ENBRIDGE

# APPLICATION OF ENBRIDGE INC. ("Enbridge")

# TO THE ALASKA DEPARTMENT OF REVENUE PURSUANT TO AS 43.82.120

# FOR APPROVALS UNDER THE *ALASKA STRANDED GAS DEVELOPMENT ACT*

APRIL 30, 2004

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## 1. INTRODUCTION

Enbridge recognizes that development of natural gas resources in remote, frontier areas such as the North Slope of Alaska depends on the development of economically efficient, safe energy delivery infrastructure. Enbridge has a significant interest in playing a constructive role in the development of Alaskan gas. Our extensive northern expertise, significant cross-border pipeline development experience and downstream market presence puts Enbridge in a strong position to assist in overcoming technical, market-related, and socio-economic challenges in bringing Alaska gas to market in a manner that is efficient, economic, sensitive to the environment and that respects and provides benefits to affected communities.

Developing the natural gas resources of the State of Alaska will require the active participation and cooperation of a number of key stakeholders that will benefit by development of this important resource. Oil and gas producers, transportation service providers, local businesses, communities and Native Corporations as well as major players in the North American natural gas market are all key to addressing the multitude of issues necessary for ultimate success in Alaska. The primary focus of the Alaska Stranded Gas Development Act (ASGDA) contracting provisions is on the State-controlled fiscal impacts on producers; however, income, property, sales, inventory and other State and local taxes that would be payable by a natural gas pipeline owner are not insignificant and to the extent that an ASGDA agreement provides qualified projects and qualified project sponsors with the opportunity to mitigate the impact of those costs on the economics of a natural gas transmission project, producers and the State of Alaska will also be expected to benefit.

On its own, Enbridge has the capacity to plan, permit, build and operate a natural gas pipeline in Alaska (the "Alaska Segment") but this application signals Enbridge's intent to take a lead role in the creation of a consortium that will pursue these opportunities. Enbridge is also pursuing opportunities for the development of a new inter-connecting pipeline from the Alaska / Yukon border to Alberta, Canada to tie into existing and new infrastructure (the "Canadian Segment"). This combined greenfield pipeline from Alaska to Alberta ("Alaska Gas Pipeline" or the "Project") would interconnect with an extensive existing transportation network that can be utilized and expanded to assure an

incremental, economical and reliable connection to markets in the United States and Canada.

The Project will require producer and market support and a strong alignment of key stakeholders to mitigate and share the significant risk that a project of this size and scope will present. This application to the State of Alaska is a first formal step for the Alaska Segment of an Alaska Gas Pipeline project which will require substantial producer and stakeholder consultation in advance of regulatory processes in the U.S. and Canada. Enbridge's extensive experience in North America and our history of collaboration in dealings with producers, shippers, major U.S. Midwest and eastern markets, and key stakeholders positions us to play a critical role in facilitating such a significant project.

In light of the significant growth in natural gas demand in North America expected over the next 20 years and beyond, a major aspect of successful development of the Project is involvement of key participants in the natural gas distribution market. Downstream distribution and industrial markets are keenly aware of the need for securing incremental North American natural gas supply along with corresponding transportation infrastructure to assure market demand is met reliably and price volatility is reduced.

U.S. energy demand has increased more than 25 percent since 1973 and, despite dramatic improvements in energy efficiencies, demand growth is expected to continue. The Energy Information Administration has estimated that natural gas will play an environmentally friendly and dominant role in meeting energy needs, driving U.S. natural gas demand from 22 Tcf/year today to 31 Tcf/year by 2012 (*EIA 2002 Annual Energy Outlook*). The natural gas reserves within the State of Alaska are widely viewed to be a major part of North America's energy solution, provided they are properly developed by experienced industry participants working collaboratively. Key players in the distribution and other downstream markets have an interest in participating in the success of the Project. Enbridge envisions building a consortium that includes such market participants.

Finally, while this application is necessarily focused on and limited to the Alaska Segment of the Project, it is our view that developing an Alaska Gas Pipeline in a way

that will provide benefits on both sides of the Canada/U.S. border will create the necessary conditions for the Alaska Segment to proceed on a timely basis.

## 2. APPLICATION REQUIREMENTS OF THE ALASKA STRANDED GAS DEVELOPMENT ACT ("ASGDA")

In order to be eligible to negotiate the terms of a contract for fiscal and related terms intended to incent and support development of natural gas in Alaska, an applicant must satisfy the commissioner that:

i) its proposal meets the criteria for a "qualified project"; and

ii) that it is a "qualified sponsor" or "sponsor group."

As evidenced by the information contained in the following sections, Enbridge is proposing a project that meets the criteria for a "qualified project" and is a "qualified sponsor" within the meaning of the ASGDA.

In support of its application, an applicant must also provide a project plan with supporting information as set out in AS 43.82.120 (b) (1) – (8) to establish that the plan reflects a proposal for diligent development on the part of the applicant and a proposal that does not materially conflict with the obligations of a lessee to the state under a lease, pool, unit or other agreement with the State and, finally, that the project describes satisfactory methods for accommodating reasonably foreseeable intra-state demand for gas.

Enbridge is confident that based on the information contained in the balance of this application, the commissioner will find that the criteria in AS 43.82.120 (b) (1) - (8) are satisfied.

## 3. PROJECT QUALIFICATION

### Enbridge's Proposed Project Meets the Requirements of AS 43.82.100

Enbridge submits that the commissioner may determine that Enbridge's proposal for new investment in the State of Alaska through development of the Alaska Segment of an Alaska Gas Pipeline is a qualified project within the meaning of that term in AS 43.82.100 based on the following information:

i) The Project Principally Involves the Transportation of Natural Gas to One or More Markets

The Alaska Segment proposed by Enbridge is a natural gas transmission pipeline from the Prudhoe Bay area, south to a point near Fairbanks, Alaska, and then along the Alaska-Canada highway to the Alaska / Yukon border. At that point, the Alaska Segment would interconnect with the Canadian Segment that would continue to follow the highway to a point or points of interconnection with pipelines in British Columbia and Alberta, Canada that could provide natural gas to the contiguous United States and Canada.

More specifically, the Alaska Segment of the Alaska Gas Pipeline route would follow the existing Trans Alaskan Pipeline System right-of-way from Prudhoe Bay to Fairbanks, Alaska. From this point the pipeline would mostly follow the Alaska Highway to the Canadian border. The Canadian Segment of the pipeline would continue to follow the highway to Fort Nelson, British Columbia and then on to Gordondale, Alberta where it would interconnect with existing infrastructure (such as Alliance, TCPL, and Duke Energy facilities).

Through delivery points to existing, well developed gas pipeline infrastructure, Alaskan natural gas would have access to major North American markets.

ii) The Project Will be Capable of Transporting at Least 500,000,000,000 cubic feet of Gas Within 20 Years of the In-Service Date

As described in more detail in the project plan, the project proposed by Enbridge, including the Alaska Segment will be designed with initial capacity specifications of 2.6 Bcf/day, expandable to in excess of 5 Bcf/day, which is more than adequate to transport more than 500,000,000,000 cubic feet of gas within 20 years from the in-service date.

iii) The Project Can be Capable of Making Gas Available to Meet Reasonably Foreseeable Demand for Gas Within the Economic Proximity of the Project

The Alaska Segment proposed by Enbridge will be capable, subject to applicable regulatory, technical and economic considerations, of facilitating distribution of natural gas to markets in the State of Alaska within the economic proximity of the

project to the extent warranted by local demand and mutually agreeable commercial arrangements.

Specifically, subject to the conditions noted previously, Enbridge can provide access points at appropriate locations along the pipeline to accommodate local gas distribution development.

## 4. QUALIFICATION AS A PROJECT SPONSOR

### Enbridge Qualifies as a Project Sponsor Under AS 43.82.110

As set out in more detail in section 5.5, Enbridge submits that the commissioner should find that Enbridge is a qualified sponsor within the meaning of that term in AS 43.82.110 based on the following information:

i) Enbridge intends to own an equity interest in a qualified project. Enbridge would be prepared to accommodate investment in the Alaska Segment by Alaskan native and other corporations on terms that would provide future part ownership, meaningful participation to those corporations and benefits to the proposed project.

ii) As evidenced by its most recent audited financial statements[1] and its most recently filed 10-K[2], Enbridge has a net worth of $4.1 billion (Canadian) and, through a U.S. subsidiary, is General Partner for Enbridge Energy Partners, L.P. that has a net worth of another $1.3 billion (U.S.). The combined net worth is equal to at least 10% ($300 million) of the total estimated cost of constructing the project, which is approximately $3,300,000,000.

## 5. PROJECT PLAN

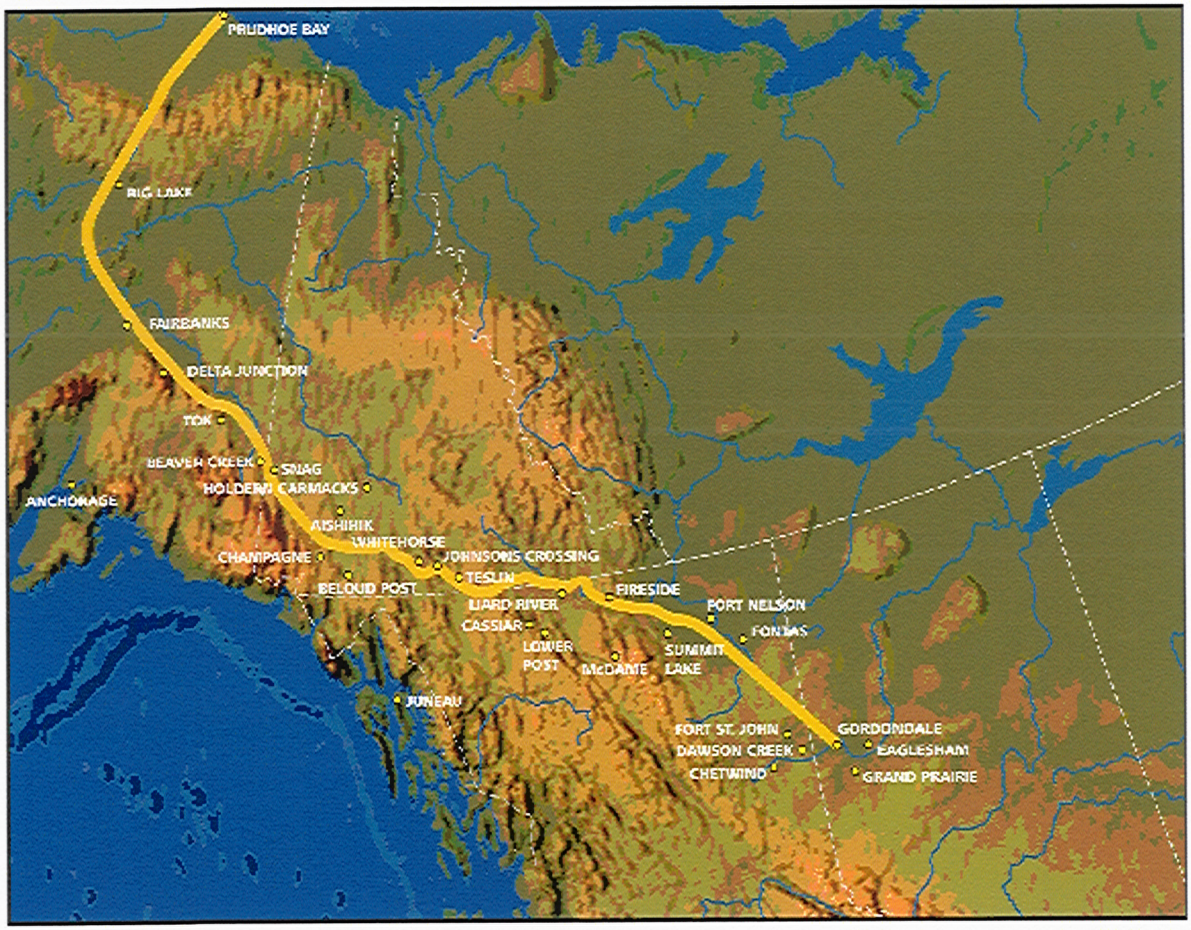
### 5.1 Project Overview

The Project being proposed by Enbridge would be developed in a manner that is responsive to continental North American natural gas demand. The Alaska and Canadian Segments would be developed in phases. The proposed initial development

[1] A copy of which is attached as Schedule 1.
[1] A copy of which is attached as Schedule 2.

would consist of a Nominal Pipe Size (NPS) 36 natural gas pipeline system and related facilities and operate at an initial capacity of 2.6 Bcf/day. The system would be expandable as dictated by exploration and continental market demand and accomplished through additional compression or looping, if required, to create an ultimate design capacity in excess of 5 Bcf/day. The pipeline would provide take away capacity for natural gas reserves located both within and outside of the Alaska North Slope region.

**Figure 1: Proposed Routing**




Enbridge believes that this measured approach to transporting Alaska natural gas will significantly reduce risks, result in an improved schedule, and provide the best benefits to producers, explorers, to the State of Alaska, the people of Alaska, North American steel manufacturers, consumers in the United States and Canada, and stakeholders located in proximity to the proposed routing. Final details of line size, operational

pressure, and planned buildup will be developed pending further discussions with producers and shippers, the results of an open season and detailed design work.

The proposed pipeline route, as described above, starts in continuous permafrost and then gradually transitions into sporadic pockets of discontinuous permafrost, found first in low-lying areas and eventually becoming more prevalent in southern sections of the pipeline. The buried pipeline(s) would operate at approximately 2500 pounds per square inch with compression facilities located at appropriate intervals along the line. The discharge gas from the compressor stations located in permafrost regions will be cooled to mitigate potential impacts on pipe and soil.

A key advantage of specifying smaller diameter pipe materials is the ability of North American pipe mills to manufacture pipe of sufficient specifications. Availability of pipe from both local and offshore suppliers will ensure competition and provide greater opportunity for the North American industry and potentially improve the Project schedule for "first gas" to Alaskan and North American markets.

Enbridge's proposed "measured approach" design will provide the following advantages to shippers, consumers, and the State of Alaska:

- Conventional sized pipe, materials, and handling equipment will result in experienced participation by North American contractors, improved competitiveness, and lower unit lay costs;
- Improved schedule – earlier gas access for Alaskan and other continental consumers; could be in service at least one year earlier than other proposals;
- Ease of expandability as a result of successful exploration;
- Cost effective capacity matched to market demand;
- Increased North American material and equipment supply potential will result from use of conventional sized pipe and materials; and
- Increased benefits to stakeholders in proximity to the pipeline route through longer construction-related employment and earlier access to gas.

The initial phase of the measured approach providing a take-away capacity of 2.6 Bcf/day is estimated at $3.3 billion for the Alaska Segment. Enbridge has estimated the eventual cost of this conceptual design (i.e. with capacity expanded to exceed 5 Bcf/day) for the Alaska Segment at $6 billion in 2004 dollars. Costs could be different once

detailed design and routing work is complete, however what will not change is the fact that the measured approach is more flexible, and capacity can be closely matched to supply and market requirements. The proposed design will result in significantly lower tolls for the initial design throughputs.

In addition, we anticipate that key challenges to the development of this pipeline system would include financial, technical and political/regulatory issues. Strategies are being developed to address each of these challenges based on Enbridge's extensive pipeline expertise, its northern experience, and through its ownership of Alliance Pipeline, a recently completed high-pressure pipeline that transports rich gas from northern Canada to the United States. While the technical challenges will be considerable, it is important not to downplay the significance of proactive and extensive stakeholder consultation and involvement, pre-filing regulatory preparation, and formal regulatory processes. The Enbridge approach to those issues for the project can be summarized in the following key points:

- Comprehensive public consultation;
- Involvement of native corporations and aboriginal/indigenous peoples;
- Inclusion of aboriginal/indigenous peoples' Traditional Knowledge;
- Coordination amongst state, provincial, U.S., and Canadian regulatory authorities;
- Development of certainty of regulatory process and protocol;
- A commitment to full, clear, concise disclosure of information; and
- Realistic, accurate, comprehensive, and timely filings.

Further, Enbridge recognizes the need for much more work in collaboration with regulators and key stakeholders in development of a detailed project proposal. Pending more extensive and collaborative planning, the concepts of the Project are presented based on Enbridge's extensive experience in planning, permitting, design, construction and operations of northern pipeline systems and recent large scale greenfield project development as discussed above.

### 5.2 Work Accomplished to Date to Further the Project

Over the past several years, Enbridge has engaged in extensive conceptual design/study work to identify methods and practices that are worthwhile for producers and stakeholders to consider and evaluate. They are designed to increase system flexibility, reduce overall costs, increase reliability, and provide additional northern and

North American benefit while maintaining a high level of environmental stewardship. Enbridge has invested over $300 million in northern pipeline development, which knowledge we intend to leverage into the proposed pipeline in Alaska.

Our assessment of the initial design and alternative design concepts are focused on the following parameters:

- Initial and ultimate pipeline capacity;
- Cost and complexity of facilities;
- Number and location of compressor stations;
- Limit states design process;
- Impact of optimizing gas composition; and
- Timelines to meet market demand.

There had been little research done in trenching in permafrost since the construction of the Alyeska and Norman Wells Pipeline systems in the 1970s and early 1980s. Yet equipment development has advanced to tackle difficult trenching conditions. As a result, Enbridge has participated in both a study and field trials in Alaska to examine the state-of-practice of trenching in permafrost terrain. The objective of this study and subsequent field trials was to identify parameters that limit and control trenching productivity in permafrost terrain and arctic conditions. The field trials were conducted in Prudhoe Bay and Fairbanks, Alaska using two chain-type trenchers. BP America Inc. has coordinated both the studies and the field trials. Enbridge headed the analysis of the field trial data and correlation of the study findings. While there were other parties participating in the trencher studies, only BP and Enbridge were common to both the study and the field trials involving the trenchers. This proprietary information would be of significant value to the development of the pipeline system. The ability to predict trenching progress will enhance project cost estimating accuracy. Incorporating this information early in the design process will result in reduced project cost risk and a reduction in the potential for rework.

*Trencor Model 1660 trencher - Prudhoe Bay 2002*

*Norman Wells Pipeline right-of-way, Northwest Territories, Canada*

Enbridge brings extensive knowledge gained through all phases of the Norman Wells Pipeline and Inuvik Gas projects plus the continued learnings over 20 plus years as a responsible operator in the northern environment. This knowledge is invaluable and will result in reduced environment and construction delays and a reduction in overall capital cost.

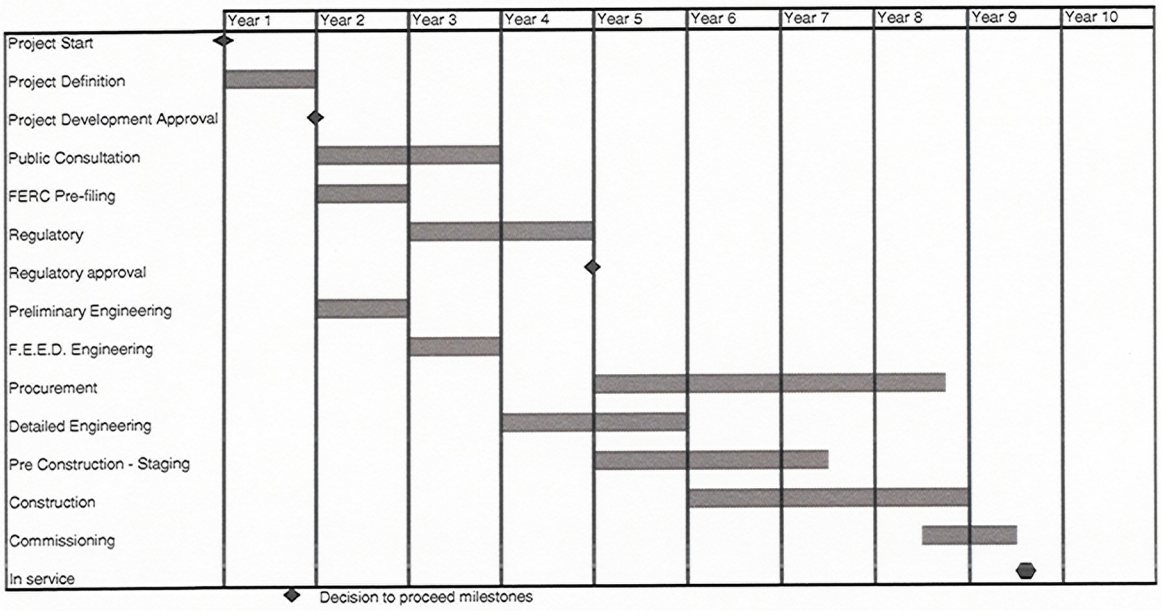
In addition, Enbridge was involved in the design and is currently a 50% owner of North America's highest pressure, dense phase, major natural gas transmission system, Alliance Pipeline. Alliance deployed high-pressure, rich gas technology to make a large greenfield project economically competitive. Enbridge also developed, constructed and now operates the Vector pipeline, which provides access to significant storage and markets in central Canada and in the area north-east of Chicago.

### 5.3 Schedule of Proposed Development Activity and Activity Proposed to be Accomplished

Enbridge's schedule of proposed development activity for the Alaska Segment is shown in Figure 2. The proposed schedule depends on the timely commitment of producers, downstream markets and other key stakeholders to the project. Once shippers are committed to capacity, Enbridge would proceed to develop the project as efficiently and expeditiously as possible. An in-service pipeline within nine years of the project kick-off is a reasonable expectation. A construction schedule that would provide access to natural gas in Fairbanks during year seven may be feasible, but would require further study.

The current schedule, shown in Figure 2, assumes that each milestone will be completed in a timely manner. However, if delays were to arise, the schedule would be modified accordingly.

**Figure 2 - Proposed Development Activity Schedule**




In comparison, based on its extensive experience, Enbridge is of the view that the timetable to first gas for a NPS 48 or greater would require at least one more year.

In order to complete the Project, in addition to filing a FERC application, Enbridge will also have to file an application with the National Energy Board and other Canadian regulatory bodies with jurisdiction over aspects of the Canadian Segment. An important precursor to those applications will be consultation with First Nations and other aboriginal communities/stakeholders. While other pipeline companies received certain approvals some 25 years ago pursuant to the *Northern Pipeline* Act, that Act does not provide exclusive rights to build a pipeline. Enbridge's proposal will ensure that the Project is subject to modern and efficient environmental assessment and regulatory processes that take into account obligations to all stakeholders. Addressing Canada's environmental and regulatory process efficiently will provide the foundation for developing both Segments of the Project in a timely manner while mitigating unnecessary risk.

### 5.4 Lease Property That Would Be Developed

Enbridge expects that, as is required by both U.S. and Canadian regulators, pipeline capacity on the Alaskan Segment and the Canadian Segment of the Alaska Gas Pipeline will be marketed and subscribed on an open-access, non-discriminatory basis. The proposed pipeline will therefore be available to transport all Alaskan gas supplies that meet standard quality requirements. Enbridge has determined, after reviewing publicly available reserves estimates, that there is sufficient supply within the region to support the project proposal.

According to a 2001 report by the Minerals Management Service (MMS), Alaska contains approximately 218 Tcf of discovered and undiscovered gas (*Prospects for Development of Alaska Natural Gas: A Review)*. The report states that 88% of this is undiscovered, while 40 Tcf is in developed and known undeveloped fields. Of known gas reserves, approximately 27 Tcf is currently available for production. In another study, the Energy Information Administration (EIA) has asserted that Alaska holds approximately 252 Tcf of conventional gas within currently undiscovered fields. This represents roughly 37% of all undiscovered gas reserves (including Alaska) in the United States (*U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2002 Annual Report*). At a price of $3.52/Mcf it was estimated that 71 Tcf of this supply would be economically recoverable.

As to what petroleum lease property would be developed as a result of the Project, Enbridge envisions that the pipeline would gather supply from the following sources:

- The Prudhoe Bay Unit: This field, which is operated by BP, contains an estimated 24 Tcf (*Alaska Dept. of Natural Resources 2002 Annual Report*) of recoverable gas that could be supplied to the pipeline using currently available technology. Ownership of the field is comprised of ExxonMobil (36%), ConocoPhillips (36%), BP (26%) and several smaller entities (1%). According to the EIA, Prudhoe Bay is the third largest field in the U.S. in terms of proved gas reserves.

- The Point Thomson Unit: The field is operated by ExxonMobil, which asserts that it contains approximately 8 Tcf of recoverable gas and associated condensate, and is located approximately 60 miles east of Prudhoe Bay. The aforementioned MMS report estimates that Point Thomson contains 5 Tcf of recoverable resource.

- A collection of smaller supply sources: In a 2003 report, the National Petroleum Council (NPC) estimated that the North Slope holds approximately 4 Tcf of discovered gas reserves outside of Prudhoe Bay and Point Thomson. Examples of areas where gas could be recovered include the Colville River Unit, Milne Point Unit, Duck Island Unit and Northstar Unit.
- Additionally, it is foreseen that the creation of pipeline access will spur further exploration activity, resulting in increased natural gas supply for the Project. Various respected agencies have estimated significant resources in other areas; the EIA estimate of 252 Tcf of undiscovered gas and, the MMS estimate of as-yet undiscovered conventional natural gas reserves in Alaska could be as high as 156 Tcf. Of the MMS total, a cumulative 92 Tcf is estimated to lie offshore in the Beaufort Shelf and Chukchi Shelf, while 64 Tcf is estimated to lie in northern Alaska. Furthermore, the NPC has noted that, according to US Geological Survey and MMS data, the total potential for undiscovered gas reserves, including non-conventional sources such as coal bed gas, is as much as 214 Tcf. Clearly, large reserves lie in wait for transport to market.

### 5.5 Methods and Terms Under Which the Applicant is Prepared to Make Gas Available to Meet Reasonably Foreseeable Demand in the State of Alaska within the Economic Proximity of the Alaska Segment

Enbridge proposes to provide valve access points on the pipeline to enable regional communities to purchase natural gas through a local distribution company. Requests for valve access would be considered on a non-discriminatory, case-by-case basis. The Project as a whole, including the initial phase and any expansion phases, will be developed in accordance with the open access requirements of both U.S. and Canadian regulators of gas pipelines that cross multiple jurisdictions. For example, Enbridge could hold an open season relating to each phase of the Project, including any expansion phases. Local distribution companies in the State of Alaska would have an opportunity to contract for capacity on such terms at least as favorable as those available to other shippers and as may be allowed by the relevant regulators.

Access to natural gas will give community governments, industry and businesses an opportunity to develop private, public, or jointly owned local distribution companies that will provide long-term benefits to community residents.

Enbridge has experience in facilitating local access to natural gas in the arctic as a joint owner of the Inuvik Gas Project, which supplies the Town of Inuvik, NWT with natural gas for power generation and commercial and residential heating. It is the first commercial natural gas development north of Canada's Arctic Circle and is the first pipeline in Canada to be buried in continuous permafrost. Inuvik Gas Ltd. (IGL) was created to construct and operate the gas distribution system. Enbridge provides management, safety and environment, technical, and administrative support services to IGL. Through this first-hand experience in the Inuvik Gas Project, Enbridge has expertise in northern regulatory development, gas franchise and supply agreements, construction, and operation of small-scale, innovative, local distribution systems and would be prepared to share this expertise with community governments and business venture proponents. As a result of this unique experience, Enbridge is able to draw on a proven working model to work with local community and government stakeholders in making gas available to local markets.

*Inuvik Gas Project well site and gas processing facility*

### 5.6 Options to Mitigate Increased Demand for Public Services and Other Negative Effects Caused by the Project

Enbridge's plan for phased development of the Project, including the Alaska Segment, is a concrete means of mitigating the increased demand for public services and other potential negative socio-economic effects that can be caused by significant construction projects in remote settings.

In addition, Enbridge's experience in constructing and operating the Norman Wells pipeline in the Northwest Territories of Canada and in constructing and operating pipelines throughout highly varied geographic settings in Canada and in the U.S. have lead to an understanding that effective measures intended to mitigate increased demand for public services and other potentially negative socio-economic effects must be tailored to the individual circumstances of the affected communities.

Throughout Enbridge's extensive history of major pipeline construction projects, it has demonstrated a commitment to minimizing impacts to the environment and contributing to the well being of communities in which we operate. We have demonstrated that, with

proactive consultation with communities and key stakeholders, we can better understand and address socio-economic issues. As the Project proceeds, Enbridge would work closely with state, provincial, and federal governments, local and regional stakeholders, communities and native / aboriginal groups before, during and after construction with an aim to minimize negative environmental and socio-economic impacts. At the same time, it will seek to maximize benefits to communities by forging partnerships and agreements that will ensure local stakeholders have access to potential benefits and opportunities arising from the Project. Enbridge is unique in that we can "hindcast" the impacts of northern pipeline project construction and subsequent operations and apply those learnings to new projects.

Specific examples of mitigative measures include:

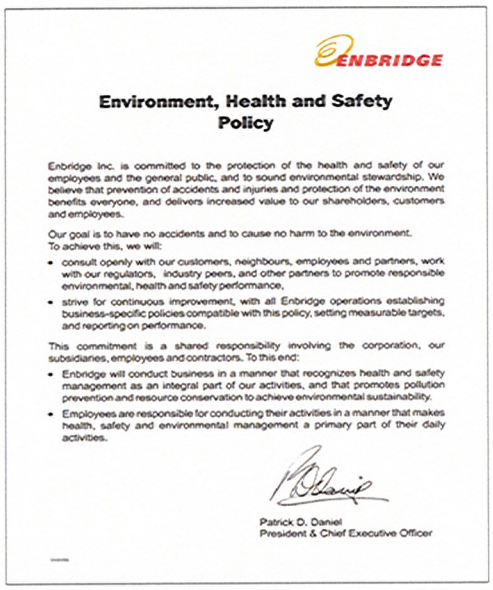
- Prior to construction, Enbridge would intend to identify potential economic opportunities and work with State officials to determine local capacity-building initiatives that may be required to maximize the participation of the broadest possible number of stakeholders.
- Enbridge would work closely with communities and other local stakeholders to develop plans to mitigate potential negative impacts such as routing and limiting impacts to biological and cultural resources.
- Enbridge would include as partners in the planning process, communities and native groups who will have the opportunity to supplement project pre-assessments to identify environmental, social and economic issues well in advance of construction and operation, resulting in minimizing local impacts and laying the groundwork for sustainable economic development in many regions of Alaska.

As an operator of cross-continent pipelines since 1950, Enbridge appreciates the ongoing need to be a responsible corporate citizen in our host communities. Enbridge recognizes project participants have a responsibility to invest in community initiatives and services that will support project success and offset potential project impacts. That commitment will be sustained throughout construction and beyond, with ongoing monitoring and control of impacts throughout the life of the pipeline project, while building long-term economic partnerships and relationships to provide ongoing benefits to communities.

## 5.7 Safe Management and Operation of the Project Once Constructed

### 5.7.1 Overview

Enbridge is committed to protecting the health and safety of employees, contractors and the public, and to sound environmental stewardship. The Company believes that prevention of accidents and injuries and protection of the environment benefit everyone and deliver increased value to shareholders, customers, and employees. Enbridge has mature health and safety and environmental management systems and established policies, programs, and practices for conducting safe and environmentally sound operations. These systems reflect industry best practices and are aligned with the ISO 14001 standard and the BSI-OHSAS 18001 specification for environmental, health and safety managements systems. Regular reviews and audits are conducted to assess compliance with legislation and company policy.



ENBRIDGE

**Environment, Health and Safety Policy**

Enbridge Inc. is committed to the protection of the health and safety of our employees and the general public, and to sound environmental stewardship. We believe that prevention of accidents and injuries and protection of the environment benefits everyone, and delivers increased value to our shareholders, customers and employees.

Our goal is to have no accidents and to cause no harm to the environment. To achieve this, we will:

- consult openly with our customers, neighbours, employees and partners, work with our regulators, industry peers, and other partners to promote responsible environmental, health and safety performance,
- strive for continuous improvement, with all Enbridge operations establishing business-specific policies compatible with this policy, setting measurable targets, and reporting on performance.

This commitment is a shared responsibility involving the corporation, our subsidiaries, employees and contractors. To this end:

- Enbridge will conduct business in a manner that recognizes health and safety management as an integral part of our activities, and that promotes pollution prevention and resource conservation to achieve environmental sustainability.
- Employees are responsible for conducting their activities in a manner that makes health, safety and environmental management a primary part of their daily activities.

Patrick D. Daniel
President & Chief Executive Officer

*Enbridge Environment, Health & Safety Policy*

Once constructed, ongoing activities during the operations phase of the proposed Project would include monitoring, auditing, and evaluating health and safety performance and developing improvement and enhancement measures. In addition, the development and implementation of specific health and safety programs would include establishing performance goals, staff and contractor orientation and training, data collection on health and safety performance including lost-time injury frequency (LTIF), total recordable injury frequency (TRIF) and health and safety improvement measures.

Enbridge has extensive and long-standing experience in the safe management and operation of northern pipeline systems and this expertise is transferable to the proposed Project. For example, Enbridge has developed safety training videos and materials to assist northern employees, contractors and inspectors in safe construction and operation

practices. Many of these materials can be modified to specifically fit the requirements of the proposed Alaska Gas Pipeline.

### 5.7.2 Specific Measures

Enbridge has a well developed Pipeline Safety and Integrity Management Program to protect the public and environment from pipeline failures during operation that it would implement for an Alaska Gas Pipeline.

Pipeline safety begins with design and construction. Enbridge has extensive experience with development of equipment specifications, overseeing construction and assuring integrity and safety inspections prior to major facilities being placed into service. Upon operation, Enbridge's approach to pipeline safety focuses on extensive facilities, equipment, maintenance and procedures to prevent the risk of corrosion, material defects, equipment failures, worker error and excavation third party damage.

Enbridge's pipeline control systems are state-of-the art and expertise will be available during the planning and construction of the Alaska Gas Pipeline to assure the highest standards of pipeline control and monitoring. Enbridge has long conducted proactive electronic internal inspection programs of large diameter and northern pipelines and is recognized as a leader in application of state-of-the-art internal inspection technologies. Enbridge also has the capability of expanding on its current worker and operator qualification and training programs and operating pipeline public awareness programs to assure these same high standards of pipeline safety and integrity are implemented during future operation of the Alaska Gas Pipeline.

Environmental protection is also a priority for Enbridge. As operator, Enbridge would monitor, audit and evaluate environment performance and develop improvement and enhancement measures. Enbridge recognizes that due to the sensitive environmental conditions in the North, care must be exercised every day in the operation and maintenance of the pipeline. For example, Enbridge has utilized an innovative approach for protecting ice rich, sensitive slopes by adding woodchip insulation and by monitoring permafrost conditions. We have developed specific Environmental Management Systems that provide a structured approach to environmental activities. As a lead

participant in the proposed pipeline, Enbridge would apply this environmental expertise and experience through all phases of the proposed project.

## 6. ENBRIDGE EXPERTISE

### 6.1 General

Enbridge has been in the natural gas transportation business for over 150 years. Starting in 1848, Enbridge Gas Distribution, formerly know as Consumers Gas, was formed to distribute coal gas to light street lamps in Toronto, Ontario. Since then Enbridge has grown into North America's 6th largest transporter of natural gas moving over 11 Bcf/d while Enbridge Gas Distribution has become Canada's largest natural gas distribution system with over 1.7 million industrial, commercial and residential customers.

In 2001, Enbridge significantly expanded its North American footprint in the natural gas industry with the acquisition of approximately 4,100 miles of natural gas pipelines operating in ten southern states. Concurrently we relocated the U.S. headquarters to Houston and have built this natural gas business (owned by Enbridge Energy Partners, L.P.) to now comprise more than 9,000 miles of gas gathering and transmission pipelines, 21 active treating and processing plans, a natural gas marketing unit and a natural gas liquid and carbon dioxide trucking operation. Included in these systems are four interstate natural gas transmission pipelines regulated by FERC. Growth has been fueled by acquisitions and expansion of existing assets within two of the lower-48's premier natural gas producing areas. Enbridge has a significant market position in the Mid-Continent and Gulf areas working with local distribution companies and other end users to serve their needs for energy through Enbridge transmission pipeline systems or marketing unit.

Enbridge has participated in a number of extensive and unique pipeline construction projects in North America over the last decade, including hundreds of miles of large diameter projects that involved multiple regulatory jurisdictions and crossings of the U.S. / Canada border. For example, Alliance pipeline, which is a 1,850 mile, rich gas, high-pressure gas pipeline that moves 1.3 Bcf/day of gas from Western Canada to the Chicago hub, was created to align the interests of producers, shippers, consumers, marketers and the equity owners.

Alliance was developed in response to insufficient pipeline capacity out of the Western Canadian Sedimentary Basin, which is a similar situation to that which exists in Alaska today. Initially, Enbridge was the only pipeline company participating in Alliance, with the majority of the owners being producers. Enbridge added value by bringing its construction and contracting expertise to the project.

Additionally, over the past 5 years, Enbridge has managed significant expansions and greenfield pipeline projects that carried budgets exceeding $2.3 billion in aggregate.

These include the Vector natural gas pipeline from Chicago to southern Ontario, which also enhanced value for Alliance shippers through market extension. Enbridge developed, constructed and now operates the interconnecting Vector pipeline. At a volume of approximately 1 Bcf/day, the Vector pipeline provides Alliance and other Chicago-area shippers with access to significant storage and markets in central Canada and in the area northeast of Chicago. During construction, Enbridge oversaw the biggest directional drilled cross border pipeline crossing ever built. Investment in the Alliance and Vector pipelines provided Enbridge a significant opportunity to participate in emerging west-to-east natural gas pipeline networks and positions it well to playing a constructive role in the development of Alaskan gas.

*Vector Pipeline horizontal directional drill of the St. Clair River*

As well, since 1994, Enbridge has expanded its mainline crude oil system from Edmonton to Chicago several times, requiring the planning, permitting, construction and operation of over 1,400 miles of large diameter pipeline through three provinces and five states.

With the development of these systems, Enbridge has continued to maintain, develop and update its significant knowledge of the state, provincial, and federal regulatory permitting requirements in the U.S. and Canada. Enbridge has developed unparalleled expertise in overseeing pipeline and facility design, construction, and operating techniques in both Canada and the United States and planning projects that proactively assess and mitigate impacts to the environment and the host communities through

which the pipeline passes. Enbridge has developed state-of-practice material specifications, construction contracting and inspection skills for the development of both gas and liquids pipeline systems. Enbridge would make these materials and procedures and experienced construction management workforce resources available as part of its participation in the development of the proposed pipeline system.

In addition, Enbridge has the most comprehensive operational knowledge of buried pipelines in northern North America. Pipelining north of 60 is considerably different than in the rest of North America with a greater possibility of project delays, construction delays, and increased project costs. Enbridge brings design, construction, and operational experience from arctic and sub arctic projects with its involvement in the Inuvik Gas Project and Norman Wells Pipeline. This knowledge of northern pipeline construction and operations would be invaluable to the success of the proposed Alaska pipeline.

*Inuvik Gas employee*

**6.2 Regulatory Expertise**

The Project will trigger the involvement of regulators at all levels of government in both the U.S. and Canada. The Alaska Segment alone is expected to trigger both federal, state and possibly local approval processes. Enbridge is firmly committed to an integrated approach to the multi-jurisdictional regulatory framework that will apply to the Alaska Segment and to the Project as a whole.

