 – 5.3 million shares), resulting from the investment in Noverco.

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

(number of common shares in millions)

December 31,	**2004**	2003	2002
Weighted average shares outstanding	**167.2**	165.5	160.3
Effect of dilutive options	**1.4**	1.4	1.7
Diluted weighted average shares outstanding	**168.6**	166.9	162.0

For the year ended December 31, 2004, 875,400 (2003 – nil, 2002 – 33,500) stock options with a weighted average exercise price of $51.47 (2003 – nil, 2002 – 46.70) were excluded from the diluted earnings per share calculation. Stock options are excluded when the exercise price exceeds the average share price in a respective period.

Dividend Reinvestment and Share Purchase Plan

Under the plan, registered shareholders may reinvest dividends in common shares of the Company or make optional cash payments to purchase additional common shares, in either case free of brokerage or other charges.

Shareholder Rights Plan

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

14. STOCK OPTION AND STOCK UNIT PLANS

The Company maintains two plans for long-term incentive compensation: the Incentive Stock Option Plan (2002) and the Performance Stock Unit Plan (2004). The Company's Incentive Stock Option Plan includes fixed stock options and performance-based stock options. A maximum of 15 million common shares is reserved for issuance under this plan. The Company's Performance Stock Unit Plan grants notional units equivalent to one Enbridge Inc. common share.

Fixed Stock Options

Full-time, key employees are granted options to purchase common shares that are exercisable at the market price of common shares at the date the options are granted. Generally, options vest in equal annual installments over a four-year period and expire ten years after the issue date. Outstanding stock options expire over a period ending no later than October 1, 2014.

Outstanding Fixed Stock Options

(options in thousands; exercise price in dollars)

December 31,	**2004**		2003		2002	
	Number	**Weighted Average Exercise Price**	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Options at beginning of year	**4,741**	**35.96**	5,042	32.16	5,120	29.06
Options granted	**891**	**51.47**	1,042	41.65	1,024	43.80
Options exercised	**(779)**	**30.08**	(1,244)	26.64	(1,003)	26.31
Options cancelled or expired	**(28)**	**47.30**	(99)	39.87	(99)	37.59
Options at end of year	**4,825**	**39.71**	4,741	35.96	5,042	32.16
Options vested	**2,521**		2,319		2,639	

Fixed Stock Option Characteristics

(options in thousands; exercise price in dollars)

December 31, 2004

	Options Outstanding				Options Vested	
	Exercise Price Range	Number (000's)	Weighted Average Remaining Life (years)	Weighted Average Exercise Price	Number (000's)	Weighted Average Exercise Price
	10.30-19.99	40	1.16	14.90	40	14.90
	20.00-29.99	750	4.55	25.91	750	25.91
	30.00-39.99	1,265	5.08	36.17	1,066	35.81
	40.00-49.99	1,895	7.48	42.62	665	42.93
	50.00-59.99	875	9.10	51.47	–	–
		4,825			2,521	

Performance-based Options

The Plan provides for the grant of performance-based options to executive officers that become exercisable based on the performance of the Company's common share price. Of the outstanding performance-based stock options as at December 31, 2004, 810,000 remain unexercisable and were granted September 16, 2002 at $46.30 per option. These performance-based stock options vest in equal annual installments over their five-year term and become exercisable, as to 50% of the grant, if the price on an Enbridge common share exceeds $61.00 per share for 20 consecutive trading days during the period the period September 16, 2002 to September 16, 2007 and, as to 100% of the grant, if the price of an Enbridge common share exceeds $71.00 for 20 consecutive trading days during the same aforementioned period. The term will extend to eight years if any of these options become exercisable before the end of the five-year term.

14. STOCK OPTION AND STOCK UNIT PLANS (continued)

Outstanding Performance-based Options

(options in thousands; exercise price in dollars)

December 31,	**2004**		2003		2002	
	Number	**Weighted Average Exercise Price**	Number	Weighted Average Exercise Price	Number	Weighted Average Exercise Price
Options at beginning of year	**1,496**	**40.05**	2,045	37.73	1,479	32.03
Options granted	–	–	–	–	810	46.30
Options exercised	**(218)**	**32.39**	(549)	31.39	(244)	31.66
Options cancelled	–	–	–	–	–	–
Options at end of year	**1,278**	**41.36**	1,496	40.05	2,045	37.73
Options vested	**468**	**32.81**	686	32.67	1,235	32.10

At December 31, 2004, the exercise prices of outstanding performance-based options ranged from $31.35 to $46.30 (2003 – $31.35 to $46.30; 2002 – $31.35 to $46.30). Outstanding performance-based options will expire over a period ending no later than September 16, 2010. Vested performance-based options will expire in 2006.

Performance Stock Units

During the year ended December 31, 2004, the Company implemented a Performance Stock Unit (PSU) plan and granted 32,975 PSUs to the Company's senior officers. Cash awards under the PSU plan may be paid out at the end of a three-year performance cycle. Awards are calculated by multiplying the number of units outstanding at the end of the performance period by the Company's share price at the time and by a performance multiplier as determined by the Company's total shareholder return over the three-year performance period relative to a specified peer group of companies. The performance multiplier ranges from 0, if the Company's performance fails to meet threshold performance levels, to a maximum of 2, if the Company outperforms its peer group. Upon settlement, the number of PSUs outstanding is increased to include additional PSUs equal to the number of additional shares that would have been received had the PSUs been treated as shares enrolled in the Dividend Reinvestment Plan (DRIP) during the three-year period.

Outstanding Performance Stock Units

December 31,	**2004**
Units at beginning of year	–
Units granted	**32,975**
DRIP	**869**
Units at end of year	**33,844**
Units vested	–

Pro forma Compensation Expense

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

(millions of dollars)

Year ended December 31,	**2004**	2003	2002
Earnings applicable to common shareholders from continuing operations			
As reported	**645.3**	667.2	330.0
Total stock-based compensation expense[1]	**(8.2)**	(5.9)	(2.9)
Included as an expense in the statement of earnings[2]	**4.2**	1.9	–
Pro forma	**641.3**	663.2	327.1
Earnings applicable to common shareholders			
As reported	**645.3**	667.2	572.3
Total stock-based compensation expense[1]	**(8.2)**	(5.9)	(2.9)
Included as an expense in the statement of earnings[2]	**4.2**	1.9	–
Pro forma	**641.3**	663.2	569.4
Earnings per common share from continuing operations			
As reported	**3.86**	4.03	2.06
Pro forma	**3.83**	4.01	2.04
Earnings per common share			
As reported	**3.86**	4.03	3.57
Pro forma	**3.83**	4.01	3.55

1 Total stock-based compensation expense if the fair value based method to expense all outstanding stock options had been applied since January 1, 2002.

2 Stock-based compensation recognized as an expense in the statement of earnings for options and performance stock units granted in 2004 and 2003 as a result of the adoption of the fair-valued based method January 1, 2003.

The Black-Scholes model was used to calculate the fair value of fixed stock options and the barrier valuation model was used to calculate the fair value of performance based options. Significant assumptions used in these models are as follows:

Year ended December 31,	**2004**	2003	2002	**2004**	2003	2002
	Fixed Stock Options			Performance Based Options		
Fair value per option	**$ 7.70**	$ 8.46	$ 11.42	–	–	$ 7.65
Valuation assumptions						
Expected option term (yrs)	**8**	8	10	–	–	8
Expected volatility	**15%**	22%	25%	–	–	24%
Expected dividend yield	**3.54%**	3.95%	3.51%	–	–	3.46%
Risk-free interest rate	**4.80%**	5.24%	5.33%	–	–	4.20%

15. FINANCIAL INSTRUMENTS

Derivative Financial Instruments Used for Risk Management

The Company is exposed to movements in foreign currency exchange rates, interest rates and the price of energy commodities. In order to manage these exposures the Company utilizes derivative financial instruments to create offsetting financial positions to specific underlying or cash market physical exposures. These instruments are not used for speculative purposes.