Enbridge has extensive experience in inter-jurisdictional project development through our 50-year ownership of the longest crude oil pipeline in the world. The Enbridge system connects Western Canada with the U.S. Midwest and with central Canada. This involvement has been supplemented through our more recent involvement in the Alliance and Vector pipelines, each of which operate in both the United States and Canada. This experience will greatly enhance our ability to satisfy regulatory and environmental assessment requirements for an Alaska Gas Pipeline in both the United States and Canada.

### 6.3 Worker Health and Safety

Through commitment, diligence and innovative programs, Enbridge has been able to consistently perform above the industry average in protecting the health and safety of its workers through the various stages of pipeline development and operations. For example, during construction of the Vector Pipeline, Enbridge safety staff, working in conjunction with contractor safety and construction staff, were able to achieve a Lost Time Incident Frequency (LTIF) of 2.1 compared to the industry average of 4.1. By following measures to address safety and workers compensation costs, Enbridge has successfully reduced worker's compensation insurance costs in the U.S. by 22%

Enbridge has also achieved strong operations safety performance. In 2003, Enbridge Transportation North achieved a LTIF of 0.09 and a Lost Time Injury Severity Rate of 0.09. Norman Wells Pipeline operations staff have accumulated approximately 8,800 days without a lost time injury.

As a result of its strong health and safety performance, Enbridge and its affiliates have received numerous awards, including the following:

- Enbridge has received the Canadian Energy Pipeline Association (CEPA) Safety Award for Lowest Recordable Injury Frequency Rates (1st place in large pipeline company category).
- Enbridge has received the Alberta Gas and Oil Pipeline Operators Safety Committee Occupational Health and Safety Award for no lost-time injuries.
- Inuvik Gas has received four employer recognition awards from the NWT Workers Compensation Board.
- Dufour Petroleum, our trucking services business in the U.S., was the recipient of the National Safety Council's Significant Improvement Award for 2002. Following acquisition by Enbridge in 2001, the business was successful in reducing annual preventable vehicle incidents by 50% over the previous year.
- Enbridge received the Minnesota Governor's Meritorious Achievement Award for Occupational Safety from the Minnesota Safety Council.

### 6.4 Environmental Protection and Stewardship

Enbridge has a strong understanding of the sensitivities of the northern environment and has developed expertise in managing environmental issues specific to the Arctic and northern environment.

Enbridge's environmental expertise has been recognized in many ways, including:

- CEPA awards for Environmental Management and Spill Prevention;
- The Environmental Practice of the Year award at the 2001 Global Energy Awards, for Enbridge's gas distribution system;
- Listing for 2003, for the second year in a row, in the prestigious Dow Jones Sustainability Index, an international index that recognizes companies for their commitment to the principles of sustainable development; and
- Joining the U.S. Environmental Protection Agency's "*Natural Gas STAR*" program in early 2004, covering a substantial portion of our natural gas systems in the Mid-Continent and Gulf Coast area. This is a voluntary program between EPA and the natural gas industry aimed at reducing methane emissions by encouraging the use of cost-effective technologies and practices

### 6.5 Pipeline Safety

Enbridge has built a strong reputation in North America - and worldwide through our consulting arm of Enbridge Technology - in state-of-the-art pipeline safety, risk management and integrity. Enbridge will contribute significantly to the leadership and expertise needed to assure the Alaska Gas Pipeline is built and operated to the highest degrees of safety to assure reliability in gas service and protect the communities through which the pipeline crosses.

### 6.6 Northern Stakeholder Relations

Enbridge recognizes that its obligation to engage with communities that may be affected by its pipelines does not end with the receipt of a Certificate and construction of a pipeline.

*Indigenous Elder from Norman Wells, NWT, Canada*

Enbridge has and continues to develop strong working relationships with a variety of stakeholders. Our unique northern involvement has provided us with invaluable experience in working and operating in the northern environment, enabling us to develop solid relationships with a multitude of northern stakeholders including Indigenous groups, communities, northern businesses and governments. Our business activities have a very

positive impact on the communities where we operate, in terms of local purchasing and contracting, employment and community investment for worthwhile causes. Enbridge has modified our operational practices, when warranted, to better reflect local needs and realities in terms of jobs, training, community involvement and economic spin-off benefits to the area.

Enbridge Philosophy (Excerpt from the Enbridge Indigenous Peoples Policy.)

*"Enbridge recognizes the history, uniqueness and diversity of indigenous peoples, and they are often key stakeholders in Enbridge's activities. Positive relations with indigenous peoples based on mutual respect and trust will help Enbridge to reach its strategic business objectives and indigenous peoples to realize their aspirations. Enbridge's commitment is to forge mutually beneficial relations with indigenous peoples in proximity to its operations."*

In the spring of 2002, Enbridge endorsed its new Indigenous Peoples Policy. The policy was developed in consultation with First Nations representatives and Enbridge subsidiaries from across the company's North American operations. Feedback from the external review indicates that the policy and its guidelines are considered leading edge. Through its operations and activities in the North, Enbridge has established relationships with key stakeholders. As lead developer, Enbridge would participate in further developing and strengthening these relationships in support of the proposed pipeline. Enbridge would also facilitate connecting communities with other industry stakeholders when desired.

*Leonard Harry and Martha Harry, Elders from Inuvik, NWT*

Enbridge's longstanding credibility with all northern stakeholders is based on the fundamental philosophy that one needs to follow through on commitments. ("Say what you are going to do and do what you said.") Successful and enduring positive northern relationships are built and maintained on a basis of mutual honesty, respect and trust.

## 7. CONCLUSION

Enbridge understands the desire of the State of Alaska to encourage new investment to diligently develop Alaskan natural gas resources and to maximize the benefit to the people of the State of Alaska of those resources. Clearly, cost efficient, competitively developed energy delivery infrastructure is a critical component of such new investment. Enbridge is of the view that it can reduce risk and bring unique value to the table through:

- our collaborative approach to major pipeline projects that require producer, customer and pipeline proponents to align interests;
- our pipeline construction and operation experience in continuous and discontinuous permafrost conditions;
- our recent experience in cost-effective planning, design and execution of sizable large-diameter projects;
- our appreciation of the need to understand and build on local benefits such as employment opportunities, economic investments, taxes and long-term opportunities for local employees to operate the pipeline;
- our extensive experience overseeing environmental impact assessment and comprehensive mitigation plans through almost every terrain found in North America and across federal, state, provincial, tribal/aboriginal and private lands;
- our understanding of the importance if the coordination of local benefits and environmental stewardship to meet the objectives of indigenous, community and other northern groups;
- our ability to create cost efficiency based on construction experience;
- our learnings about northern logistics management gained on the Norman Wells Pipeline and the Inuvik Gas project construction; and
- our local and North American distribution expertise through Enbridge Gas Distribution, AltaGas and Inuvik Gas infrastructure which can facilitate the development of local infrastructure.

Enbridge respectfully submits that this Application meets the requirements of the ASGDA, specifically:

a. the Project involves transportation of natural gas by pipeline to one or more markets;

b. the Alaska Segment would be capable of making gas available to meet reasonably foreseeable demand in Alaska for gas within the "economic proximity" of the project;

c. Enbridge is a qualified sponsor as a result of its intention to own an equity interest in the Project, including the Alaska Segment; and has a net worth of at least 10% of the estimated cost of constructing the project.

d. Enbridge proposes a project plan based on information known at the present time that includes:

    i. a description of the work accomplished as of the date of this Application;

    ii. a schedule of the proposed development activity leading to the projected commencement of commercial operations;

    iii. a description of development activity proposed to be accomplished under the proposed plan; and

    iv. a description of each lease or property that we believe to contain the stranded gas that would be developed if the project (as proposed) were built.

On the basis of all the foregoing, Enbridge respectfully requests that the Commissioner determine that with respect to the Alaska Segment in the context of the Project as whole:

i. Enbridge is proposing a qualified project within the meaning of AS 43.82.100;

ii. Enbridge is a qualified sponsor of a qualified project within the meaning of AS 43.82.110; and

iii. Enbridge has proposed a qualified project plan within the meaning of AS 43.82.130.

All of which is respectfully submitted.

| | |
|---|---|
| Stephen J.J. Letwin<br>Group Vice President,<br>Gas Strategy & Corporate Development | John Carruthers<br>Vice President,<br>Northern Development |

April 30, 2004

Contact Information:

**Enbridge Inc.**

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Calgary, Alberta, Canada T2P 3L8

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Schedule 1: Enbridge Inc. 2003 Annual Report and Audited Financial Statements

Schedule 2: United States Securities and Exchange Commission Form 10-K for Fiscal Year Ended December 31, 2003

Schedule 3: Enbridge 2003 Environment, Health, and Safety Report

# Consistent Continental Growth

ENBRIDGE

2003 Annual Report

ENBRIDGE*

**Enbridge is an energy delivery company: as such, we provide an essential service for our customers. We deliver crude oil and natural gas to heat homes, power transportation systems, and provide fuel and feedstock for industries. Our vision is to be North America's leading energy delivery company while adding long-term value for our shareholders. In 2003, we expanded our continental footprint in North America by acquiring additional energy delivery assets, and announcing a number of new projects for future growth and expansion.**

— **Patrick D. Daniel,** President & Chief Executive Officer

The cover of this year's annual report, and the other illustrations in the book, are the work of artist Pascal Milelli, an internationally-recognized illustrator based in Western Canada and a graduate of The Alberta College of Art & Design. Pascal's paintings capture and combine the vitality of the people of Enbridge with the Company's diverse portfolio of energy delivery assets.

The photographs used in this report also reflect that successful combination of people and assets, and represent all of the Company's business segments, throughout North America and internationally. Quality people and quality assets, coming together "where energy meets people" — that's Enbridge.


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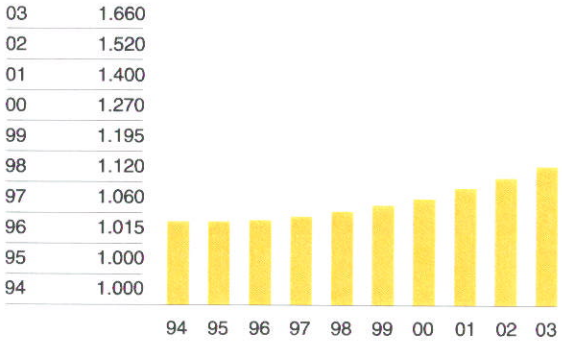
* ENBRIDGE, the ENBRIDGE LOGO and the ENBRIDGE ENERGY SPIRAL are trademarks or registered trademarks of Enbridge Inc. in Canada and other countries.

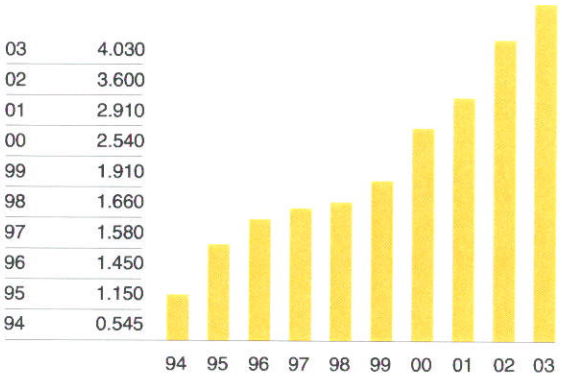
### Dividends Per Common Share

*(dollars per share)*




### Earnings Per Common Share

*(dollars per share)*




| **Financial** *(millions of Canadian dollars, except per share amounts)* | **2003** | 2002 | 2001 |
|---|---|---|---|
| Earnings Applicable to Common Shareholders | | | |
| Continuing Operations | **667.2** | 334.2 | 413.2 |
| Discontinued Operations | **–** | 242.3 | 45.3 |
| | **667.2** | 576.5 | 458.5 |
| Per Common Share Amounts | | | |
| Earnings — Continuing Operations | **4.03** | 2.09 | 2.63 |
| Earnings — Discontinued Operations | **–** | 1.51 | 0.28 |
| | **4.03** | 3.60 | 2.91 |
| Dividends | **1.66** | 1.52 | 1.40 |
| Common Share Dividends Paid | **283.9** | 251.1 | 227.5 |
| Return on Average Common Shareholders' Equity | **19.9%** | 19.9% | 18.6% |
| Debt to Debt Plus Shareholders' Equity at Year End | **61.4%** | 64.4% | 72.9% |

| **Operating** | **2003** | 2002 | 2001 |
|---|---|---|---|
| Liquids Pipelines [1] | | | |
| Deliveries *(thousands of barrels per day)* | **2,189** | 2,088 | 2,109 |
| Barrel miles *(billions)* | **710** | 705 | 695 |
| Average haul *(miles)* | **889** | 925 | 903 |
| Gas Distribution [2] | | | |
| Volume of gas distributed *(billion cubic feet)* | **458** | 410 | 427 |
| Number of active customers *(thousands)* | **1,679** | 1,623 | 1,571 |
| Degree day deficiency [3] *(degrees Celsius)* | | | |
| Actual | **4,029** | 3,362 | 3,766 |
| Forecast based on normal weather | **3,565** | 3,700 | 3,816 |

*1 Liquids Pipelines operating highlights include the statistics of the Lakehead System and wholly owned liquid pipeline operations.*

*2 Highlights of Gas Distribution reflect the results of Enbridge Gas Distribution and other gas distribution operations on a quarter lag basis for the years ended September 30, 2003, 2002 and 2001. Energy Distribution 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.*

**Enbridge is well positioned to capitalize on future growth opportunities as a result of another very strong year in 2003.**

**Donald J. Taylor,** Chair *(left)*
and **Patrick D. Daniel,** President & Chief Executive Officer

Earnings grew to a record $667.2 million in 2003, or $4.03 per common share, including gains on sale of assets. Removing gains and other unusual items, earnings were $2.84 per common share, up another 6.4% from one year ago. All five operating segments — crude oil pipelines, natural gas distribution systems, natural gas pipelines, international operations, and our two sponsored investments (Enbridge Energy Partners in the U.S. and Enbridge Income Fund in Canada) — reported increased earnings. This growth was accomplished while debt to total capitalization was reduced and A-level credit ratings were confirmed with stable outlooks.

During the year, the Company also celebrated its 50th anniversary as a publicly traded entity, having provided a 13.1% compound annual shareholder return over that period of time. This sustained, consistent performance in providing the "energy bridge" between energy suppliers and energy consumers is what best defines your Company.

As a result of the Company's past performance, Enbridge started 2004 in the strongest relative position in its history. The balance sheet is strong, the business model is proven and stable, and the Company is geographically well located to expand and extend its role in delivering energy to customers in North America and internationally.

## Achievements in 2003

Our crude oil pipeline system grew significantly in 2003, as we completed the Phase III Terrace expansion on our crude oil mainline. We put into service Canada's first underground crude oil storage facility at Hardisty, Alberta. We also acquired a pipeline that currently runs from Cushing, Oklahoma to Chicago and plan on reversing it to transport Western Canadian crude further south into the strong U.S. Midcontinent market. This "Spearhead" project, coupled with Enbridge Energy Partners' new proposal for the Southern Access line from Superior, Wisconsin, to Wood River, Illinois, will broaden markets for Canadian producers and improve access by American consumers to the huge oil sands reserves of Western Canada. Enbridge intends to further expand that access with future pipelines to the U.S. Gulf Coast, eastern PADD II region of the U.S. Midwest, and the Canadian West Coast (our Gateway Project).

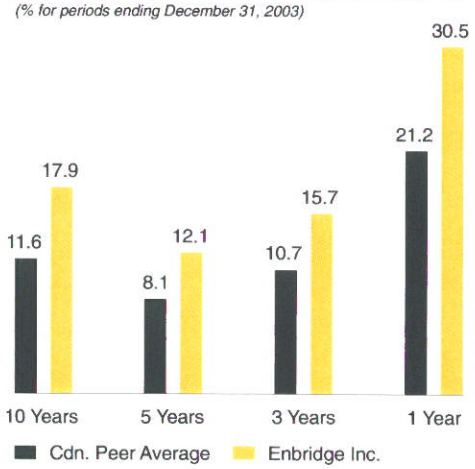
In 2003, we set a record by adding more than 60,000 new customers to our gas distribution network in Ontario, which is one of the most cost-efficient gas distribution systems in North America. Enbridge has proven in its liquids transportation business that it can provide additional benefits to its customers and shareholders through implementation of incentive rate-setting mechanisms. In Ontario, however, a common understanding and cooperation among regulators, distribution customers and Enbridge will be required to achieve this. In 2004, we will work with these parties to advance this understanding.

Five years ago Enbridge marked its entry into the natural gas pipelining business. In a short period of time we have built a very strong position in the corridor serving the U.S. Midwest and Eastern Canadian markets with Western Canada gas supply. In 2003, we increased our interest in the Alliance Pipeline to 50% and in the Vector Pipeline to 60%. In addition, Enbridge Energy Partners acquired gas gathering and processing assets in North Texas, which complement the Partnership's existing East Texas assets and growing presence in the U.S. Gulf Coast states and Midwest; and announced plans to acquire crude oil and liquids pipeline and storage systems in the Midcontinent region, including the Ozark Pipeline which transports crude oil from Cushing to Wood River.

In the U.S., our growth continues to be led by Enbridge Energy Partners, which has grown into a large master limited partnership with geographic and commodity diversity. In Canada, we successfully launched Enbridge Income Fund, already a premier Canadian income fund with a low-risk profile focused on pipeline transportation assets. Both entities are self-financing vehicles with proven low-cost capital, and we expect them to play major roles in the future acquisition of mature energy delivery assets in their respective countries.

**Total Shareholder Return**

*(% for periods ending December 31, 2003)*




## Future growth opportunities

Enbridge is focused on delivering energy to meet the needs of consumers and society in general. As a large, successful corporation we have a responsibility to conduct our business to very

high standards of integrity, transparency, safety and environmental protection. We consider it our responsibility to continue to earn the right to do business in the countries and communities in which we operate.

With our strong financial position and growing portfolio of assets in key markets, Enbridge is uniquely positioned to deliver new supplies of oil and gas to meet growing market demand. Enbridge is specifically committed to:

- Broadening markets for Canadian oil (particularly crude oil from Alberta's oil sands) and helping ensure security of supply for U.S. and other consumers. We have many excellent projects ahead of us, and we are working with our customers to identify continental opportunities and propose new delivery solutions.

- Increasing security of supply and ensuring an effective price mechanism for natural gas consumers in Ontario, at the same time as we operate one of the most cost-efficient distribution businesses in the world.

- Ensuring North American natural gas markets continue to have sufficient supplies to meet their needs. This could include participation in Liquefied Natural Gas (LNG) projects and pipeline projects to connect frontier supply basins.

- Helping producers receive fair netbacks for their natural gas production by debottlenecking areas such as the U.S. Rockies, and the Barnett Shale and Bossier gas play areas of Texas.

- Building and operating international pipelines like those in Colombia and Spain that generate attractive rates of return and complement our North American base of operations.

### In conclusion

We thank Enbridge's Board of Directors for their ongoing support and counsel. And we thank Michel Gourdeau, one of our Directors who left the Board in 2003, for his contributions.

We also thank all of our employees for their continued hard work and commitment to excellence. At Enbridge we pride ourselves on being superior asset managers, recognizing that it is truly the combination of quality assets and quality people that has made Enbridge successful.

On behalf of the Board of Directors:

**Donald J. Taylor**
Chair of the Board of Directors
March 3, 2004

**Patrick D. Daniel**
President & Chief Executive Officer

# Enbridge — A Profile

**The Enbridge group of companies includes the world's longest crude oil pipeline system, Canada's largest natural gas distribution company, and a variety of investments in natural gas pipelines.**

Enbridge is an experienced and knowledgeable asset manager with a reputation for steady growth and a low-risk profile. It is also a values-based organization with a commitment to corporate responsibility in all of its business activities.

**In 2003, Enbridge and its affiliate companies made significant progress in expanding their continental base, adding crude oil and natural gas pipeline assets, and in positioning the companies to take advantage of future growth opportunities.**

**March** Enbridge, having increased its interest in the Alliance Pipeline from 21.4% at year-end 2001 to 37.1% at year-end 2002, announced it was acquiring additional interests in the pipeline. In 2003, the Company increased its interest in both the Canadian and U.S. segments of the pipeline to 50%. In June, Enbridge Inc. sold its 50% interest in the Canadian segment of the Alliance Pipeline to the Enbridge Income Fund.

**April** The Terrace Phase III expansion of Enbridge's crude oil mainline was officially completed and placed into service on April 1, 2003. Phase III increased delivery capacity by 140,000 barrels per day on the Enbridge and Lakehead Systems.

**May** Enbridge announced the creation of Enbridge Income Fund. The Fund is a premier income fund in Canada with a low-risk profile focused on pipeline transportation assets. The successful initial public offering closed on June 30, and the Fund began trading on the Toronto Stock Exchange under the trading symbol ENF.UN. At that time, the Fund acquired from Enbridge Inc. a 50% interest in the Canadian portion of the Alliance Pipeline and a 100% interest in Enbridge Pipelines (Saskatchewan) Inc. for gross proceeds of $905 million. Enbridge Inc. owns a 72.3% overall interest in the Fund.

**July** Enbridge announced it was acquiring BP's Cushing-to-Chicago Pipeline, to open new markets for Canadian crude oil producers. The Company acquired a 90% interest in September for US$122 million. Subject to acceptance of proposed tolling arrangements by Canadian producers and regulatory approval, Enbridge plans to reverse the flow to transport Canadian crude oil south from Chicago to Cushing. The reversed-flow pipeline will be renamed the Spearhead Pipeline.

**September** Enbridge announced it was acquiring an additional 15% interest in the Vector Pipeline for US$72.5 million. Enbridge now has a 60% interest in Vector, a natural gas transmission pipeline with capacity of 1 billion cubic feet per day that delivers gas from the Chicago-area market hub in Illinois to the hub at Dawn, Ontario.

**September** As of its fiscal year-end September 30, Enbridge Gas Distribution had added more than 60,000 new customers during the 12-month period. The Company now delivers natural gas to approximately 1.7 million customers.

**October** Enbridge and Enbridge Energy Partners jointly announced plans to develop a new crude oil pipeline from the terminal at Superior, Wisconsin, south to the Wood River hub in southern Illinois. The proposed US$600-million pipeline, to be owned by the Partnership and called Southern Access, would have an initial capacity of 250,000 barrels per day and could be in service in 2007. It would provide increased capacity on the Lakehead System to accommodate growing production from the Alberta oil sands.

**November** Enbridge and CCS Inc. officially opened their jointly owned underground crude oil storage facility at Hardisty, Alberta. The $70-million Hardisty Caverns facility has four existing salt caverns, ranging in size from 600,000 to 900,000 barrels, and there are plans for expansion. Crude oil from a number of sources in Western Canada will be stored at the facility for eventual delivery to market through the Enbridge terminal at Hardisty, and will provide customers with flexible operating and marketing options for the long-term development of oil sands production.

**December** Enbridge Energy Partners announced plans to acquire crude oil and liquids pipeline and storage systems located at, or originating from, Cushing, Oklahoma. The main assets are the Ozark Pipeline, which currently transports 170,000 barrels per day of crude oil from Cushing to Wood River, and a storage terminal at Cushing.

Also in December, Enbridge Energy Partners closed its US$247 million acquisition of the North Texas System, which primarily serves the Fort Worth Basin, including growing natural gas production from the Barnett Shale zone. The system includes more than 3200 kilometres (2,000 miles) of gas gathering pipeline and five active processing plants.

Inuvik
Norman Wells
Fort St. John
Zama
Fort McMurray
Edmonton
Hardisty
Calgary
Regina
Superior
Ottawa
Montreal
Casper
Salt Lake City
Sarnia
Toronto
Buffalo
Chicago
Toledo
Kansas City
Patoka
Wood River
Cushing
Houston
New Orleans
Coveñas
Cusiana/ Cupiagua
Bogota
COLOMBIA

SPAIN
Barcelona
Madrid

LEGEND
Liquids Systems
Gas Systems
Gas Distribution

**Enbridge's operations are focused on three energy delivery businesses: crude oil pipelines, natural gas pipelines, and natural gas distribution. The business of the Company is carried out by a variety of affiliates owned in whole or in part by Enbridge Inc.**

### 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%)

### Gas Pipelines

- Alliance Pipeline L.P. (U.S. portion) (50%)
- Vector Pipeline Limited Partnership (60%)

### Sponsored Investments

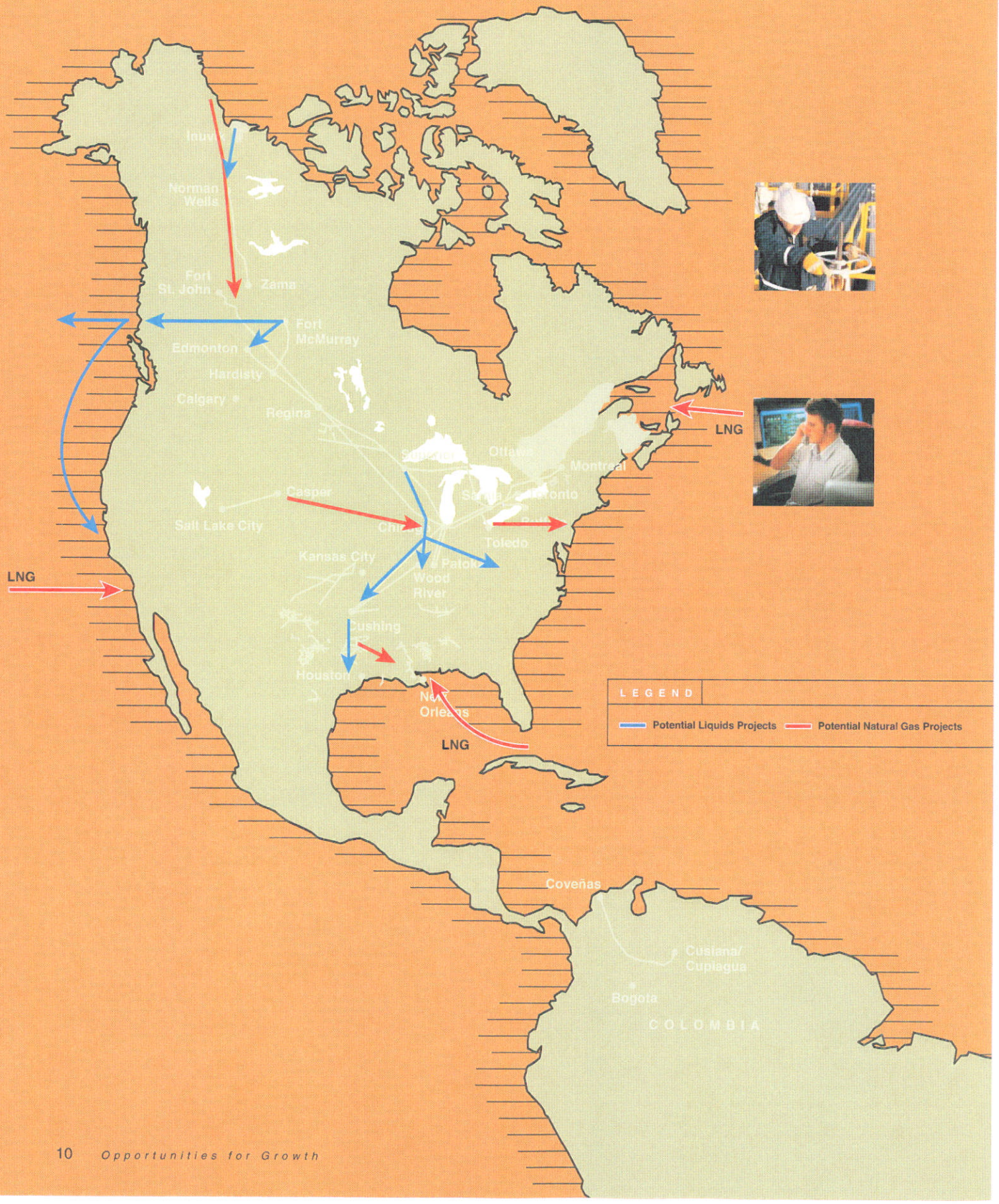
- Enbridge Energy Partners, L.P. (12.2%)
  - Lakehead System
  - Enbridge Pipelines (North Dakota) System
  - Midcontinent and Gulf Coast Systems
- Enbridge Income Fund (72.3% overall interest)
  - Enbridge Pipelines (Saskatchewan) Inc. (100%)
  - Alliance Pipeline Limited Partnership (Canadian portion) (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 (74.7%), 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%)
- AltaGas Services Inc. (40.3%)
- 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%)
- FuelCell Energy/Global Thermoelectric Inc. (strategic alliance)

### International

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


Inuvik
Norman Wells
Fort St. John
Zama
Fort McMurray
Edmonton
Hardisty
Calgary
Regina
Ottawa
Montreal
Toronto
Casper
Salt Lake City
Chicago
Toledo
Kansas City
Patoka
Wood River
Cushing
Houston
New Orleans
LNG
LNG
LNG
LEGEND
Potential Liquids Projects
Potential Natural Gas Projects
Coveñas
Cusiana/ Cupiagua
Bogota
COLOMBIA

## Accessing new markets to bring new supplies of crude oil and natural gas on stream is a crucial strategy for growth for Enbridge. The Company plans to do this by extending its continental reach.

As the primary transporter of Western Canadian crude oil, Enbridge is well positioned to develop additional infrastructure to deliver the growing volumes that are coming from Alberta's oil sands. With an estimated $50 billion in active or planned projects in the oil sands, new production is expected to come on stream steadily during the next 10 to 15 years, with an additional 800,000 barrels per day likely available by 2010.

Enbridge has been working with its customers to develop market solutions that will enable crude oil shippers to have access to new markets in a timely, cost-effective manner. Our transportation development strategy is to provide Canadian producers with continued access to the premier markets Enbridge currently serves, and to gain access to southwestern and eastern PADD II markets, the Gulf Coast, California, and the Far East.

Key components of the Enbridge strategy include the following:

- Subject to acceptance of proposed tolling arrangements by Canadian producers and regulatory approvals, Enbridge plans to reverse the Cushing-to-Chicago Pipeline that it acquired in 2003 to flow from north to south. The pipeline will be renamed the Spearhead Pipeline and will transport Western Canadian production and incremental oil sands volumes to new markets in the Central and Midwestern U.S. The Company is also pursuing delivery options for Canadian crude extending beyond Cushing to U.S. Gulf Coast markets.

- Enbridge Energy Partners has proposed building a new crude oil pipeline to provide access from its existing terminal at Superior, Wisconsin, south to the Wood River hub in southern Illinois. This Southern Access Pipeline, to be part of the Lakehead System, will interconnect with the Spearhead Pipeline. In December 2003, EEP also announced plans to acquire the Ozark Pipeline that transports crude oil from Cushing to Wood River, and a number of complementary pipeline and terminal assets.

- Enbridge has proposed constructing a new crude oil pipeline from the Athabasca oil sands region to the B.C. coast, for tidewater access to California and Asia-Pacific markets.

The growing requirement to provide North American natural gas markets with new sources of supply is also presenting Enbridge with opportunities for growth.

In 2003 Enbridge increased its interests in the Alliance and Vector natural gas pipeline systems to 50% and 60%, respectively, strengthening its position in gas transmission. The Company is looking at opportunities to deliver gas production from the Wyoming area to U.S. Midwest markets, and to move gas volumes further east. It is pursuing opportunities to invest in Liquefied Natural Gas projects: increased imports of LNG are expected to become an important source of supply for North America, and Enbridge is interested in participating as a provider of regasification and take-away infrastructure. Enbridge also remains interested in northern gas and liquids development.

**At Enbridge, corporate governance means ensuring that a comprehensive system of stewardship and accountability is in place and functioning among Directors, management and employees of the Company.**

Enbridge is committed to the principles of good governance, and the Company employs a variety of policies, programs and practices to manage corporate governance and ensure compliance.

The Board of Directors of Enbridge functions independent of management and is accountable to shareholders. The Board has delegated to the Governance Committee the role of overseeing corporate governance generally, and Enbridge has demonstrated vision and a comprehensive approach to governance through the integration of empowerment and accountability involving all employees up to the Board of Directors and ultimately to shareholders. This commitment has resulted in Enbridge being recognized as a leader in corporate governance.

In 2003, Enbridge was listed in the top 5 in the Globe & Mail Report on Business Corporate Governance/Best Boards rankings and the Clarkson Centre for Business Ethics & Board Effectiveness at the Rotman School of Management, in its Board Shareholder Confidence Index, ranked Enbridge AAA+, which is the highest ranking possible.

## Senior Management

*Standing (left to right)*

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

**J. Richard Bird**
Group Vice President, Transportation North

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

**Dan C. Tutcher**
Group Vice President, Transportation South

**Bonnie D. DuPont**
Group Vice President, Corporate Resources

*Seated (left to right)*

**Patrick D. Daniel**
President & Chief Executive Officer

**Stephen J. Wuori**
Group Vice President & Chief Financial Officer

## Board of Directors

*Standing (left to right)*

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

**Robert W. Martin,** Toronto, Ontario
Corporate Director

**Richard L. George,** Calgary, Alberta
President & Chief Executive Officer, Suncor Energy Inc.

**James J. Blanchard**, Beverly Hills, Michigan
Senior Partner, Piper Rudnick

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

*Seated (left to right)*

**J. Lorne Braithwaite,** Toronto, Ontario
Corporate Director

**David A. Arledge,** Naples, Florida
Corporate Director

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

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

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

**E. Susan Evans**, Calgary, Alberta
Corporate Director

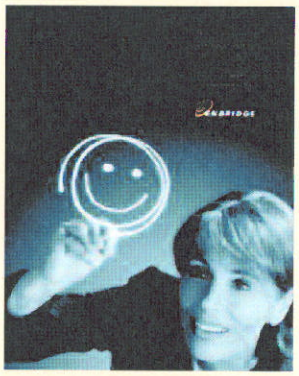
**Enbridge has always considered the safety of employees and the public, a clean and healthy environment, and strong, vibrant communities to be priorities. That's why the adoption in December 2003 of a full corporate responsibility platform was a logical step for the Company.**

Corporate responsibility defines how we will relate to others in terms of our performance in areas such as the environment, health, safety, governance, human rights, community investment and stakeholder engagement.

Enbridge had already taken many of the steps to move in that direction. At the same time, stakeholders key to our success were asking for a commitment to sustainable business practices in a visible and permanent way. A corporate responsibility platform will document the commitments we have already made and will make our sustainable approach replicable by helping us define and measure our performance.

The cornerstone of corporate responsibility is sustainability, and simply put, a sustainable enterprise is one that is built for the long-term. Business decisions combine economic realities with the social and environmental considerations that ensure longevity.

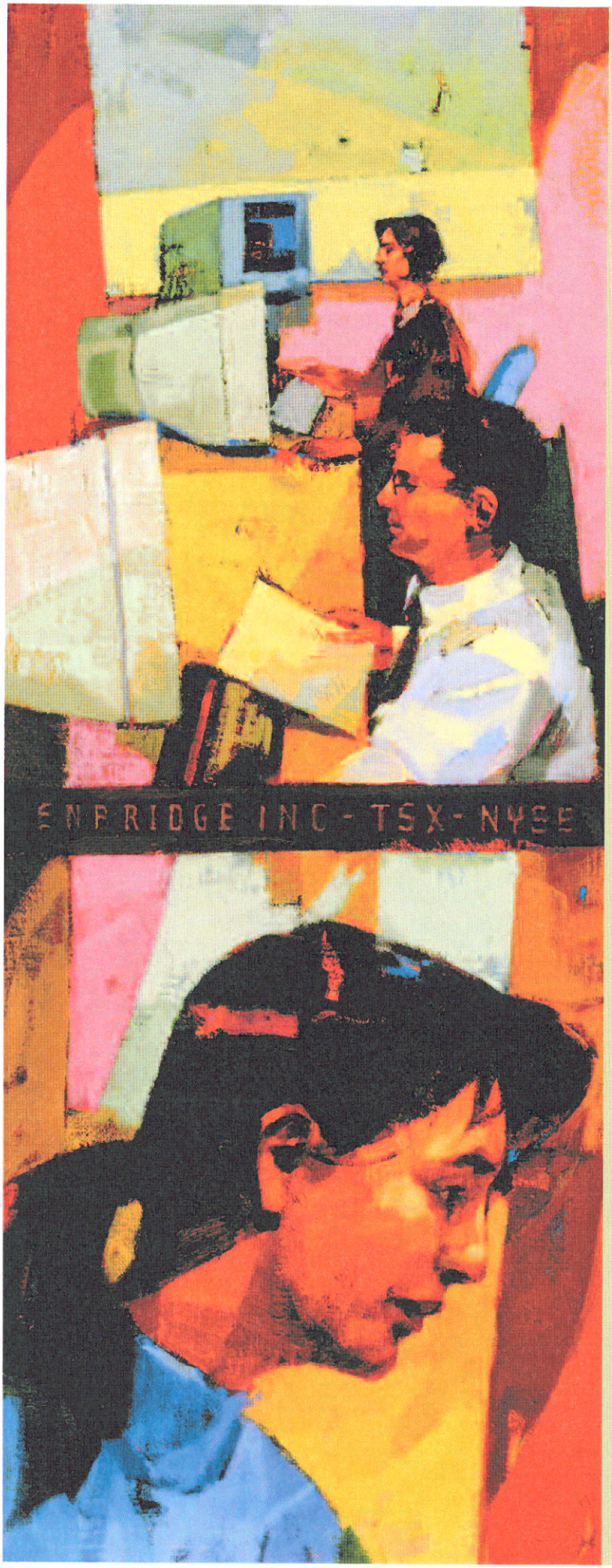
**Where Energy Meets People**



*In 2003, Enbridge launched a corporate reputation campaign to advance the company's brand image and profile the valuable relationships we foster with stakeholder communities. The campaign profiles the leadership attributes of key community investment partners from the various regions where Enbridge operates.*

In 2003, Enbridge had a number of notable achievements in areas that fall under the corporate responsibility banner.

- Enbridge employees, senior management and Board of Directors are all guided by the Company's basic code of business conduct — the *Statement on Business Conduct.* Adherence to this code of conduct, which incorporates the internationally recognized *Voluntary Principles on Security and Human Rights*, is a condition of employment. In an effort to share Company experiences and 'lessons learned' in these fields, in 2003 Enbridge became a signatory to the *United Nations Global Compact.* This initiative, under the direction of UN Secretary-General Kofi Annan, brings companies together with UN agencies, labour organizations and civil society to support nine principles in the areas of human rights, labour and the environment.
- In 2003, Enbridge again invested $3 million in communities where the Company operates, primarily in health, the environment, arts and culture, social services, education, and civic leadership. And for the fifth consecutive year, Enbridge employees across Canada and the United States raised more than $1 million for United Way campaigns.
- In Colombia, where Enbridge operates and has a 24.7% investment in the OCENSA crude oil pipeline, OCENSA celebrated the first anniversary of its formalized human rights policy, which was developed and implemented using the *Voluntary Principles on Security and Human Rights* as a guideline. The policy commits OCENSA to respect human rights and obligates employees and contractors to reject violence and avoid associating with any of the illegal armed groups in Colombia. OCENSA conducted human rights training for 100% of its employees and its major contractors, and for nearly 1,000 military personnel stationed near the pipeline. OCENSA has also hired a designated Human Rights Coordinator who, along with the company's Auditor, has the authority to review and audit the conduct of all contractors and employees as their actions pertain to human rights and to ensure compliance with OCENSA's human rights policy.




# Financial Review

**Enbridge made good progress on all of its strategic priorities in 2003, and is well positioned to pursue multiple growth opportunities in 2004.**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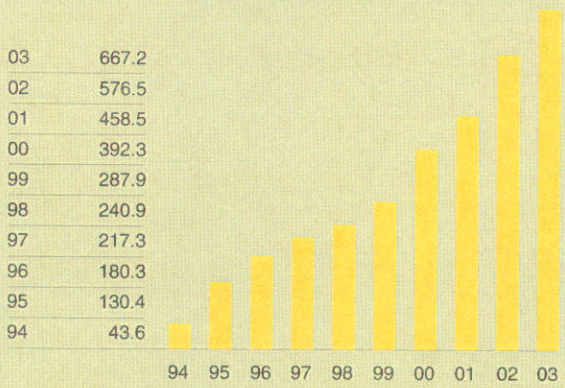
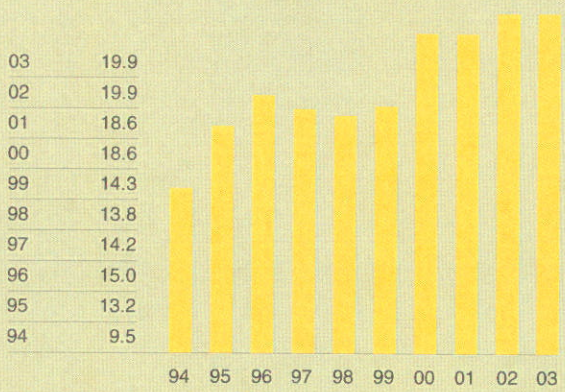
**Earnings Applicable to Common Shareholders**

*(millions of dollars)*




**Return on Average Common Shareholders' Equity**

*(%)*




## In 2003, Enbridge increased earnings in each of its five operating segments.

## CONSOLIDATED RESULTS

**Financial Highlights** [1]

| *(millions of Canadian dollars, except per share amounts)* | 2003 | 2002 | 2001 |
|---|---|---|---|
| Earnings Applicable to Common Shareholders | | | |
| Liquids Pipelines | 213.5 | 189.6 | 164.4 |
| Gas Pipelines | 70.1 | 47.8 | 41.5 |
| Sponsored Investments | 234.3 | (51.1) | 37.2 |
| Gas Distribution and Services | 153.6 | 124.3 | 189.6 |
| International | 72.3 | 68.0 | 35.6 |
| Corporate | (76.6) | (44.4) | (55.1) |
| Earnings from continuing operations | 667.2 | 334.2 | 413.2 |
| Discontinued operations | – | 242.3 | 45.3 |
| | 667.2 | 576.5 | 458.5 |
| Earnings Per Share | | | |
| Earnings — Continuing operations | 4.03 | 2.09 | 2.63 |
| Earnings — Discontinued operations | – | 1.51 | 0.28 |
| | 4.03 | 3.60 | 2.91 |
| Diluted Earnings Per Share | | | |
| Earnings – Continuing operations | 4.00 | 2.06 | 2.60 |
| Earnings – Discontinued operations | – | 1.50 | 0.28 |
| | 4.00 | 3.56 | 2.88 |
| Total Assets | 13,823.3 | 12,987.4 | 13,127.7 |
| Total Long-term Liabilities | 7,347.5 | 7,438.5 | 6,885.8 |
| Dividends Per Common Share | 1.66 | 1.52 | 1.40 |
| Common Share Dividends | 283.9 | 251.1 | 227.5 |

1 *Financial Highlights have been prepared in accordance with Canadian Generally Accepted Accounting Principles.*

Earnings for the year ended December 31, 2003 were $667.2 million, or $4.03 per share, compared with $576.5 million, or $3.60 per share, in 2002. Growth in earnings from all core business segments were noted, 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 noted in both Liquids and Gas Pipelines primarily due to the Company's increased ownership interest in both Alliance Pipeline and Vector Pipeline. 2003 also marked the completion of the Terrace Phase III project and the storage cavern project, both providing a positive contribution to net earnings.

Significant factors and variances affecting consolidated earnings are as follows:

- Sponsored Investments includes a $169.1 million after-tax gain on the sale of assets to Enbridge Income Fund (EIF) in 2003.
- Sponsored Investments included an $82.2 million after-tax writedown recorded in 2002, relating to the Enbridge Midcoast Energy (Midcoast) assets.
- Sponsored Investments includes a $20.3 million dilution gain in 2003 relating to two unit issuances by Enbridge Energy Partners (EEP). The prior year included only one dilution gain from EEP of $6.1 million.
- Gas Distribution and Services includes the positive effect of colder than normal weather of $46.1 million in 2003. In 2002, warm weather negatively affected earnings by $29.3 million. The positive weather effect in 2003 is partially offset by several regulatory disallowances in 2003, including a $4.6 million outsourcing disallowance, a $7.1 million gas cost disallowance, and a $26.0 million regulatory receivable writedown.
- The results of Noverco, included in Gas Distribution and Services, reflect a $6.0 million dilution gain relating to a unit issuance by Gaz Metro Limited Partnership.
- Corporate included a $17.8 million after-tax gain on a sale of marketable securities in 2002.
- Each year includes the effect of the Alberta 0.5% tax rate reductions. The 2003 results also include the effect of a higher federal future tax rate since federal surtax will apply when large corporations tax is eliminated. These tax rate changes result in a $7.1 million net charge to earnings in 2003 compared with a net recovery of $1.4 million in the prior year.
- Discontinued operations included a $240.0 million after-tax gain on the sale of the retail Energy Services business in 2002.

Enbridge made several strategic achievements during the year.

- The creation of the Enbridge Income Fund, on June 30, 2003, seeded with assets from the Company.
- Growth in core businesses through the acquisition of additional interests in the Alliance Pipeline, the Aux Sable NGL facility, and the Vector Pipeline. The Company also acquired a 90% interest in the Cushing-to-Chicago Pipeline System during 2003. Upon reversal, this pipeline will provide crude oil shippers with access to new markets.
- EEP has also actively pursued growth through a number of strategic acquisitions, which will support earnings growth in the future.
- The completion and placement into service of the Terrace Phase III expansion on April 1, 2003. This increased delivery capacity by 140,000 barrels per day on the Enbridge and Lakehead Systems.

For the year ended December 31, 2002, earnings from continuing operations were $334.2 million, or $2.09 per share, compared with $413.2 million, or $2.63 per share, in 2001. Growth in earnings from the Liquids Pipelines and International operations, as well as higher earnings from EEP, were more than offset by the loss on sale of the United States assets of Enbridge Midcoast Energy, warmer weather than 2001, and the positive impact on earnings of income tax rate reductions in 2001.

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

In 2003, the Company changed its financial reporting segments to better reflect the business operations and management structure of the Company. All financial information has been restated to reflect the new segments.

## CORPORATE STRATEGY

Enbridge's resources are focused on three broad strategic thrusts and three areas of increased emphasis. The major strategies are to:

- continue to expand the Company's core platforms, increase its asset base through a variety of means including organic growth and acquisition of strategic assets. The four core platforms are Liquids Pipelines, Gas Pipelines, Gas Distribution and Services and International;
- capitalize on the Enbridge Energy Partners and Enbridge Income Fund vehicles through acquisition of assets from third parties and transfers of mature assets from Enbridge; and,
- focus on operational excellence, including the application of incentive regulatory structures.

Strategic emphasis is placed on increasing the Company's North American footprint, increasing the scale of operations, and developing and applying new technologies. Enbridge's proposed actions with respect to these strategies are described in the "Outlook" for each business unit.

The achievement of the Company's major strategies is dependent on successful mitigation of business risks, discussed in each of the business segments. Enbridge believes it has identified and mitigated the risks, to the extent practical.

Enbridge remained on track with this strategy in 2003 and is committed to identifying and implementing the actions required to create value and sustainable growth.

## LIQUIDS PIPELINES

### Financial Results

| *(millions of Canadian dollars)* | **2003** | 2002 | 2001 |
|---|---|---|---|
| Enbridge System | **162.0** | 123.7 | 111.1 |
| Athabasca System | **44.8** | 41.2 | 29.9 |
| NW System | **8.3** | 9.5 | 9.5 |
| Saskatchewan System | **3.1** | 6.4 | 5.9 |
| Feeder Pipelines and Other | **(4.7)** | 8.8 | 8.0 |
| | **213.5** | 189.6 | 164.4 |

### Business Activities

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

The mainline pipeline, comprised of the Enbridge System and the Lakehead System (the portion of the mainline pipeline in the United States 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 centres in the Province of Ontario, as well as the Midwest region of the United States.

Enbridge also owns the Athabasca System and the NW System. The Athabasca System is 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. The Athabasca System also includes the MacKay River and Christina Lake lateral feeder lines and tankage facilities, as well as the Company's interest in the Hardisty Cavern Storage Partnership. The NW System is an 864-kilometre (540-mile) pipeline that transports crude oil from Norman Wells, in the Northwest Territories to Zama, Alberta.

During the third quarter of 2003, the Company acquired a 90% interest in the Cushing-to-Chicago Pipeline System. This is a 1,050-kilometre (650-mile) pipeline that transports crude oil from Cushing, Oklahoma to Chicago, Illinois, with a service capacity of 300,000 barrels per day, including 4.3 million barrels of tankage. The pipeline is currently inactive except for an approximately 145-kilometre (90-mile) portion of the pipeline from Cushing to Caney, Kansas. Subject to acceptance of proposed tolling arrangements by Canadian producers and regulatory approval, Enbridge intends to reverse the flow of this pipeline by the end of 2004. The reversed line would be renamed the Spearhead Pipeline and would provide pipeline service from the Chicago area to the Cushing market.

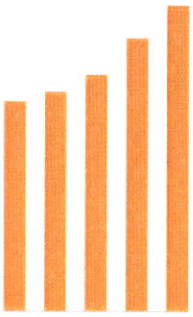
Feeder Pipelines and Other primarily includes a number of liquids pipelines in the United States (Frontier, Toledo, Mustang and Chicap), as well as business development costs related to Liquids Pipelines activities.

### Results of Operations

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 reflect higher earnings from the Enbridge and Athabasca Systems, which include incremental earnings from Terrace Phase III and the cavern storage partnership. Offsetting these positive factors is a provision for costs associated with toll complaints on the Frontier pipeline and higher business development costs as the Company evaluates growth opportunities. In addition, the Saskatchewan System was sold to Enbridge Income Fund effective June 30, 2003; however, the Company continues to have an interest in this pipeline through its 41.9% ownership of Enbridge Income Fund, included in the Sponsored Investments segment.

**Liquids Pipelines Earnings**

*(millions of dollars)*



99 00 01 02 03

| | |
|---|---|
| 99 | 146.0 |
| 00 | 152.5 |
| 01 | 164.4 |
| 02 | 189.6 |
| 03 | 213.5 |

Earnings were $189.6 million for the year ended December 31, 2002, compared with $164.4 million for 2001. The higher earnings resulted from expansions of the Enbridge and Athabasca Systems. Higher earnings from the Enbridge System were due to the request from shippers in mid-2001 to construct Phase III of the Terrace expansion, which resulted in incremental earnings and to Phase II of the Terrace expansion, which was placed into service in early 2002. These increases were partially offset by an adjustment to the power allowance credit due to shippers as a result of Terrace operating at less than capacity. The Athabasca System generated higher earnings due to the construction of new laterals and tankage, which commenced operations in the second half of 2002.

#### Enbridge System

In 2003, Enbridge System earnings were $38.3 million higher than last year primarily due to full year earnings from the Terrace Phase II expansion, incremental earnings from Terrace Phase III, which commenced operations ahead of schedule on April 1, 2003, 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 is 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.

Earnings from the Enbridge System increased to $123.7 million in 2002 from $111.1 million in 2001. The increase was mainly due to higher earnings from the Terrace expansion as Phase II was placed into service in early 2002 and Phase III was triggered in mid-2001. The increase in Terrace earnings was partially offset by an adjustment to the power allowance credit due to shippers as a result of Terrace operating at less than capacity.

Tolls on the Enbridge System are governed by the provisions of the Incentive Tolling Settlement (ITS). The ITS, which has been approved by the NEB, is in its second five-year term which expires on December 31, 2004. Under the ITS, tolls are determined based on a starting revenue requirement, which is adjusted each year for 75% of the change in the Gross Domestic Product Implicit Price Index. The ITS allows the Company and its customers to share in cost savings, protects Enbridge from fluctuations in volumes, and incorporates 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 is allowed to earn a separate return on facilities expansions or additions that qualify 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 by Enbridge and its customers of $96.8 million have been shared approximately 53% and 47%, respectively. Customers also have realized an additional after-tax benefit of $7.9 million through the power guarantee mechanism of the ITS.

### Athabasca System

In 2003, earnings on the Athabasca System were $3.6 million 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 cavern facilities to provide crude oil storage services. These facilities are located near Enbridge's main pipeline terminal at Hardisty, Alberta, and are jointly owned by Enbridge and an industry partner. The facilities have storage capacity approximating 3.1 million barrels, all of which have been fully subscribed to under a long-term fee-for-service agreement with a major energy producer.

In 2002, the construction of additional tankage and terminal facilities at the Athabasca terminal in Fort McMurray increased the investment base resulting in higher earnings than in 2001.

The Company has a long-term contract with the major shipper on the Athabasca System. Earnings are recognized based on the contract terms negotiated with the major shipper. Differences between actual cash tolls and toll revenue as determined under the contract is recognized in the period. The deferred amounts will be collected over the term 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 and 2001. 2003 does not include an incentive component as 2003 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

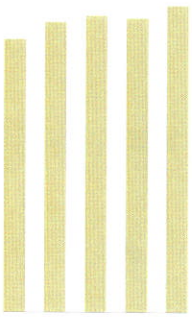
The earnings decrease noted in the Saskatchewan System of $3.3 million from 2002 is due to the Company's sale of this asset to EIF effective June 30, 2003.

### Feeder Pipelines and Other

The earnings decrease in Feeder Pipelines and Other primarily reflects a provision for costs associated with toll complaints on Frontier. Business development costs were also higher in 2003 due to the continuing review of a number of liquids pipelines opportunities. Other factors contributing to the earnings variance include lower tolls on the Frontier Pipeline while the prior year included a positive revenue adjustment on the Toledo Pipeline.

**Deliveries**[1]

*(thousands of barrels per day)*




| | |
|---|---|
| 99 | 1,942 |
| 00 | 2,072 |
| 01 | 2,109 |
| 02 | 2,088 |
| 03 | 2,189 |

1 Includes deliveries by the 12.2% owned Lakehead System

## Outlook

### Enbridge System

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 914-millimetre (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 barrels per day when it was placed into service on April 1, 2003 and was requested by shippers to handle anticipated increases in oil sands volumes in the next few years.

Volumes transported are expected to increase in 2004 due to continuing increases in production from the oil sands region of Alberta. Oil sands production growth is more than offsetting declines in the Western Canadian Sedimentary Basin (WCSB) conventional production. Fluctuations in volumes do not impact the majority of net earnings from the Enbridge System due to provisions in the ITS.

The ITS allows Enbridge and its customers to share in cost savings achieved. The Company will continue to focus on operational excellence in order to ensure continued savings for customers and increased returns for shareholders.

### Enbridge Athabasca System

The Enbridge Athabasca System is the only liquids pipeline directly linking both the Athabasca and Cold Lake oil sands deposits with the pipeline transportation hub at Hardisty, Alberta. With a design capacity of 570,000 barrels per day, the pipeline is well positioned to carry more of the region's oil sands and heavy oil production in the future.

Earnings from the Athabasca System are expected to increase in 2004 as a result of a full year of operations from underground storage and other facilities placed into service in 2003.

### Supply

Liquids supply growth from the WCSB is expected to continue to increase over the next 10 years. The NEB's latest estimates for 2003 project WCSB production growth of oil sands and heavy oil volumes of 120,000 barrels per day over 2002 volumes, offset by a decline in conventional production of 35,000 barrels per day. The net increase in WCSB production of 85,000 barrels per day over 2002 levels translates into the highest level of production ever achieved by the WCSB and reflects the growth in bitumen and upgraded synthetic production.

Remaining established conventional oil reserves in Western Canada were estimated to be five billion barrels in 2002. During 2002, approximately 65% of volumes produced were replaced with reserve additions. Remaining established reserves from oil sands currently stand at 174 billion barrels, with nearly four billion barrels having been produced to date. According to the Oil and Gas Journal's Worldwide Look at Reserves and Production, Canada's reserves represent 14% of world oil reserves, second only to Saudi Arabia in size. [1]

### Capital Expenditures

Liquids Pipelines expects to spend approximately $80 million in 2004 for ongoing capital improvements and core maintenance capital projects relating to the main pipeline system. Additional expenditures of US$20 million are also expected in 2004 to reverse the flow of the Cushing-to-Chicago Pipeline System, which was acquired in 2003. At that time, the final payment of US$65 million will be paid to the vendor.

## Business Risks

### 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. Oil targeted drilling licenses in Western Canada increased 25% in 2003 from 2002. This strong drilling activity, along with the start-up of Shell's Athabasca oil sands project, resulted in significant production growth over 2002. For 2004, growth is expected to continue with full year production from Shell's Athabasca oil sands project and expansions at Cold Lake, and the completion of expansions at Syncrude and Suncor.

*1 CAPP Statistical Handbook — current year*

Historically, refiners in the U.S. Midwest have utilized large volumes of Western Canadian light crude versus other imported crude. Line 9 transports offshore crude to Ontario and is owned by Enbridge. Volumes on Line 9 have displaced some Canadian and U.S. domestic deliveries in the Ontario market, requiring an increase in deliveries to the U.S. Midwest, which has limits on the volume of Canadian crude which can be readily absorbed.

Following Canada's ratification of the Kyoto Protocol, Enbridge has continued to assess the potential impact on oil sands investment. Moody's Investors Service recently surveyed oil sands operators and concluded that Kyoto is expected to have a minimal effect on the development of Alberta's oil sands resource. Enbridge is encouraged by this conclusion as it supports the sustainability of supply for liquids pipelines.

### 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 changes. The Company believes that regulatory risk has been reduced through the negotiation of long-term agreements, such as the ITS, with its customers.

### Competition

The Enbridge System transported approximately 67% of total Western Canadian crude oil production in 2003 and provides approximately 77% of the capacity for the transportation of Western Canadian crude oil out of Canada. 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. Due to the size of the oil sands reserves, competitive pressures to provide economical transportation service continue.

### Environment and Safety

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. These systems reflect industry best practices and are aligned with the ISO 14001 standard and the BSI-OHSAS 18001 specification for environmental, health and safety management systems. Regular reviews and audits are conducted to assess compliance with legislation and company policy.

Pipeline leaks are an inherent risk of operations. 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.

## GAS PIPELINES

### Financial Results

| *(millions of Canadian dollars)* | **2003** | 2002 | 2001 |
|---|---|---|---|
| Alliance Pipeline (US) | **40.3** | 19.6 | 19.0 |
| Alliance Pipeline (Canada) | **19.6** | 21.1 | 18.6 |
| Vector Pipeline | **10.2** | 7.1 | 3.9 |
| | **70.1** | 47.8 | 41.5 |

### Business Activities

Gas Pipelines activities consist of investments in the Alliance and Vector pipelines, accounted for under proportionate consolidation.

Enbridge owns a 50.0% interest in Alliance Pipeline (US), the U.S. portion of a 3,000-kilometre (1,800-mile) pipeline that transports liquids-rich natural gas from Fort St. John, British Columbia to Chicago, Illinois. The Company provides operating services to and holds a 60% investment in Vector, which transports natural gas from Chicago to Dawn, Ontario. Both Alliance and Vector commenced operations in December 2000. Alliance and Vector have the capacity to deliver 1.55 billion cubic feet per day (bcfd) and 1.0 bcfd, respectively.

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.

### Results of Operations

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.

Earnings were relatively constant between 2002 and 2001 with the exception of higher earnings from the Vector Pipeline.

#### Alliance Pipeline (US)

The increase in earnings of $20.7 million from Alliance Pipeline (US) in 2003, compared with 2002, reflects the acquisition of additional ownership interests of 1.1% in March 2003, 10.7% in April 2003, and 1.1% in October 2003. The Company's current ownership is 50.0%.

In late 2002, the Company acquired an additional ownership interest of 15.7%. However, due to the timing of the transaction, there was no significant effect on 2002 earnings in comparison to 2001.

#### 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

The contribution from Vector is $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 is further enhanced by additional ownership interests of 15.0% acquired in the fourth quarter of 2003. The Company's current ownership is 60.0%.

Earnings in 2002 were $3.2 million higher than in 2001 as a result of a one-time adjustment to depreciation expense, reflecting a revision to depreciation rates to be consistent with the rates approved by the Federal Energy Regulatory Commission (FERC). In addition, an adjustment was booked in 2001 to reverse earnings that were over accrued in 2000.

**Gas Pipelines Earnings**

*(millions of dollars)*



| | |
|---|---|
| 99 | 33.2 |
| 00 | 39.6 |
| 01 | 41.5 |
| 02 | 47.8 |
| 03 | 70.1 |

### Outlook

Earnings from Alliance Pipeline (US) and Vector should increase in 2004 as a result of Enbridge's higher ownership interest. There is no near-term requirement for further partner investment in either pipeline.

#### 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. 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. This is expected to improve the stability of natural gas prices and provide a more favourable pricing structure that will facilitate further growth in the power generation market.

### Business Risks

Alliance and Vector are regulated federally and are subject to regulatory risk. The Company believes that this risk has been mitigated through the execution of long-term contracts with customers. Currently, pipeline capacity out of the WCSB exceeds supply. Alliance has been unaffected but Vector has not fully contracted its capacity and, as a result, is negatively impacted by the basis (location) differential between Chicago and Dawn, Ontario.

#### Exposure to Shippers

Alliance is highly dependent upon the shippers for revenues from contracted capacity on the Alliance system. 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 could impair the ability of Alliance to meet its debt obligations and make distributions to its limited partners. A prolonged economic downturn in the energy industry, among other things, could impact the ability of some or all of the shippers to fulfill their obligations under the transportation contracts. To reduce this risk, Alliance has put certain controls in place to monitor the creditworthiness of each shipper.

#### Pipeline Operating Risk

As with any comprehensive pipeline system, the operation of Alliance and Vector involves many risks, including: 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 respective systems. The occurrence or continuance of any of these events could increase the cost of operating Alliance or Vector and reduce transportation capacity, thereby impacting earnings. Risks of substantial costs and liabilities, including those from leaks and explosions, are inherent in pipeline operations and there can be no assurance that significant costs and liabilities will not be incurred, including those relating to claims for damages to property and persons.

## SPONSORED INVESTMENTS

### Financial Results

| *(millions of Canadian dollars)* | **2003** | 2002 | 2001 |
|---|---|---|---|
| Enbridge Energy Partners | **27.3** | 19.5 | 12.5 |
| Enbridge Income Fund | **17.6** | – | – |
| Enbridge Midcoast Energy | **–** | 5.5 | 9.5 |
| Gain on sale of assets to Enbridge Income Fund | **169.1** | – | – |
| Writedown of Enbridge Midcoast Energy assets | **–** | (82.2) | – |
| Dilution gains | **20.3** | 6.1 | 15.2 |
| | **234.3** | (51.1) | 37.2 |

## Business Activities

Sponsored Investments includes the Company's ownership interests in the operations of EEP and EIF. Enbridge operates the assets of both investments.

Enbridge has an effective 12.2% ownership interest (2002 – 14.1%, 2001 – 13.6%) in EEP. This ownership interest represents the Company's direct investment in EEP of 9.1% and an indirect investment of 3.1% through the Company's 17.2% ownership interest in Enbridge Energy Management (EEM). Enbridge, as the general partner of EEP, receives incentive income based on the level of quarterly cash distributions. EEP owns the Lakehead System, a feeder pipeline in North Dakota, the Enbridge Midcoast Energy (Midcoast) assets, and natural gas gathering and processing assets in East Texas (East Texas System).

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.

In October 2002, Enbridge sold the United States assets of Midcoast to EEP. From May 2001 until October 2002, Enbridge owned 100% of Midcoast. The results of operations of Midcoast, in the preceding table, relate to the period when the assets were wholly-owned.

## Results of Operations

For the year ended December 31, 2003, earnings were $234.3 million compared with a loss of $51.1 million for 2002. The current year results include an after-tax gain of $169.1 million on the sale of the Company's interests in Alliance Pipeline (Canada) and Enbridge Pipelines (Saskatchewan) Inc. to EIF. The 2003 results also include dilution gains of $20.3 million, compared with $6.1 million in 2002. This reflects two unit issuances by EEP in 2003, compared with only one in the prior year.

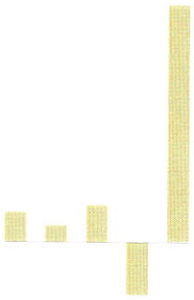
Excluding the impact of these gains, earnings in this segment increased $102.1 million from 2002. A significant portion of this year-over-year change is due to an $82.2 million writedown recorded in 2002 on the sale of the Midcoast assets. The remainder of the $19.9 million increase is attributed to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

For the year ended December 31, 2002, earnings from Sponsored Investments decreased by $88.3 million from $37.2 million from 2001. The 2002 results included an $82.2 million writedown on the sale of the Midcoast assets. Excluding this writedown, earnings for 2002 were $6.1 million lower than 2001. Increased earnings from EEP resulted from the acquisitions of the North Dakota and East Texas Systems, and the Midcoast assets. These additional earnings were more than offset by lower earnings from Midcoast prior to its sale and higher dilution gains in 2001.

In October 2002, the Company closed the sale of the United States assets of Midcoast to EEP for consideration of US$820.0 million, including cash and the assumption of affiliate debt. Concurrent with the sale transaction, EEM, a subsidiary of Enbridge, completed an initial public offering of 9,000,000 shares representing limited liability company interests with limited voting rights. The net proceeds from the offering were used to purchase i-units, a new class of limited partnership interests, from EEP. The proceeds from the i-units were used to finance a portion of the acquisition cost of the assets. In connection with the offering, Enbridge purchased 17.2% of the EEM shares, increasing its effective ownership in EEP to 14.1% from 12.9%. EEM has no assets or operations other than those related to the interest in EEP and, by agreement, will manage the business and affairs of EEP.

**Sponsored Investments Earnings**

*(millions of dollars)*



| | |
|---|---|
| 99 | 30.4 |
| 00 | 16.3 |
| 01 | 37.2 |
| 02 | (51.1) |
| 03 | 234.3 |

### Enbridge Energy Partners

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

The increased contribution from EEP in 2002 compared with 2001 resulted from the acquisitions of the North Dakota and East Texas Systems in 2001, which contributed a full year's earnings in 2002. The acquisition of the Enbridge Midcoast Energy assets also increased earnings in the fourth quarter of 2002.

### Enbridge Midcoast Energy

Midcoast was sold to EEP in October 2002. Enbridge purchased Midcoast in May 2001 for cash consideration of $561.8 million and the assumption of long-term debt. Earnings from Midcoast in 2002 were $5.5 million, a decrease of $4.0 million from the prior year. While 2002 results reflected improved operating performance, earnings were more than offset by adjustments related to 2001 that were recorded in 2002 and working capital and other closing adjustments identified prior to the disposition. Earnings for 2002 are for the period prior to the October 2002 disposition. Earnings for 2001 represent earnings from the May 2001 date of acquisition.

In March 2002, the Company acquired natural gas gathering and processing facilities in northeast Texas for approximately $290 million. These assets were included with Midcoast and were part of the October 2002 sale to EEP.

### 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. EIF has positively contributed to the Company's earnings in the year.

## Outlook

### Enbridge Energy Partners

Earnings from the Lakehead System and certain of the gas gathering assets are volume-sensitive and expected increases in volumes should have a positive impact on EEP's earnings.

EEP is also expected to experience growth as it reaches new markets through assets acquired in 2003. Effective December 31, 2003, EEP closed its acquisition of 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.

Also in the fourth quarter of 2003, EEP announced that it had signed an agreement to acquire crude oil pipeline and storage systems in the U.S. Midcontinent. The assets being acquired serve refineries in the Midcontinent from the Cushing, Oklahoma hub and consist of approximately 615 miles (990 kilometres) of active crude oil pipelines and 9.5 million barrels of storage capacity. Included in these assets are the 433-mile (697-kilometre) Ozark Pipeline, which currently transports 170,000 barrels of crude oil per day from Cushing to Wood River, Illinois; the 47-mile (76-kilometre) West Tulsa Pipeline, which currently transports 55,000 barrels per day to two refineries in Oklahoma; and the Shell storage terminal at Cushing, which is one of the largest terminal facilities in North America with 8.3 million barrels of storage capacity. Most notably, though, this acquisition diversifies the Company's sources of income from crude oil transportation and storage services, reducing its dependence on production from the WCSB.

### Enbridge Income Fund

Enbridge Income Fund will continue to focus its efforts in 2004 on managing system assets and infrastructure, and further developing its operational procedures and processes with a view to maximizing available transportation capacity and the competitiveness of its tolls. The Fund remains confident that it will generate built-in, predictable growth in cash flow from its assets in order to provide modest but regular on-going distribution increases, supplemented with some acquisition-based growth.

## 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.

### Enbridge Energy Partners

#### *Supply and Demand*

The operation 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, future plans to expand into the southern United States will increase demand for Western Canadian crude.

Supply is dependent upon a number of variables including the level of exploration, drilling, reserves and production of natural gas, crude oil and other liquid hydrocarbons. It is also impacted by the accessibility, price and quality of commodities available from alternate Canadian and U.S. sources, and the regulatory environments in Canada and the U.S., including the continued willingness of the governments of both countries to permit the export of natural gas, crude oil, and other liquid hydrocarbons from Canada to the United States on a commercially acceptable basis.

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 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 the Gas Pipelines segment, 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.

#### *Competition*

The Saskatchewan System faces competition in pipeline transportation from other pipelines, as well as other forms of transportation, most notably trucking. For the Weyburn and Virden pipeline systems, which use market based tolls, the cost of alternative transportation options affects the rates that can be charged for transportation service on these pipelines. The cost of alternative transportation options also provides a competitive force on the Saskatchewan System's cost of service based pipelines, the Saskatchewan and Westspur pipeline systems. These alternative transportation options could charge rates or provide service to locations that result in greater net profit for shippers with the effect of forcing the Saskatchewan System, for commercial reasons, to lower the transportation rates to avoid losing shippers, thereby reducing the Saskatchewan System's cash flow from transportation services.

## GAS DISTRIBUTION AND SERVICES

### Financial Results

| *(millions of Canadian dollars)* | 2003 | 2002 | 2001 |
|---|---|---|---|
| Enbridge Gas Distribution | 103.0 | 85.3 | 156.1 |
| CustomerWorks/ECS | 16.9 | 10.7 | 14.3 |
| Noverco | 24.2 | 20.6 | 16.3 |
| Other Gas Distribution | 6.6 | 6.2 | 5.5 |
| Enbridge Gas New Brunswick | 4.4 | 3.6 | 2.3 |
| Gas Services | (5.9) | (7.8) | (5.3) |
| Aux Sable | (6.9) | (3.1) | (6.2) |
| Other | 11.3 | 8.8 | 6.6 |
| | 153.6 | 124.3 | 189.6 |

### 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; the Company's investment in Aux Sable, which is accounted for through proportionate consolidation; as well as the equity investment in AltaGas Services.

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. Its operations in Ontario are regulated by the Ontario Energy Board (OEB).

CustomerWorks/ECS includes the operations of CustomerWorks LP, whose operations commenced on January 1, 2002, and provides services covering the entire meter-to-cash process, including many of the services which, until then, were provided by Enbridge Commercial Services (ECS). The results of ECS in 2002 and 2001 also include information technology and fleet services, which were rebundled into EGD in the fourth quarter of 2002. CustomerWorks was formed by Enbridge and Terasen and serves over 3.5 million customers including those of Terasen's and Enbridge's gas distribution operations. In August 2002, CustomerWorks outsourced the provision of its customer care services to a new entity owned and operated by Accenture Inc.

Enbridge owns an equity interest in Noverco through ownership of 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), the natural gas distribution franchise in the province of New Brunswick. EGNB is constructing a new distribution system and has approximately 2,300 customers. Over 200 kilometres (124 miles) of distribution main has been installed with the capability of attaching 6,000 customers. EGNB is regulated by the New Brunswick Board of Commissioners of Public Utilities.

### Results of Operations

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.

Earnings from Gas Distribution and Services were $124.3 million for the year ended December 31, 2002, compared with $189.6 million in 2001. The results reflect strong operating performance from EGD, more than offset by a smaller positive impact of tax rate reductions in 2002 than in 2001. Earnings from Noverco were also lower in 2002 due to the positive effect of tax rate reductions on earnings in 2001.

### Enbridge Gas Distribution

Earnings from EGD increased by $17.7 million in 2003 from 2002. The increase was due to higher gas distribution margins caused by increased distribution volume resulting from colder weather. This is partially offset by a $26.0 million regulatory receivable writedown related to a prior year, a $7.1 million OEB gas cost disallowance related to long-term transportation contracts and a $4.6 million OEB outsourcing disallowance. Had EGD experienced normal weather in its franchise area, reported net earnings would have decreased by approximately $46.1 million after tax. 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. The effect of weather is measured by degree-day deficiency and is calculated by accumulating, from October 1, the total number of degrees each day by which the daily mean temperature falls below 18 degrees Celsius. 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 uses the degree-days from the most recent years to determine the estimate. This weather-normalized adjustment is consistent with the manner in which EGD calculates degree-days for regulatory purposes.

The results for 2002 decreased by $70.8 million from 2001 due to the effect of the significantly warmer than normal weather in 2002. On a weather-normalized basis, earnings would have been higher by $29.3 million after tax while, for 2001, earnings would have decreased $5.0 million. In addition, 2001 included the positive impact of tax rate reductions of $45.0 million.

**Gas Distribution and Services Earnings**

*(millions of dollars)*




| | |
|---|---|
| 99 | 97.7 |
| 00 | 211.7 |
| 01 | 189.6 |
| 02 | 124.3 |
| 03 | 153.6 |

Prior to 2000, EGD's rates were typically determined using a cost-of-service methodology that allowed the 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 the investment in all assets used in gas distribution, storage and transmission, as well as an allowance for working capital. A requested increase in rates to recover forecast costs reflects a revenue deficiency, while a reduction in rates reflects a revenue sufficiency. Under cost of service, it is the responsibility of EGD to demonstrate to the OEB the prudence of the costs it is forecasting to incur over the year. EGD does not profit from the sale of the natural gas commodity.

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

EGD's 2003 rates were established pursuant to the cost-of-service methodology.

The allowed rate of return on common 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%, 2001 – 9.54%) on a deemed common equity ratio of 35.0%.

Over the last four years, EGD added 209,000 customers, including over 50,000 customers (net) in 2003. EGD services approximately 95% of residential space heating in its franchise area. This growth was attributable to the continued preference for natural gas among homeowners, builders and business operators, primarily because of the ongoing price advantage of natural gas and environmental benefits over other forms of energy. The residential construction market showed continued strength in 2003, which fueled demand for natural gas used in space and water heating. In addition, builders are increasingly using portable natural gas-fired heaters during cold weather construction.

### CustomerWorks/ECS

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 is 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 reflect higher weather-related customer service call volumes and growth in the CustomerWorks customer base.

Lower earnings from CustomerWorks/ECS in 2002, compared with 2001, reflect the positive impact of tax rate reductions in 2001 and the transfer of a vast majority of the remaining ECS operations into Enbridge Gas Distribution in the fourth quarter of 2002.

### Noverco

The contribution from Noverco was $24.2 million in 2003, compared with $20.6 million in 2002. The increase is due to the 2003 results including a $6.0 million dilution gain, resulting from a Gaz Metro Limited Partnership unit issuance that Noverco did not participate in. Equity earnings from Noverco in 2002 were higher than 2001, mainly due to lower financing costs and higher incentive earnings.

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.

### Enbridge Gas New Brunswick

Earnings from Enbridge Gas New Brunswick improved in 2003 due to increased customer connections. Earnings were better in 2002 than 2001 due to a full year of operations.

### Gas 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 is 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 and associated transmission services, reducing merchant capacity losses on Alliance and Vector. Losses in 2002 were $2.5 million higher than those in 2001 due to the reduced basis differentials between Alberta and Chicago, and between Chicago and Dawn, Ontario, which increased the losses on the Company's Alliance and Vector merchant capacity. The basis differential is the cost of transportation between natural gas hubs and determines the revenue that can be obtained from merchant transportation capacity.

**Energy Distribution Degree Day Deficiency**

*(degrees Celsius)*

| | Forecast | Actual |
|---|---|---|
| 99 | 4,060 | 3,460 |
| 00 | 3,629 | 3,569 |
| 01 | 3,816 | 3,766 |
| 02 | 3,700 | 3,362 |
| 03 | 3,565 | 4,029 |

### Aux Sable

Enbridge owns a 42.7% interest in the Aux Sable facilities, which process natural gas delivered through Alliance. As the gas transported by Alliance is liquids-rich, it must be processed prior to delivery to other systems. Aux Sable commenced operations in December 2000 and has the capacity to process up to 1.6 bcfd of natural gas. 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 reflects 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 reflect 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.

Losses in 2002 were lower than those in 2001 by $3.1 million due to better margins between natural gas liquids and natural gas throughout 2002. The Company's ownership interest in Aux Sable increased from 21.4% to 30.9% in the fourth quarter of 2002.

## Outlook

### Enbridge Gas Distribution

#### *2004 Rate Application*

EGD filed its fiscal 2004 rate application with the OEB in April 2003. EGD's objective was to return to an appropriate regulatory schedule whereby rates would be set prospectively. EGD's 2004 rate application requested that rates for 2004 be set by increasing 2003 rates by 90% of the forecast Ontario consumer price index, that being an increase of 1.8%. EGD reached a partial settlement with certain intervenors to accept this innovative approach to rate setting.

The OEB accepted the negotiated settlement proposal for the 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 return on equity (ROE), these excess earnings would be shared on a 50/50 basis between the ratepayers and Enbridge.

Acceptance by the OEB of EGD's 2004 Rate Application was successful in returning the rate-making schedule to a prospective basis by setting 2004 rates as a function of the forecast consumer price index for the fiscal 2004 year. EGD filed the 2005 Rate Application with the OEB in December 2003. The hearing is expected to be held in June 2004.

#### *Review of OEB Formula for Setting ROE*

In September 2003, the OEB completed a hearing to review and consider possible revisions to the current ROE formula that is adjusted by any change in the long-term Canadian bond yield. EGD filed evidence to propose a ROE for 2004 of 11.2%. The increase in the requested ROE reflects EGD's belief that this is more representative of a risk-adjusted return within the North American equity markets. A decision was issued on January 16, 2004, which dismissed the application and confirmed the use of the existing formula. A ROE of 9.69% is embedded in the 2004 rates.

#### *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.

**Energy Distribution Number of Active Customers**

*(thousands)*

99 00 01 02 03

| | |
|---|---|
| 99 | 1,466 |
| 00 | 1,520 |
| 01 | 1,571 |
| 02 | 1,623 |
| 03 | 1,679 |

### *Gas Distribution Access Rule*

The 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. Accordingly, EGD and Union Gas Limited both appealed the so-called vendor consolidated billing aspects of the GDAR to the Ontario Divisional Court. The Ontario Divisional Court heard the appeals in August 2003 and in September 2003, the Court issued a decision dismissing the appeals and upholding the OEB's jurisdiction to enact the vendor consolidated billing portions of the GDAR. Both EGD and Union Gas Limited, Ontario's other principal gas distributor, have been granted leave from the Ontario Court of Appeals to hear an appeal of the Ontario Divisional Court's decision.