Derivative financial instruments involve credit and market risks. Credit risk arises from the possibility that a counterparty will default on its contractual obligations and is limited to those contracts where the Company would incur a loss in replacing the instrument. The Company minimizes credit risk by entering into risk management transactions only with institutions that possess investment grade credit ratings or with approved forms of collateral. For transactions with terms greater than five years, the Company may also retain the right to require a counterparty, that would otherwise meet the Company's credit criteria, to provide collateral.

Foreign Exchange

The Company has an exposure to foreign currency exchange rates, primarily because of its U.S. dollar denominated investments and its Euro investment in CLH where both carrying values and earnings are subject to foreign exchange risk. The Company utilizes par forward contracts and cross currency swaps to manage a portion of the foreign exchange exposure. In addition, US$275 million (2003 – US$275 million) cross currency swaps have been entered into to hedge the Company's exposure on its U.S. dollar denominated senior term notes.

Interest Costs

The Company enters into forward interest rate agreements, swaps and collars to swap floating rate debt to fixed and hedge against the effect of future interest rate movements on its variable rate debt. The Company monitors its debt portfolio mix of fixed and variable rate instruments and has entered into fixed to floating interest rate swaps, with an aggregate notional amount of $300 million (2003 – $300 million), to manage the balance of fixed and floating rate debt.

Energy Commodity Costs

The Company uses over-the-counter natural gas price swaps, futures, options and collars to manage the value of pipeline capacity that arise from capacity commitments to the Alliance and Vector pipelines. The Company also uses derivative instruments to fix the value of variable price exposures that arise from physical asset optimization and natural gas supply agreements.

As a result of the Company's ownership interest in Aux Sable Products L.P., it is exposed to price differential between natural gas and natural gas liquids ("NGL"). This risk is hedged through the use of over-the-counter derivatives whereby the forward prices of natural gas and NGLs are fixed with swaps, or capped or collared with options.

Natural Gas Supply Management

The Company hedges a portion of the cost of future natural gas supply requirements of EGD, on behalf of its ratepayers, as allowed by the regulator. Amounts paid or received under the hedge agreements are recognized as part of the cost of the natural gas purchases and are recovered through the ratemaking process. At December 31, 2004, the Company had entered into natural gas price swaps and options to manage the price for approximately 27%, or 34.9 billion cubic feet, of its forecast fiscal 2005 system gas supply.

Fair Values

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.

(millions of dollars unless otherwise noted)

December 31,	**2004**			2003		
	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	**535.8**	**(51.1)**	**2005-2022**	535.8	(30.6)	2005-2022
Euro cross currency swaps	**493.5**	**(51.3)**	**2004-2019**	434.7	(46.1)	2004-2019
Forwards (cumulative exchange amounts)	**1,740.3**	**181.0**	**2005-2022**	1,889.5	67.9	2004-2022
Energy commodities						
Natural gas (bcf)	**107.8**	**(1.0)**	**2005-2010**	63.6	12.4	2004-2008
Natural gas supply management (bcf)	**34.9**	**(28.1)**	**2005**	13.1	(3.4)	2004
Interest rates						
Interest rate swaps	**1,069.0**	**1.5**	**2005-2029**	561.0	1.9	2005-2029
Forward interest rate swaps	**200.0**	**–**	**2006**	532.0	(1.0)	2004-2005

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $214.0 million (2003 – $214.0 million), to exchange Canadian for U.S. dollars. The outstanding instruments expire in 2005 and 2007. The contracts are not effective hedges for accounting purposes but offset an exposure related to income taxes on foreign currency gains or losses on Canadian dollar debt of a U.S. subsidiary. These instruments are recorded at fair value and have a fair value payable of $28.8 million as at December 31, 2004 (2003 – $10.5 million).

As the Company has not settled any hedging instruments in advance of the hedged transactions, there were no deferred gains or losses for any of the Company's hedges of anticipated transactions at December 31, 2004 and 2003. A credit risk on derivative financial instruments amounted to $211.2 million at December 31, 2004 (2003 – $94.8 million) with no significant concentration with any single counterparty.

Interest Rate Management

The derivative instruments used to manage interest rate risk and the associated debt related to these instruments are as follows:

(millions of dollars) **December 31, 2004**	Maturity	Effective Interest Rate[1]	Notional Amounts
Liquids Pipelines			
Commercial paper (floating interest to fixed interest swap)	2029	6.0%	25.4
Corporate			
Commercial paper (floating interest to fixed interest swap)	2005	2.7%	400.0
Commercial paper (floating interest to fixed interest swap)	2005-2006	2.3%	US$285.5
Senior term notes (cross currency swap)	2005-2007	7.4%	US$275.0
Medium term notes 5.45% (fixed to floating interest swap)	2006	floating	300.0

1 After giving effect to the derivative financial instruments.

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 fair value of other financial instruments reflect the Company's best estimate and are based on the Company's valuation techniques or models to estimate market values.

Total Debt

(millions of dollars) December 31,	**2004**		2003	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Liquids Pipelines	**913.4**	**1,037.8**	881.4	990.6
Gas Distribution and Services	**1,823.4**	**2,168.9**	1,674.5	1,972.1
Corporate	**4,020.4**	**4,275.6**	3,855.5	4,089.6
	6,757.2	**7,482.3**	6,411.4	7,052.3

The fair value of debt does not include the effects of hedging. Non-recourse debt of joint ventures has a carrying value of $695.4 million (2003 – $786.6 million) and a fair value of $769.4 million (2003 – $845.7 million).

Trade Credit Risk

Trade receivables related to Liquids Pipelines consist primarily of amounts due from companies operating in the oil and gas industry and are collateralized by the crude oil and other products contained in the Company's pipelines and storage facilities. Trade receivables in Gas Pipelines also consist primarily of amounts due from companies in the oil and gas industry and are collateralized by the products contained in the pipelines and storage facilities. Credit risk in the Gas Distribution and Services segment is reduced by the large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. Included in accounts receivable is an allowance for doubtful accounts of $45.5 million at December 31, 2004 (2003 – $35.1 million).

16. INCOME TAXES

Income Tax Rate Reconciliation

(millions of dollars)

Year ended December 31,	**2004**	2003	2002
Earnings before income taxes	**941.4**	846.7	700.4
Combined statutory income tax rate	**34.4%**	35.6%	38.0%
Income taxes at statutory rate	**323.8**	301.4	266.2
Increase/(decrease) resulting from:			
Tax rate changes on future income tax balances	**42.7**	6.2	8.1
Future income taxes related to regulated operations	**(13.2)**	(34.5)	(36.7)
Non-taxable items, net	**(44.6)**	(70.5)	(99.5)
Lower foreign tax rates	**(40.9)**	(44.4)	(42.2)
Large Corporations Tax	**17.6**	18.1	16.9
Other	**3.8**	(3.7)	8.4
Income Taxes	**289.2**	172.6	121.2
Continuing operations	**289.2**	172.6	86.6
Discontinued operations	**–**	–	34.6
	289.2	172.6	121.1
Effective income tax rate	**30.7%**	30.4%	17.0%

In 2004, income taxes paid amounted to $243.2 million (2003 – $202.9 million; 2002 – $105.2 million).