In the interim, the Company is working closely with the OEB and gas marketers to resolve other outstanding GDAR implementation issues.

### Enbridge Gas New Brunswick

Customer attachment to the EGNB system has been slower than expected. EGNB plans to increase the attachment rate by becoming actively involved in the sale of the natural gas commodity and the sale, installation and service of natural gas equipment to the residential and small commercial markets. This "bundled" approach was approved by the provincial legislation during 2003.

## Capital Expenditures

Capital expenditures in 2004 for the Gas Distribution and Services business are expected to be approximately $287 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.

## Business Risks

### 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. The new Ontario government's intentions with respect to the current freeze in electricity prices, which expires in 2006, and the direction of natural gas prices in the medium to long term will impact EGD's competitiveness in the energy market.

### *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 rate-making 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.

Sales and transportation of gas for customers in the residential and commercial sectors account for approximately 77% (2002 – 74%) 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. In addition, technology issues combined with increased costs of residential natural gas water heaters may pressure EGD's market share for natural gas water heaters.

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 volume 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. The timing of gas sales is also a factor, as higher rates are charged during the winter season than during the summer season.

### *Rate Relief*

Through the regulatory process, the OEB approves the return on equity that 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.

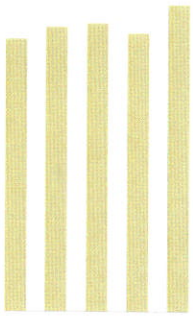
EGD does not profit from the sale of the natural gas commodity nor is it at risk for the difference between the actual cost of gas purchased and the price approved by the OEB. This difference is deferred as a receivable from or payable to ratepayers until the OEB approves its disposition. EGD monitors the balance and its potential impact on ratepayers and requests, on a quarterly basis, interim rate relief that will allow EGD to recover or refund the gas commodity cost differential.

### *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, the forecasting process ensures 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.

**Energy Distribution Volume of Gas Distributed**

*(billions of cubic feet)*



| | |
|---|---|
| 99 | 402 |
| 00 | 421 |
| 01 | 427 |
| 02 | 410 |
| 03 | 458 |

### 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 unfavorable 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. Aux Sable has initiated a hedging program which will mitigate its earnings volatility.

## INTERNATIONAL

### Financial Results

| *(millions of Canadian dollars)* | 2003 | 2002 | 2001 |
|---|---|---|---|
| OCENSA/CITCol | 32.3 | 35.3 | 35.1 |
| CLH | 46.3 | 33.3 | – |
| Jose Terminal and Other | (6.3) | (0.6) | 0.5 |
| | 72.3 | 68.0 | 35.6 |

### Business Activities

International includes earnings from the investments in OCENSA, a crude oil pipeline in Colombia, and CLH, Spain's largest refined products transportation and storage business. Earnings also include fees earned from technology and consulting services provided by Enbridge Technology Inc.

OCENSA is a cost investment on which the Company earns a stated return and which contributes a significant portion of the earnings. The Company also has responsibility for the operations of the pipeline, through CITCol, and earns a fee for this service, which includes incentive earnings for operating performance.

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 throughout Spain. Earnings are based on a fee for service and are dependent on throughput volumes and storage levels.

As a result of a breach of the Jose Terminal operating agreement by PDVSA, the Venezuelan state oil company, the SWEC Partnership, in which the company holds a 45% ownership, has filed a notice of contract termination and has filed for international arbitration, as provided for in the operating agreement. The company ceased recognition of earnings commencing February 1, 2003. Other is primarily administration and business development costs and the results of the Technology business.

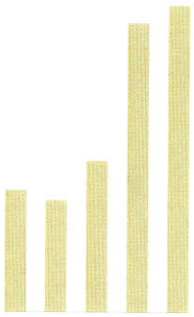
### Results of Operations

Earnings increased by $4.3 million to $72.3 million in 2003 primarily as a result of higher earnings from CLH, which was due to increased volumes and the impact of a stronger Euro, partially offset by a reduction in marine fleet revenues due to the scheduled retirement of certain ships. These increased earnings were partly offset by the termination of the Jose Terminal operating agreement and lower incentive earnings from CITCol.

Earnings in 2002 increased by $32.4 million to $68.0 million. The increase was primarily due to the acquisition of a 25% interest in CLH during the first quarter of 2002.

**International Earnings**

*(millions of dollars)*




| | |
|---|---|
| 99 | 28.7 |
| 00 | 26.4 |
| 01 | 35.6 |
| 02 | 68.0 |
| 03 | 72.3 |

### Outlook

The International business will continue to focus on select countries in key regions based on global trends in supply and demand. In addition, opportunistic acquisitions will be assessed based on risk and reward. The technology and consulting business provides support in connection with identification and development of equity participation projects.

Increased international asset rationalization, the changing corporate strategies of multinationals, and the privatization of energy transportation activities in focus regions should continue to present grassroots investment and acquisition opportunities. Opportunities will be evaluated against the Company's strict investment criteria. Latin America and Western Europe are key regions of interest. Enbridge plans for the International segment to contribute approximately 15% of the Company's earnings over the long term.

### Business Risks

The International business is subject to risks related to political and economic instability, currency volatility, market 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, operation of the assets, regular analysis of country risk, as well as foreign currency hedging and insurance programs.

## CORPORATE

| *(millions of Canadian dollars)* | **2003** | 2002 | 2001 |
|---|---|---|---|
| Corporate | **(76.6)** | (44.4) | (55.1) |

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

Corporate costs amounted to $76.6 million in 2003, an increase of $32.2 million from 2002. During 2003, the Company incurred slightly lower financing costs more than offset by various negative factors in the fourth quarter 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.

Corporate costs totalled $44.4 million in 2002, compared with $55.1 million in 2001. In 2002, Corporate included an after-tax gain on the sale of securities of $17.8 million and lower financing costs. Preferred securities distributions increased in 2002 due to the new issue in February 2002.

## DISCONTINUED OPERATIONS

In January 2002, the Company announced the sale of the retail and commercial Energy Services business, including the water heater rental program, to focus on its core activities of energy transportation and distribution. The sale, for proceeds of $1 billion, was completed in the second quarter of 2002. This business included: the water heater rental program; retail appliance, fireplace and water heater sales and service; and mass market commercial plumbing, heating, ventilation and air conditioning, appliance repair and electrician contractor services in Canada and the United States.

Earnings from discontinued operations for the year ended December 31, 2002 were $242.3 million, compared with $45.3 million for 2001. The 2002 results included a gain on sale of $240.0 million. Earnings in 2001 included a full year's results of operations and $14.3 million related to the positive effect of income tax rate reductions.

## CRITICAL ACCOUNTING POLICIES

### Rate Regulation

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

The accounting for these items is based on an expectation of the future actions of the regulator. For example, the Company does not record future income taxes related to its regulated operations as the taxes payable method is prescribed by the regulator for rate-making purposes and there is reasonable expectation that all such future income taxes will be recovered in rates when they become payable. Similarly, the deferral of differences between amounts included in rates and actual experience for specified expenses is based on the expectation that the regulator will approve the refund to or recovery from ratepayers of the deferred balance, normally in the following year.

If the regulator's 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.

## 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 is expected to be sufficient to satisfy liquidity requirements.

The Company continues to manage its debt-to-equity ratio to maintain a strong balance sheet. The debt-to-equity ratio at December 31, 2003, including short term borrowings, but excluding non-recourse short and long-term debt of its joint ventures, was 61.4%, compared with 64.4% at the end of 2002. The reduced leverage was primarily a result of the proceeds received on the sale of assets to EIF.

### Operating Activities

Cash provided by operating activities, before changes in operating assets and liabilities and cash from discontinued operations, was $965.0 million for the year ended December 31, 2003, compared with $732.7 million and $735.7 million for 2002 and 2001, respectively.

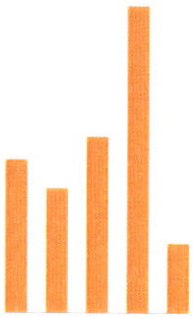
Cash from operations in 2003 reflects fluctuations due to the higher gas prices and distribution volumes of the Enbridge Gas Distribution business. Temporary differences between accounting and taxable income, driven by changes in gas costs to be settled with ratepayers, have increased the amount of future 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.

In 2002, cash from operations before changes in operating assets and liabilities was consistent with the prior year. Earnings from continuing operations were lower but include higher non-cash charges, which increased cash from operations. The non-cash charges include the writedown on the sale of the Midcoast assets and higher future income tax expense. The decreased funding requirements for operating assets and liabilities in 2002 was due to lower gas in storage and decreased accounts receivable, commensurate with the lower cost of gas in 2002.

Since the Company's pension plans are adequately funded, no additional funding above usual levels is anticipated for 2004.

**Capital Expenditures, Investments and Acquisitions**

*(millions of dollars)*




| | |
|---|---|
| 99 | 1,141.2 |
| 00 | 935.7 |
| 01 | 1,324.2 |
| 02 | 2,301.9 |
| 03 | 520.1 |

### Investing Activities

Cash provided from investing activities for the year ended December 31, 2003 was $259.5 million compared with cash used in investing activities of $251.7 million in 2002 and $1,621.7 million in 2001. 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 reflect the repayment by EEP of short-term loans required to finance acquisitions with additional amounts received in 2003 as a majority of these loans have now been repaid.

Additions to property, plant and equipment primarily related to the gas distribution utility and are consistent with prior years. Other capital additions include the construction of the Hardisty caverns and the core maintenance on the other systems. In 2002 and 2001, capital additions were higher as a result of the Terrace expansion, new facilities on the Athabasca System, and those related to Enbridge Midcoast Energy while owned by the Company.

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

Other investing in 2002 and 2001 was significantly higher as a result of some significant transactions. During 2002, the Company completed the acquisition of the Northeast 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.

Financing activity in 2003 includes 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 companies' 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, as described above.

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 | 4,693.1 | 450.0 | 968.6 | 589.3 | 2,685.2 |
| Non-recourse long-term debt | 725.4 | 32.5 | 84.4 | 72.0 | 536.5 |
| Non-recourse capital leases | 61.2 | 1.7 | 3.6 | 3.6 | 52.3 |

## RISK MANAGEMENT

### Operating Risk

As Enbridge continues to diversify its energy transportation and distribution businesses in North America and internationally, the risk profile of the Company will 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 in Note 15 to the consolidated financial statements.

### 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 and floating to fixed swaps 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 natural gas liquids ("NGL"). This risk is hedged through the use of over-the-counter derivatives whereby the forward prices of gas and NGLs 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 natural gas liquids. Enbridge used over-the-counter commodity derivatives to fix the selling price of the natural gas liquids 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

*(millions of dollars unless otherwise noted)*

| December 31, | 2003 | | | 2002 | | |
|---|---|---|---|---|---|---|
| | 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** | **(30.6)** | **2005-2022** | 535.8 | 24.9 | 2005-2022 |
| Euro cross currency swaps | **434.7** | **(46.1)** | **2004-2019** | 371.1 | (54.4) | 2003 |
| Forwards *(cumulative exchange amounts)* | **1,889.5** | **67.9** | **2004-2022** | 1,993.0 | (244.6) | 2003-2022 |
| Energy commodities | | | | | | |
| Natural gas *(bcf)* | **63.6** | **12.4** | **2004-2008** | 35.3 | (1.5) | 2003-2004 |
| Natural gas supply management *(bcf)* | **13.1** | **(3.4)** | **2004** | 5.9 | (0.2) | 2003 |
| Interest rates | | | | | | |
| Interest rate swaps | **561.0** | **1.9** | **2005-2029** | 934.1 | 0.6 | 2003-2029 |
| Forward interest rate swaps | **532.0** | **(1.0)** | **2004-2005** | – | – | – |

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $214.0 million (2002 – $448.6 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 $10.5 million as at December 31, 2003 (2002 – $36.9 million receivable).

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.

The carrying amounts of all financial instruments, except for debt, approximate fair value. The fair value of debt does not include the effects of hedging.

### Total Debt

*(millions of dollars)*

| December 31, | 2003 | | 2002 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Liquids Pipelines | 881.4 | 990.6 | 981.3 | 1,084.5 |
| Gas Distribution and Services | 1,674.5 | 1,972.1 | 1,749.0 | 1,989.2 |
| Corporate | 3,362.1 | 3,540.1 | 3,962.3 | 4,081.3 |
| | 5,918.0 | 6,502.8 | 6,692.6 | 7,155.0 |

Non-recourse debt of the joint ventures has a carrying value of $786.6 million and fair value of $845.7 million.

## QUARTERLY FINANCIAL INFORMATION[1]

*(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 | | | | | |
| Continuing operations | 103.8 | 445.4 | 90.7 | 27.3 | 667.2 |
| Discontinued operations | – | – | – | – | – |
| | 103.8 | 445.4 | 90.7 | 27.3 | 667.2 |
| Earnings per common share | | | | | |
| Continuing operations | 0.63 | 2.70 | 0.54 | 0.16 | 4.03 |
| Discontinued operations | – | – | – | – | – |
| | 0.63 | 2.70 | 0.54 | 0.16 | 4.03 |
| Dividends per common share | 0.415 | 0.415 | 0.415 | 0.415 | 1.660 |

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

| 2002 | First | Second | Third | Fourth | Total |
|---|---|---|---|---|---|
| Operating revenue from continuing operations | 1,073.2 | 1,645.8 | 1,171.0 | 657.5 | 4,547.5 |
| Operating income from continuing operations | 152.9 | 336.4 | 30.8 | 88.7 | 608.8 |
| Margin | 0.138 | 0.203 | 0.026 | 0.135 | 0.132 |
| Earnings applicable to common shareholders | | | | | |
| Continuing operations | 105.0 | 199.1 | (3.9) | 34.0 | 334.2 |
| Discontinued operations | 8.1 | 234.2 | – | – | 242.3 |
| | 113.1 | 433.3 | (3.9) | 34.0 | 576.5 |
| Earnings per common share | | | | | |
| Continuing operations | 0.66 | 1.26 | (0.03) | 0.20 | 2.09 |
| Discontinued operations | 0.05 | 1.48 | – | (0.02) | 1.51 |
| | 0.71 | 2.74 | (0.03) | 0.18 | 3.60 |
| Dividends per common share | 0.38 | 0.38 | 0.38 | 0.38 | 1.52 |

*1 Quarterly Financial Information has been 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. This business has a September 30 year end, which results in consolidation by the Company on a quarter lag basis. Therefore, peak revenues are recorded in the Company's second quarter, which represents Enbridge Gas Distribution's winter months. The positive effect of colder than normal weather contributed to an increase in revenues and earnings during the second and fourth quarters of 2003, as well as the third quarter of 2002. Significant items which impacted 2003 and 2002 quarterly earnings are as follows:

- First quarter earnings in 2003 include a $7.1 million regulatory disallowance in the Company's gas distribution business.
- First quarter earnings in 2002 include a $17.8 million after-tax gain on a sale of marketable securities and a $6.1 million dilution gain on an EEP unit issuance.
- 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.
- Second quarter earnings in 2002 include a $240.0 million after-tax gain on the sale of the Company's Energy Services business in May 2002.
- Third quarter earnings in 2002 include a $76.3 million after-tax writedown of the Enbridge Midcoast Energy assets, which were subsequently sold to Enbridge Energy Partnership.
- Fourth quarter earnings in 2003 include a $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 decision on outsourcing, both in the Company's gas distribution business.
- Fourth quarter earnings in 2002 include a further $5.9 million after-tax writedown of the Enbridge Midcoast Energy assets from that recorded in the fourth quarter of 2002.

## FOURTH QUARTER 2003 HIGHLIGHTS

Fourth quarter earnings of $27.3 million in 2003 were $6.7 million lower than earnings for the fourth quarter of 2002. Earnings growth was noted in the quarter from additional facilities put into service at the Enbridge and Athabasca Systems in early 2003, and from equity earnings from Enbridge Income Fund. In addition, the fourth quarter of 2003 also included a dilution gain from EEP of $11.1 million. These additional sources of earnings were more than offset by additional corporate expenses relating to business development, an expense for stock-based compensation, and other corporate costs primarily relating to prior year business dispositions and final settlements. Fourth quarter earnings were further reduced as a result of a $26.0 million writedown of a regulatory receivable, and a $4.6 million affiliate outsourcing disallowance in the Gas Distribution and Services segment.

## 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) | 171,963,027 |
| Total issued and outstanding stock options | 4,685,762 |

Outstanding share data information is provided as at January 23, 2004.

### Related Party Transactions

Neither EEP nor EIF have employees and accordingly they 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 $128.9 million (2002 – $97.2 million; 2001 – $56.2 million) for EEP and $4.7 million for EIF, which began operation on June 30, 2003.

Vector Pipeline 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 $3.3 million for 2003 (2002 – $4.1 million; 2001 – $3.4 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 $95.5 million in 2003 (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 $40.7 million in 2003 (2002 – $41.3 million; 2001 – $34.8 million) for Alliance Pipeline, and $23.2 million in 2003 (2002 – $25.2 million; 2001 – $20.7 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 2003, this revenue amounted to $25.5 million (2002 – $35.1 million). CustomerWorks Limited Partnership began operations on January 1, 2002.

In 2003, Enbridge Gas Services Inc. purchased $33.6 million (2002 – $6.3 million; 2001 – nil) of gas from Enbridge Marketing (US) Inc.

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 is available on www.sedar.com.

Dated February 24, 2004

*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.*

ENBRIDGE

## 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 not officers or employees of the Company, has a specific responsibility for ensuring that management fulfills 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 23, 2004

**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, 2003 and 2002 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2003. These financial statements are the responsibility of the Corporation'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, 2003 and 2002 and the results of its operations and cash flows for each of the years in the three year period ended December 31, 2003 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP

Calgary, Alberta, Canada
January 23, 2004

Chartered Accountants

## 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 accounting for goodwill described in Note 1 to the consolidated financial statements. Our report to the shareholders dated January 23, 2004 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

Calgary, Alberta, Canada
January 23, 2004

Chartered Accountants

ENBRIDGE

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

| Year ended December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Revenues | | | |
| Gas sales | 3,061.7 | 2,987.7 | 2,675.3 |
| Transportation | 1,560.6 | 1,296.6 | 1,177.6 |
| Energy services | 233.0 | 263.2 | 228.0 |
| | 4,855.3 | 4,547.5 | 4,080.9 |
| Expenses | | | |
| Gas costs | 2,720.1 | 2,578.0 | 2,202.8 |
| Operating and administrative | 800.8 | 834.1 | 739.1 |
| Depreciation | 443.0 | 403.9 | 392.5 |
| Writedown of Enbridge Midcoast Energy assets *(Note 3)* | – | 122.7 | – |
| | 3,963.9 | 3,938.7 | 3,334.4 |
| Operating Income | 891.4 | 608.8 | 746.5 |
| Investment and Other Income *(Note 18)* | 208.2 | 283.1 | 194.9 |
| Gain on Sale of Assets to Enbridge Income Fund *(Note 3)* | 239.9 | – | – |
| Interest Expense *(Note 10)* | (451.3) | (422.0) | (437.1) |
| | 888.2 | 469.9 | 504.3 |
| Income Taxes *(Note 16)* | (187.4) | (102.1) | (66.7) |
| Earnings From Continuing Operations | 700.8 | 367.8 | 437.6 |
| Earnings From Discontinued Operations *(Note 5)* | – | 242.3 | 45.3 |
| Earnings | 700.8 | 610.1 | 482.9 |
| Preferred Security Distributions *(Note 12)* | (26.7) | (26.7) | (17.5) |
| Preferred Share Dividends *(Note 13)* | (6.9) | (6.9) | (6.9) |
| Earnings Applicable to Common Shareholders | 667.2 | 576.5 | 458.5 |
| Earnings Applicable to Common Shareholders | | | |
| Continuing Operations | 667.2 | 334.2 | 413.2 |
| Discontinued Operations | – | 242.3 | 45.3 |
| | 667.2 | 576.5 | 458.5 |
| Earnings Per Common Share *(Note 13)* | | | |
| Continuing Operations | 4.03 | 2.09 | 2.63 |
| Discontinued Operations | – | 1.51 | 0.28 |
| | 4.03 | 3.60 | 2.91 |
| Diluted Earnings Per Common Share *(Note 13)* | | | |
| Continuing Operations | 4.00 | 2.06 | 2.60 |
| Discontinued Operations | – | 1.50 | 0.28 |
| | 4.00 | 3.56 | 2.88 |

## Consolidated Statements Of Retained Earnings

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

| Year ended December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Retained Earnings at Beginning of Year | 1,128.1 | 812.3 | 581.3 |
| Earnings Applicable to Common Shareholders | 667.2 | 576.5 | 458.5 |
| Effect of Change in Accounting for Stock-Based Compensation | – | (5.4) | – |
| Preferred Securities Issue Costs | – | (4.2) | – |
| Common Share Dividends | (283.9) | (251.1) | (227.5) |
| Retained Earnings at End of Year | 1,511.4 | 1,128.1 | 812.3 |
| Dividends Paid Per Common Share | 1.66 | 1.52 | 1.40 |

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

ENBRIDGE

| *(millions of Canadian dollars)* | | | |
|---|---|---|---|
| Year ended December 31, | **2003** | 2002 | 2001 |
| Cash Provided By Operating Activities | | | |
| Earnings from continuing operations | **700.8** | 367.8 | 437.6 |
| Charges/(credits) not affecting cash | | | |
| Depreciation | **443.0** | 403.9 | 392.5 |
| Equity less than/(in excess of) cash distributions | **(22.1)** | (44.6) | 1.2 |
| Gain on sale of assets to Enbridge Income Fund | **(239.9)** | – | – |
| Gain on reduction of ownership interest | **(50.0)** | (10.0) | (23.4) |
| 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 | **85.8** | (64.7) | 3.4 |
| Other | **21.4** | (21.0) | (75.6) |
| Changes in operating assets and liabilities *(Note 19)* | **(569.8)** | 151.6 | (323.1) |
| Cash provided by operating activities of discontinued operations | **–** | 26.3 | 1.9 |
| | **395.2** | 910.6 | 414.5 |
| Investing Activities | | | |
| Acquisitions *(Note 4)* | **(78.3)** | (289.3) | (599.1) |
| Long-term investments | **(50.5)** | (1,282.7) | (41.8) |
| Additions to property, plant and equipment | **(391.3)** | (729.9) | (683.3) |
| Proceeds on redemption of Enbridge Commercial Trust preferred units *(Note 8)* | **24.9** | – | – |
| Sale of assets to Enbridge Income Fund *(Note 3)* | **331.2** | – | – |
| Sale of Energy Services business *(Note 5)* | **–** | 993.3 | – |
| Sale of Enbridge Midcoast Energy assets *(Note 3)* | **–** | 529.3 | – |
| Sale of securities and other assets | **–** | 184.3 | – |
| Repayments by/(loans to) affiliate | **427.2** | 358.1 | (280.6) |
| Changes in construction payable | **(3.7)** | (14.8) | (14.0) |
| Other | **–** | – | (2.9) |
| | **259.5** | (251.7) | (1,621.7) |
| Financing Activities | | | |
| Net change in short-term borrowings and short-term debt | **359.8** | (1,180.9) | 1,521.4 |
| Long-term debt issues | **150.0** | 247.4 | 905.6 |
| Long-term debt repayments | **(725.0)** | (382.7) | (979.6) |
| Non-recourse long-term debt issued by joint ventures | **538.3** | – | – |
| Non-recourse long-term debt repaid by joint ventures | **(663.8)** | – | – |
| Non-controlling interests | **(4.0)** | 0.2 | (4.1) |
| Preferred securities issued | **–** | 193.5 | – |
| Common shares issued | **70.9** | 293.1 | 23.3 |
| Enbridge Energy Management shares issued *(Note 8)* | **–** | 421.9 | – |
| Preferred security distributions | **(26.7)** | (26.7) | (17.5) |
| Preferred share dividends | **(6.9)** | (6.9) | (6.9) |
| Common shares dividends | **(283.9)** | (251.1) | (227.5) |
| | **(591.3)** | (692.2) | 1,214.7 |
| Increase/(Decrease) in Cash | **63.4** | (33.3) | 7.5 |
| Cash at Beginning of Year | **40.7** | 74.0 | 66.5 |
| Cash at End of Year | **104.1** | 40.7 | 74.0 |

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

ENBRIDGE

| *(millions of Canadian dollars)* December 31, | 2003 | 2002 |
|---|---|---|
| **Assets** | | |
| Current Assets | | |
| Cash | 104.1 | 40.7 |
| Accounts receivable and other | 1,138.8 | 817.5 |
| Gas in storage | 809.8 | 583.8 |
| | 2,052.7 | 1,442.0 |
| Property, Plant and Equipment, net *(Note 6)* | 8,530.9 | 6,947.6 |
| Long-Term Investments *(Note 8)* | 2,390.9 | 3,371.5 |
| Receivable from Affiliate | 169.8 | 701.5 |
| Deferred Amounts and Other Assets *(Note 9)* | 486.5 | 315.8 |
| Future Income Taxes *(Note 16)* | 192.5 | 209.0 |
| | 13,823.3 | 12,987.4 |
| **Liabilities And Shareholders' Equity** | | |
| Current Liabilities | | |
| Short-term borrowings | 649.6 | 247.5 |
| Accounts payable and other | 894.1 | 714.1 |
| Interest payable | 97.0 | 102.6 |
| Current maturities and short-term debt *(Note 10)* | 674.9 | 652.3 |
| Current portion of non-recourse long-term debt *(Note 11)* | 34.2 | – |
| | 2,349.8 | 1,716.5 |
| Long-Term Debt *(Note 10)* | 5,243.1 | 6,040.3 |
| Non-Recourse Long-Term Debt *(Note 11)* | 752.4 | – |
| Future Income Taxes *(Note 16)* | 829.0 | 837.4 |
| Non-Controlling Interests *(Note 8)* | 523.0 | 560.8 |
| | 9,697.3 | 9,155.0 |
| Shareholders' Equity | | |
| Share capital | | |
| Preferred securities *(Note 12)* | 532.4 | 533.7 |
| Preferred shares *(Note 13)* | 125.0 | 125.0 |
| Common shares *(Note 13)* | 2,239.9 | 2,169.0 |
| Retained earnings | 1,511.4 | 1,128.1 |
| Foreign currency translation adjustment | (147.0) | 12.3 |
| Reciprocal shareholding *(Note 8)* | (135.7) | (135.7) |
| | 4,126.0 | 3,832.4 |
| Commitments and Contingencies *(Note 21)* | | |
| | 13,823.3 | 12,987.4 |

*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.

### 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. From May 2001 to October 2002, the Company, through its subsidiary, Enbridge Pipelines Inc., owned 100% of Enbridge Midcoast Energy Inc., which is now a wholly owned subsidiary of EEP. 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, as well as gas service operations, including the Company's proportionately consolidated investment in Aux Sable and natural gas gathering and processing operations through an equity investment in AltaGas Services Inc.

### International

The Company's International business invests 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 the Gas Distribution and Services segment are conducted primarily through a wholly-owned subsidiary, Enbridge Gas Distribution Inc. (Enbridge Gas). The fiscal year-end of Enbridge Gas is September 30 and its results are consolidated on a one quarter lag basis, which reflects the results of Enbridge Gas operations in accordance with its regulatory, tax and operating cycles. Accordingly, references to "December 31" mean the financial position of Enbridge Gas as at September 30 and references to the "year ended December 31" mean the results of Enbridge Gas for the year ended September 30. Events subsequent to September 30 may provide additional information relating to items included in the financial statements of Enbridge Gas and may reveal conditions existing at the financial statement date that affect the estimates involved in the preparation of the financial statements. All such information that becomes available prior to completion of the Enbridge Inc. consolidated financial statements would be used in evaluating the estimates made and the financial statements would be adjusted where necessary.

### Regulation

The Company's Liquids Pipelines, Gas Pipelines, and gas distribution activities within the Gas Distribution and Services segment 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.

### 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 the Gas Distribution and Services segment 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 design as mandated by the regulatory authority. Certain other operations recognize revenue under the terms of enforceable, committed long-term delivery contracts.

### 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 there is reasonable expectation 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 functional currency of the Company's foreign operations, except for certain financing and investing operations, is the U.S. dollar. The Company also holds a Euro dollar equity investment in a foreign operation in Spain. These operations, which include those of proportionately consolidated U.S. dollar investments and the Euro dollar 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 assumed. 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 includes short-term and demand deposits with a term to maturity of three months or less when purchased and are recorded at cost.

### Gas in Storage

Natural gas in storage is recorded in inventory at 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.

### Future Removal and Site Restoration Costs

Future removal and site restoration costs are not determinable due to the indeterminable life of certain assets. Accordingly, no provision has been made for these costs. There is also reasonable expectation that any costs incurred will be recovered through future tolls when they become payable.

Depreciation expense for Gas Distribution and Services operations includes a provision for future removal and site restoration costs at rates approved by the regulator. Actual costs incurred are charged to accumulated depreciation.

### Deferred Amounts

The Company defers certain charges which the regulatory authorities permit to be recovered through future rates. These charges are recognized when regulatory approval for these recoveries has been 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 hedge agreements.

### Goodwill

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets upon acquisition of a business. Effective January 1, 2002, the Company adopted the standard of the Canadian Institute of Chartered Accountants (CICA) related to goodwill and other intangible assets. Under the standard, goodwill is not amortized but is tested for impairment at least annually and written down to fair value if the criteria for impairment are met. The standard has been applied prospectively.

Goodwill arising from the acquisition of Midcoast Energy Resources, Inc. in May 2001 (sold to EEP in October 2002) was amortized on a straight-line basis over 30 years prior to the adoption of the new standard. Results of operations for the year ended December 31, 2001 included goodwill amortization of $7.2 million. This amortization reduced both earnings per common share and diluted earnings per common share by $0.05 for the year ended December 31, 2001.

### 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 the Gas Distribution and Service segment 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.

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 the Gas Distribution and Services segment where the cost of providing these benefits is expensed as paid, consistent with the recovery of such costs in rates.

### 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 expire in 2004.

Effective January 1, 2003, the Company early adopted new requirements in the CICA standard for stock-based compensation. The standard now 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 has resulted in a charge to income, in the year of adoption, of $1.9 million.

### Comparative Amounts

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

## New Accounting Standards

### 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 standard requires that an impairment loss be recognized in an amount equal to the difference between carrying value and fair value when the carrying value of a long-lived asset exceeds the expected undiscounted future cash flows. A recoverability test will be performed on asset groups as events or circumstances change in order to determine whether or not the assets are impaired. The Company is currently assessing the impact of the standard, if any, on its financial statements, and will adopt the standard for the fiscal year commencing January 1, 2004.

### 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 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 is to be recognized in income for the period. The Company is currently assessing the impact of the guideline, if any, on its financial statements, and will adopt the guideline for the fiscal year commencing January 1, 2004.

### 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. Any changes to accounting policies resulting from the adoption of this standard are to be applied prospectively. At present, the standard has an exemption for rate-regulated operations. The Company is currently assessing the impact of this standard and its related exemption, if any, on the 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. A similar standard has been adopted by the Financial Accounting Standards Board in the United States, effective for fiscal years beginning after June 15, 2002. This new standard is not expected to have a material impact 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. A similar standard has been adopted by the Financial Accounting Standards Board in the United States (FIN 46), effective for interim periods commencing after July 15, 2003. If the interpretation of the Canadian standard is consistent with FIN 46, it would result in the consolidation of Enbridge Income Fund as described in Note 22.

## 2. SEGMENTED INFORMATION

**Year ended December 31, 2003**

| | Liquids Pipelines | Gas Pipelines | Sponsored Investments | Gas Distribution & 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/(loss) | 390.1 | 124.2 | – | 411.8 | (6.3) | (28.4) | 891.4 |
| Investment and other income/(expense) | 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 equity charges | (102.1) | (58.7) | – | (162.2) | (0.5) | (161.4) | (484.9) |
| Income taxes | (77.9) | (32.0) | (118.7) | (115.8) | 1.0 | 156.0 | (187.4) |
| Earnings/(loss) 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 & 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/(loss) | 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 equity charges | (99.8) | – | (28.1) | (161.7) | (1.6) | (164.4) | (455.6) |
| Income taxes | (70.0) | (18.5) | 14.1 | (93.1) | 0.3 | 65.1 | (102.1) |
| Earnings/(loss) applicable to common shareholders | 189.6 | 47.8 | (51.1) | 124.3 | 68.0 | (44.4) | 334.2 |
| Earnings from discontinued operations | | | | | | | 242.3 |
| Earnings applicable to common shareholders | | | | | | | 576.5 |

Year ended December 31, 2001

| *(millions of dollars)* | Liquids Pipelines | Gas Pipelines | Sponsored Investments | Gas Distribution and Services | International | Corporate[1] | Consolidated |
|---|---|---|---|---|---|---|---|
| Revenues | 722.9 | – | 681.5 | 2,645.7 | 30.8 | – | 4,080.9 |
| Gas costs | – | – | (558.9) | (1,643.9) | – | – | (2,202.8) |
| Operating and administrative | (258.7) | – | (53.3) | (392.0) | (19.0) | (16.1) | (739.1) |
| Depreciation | (139.8) | – | (24.1) | (223.3) | (2.5) | (2.8) | (392.5) |
| Operating income/(loss) | 324.4 | – | 45.2 | 386.5 | 9.3 | (18.9) | 746.5 |
| Investment and other income | 13.7 | 57.8 | 43.1 | 5.5 | 27.0 | 47.8 | 194.9 |
| Interest and preferred equity charges | (106.0) | (0.1) | (26.2) | (162.4) | (0.1) | (166.7) | (461.5) |
| Income taxes | (67.7) | (16.2) | (24.9) | (40.0) | (0.6) | 82.7 | (66.7) |
| Earnings/(loss) applicable to common shareholders | 164.4 | 41.5 | 37.2 | 189.6 | 35.6 | (55.1) | 413.2 |
| Earnings from discontinued operations | | | | | | | 45.3 |
| Earnings applicable to common shareholders | | | | | | | 458.5 |

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

*3 Segmented information of all years is restated consistent with the change in segments in the fourth quarter of 2003.*

## Total Assets

*(millions of dollars)*

| December 31, | 2003 | 2002 |
|---|---|---|
| Liquids Pipelines | 3,406.0 | 3,468.5 |
| Gas Pipelines | 1,649.7 | 1,243.8 |
| Sponsored Investments | 1,396.3 | 850.8 |
| Gas Distribution and Services | 6,156.4 | 5,543.0 |
| International | 835.7 | 830.7 |
| Corporate | 379.2 | 1,050.6 |
| | 13,823.3 | 12,987.4 |

## Additions to Property, Plant and Equipment

*(millions of dollars)*

| Year ended December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Liquids Pipelines | 123.4 | 255.7 | 216.8 |
| Gas Pipelines | 11.3 | – | – |
| Sponsored Investments | – | 128.9 | 85.2 |
| Gas Distribution and Services | 249.0 | 315.0 | 314.1 |
| International and Corporate | 7.6 | 7.4 | 23.7 |
| | 391.3 | 707.0 | 639.8 |
| Discontinued Operations | – | 22.9 | 43.5 |
| | 391.3 | 729.9 | 683.3 |

## 2. SEGMENTED INFORMATION *(continued)*

### Geographic Information

Revenues [1]

*(millions of dollars)*

| Year ended December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Canada | 3,739.4 | 3,102.3 | 3,317.7 |
| United States | 1,089.6 | 1,418.0 | 736.8 |
| Other | 26.3 | 27.2 | 26.4 |
| | 4,855.3 | 4,547.5 | 4,080.9 |

*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, | 2003 | 2002 |
|---|---|---|
| Canada | 6,747.3 | 6,733.6 |
| United States | 1,776.6 | 204.8 |
| Other | 7.0 | 9.2 |
| | 8,530.9 | 6,947.6 |

## 3. 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.

## 4. ACQUISITIONS

### 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, $78.3 million was paid on the date of acquisition. Payment of the remaining US$65.0 million depends upon completion of reversal of the flow of the pipeline and must be paid no later than December 31, 2004 to allow reversal to proceed. 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.

### 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 sale described in Note 3. The results of operations have been included in the consolidated statement of earnings for the period of ownership.

| *(millions of dollars)* | |
|---|---|
| Fair Value of Assets Acquired | |
| Property, plant and equipment | 242.3 |
| Goodwill | 56.2 |
| Working capital deficiency | (9.2) |
| | 289.3 |
| Purchase Price | |
| Cash | 288.2 |
| Transaction costs | 1.1 |
| | 289.3 |

### Midcoast Energy Resources, Inc.

On May 11, 2001, the Company acquired all the outstanding shares of Midcoast Energy Resources, Inc., a Houston-based energy company, for cash consideration of $561.8 million and the assumption of long-term debt. This business is included in the sale described in Note 3. The acquisition was accounted for using the purchase method and the results of operations have been included in the consolidated statements of earnings from the date of acquisition until they were sold in October 2002.

| *(millions of dollars)* | |
|---|---|
| Fair Value of Assets Acquired | |
| Property, plant and equipment | 677.3 |
| Working capital deficiency | (37.2) |
| Goodwill | 328.9 |
| Future income taxes | (39.0) |
| Other non-current assets | 37.8 |
| | 967.8 |
| Purchase Price | |
| Cash | 554.5 |
| Long-term debt assumed | 406.0 |
| Transaction costs | 7.3 |
| | 967.8 |

### Frontier Pipeline Company

The Company acquired an additional 34.0% interest in Frontier Pipeline Company for $46.0 million in December 2001, increasing the Company's ownership to 77.8%. The purchase price was allocated primarily to property, plant and equipment.

## 5. DISCONTINUED OPERATIONS

The sale of the Company's operations that provide energy products and services to retail and commercial customers, including the water heater rental program, closed in May 2002.

Selected financial information related to discontinued operations is as follows.