Components of Future Income Taxes

(millions of dollars)

December 31,	**2004**	2003
Future Income Tax Liabilities		
Differences in accounting and tax bases of property, plant and equipment	**425.3**	368.0
Differences in accounting and tax bases of investments	**323.0**	368.2
Other	**197.2**	187.2
	945.5	923.4
Future Income Tax Assets		
Loss carryforwards	**207.5**	241.7
Other	**85.7**	45.2
	293.2	286.9
Total Net Future Income Tax Liability	**652.3**	636.5

Accumulated future income taxes related to rate-regulated operations, which have not been recorded in the accounts amounted to $596.8 million at December 31, 2004 (2003 – $551.2 million). Had the liability method been prescribed by the regulatory authorities for ratemaking purposes, such amounts would have been recorded and recovered in revenues.

At December 31, 2004, the Company has recognized the benefit of unused tax loss carryforwards of $596.4 million (2003 – $708.8 million). Unused tax loss carryforwards expire as follows: 2005 – $0.3 million; 2006 – $24.9 million; 2007 – $24.6 million; 2008 – $22.1 million, 2009 – $9.5 million and 2010 – $4.6 million and 2011 and beyond – $510.4 million.

Geographic Components of Pretax Earnings and Income Taxes

(millions of dollars)

Year ended December 31,	2004	2003	2002
Earnings before income taxes			
Canada	**682.9**	651.5	299.7
United States	**123.2**	40.1	(5.0)
Other	**135.3**	155.1	128.8
Continuing operations	**941.4**	846.7	423.5
Discontinued operations	**–**	–	276.9
	941.4	846.7	700.4
Current income taxes			
Canada	**267.4**	93.7	152.4
United States	**5.0**	(10.9)	3.2
Other	**4.1**	4.0	8.8
Continuing operations	**276.5**	86.8	164.4
Discontinued operations	**–**	–	36.9
	276.5	86.8	201.3
Future income taxes			
Canada	**(18.3)**	116.6	(67.6)
United States	**30.6**	(31.0)	(10.5)
Other	**0.4**	0.2	0.3
Continuing operations	**12.7**	85.8	(77.8)
Discontinued operations	**–**	–	(2.3)
	12.7	85.8	(80.1)
Current and future income taxes			
Continuing operations	**289.2**	172.6	86.6
Discontinued operations	**–**	–	34.6
	289.2	172.6	121.2

17. POST-EMPLOYMENT BENEFITS

Pension Plans

The Company has three pension plans which provide either defined benefit or defined contribution pension benefits or both for employees of the Company. The Liquids Pipelines and Gas Distribution and Services pension plans provide non-contributory defined pension and/or defined contribution benefits to Canadian employees of Enbridge. The Enbridge U.S. pension plan provides non-contributory defined benefit pension benefits. The Company has four supplemental pension plans which provide pension benefits that exceed those benefits earned in the regulated plan.

Defined Benefit Plans

Retirement benefits under defined benefit plans are based on employees' years of service and remuneration. Contributions made by the Company are made in accordance with independent actuarial valuations and are invested primarily in publicly-traded equity and fixed income securities. The effective dates of the most recent actuarial valuations and the next required actuarial valuations are as follows:

	Effective Date of Most Recently Filed Actuarial Valuation	Effective Date of Next Required Actuarial Valuation
Liquids Pipelines	January 1, 2004	January 1, 2007
Enbridge U.S.	January 1, 2004	January 1, 2005
Gas Distribution and Services	January 1, 2002	January 1, 2005

Pension costs under the defined benefit pension plans reflect management's best estimates of the rate of return on pension plan assets, rate of salary increases and various other factors including mortality rates, terminations and retirement ages.

Defined Contribution Plans

Contributions are generally based on the employee's age, years of service and remuneration. For defined contribution pension benefits, pension costs equal amounts required to be contributed by the Company. Pension costs in respect of these plans during the year were $2.3 million (2003 – $2.0 million; 2002 – $2.3 million).

Post-employment Benefits Other than Pensions

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

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

	OPEB		Pension Benefit	
(millions of dollars)	**2004**	2003	**2004**	2003
Change in benefit obligation				
Benefit obligation, January 1	**155.7**	160.5	**788.3**	710.1
Service cost	**4.0**	5.8	**22.7**	20.0
Interest cost	**9.4**	10.6	**49.4**	46.8
Amendments	**(2.2)**	(3.3)	**0.7**	–
Employee contributions	**0.4**	0.4	**–**	–
Actuarial loss	**13.5**	0.8	**30.4**	68.8
Benefits paid	**(5.4)**	(5.6)	**(38.9)**	(37.8)
Other	**–**	–	**3.3**	–
Effect of exchange rate changes	**(5.1)**	(13.5)	**(8.0)**	(19.6)
Benefit obligation, December 31	**170.3**	155.7	**847.9**	788.3
Fair value of plan assets				
Fair value of plan assets, January 1	**36.2**	35.5	**986.7**	933.1
Actual return on plan assets	**1.7**	0.8	**110.0**	109.7
Employer's contributions	**9.9**	11.2	**14.5**	11.2
Employee contributions	**0.4**	0.4	**–**	–
Benefits paid	**(5.4)**	(5.6)	**(38.9)**	(37.8)
Other	**–**	–	**(0.8)**	(1.7)
Effect of exchange rate changes	**(2.6)**	(6.1)	**(9.7)**	(27.8)
Fair value of plan assets, December 31	**40.2**	36.2	**1,061.8**	986.7
Asset/(Liability)				
Benefit obligation, December 31	**(170.3)**	(155.7)	**(847.9)**	(788.3)
Fair value of plan assets, December 31	**40.2**	36.2	**1,061.8**	986.7
Surplus/(deficit)	**(130.1)**	(119.5)	**213.9**	198.4
Contribution after measurement date	**–**	–	**2.9**	2.9
Unamortized prior service cost	**0.4**	0.5	**17.2**	19.0
Unamortized transitional obligation/(asset)	**24.2**	29.4	**(24.1)**	–
Unrecognized net loss	**38.9**	28.0	**26.0**	21.0
Recorded asset/(liability)	**(66.6)**	(61.6)	**235.9**	241.3

The previous table reflects the funded status and recorded pension and OPEB assets and liabilities for all of the Company's benefit plans on an accrual basis. However, in accordance with its ability to recover employee benefit costs on a pay-as-you-go basis for the regulated operations of Gas Distribution and Services, the Company records the cost of such benefits on a cash basis. Using the cash basis for the Gas Distribution and Services plans and the accrual method for other plans, the Company's net pension asset was $72.9 million (2003 – $71.4 million). The net OPEB liability was $11.8 million (2003 – $10.0 million). These net assets or liabilities are recorded on the balance sheet in Deferred Amounts and Other Assets with the current portion recorded in working capital accounts.