### Earnings

*(millions of dollars)*

| Year ended December 31, | 2002 | 2001 |
|---|---|---|
| Gain on disposition, net of tax | 240.0 | – |
| Earnings | 2.3 | 45.3 |
| Earnings from discontinued operations | 242.3 | 45.3 |

### Selected Earnings Information

*(millions of dollars)*

| Year ended December 31, | 2002 | 2001 |
|---|---|---|
| Revenues | 181.9 | 463.0 |
| Income tax expense | 34.6 | 2.5 |
| Allocated interest expense | 12.1 | 35.4 |

## 6. PROPERTY, PLANT AND EQUIPMENT

| *(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 |

| *(millions of dollars)*<br>December 31, 2002 | Weighted Average Depreciation Rate | Cost | Accumulated Depreciation | Net |
|---|---|---|---|---|
| Liquids Pipelines | | | | |
| Pipeline | 2.5% | 2,489.7 | 1,030.0 | 1,459.7 |
| Pumping Equipment, Buildings, Tanks and Other | 4.2% | 2,166.1 | 711.6 | 1,454.5 |
| Land and Right-of-Way | 1.7% | 34.3 | 16.0 | 18.3 |
| Under Construction | – | 92.7 | – | 92.7 |
| | | 4,782.8 | 1,757.6 | 3,025.2 |
| Gas Distribution and Services | | | | |
| Gas Mains | 3.0% | 1,758.1 | 236.1 | 1,522.0 |
| Gas Services | 4.3% | 1,682.3 | 287.3 | 1,395.0 |
| Regulating and Metering Equipment | 3.6% | 551.5 | 81.4 | 470.1 |
| Storage | 2.7% | 268.8 | 30.3 | 238.5 |
| Computer Technology | 25.0% | 150.5 | 141.2 | 9.3 |
| Other | 4.0% | 293.5 | 48.5 | 245.0 |
| | | 4,704.7 | 824.8 | 3,879.9 |
| Other | 6.6% | 61.1 | 18.6 | 42.5 |
| | | 9,548.6 | 2,601.0 | 6,947.6 |

## 7. JOINT VENTURE

Alliance Pipeline Canada, Alliance Pipeline U.S., Aux Sable, and Alliance Canada Marketing, have been jointly controlled since April 1, 2003. Vector Pipeline Canada, and Vector Pipeline U.S. have been jointly controlled since October 1, 2003. The Company's proportionate share of earnings, cash flows and financial position related to these entities is summarized below, with the exception of Alliance Pipeline Canada for the period subsequent to June 30, 2003 as the Company's 50% interest in Alliance Pipeline Canada was sold effective June 30, 2003 to EIF.

| *(millions of dollars)* | April 1, 2003 to December 31, 2003 |
|---|---|
| Earnings | |
| Revenues | 421.7 |
| Gas sales | (168.1) |
| Operating and administrative | (81.5) |
| Depreciation | (59.7) |
| Interest expense | (59.7) |
| Investment and other income | 5.1 |
| Income taxes | 0.3 |
| Proportionate share of net earnings | 58.1 |
| Cash Flows | |
| Cash provided by operations | 99.4 |
| Cash provided by investing activities | (1.4) |
| Cash used in financing activities | (197.7) |
| Proportionate share of decrease in cash | (99.7) |

## 7. JOINT VENTURE *(continued)*

| *(millions of dollars)* | December 31, 2003 |
|---|---|
| Financial Position | |
| Current assets | 118.7 |
| Property, plant and equipment, net | 1,562.2 |
| Other long-term assets | 102.9 |
| Current liabilities | (122.6) |
| Long-term debt | (752.4) |
| Other long-term liabilities | (17.8) |
| Proportionate share of net assets | 891.0 |

Included in the Company's proportionate share of cash from joint ventures is $18.7 million held in trust, pursuant to finance agreements of the joint venture. Under these finance agreements, funds received from shippers, in settlement of transportation rates, as well as interest earned on trust account balances, are segregated in trust accounts and first applied to meet debt service and operating requirements. Amounts in excess of these requirements are transferred to a non-trust account for partnership distributions on a quarterly basis.

## 8. LONG-TERM INVESTMENTS

| *(millions of dollars)* December 31, | Ownership Interest | 2003 | 2002 |
|---|---|---|---|
| **Equity Investments** | | | |
| Liquids Pipelines | | | |
| Chicap Pipeline | 22.8% | 25.0 | 32.4 |
| Gas Pipelines | | | |
| Alliance Pipeline Canada | – | – | 333.6 |
| Alliance Pipeline U.S. | – | – | 345.0 |
| Vector Pipeline | – | – | 474.8 |
| | | – | 1,153.4 |
| Sponsored Investments | | | |
| The Partnership | 12.2% | 743.6 | 815.5 |
| Enbridge Income Fund | 41.9% | – | – |
| | | 743.6 | 815.5 |
| Gas Distribution and Services | | | |
| AltaGas Services | 40.3% | 210.7 | 204.2 |
| Noverco | 32.1% | 36.7 | 28.9 |
| Aux Sable | – | – | 135.0 |
| Other | | 16.0 | 14.0 |
| | | 263.4 | 382.1 |
| International | | | |
| Compañía Logistica de Hidrocarburos *(CLH)* | 25.0% | 531.2 | 541.2 |
| Corporate | | 17.8 | 17.2 |
| **Cost Investments** | | | |
| Sponsored Investments | | | |
| Enbridge Income Fund | | 380.2 | – |
| Gas Distribution and Services | | | |
| Noverco | | 181.4 | 181.4 |
| FuelCell Energy/Global Thermoelectric | | 25.0 | 25.0 |
| | | 206.4 | 206.4 |
| International | | | |
| OCENSA Pipeline | | 223.3 | 223.3 |
| | | 2,390.9 | 3,371.5 |

Equity investments include $536.4 million (2002 – $551.9 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 has been allocated to property, plant and equipment on the basis of estimated fair values and is amortized over the economic life of the assets.

### Alliance Pipeline, Aux Sable and Vector Pipeline

In 2003, the Company invested $223.2 million (2002 – $315.3 million) in Alliance 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 (2002 – ($7.1) million) less than the underlying net book value of the assets. This amount has been allocated to property, plant and equipment and is being amortized over the economic life of the assets.

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 has been allocated to property plant and equipment and is being amortized over the economic life of the assets.

As a result of these additional investments, the Company established joint control (see Note 7). Therefore, the Company's interest in Alliance Pipeline Canada, Alliance Pipeline U.S., Aux Sable and Alliance Canada Marketing are accounted for as joint ventures effective April 1, 2003 and the Company's interest in Vector Pipeline Canada and Vector Pipeline U.S. are accounted for as joint ventures effective October 1, 2003. On June 30, 2003, the Company sold its 50% interest in Alliance Pipeline Canada to Enbridge Income Fund.

### The Partnership

In October 2002, EEM, a partially-owned subsidiary, completed an initial public offering of 9,000,000 limited liability shares. The proceeds from the offering were used to purchase I-units, a new class of limited partnership interest from EEP. The Company purchased 17.2% of the EEM shares, increasing its total net investment in the Partnership to 14.1% from 12.9%. 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 $478.8 million (2002 – $529.9 million). The Company's net investment in the Partnership, after deducting the non-controlling interest of $396.4 million (2002 – $438.8 million), is $347.7 million (2002 – $376.7 million).

In 2003, EEP completed two public issuances of partnership units. As the Company elected not to participate in either of these offerings, its effective interest in EEP was reduced to 12.2% from 14.1%. This resulted in recognition of a total dilution gain of $20.3 million (2002 – $6.1 million), net of tax and minority interest.

### Noverco

Noverco holds an approximate 10% reciprocal shareholding in the Company. As a result, the Company has a pro-rata interest of 3.2% (2002 – 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 (2002 – $135.7 million).

The Company owns a cost investment in Noverco of $181.4 million (2002 – $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%.

### 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. Contingent consideration of up to 84.3 million Euros ($137.2 million) will become payable over the next three years if certain minimum annual and cumulative volume targets are met. The purchase price included $340.9 million representing the excess of purchase price over the underlying net book value of the assets. The excess has been allocated to property, plant and equipment and is being amortized over the economic life of the assets.

## 8. LONG-TERM INVESTMENTS *(continued)*

### Enbridge Income Fund

On June 30, 2003, the Company formed EIF, an unincorporated open-ended trust established under the laws of Alberta. On formation, EIF acquired the Company's 50% interest in the Canadian segment of the Alliance Pipeline together with its 100% interest in Enbridge Pipelines (Saskatchewan) Inc. The Company has 14,500,000 subordinated trust units of EIF and 38,023,750 preferred units of Enbridge Commercial Trust (ECT), a direct subsidiary of EIF, at December 31, 2003. The subordinated trust 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 million preferred units are accounted for as a $380.2 million cost investment at December 31, 2003. 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, 2003 closing price of $12.89 per ordinary common unit, is $490.1 million.

### OCENSA Pipeline

The Company owns a cost investment in the OCENSA Pipeline of $223.3 million (2002 – $223.3 million) which earns a fixed rate of return. The fair value of this investment is approximately $270.0 million, estimated using year-end market information and various assumptions. As no market exists for an instrument of this nature, the actual fair value in an open market may vary significantly.

### Income from Equity Investments

*(millions of dollars)*

| Year ended December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Liquids Pipelines | 1.1 | 1.0 | 8.5 |
| Gas Pipelines | 31.6 | 67.1 | 57.6 |
| Sponsored Investments | 73.3 | 40.9 | 23.3 |
| Gas Distribution and Services | 19.9 | 7.7 | (9.7) |
| International | 45.7 | 34.2 | 0.3 |
| Corporate | 1.2 | – | – |
| | 172.8 | 150.9 | 80.0 |

Consolidated retained earnings at December 31, 2003 includes undistributed earnings from equity investments of $130.5 million (2002 – $148.7 million).

## 9. DEFERRED AMOUNTS AND OTHER ASSETS

*(millions of dollars)*

| Year ended December 31, | 2003 | 2002 |
|---|---|---|
| Regulatory and contractual deferrals | 232.9 | 159.6 |
| Long-term portion of receivables from hedge counterparty | 127.7 | 36.9 |
| Deferred pension funding | 66.3 | 72.7 |
| Deferred financing charges | 37.3 | 34.6 |
| Other | 22.3 | 12.0 |
| | 486.5 | 315.8 |

At December 31, 2003, $105.1 million (2002 – $102.9 million) was subject to amortization. Amortization expense of deferred amounts in 2003 was $18.4 million (2002 – $21.7 million; 2001 – $23.5 million). Accumulated amortization at the end of 2003 was $38.9 million (2002 – $27.2 million).

## 10. DEBT

| *(millions of dollars)*<br>December 31, | Weighted Average Interest Rate | Maturity | 2003 | 2002 |
|---|---|---|---|---|
| Liquids Pipelines | | | | |
| Debentures | 8.20% | 2024 | 200.0 | 300.0 |
| Medium-term notes | 6.66% | 2005-2029 | 622.7 | 622.5 |
| Other[1] | | | 58.7 | 58.8 |
| Gas Distribution and Services | | | | |
| Debentures | 11.00% | 2004-2024 | 635.0 | 635.0 |
| Medium-term notes | 6.34% | 2004-2032 | 1,030.0 | 1,105.0 |
| Other | | | 9.5 | 9.0 |
| Corporate | | | | |
| Senior term notes[2] *(US$275.0 million)* | 8.08% | 2005-2007 | 397.8 | 397.8 |
| Medium-term notes | 6.14% | 2004-2032 | 1,790.0 | 1,788.7 |
| Variable rate credit facility | | | – | 400.0 |
| Variable rate credit facility[3] | | | – | 252.7 |
| Preferred securities *(Note 12)* | 7.79% | 2048-2051 | 17.6 | 16.3 |
| Other[4] | | | 1,156.7 | 1,106.8 |
| Total Debt | | | 5,918.0 | 6,692.6 |
| Current maturities of long-term debt | | | 450.0 | 225.0 |
| Other short-term debt | | | 224.9 | 427.3 |
| Current Maturities and Short-Term Debt | | | 674.9 | 652.3 |
| Long-Term Debt | | | 5,243.1 | 6,040.3 |

*1 Primarily commercial paper borrowings.*
*2 The principal amount is recorded at the swapped rate.*
*3 2002 included US$160.0 million.*
*4 Primarily commercial paper borrowings. Includes US$306.0 million (2002 – US$582.5 million).*

Short-term debt in the amount of $1,000.0 million (2002 – $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, 2004 through 2008 are $450.0 million, $528.6 million, $440.0 million, $369.3 million and $220.0 million, respectively.

### Interest Rate Management

| *(millions of dollars)*<br>December 31, | Weighted Average Effective Rate | 2003 | 2002 |
|---|---|---|---|
| | | Notional Amounts | |
| Liquids Pipelines | | | |
| Commercial paper | 6.04% | 25.4 | 25.4 |
| Corporate | | | |
| Senior term notes[1] | 7.40% | US$275.0 | US$275.0 |
| Variable rate debt | 2.30% | – | 400.0 |

*1 Subject to a cross-currency swap.*

## 10. DEBT *(continued)*

The weighted average effective rate reflects the interest rate of debt instruments after giving effect to interest swap agreements.

### Interest Expense

*(millions of dollars)*

| December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Long-term debt | 431.7 | 392.9 | 345.0 |
| Commercial paper and other short-term debt | 20.2 | 29.0 | 85.8 |
| Short-term borrowings | 9.6 | 9.6 | 12.2 |
| Capitalized | (10.2) | (9.5) | (5.9) |
| | 451.3 | 422.0 | 437.1 |

In 2003, total interest paid was $467.1 million (2002 – $429.3 million; 2001 – $452.2 million).

### Credit Facilities

*(millions of dollars)*

| December 31, 2003 | Committed | Uncommitted | Drawdowns |
|---|---|---|---|
| Liquids Pipelines | 150.0 | – | – |
| Gas Distribution and Services | 659.0 | 6.5 | 14.5 |
| Corporate | 1,887.7 | – | – |
| | 2,696.7 | 6.5 | 14.5 |

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 2004 and are extendible annually thereafter subject to the approval of lenders. The committed facilities for Gas Distribution and Services expire in 2004 and 2006 and are extendible annually thereafter subject to the approval of the lenders. The committed facilities for Corporate expire in 2004 and 2008 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, | 2003 |
|---|---|
| Credit Facilities (US$21.7 million) | 28.0 |
| Senior Notes: | |
| 7.770% due 2015 (US$140.0 million) | 180.9 |
| 6.996% due 2019 (US$153.4 million) | 198.3 |
| 7.877% due 2025 (US$100.0 million) | 129.2 |
| 4.591% due 2025 (US$146.2 million) | 189.0 |
| Obligations under capital leases (US$47.4 million) | 61.2 |
| | 786.6 |
| Less current portion of long-term debt (US$26.5 million) | (34.2) |
| | 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, except to the extent of Enbridge's investment.

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 on the Senior Notes is payable semi-annually. Principal repayments commenced June 30, 2001 on the 6.996% Senior Notes, December 31, 2001 on the 7.770% Senior Notes, June 30, 2003 on the 4.591% Senior Notes and commences June 30, 2019 on the 7.877% Senior Notes. Principal repayments are due semi-annually thereafter in each instance and 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, 2004 through 2008 are $34.2 million, $32.0 million, $56.0 million, $37.6 million and $38.0 million, respectively.

## 12. PREFERRED SECURITIES

The Company has $175.0 million of 7.6%, $200 million of 7.8%, and $175.0 million of 8.0% Preferred Securities outstanding. The Preferred Securities may be redeemed at the Company's option, in whole or in part, after the fifth anniversary of each issue and have no stated maturity date. The Company has the 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. As a result, the Preferred Securities are classified into their respective debt and equity components. The equity component of the Preferred Securities is $532.4 million at December 31, 2003 (2002 – $533.7 million).

## 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, | 2003 | | 2002 | | 2001 | |
|---|---|---|---|---|---|---|
| | Number of Shares | Amount | Number of Shares | Amount | Number of Shares | Amount |
| Balance at beginning of year | 169.7 | 2,169.0 | 162.9 | 1,875.9 | 161.8 | 1,852.6 |
| Dividend Reinvestment and Share Purchase Plan | 0.4 | 17.1 | 0.2 | 8.3 | 0.2 | 7.2 |
| Stock based compensation expense | – | 1.9 | – | – | – | – |
| Issued to Noverco | – | – | 0.5 | 23.1 | – | – |
| Public issue | – | – | 5.0 | 225.4 | – | – |
| Exercise of stock options and other | 1.8 | 51.9 | 1.1 | 36.3 | 0.9 | 16.1 |
| Balance at end of year | 171.9 | 2,239.9 | 169.7 | 2,169.0 | 162.9 | 1,875.9 |

### 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, 2003, the Company may, at its option, redeem all or a portion of the outstanding preferred shares for $26.00 per share if redeemed on or prior to December 1, 2004; $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.

## 13. SHARE CAPITAL *(continued)*

### 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 (2002 – 5.3 million shares), resulting from the investment in Noverco.

The treasury stock method, used for calculating diluted earnings per share, uses an adjusted weighted average number of common shares outstanding, which reflects the effect of exercising all dilutive securities.

*(number of common shares in millions)*

| December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Weighted average shares outstanding | 165.5 | 160.3 | 157.3 |
| Effect of dilutive securities | 1.4 | 1.7 | 1.5 |
| Diluted weighted average shares outstanding | 166.9 | 162.0 | 158.8 |

### 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 the intention to acquire 20% or more of the Company's outstanding common shares without complying with certain provisions set out in the plan or without approval of the Board of Directors of the Company. Should such an acquisition or announcement 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 PLAN

The Company's Incentive Stock Option Plan (2002) includes fixed stock options and performance-based stock options. A maximum of 15 million common shares is reserved for issuance under the plan.

### 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 February 6, 2013.

### Outstanding Fixed Stock Options

*(options in thousands; exercise price in dollars)*

| December 31, | 2003 | | 2002 | | 2001 | |
|---|---|---|---|---|---|---|
| | Number | Weighted Average Exercise Price | Number | Weighted Average Exercise Price | Number | Weighted Average Exercise Price |
| Options at beginning of year | 5,042 | 32.16 | 5,120 | 29.06 | 4,112 | 26.76 |
| Options granted | 1,042 | 41.65 | 1,024 | 43.80 | 2,024 | 30.11 |
| Options exercised | (1,244) | 26.64 | (1,003) | 26.31 | (843) | 19.27 |
| Options cancelled or expired | (99) | 39.87 | (99) | 37.59 | (173) | 34.47 |
| Options at end of year | 4,741 | 35.96 | 5,042 | 32.16 | 5,120 | 29.06 |
| Options vested | 2,319 | | 2,639 | | 2,853 | |

### Fixed Stock Option Characteristics

*(options in thousands; exercise price in dollars)*

**December 31, 2003**

| | Options Outstanding | | | Options Vested | |
|---|---|---|---|---|---|
| Exercise Price Range | Number | Weighted Average Remaining Life (years) | Weighted Average Exercise Price | Number | Weighted Average Exercise Price |
| 10.30-19.99 | 117 | 1.72 | 14.70 | 117 | 14.70 |
| 20.00-29.99 | 1,078 | 5.44 | 26.02 | 796 | 25.77 |
| 30.00-39.99 | 1,564 | 5.76 | 35.95 | 1,165 | 35.22 |
| 40.00-47.71 | 1,982 | 8.29 | 42.64 | 241 | 43.63 |
| | 4,741 | | | 2,319 | |

### Performance-based Options

The Plan provides for the grant of performance-based stock 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, 2003, 810,000 remain unexercisable and were granted September 16, 2002 at $46.30 per share. 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 for 20 consecutive trading days during 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.

### Outstanding Performance-based Options

*(options in thousands; exercise price in dollars)*

| December 31, | 2003 | | 2002 | | 2001 | |
|---|---|---|---|---|---|---|
| | Number | Weighted Average Exercise Price | Number | Weighted Average Exercise Price | Number | Weighted Average Exercise Price |
| Options at beginning of year | 2,045 | 37.73 | 1,479 | 32.03 | 1,480 | 31.60 |
| Options granted | – | – | 810 | 46.30 | 65 | 41.13 |
| Options exercised | (549) | 31.39 | (244) | 31.66 | – | – |
| Options cancelled | – | – | – | – | (66) | 31.35 |
| Options at end of year | 1,496 | 40.05 | 2,045 | 37.73 | 1,479 | 32.03 |
| Options vested | 686 | 32.67 | 1,235 | 32.10 | 740 | 31.31 |

At December 31, 2003, the exercise prices of outstanding performance-based options ranged from $31.35 to $46.30 (2002 – $31.35 to $46.30; 2001 – $31.35 to $41.13). Outstanding performance-based options will expire over a period ending no later than September 16, 2010.

## 14. STOCK OPTION PLAN *(continued)*

### 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, | 2003 | 2002 |
|---|---|---|
| Earnings applicable to common shareholders from continuing operations | | |
| As reported | 667.2 | 334.2 |
| Total stock-based compensation expense [1] | (5.9) | (2.9) |
| Included as an expense in the statement of earnings [2] | 1.9 | – |
| Pro forma | 663.2 | 331.3 |
| Earnings applicable to common shareholders | | |
| As reported | 667.2 | 576.5 |
| Total stock-based compensation expense [1] | (5.9) | (2.9) |
| Included as an expense in the statement of earnings [2] | 1.9 | – |
| Pro forma | 663.2 | 573.6 |
| Earnings per common share from continuing operations | | |
| As reported | 4.03 | 2.09 |
| Pro forma | 4.01 | 2.07 |
| Earnings per common share | | |
| As reported | 4.03 | 3.60 |
| Pro forma | 4.01 | 3.58 |

*1 Total stock-based compensation expense if the fair value based method to expense stock options had been applied since January 1, 2002.*
*2 Stock-based compensation recognized as an expense in the statement of earnings for options granted in 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, | 2003 | 2002 | 2003 | 2002 |
|---|---|---|---|---|
| | Fixed Stock Options | | Performance-based Options | |
| Fair value per option | $ 8.46 | $ 11.42 | – | $ 7.65 |
| Valuation assumptions | | | | |
| Expected option term *(years)* | 8 | 10 | – | 8 |
| Expected volatility | 22% | 25% | – | 24% |
| Expected dividend yield | 3.95% | 3.51% | – | 3.46% |
| Risk-free interest rate | 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, primarily natural gas. In order to manage these exposures for both shareholders and ratepayers, the Company utilizes derivative financial instruments to create offsetting positions to specific 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, 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 notional amounts of $300.0 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 physical exposures that arise in the management of merchant capacity commitments to 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 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 Enbridge Gas, 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, 2003, the Company had entered into natural gas price swaps and options to manage the price for approximately 8.9%, or 13.1 billion cubic feet, of its forecast fiscal 2004 system gas supply.

## 15. FINANCIAL INSTRUMENTS *(continued)*

### 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, | 2003 | | | 2002 | | |
|---|---|---|---|---|---|---|
| | 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 | (30.6) | 2005-2022 | 535.8 | 24.9 | 2005-2022 |
| Euro cross currency swaps | 434.7 | (46.1) | 2004-2019 | 371.1 | (54.4) | 2003 |
| Forwards *(cumulative exchange amounts)* | 1,889.5 | 67.9 | 2004-2022 | 1,993.0 | (244.6) | 2003-2022 |
| Energy commodities | | | | | | |
| Natural gas *(bcf)* | 63.6 | 12.4 | 2004-2008 | 35.3 | (1.5) | 2003-2004 |
| Natural gas supply management *(bcf)* | 13.1 | (3.4) | 2004 | 5.9 | (0.2) | 2003 |
| Interest rates | | | | | | |
| Interest rate swaps | 561.0 | 1.9 | 2005-2029 | 934.1 | 0.6 | 2003-2029 |
| Forward interest rate swaps | 532.0 | (1.0) | 2004-2005 | – | – | – |

In addition, the Company has forward foreign exchange contracts with a notional principal of Canadian $214.0 million (2002 – $448.6 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 $10.5 million as at December 31, 2003 (2002 – $36.9 million receivable).

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, 2003 and 2002. A credit risk on derivative financial instruments amounted to $94.8 million at December 31, 2003 with no significant concentration with any single counterparty.

### Fair Values of Other Financial Instruments

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

The carrying amounts of all financial instruments, except for debt, approximate fair value. The fair value of debt does not include the effects of hedging.

### Total Debt

*(millions of dollars)*

| December 31, | 2003 | | 2002 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Liquids Pipelines | 881.4 | 990.6 | 981.3 | 1,084.5 |
| Gas Distribution and Services | 1,674.5 | 1,972.1 | 1,749.0 | 1,989.2 |
| Corporate | 3,362.1 | 3,540.1 | 3,962.3 | 4,081.3 |
| | 5,918.0 | 6,502.8 | 6,692.6 | 7,155.0 |

Non-recourse debt of joint ventures has a carrying value of $786.6 million and a fair value of $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. 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 $35.1 million at December 31, 2003 (2002 – $31.1 million).

## 16. INCOME TAXES

### Income Tax Rate Reconciliation

*(millions of dollars)*

| Year ended December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Earnings before income taxes | 888.2 | 746.8 | 552.1 |
| Combined statutory income tax rate | 35.6% | 38.0% | 41.0% |
| Income taxes at statutory rate | 316.2 | 283.8 | 226.3 |
| Increase/(decrease) resulting from: | | | |
| Tax rate changes on future income tax balances | 6.2 | 8.1 | (67.5) |
| Future income taxes related to regulated operations | (34.5) | (36.7) | (35.7) |
| Non-taxable items, net | (70.5) | (99.5) | (28.2) |
| Lower foreign tax rates | (44.4) | (42.2) | (36.8) |
| Large Corporations Tax | 18.1 | 16.9 | 18.8 |
| Other | (3.7) | 6.3 | (7.7) |
| Income Taxes | 187.4 | 136.7 | 69.2 |
| Continuing operations | 187.4 | 102.1 | 66.7 |
| Discontinued operations | – | 34.6 | 2.5 |
| | 187.4 | 136.7 | 69.2 |
| Effective income tax rate | 21.1% | 18.3% | 12.5% |

In 2003, income taxes paid amounted to $202.9 million (2002 – $105.2 million; 2001 – $110.5 million).

## 16. INCOME TAXES *(continued)*

### Components of Future Income Taxes

*(millions of dollars)*

| December 31, | 2003 | 2002 |
|---|---|---|
| Future Income Tax Liabilities | | |
| Differences in accounting and tax bases of property, plant and equipment | 368.0 | 313.8 |
| Differences in accounting and tax bases of investments | 368.2 | 525.7 |
| Other | 187.2 | 110.1 |
| | 923.4 | 949.6 |
| Future Income Tax Assets | | |
| Loss carryforwards | 241.7 | 283.0 |
| Other | 45.2 | 38.2 |
| | 286.9 | 321.2 |
| Total Net Future Income Tax Liability | 636.5 | 628.4 |

Accumulated future income taxes related to rate-regulated operations which have not been recorded in the accounts amounted to $551.2 million at December 31, 2003 (2002 – $511.2 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, 2003, the Company has recognized the benefit of unused tax loss carryforwards of $708.8 million. Unused tax loss carryforwards expire as follows: 2004 – $0.1 million; 2005 – $3.4 million; 2006 – $26.1 million; 2007 – $71.9 million; 2008 – $56.8 million, 2009 – $17.4 million and 2010 and beyond – $533.1 million.

### Geographic Components of Pretax Earnings and Income Taxes

*(millions of dollars)*

| Year ended December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Earnings before income taxes | | | |
| Canada | 693.0 | 346.1 | 297.2 |
| United States | 40.1 | (5.0) | 103.8 |
| Other | 155.1 | 128.8 | 103.3 |
| Continuing operations | 888.2 | 469.9 | 504.3 |
| Discontinued operations | – | 276.9 | 47.8 |
| | 888.2 | 746.8 | 552.1 |
| Current income taxes | | | |
| Canada | 108.4 | 154.8 | 44.4 |
| United States | (10.9) | 3.2 | 8.9 |
| Other | 4.1 | 8.8 | 10.0 |
| Continuing operations | 101.6 | 166.8 | 63.3 |
| Discontinued operations | – | 36.9 | 20.1 |
| | 101.6 | 203.7 | 83.4 |
| Future income taxes | | | |
| Canada | 116.6 | (54.5) | (9.0) |
| United States | (31.0) | (10.5) | 12.4 |
| Other | 0.2 | 0.3 | – |
| Continuing operations | 85.8 | (64.7) | 3.4 |
| Discontinued operations | – | (2.3) | (17.6) |
| | 85.8 | (67.0) | (14.2) |
| Current and future income taxes | | | |
| Continuing operations | 187.4 | 102.1 | 66.7 |
| Discontinued operations | – | 34.6 | 2.5 |
| | 187.4 | 136.7 | 69.2 |

## 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 either non-contributory defined benefit pension benefits or contributory defined contribution pension benefits to U.S. employees of Enbridge.

#### 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 measurement date used to determine the plan assets and the accrued benefit obligation was September 30, 2003. 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, 2002 | January 1, 2005 |
| Enbridge U.S. | January 1, 2003 | January 1, 2004 |
| 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. Adjustments arising from plan amendments, actuarial gains and losses, and changes to assumptions are amortized over the expected average remaining service lives of the employees.

#### Defined Contribution Plans

Contributions are generally based on the employee's age and/or years of service. For the Enbridge U.S. pension plan, contributions to the defined contribution plans are also based on employee contributions. For defined contribution pension benefits, pension cost equals amounts required to be contributed by the Company.

### 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.

## 17. POST-EMPLOYMENT BENEFITS *(continued)*

The following tables detail the changes in the benefit obligation, the fair value of plan assets and the recorded asset or liability using the accrual method.

*(millions of dollars)*

| | 2003 | 2002 | 2003 | 2002 |
|---|---|---|---|---|
| | OPEB | | Pension Benefit | |
| **Change in benefit obligation** | | | | |
| Benefit obligation, January 1 | 160.5 | 132.3 | 710.1 | 742.7 |
| Service cost | 5.8 | 4.2 | 20.0 | 18.7 |
| Interest cost | 10.6 | 8.8 | 46.8 | 45.9 |
| Amendments | (3.3) | – | – | 0.7 |
| Employee contributions | 0.4 | 0.3 | – | 0.1 |
| Actuarial loss | 0.8 | 31.4 | 68.8 | 8.5 |
| Benefits paid | (5.6) | (5.7) | (37.8) | (37.9) |
| Divestitures | – | (10.6) | – | (67.8) |
| Effect of exchange rate changes | (13.5) | (0.2) | (19.6) | (0.8) |
| Benefit obligation, December 31 | 155.7 | 160.5 | 788.3 | 710.1 |
| **Fair value of plan assets** | | | | |
| Fair value of plan assets, January 1 | 35.5 | 29.6 | 933.1 | 1,076.7 |
| Actual return on plan assets | 0.8 | 3.0 | 109.7 | (20.3) |
| Employer's contributions | 11.2 | 8.5 | 11.2 | 19.7 |
| Employee contributions | 0.4 | 0.3 | – | 0.1 |
| Benefits paid | (5.6) | (5.7) | (37.8) | (37.9) |
| Other | – | – | (1.7) | (2.3) |
| Divestitures | – | – | – | (100.9) |
| Effect of exchange rate changes | (6.1) | (0.2) | (27.8) | (2.0) |
| Fair value of plan assets, December 31 | 36.2 | 35.5 | 986.7 | 933.1 |
| **Asset/(Liability)** | | | | |
| Benefit obligation, December 31 | (155.7) | (160.5) | (788.3) | (710.1) |
| Fair value of plan assets, December 31 | 36.2 | 35.5 | 986.7 | 933.1 |
| Surplus/(deficit) | (119.5) | (125.0) | 198.4 | 223.0 |
| Contribution after measurement date | – | – | 2.9 | – |
| Unrecognized prior service cost | 0.5 | 3.4 | 19.0 | 20.8 |
| Unrecognized plan liability | 29.4 | 36.2 | – | – |
| Unrecognized net loss/(gain) | 28.0 | 31.5 | 21.0 | 4.8 |
| Recorded asset/(liability) | (61.6) | (53.9) | 241.3 | 248.6 |

### Major Categories of Plan Assets

*(millions of dollars)*

| Year ended December 31, | % | 2003 | 2002 | % | 2003 | 2002 |
|---|---|---|---|---|---|---|
| | | OPEB | | | Pension Benefit | |
| Equity securities | 0.0% | – | – | 58.5% | 639.1 | 542.2 |
| Debt securities | 85.9% | 31.1 | 32.2 | 37.1% | 404.4 | 447.8 |
| Other | 14.1% | 5.1 | 3.3 | 4.4% | 47.8 | 35.7 |
| | 100.0% | 36.2 | 35.5 | 100.0% | 1,091.3 | 1,025.7 |
| Assets attributable to Non-Consolidated Affiliates | | – | – | | (104.6) | (92.6) |
| Total Assets | | 36.2 | 35.5 | | 986.7 | 933.1 |

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

### Rate of Return on Plan Assets

*(millions of dollars)*

| Year ended December 31, | % | 2003 | 2002 | % | 2003 | 2002 |
|---|---|---|---|---|---|---|
| | | OPEB | | | Pension Benefit | |
| **Canadian Plans** | | | | | | |
| Equity securities | – | – | – | 60.0% | 8.75% | 9.25% |
| Fixed income securities | 100.0% | 4.5% | 4.5% | 40.0% | 5.00% | 6.00% |
| | | | | | 7.25% | 7.75% |
| **United States Plan** | | | | | | |
| Equity securities | – | – | – | 60.0% | 8.75% | 9.25% |
| Fixed income securities | 100.0% | 4.50% | 4.50% | 40.0% | 5.00% | 6.00% |
| | | | | | 7.25% | 8.00% |

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 period, 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)*

| Year ended December 31, | 2003 | 2002 | 2003 | 2002 |
|---|---|---|---|---|
| | OPEB | | Pension Benefit | |
| Minimum contributions required | – | – | – | – |
| Additional contributions | 11.2 | 8.5 | 11.2 | 19.7 |
| Total contributions | 11.2 | 8.5 | 11.2 | 19.7 |
| Contributions expected to be paid in 2004 | 10.6 | | 14.8 | |

## 17. POST-EMPLOYMENT BENEFITS *(continued)*

### Net Pension Plan and OPEB Costs Incurred

*(millions of dollars)*

| Year ended December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Benefits earned during the year | 27.7 | 25.2 | 26.3 |
| Interest cost on projected benefit obligations | 57.4 | 54.5 | 55.2 |
| Actual return on plan assets | (110.5) | 16.7 | (125.1) |
| Actuarial gain in the year | 69.6 | 38.0 | 45.0 |
| Amount credited/(charged) to the EEP | (10.2) | (1.7) | 5.5 |
| Pension and OPEB costs incurred | 34.0 | 132.7 | 6.9 |

### Net Pension Plan and OPEB Costs Recognized

*(millions of dollars)*

| Year ended December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Benefits earned during the year | 27.7 | 25.2 | 26.3 |
| Interest cost on projected benefit obligations | 57.4 | 54.5 | 55.2 |
| Expected return on plan assets | (64.8) | (75.3) | (93.7) |
| Amortization and deferral of unrecognized amounts | 15.3 | 6.9 | (6.8) |
| Amount credited/(charged) to EEP | (10.2) | (1.7) | 5.5 |
| Pension and OPEB cost/(credit) recognized | 25.4 | 9.6 | (13.5) |

The above tables reflect the funded status, recorded pension and OPEB assets and liabilities and 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 $9.4 million (2002 – $3.6 million credit; 2001 – $4.0 million cost). The pension asset was $71.4 million (2002 – $73.1 million). The Company's OPEB cost totaled $7.0 million (2002 – $6.8 million; 2001 – $5.9 million). The OPEB liability was $10.0 million (2002 – $8.4 million). These net benefits or liabilities are recorded on the balance sheet in Deferred Amounts and Other Assets. The pension and OPEB assets and obligations for discontinued operations were included in the sale transaction.

### Economic Assumptions

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

| Year ended December 31, | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
|---|---|---|---|---|---|---|
| | | OPEB | | | Pension Benefit | |
| Discount rate | 6.79% | 6.95% | 7.15% | 6.75% | 6.81% | 7.06% |
| 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% | 7.25% | 7.79% | 7.79% |

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

| Year ended December 31, | 2003 | 2002 | 2001 | 2003 | 2002 | 2001 |
|---|---|---|---|---|---|---|
| | | OPEB | | | Pension Benefit | |
| 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% |

### 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% | 4.5% | 2011 |
| Other Medical | 4.5% | 4.5% | 2004 |
| Enbridge U.S. | 14% | 5.5% | 2011 |

A 1% increase in the assumed medical and dental care trend rate would result in a change of $26.2 million in the accumulated post-employment benefit obligations and a change of $2.8 million in OPEB cost. A 1% decrease in the assumed medical and dental care trend rate would result in a change of $20.7 million in the accumulated post-employment benefit obligations and a change of $2.1 million in OPEB cost.

## 18. INVESTMENT AND OTHER INCOME

*(millions of dollars)*

| Year ended December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Equity investments | 146.3 | 143.5 | 56.7 |
| Gain on reduction of EEP ownership interest | 50.0 | 10.0 | 23.4 |
| EEM's equity income from EEP | 26.5 | 7.4 | 23.3 |
| Minority interest in EEM (equity income and dilution gain) | (25.9) | (4.0) | – |
| Cost investments | 67.2 | 61.1 | 51.9 |
| Investment income | 32.9 | 22.9 | 16.3 |
| Allowance for equity funds used during construction | 3.2 | 5.3 | 3.9 |
| Gain/(loss) on foreign currency contracts | (87.2) | 0.1 | (1.7) |
| Gain on sale of marketable securities | – | 21.4 | – |
| Other | (4.8) | 15.4 | 21.1 |
| | 208.2 | 283.1 | 194.9 |

## 19. CHANGES IN OPERATING ASSETS AND LIABILITIES

*(millions of dollars)*

| Year ended December 31, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Accounts receivable and other | (354.5) | 75.0 | (583.7) |
| Gas in storage | (224.8) | 76.0 | (145.8) |
| Deferred amounts and other assets | (78.9) | 72.4 | (77.6) |
| Accounts payable and other | 93.9 | (76.4) | 493.1 |
| Interest payable | (5.5) | 4.6 | (9.1) |
| | (569.8) | 151.6 | (323.1) |

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 $128.9 million (2002 – $97.2 million; 2001 – $56.2 million) for EEP and $4.7 million for EIF, which began operation on June 30, 2003.

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 $3.3 million for 2003 (2002 – $4.1 million; 2001 – $3.4 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 $95.5 million in 2003 (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 $40.7 million in 2003 (2002 – $41.3 million; 2001 – $34.8 million) for Alliance Pipeline, and $23.2 million in 2003 (2002 – $25.2 million; 2001 – $20.7 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 2003, this revenue amounted to $25.5 million (2002 – $35.1 million). CustomerWorks Limited Partnership began operations on January 1, 2002.

In 2003, Enbridge Gas Services Inc. purchased $33.6 million (2002 – $6.3 million; 2001 – nil) of gas from Enbridge Marketing (US) Inc.

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.

The remediation of discontinued manufactured gas plant sites may result in future costs to Enbridge Gas. In October 2002, a claim was filed for $55 million in damages relating to a certain manufactured gas plant site. Enbridge Gas filed a statement of defence in June 2003 denying liability. 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. Enbridge Gas 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 a material impact on the financial statements.

In October 2002, the Supreme Court of Canada granted an Application for Leave to Appeal to a customer who commenced an action against Enbridge Gas claiming that the OEB-approved late payment penalties charged to customers were contrary to Canadian federal law. The Court heard the plaintiff's appeal of the Ontario Court of Appeal's decision on October 9, 2003 and reserved issuing judgment.

### 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.

### 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$248 million at December 31, 2003.

## 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, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Earnings under Canadian GAAP | 700.8 | 610.1 | 482.9 |
| Preferred security distributions [1] | (26.7) | (26.7) | (17.5) |
| Stock-based compensation [2] | – | (12.1) | (15.2) |
| Loss on ineffective hedges [5] | (53.8) | – | – |
| Change in income due to consolidation of EIF [7] | (2.3) | – | – |
| Change in gain due to consolidation of EIF [7] | (173.0) | – | – |
| Tax effect of the above adjustments | 51.5 | 4.9 | 6.1 |
| Future income tax recovery/(expense) [3] | – | – | 92.8 |
| Earnings under U.S. GAAP | 496.5 | 576.2 | 549.1 |
| Unrealized net gain/(loss) on cash flow hedges [6] | 66.9 | 19.5 | (150.8) |
| Reclassification adjustment on cash flow hedges [6] | 80.6 | – | – |
| Foreign currency translation adjustment [6] | (159.6) | (1.3) | 15.1 |
| Comprehensive income | 484.4 | 594.4 | 413.4 |
| Earnings per common share | 3.00 | 3.55 | 3.45 |
| Diluted earnings per common share | 2.98 | 3.51 | 3.41 |

## Financial Position

*(millions of dollars)*

| December 31, | 2003 | | 2002 | |
|---|---|---|---|---|
| | Canada | United States | Canada | United States |
| Cash [7] | 104.1 | 131.7 | 40.7 | 42.7 |
| Accounts receivable and other [6,7] | 1,138.8 | 1,192.8 | 817.5 | 843.4 |
| Property, plant and equipment [7] | 11,481.5 | 12,778.2 | 9,548.6 | 9,506.6 |
| Accumulated depreciation [7] | 2,950.6 | 2,974.2 | 2,601.0 | 2,596.3 |
| Long-term investments [7] | 2,390.9 | 2,010.7 | 3,371.5 | 3,421.0 |
| Deferred amounts [3,7] | 486.5 | 1,355.8 | 315.8 | 1,178.7 |
| Short-term borrowings | 649.6 | 649.6 | 247.5 | 256.8 |
| Accounts payable and other [7] | 894.1 | 1,000.7 | 714.1 | 915.0 |
| Current maturities and short-term debt [7] | 674.9 | 721.4 | 652.3 | 658.5 |
| Long-term debt [1] | 5,243.1 | 6,761.0 | 6,040.3 | 6,612.5 |
| Future income taxes [3, 6] | 636.5 | 1,429.2 | 628.4 | 1,403.0 |
| Non-controlling interests [7] | 523.0 | 599.7 | 560.8 | 560.8 |
| Preferred securities [1] | 532.4 | – | 533.7 | – |
| Retained earnings | 1,511.4 | 1,289.5 | 1,128.1 | 1,089.8 |
| Additional paid in capital [2] | – | 27.3 | – | 27.3 |
| Foreign currency translation adjustment [6] | (147.0) | – | 12.3 | – |
| Accumulated other comprehensive loss [6] | – | (116.6) | – | (103.2) |

*1 Preferred Securities*

*Under U.S. GAAP, the full amount of the Company's Preferred Securities and related distributions would be recognized as debt and interest expense, respectively. The Preferred Securities have a fair market value of $625.5 million at December 31, 2003 (2002 – $565.0 million).*

*2 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 for options 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 and 2001, gave rise to pre-tax compensation expense of $12.1 million and $6.9 million respectively. No performance-based options vested in 2003. In addition, under U.S. GAAP in 2001, the Company's Stock Appreciation Rights (SARs) were accounted for using the intrinsic value method, which resulted in pre-tax compensation expense of $8.3 million, whereas, under Canadian GAAP, SARs did not give rise to compensation expense.*

*3 Future Income Taxes*

*Canadian GAAP requires that the effects of tax rate reductions be recognized when they are substantively enacted. Under U.S. GAAP, the effect of tax rate reductions cannot be recognized until enacted. In 2000, the Company recognized $92.8 million of earnings related to substantively enacted tax rate reductions that are recognized in 2001 under U.S. GAAP.*

*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 $551.2 million (2002 – $549.3 million) and the incremental revenue required for the recovery of unrecorded taxes of $286.6 million (2002 – $316.0 million).*

*4 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.*

5 *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.*

*In order to qualify for hedge accounting, FAS 133 requires that extensive documentation be maintained and that hedge effectiveness tests prescribed by that standard be met at both the inception of a hedge relationship and on a periodic, ongoing basis. Management maintains the necessary level of documentation required to qualify for hedge accounting under FAS 133. However, in one instance during 2003, certain instruments were classified as ineffective hedges resulting in a loss after tax of $32.3 million under U.S. GAAP.*

6 *Accumulated Other Comprehensive Loss*

*At December 31, 2003, Accumulated Other Comprehensive Loss consists of an accumulated foreign currency translation adjustment of $(131.5) million (2002 – $28.1 million) and net unrealized gains of $14.9 million (2002 – $(131.3) million) both for derivative financial instruments due to cash flow hedges, including a reclassification adjustment in 2003. The reclassification adjustment of $80.6 million relates to the change in classification of hedging instruments between periods.*

*Of the Accumulated Other Comprehensive Loss of $116.6 million, the Company estimates that approximately $5.6 million, representing unrecognized net losses on derivative activities at December 31, 2003, is expected to be reclassified into earnings during the next twelve months.*

7 *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 46 requires the primary beneficiary of a variable interest entity's activities to consolidate the variable interest entity. FIN 46 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.*

*FIN 46 is immediately applicable to variable interest entities created, or interests in variable interest entities obtained, after January 31, 2003. For variable interest entities created, or interests in variable interest entities obtained, on or before January 31, 2003, FIN 46 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 46.*

*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. Under U.S. GAAP, the results of EIF are consolidated with a 27.7% minority interest. The assets and liabilities of EIF have been measured at the same amounts as they were prior to the transfer to EIF and the gain is recorded based on the equity issued to external third parties.*

*The U.S. GAAP adjustment reflecting the consolidation of EIF includes a $380.2 million reduction to long-term investments, a $76.7 million increase in non-controlling interests, a reduction in the pre-tax gain on sale from $239.9 million to $66.9 million, and net income is reduced by $2.3 million.*

*The following accounts of EIF are consolidated for the purposes of the U.S. GAAP financial statements as at December 31, 2003.*

| | |
|---|---|
| Cash | $ 27.6 million |
| Accounts receivable and other | $ 34.2 million |
| Property, plant and equipment | $ 1,273.1 million |
| Deferred amounts | $ 31.5 million |
| Accounts payable and other | $ 31.0 million |
| Current portion of long-term debt | $ 40.0 million |
| Long-term debt | $ 1,022.6 million |
| Future income taxes | $ 2.8 million |

*The consolidation of EIF increases cash by $27.6 million and the statement of cash flows would reflect an increase in cash from operations of $30.4 million, cash from investing activities would decrease by $384.3 million, and cash used in financing activities would increase by $381.5 million.*

### 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, | 2003 | 2002 | 2001 |
|---|---|---|---|
| Earnings under U.S. GAAP | | | |
| As reported | 496.5 | 576.2 | 549.1 |
| Stock-based compensation expense | (7.9) | (7.3) | (4.6) |
| Included as an expense in the statement of earnings | 1.9 | – | – |
| Pro forma | 490.5 | 568.9 | 544.5 |
| Earnings per common share | | | |
| As reported | 3.00 | 3.55 | 3.45 |
| Stock-based compensation expense | 0.04 | 0.05 | 0.03 |
| Pro forma | 2.96 | 3.50 | 3.42 |
| Diluted earnings per common share | | | |
| As reported | 2.98 | 3.51 | 3.41 |
| Stock-based compensation expense | 0.04 | 0.04 | 0.03 |
| Pro forma | 2.94 | 3.47 | 3.38 |

The fair value of stock options was calculated in the same manner, using the same assumptions, as disclosed in Note 14 except that for Canadian GAAP, only awards granted since the adoption of the CICA standard for stock-based compensation on January 1, 2002 are included. Assumptions used for U.S. GAAP comparatives in 2001 are as follows.

| Year ended December 31, | 2001 |
|---|---|
| Risk-free interest rate | 5.38% |
| Expected life *(years)* | 10 |
| Expected volatility | 25% |
| Expected quarterly dividends | $0.38 |

The weighted average grant-date fair value of options granted during 2001 under the fixed option plan was $10.09.

## Quarterly Share Trading Information

The Toronto Stock Exchange

| **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** |

| 2002 *(dollars)* | First | Second | Third | Fourth |
|---|---|---|---|---|
| High | 46.15 | 48.94 | 49.25 | 46.85 |
| Low | 41.50 | 43.06 | 42.71 | 41.11 |
| Close | 44.73 | 47.16 | 46.27 | 42.61 |
| Volume *(millions)* | 21.3 | 15.5 | 17.0 | 18.5 |

The New York Stock Exchange

| **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** |

| 2002 *(U.S. dollars)* | First | Second | Third | Fourth |
|---|---|---|---|---|
| High | 27.57 | 30.49 | 31.03 | 29.14 |
| Low | 24.20 | 25.61 | 26.29 | 26.05 |
| Close | 26.52 | 30.11 | 28.37 | 26.73 |
| Volume *(millions)* | 0.6 | 0.6 | 1.7 | 1.3 |

### *Corporate Responsibility and Environment, Health and Safety*

*Prevention of accidents and injuries, and protection of the environment benefits everyone. That's why environmental, health and safety performance is an integral part of Enbridge's businesses, and objectives and performance targets are established, implemented and monitored. For the past three years the results have been published in the Company's Environment, Health and Safety Annual Report. You can obtain a copy of the most recent report by e-mailing webmaster@enbridge.com, or visiting the Enbridge website at www.enbridge.com.*

*In 2004, the Company's Environment, Health and Safety report will be incorporated into Enbridge's first annual Corporate Responsibility report. The document, expected to be available by mid-year, will take the "triple bottom line" approach to CR reporting and discuss Enbridge's environmental, social and economic performance. It will still provide detailed information about the Company's Environment, Health and Safety performance, but it will also discuss community investment, community consultation, stakeholder relations, human rights and other CR topics.*

## Financial and Operating Information [1]

*(millions of dollars, except per share amounts)*

| Earnings by Segment | 2003 | 2002 | 2001 | 2000 | 1999 |
|---|---|---|---|---|---|
| Liquids Pipelines | 213.5 | 189.6 | 164.4 | 152.5 | 146.0 |
| Gas Pipelines | 70.1 | 47.8 | 41.5 | 39.6 | 33.2 |
| Sponsored Investments | 234.3 | (51.1) | 37.2 | 16.3 | 30.4 |
| Gas Distribution and Services [2] | 153.6 | 124.3 | 189.6 | 211.7 | 97.7 |
| International | 72.3 | 68.0 | 35.6 | 26.4 | 28.7 |
| Corporate | (76.6) | (44.4) | (55.1) | (88.8) | (48.1) |
| Continuing operations | 667.2 | 334.22 | 413.2 | 357.7 | 287.9 |
| Discontinued operations [3] | – | 242.3 | 45.3 | 34.6 | – |
| Earnings applicable to common shareholders | 667.2 | 576.5 | 458.5 | 392.3 | 287.9 |
| **Cash Flow Data** | | | | | |
| Cash provided from operating activities | 395.2 | 910.6 | 414.5 | 263.5 | 495.1 |
| Expenditures on property plant and equipment | 391.3 | 729.9 | 683.3 | 364.3 | 783.7 |
| Dividends paid on common shares | 283.9 | 251.1 | 227.5 | 202.1 | 186.4 |
| **Operating Data** | | | | | |
| Liquids Pipelines [4] | | | | | |
| Deliveries *(thousands of barrels per day)* | 2,189 | 2,088 | 2,109 | 2,072 | 1,942 |
| Barrel miles *(billions)* | 710 | 705 | 695 | 735 | 687 |
| Average haul *(miles)* | 889 | 925 | 903 | 972 | 968 |
| Gas Distribution | | | | | |
| Distribution volume *(billion cubic feet)* | 458 | 410 | 427 | 421 | 402 |
| Number of active customers *(thousands)* | 1,679 | 1,623 | 1,571 | 1,520 | 1,466 |
| Degree day deficiency [5] *(degrees Celsius)* | | | | | |
| Actual | 4,029 | 3,362 | 3,766 | 3,569 | 3,460 |
| Forecast based on normal weather | 3,565 | 3,700 | 3,816 | 3,629 | 4,060 |

1 *Certain comparative amounts have been reclassified to conform with the current year's basis of presentation.*

2 *The highlights of the Gas Distribution activities reflect the results of Enbridge Gas Distribution and other gas distribution assets on a quarter lag basis of consolidation.*

3 *The results of discontinued operations cannot be disaggregated from continuing operations prior to 2000.*

4 *Liquids Pipelines operating highlights include the statistics of the 12.2% owned portion of the mainline system located in the United States.*

5 *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.*

| Shareholder and Investor Information | | | | | |
|---|---|---|---|---|---|
| *(per share amounts in dollars)* | **2003** | 2002 | 2001 | 2000 | 1999 |
| Average common shares outstanding weighted monthly during the year *(thousands)* | **165,471** | 160,310 | 157,297 | 154,469 | 150,995 |
| Number of registered common shareholders at year end | **7,167** | 7,406 | 7,832 | 8,265 | 8,877 |
| **Common Share Trading** *(TSX)* [1] | | | | | |
| High | **54.14** | 49.25 | 45.55 | 44.00 | 36.33 |
| Low | **40.95** | 41.11 | 33.90 | 23.00 | 28.60 |
| Close | **53.70** | 42.61 | 43.40 | 43.70 | 28.65 |
| Volume *(millions)* | **75.0** | 72.3 | 67.6 | 68.2 | 51.8 |
| **Per Common Share Data** [1] | | | | | |
| Earnings applicable to common shareholders | | | | | |
| Continuing operations | **4.03** | 2.09 | 2.63 | 2.32 | 1.91 |
| Discontinued operations | **–** | 1.51 | 0.28 | 0.22 | – |
| | **4.03** | 3.60 | 2.91 | 2.54 | 1.91 |
| Dividends paid on common shares | **1.660** | 1.520 | 1.400 | 1.270 | 1.195 |
| **Financial Ratios** | | | | | |
| Return on average shareholders' equity [2] | **19.9%** | 19.9% | 18.6% | 18.6% | 14.3% |
| Return on average capital employed [3] | **8.1%** | 7.5% | 7.3% | 7.2% | 6.6% |
| Debt to debt plus shareholders' equity [4] | **61.4%** | 64.4% | 72.9% | 69.4% | 68.9% |
| Debt to total capital employed | **52.3%** | 57.0% | 66.3% | 61.6% | 63.7% |
| Earnings coverage of interest [5] | **3.0x** | 2.7x | 2.2x | 2.0x | 2.0x |
| Dividend payout ratio [6] | **41.2%** | 42.2% | 48.1% | 50.0% | 62.6% |

1 *Data for 2003, 2002, 2001 and 2000 are for Toronto Stock Exchange only. Prior year data include the Toronto and Montreal stock exchanges.*
2 *Earnings applicable to common shareholders divided by average common equity (weighted monthly during the year).*
3 *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).*
4 *Total debt (including short-term borrowings) divided by the sum of total debt and shareholders' equity.*
5 *Sum of earnings before income taxes, non-controlling interest and interest expense, divided by interest expense. Includes earnings from discontinued operations.*
6 *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 B, C and D of Enbridge Inc. trade in Canada on the Toronto Stock Exchange under the trading symbols "ENB.PR.B", "ENB.PR.C" and "ENB.PR.D", respectively. 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 — 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 Imperial Room at the Fairmont Royal York Hotel, Toronto, Ontario, at 1:30 p.m. EDT on Wednesday, May 5, 2004.

### 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**

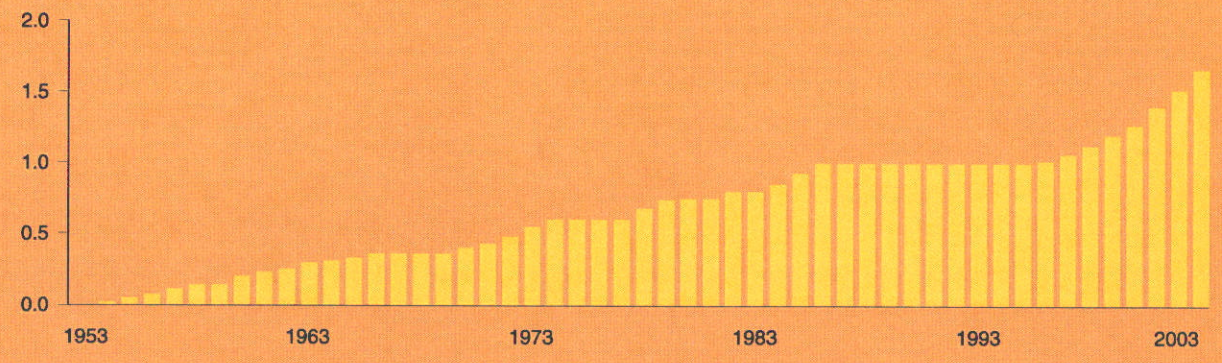
| 2004 Dividend Information for Common Shares and Preferred Shares, Series A | 1st Q | 2nd Q | 3rd Q | 4th Q |
|---|---|---|---|---|
| Record date | Feb. 13 | May 17 | Aug. 16 | Nov. 15 |
| Payment date | March 1 | June 1 | Sept. 1 | Dec. 1 |
| Common Share Dividend Reinvestment Plan (DRIP) enrolment cut-off date | Feb. 6 | May 10 | Aug. 9 | Nov. 8 |
| Common Share Purchase Plan cut-off date for DRIP | Feb. 23 | May 25 | Aug. 25 | Nov. 24 |

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

| 2004 Interest Payment Information for Preferred Securities, Series B, C and 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 |

*Le présent document est disponible en français.*

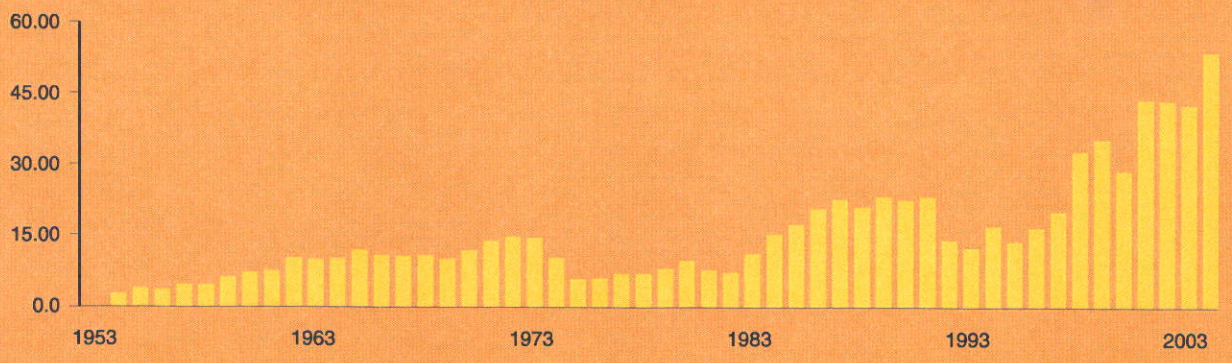
## 50-Year Annual Dividend




**50 Years of Delivering Value to Shareholders.** In 2003, Enbridge marked the completion of its 50th year as a publicly traded company — the stock of its predecessor company, Interprovincial Pipe Line Company, Inc., was listed on the Toronto and Montreal stock exchanges on February 13, 1953. The accompanying graphs, showing annual dividends and share price for the 50-year period since the listings, reflect some of the major events in the Company's history — events such as the 1991 spinoff of Home Oil and the creation that same year of Enbridge Energy Partners to own and operate the Lakehead System, and the 1994 acquisition of what is now Enbridge Gas Distribution. The graphs also illustrate the steady, sustained growth that has characterized Enbridge for half a century.

**Since 1953, the calculated annual total shareholder return, including dividends, has averaged just over 13%.** That's a very positive story for Enbridge shareholders, and an achievement that we at Enbridge are justifiably proud of.

## 50-Year Share Price




Creative Development by Rivard Communications Inc., Calgary. Printed by Quebecor World Calgary.

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".

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

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-K

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

**For the fiscal year ended DECEMBER 31, 2003**

**OR**

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from _____ to _____**

**Commission File Number: 1-10934**

# ENBRIDGE ENERGY PARTNERS, L.P.

(Exact name of Registrant as specified in its charter)

| | |
|---|---|
| **Delaware**<br>(State or other jurisdiction of incorporation or organization) | **39-1715850**<br>(I.R.S. Employer Identification No.) |

**1100 Louisiana**
**Suite 3300**
**Houston, Texas 77002**
(Address of principal executive offices and zip code)

**(713) 821-2000**
(Registrant's telephone number, including area code)

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

| Title of each class | Name of each exchange on which registered |
|---|---|
| **Class A Common Units** | **New York Stock Exchange** |

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☐

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act) Yes ☒ No ☐

The aggregate market value of the Registrant's Class A Common Units held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of June 30, 2003, was $1,683,394,439.

**DOCUMENTS INCORPORATED BY REFERENCE: NONE**

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*This Annual Report on Form 10-K contains forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "continue," "estimate," "expect," "forecast," "intend," "may," "plan," "position," "projection," "strategy," could," "should," or "will" or the negative of those terms or other variations of them or comparable terminology. In particular, statements, expressed or implied, concerning future actions, conditions or events or future operating results or the ability to generate revenue, income or cash flow are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results of operations may differ materially from those expressed in these forward-looking statements. Many of the factors that will determine these results are beyond the ability of the Partnership to control or predict. For additional discussion of risks, uncertainties and assumptions, see "Items 1. & 2. Business and Properties—Risk Factors" included elsewhere in this Form 10-K.*

## Glossary

The following abbreviations, acronyms, or terms used in this Form 10-K are defined below:

| | |
|---|---|
| Act | Pipeline Safety Act |
| Anadarko system | Natural gas gathering and processing assets located in western Oklahoma and the Texas panhandle, which were acquired on October 17, 2002 |
| AOSP | Athabasca Oil Sands Project |
| Bbl | Barrel of liquids (approximately 42 U.S. gallons) |
| Bpd | Barrels per day |
| CAA | Clean Air Act |
| CAPP | Canadian Association of Petroleum Producers, a trade association representing a majority of the Lakehead system's customers |
| CERCLA | Comprehensive Environmental Response, Compensation, and Liability Act |
| Cdn. | Amount denominated in Canadian dollars |
| Cold Lake | Oil sands reserves in the province of Alberta, Canada |
| CWA | Clean Water Act |
| DOT | Department of Transportation |
| East Texas system | Natural gas gathering, treating and processing assets in East Texas acquired on November 30, 2001 |
| Enbridge | Enbridge Inc., of Calgary, Alberta, Canada, the ultimate parent of the General Partner |
| Enbridge Management | Enbridge Energy Management, L.L.C. |
| Enbridge system | Canadian portion of the System |
| Enbridge Pipelines | Enbridge Pipelines Inc. |
| Enbridge U.S. | Enbridge (U.S.) Inc. |
| Energy Policy Act | Energy Policy Act of 1992 |
| EES | Enbridge Employee Services, Inc. |
| EPA | Environmental Protection Agency |
| Epu | Earnings per unit |
| Exchange Act | Securities Exchange Act of 1934 |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| General Partner | Enbridge Energy Company, Inc., general partner of the Partnership |
| HCA | High consequence area |
| Hinshaw pipeline | An intrastate pipeline that receives gas in interstate commerce at or within the boundaries of the state and is ultimately consumed within that state. |
| HLPSA | Hazardous Liquid Pipeline Safety Act |
| ICA | Interstate Commerce Act |
| KPC | Kansas Pipeline Company |
| Lakehead Partnership | Enbridge Energy, Limited Partnership, a subsidiary of the Partnership |

| | |
|---|---|
| Lakehead system | U.S. portion of the System |
| LIBOR | London Interbank Offered Rate—British Bankers Association's average settlement rate for deposits in U.S. dollars |
| MMBtu/d | Million British Thermal units per day |
| MMcf/d | Million cubic feet per day |
| Midcoast system | Natural gas gathering, treating, processing, transmission and marketing assets comprised of the Midcoast system, Northeast Texas System and South Texas System. |
| NEB | National Energy Board |
| NGA | Natural Gas Act |
| NGL or NGLs | Natural gas liquids |
| NGPA | Natural Gas Policy Act |
| North Dakota system | Liquids petroleum pipeline system in the Upper Midwest |
| Northeast Texas system | Natural gas gathering and processing assets acquired on October 17, 2002 |
| North Texas system | Natural gas gathering and processing assets acquired on December 31, 2003 |
| NYMEX | The New York Mercantile Commodity Exchange where natural gas futures, options contracts, and other energy futures are traded. |
| NYSE | New York Stock Exchange |
| OBA | Operational balancing agreement |
| OCSLA | Outer Continental Shelf Lands Act |
| OPA | Oil Pollution Act |
| OPS | Office of Pipeline Safety |
| OSHA | Occupational Safety and Health Administration |
| OTC | Over-the-Counter derivatives are privately negotiated contracts between two parties and are not limited to restrictions of contracts traded on exchanges |
| PADD | Petroleum Administration for Defense Districts |
| PADD II | Consists of Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, North Dakota, Ohio, Oklahoma, South Dakota, Tennessee and Wisconsin |
| PADD III | Consists of Alabama, Arkansas, Louisiana, Mississippi, New Mexico and Texas |
| PADD IV | Consists of Idaho, Montana, Wyoming and Colorado |
| PADD V | Consists of Washington, Oregon, California, Arizona, Alaska, Hawaii and Nevada |
| Partnership Agreement | Third Amended and Restated Agreement of Limited Partnership of the Partnership |
| Partnership | Enbridge Energy Partners, L.P. and subsidiaries |
| PPIFG-1 | Producer Price Index for Finished Goods minus 1% |
| PSA | Pipeline Safety Act |
| RCRA | Resource Conservation and Recovery Act |

| | |
|---|---|
| RSPA | Research and Special Programs Administration |
| SAGD | Steam Assisted Gravity Drainage |
| SEC | Securities and Exchange Commission |
| SEP II | System Expansion Program II |
| Settlement Agreement | A FERC approved settlement agreement, signed October 1996 |
| SFAS | Statement of Financial Accounting Standards |
| SFPP | Santa Fe Pacific Pipelines, L.P., an unrelated company |
| SPCC | Spill Prevention, Control and Countermeasure |
| Suncor | Suncor Energy Inc., an unrelated company |
| Syncrude | Syncrude Canada Ltd., an unrelated company |
| System | The combined liquid petroleum pipeline operations of the Lakehead system and the Enbridge system |
| Tariff Agreement | A 1998 offer of settlement filed with the FERC |
| Terrace | Terrace Expansion Program |
| WCSB | Western Canadian Sedimentary Basin |

## PART I

### Items 1. & 2.—Business & Properties

### OVERVIEW

The Partnership is a publicly traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation assets and natural gas gathering, treating, processing, transmission and marketing assets in the United States. The Class A common units of the Partnership are traded on the NYSE under the symbol "EEP."

The Partnership was formed in 1991 by the General Partner to own and operate the Lakehead system, which is the U.S. portion of a crude oil and liquid petroleum pipeline system extending from western Canada through the upper and lower Great Lakes region of the United States to eastern Canada. Since the Partnership's initial public offering in 1991, it has increased its quarterly cash distribution by 57% from $0.59 per unit to the current quarterly rate of $0.925 per unit.

The Partnership's ownership is comprised of a 2% general partner interest and a 98% limited partner interest. The General Partner owns the 2% general partner interest and a 7.1% limited partner interest, in the form of 3,912,750 Class B common units in the Partnership. The remaining 90.9% limited partner interest is represented by a 72.7% ownership interest of 40,166,134 publicly traded Class A common units and an 18.2% ownership interest of 10,062,170 i-units, which are wholly-owned by Enbridge Management.

Enbridge Management is a Delaware limited liability company that was formed on May 14, 2002. Enbridge Management's shares represent limited liability company interests and are traded on the NYSE under the symbol "EEQ." Its principal asset is its 18.2% limited partnership interest in the Partnership through its ownership of i-units. Enbridge Management's principal activity is managing the business and affairs of the Partnership and its subsidiaries. Under a Delegation of Control Agreement, the General Partner delegated substantially all of its power and authority to manage the business and affairs of the Partnership to Enbridge Management. The General Partner, through its direct ownership of the voting shares of Enbridge Management, elects all of the directors of Enbridge Management.

Since May 2001, the Partnership has diversified its operations both geographically and by industry. The North Dakota system, acquired in May 2001, connects to the Partnership's Lakehead system and accessed a different crude oil supply basin in North Dakota and Montana. The East Texas system, acquired in November 2001, was the Partnership's first entry into the natural gas gathering and processing business and diversified the geographic focus of the Partnership to include the southern United States. In October 2002, the Partnership continued its diversification through the acquisition of the Midcoast system, which included natural gas gathering, treating, processing, transmission and marketing activities located in the southern United States. On December 31, 2003, the Partnership acquired the North Texas system, a natural gas gathering and processing business in Texas.

### AVAILABLE INFORMATION

The Partnership files annual, quarterly and other reports and information with the SEC under the Exchange Act. You may read and copy any materials that the Partnership files with the SEC at the SEC's Public Reference Room at 450 Fifth Street, NW, Washington, DC 20549. You may obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains an Internet site *http://www.sec.gov* that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including the Partnership.

The Partnership also makes available free of charge on or through its Internet website *http://www.enbridgepartners.com* its Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and other information statements, and if applicable, amendments to

those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after the Partnership electronically files such material with the SEC.

**BUSINESS STRATEGY**

The primary strategy of the Partnership is to grow cash distributions through the profitable expansion of existing assets and through the development and acquisition of complementary businesses with risk profiles similar to the Partnership's current business.

A number of developments in 2003 strengthened the Partnership's position as a crude oil carrier into the U.S. Mid-Continent. The Partnership continues to expand the Lakehead system's capacity through the construction of Terrace and the complementary expansion of pipeline facilities in the Chicago area. CAPP had requested these expansions, in anticipation of future growth in crude oil production from the prolific Alberta oil sands. In September 2003, Enbridge purchased a crude oil pipeline that currently flows from Cushing, Oklahoma to Chicago, Illinois. Enbridge intends to reverse the direction of flow on this system, which should ultimately increase market access for Canadian crude oil delivered on the Lakehead system. In December 2003, the Partnership announced the acquisition of crude oil pipeline and storage facilities in the U.S. Mid-Continent, which closed in the first quarter of 2004. This acquisition is expected to be accretive to cash distributions while, at the same time, increasing the diversity of sources of crude oil, thereby reducing the Partnership's dependence on western Canadian crude oil volumes.

The Partnership continues to grow its natural gas business with the acquisition of the North Texas gathering and processing system on December 31, 2003, adding to its presence in Texas. Effective October 2003, the Partnership made a decision to proceed with the construction of a pipeline to connect its East Texas system to the Carthage, Texas hub. Carthage access is important to shippers because it offers a number of connections to interstate natural gas pipelines. These projects are allowing the Partnership to achieve a larger scale and geographic profile from its East Texas system to its Anadarko system in the Texas panhandle, where it can pursue commercial and operating synergies that will make it the operator of choice in Texas.

The Partnership will continue to analyze potential acquisitions, with a focus on crude oil, refined products and natural gas pipelines, terminals and related facilities. Major energy companies have sold their non-strategic assets in recent years, continuing the trend of rationalization of the energy infrastructure in the United States. The Partnership expects this trend to continue and believes it is well positioned to participate in these opportunities. The Partnership will seek out opportunities throughout the United States, particularly in the U.S. Gulf Coast area, where asset divestitures are anticipated in and around its existing natural gas gathering, processing and transportation businesses.

**BUSINESS SEGMENTS**

The Partnership conducts its business through four business segments: Liquids Transportation, Gathering and Processing, Natural Gas Transportation and Marketing.

- Liquids Transportation includes the operations of a common carrier pipeline and a feeder pipeline, which transport crude oil and other liquid hydrocarbons.
- Gathering and Processing consists of natural gas gathering pipelines, treating plants and processing plants. This segment also includes the transportation of natural gas liquids, crude oil and carbon dioxide by rail and road.
- Natural Gas Transportation includes the operations of natural gas transmission pipeline systems.
- The Marketing segment provides natural gas supply, transmission and sales services for customers.

**Liquid Transportation Segment**

*Lakehead system*

The Lakehead system in the United States and the Enbridge system in Canada, which is owned by Enbridge Pipelines, a wholly-owned subsidiary of Enbridge, together form the System. The System, which spans 3,100 miles, is the longest liquid petroleum pipeline system in the world and transports crude oil and other liquid petroleum products as a common carrier. The System is the primary transporter of crude oil from western Canada to the United States and the only pipeline that transports crude oil from western Canada to the province of Ontario in eastern Canada.

The System serves all the major refining centers in the Great Lakes and upper Midwest regions of the United States and the province of Ontario, and, through interconnects, the Patoka/Wood River pipeline hub located in southern Illinois. Deliveries of crude oil and NGLs from the Lakehead system are made principally to refineries, either directly or through connecting pipelines of other companies, and serve as feedstocks for refineries and petrochemical plants.

The Lakehead system is a FERC regulated interstate common carrier pipeline system. The Lakehead system spans approximately 1,900 miles, and consists of approximately 3,300 miles of pipe with diameters ranging from 12 inches to 48 inches, 59 pump station locations with a total of approximately 752,000 installed horsepower and 60 crude oil storage tanks with an aggregate working capacity of approximately 14 million barrels. The System operates in a segregation, or batch mode. This operating mode allows the Lakehead system to transport up to 45 different types of liquid hydrocarbons including light, medium and heavy crude oil (including bitumen, which is a naturally occurring tar-like mixture of hydrocarbons), condensate and NGLs. This flexibility increases utilization of the system and enhances the Partnership's ability to serve its customers.

*Customers.* The Lakehead system operates under month-to-month transportation arrangements with its shippers. During 2003, 36 shippers tendered crude oil and liquid petroleum for delivery through the Lakehead system. These customers include integrated oil companies, major independent oil producers, refiners and marketers.

*Supply and Demand.* The Lakehead system is well positioned as the primary transporter of western Canadian crude oil and will benefit from the growing production of crude oil from the Alberta oil sands. As with U.S. domestic conventional crude oil production, western Canada's conventional crude oil production is in decline. More than offsetting this decline is substantial growth in production from Canada's prolific oil sands resource from the WCSB.

The western Canadian oil sands are naturally occurring mixtures of sand, water, clay, and approximately 12% bitumen. According to the Alberta Energy and Utilities Board, using existing technology, knowledge and economics, the remaining recoverable bitumen reserves in the province of Alberta were estimated at the end of 2002 at approximately 174 billion barrels. This represents a recovery of approximately 10% of the initial volume in place (over 1.6 trillion barrels). The cumulative production of bitumen to the end of 2002 stood at approximately 3.8 billion barrels. According to industry sources, the economics of producing bitumen have improved substantially from the late 1970's when average production costs were nearly $23 per barrel (including extraction and upgrading costs). Bitumen production must be blended with lighter, less viscous materials to permit transportation via pipelines to refinery markets. Alternatively, bitumen can be upgraded into a synthetic crude oil to meet the demand from a greater number of refineries. Recent industry estimates of the cost of producing upgraded crude oil from the bitumen deposits are $7 to $10 per barrel.

Firms involved in the development of heavy crude oil from the Alberta oil sands have invested approximately $20.0 billion since 1995, with additional previously announced extraction or up-grader projects valued in excess of approximately $30.0 billion over the next ten years. This could provide up to 1.5 million bpd of incremental crude oil production from western Canada. Based upon Enbridge's

survey of producers, refiners and governments conducted in early 2003, the supply of western Canadian crude oil and liquid petroleum is expected to be approximately 2.3 million bpd in 2004, 2.5 million bpd in 2005 and approximately 2.8 million bpd in 2010.

Although substantially all of the crude oil and liquid petroleum delivered through the Lakehead system originates in oilfields in western Canada, the Lakehead system also receives approximately 5% of its receipts from domestic sources including:

- U.S. and Canadian production at Clearbrook, Minnesota through a connection with the North Dakota system;
- U.S. production at Lewiston, Michigan; and
- both U.S. and offshore production in the Chicago area.

Supply from the WCSB, and hence future deliveries on the Lakehead system, is expected to grow over 2003 levels. The near-term growth in supply comes from the completion of the Syncrude and Suncor oil sands expansions and full year production from the AOSP and Cold Lake expansions. Syncrude and Suncor were the original oil sands producers in northern Alberta, and AOSP and Cold Lake expansions are separate producers and producing areas.

During the fourth quarter of 2003, Syncrude announced the completion of the second mining train at its Aurora Mining site, which increases the bitumen mining capacity of the Syncrude project in preparation for its Aurora Upgrader Expansion project. With the completion of this project, Syncrude's synthetic crude oil production capacity is expected to grow to approximately 350,000 bpd by 2005-2006 from approximately 230,000 bpd in 2002.

Suncor began upgrading bitumen from the first phase of its Firebag in-situ oil sands development near the end of 2003. Firebag phase one is expected to reach full production capacity of 35,000 bpd of bitumen production in mid-2005. When complete, the first phase of Firebag and expanded upgrader facilities are expected to bring Suncor's production capacity to 260,000 bpd in 2005, compared with 205,000 bpd in 2002.

The AOSP, owned by Shell Canada Limited (60%), Chevron Canada Limited (20%) and Western Oil Sands L.P. (20%) began commercial operation in June 2003. AOSP consists of oil sands mining and bitumen extraction operations in the Fort McMurray, Alberta region with transportation to the Fort Saskatchewan, Alberta area for upgrading to sweet and heavy synthetic crude oil products. Production from this operation averaged 122,500 bpd during initial operations in 2003. The project has a design capacity to process 155,000 of bpd bitumen.

Imperial Oil Limited recently completed certain phases of its Cold Lake expansion project. This project is expected to increase overall WCSB bitumen production by 30,000 bpd in 2004.

Based on the above noted oil sands activity and its most recent survey of crude oil shippers, the Partnership estimates that deliveries on the Lakehead system will average approximately 1.45 million bpd in 2004, an increase of approximately 100,000 bpd over 2003. The Partnership further believes that the outlook for increased crude oil production in western Canada continues to be positive and will yield additional volumes. In that event, the Partnership should expect increased earnings contributions from the Lakehead system. As an example, an incremental 100,000 bpd of deliveries on the Lakehead system to Chicago would increase operating income by approximately $10.0 million. The Partnership expects that increased capacity utilization on the Lakehead system should support a significant component of its future earnings growth. The timing of growth in the supply of western Canadian crude oil will depend upon the level of crude oil prices, oil drilling activity, the development of the oil sands resource, and access to compatible markets for Canadian oil sands production.

The Partnership's ability to increase deliveries and to expand its Lakehead system in the future will ultimately depend upon numerous factors. The investment levels and related development activities by

crude oil producers in conventional and oil sands production directly impacts the level of supply from the WCSB. Investment levels are influenced by crude oil producers' expectations of crude oil and natural gas prices. Higher crude oil production from the WCSB should result in higher deliveries on the Lakehead system. Deliveries on the Lakehead system are also affected by periodic maintenance, turnarounds and other shutdowns at producing plants that supply crude oil to, or refineries that take delivery from, the System.

The Partnership forecasts that demand for WCSB production will continue to increase in PADD II, which is the U.S. Government's designation for the area that includes the Great Lakes and Midwest regions of the United States. PADD II refinery configurations and crude oil requirements continue to be an attractive market for western Canadian supply. According to the U.S. Department of Energy's Energy Information Administration, demand for crude oil in PADD II increased from approximately 2.75 million bpd in 1984 to approximately 3.2 million bpd in 2002. Over that same period, production of crude oil within PADD II decreased from over 1.0 million bpd to approximately 450,000 bpd. The Partnership expects this gap between PADD II demand and production will continue to widen, contributing to increased demand for imports of crude oil to PADD II.