Major Categories of Plan Assets

(millions of dollars)	OPEB				Pension Benefit			
Year ended December 31,	**2004**		2003		**2004**		2003	
	%	**Amount**	%	Amount	%	**Amount**	%	Amount
Equity securities	**–**	**–**	–	–	**58.7%**	**691.1**	58.5%	639.1
Debt securities	**84.1%**	**33.8**	85.9%	31.1	**37.0%**	**435.4**	37.1%	404.4
Other	**15.9%**	**6.4**	14.1%	5.1	**4.3%**	**50.4**	4.4%	47.8
	100.0%	**40.2**	100.0%	36.2	**100.0%**	**1,176.9**	100.0%	1,091.3
Assets attributable to Non-Consolidated Affiliates		**–**		–		**(115.1)**		(104.6)
Total Assets		**40.2**		36.2		**1,061.8**		986.7

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

Expected Rate of Return on Plan Assets

	OPEB		Pension Benefit	
Year ended December 31,	**2004**	2003	**2004**	2003
Canadian Plans	**4.50%**	4.50%	**7.25%**	7.25%
United States Plan	**4.50%**	4.50%	**7.75%**	7.25%

The pension funds exist to ensure that pension benefits will be paid. The Company manages the investment risk of its pension funds by setting a long term asset mix policy for each pension fund after consideration of: (i) the nature of pension plan liabilities; (ii) the investment horizon of the plan; (iii) the going concern and solvency funded status and cash flow requirements of the plans; (iv) the operating environment and financial situation of the Company and its ability to withstand fluctuations in pension contributions; and (v) the future economic and capital markets outlook with respect to investment returns, volatility of returns and correlation between assets. The above table reflects both the target allocation percentage for each of the categories presented at the end of the years, as well as, the expected long-term rate of return on assets, both on a weighted-average basis. The overall expected rate of return is based on the asset allocation targets with estimates for returns on equity and debt securities based on long term expectations.

Plan Contributions by the Company

(millions of dollars)	OPEB		Pension Benefit	
Year ended December 31,	**2004**	2003	**2004**	2003
Total contributions	**9.9**	11.2	**14.5**	11.2
Contributions expected to be paid in 2005	**10.9**		**12.2**	

Benefits Expected to be Paid by the Company

(millions of dollars)						
Year ended December 31,	2005	2006	2007	2008	2009	2010-2014
Expected future benefit payments	48.2	47.6	49.7	52.0	54.4	316.2

17. POST-EMPLOYMENT BENEFITS (continued)

Net Pension Plan and OPEB Costs Recognized

(millions of dollars)

Year ended December 31,	2004	2003	2002
Benefits earned during the year	**29.0**	27.7	25.2
Interest cost on projected benefit obligations	**58.8**	57.4	54.5
Actual return on plan assets	**(111.7)**	(110.5)	16.7
Difference between actual and expected return on plan assets	**41.1**	45.7	(92.0)
Amortization of prior service costs	**2.3**	2.8	2.3
Amortization of transitional obligation	**2.2**	0.5	4.2
Amortization of actuarial loss	**10.1**	12.0	0.4
Special Termination Benefits	**3.3**	–	–
Amount charged to EEP	**(7.8)**	(10.2)	(1.7)
Pension and OPEB cost recognized	**27.3**	25.4	9.6

The above table reflects the pension and OPEB cost for all of the Company's benefit plans on an accrual basis. However, in accordance with its ability to recover employee benefit costs on a pay-as-you-go basis for the regulated operations of Gas Distribution and Services, the Company records the cost of such benefits on a cash basis. Using the cash basis for the Gas Distribution and Services plans and the accrual method for other plans, the Company's pension cost was $11.6 million (2003 – $9.4 million; 2002 – $(3.6) million).

Economic Assumptions

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

	OPEB			Pension Benefits		
Year ended December 31,	**2004**	2003	2002	**2004**	2003	2002
Discount rate	**6.31%**	6.79%	6.95%	**6.29%**	6.75%	6.81%
Average rate of salary increases				**4.00%**	4.00%	4.00%
Average rate of return on pension plan assets	**4.50%**	4.50%	4.50%	**7.32%**	7.25%	7.79%

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

	OPEB			Pension Benefits		
Year ended December 31,	**2004**	2003	2002	**2004**	2003	2002
Discount rate	**6.21%**	6.31%	6.79%	**6.26%**	6.29%	6.75%
Average rate of salary increases				**4.00%**	4.00%	4.00%

Medical Cost Trend Rates

The assumed medical cost trend rates for the next year used to measure the expected cost of benefits and the ultimate trend rate and the year in which the ultimate trend rate is assumed to be achieved are as follows:

	Medical Cost Trend Rate Assumption for Next Fiscal Year	Ultimate Medical Cost Trend Rate Assumption	Year in which Ultimate Medical Cost Trend Rate Assumption is Achieved
Canadian Plans			
Drugs	10%	5%	2017
Other Medical	5%	5%	2005
Enbridge U.S.	12%	5%	2012

A one percent increase in the assumed medical and dental care trend rate would result in a change of $27.1 million in the accumulated post-employment benefit obligations and a change of $2.5 million in benefit and interest costs. A one percent decrease in the assumed medical and dental care trend rate would result in a change of $21.6 million in the accumulated post-employment benefit obligations and a change of $1.9 million in benefit and interest costs.

18. INVESTMENT AND OTHER INCOME

(millions of dollars)

Year ended December 31,	2004	2003	2002
Equity investments	**132.2**	146.3	143.5
Gain on reduction of EEP ownership interest	**19.7**	50.0	10.0
EEM's equity income from EEP	**28.1**	26.5	7.4
Minority interest in EEM (equity income and dilution gain)	**(20.2)**	(25.9)	(4.0)
Gain on reduction of AltaGas ownership interest	**9.9**	–	–
Cost investments	**84.0**	67.2	61.1
Investment income	**25.8**	32.9	22.9
Allowance for equity funds used during construction	**0.9**	3.2	5.3
Gain/(loss) on foreign currency contracts	**(21.3)**	(87.2)	0.1
Gain on sale of marketable securities	**–**	–	21.4
Other	**2.6**	(4.8)	15.4
	261.7	208.2	283.1

19. CHANGES IN OPERATING ASSETS AND LIABILITIES

(millions of dollars)

Year ended December 31,	2004	2003	2002
Accounts receivable and other	**(347.4)**	(346.9)	81.5
Inventory	**35.3**	(232.4)	69.5
Deferred amounts and other assets	**(94.2)**	(78.9)	72.4
Accounts payable and other	**278.3**	93.9	(76.4)
Interest payable	**(13.1)**	(5.5)	4.6
	(141.1)	(569.8)	151.6

Changes in accounts payable exclude changes in construction payables which are investing activities.

20. RELATED PARTY TRANSACTIONS

Neither, EEP nor EIF have employees and use the services of the Company for managing and operating their businesses. These services, which are charged at cost in accordance with service agreements, amount to $173.0 million (2003 – $128.9 million; 2002 – $97.2 million) for EEP and $9.4 million (2003 – $4.7 million) for EIF, which began operation on June 30, 2003.

Through the ownership of Enbridge Income Fund, Enbridge has an ownership interest in Alliance Canada. Alliance Canada has administrative and operation services agreements to provide services to Alliance Pipeline L.P. (an entity Enbridge jointly controls) in exchange for reimbursement of incurred costs or at rates consistent with those obtainable from independent third parties. Certain amounts reimbursed under the services agreements with Alliance Pipeline L.P. also include a recovery of costs relating to the use of common administrative assets. The Company's share of the amounts charged to Alliance Pipeline L.P. during the year ended December 31, 2004 were $3.2 million (six month period ended December 31, 2003 – $1.6 million).

The receivable from affiliate of $171.7 million (2003 – $169.8 million) resulted from the sale of Enbridge Midcoast Energy to EEP and the assumption of affiliate debt. The weighted average interest rate is 6.60% for 2004 and 2003. The receivable, which matures in 2007 is denominated in U.S. dollars. The balance on December 31, 2004 was US$142.1 million (2003 – US$133.1 million). Interest income related to the affiliate receivable was $11.8 million (US$9.0 million), $21.7 million (US$15.5 million) and $7.6 million (US$4.9 million), in 2004, 2003 and 2002, respectively. The fair value of the receivable at December 31, 2004 is $171.1 million.

20. RELATED PARTY TRANSACTIONS (continued)

Vector uses the services of Enbridge, a 60% interest owner, to operationally manage its business. These services, which are charged at cost in accordance with service agreements, amounted to $4.4 million for 2004 (2003 – $3.3 million; 2002 – $4.1 million).

EGD acquires its customer care services from CustomerWorks Limited Partnership under an agreement having a five-year term starting January 2002. EGD is charged market prices for these services, which amounted to $127.0 million in 2004 (2003 – $95.5 million; 2002 – $71.8 million).

EGD has contracted for gas transportation services from Alliance Pipeline Limited Partnership and Vector Pipeline Limited Partnership. EGD is charged market prices for these services, which amounted to $50.6 million in 2004 (2003 – $40.7 million; 2002 – $41.3 million) for Alliance Pipeline, and $39.1 million in 2004 (2003 – $23.2 million; 2002 – $25.2 million) for Vector Pipeline.

A subsidiary of the Company earns rental revenue from CustomerWorks Limited Partnership for the use of an automated billing system. In 2004, this revenue amounted to $22.5 million (2003 – $25.5 million; 2002 – $35.1 million). CustomerWorks Limited Partnership began operations on January 1, 2002.

In 2004, Enbridge Gas Services Inc., a subsidiary of the Company, purchased $30.7 million (2003 – $33.6 million; 2002 – $6.3 million) and sold $8.8 million (2003 – $1.3 million, 2002 – nil) of gas from/to Enbridge Marketing (US) Inc., a subsidiary of EEP.

The Company also provides consulting and other services to affiliates. 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 trade receivable and payable balances include amounts received or paid on behalf of the Company or affiliates.

The Company and affiliates invoice on a monthly basis and amounts are due and paid on a quarterly basis.

21. COMMITMENTS AND CONTINGENCIES

Enbridge Gas Distribution Inc.

Class Action Lawsuit – late payment penalties

On April 22, 2004, the Supreme Court of Canada released its decision in a case commenced against Enbridge Gas Distribution (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 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 2005.

Late payment penalty revenues are included in EGD's estimate of revenues for the year and therefore offset rates charged to customers. Revenues from late payment penalties accrue to the benefit of all customers, thereby reducing the cost of providing distribution services. The Ontario Energy Board (OEB) approved 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 (the TSSA) and the Ontario Occupational Health and Safety Act (the 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 approximately $5.0 million in the aggregate. EGD has also been named as a defendant in a number of civil actions related to the explosion. A Coroner's Inquest in connection with the explosion is also possible. The courts have not yet dealt with 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. EGD does not expect the civil actions to result in any material financial impact.

Remediation of Discontinued Manufactured Gas Plant Sites

The remediation of discontinued manufactured gas plant sites may result in future costs to EGD. In October 2002, a claim was filed for $55 million in damages relating to a certain manufactured gas plant site. EGD filed a statement of defence in June 2003 denying liability. EGD expects that trial scheduling will take place in the summer of 2005 and that a trial date will be fixed for early 2006. Although management believes that it has a valid defence to this claim, certain risks exist. The probable overall cost cannot be determined at this time due to uncertainty about the presence and extent of damage in addition to the potential alternative remediation approaches which vary in cost. EGD expects that costs, if any, not recovered through insurance would be recovered through rates. As such, management does not believe that the outcome will have any material financial impact.

CAPLA Claim

The Canadian Alliance of Pipeline Landowners' Associations and two individual landowners have commenced an action, which they will be applying for certification as a class action, against Enbridge Pipelines Inc. 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. Enbridge Pipelines Inc. believes it has a sound defence and intends to vigorously defend the claim. Since the outcome is indeterminable, Enbridge Pipelines Inc. has made no provision for any potential liability.

Enbridge Energy Partners

Enbridge Energy Company, Inc. (EEC), which holds a portion of the Company's equity interest in EEP, has agreed to indemnify EEP from and against substantially all liabilities, including liabilities relating to environmental matters, arising from operations prior to the transfer of its pipeline operations to EEP in 1991. This indemnification does not apply to amounts that EEP would be able to recover in its tariff rates if not recovered through insurance, or to any liabilities relating to a change in laws after December 27, 1991. In addition, in the event of default, EEC, as the General Partner, is subject to recourse with respect to a portion of EEP's long-term debt, which amounts to US$217 million at December 31, 2004 (2003 – US$248 million).

22. UNITED STATES ACCOUNTING PRINCIPLES

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

Earnings and Comprehensive Income

(millions of dollars except per share amounts)

Year ended December 31,	**2004**	2003	2002
Earnings under Canadian GAAP	**645.3**	667.2	572.3
Stock-based compensation[1]	**–**	–	(12.1)
Loss on ineffective hedges[4]	**–**	(53.8)	–
Tax effect of the above adjustments	**–**	21.5	4.9
Earnings under U.S. GAAP	**645.3**	634.9	565.1
Unrealized net gain/(loss) on cash flow hedges[5]	**(32.9)**	66.9	19.5
Reclassification adjustment on cash flow hedges[5]	**–**	80.6	–
Foreign currency translation adjustment[5]	**2.4**	(159.6)	(1.3)
Comprehensive income	**614.8**	622.8	583.3
Earnings per common share	**3.86**	3.84	3.53
Diluted earnings per common share	**3.83**	3.80	3.49

22. UNITED STATES ACCOUNTING PRINCIPLES (continued)

Financial Position

(millions of dollars)

December 31,	2004		2003	
	Canada	United States	Canada	United States
Cash[6]	**105.5**	**120.3**	104.1	131.7
Accounts receivable and other[5,6]	**1,451.9**	**1,483.6**	1,120.7	1,174.7
Property, plant and equipment[6]	**12,427.7**	**13,802.3**	11,481.5	12,829.9
Accumulated depreciation[6]	**3,361.2**	**3,468.2**	2,950.6	2,986.0
Goodwill and intangibles[6]	**165.4**	**581.8**	–	421.5
Long-term investments[6]	**2,278.3**	**1,898.1**	2,390.9	2,009.0
Deferred amounts[2,6]	**729.2**	**1,699.2**	745.7	1,477.5
Accounts payable and other[6]	**1,275.9**	**1,375.8**	894.1	1,011.7
Current maturities and short-term debt[6]	**703.9**	**715.2**	674.9	642.4
Current portion of non-recourse debt[6]	**30.2**	**71.7**	34.2	74.2
Long-term debt[6]	**6,053.3**	**6,264.9**	5,775.5	5,940.3
Non-recourse debt[6]	**665.2**	**1,503.5**	752.4	1,637.8
Other long-term liabilities[6]	**151.8**	**158.5**	148.3	154.8
Future income taxes[2]	**652.3**	**1,638.9**	636.5	1,558.0
Non-controlling interests[6]	**514.9**	**689.9**	523.0	709.5
Retained earnings	**1,840.9**	**1,770.3**	1,511.4	1,440.8
Additional paid in capital[1]	**–**	**27.3**	–	27.3
Foreign currency translation adjustment[5]	**(139.8)**	**–**	(147.0)	–
Accumulated other comprehensive loss[5]	**–**	**(147.1)**	–	(116.6)

1 *Stock-based Compensation*

Effective January 1, 2003, the Company adopted FAS 123, Accounting for Stock-Based Compensation, on a prospective basis for U.S. GAAP, and elected to use the fair value-based method to measure compensation expense. The adoption of the fair value method for U.S.GAAP eliminates all differences between Canadian and U.S. GAAP for options granted subsequent to the date of adoption. Disclosure differences in pro forma earnings between Canadian and U.S. GAAP will remain only for those options granted prior to adoption, January 1, 2002, of the Canadian accounting standard for stock-based compensation.