The closure of Petro-Canada's Oakville, Ontario refinery in late 2004, is expected to result in a decline in the volume of crude oil delivered by the Lakehead system to the province of Ontario and a corresponding increase in deliveries into the PADD II market. Following the announced refinery closure, Lakehead system deliveries into Ontario are expected to remain relatively constant.

In anticipation of improving supply and demand fundamentals, a major expansion of the System was commenced in 1999. This expansion, referred to as the Terrace expansion program, was undertaken at the request of CAPP and consists of a multi-phase expansion of both the Canadian and U.S. portions of the System. With the completion of the Terrace expansion program, as discussed below, approximately 350,000 bpd of incremental capacity has been added to the System.

- Phase I of the Terrace expansion program was completed in 1999 and included construction of a new 36-inch diameter pipeline facility from Kerrobert, Saskatchewan to Clearbrook, Minnesota that added approximately 170,000 bpd of capacity to the System. The Partnership's share of the cost of Phase I was approximately $140.0 million.
- Phase II of the Terrace expansion program was completed in early 2002. Although Phase II did not involve construction on the Lakehead system, the approximate 40,000 bpd increase in capacity of the Enbridge system is expected to benefit the Partnership directly by accommodating additional deliveries on the Lakehead system from the Alberta oil sands.
- Phase III of the Terrace expansion program was substantially complete in early 2003 and is designed primarily to increase heavy crude oil transportation capacity on the Lakehead system between Clearbrook and Superior, Wisconsin by approximately 140,000 bpd. The Partnership's cost of Phase III was approximately $195.0 million.
- Following Phase III of the Terrace expansion program, CAPP has also requested, and the Partnership has undertaken, the expansion of pipeline capacity into the Chicago market. Construction of additional facilities is underway and expected to be in service in 2004. The Partnership's cost is expected to be approximately $80.0 million.

*Competition.* As pipelines are the lowest cost method for intermediate and long haul movement of crude oil over land, the most significant existing competitors for the transportation of western Canadian crude oil are other pipelines. In 2003, the Enbridge system transported approximately 67% of total western Canadian crude oil production; the remainder was either refined in the provinces of Alberta, British Columbia or Saskatchewan, Canada or transported through other pipelines. Of the pipelines transporting western Canadian crude oil out of Canada, the System provides approximately 77% of the total pipeline design capacity. The remaining 23% is shared among five other pipelines

transporting crude oil to British Columbia, Washington, Montana and other states in the northwestern United States.

To address growing demand in the PADD IV and Puget Sound Area of PADD V, several expansions of these competing pipeline systems have been announced. Competing pipelines are owned by Terasen Inc. and transport crude oil from Alberta to British Columbia and Washington State through the Trans Mountain pipeline and from Alberta to the PADD IV region of the U.S. through the Express pipeline.

Terasen Inc. has stated that it plans to apply to the NEB for approval to increase the capacity of its Trans Mountain pipeline from approximately 188,100 bpd to 214,500 bpd. It is anticipated that this expansion will be in service during the third quarter of 2004.

Terasen Inc. has also announced plans to proceed with the expansion of the Express pipeline system from current capacity of 172,000 bpd to 280,000 bpd. Terasen Inc. expects this expansion to be in service by April 2005.

Another competitor, Inter Pipeline Fund, has announced a commercial agreement with four shippers to increase southbound capacity on its Bow River pipeline by 17,000 bpd. This system transports western Canadian crude to markets in Montana. Inter Pipeline Fund expects the new facilities will be in place by May 1, 2004.

The pipeline expansions into PADD IV are in line with management expectations as the PADD IV region indigenous supply continues to decline. Management expects the growing supply from Western Canada to substantially exceed the impact requirements of the PADD IV region, leaving the balance to be transported on the Lakehead system.

In the United States, the Lakehead system encounters competition from other liquid petroleum pipelines and other modes of transportation delivering crude oil and refined products to the refining centers of Minneapolis-St. Paul, Minnesota; Superior, Wisconsin; Chicago, Illinois; Detroit, Michigan; Toledo, Ohio; and the Patoka/Wood River area in southern Illinois.

The following table sets forth Lakehead system average deliveries per day and barrel miles for each of the five-year periods ended December 31, 2003.

| | Deliveries | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| | (thousands of bpd) | | | | |
| **United States** | | | | | |
| Light crude oil | 258 | 266 | 292 | 321 | 299 |
| Medium and heavy crude oil | 741 | 665 | 663 | 630 | 575 |
| NGL | 4 | 6 | 5 | 25 | 24 |
| Total United States | 1,003 | 937 | 960 | 976 | 898 |
| **Ontario** | | | | | |
| Light crude oil | 174 | 171 | 174 | 174 | 282 |
| Medium and heavy crude oil | 68 | 83 | 77 | 85 | 87 |
| NGL | 109 | 111 | 104 | 103 | 102 |
| Total Ontario | 351 | 365 | 355 | 362 | 471 |
| **Total Deliveries** | 1,354 | 1,302 | 1,315 | 1,338 | 1,369 |
| **Barrel miles** (billions per year) | 345 | 341 | 333 | 341 | 350 |

*North Dakota system*

The North Dakota system is a crude oil gathering and transportation system servicing the Williston Basin in North Dakota and Montana. The North Dakota system's crude oil gathering pipelines collect crude oil from points near producing wells in approximately 36 oil fields in North Dakota and Montana and receive Canadian crude oil via an interconnect with an Enbridge gathering system in the province of Saskatchewan, Canada. Most deliveries are made at Clearbrook to the Lakehead system and to a third-party pipeline system. The North Dakota system includes approximately 330 miles of crude oil gathering lines connected to a transportation line that is approximately 620 miles long, with an aggregate working capacity of approximately 84,000 barrels per day. The North Dakota system also has 16 pump stations and 12 terminaling facilities with an aggregate working storage capacity of approximately 700,000 barrels.

*Customers.* Customers of the North Dakota system include producers of crude oil and purchasers of crude oil at the wellhead, such as marketers, that require crude oil gathering and transportation services. Producers range in size from small independent owner/operators to the largest integrated oil companies.

*Supply and Demand.* Like the Lakehead system, the North Dakota system depends upon demand for crude oil in the Great Lakes and Midwest regions of the United States, and the ability of crude oil producers to maintain their crude oil production and exploration activities.

*Competition.* Competitors of the North Dakota system include integrated oil companies, interstate and intrastate pipelines or their affiliates and other crude oil gatherers. Many crude oil producers in the oil fields served by the North Dakota system have alternative gathering facilities available to them or have the ability to build their own facilities.

**Gathering and Processing Segment**

The Partnership owns and operates natural gas gathering, treating and processing systems. These systems purchase and/or gather natural gas from the wellhead, deliver it to plants for treating and/or processing and to intrastate or interstate pipelines for transmission or to wholesale customers such as power plants, industrial customers and local distribution companies.

Natural gas treating involves the removal of hydrogen sulfide, carbon dioxide, water and other substances from raw natural gas so that it will meet the standards for transportation on transmission pipelines. Natural gas processing involves the separation of raw natural gas into residue gas and NGLs. Residue gas is the processed natural gas that ultimately is consumed by end users. NGLs separated from the raw natural gas are either sold and transported as NGL raw mix or further separated through a process known as fractionation, and sold as their individual components, including ethane, propane, butanes and natural gasoline.

Most of the natural gas gathering, treating and processing assets are located in Texas, with additional facilities in Oklahoma, Mississippi, Louisiana, Kansas and Alabama. The major facilities are listed in the following table:

| System | Miles of Pipeline | Active Treating Plants | Active Processing Plants | 2003 Volume (MMBtu/d) |
|---|---|---|---|---|
| East Texas | 2,000 | 2 | 2 | 446,000 |
| Northeast Texas | 1,200 | 4 | 2 | 133,000 |
| North Texas | 2,000 | – | 5 | 198,000 |
| Anadarko | 730 | 1 | 2 | 256,000 |
| South Texas | 175 | 1 | 0 | 38,000 |
| Harmony | 150 | 1 | 1 | 9,000 |
| | | 9 | 12 | |

In total, the Partnership has over 6,200 miles of gathering pipelines, 9 active treating plants and 12 active processing plants. The active treating and processing capacities are currently over 700 MMcf/d and 600 MMcf/d respectively.

The Northeast Texas system is capable of handling sour gas, which has a high hydrogen sulfide and/or carbon dioxide and water content and which requires specialized treating processes before it can be delivered for transportation on downstream pipelines. These treating plants are capable of producing approximately 1,100 long tons of sulfur per day.

The Partnership acquired the North Texas system on December 31, 2003, for approximately $249.7 million, which also includes the buyout of a capital lease of $1.9 million and transaction costs of $1.8 million. Three of the processing plants receive natural gas primarily from a conglomerate formation in the Fort Worth Basin. A fourth plant receives gas from both the conglomerate and Barnett Shale formations in the Fort Worth Basin. The fifth active processing plant processes gas on a third party pipeline under a combination of a fee-for-service and a products-sharing arrangement with that third party pipeline. The system also includes two pipeline systems that gather lean gas in the Barnett Shale region for a fixed gathering fee. The larger of these two pipelines commenced operation in 2001 and has been growing rapidly with the expansion of the Barnett Shale production. Volume data for 2003, noted in the table above, is derived from the records of the prior owner.

*Customers.* Customers of the Partnership's gathering, treating and processing systems include both natural gas purchasers and producers. Purchasers include marketers and large users of natural gas, such as power plants, industrial facilities and local distribution companies. Producers served by the Partnership's systems consist of small, medium and large independent operators and large integrated energy companies. The Partnership sells NGLs resulting from its processing activities to a variety of customers ranging from large petrochemical and refining companies to small regional retail propane distributors.

*Supply and Demand.* Supply for the Partnership's gathering, treating and processing services primarily depends upon the rate of depletion of natural gas reserves and the drilling rate of new wells. Treating services also are affected by the level of impurities in the natural gas gathered. Demand for these services depends upon overall economic conditions and the prices of natural gas and NGLs. Three of the Partnership's larger systems are located in basins that have experienced recent growth in natural gas land purchases, drilling and production.

The East Texas system is primarily located in the East Texas Basin. While production from most regions within this basin have remained flat for several years, the Bossier trend within the East Texas Basin has experienced substantial growth. The Bossier trend is located on the western side of the East Texas system. Bossier production has grown from under 200 MMcf/d in 1997 to over 800 MMcf/d in 2003.

A substantial portion of natural gas on the North Texas system is produced in the Barnett Shale within the Fort Worth Basin Comglomerate. The Fort Worth Basin Conglomerate is a mature zone that is experiencing slow decline. In contrast, the Barnett Shale is one of the most active natural gas plays in North America. While abundant natural gas reserves have been known to exist in the Barnett Shale since the early 1980s, recent technological development in fracturing the shale formation allows commercial production of this gas. Barnett Shale production has risen from 180 MMcf/d to 750 MMcf/d since 2000 with the drilling of over 2,000 wells. Growth in this region is expected for at least ten years.

The Anadarko system is located within the Anadarko Basin. Within that basin, recent growth is occurring in the Granite Wash play, particularly in Hemphill County, Texas.

The Partnership intends to expand its natural gas gathering and processing services through a combination of internal growth and acquisitions, which should provide exposure to incremental supplies

of natural gas at the wellhead, increase opportunities to serve additional customers and allow expansion of the treating and processing businesses.

*Competition.* Competitors of the Partnership's gathering, treating and processing systems include interstate and intrastate pipelines or their affiliates and other natural gas gatherers that gather, treat, process and market natural gas or NGLs. Some of these competitors are substantially larger than the Partnership. Competition for these services varies based upon the location of gathering, treating and processing facilities. Most natural gas producers and owners have alternate gathering, treating and processing facilities available to them. In addition, they have alternatives such as building their own gathering facilities or in some cases, selling their natural gas supplies without treating and processing. In addition to location, competition also varies based upon pricing arrangements and reputation. On the sour gas systems, such as the Partnership's Northeast Texas system, competition is more limited due to the infrastructure required to treat sour gas.

Competition for customers in the marketing of residue gas is based primarily upon the price of the delivered gas, the services offered by the seller and the reliability of the seller in making deliveries. Residue gas also competes on a price basis with alternative fuels such as crude oil and coal, especially for customers that have the capability of using these alternative fuels, and on the basis of local environmental considerations. Competition in the marketing of NGLs comes from other NGL marketing companies, producers/traders, chemical companies and other asset owners.

*Trucking Operations*

Also included in the Partnership's Gathering and Processing segment are its trucking operations. Trucking operations include the transportation of NGLs, crude oil and carbon dioxide by truck and railcar from wellheads to treating, processing and fractionation facilities and to wholesale customers, such as distributors, refiners and chemical facilities. In addition, the trucking operations market these products. These services are provided using 105 trucks and trailers and 48 rail cars, product treating and handling equipment and over 400,000 gallons of NGL storage facilities. In addition, a $CO_2$ plant with 250 tons per day of capacity, takes excess $CO_2$ from hydrogen producers and sells it to a variety of customers.

*Customers.* Most of the customers of the crude oil and NGL trucking operations are wholesale customers, such as refineries and propane distributors. The trucking operations also market products to wholesale customers such as refineries and petrochemical plants.

*Supply and Demand.* The areas served by the Partnership's trucking operations are geographically diverse, and the forces that affect the supply of the products transported vary by region. The supply of these products is affected by crude oil and natural gas prices and production levels. The demand for trucking operations is affected by the demand for NGLs and crude oil by large industrial, refineries, and similar customers in the regions served by this business.

*Competition.* The trucking operations have a number of competitors, including other trucking and railcar operations, pipelines, and, to a lesser extent, marine transportation and alternative fuels. In addition, the marketing activities of the trucking operations have numerous competitors, including marketers of all types and sizes, affiliates of pipelines and independent aggregators.

**Natural Gas Transportation Segment**

Included in this segment are the following major systems that were acquired in connection with the Midcoast system acquisition in October 2002:

- the KPC Pipeline, MidLa Pipeline, AlaTenn Pipeline, and UTOS Pipeline systems, which are FERC regulated natural gas interstate transmission pipelines; and

- the Bamagas Pipeline, Mid-Louisiana Gas Transmission Pipeline and Magnolia Pipeline systems, which are natural gas intrastate transmission pipelines.

Each of these pipeline systems typically consists of a natural gas transmission pipeline as well as various interconnects to other pipelines that serve wholesale customers.

*Customers.* The Partnership's natural gas transportation pipelines serve customers in Alabama, Kansas, Louisiana, Mississippi, Missouri and Tennessee. Customers include large users of natural gas, such as power plants, industrial facilities, local distribution companies, large consumers seeking an alternative to their local distribution company, and shippers of natural gas, such as natural gas producers and marketers.

*Supply and Demand.* As the Partnership's natural gas transportation pipelines generally serve different geographical areas, supply and demand vary in each market.

The Partnership believes that demand for natural gas in the areas served by its natural gas transportation assets generally will remain strong as a result of being located in areas where industrial, commercial or residential growth is occurring. The greatest demand for natural gas transmission services in the markets served by these assets occurs in the winter months.

The table below indicates the capacity in million cubic feet per day of the transmission and wholesale customer pipelines with firm transportation contracts as of December 31, 2003 and the amount of capacity that is reserved under those contracts as of that date.

| Major System | Capacity MMcf/d | Percentage Reserved Under Contract as of December 31, 2003 |
|---|---|---|
| UTOS System | 1,200 | 0% |
| MidLa System | 200 | 88% |
| AlaTenn System | 200 | 49% |
| KPC System | 160 | 94% |
| Bamagas System | 450 | 61% |

The UTOS system is a FERC-regulated offshore pipeline system with a capacity of 1.2 billion cubic feet of natural gas per day that transmits natural gas from offshore platforms to other pipelines onshore for further delivery. The UTOS system's average daily throughput during 2003 was 209,000 MMBtu/d. The FERC has approved the Partnership's negotiated settlement with UTOS shippers, keeping the current rates in effect through 2006.

The MidLa, AlaTenn and Bamagas systems primarily serve industrial corridors and power plants in Louisiana, Alabama and Tennessee. Industries in the area include energy intensive segments of the petrochemical and pulp and paper industries. The Bamagas system in northern Alabama serves two power plants. This system is contiguous with the AlaTenn system and a third party pipeline, allowing for operational flexibility as natural gas could flow between Bamagas and either of the other two systems. The Partnership markets the unused capacity on these systems under both short-term firm and interruptible transportation contracts and long-term firm transportation contracts. These systems are located in areas where opportunities exist to serve new industrial facilities and to make delivery interconnects to alleviate capacity constraints on other third party pipeline systems. The AlaTenn system had contracts representing 21% of its capacity that terminated in 2003. Expiration of the AlaTenn contracts did not have a material impact on the business segment. As of December 31, 2003, approximately 62% of the capacity of the MidLa system is under contract to affiliated entities.

The KPC system has 82% of its capacity reserved under firm transportation contracts extending through 2009 and an additional 12% of its capacity reserved under contracts extending through 2017. The KPC system's primary customers are local distribution companies.

The Partnership's long-term financial condition depends on the continued availability of natural gas for transportation to the markets served by its systems. Existing customers may not extend their contracts if the availability of natural gas from the Mid-Continent and Gulf Coast producing regions was to decline and if the cost of transporting natural gas from other producing regions through other pipelines into the areas served by the Partnership was to render the delivered cost of natural gas uneconomical. The Partnership may be unable to find additional customers to replace the lost demand or transportation fees.

*Competition.* Because pipelines are generally the only practical mode of transportation for natural gas over land, the most significant competitors of the Partnership's natural gas transportation pipelines are other pipelines. Pipelines typically compete with each other based on location, capacity, price and reliability. Many of the large wholesale customers served by the Partnership have multiple pipelines connected or adjacent to their facilities. Accordingly, many of these customers have the ability to purchase natural gas directly from a number of pipelines or third parties that may hold capacity on the various pipelines.

**Marketing Segment**

The natural gas Marketing segment provides natural gas supply, transportation, balancing and sales services to producers and wholesale customers on the Partnership's gathering, transmission and wholesale customer pipelines, as well as interconnected third-party pipelines. In general, the Marketing segment makes natural gas purchases from the Partnership's gathering systems and from other producers and marketers. It then makes natural gas sales to wholesale customers on the Partnership's transmission and wholesale customer pipelines. The Marketing segment also arranges transportation for wholesale customers, provides storage services, and contracts capacity on certain third-party pipeline systems.

Natural gas purchased and sold by the Marketing segment is typically priced based upon a published daily or monthly price index. Sales to wholesale customers incorporate a pass-through charge for costs of transportation and generally include an additional margin.

The Marketing segment has numerous competitors, including large natural gas marketing companies, marketing affiliates of pipelines, major oil and gas producers, independent aggregators and regional marketing companies.

**RISK FACTORS**

The following risk factors should be read in conjunction with the other sections in this Report on Form 10-K.

**Transportation Volumes**

The Partnership's financial performance 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 and demand factors in the markets these systems serve, or otherwise, can directly and adversely affect the Partnership's revenues and results of operations. See "Business Segments—Liquids Transportation Segment—Lakehead system—Supply and Demand";—"Business Segments—Gathering and Processing Segment—Supply and Demand"; and "Business Segments—Natural Gas Transportation Segment—Supply and Demand".

**Regulation**

The tariff rates charged by several of the Partnership's systems are regulated by the FERC or various state regulatory agencies. If the Partnership's tariffs are reduced by one of these regulatory

agencies on its own initiative or as a result of challenges by third parties, the profitability of the Partnership's pipeline businesses may suffer. If the Partnership is permitted to raise its tariffs for a particular pipeline, there may be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect. Furthermore, competition from other pipeline systems may prevent the Partnership from raising its tariff rates even if regulatory agencies permit the Partnership to do so. The regulatory agencies that regulate the Partnership's systems periodically propose and implement new rules and regulations, terms and conditions of services and rates subject to their jurisdiction. New initiatives or orders may adversely affect the tariff rates charged for services by the Partnership. Several states, including Oklahoma and Texas, are taking a more active role in the rate and service regulation of intrastate natural gas systems. Increased state regulation could adversely impact the Partnership's natural gas systems.

**Competition with Enbridge**

Enbridge has agreed with the Partnership that, so long as an affiliate of Enbridge is the general partner of the Partnership, Enbridge and its subsidiaries may not engage in or acquire any business that is in direct material competition with the businesses of the Partnership, subject to the following exceptions:

- Enbridge and its subsidiaries are not restricted from continuing to engage in businesses, including the normal development of such businesses, in which they were engaged at the time of the Partnership's initial public offering in December 1991;
- such restriction is limited geographically only to those routes and products for which the Partnership provided transportation at the time of the Partnership's initial public offering;
- Enbridge and its subsidiaries are not prohibited from acquiring any competitive business as part of a larger acquisition, so long as the majority of the value of the business or assets acquired, in Enbridge's reasonable judgment, is not attributable to the competitive business; and
- Enbridge and its subsidiaries are not prohibited from acquiring any competitive business if that business is first offered for acquisition to the Partnership and the Partnership fails to approve, after submission to a vote of unitholders, the making of the acquisition.

As the Partnership was not engaged in any aspect of the natural gas business at the time of its initial public offering, Enbridge and its subsidiaries are not restricted from competing with the Partnership in any aspects of the natural gas business. In addition, Enbridge and its subsidiaries would be permitted to transport crude oil and liquid petroleum over routes that are not the same as the Lakehead system even if such transportation is in direct material competition with the business of the Partnership.

This agreement also expressly permitted the reversal by Enbridge in 1999 of one of its pipelines that extends from Sarnia, Ontario to Montreal, Quebec. As a result of this reversal, Enbridge competes with the Partnership to supply crude oil to the Ontario, Canada market. This competition from Enbridge has reduced the Partnership's deliveries of crude oil to Ontario.

**Market Risk**

As part of its natural gas marketing activities, the Partnership purchases natural gas at prevailing market prices. Following the purchase of natural gas, the Partnership generally resells it at a higher price under a sales contract that has comparable terms to the purchase contract, including any price

escalation provisions. The profitability of the Partnership's natural gas operations may be affected by the following factors:

- the ability to negotiate, on a timely basis, natural gas purchase and sales agreements in changing markets;
- reluctance of wholesale customers to enter into long-term purchase contracts;
- consumers' willingness to use other fuels when natural gas prices increase significantly;
- timing of imbalance or volume discrepancy corrections and their impact on financial results; and
- the ability of its customers to make timely payment, customer default, and concentration of receivables with third parties in the energy sector.

**Environmental and Safety Regulations**

The Partnership's pipeline, gathering, processing and trucking operations are subject to federal and state laws and regulations relating to environmental protection and operational safety. Liquid petroleum and natural gas transportation and processing operations always involve the risk of costs or liabilities related to environmental protection and operational safety matters. It is also possible that the Partnership will have to pay amounts in the future because of changes in environmental and safety laws or enforcement policies or claims for environmentally related damage to persons or property. The Partnership may not be able to recover these costs from insurance, higher fees or through higher pipeline tariffs rates.

**Kyoto Protocol**

In December 2002, Canada ratified the Kyoto Protocol, a 1997 treaty designed to reduce greenhouse gas emissions to 6% below 1990 levels. The Partnership and Enbridge are assessing and evaluating the Canadian federal government's approach to implementation. Until these plans become certain, the Partnership will not be able to quantify the impact, if any, of the Kyoto Protocol on its operations. The Partnership is encouraged by reactions by western Canadian crude oil producers to Kyoto, particularly their commitment to oil sands development, which supports the outlook for the sustainability of crude oil supplies for the Lakehead system.

**Transportation of Hazardous Materials**

Operation of complex liquid petroleum and natural gas transportation and processing systems involve risks, hazards and uncertainties, such as operational hazards and unforeseen interruptions caused by events beyond the control of the Partnership. For example, the East Texas, Northeast Texas and South Texas systems, and some facilities in Mississippi, handle or transport large quantities of natural gas containing hydrogen sulfide, a highly toxic substance when workers or the public are exposed above safe limits. Some of these pipelines are located in or near densely populated areas. A major release of natural gas containing hydrogen sulfide from one of these pipelines or plants could result in severe injuries or death, as well as severe environmental damage. Insurance proceeds may not be adequate to cover all liabilities incurred or lost revenues.

**Growth Strategy**

The acquisition of complementary energy delivery assets is a focus of the Partnership's strategic plan. Acquisitions may present various risks and challenges, including the risks of incorrect assumptions in the acquisition models, effective integration of the acquired operations and diversion of management's attention from existing operations. In addition, the Partnership may be unable to identify

acquisition targets and consummate acquisitions in the future or be unable to raise, on terms acceptable to it, any debt or equity financing that may be required for any such acquisition.

**Oil Measurement Losses**

Oil measurement losses occur as part of the normal operating conditions associated with the Partnership's liquid petroleum pipelines. The three types of oil measurement losses include:

- physical losses, which occur through evaporation, shrinkage, differences in measurement between receipt and delivery locations and other operational incidents;
- degradation losses, which result from mixing at the interface between higher quality light crude oil and lower quality heavy crude oil in pipelines; and
- revaluation losses, which are a function of crude oil prices, the level of the carrier's inventory and the inventory positions of customers.

There are inherent difficulties in quantifying oil measurement losses because physical measurements of volumes are not practical, as products continuously move through the Partnership's pipelines and virtually all of these pipelines are located underground. Quantifying oil measurement losses is especially difficult for the Partnership because of the length of the Lakehead system and the number of different grades of crude oil and types of crude oil products it carries. The Partnership utilizes engineering-based models and operational assumptions to estimate product volumes in its system and associated oil measurement losses. If there is a material change in these assumptions, it may result in a revision of oil measurement loss estimates.

**Conflicts of Interest**

Enbridge indirectly owns all of the stock of the general partner of the Partnership and elects all of its directors. Furthermore, some of the Partnership's directors and officers are also directors and officers of Enbridge. Consequently, conflicts of interest could arise between the Partnership's unitholders and Enbridge.

The Partnership's partnership agreement limits the fiduciary duties of the general partner of the Partnership to the Partnership's unitholders. These restrictions allow the general partner of the Partnership to resolve conflicts of interest by considering the interests of all the parties to the conflict, including Enbridge Management's interests, the interests of the Partnership and the General Partner. Additionally, these limitations reduce the rights of the Partnership's unitholders under the Partnership's partnership agreement to sue the general partner of the Partnership or Enbridge Management, its delegee, should its directors or officers act in a way that, were it not for these limitations of liability, would constitute breaches of their fiduciary duties.

**State Tax Legislation**

State tax legislation resulting in the imposition of a partnership-level income tax on the Partnership could reduce the cash distributions on the common units and the value of the i-units that the Partnership will distribute quarterly to Enbridge Management. Currently, state-level income taxation of the Partnership is not significant. However, many states have considered increasing their taxes, including some partnership-level taxes, in their recent legislative processes. The enactment of significant legislation imposing partnership-level income taxes would cause a reduction in the value of the partnership units.

**TITLE TO PROPERTIES**

The Partnership currently conducts business and owns properties located in 20 states: Alabama, Arkansas, Florida, Georgia, Illinois, Indiana, Kansas, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, New York, North Carolina, North Dakota, Oklahoma, Texas, Tennessee and Wisconsin. In general, the Partnership's systems are located on land owned by others and are operated under perpetual easements and rights of way, licenses or permits that have been granted by private land owners, public authorities, railways or public utilities. The pumping stations, tanks, terminals and certain other facilities of these systems are located on land that is owned by the Partnership, except for five pumping stations that are situated on land owned by others and used by the Partnership under easements or permits.

Substantially all of the Lakehead system assets are subject to a first mortgage securing indebtedness of the Lakehead Partnership, a principal operating subsidiary of the Partnership.

In connection with the acquisition of the Midcoast system, certain filings with respect to title records were not made prior to the closing of the transaction. The Partnership or its subsidiaries have now made these filings. Although title to these properties is subject to encumbrances in some cases, the Partnership believes that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of the Partnership's business.

**REGULATION**

**Regulation by the FERC of Interstate Common Carrier Liquids Pipelines**

The Lakehead and North Dakota systems are interstate common carrier liquids pipelines subject to regulation by the FERC under the ICA. As interstate common carriers, these pipelines provide service to any shipper who requests transportation services, provided that products tendered for transportation satisfy the conditions and specifications contained in the applicable tariff. The ICA requires the Partnership to maintain tariffs on file with the FERC that set forth the rates it charges for providing transportation services on its interstate common carrier pipelines, as well as the rules and regulations governing these services.

The ICA gives the FERC the authority to regulate the rates the Partnership charges for service on its interstate common carrier pipelines. The ICA requires, among other things, that such rates be "just and reasonable" and nondiscriminatory. The ICA permits interested persons to challenge new or proposed changes to existing rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to order a hearing concerning such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff during the term of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained for a period of up to two years prior to the filing of a complaint.

On October 24, 1992, Congress passed the Energy Policy Act, which deemed petroleum pipeline rates that were in effect for the 365-day period ending on the date of enactment and had not been subject to complaint, protest or investigation, to be just and reasonable under the ICA (i.e., "grandfathered"). The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. In order to challenge grandfathered rates, a party would have to show that it was previously contractually barred from challenging the rates or that the economic circumstances or the nature of service underlying the rate had substantially changed or that the rate was unduly discriminatory or preferential. These grandfathering provisions and the circumstances under which they may be challenged have received only limited attention from the

FERC, causing a degree of uncertainty as to their application and scope. The North Dakota system is largely covered by the grandfathering provisions of the Energy Policy Act. The Lakehead system is not covered by the grandfathering provisions of the Energy Policy Act.

The Energy Policy Act required the FERC to issue rules establishing a simplified and generally applicable ratemaking methodology for petroleum pipelines, and to streamline procedures in petroleum pipeline proceedings. The FERC responded to this mandate by issuing Order No. 561, which, among other things, adopted an indexing rate methodology for petroleum pipelines. Under the regulations, which became effective January 1, 1995, petroleum pipelines are able to change their rates within prescribed ceiling levels that are tied to an inflation index. Rate increases made within the ceiling levels may be protested, but such protests must show that the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs. If the indexing methodology results in a reduced ceiling level that is lower than a pipeline's filed rate, Order No. 561 requires the pipeline to reduce its rate to comply with the lower ceiling. A pipeline may not be required to reduce its rate below the level grandfathered under the Energy Policy Act. Under Order No. 561, a pipeline must, as a general rule, utilize the indexing methodology to change its rates. The FERC, however, retained cost-of-service ratemaking, market-based rates and settlement as alternatives to the indexing approach, which alternatives may be used in certain specified circumstances.

The Partnership believes that the rates charged for transportation services on its interstate common carrier liquids pipelines are just and reasonable under the ICA. However, because the rates that the Partnership charges are subject to review upon an appropriately supported complaint, the Partnership cannot predict what rates it will be allowed to charge in the future for service on its interstate common carrier liquids pipelines. Furthermore, because rates charged for transportation services must be competitive with those charged by other transporters, the rates set forth in the Partnership's tariffs will be determined based on competitive factors in addition to regulatory considerations.

*Allowance for Income Taxes in Rates*

In a 1995 decision involving the Partnership's Lakehead system, the FERC partially disallowed the inclusion of income taxes in the cost of service for the Lakehead system. Subsequent appeals of this ruling were resolved by settlement and were not adjudicated. In another FERC proceeding involving SFPP, L.P., an unrelated pipeline limited partnership, the FERC held that the limited partnership may not claim an income tax allowance for income attributable to non-corporate partners, both individuals and other entities. SFPP and other parties to the proceeding have appealed the FERC's orders to the U.S. Court of Appeals for the District of Columbia Circuit. Arguments in the appeals were completed in the fall of 2003 and the court's decision is pending. The effect of the FERC's policy stated in the Lakehead proceeding (and the results of the ongoing SFPP litigation regarding that policy) on the Partnership is uncertain. Parties may challenge rates on the Partnership's common carrier interstate liquids pipelines on the basis that its rates are not just and reasonable because the level of income tax allowance in its rates exceeds that permitted under the Lakehead and/or SFPP decisions. It is not possible to predict the likelihood that parties will assert such challenges or that such challenges would succeed. If the Court of Appeals were to follow the Lakehead decision, and challenges were to be raised and succeeded, application of the Lakehead/SFPP and related rulings would reduce permissible income tax allowance in any cost-of-service based rate, to the extent income tax is attributed to partnership interests held by individuals and other non-corporate entities.

**Regulation by the FERC of Interstate Natural Gas Pipelines**

The Partnership's AlaTenn, MidLa, KPC and UTOS systems are interstate natural gas pipelines regulated by the FERC under the NGA, and the NGPA. Each system operates under separate FERC-approved tariffs that establish rates, terms and conditions under which each system provides

service to its customers. In addition, the FERC's authority over natural gas companies that provide natural gas pipeline transportation services in interstate commerce includes:

- the certification and construction of new facilities;
- the extension or abandonment of services and facilities;
- the maintenance of accounts and records;
- the acquisition and disposition of facilities;
- the initiation and discontinuation of services;
- conduct and relationship with energy affiliates; and
- various other matters.

Tariff changes can only be implemented upon approval by the FERC. There are two primary methods by which the rates, terms and conditions of service of an interstate pipeline may be changed. Under the first method, the company voluntarily seeks a tariff change by making a tariff filing with the FERC, which justifies the proposed tariff change and provides notice, generally 30 days, to the appropriate parties. If the FERC determines that a proposed change may not be just and reasonable as required by the NGA, then the FERC may suspend such change for up to five months and set the matter for an administrative hearing. Subsequent to any suspension period ordered by the FERC, the proposed change may be placed into effect by the company pending final FERC approval. In most cases, a proposed rate increase is placed into effect before a final FERC determination on such rate increase, and the proposed increase is collected subject to refund (plus interest). Under the second method, the FERC may, on its own motion or based on a complaint, initiate a proceeding seeking to compel the company to change its rates, terms and/or conditions of service. If the FERC determines that the existing rates, terms and/or conditions of service are unjust, unreasonable, unduly discriminatory or preferential, then any rate reduction or change that it orders generally will be effective prospectively from the date of the FERC order requiring this change.

In addition to its jurisdiction over the UTOS system under the NGA and the NGPA, the FERC also has jurisdiction over the UTOS system and the Partnership's offshore gathering systems under the Outer Continental Shelf Lands Act. The OCSLA requires that all pipelines operating on or across the outer continental shelf, referred to as the "OCS," provide open-access, non-discriminatory transportation service on their systems. In 2000, the FERC issued Order Nos. 639 and 639-A, referred to collectively as "Order No. 639," which required gas service providers operating on the OCS to make public their rates, terms and conditions of service. The purpose of Order No. 639 was to provide regulators and other interested parties with sufficient information to detect and to remedy discriminatory conduct by such service providers. In January 2002, the U.S. District Court for the District of Columbia Circuit permanently enjoined the FERC from enforcing Order No. 639, on the basis that the FERC did not possess the requisite rule-making authority under the OCSLA for issuing Order No. 639. The U.S. Court of Appeals for the District of Columbia Circuit affirmed the lower courts ruling by its October 10, 2003 Order, which is now final.

On November 25, 2003 the FERC issued Order No. 2004 governing the Standards of Conduct for Transmission Providers (interstate pipelines). The new standards provide that (1) a Transmission Providers' employees engaged in transmission system operations must function independently from the Transmission Providers' sales or marketing employees and from any employees of their Energy Affiliates; and (2) a Transmission Provider must treat all transmission customers, affiliated and non-affiliated, on a non-discriminatory basis, and cannot operate its transmission system to benefit preferentially an Energy Affiliate. The rule defined an "Energy Affiliate" as any affiliated company that engages in or is involved in transmission transactions in U.S. energy or transmission markets, or one that manages the capacity of a Transmission Provider, or buys, sales, trades or administers natural gas

in U.S. markets, or engages in financial transactions relating to the sale or transmission of natural gas in U.S. markets. Affiliated interstate pipelines are not considered Energy Affiliates. However, gatherers, processors, intrastate and Hinshaw pipelines are considered Energy Affiliates, in addition to marketing affiliates. The new rule will result in additional costs and increased difficulty in the Partnership's operations, although the Partnership does not believe that these regulations will affect it any differently than any other interstate pipelines with which its competes.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by the FERC and Congress will continue, especially in light of alleged market power abuse by marketing affiliates of certain large interstate pipeline companies.

**Intrastate Pipeline Regulation**

The Partnership's intrastate liquids and natural gas pipeline operations generally are not subject to rate regulation by the FERC, but they are subject to regulation by various agencies of the states in which they are located. However, to the extent that the Partnership's intrastate pipeline systems deliver natural gas into interstate commerce, the rates, terms and conditions of such transportation service are subject to FERC jurisdiction under Section 311 of the NGPA, which regulates, among other things, the provision of transportation services by an intrastate natural gas pipeline making deliveries on behalf of a local distribution company or an interstate natural gas pipeline. Most states have agencies that possess the authority to review and authorize natural gas transportation transactions and the construction, acquisition, abandonment and interconnection of physical facilities. Some states also have state agencies that regulate transportation rates, service terms and conditions and contract pricing to ensure their reasonableness and to ensure that the intrastate pipeline companies that they regulate do not discriminate among similarly situated customers.

**Natural Gas Gathering Pipeline Regulation**

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC under the NGA. The Partnership owns certain natural gas pipelines that it believes meet the traditional tests the FERC has used to establish a pipeline's status as a gatherer not subject to the FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, but historically has not entailed rate regulation. Natural gas gathering may receive greater regulatory scrutiny at both the state and federal levels now that the FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies and a number of such companies have transferred gathering facilities to unregulated affiliates. For example, the Texas Railroad Commission has approved changes to its regulations governing transportation and gathering services performed by intrastate pipelines and gatherers, which prohibit such entities from unduly discriminating in favor of their affiliates. Many of the producing states have adopted some form of complaint-based regulation that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering access and rate discrimination. The Partnership's gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. The Partnership's gathering operations also may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. The Partnership cannot predict what effect, if any, such changes might have on its operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

**Sales of Natural Gas, Crude Oil, Condensate and Natural Gas Liquids**

The price at which the Partnership sells natural gas currently is not subject to federal or state regulation except for certain systems in Texas. The Partnership's sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive federal and state regulation. The FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies, that remain subject to the FERC's jurisdiction. These initiatives also may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry and these initiatives generally reflect more light-handed regulation. The Partnership cannot predict the ultimate impact of these regulatory changes to its natural gas marketing operations. Some of the FERC's more recent proposals may adversely affect the availability and reliability of interruptible transportation service on interstate pipelines. The Partnership does not believe that it will be affected by any such FERC action in a manner that is materially different than other natural gas marketers with whom it competes.

The Partnership's sales of crude oil, condensate and natural gas liquids currently are not regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to the FERC's jurisdiction under the ICA. Certain regulations implemented by the FERC in recent years could increase the cost of transportation service on certain petroleum products pipelines. However, the Partnership does not believe that these regulations affect it any differently than other marketers of these products.

**Other Regulation**

The governments of the United States and Canada have, by treaty, agreed to ensure nondiscriminatory treatment for the passage of oil and natural gas through the pipelines of one country across the territory of the other. Individual border crossing points require U.S. government permits that may be terminated or amended at the will of the U.S. government. These permits provide that pipelines may be inspected by or subject to orders issued by federal or state government agencies.