Prior to the adoption of FAS 123, the Company accounted for stock-based compensation for U.S. GAAP in accordance with APB 25, Accounting for Stock Issued to Employees, which required the use of the intrinsic value-based method to measure compensation expense. Under Canadian GAAP, the Company's performance-based options did not give rise to compensation expense. Under U.S. GAAP, the Company's performance-based options, which vested during 2002, gave rise to pre-tax compensation expense of $12.1 million. No performance-based options vested in 2003 or 2004.

2 *Future Income Taxes*

Under U.S. GAAP, deferred income tax liabilities are recorded for rate-regulated operations, which follow the taxes payable method for ratemaking purposes. As these deferred income taxes are expected to be recoverable in future revenues, a corresponding regulatory asset is also recorded. These assets and liabilities are adjusted to reflect changes in enacted income tax rates. The additional deferred income taxes under U.S. GAAP include the difference between capital cost allowance and depreciation of property, plant and equipment of $596.8 million (2003 – $551.2 million) and the incremental revenue required for the recovery of unrecorded taxes of $331.3 million (2003 – $286.6 million).

3 *Accounting for Joint Ventures*

U.S. GAAP requires the Company's investments in joint ventures be accounted for using the equity method. However, under an accommodation of the U.S. Securities and Exchange Commission, accounting for joint ventures need not be reconciled from Canadian to U.S. GAAP. The different accounting treatment affects only display and classification and not earnings or shareholders' equity. See Note 7 for summarized financial information of joint ventures.

4 *Financial Instruments*

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

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

5 Accumulated Other Comprehensive Loss

At December 31, 2004, Accumulated Other Comprehensive Loss consists of an accumulated foreign currency translation balance of $129.1 million (2003 – $131.5 million) and net unrealized losses of $18.0 million (2003 – gains of $14.9 million). For U.S. GAAP purposes the foreign currency translation adjustment balance is classified as a component of Accumulated Other Comprehensive Loss. The fair value of derivative financial instruments that qualify as cash flow hedges are also included in Accumulated Other Comprehensive Loss. The reclassification adjustment of $80.6 million relates to the change in classification of hedging instruments between periods.

Of the total Accumulated Other Comprehensive Loss of $147.1 million (2003 – $116.6 million), the Company estimates that approximately $27.9 million (2003 – $5.6 million), representing unrecognized net losses on derivative activities at December 31, 2004, is expected to be reclassified into earnings during the next twelve months and primarily relates to natural gas supply management.

6 Consolidation of Variable Interest Entities

On December 24, 2003, the Financial Accounting Standards Board issued a revision to FASB Interpretation (FIN) 46, which replaces the interpretation released in January 2003.

FIN 46R requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. FIN 46R defines a variable interest entity as an entity which has one or more of the following characteristics:

1 The equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by any parties, including the equity holders.
2 The equity investors as a group lack one or more of the following essential characteristics of a controlling financial interest:
   a) The direct or indirect ability to make decisions about the entity's activities through voting rights or similar rights that have a significant effect on the success of the entity.
   b) The obligation to absorb the expected losses of the entity.
   c) The right to receive the expected residual returns of the entity. The equity investors do not have that right if their return is capped by the entity's governing documents or arrangements with other variable interest holders or the entity.
3 The equity investors have voting rights that are not proportionate to their economic interests, and the activities of the entity involve or are conducted on behalf of an investor with a disproportionately small voting interest.

The primary beneficiary is the party that absorbs a majority of the expected losses and/or receives a majority of the expected residual returns of the variable interest entity's activities.

For variable interest entities created, or interests in variable interest entities obtained, on or before January 31, 2003, FIN 46R is required to be applied by the first fiscal year or interim period ending after December 15, 2003. The Company has not identified any material variable interest entities created, or interests in variable entities obtained, before January 31, 2003, which would require consolidation or disclosure under FIN 46R.

On June 30, 2003, the Company formed Enbridge Income Fund (EIF), a publicly traded entity with assets purchased from the Company. The Company has a 41.9% equity interest in EIF, 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.

EIF is considered a variable interest entity as the equity investors lack the right to receive the expected residual returns of the entity. FIN 46 defines expected residual returns as the expected positive variability in the fair value of EIF's net assets exclusive of variable interests. The preferred units participate in the positive variability as they receive a coupon rate that floats with changes in the cash distributions made to the equity holders of EIF. Consequently, the equity investors lack the right to receive the expected residual returns of the entity.

The Company is the primary beneficiary of EIF through a combination of the 41.9% equity interest and the preferred unit interest.

The U.S. GAAP adjustment reflecting the consolidation of EIF includes a $380.4 million (2003 – $381.9 million) reduction to long-term investments and a $175.0 million (2003 – $186.5 million) increase in non-controlling interests.

The following accounts of EIF are consolidated for the purposes of the U.S. GAAP financial statements:

(millions of dollars)

December 31,	**2004**	2003
Cash	**14.8**	27.6
Accounts receivable and other	**34.7**	34.2
Property, plant and equipment	**1,395.4**	1,454.6
Deferred amounts	**42.0**	31.5
Intangibles	**108.3**	113.4
Goodwill	**308.1**	308.1
Accounts payable and other	**33.8**	31.0
Current portion of non-recourse long-term debt	**41.5**	40.0
Long-term debt	**207.0**	201.9
Non-recourse long-term debt	**838.3**	885.4
Other long-term liabilities	**6.7**	6.5
Future income taxes	**92.1**	96.0

The consolidation of EIF increases cash by $14.8 million (2003 – $27.6 million) and the statement of cash flows would reflect an increase in cash from operations of $73.0 million (2003 – $36.4 million), cash from investing activities would decrease by $14.7 million (2003 – $359.4 million), and cash used in financing activities would decrease by $71.1 million (2003 – $350.6 million).

The method of consolidating EIF has been revised and the comparative amounts re-calculated to better reflect the attributes of the ECT preferred units. In the prior period the ECT preferred units were included in equity and consolidated on that basis, however because they are a preferred unit investment that has no voting rights, a stated par value and a fixed-term maturity, they have been reclassified from equity to liabilities. Therefore, the non-controlling interests increase from 27.7% to 58.1%, better reflecting their interest in the net assets of EIF.

The 2003 income reduction of $2.3 million and the $173.0 million gain reduction, as reported under US GAAP have been eliminated as a result of the change in consolidation method.

22. UNITED STATES ACCOUNTING PRINCIPLES (continued)

Supplemental Disclosure – Pro Forma Compensation Expense

U.S. GAAP requires that, where the fair value based method is not used to measure compensation expense, pro forma earnings and earnings per share, calculated as if the fair value based method had been used, must be disclosed. In Canada, these requirements apply to options granted on or after January 1, 2002 and therefore, the Company's Canadian GAAP disclosure does not include any options granted prior to that date.

(millions of dollars except per share amounts)

Year ended December 31,	**2004**	2003	2002
Earnings under U.S. GAAP			
As reported	**645.3**	634.9	565.1
Stock-based compensation expense	**(8.2)**	(7.9)	(7.3)
Included as an expense in the statement of earnings	**4.2**	1.9	–
Pro forma	**641.3**	628.9	557.8
Earnings per common share			
As reported	**3.86**	3.84	3.53
Stock-based compensation expense	**0.02**	0.04	0.05
Pro forma	**3.84**	3.80	3.48
Diluted earnings per common share			
As reported	**3.83**	3.80	3.49
Stock-based compensation expense	**0.02**	0.04	0.05
Pro forma	**3.81**	3.76	3.44

Supplementary Information (unaudited)

Quarterly Share Trading Information

The Toronto Stock Exchange

2004 *(dollars)*	First	Second	Third	Fourth
High	**55.0**	**54.39**	**53.35**	**60.15**
Low	**50.36**	**47.60**	**47.25**	**51.05**
Close	**53.30**	**48.71**	**52.75**	**59.70**
Volume *(millions)*	**22.8**	**23.7**	**15.7**	**15.5**

2003 *(dollars)*	First	Second	Third	Fourth
High	44.33	49.30	52.00	54.14
Low	40.95	42.71	47.50	47.90
Close	43.94	47.93	51.05	53.70
Volume *(millions)*	19.0	17.6	20.4	18.1

The New York Stock Exchange

2004 *(U.S. dollars)*	First	Second	Third	Fourth
High	**42.32**	**41.25**	**41.85**	**49.99**
Low	**37.72**	**35.18**	**36.38**	**40.70**
Close	**40.69**	**36.59**	**41.64**	**49.78**
Volume *(millions)*	**0.8**	**0.9**	**0.8**	**1.9**

2003 *(U.S. dollars)*	First	Second	Third	Fourth
High	30.02	36.76	37.75	41.66
Low	26.90	29.45	34.80	35.61
Close	29.80	35.62	35.63	41.39
Volume *(millions)*	1.3	0.9	0.6	0.5

Five-Year Consolidated Highlights

Financial and Operating Information[1]

(millions of dollars, except per share amounts)

Earnings by Segment	**2004**	2003	2002	2001	2000
Liquids Pipelines	**219.9**	213.5	189.6	164.4	152.5
Gas Pipelines	**53.8**	70.1	47.8	41.5	39.6
Sponsored Investments	**66.2**	234.3	(51.1)	37.2	16.3
Gas Distribution and Services[2]	**313.1**	153.6	124.3	189.6	211.7
International	**73.6**	72.3	68.0	35.6	26.4
Corporate	**(81.3)**	(76.6)	(48.6)	(55.1)	(88.8)
Continuing operations	**645.3**	667.2	330.0	413.2	357.7
Discontinued operations	**–**	–	242.3	45.3	34.6
Earnings applicable to common shareholders	**645.3**	667.2	572.3	458.5	392.3
Cash Flow Data					
Cash provided from operating activities	**886.7**	368.5	877.4	397.0	248.5
Expenditures on property, plant and equipment	**496.4**	391.3	729.9	683.3	364.3
Acquisitions and long-term investments	**850.5**	128.8	1,572.0	640.9	571.4
Dividends paid on common shares	**315.8**	283.9	251.1	227.5	202.1
Operating Data					
Liquids Pipelines[3]					
Deliveries *(thousands of barrels per day)*	**2,138**	2,189	2,088	2,109	2,072
Barrel miles *(billions)*	**757**	710	705	695	735
Average haul *(miles)*	**970**	889	925	903	972
Gas Distribution					
Distribution volume *(billion cubic feet)*	**575**	458	410	427	421
Number of active customers *(thousands)*	**1,756**	1,679	1,623	1,571	1,520
Degree day deficiency[4] *(degrees Celsius)*					
Actual	**5,052**	4,029	3,362	3,766	3,569
Forecast based on normal weather	**4,849**	3,565	3,700	3,816	3,629

1 *Certain comparative amounts have been restated to reflect the retroactive adoption of new accounting rules requiring the preferred securities to be classified wholly as debt.*

2 *In 2004, Enbridge Gas Distribution (EGD) changed its fiscal year end from September 30 to December 31 to be consistent with Enbridge. Consequently, highlights of Gas Distribution and Services for 2004 include the 15-month period ended December 31 for EGD and other gas distribution operations. Gas Distribution and Services volumes and the number of active customers are derived from the aggregate system supply and direct purchase gas supply arrangements.*

3 *Liquids Pipelines operating highlights include the statistics of the 11.2% owned portion of the mainline system located in the United States.*

4 *Degree day deficiency is a measure of coldness. It is calculated by accumulating for each day in the fiscal period the total number of degrees by which the daily mean temperature fell below 18 degrees Celsius. The figures given are those accumulated in the Toronto area.*

Five-Year Consolidated Highlights

Shareholder and Investor Information

(per share amounts in dollars)	**2004**	2003	2002	2001	2000
Average common shares outstanding weighted monthly during the year *(thousands)*	**167,240**	165,471	160,310	157,297	154,469
Number of registered common shareholders at year end	**6,794**	7,167	7,406	7,832	8,265
Common Share Trading (TSX)					
High	**60.15**	54.14	49.25	45.55	44.00
Low	**47.25**	40.95	41.11	33.90	23.00
Close	**59.70**	53.70	42.61	43.40	43.70
Volume *(millions)*	**77.7**	75.1	72.3	67.6	68.2
Per Common Share Data					
Earnings applicable to common shareholders					
Continuing operations	**3.86**	4.03	2.06	2.63	2.32
Discontinued operations	**–**	–	1.51	0.28	0.22
	3.86	4.03	3.57	2.91	2.54
Dividends paid on common shares	**1.83**	1.66	1.52	1.40	1.27
Financial Ratios					
Return on average shareholders' equity[1]	**17.0%**	19.0%	18.7%	17.7%	17.0%
Return on average capital employed[2]	**8.5%**	8.1%	7.7%	7.5%	7.4%
Debt to debt plus shareholders' equity[3]	**65.1%**	67.9%	69.4%	75.9%	73.1%
Debt to total capital employed	**56.1%**	58.6%	61.5%	69.2%	65.1%
Earnings coverage of interest[4]	**2.8x**	2.8x	2.5x	2.1x	1.9x
Dividend payout ratio[5]	**47.4%**	41.2%	42.6%	48.1%	50.0%

1 *Earnings applicable to common shareholders divided by average common equity (weighted monthly during the year).*
2 *Sum of earnings (including earnings from discontinued operations), non-controlling interest and after-tax interest expense divided by average capital employed (weighted monthly during the year). Capital employed is equal to the sum of shareholders' equity, non-controlling interest, future income taxes, deferred credits, and total debt (excluding short-term borrowings which finance gas in storage).*
3 *Total debt (including short-term borrowings) divided by the sum of total debt and shareholders' equity.*
4 *Sum of earnings before income taxes, non-controlling interest and interest expense, divided by interest expense. Includes earnings from discontinued operations.*
5 *Dividends per common share divided by total earnings per share applicable to common shareholders.*

Common and Preferred Shares
The Common Shares of Enbridge Inc. trade in Canada on the Toronto Stock Exchange and in the United States on the New York Stock Exchange under the trading symbol "ENB". The Preferred Shares, Series A, of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbol "ENB.PR.A".

Registrar and Transfer Agent in Canada
CIBC Mellon Trust Company
199 Bay Street
Commerce Court West
Securities Level
Toronto, Ontario M5L 1G9
Telephone: (416) 643-5500
Toll free: (800) 387-0825
Internet: www.cibcmellon.com
CIBC Mellon Trust Company also has offices in Halifax, Montreal, Winnipeg, Calgary and Vancouver.

Co-Registrar and Co-Transfer Agent in the United States
Mellon Investor Services
85 Challenger Road
Overpeck Centre
Ridgefield Park, NJ, 07660 U.S.A.
Toll free: (800) 526-0801

Preferred Securities
The Preferred Securities, Series D, of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbol "ENB.PR.D". The registrar and transfer agent is Computershare Trust Company of Canada.

Debentures
The registrar and trustee for Enbridge Debentures is Computershare Trust Company of Canada, with offices in Montreal, Toronto, Winnipeg, Edmonton and Vancouver.

Auditors
PricewaterhouseCoopers LLP

Shareholder Inquiries
If you have inquiries regarding the following:

- Dividend Reinvestment and Share Purchase Plan
- change of address
- share transfer
- lost certificates
- dividends
- duplicate mailings

Please contact the registrar and transfer agent – CIBC Mellon Trust Company in Canada or Mellon Investor Services in the United States.

Other Investor Inquiries
If you have inquiries regarding the following:

- additional financial or statistical information
- industry and company developments
- latest news releases or investor presentations

Please contact Enbridge Investor Relations or visit Enbridge's web site at **www.enbridge.com.**

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

Annual and Special Meeting
The Annual and Special Meeting of Shareholders will be held in the Crystal Ballroom at the Fairmont Palliser Hotel, Calgary, Alberta, at 1:30 p.m. MDT on Thursday, May 5, 2005.

Form 40-F
The Company files annually with the Securities and Exchange Commission of the United States a report known as the Annual Report on Form 40-F. Copies of the Form 40-F are available, free of charge, upon written request to the Corporate Secretary of the Company.

Dividend Reinvestment and Share Purchase Plan, and Dividend Direct Deposit
Enbridge Inc. offers a Dividend Reinvestment and Share Purchase Plan that enables shareholders to reinvest their cash dividends in Common Shares and to make additional cash payments for purchases at the market price. The Company also offers Dividend Direct Deposit which enables shareholders to receive dividends by electronic fund transfer to the bank account of their choice in Canada. Details may be obtained from the Investor Information section of the Enbridge web site at www.enbridge.com, or by contacting CIBC Mellon Trust Company at any of the locations listed above.

Registered Office
Enbridge Inc.
3000, 425-1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 231-3900
Facsimile: (403) 231-3920
Internet: **www.enbridge.com**

Le présent document est disponible en français.

Enbridge Inc. Businesses

Liquids Pipelines

- Enbridge Pipelines Inc. (100%)
- Enbridge Pipelines (NW) Inc. (100%)
- Enbridge Pipelines (Athabasca) Inc. (100%)
- Enbridge Pipelines (Toledo) Inc. (100%)
- Mustang Pipe Line Partners (30%)
- Chicap Pipe Line Company (22.8%)
- Frontier Pipeline Company (77.8%)
- Spearhead Pipeline (90%)
- Hardisty Caverns LP (50%)

Gas Pipelines

- Alliance Pipeline L.P. (U.S. portion) (50%)
- Vector Pipeline Limited Partnership (60%)
- Enbridge Offshore Pipelines, L.L.C. (100%)

Sponsored Investments

- Enbridge Energy Partners, L.P. (11.2%)
  - Lakehead System
  - North Dakota System
  - Mid-Continent System
  - Various Natural Gas Systems
- Enbridge Income Fund (72.3% overall interest)
  - Enbridge Pipelines (Saskatchewan) Inc. (100%)
  - Alliance Pipeline Limited Partnership (Canadian portion) (50%)

Gas Distribution and Services

- Enbridge Gas Distribution (100%)
  - Gazifere Inc.
  - Niagara Gas Transmission Limited
  - St. Lawrence Gas Company, Inc.
- Noverco Inc. (32.1%), which owns:
  - Gaz Métro Limited Partnership (72.8%), which owns:
    - Vermont Gas Systems, Inc. (100%)
    - TQM Pipeline and Company, Limited Partnership (50%)
    - Portland Natural Gas Transmission System (38.3%)
- Enbridge Gas New Brunswick Limited Partnership (63%)
- CustomerWorks Limited Partnership (70%)
- Enbridge Commercial Services (100%)
- Aux Sable Liquids Products Inc. (42.7%)
- Enbridge Gas Services Inc. (100%)
- Inuvik Gas Ltd. (33⅓%)
- Tidal Energy Marketing Inc. (100%)
- NetThruPut Inc. (52%)
- SunBridge Wind Power Project (50%)
- Magrath Wind Power Project (33⅓%)
- FuelCell Energy (strategic alliance)

International

- Oleoducto Central S.A. (24.7%)
- Compañia Logistica de Hidrocarburos CLH, S.A. (25%)
- Enbridge Technology Inc. (100%)

2005 Dividend Information for Common Shares and Preferred Shares, Series A*	1st Q	2nd Q	3rd Q	4th Q
Record date	Feb. 15	May 16	Aug. 15	Nov. 15
Payment date	March 1	June 1	Sept. 1	Dec. 1
Common Share Dividend Reinvestment Plan (DRIP) enrolment cut-off date	Feb. 8	May 9	Aug. 8	Nov. 8
Common Share Purchase Plan cut-off date for DRIP	Feb. 22	May 25	Aug. 25	Nov. 24

**Dividend dates are subject to the dividends being declared by the Board of Directors.*

2005 Interest Payment Information for Preferred Securities, Series D	1st Q	2nd Q	3rd Q	4th Q
Record date	March 15	June 15	Sept. 15	Dec. 15
Payment date	March 31	June 30	Sept. 30	Dec. 31

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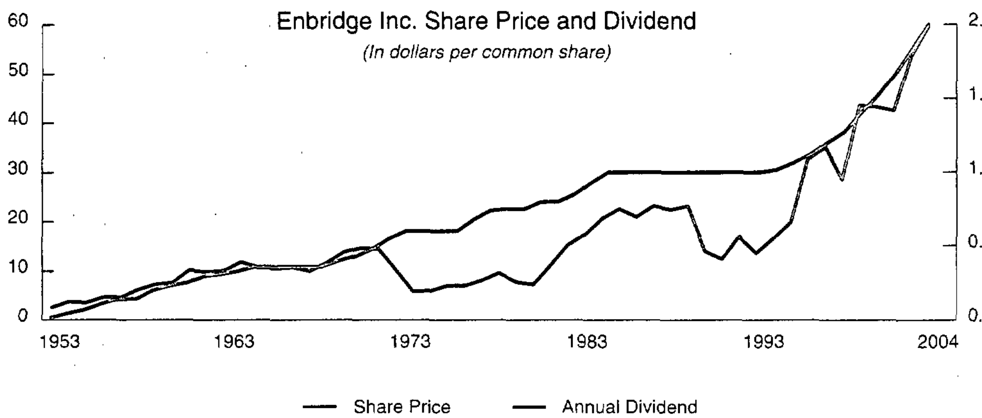
Enbridge common shares trade on the Toronto Stock Exchange
in Canada and on the New York Stock Exchange in the U.S.
under the symbol "ENB".



In the 51 years that Enbridge Inc. has been a publicly traded Company,
annual total shareholder return averaged just over 13%.

Enbridge Inc.
3000, 425 - 1st Street S.W. Calgary, Alberta, Canada T2P 3L8
Telephone: (403) 231-3900 Fax: (403) 231-3920
Toll free line: 1-800-481-2804
www.enbridge.com