**Tariffs and Rate Cases**

*Lakehead system*

Under published tariffs at December 31, 2003 (including the tariff surcharges related to Lakehead system expansions), for transportation on the Lakehead system, the rates for transportation of light crude oil from Neche, North Dakota, where the System enters the U.S. (unless otherwise stated), to principal delivery points are set forth below.

| | Published Tariff Per Barrel |
|---|---|
| To Clearbrook, Minnesota | $0.171 |
| To Superior, Wisconsin | $0.332 |
| To Chicago, Illinois area | $0.676 |
| To Marysville, Michigan area | $0.807 |
| To Buffalo, New York area | $0.826 |
| Chicago to the international border near Marysville | $0.301 |

The rates at December 31, 2003 for medium and heavy crude oils are higher, and those for NGLs are lower than the rates set forth in the table to compensate for differences in the costs of shipping different types and grades of liquid hydrocarbons. The Partnership periodically adjusts its tariff rates as allowed under the FERC's indexing methodology and the tariff agreement described below.

Under a tariff agreement approved by the FERC in 1998, the Partnership implemented a tariff surcharge for the Terrace expansion program of approximately $0.013 per barrel for light crude oil from the Canadian border to Chicago. On April 1, 2001, pursuant to an agreement between the Partnership and Enbridge Pipelines, the Partnership's share of the surcharge was increased to $0.026 per barrel. Subject to any adjustments permitted under the tariff agreement, this surcharge will be effective until April 1, 2004, when the surcharge to the Partnership will change to $0.007 per barrel. This new tariff is expected to be in effect for the next six years, after which time it will return to $0.013 per barrel for the Partnership through 2013, the term of the agreement.

*Natural Gas Transportation Systems*

Tariff rates on the FERC-regulated natural gas pipelines vary by pipeline and, in the case of KPC, by receipt point and delivery point. The rates charged for transmission of natural gas on pipelines not regulated by the FERC, or a state agency, are established by competitive forces. Please read "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

**Environmental and Safety Regulation**

*General*

The Partnership's transmission and gathering pipelines and storage and processing facilities are subject to extensive federal and state environmental, operational and safety regulation. The failure to comply with such rules and regulations can result in substantial penalties and/or enforcement actions and added operational costs. However, the added costs imposed by regulations are generally no different than those imposed on the Partnership's competitors.

*Pipeline Safety and Transportation Regulation*

The Partnership's transmission and non-rural gathering pipelines are subject to regulation by the U.S. Department Of Transportation, under the Title 49 United States Code (Pipeline Safety Act) relating to the design, installation, testing, construction, operation, replacement and management of transmission and non-rural gathering pipeline facilities. Periodically the PSA has been reauthorized and amended, imposing new mandates on the regulator to promulgate new regulations, imposing direct mandates on operators of pipelines.

On December 17, 2002 the "Pipeline Safety Improvement Act of 2002" (Act) was signed into legislation reauthorizing and amending the PSA in several important respects.

Following requirements of mandates in the PSA, the DOT has issued regulations requiring operators of hazardous liquid and natural gas transmission pipelines subject to the regulations to assess, evaluate, repair and validate, through a comprehensive analysis, the integrity of pipeline segments that, in the event of a leak or failure, could affect a high consequence area. HCA's for liquid pipelines have been defined as: populated areas, areas unusually sensitive to environmental damage and commercially navigable waterways. For natural gas pipelines, HCA's are defined as segments in proximity to population density or places of public congregation.

The DOT has issued recent rules on requirements to submit maps, additional reports and enhance operator personnel qualification programs. The Partnership anticipates new rules regulating pipeline security, contractor drug testing, inspection, public awareness programs and annual information reporting. Additionally, revised regulations are anticipated that may impose new federal mandates on certain non-DOT jurisdictional pipelines currently classified as "rural gathering lines". Pending specific proposed regulations, the Partnership is not certain of the effect or costs that the new requirements may have on its operations.

Various states in which the Partnership operates have authority to issue additional regulations affecting intrastate or gathering pipeline design, safety and operational requirements.

The Partnership's trucking and railcar operations are also subject to safety and permitting regulation by the DOT and state agencies with regard to the safe transportation of hazardous materials and other materials.

The Partnership believes that its pipeline, trucking and railcar operations are in substantial compliance with applicable operational and safety requirements. In instances of non-compliance, the Partnership has taken actions to remediate the situations. Nevertheless, significant expenses could be incurred in the future if additional safety measures are required or if safety standards are raised and exceed the capabilities of its current pipeline control system or other safety equipment.

*Pressure Restrictions on the Lakehead system*

Following a leak that occurred on the Lakehead system in July 2002, the federal Office of Pipeline Safety imposed pressure restrictions on the entire line that was affected. The Partnership then proposed a Return-to-Service-plan, which included implementing certain internal inspections and other strategies to verify the integrity of the pipeline in the affected area. During 2003, the OPS removed the majority of the restrictions, while directing that a small restriction remain in place in one area of the line in Minnesota. OPS has indicated that this restriction is expected to be removed following another internal inspection and associated repairs in 2005, and after evaluation of the interim performance of the line and the Partnership's progress in implementing its risk management plan. Based on the Partnership's forecast of deliveries for 2004, the remaining ten percent pressure restriction is not expected to negatively impact its earnings.

*Environmental Regulation*

*General.* The Partnership's operations are subject to complex federal, state, and local laws and regulations relating to the protection of health and the environment, including laws and regulations which govern the handling, storage and release of crude oil and other liquid hydrocarbon materials or emissions from natural gas compression facilities. As with the pipeline and processing industry in general, complying with current and anticipated environmental laws and regulations increases the overall cost of doing business, including its capital costs to construct, maintain, and upgrade equipment and facilities. While these laws and regulations affect its maintenance capital expenditures and net income, the Partnership believes that they do not affect its competitive position since the operations of its competitors are similarly affected.

In addition to compliance costs, violations of environmental laws or regulations can result in the imposition of significant administrative, civil and criminal fines and penalties and, in some instances, injunctions banning or delaying certain activities. The Partnership believes that its operations are in substantial compliance with applicable environmental laws and regulations.

There are also risks of accidental releases into the environment associated with the Partnership's operations, such as leaks or spills of crude oil, liquids or natural gas or other substances from its pipelines or storage facilities. Such accidental releases could, to the extent not insured, subject the Partnership to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage, and fines, penalties, or damages for related violations of environmental laws or regulations.

Although the Partnership is entitled in certain circumstances to indemnification from third parties for environmental liabilities relating to assets it acquired from those parties, these contractual indemnification rights are limited and, accordingly, the Partnership may be required to bear substantial

environmental expenses. However, the Partnership believes that through its due diligence process substantial issues are identified and managed.

*Air and Water Emissions.* The Partnership's operations are subject to the federal Clean Air Act and the federal Clean Water Act and comparable state and local statutes. The Partnership anticipates, therefore, that it will incur certain capital expenses in the next several years for air pollution control equipment and spill prevention measures in connection with maintaining existing facilities and obtaining permits and approvals for any new or acquired facilities. The Partnership believes compliance with these CAA and CWA requirements will not have a material adverse effect on its financial condition.

An operating permit excursion occurred at the Bryans' Mill Treating Plant in 2003 where a significant amount (approximately 7000 tons) of sulphur-dioxide (SO2) was released above permit limits and was self-reported to the applicable state agency. A plant catalyst bed was found to be deficient and the problem has been corrected. Administrative reporting systems and operations procedures have been augmented for the prevention of future occurrences. An accrual has been made for the amount of the expected penalty.

The OPA was enacted in 1990 and amends parts of the CWA and other statutes as they pertain to the prevention of and response to oil spills. Under the OPA, the Partnership could be subject to strict, joint and potentially unlimited liability for removal costs and other consequences of an oil spill from its facilities into navigable waters, along shorelines or in an exclusive economic zone of the United States. The OPA also imposes certain spill prevention, control and countermeasure requirements for many of the Partnership's non-pipeline facilities, such as the preparation of detailed oil spill emergency response plans and the construction of dikes or other containment structures to prevent contamination of navigable or other waters in the event of an oil overflow, rupture or leak. For the Partnership's pipeline facilities, the OPA imposes requirements for emergency plans to be prepared, submitted and approved by the DOT. For the Partnership's non-transportation facilities, such as storage tanks, the OPA regulations are promulgated by the EPA. The Partnership believes it is in material compliance with these laws and promulgating regulations.

*Hazardous Substances and Waste Management.* The federal CERCLA (also known as the "Superfund" law), and similar state laws, impose liability without regard to fault or the legality of the original conduct, on certain classes of persons, including the owners or operators of waste disposal sites and companies that disposed or arranged for disposal of hazardous substances found at such sites. The Partnership may generate some wastes that fall within the definition of a "hazardous substance." The Partnership may, therefore, be jointly and severally liable under CERCLA for all or part of any costs required cleaning up and restoring sites at which such wastes have been disposed. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Analogous state laws may apply to a broader range of substances than CERCLA and, in some instances, may offer fewer exemptions from liability. The Partnership has not received any notification that it may be potentially responsible for cleanup costs under CERCLA or similar state laws.

*Employee Health and Safety.* The workplaces associated with the Partnership's operations are subject to the requirements of the federal OSHA and comparable state statutes that regulate worker health and safety. The Partnership has an ongoing safety-training program for its employees and believes that its operations are in compliance with applicable occupational health and safety requirements, including general industry standards, record keeping requirements, monitoring of occupational exposure to regulated substances, and hazard communication standards.

*Site Remediation.* The Partnership owns and operates a number of pipelines, gathering systems, storage facilities and processing facilities that have been used to transport, distribute, store and process

crude oil, natural gas and other petroleum products. The Partnership or its predecessors have operated certain facilities, including the Lakehead system since 1950. Many of the other facilities of the Partnership were previously owned and operated by third parties whose handling, disposal and release of petroleum and waste materials were not under the Partnership's control. The age of the facilities, combined with the past operating and waste disposal practices, which were standard for the industry and regulatory regime at the time, have resulted in soil and groundwater contamination at some facilities due to historical spills and releases. Such contamination is not unusual within the natural gas and petroleum industry. Historical contamination found on, under or originating from the Partnership's properties may be subject to CERCLA, RCRA and analogous state laws as described above. Under these laws, the Partnership could incur substantial expense to remediate such contamination, including contamination caused by prior owners and operators. In addition, Enbridge Management, as the entity with managerial responsibility for the Partnership, could also be liable for such costs to the extent that the Partnership is unable to fulfill its obligations. The Partnership has conducted site investigations at some of its facilities to assess historical environmental issues, and it is currently addressing soil and groundwater contamination at various facilities through remediation and monitoring programs, with oversight by the applicable government agencies where appropriate.

In connection with the Partnership's acquisition of the Midcoast system from Enbridge, the General Partner agreed to indemnify the Partnership and other related persons for certain environmental liabilities of which the General Partner had knowledge. Pursuant to the contribution agreement related to this acquisition, the General Partner will not be required to indemnify the Partnership until the aggregate liabilities, including environmental liabilities, exceed $20.0 million, and the General Partner's aggregate liability, including environmental liabilities, may not exceed, with certain exceptions, $150.0 million. The Partnership will be liable for any environmental conditions related to the acquired systems that were not known to the General Partner or were disclosed under the contribution agreement between the General Partner and the Partnership. In addition, the Partnership will be liable for all removal, remediation and disposal of all asbestos-containing materials and all naturally occurring radioactive materials associated with the Northeast Texas system and for which the General Partner is liable to the prior owner of that system.

Although the Partnership believes these indemnities and conditions provide valuable protection, it is possible that the sellers from whom these assets were purchased will not be able to satisfy their indemnity obligations or their remedial obligations related to retained liabilities or properties. In this case, it is possible that governmental agencies or third party claimants could assert that the Partnership may be liable or bears some responsibility for such obligations.

**EMPLOYEES**

Neither the Partnership, nor Enbridge Management, has any employees. The General Partner has delegated to Enbridge Management, pursuant to the Delegation of Control Agreement, substantially all of the responsibility for the day-to-day management and operation of the Partnership. The General Partner, however, retains certain functions and approval rights over the operations of the Partnership. To fulfill its management obligations, Enbridge Management has entered into agreements with Enbridge and several of its affiliates to provide Enbridge Management with the necessary services and support personnel, who act on Enbridge Management's behalf as its agents. The Partnership is ultimately responsible for reimbursing these service providers based on the costs that they incur in performing these services.

**INSURANCE**

The operations of the Partnership are subject to many hazards inherent in the liquid petroleum and natural gas gathering, processing and transmission industry. The Partnership maintains insurance coverage for its operations and properties considered to be customary in the industry. There can be no assurance, however, that insurance coverages maintained by the Partnership will be available or adequate for any particular risk or loss or that it will be able to maintain adequate insurance in the future at rates it considers reasonable. Although management believes that the assets of the Partnership are adequately covered by insurance, a substantial uninsured loss could have a material adverse effect on the Partnership's financial position, results of operations or cash flows.

**CAPITAL EXPENDITURES**

In 2003, the Partnership made capital expenditures of $129.3 million, of which $65.9 million was for pipeline system enhancements, $28.8 million for core maintenance activities and $34.6 million for the Terrace expansion program. See also "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Cash Requirements for Future Growth—Capital Spending."

**TAXATION**

For U.S. federal and state income tax purposes, the Partnership is not a taxable entity. Federal and state income taxes on Partnership taxable income are borne by the individual partners through the allocation of Partnership taxable income. Such taxable income may vary substantially from net income reported in the statement of income.

**OTHER MATTERS**

In October 2002, the Partnership acquired the Midcoast, Northeast Texas, and South Texas systems from the General Partner (the "Acquisition"). A committee of independent members of the Board of Directors of the General Partner negotiated the purchase price and terms of the Acquisition on behalf of the Partnership's public unitholders and recommended that the Board approve the Acquisition. The independent committee retained its own expert financial and legal advisors to assist in this process and the financial advisor rendered a fairness opinion in connection with the Acquisition.

In November 2002, the staff of the SEC advised the Partnership, Enbridge Management, the General Partner and Enbridge (the "Enbridge Group"), that it had commenced an informal inquiry into the Acquisition and the initial public offering by Enbridge Management. The SEC staff has advised the Enbridge Group that its principal focus includes the financial forecast made in connection with the Acquisition and the price paid for the assets. The SEC staff has not asserted that the Partnership or the other Enbridge entities has acted improperly or illegally, and it has not indicated an intention to seek a formal order of investigation. The Enbridge Group is cooperating fully with the SEC staff.

Based on an internal review of the forecast and terms of the Acquisition, the Enbridge Group continues to believe that the financial forecast had a reasonable basis and the price paid for the assets was fair to the Partnership. The Partnership believes that the informal investigation will not have a material adverse effect on the financial condition of the Partnership.

**Item 3. Legal Proceedings**

The Partnership is a party in a limited number of legal proceedings arising in the ordinary course of business. The Partnership believes that the outcome of these matters will not, individually or in the aggregate, have a material adverse effect on the financial condition of the Partnership.

**Item 4. Submission of Matters to a Vote of Security Holders**

No matters were submitted to a vote of security holders during the fourth quarter of 2003.

## PART II

### Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

The Partnership's Class A Common Units are listed and traded on the New York Stock Exchange, the principal market for the Class A Common Units, under the symbol EEP. The quarterly price ranges per Class A Common Unit and cash distributions paid per unit for 2003 and 2002 are summarized as follows:

| | First | Second | Third | Fourth |
|---|---|---|---|---|
| **2003 Quarters** | | | | |
| High | $45.85 | $48.20 | $50.33 | $52.93 |
| Low | $41.70 | $42.00 | $45.45 | $48.70 |
| Cash distributions paid | $0.925 | $0.925 | $0.925 | $0.925 |
| **2002 Quarters** | | | | |
| High | $46.25 | $46.75 | $46.25 | $44.00 |
| Low | $41.00 | $43.15 | $35.68 | $37.80 |
| Cash distributions paid | $ 0.90 | $ 0.90 | $ 0.90 | $ 0.90 |

On March 1, 2004, the last reported sales price of the Class A Common Units on the NYSE was $50.20. At March 1, 2004, there were approximately 70,000 Class A Common Unitholders, of which there were approximately 2,200 registered Class A Common Unitholders of record. There is no established public trading market for the Partnership's Class B Common Units, all of which are held by the General Partner, or the Partnership's i-units, all of which are held by Enbridge Management.

**Item 6. Selected Financial Data**

The following table sets forth, for the periods and at the dates indicated, summary historical financial data for the Partnership. The table is derived from the consolidated financial statements of the Partnership and notes thereto, and should be read in conjunction with those audited financial statements. See also "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2003 | 2002 | 2001 | 2000 | 1999 |
| | (dollars in millions, except per unit amounts) | | | | |
| **Income Statement Data:** | | | | | |
| Operating revenue | $3,172.3 | $1,185.5 | $ 342.3 | $ 307.0 | $ 314.0 |
| Operating expenses | 2,978.0 | 1,047.5 | 244.5 | 189.1 | 182.3 |
| Operating income | 194.3 | 138.0 | 97.8 | 117.9 | 131.7 |
| Interest expense | (85.0) | (59.2) | (59.3) | (60.4) | (54.1) |
| Other income (expense) | 2.4 | (0.2) | 0.9 | 3.4 | 2.0 |
| Minority interest | — | (0.5) | (0.5) | (0.7) | (0.9) |
| Net income | $ 111.7 | $ 78.1 | $ 38.9 | $ 60.2 | $ 78.7 |
| Net income per unit (1) | $ 1.93 | $ 1.76 | $ 0.98 | $ 1.78 | $ 2.48 |
| Cash distributions paid per unit | $ 3.70 | $ 3.60 | $ 3.50 | $ 3.50 | $ 3.485 |
| **Financial Position Data (at year end):** | | | | | |
| Property, plant and equipment, net | $2,465.6 | $2,253.3 | $1,486.6 | $1,281.9 | $1,321.3 |
| Total assets | $3,231.8 | $2,834.9 | $1,649.2 | $1,376.7 | $1,413.7 |
| Long-term debt | $1,155.8 | $1,011.4 | $ 715.4 | $ 799.3 | $ 784.5 |
| Loans from General Partner and affiliates | $ 133.1 | $ 444.1 | $ 176.2 | — | — |
| Partners' capital: | | | | | |
| Class A common units | $ 914.9 | $ 604.8 | $ 577.0 | $ 488.6 | $ 533.1 |
| Class B common units | 64.2 | 48.7 | 48.8 | 42.1 | 47.4 |
| i-units | 370.7 | 335.6 | — | — | — |
| General Partner | 27.5 | 18.8 | 6.5 | 5.2 | 5.6 |
| Accumulated other comprehensive (loss) income | (64.0) | (16.3) | 11.9 | — | — |
| | $1,313.3 | $ 991.6 | $ 644.2 | $ 535.9 | $ 586.1 |
| **Cash Flow Data:** | | | | | |
| Cash flows from operating activities | $ 132.1 | $ 200.6 | $ 125.3 | $ 118.9 | $ 101.6 |
| Cash flows used in investing activities | (431.0) | (557.2) | (302.1) | (22.3) | (91.1) |
| Cash flows from (used in) financing activities | 303.0 | 376.7 | 179.8 | (99.4) | (17.5) |
| Acquisitions and capital expenditures included in investing activities, net of acquired working capital | (423.5) | (563.9) | (300.0) | (21.7) | (82.9) |

(1) The allocation of net income to the General Partner in the following amounts has been deducted before calculating net income per unit: 2003, $19.6 million; 2002, $13.1 million; 2001, $9.1 million; 2000, $8.8 million and 1999, $9.1 million.

**Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations**

The following discussion and analysis of the Partnership's financial condition and results of operations are based on its Consolidated Financial Statements, which were prepared in accordance with accounting principles generally accepted in the United States of America. The discussion and analysis should be read in conjunction with the Consolidated Financial Statements and accompanying notes of the Partnership listed in the Index to Consolidated Financial Statements on page F-1 of this report.

**Business Overview**

The Partnership provides services to its customers and creates value for its unitholders primarily through the following activities:

- Interstate transportation of crude oil and liquid petroleum;
- Gathering, treating, processing and transmission of raw natural gas;
- Interstate and intrastate transmission of natural gas; and
- Providing supply, transmission and sales service, including purchasing and selling natural gas.

The Partnership primarily provides fee-based services to customers to minimize commodity price risks. However, in the Partnership's natural gas businesses, a portion of its earnings and cash flows are exposed to movements in the prices of natural gas and NGLs. To substantially mitigate this exposure, the Partnership enters into hedge transactions.

The Partnership conducts its business through four business segments: Liquids Transportation, Gathering and Processing, Natural Gas Transportation and Marketing. These segments are strategic business units established by senior management to facilitate the achievement of the Partnership's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

*Liquids Transportation*

Liquids Transportation includes the operations of the Lakehead and North Dakota systems. The Lakehead and North Dakota systems largely consist of FERC-regulated interstate crude oil and liquid petroleum pipelines. These systems generate most of their revenues by charging shippers a per barrel tariff rate to transport crude oil and liquid petroleum.

The Lakehead system links crude oil production from western Canada to markets in the Great Lakes and Midwest regions of the United States and the province of Ontario, Canada. Western Canadian crude oil production comes from two sources, conventional drilling and oil sands extraction projects. Currently, conventional drilling produces the majority of the supply, however, with the number of new oil sands construction projects in progress, this stable source of supply is expected to increase significantly over the next ten years.

Deliveries on the North Dakota system are impacted by the willingness of crude oil producers to maintain their crude oil production and exploration activities in North Dakota, Montana and the province of Saskatchewan, Canada. Similar to the Lakehead system, the North Dakota system depends upon demand for crude oil in the Great Lakes and Midwest regions of the United States.

*Gathering and Processing*

Gathering and Processing includes the East Texas system, acquired on November 30, 2001, the Northeast Texas system, the South Texas system and certain other assets of the Midcoast system, all of which were acquired from the General Partner in October 2002, and the North Texas system, acquired on December 31, 2003. Collectively, these systems include natural gas gathering and transmission pipelines, nine active natural gas treating plants and twelve active natural gas processing plants. The

Midcoast system assets acquired also include trucks, trailers and rail cars used for transporting NGLs, crude oil and carbon dioxide. The Gathering and Processing assets are largely located in the Mid-Continent and Gulf Coast regions of the United States.

The Partnership receives revenues for its gathering and processing services under the following types of arrangements:

*Fee-Based Arrangements:* Under a fee-based contract, the Partnership receives a set fee for gathering, treating, processing and transmission of raw natural gas and providing other gathering services. These revenues correlate with volumes and types of service, and do not depend directly on commodity prices. The Partnership prefers fee-based contracts because they produce relatively stable cash flows.

*Other Arrangements:* While the Partnership prefers fee-based contracts, it also utilizes other types of arrangements in its natural gas gathering and processing business, including:

- Percentage-of-Index Contracts—Under these contracts, the Partnership purchases raw natural gas at a negotiated discount to an agreed upon index. The Partnership then resells the natural gas, generally for the index price, keeping the difference as its fee.
- Percentage-of-Proceeds Contracts—Under these contracts, the Partnership receives a negotiated percentage of the natural gas it processes in the form of residue natural gas, NGLs and sulfur, which it then sells at market prices.
- Keep-Whole Contracts—Under these contracts, the Partnership gathers or purchases raw natural gas from the producer for processing. A portion of the gathered or purchased gas is consumed during processing. The Partnership extracts and retains the NGLs produced during processing, which it sells at market prices. In instances when the Partnership purchases raw gas at the wellhead, it also sells for its own account at market prices the residue gas resulting from processing. In those instances where the Partnership gathers and processes raw natural gas for the account of the producer, it must return to the producer residue gas with a British thermal unit content equivalent to the original raw gas it received.

Some of these arrangements expose the Partnership to commodity price risk, which is mitigated by offsetting physical purchases and sales and the use of financial derivative instruments. In addition, the Partnership occasionally takes title to natural gas and NGLs for other reasons, such as to sell these products to customers. The Partnership will continue to hedge a significant amount of this commodity price risk to support the stability of cash flows. Please read "Item 7A. Quantitative and Qualitative Disclosures about Market Risk—Commodity Price Risk" for more information.

*Natural Gas Transportation*

Natural Gas Transportation consists of four FERC regulated natural gas transmission pipeline systems and 35 intrastate natural gas transmission and wholesale customer pipeline systems located in the Mid-Continent and Gulf Coast regions of the United States. These pipeline systems form part of the Midcoast system assets that were acquired from the General Partner in October 2002.

The Partnership's FERC-regulated interstate natural gas transmission pipeline systems generally derive their revenue from capacity reservation fees charged for transmission of natural gas, while its intrastate pipelines generally derive their revenue from the bundled sales of natural gas and from transmission services. Customers of the Partnership's FERC-regulated natural gas pipeline systems typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transmission volumes. In some cases, the Partnership's Marketing operation uses the capacity on these pipeline systems to sell natural gas it owns to its customers, such as local distribution companies or industrial facilities.

*Marketing*

The Partnership's Marketing segment provides supply, transmission and sales service for producers and wholesale customers on its gathering, transmission and customer pipelines as well as other interconnected pipeline systems. Marketing activities are primarily undertaken to realize incremental margins on gas purchased at the wellhead, increase pipeline utilization and provide value added services to customers.

In general, natural gas purchased and sold by the Marketing segment is priced at a published daily or monthly price index. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated margins result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. At their request, the Partnership will enter into long-term fixed price purchase or sales contracts with its customers and generally will enter into offsetting hedged positions under the same or similar terms.

**Critical Accounting Policies and Estimates**

The Partnership's consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures with respect to contingent assets and liabilities. The basis for these estimates is historical experience, consultation with experts and various other assumptions that are believed to be reasonable, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results could differ from these estimates under different assumptions or conditions. Any effects on the Partnership's business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known. The Partnership believes the critical accounting policies and estimates discussed in the following paragraphs affect the more significant judgments and estimates used in the preparation of its consolidated financial statements.

*Revenue Recognition*

In general, the Partnership recognizes revenue when delivery has occurred or services have been rendered, pricing is determinable and collectibility is reasonably assured. For its natural gas businesses, the Partnership records an estimate each month for its operating revenues and cost of natural gas based on quantities delivered, along with a true-up of the prior month's estimate to equal the prior month's actual data. As a result, there is one month of estimated data recorded in the Partnership's operating revenues and cost of natural gas for each of the years ended December 31, 2003, 2002 and 2001. These estimates are based on the best available volume and price data. The Partnership believes that the assumptions underlying these estimates will not be significantly different from actual amounts due to the routine nature of these estimates and the stability of the Partnership's processes.

*Property, Plant and Equipment*

Property, plant and equipment is recorded at its original cost and is depreciated based on the lesser of the estimated useful lives of the assets or the estimated remaining life of crude oil or natural gas production in the basins served by the pipelines. Determining the useful life requires various assumptions to be made, including the supply of and demand for hydrocarbons in the markets served by assets, normal wear and tear of the facilities, and the extent and frequency of maintenance programs. Changes in any of these assumptions may impact the rate at which depreciation is recognized in the financial statements. Additionally, if it is determined that an asset's undepreciated cost may not

be recoverable due to economic obsolescence, the business climate, legal and other factors, the asset would be reviewed for impairment and any necessary reduction in its value would be recorded as a charge against earnings. If there are changes to any of the estimates and assumptions, actual results may differ. If an average remaining service life of 20 years had been used (compared to the average remaining service life of approximately 25 years in the 2003 results), depreciation expense would be $119.3 million or $23.1 million higher and net income per unit would have been $1.45 or $0.48 lower. If an average remaining service life of 30 years had been used, depreciation expense would be $79.5 million or $16.7 million lower and net income per unit would have been $2.28 or $0.35 higher.

*Assessment of Recoverability of Goodwill and Intangibles*

Goodwill represents the excess of the purchase price over the fair value of net assets acquired in a business combination. Goodwill is not amortized but is tested for impairment annually as of the end of the second quarter or more frequently if impairment indicators arise that indicate the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds its fair value. At the time the Partnership determines that impairment has occurred, the carrying value of the goodwill is written down to its fair value. To estimate the fair value of the reporting units, management makes estimates and judgments about future cash flows, as well as revenue, cost of sales, operating expenses, capital expenditures and net working capital based on assumptions that are consistent with the Partnership's most recent five-year plan to manage the business. Preparation of forecast information for use in the five-year plan involves significant judgments. Based on the results of the impairment analysis, the fair value of the total equity of each reporting unit is deemed to exceed the respective carrying value.

Actual results can, and often do, differ from the projections and assumptions made. These changes can have a negative impact on the estimates of impairment, which would result in charges to income. In addition, further changes in the economic and business environment can impact the Partnership's original and ongoing assessments of potential impairment.

Other intangible assets consist of natural gas purchase and sale customer contracts, and natural gas supply opportunities, which are amortized on a straight-line basis over the weighted average useful life of the underlying assets, which is the period over which the asset is expected to contribute directly or indirectly to the future cash flows of the Partnership.

The Partnership evaluates the carrying value of the intangible assets whenever certain events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangibles, the Partnership compares the carrying value to the undiscounted future cash flows the intangibles are expected to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles, the intangibles are written down to their fair value. If there are changes to any of the estimates and assumptions, actual results may differ.

*Derivative Financial Instruments*

Net income and cash flows are subject to volatility from changes in market prices such as interest rates, natural gas prices, natural gas liquids prices and fractionation margins. In order to manage the risks to Partnership unitholders, the General Partner uses a variety of derivative financial instruments to create offsetting positions to specific commodity or interest rate exposures. Under SFAS No. 133, all derivative financial instruments are reflected in the balance sheet at their fair value. For those instruments that qualify for hedge accounting, the accounting treatment depends on each instrument's intended use and how it is designated.

Derivative financial instruments qualifying for hedge accounting treatment and in use by the Partnership can be divided into two categories: 1) cashflow hedges, or 2) fair value hedges. Cashflow

hedges are entered into to hedge the variability in cashflow(s) related to a forecasted transaction. Fair value hedges are entered into to hedge the value of a recognized asset or liability.

Price assumptions used to value the cash flow and fair value hedges can have an impact on net income results for each period. The Partnership uses published market price information where available, or quotations from OTC market makers to find executable bids and offers. The valuations also reflect the potential impact of liquidating the Partnership's position in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of our counterparties and operational risk. The amounts reported in the Partnership's consolidated financial statements change quarterly as these estimates are revised to reflect actual results, changes in market conditions or other factors, many of which are beyond the Partnership's control.

At inception and on an ongoing basis, the Partnership also assesses whether the derivatives that are used in its hedging transactions are highly effective in offsetting changes in cash flows or fair value of the hedged item. To the extent the hedges are determined to be highly effective, changes in the derivative fair values are recorded as a component of Accumulated Other Comprehensive Income until the hedged transactions occur and are then recognized into earnings. If the hedge is determined to not be highly effective, it can no longer be designated as a cash flow or fair value hedge and changes in the fair value would be reported directly in the income statement.

The Partnership's earnings are also affected by use of the mark-to-market method of accounting required under GAAP for certain basis swap financial instruments. The Partnership uses short-term, highly liquid financial instruments such as basis swaps and other contracts to economically hedge market price risks associated with inventories, firm commitments and certain anticipated transactions, primarily within our Marketing segment. As of December 31, 2003, certain basis swap financial instruments, however, did not qualify for hedge accounting treatment under SFAS No. 133, and thus the changes in fair value of these instruments are recorded on the balance sheet and through earnings (i.e., using the "mark-to-market" method) rather than being deferred until the firm commitment or anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments may cause the Partnership's non-cash earnings to fluctuate based upon changes in underlying indexes, primarily commodity prices. Fair value for these financial instruments is determined using price data from highly liquid markets such as the NYMEX commodity exchange or from OTC market makers.

For the year ended December 31, 2003, the Partnership recognized losses of $0.3 million in the Consolidated Statement of Income, as part of the Cost of Natural Gas balance of the Marketing segment. The fair value of the basis swaps at December 31, 2003, is a payable of $0.3 million, and is included in the Consolidated Statement of Financial Position as part of the Deferred Credits balance. These losses resulted from the negative change in market value of these basis swap hedging portfolio activities. At that date, the Partnership had a limited number of open positions that extend beyond December 31, 2004.

*Commitments, Contingencies and Environmental Liabilities*

The Partnership accrues reserves for contingent liabilities, including environmental remediation and clean-up costs, when its assessments indicate that it is probable that a liability has been incurred and an amount can be reasonably estimated. Estimates of the liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and the revisions are reflected in the Partnership's income in the period in which they are reasonably determinable. The Partnership evaluates recoveries from insurance coverage separately from its liability and, when recovery is reasonably assured, it

records and reports an asset separately from the associated liability in its financial statements. New environmental developments, such as increasingly strict environmental laws and regulations and new claims for damages to property, employees, other persons and the environment resulting from current or past operations, could result in substantial cost and future liabilities.

The Partnership recognizes liabilities for other contingencies when it has an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. The Partnership's potential exposure to adverse outcomes is evaluated by both internal and external counsel. When a range of probable loss can be estimated, the Partnership accrues the most likely amount, or at least the minimum of the range of probable loss. To the extent that actual outcomes differ from estimates or additional facts and circumstances cause the Partnership to review its estimates, income may be affected.

*Oil Shortage Balance and Oil Measurement Losses*

Oil shortage balance and oil measurement losses are inherent in the transportation of crude oil due to, among other factors, evaporation, measurement differences and blending of commodities in transit. The estimates recorded on the Partnership are based on mathematical calculations and physical measurement and include assumptions related to the type of crude oil, its market value, normal physical losses due to evaporation and capacity limitations of the system. A material change in these assumptions may result in a change to the carrying value of the oil shortage balance or revision of oil measurement loss estimates. The balances are included in the Accounts Payable and other in the Consolidated Statement of Financial Position.

*Operational Balancing Agreements and Natural Gas Imbalances*

Payables and receivables associated with natural gas pipeline operational balancing agreements and natural gas imbalances recorded monthly. These balances are either settled on a cash basis or are carried by the pipelines and shippers on an in-kind basis. Accruals associated with these in-kind balances are derived from the best available third party and internal documentation and are valued on a published third party index. If there is a change to these estimates and assumptions, actual results may differ.

**Results of Operations**

The following table shows the Partnership's consolidated revenues, expenses, operating income, net income and net income per unit.

| | Year ended December 31, | | |
|---|---|---|---|
| | **2003** | **2002** | **2001** |
| | (dollars in millions, except per unit amounts) | | |
| **Operating Revenues** | $ 3,172.3 | $ 1,185.5 | $ 342.3 |
| **Expenses** | (2,978.0) | (1,047.5) | (244.5) |
| **Operating income** | $ 194.3 | $ 138.0 | $ 97.8 |
| **Net income** | $ 111.7 | $ 78.1 | $ 38.9 |
| **Net income per unit** | $ 1.93 | $ 1.76 | $ 0.98 |

The increases in overall operating revenue, expenses, operating income and net income in 2003 compared with 2002 are attributable to the full year contribution from the Midcoast system, which was acquired by the Partnership in October 2002 and improved performance on the Lakehead and East Texas systems. Increases in operating revenue, expenses, operating income and net income in 2002

compared with 2001 resulted from the full-year contribution of the East Texas system acquired in December 2001 and the partial year contribution from the Midcoast system.

The following table reflects operating income by business segment and corporate charges.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (dollars in millions) | | |
| **Operating Income** | | | |
| Liquids Transportation | $124.5 | $112.1 | $ 97.7 |
| Gathering and Processing | 48.4 | 20.2 | 0.1 |
| Natural Gas Transportation | 15.2 | 3.9 | — |
| Marketing | 9.4 | 1.8 | — |
| Corporate, operating and administrative* | (3.2) | — | — |
| **Total Operating Income** | $194.3 | $138.0 | $ 97.8 |
| Corporate* | (82.6) | (59.9) | (58.9) |
| **Net Income** | $111.7 | $ 78.1 | $ 38.9 |

* Corporate consists of interest expense, interest income, minority interest and certain other operating and administrative costs such as franchise taxes, that are not allocated to the other business segments.

**Liquids Transportation**

The results of operations for the Liquids Transportation segment include the Lakehead system and the North Dakota system, since its acquisition by the Partnership in May 2001.

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (dollars in millions) | | |
| **Operating Revenues** | $ 344.2 | $ 334.3 | $ 313.3 |
| Operating and administrative | $(104.1) | $(104.7) | $(102.7) |
| Power | (56.1) | (52.7) | (49.9) |
| Depreciation and amortization | (59.5) | (64.8) | (63.0) |
| **Expenses** | $(219.7) | $(222.2) | $(215.6) |
| **Operating income** | $ 124.5 | $ 112.1 | $ 97.7 |

The following table sets forth the Lakehead system's average deliveries per day, barrel miles, and average haul:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | | (average bpd) | |
| United States | 1,003 | 937 | 960 |
| Province of Ontario | 351 | 365 | 355 |
| **Total deliveries (thousands)** | 1,354 | 1,302 | 1,315 |
| **Barrel miles (billions)** | 345 | 341 | 333 |

*Year ended December 31, 2003 compared with year ended December 31, 2002*

Operating income was higher in 2003 compared with 2002 due to higher revenue and lower operating expenses, including depreciation. Operating revenue was $9.9 million higher in 2003 compared with 2002 due to higher deliveries on the Lakehead and North Dakota systems, partially offset by slightly lower tariffs.

Overall, production of western Canadian crude oil increased in 2003 over 2002 mainly due to the start up of new oil sands projects in the province of Alberta. These latest oil sands projects differ from conventional oil production in two ways. First, oil sands deposits are a mixture of bitumen, water, sand and clay. As a result, oil production takes the form of either mining the oil sands from subsurface deposits and separating out the water, sand and clay components, or, if the deposits are deeper, heating the reservoir sufficiently to flow the pure bitumen to the surface. Second, the bitumen requires either upgrading or blending prior to being sent to market. The upgrading process partially refines the bitumen into a crude stream, which can be readily refined by most conventional refineries. This product is known as synthetic crude oil. Due to startup challenges at the newest upgrader, known as the Athabasca Oil Sands Project ("AOSP"), 2003 crude oil production lagged behind expectations. This delayed the expected increase in western Canadian oil production during the year, and as a result, impacted the level of deliveries on the Lakehead system.

On a full year basis, tariffs were lower during 2003 due to negative indexing adjustments calculated under FERC regulations and tariff reductions related to existing agreements with customers. In February 2003, the FERC issued an Order on Remand, which replaced the annual index of Producers Price Index for Finished Goods ("PPI") less one percent with an index of PPI without the minus one percent. The FERC allowed the indexed levels to increase for a short period of time in 2003 to reflect the change in the index during 2002. However, effective July 2003, the PPI adjustment was negative.

Power costs increased by $3.4 million in 2003 to $56.1 million from $52.7 million in 2002 primarily due to the increase in deliveries on the Lakehead and North Dakota systems.

Operating and administrative expenses decreased by $0.6 million to $104.1 million in 2003 from $104.7 million in 2002. The Partnership experienced higher leak clean-up and remediation costs related to two leaks in Minnesota during 2003, as well as higher workforce costs related to benefits. These increases were offset by lower oil measurement expenses and higher labor costs capitalized to construction projects.

Depreciation expense was lower in 2003 by $5.3 million compared with 2002. The decrease was due to revised depreciation rates effective January 1, 2003 on the Lakehead system of $13.4 million, offset by depreciation on new facilities placed into service during the fourth quarter of 2002 and throughout 2003 of $8.1 million. The reduction in depreciation rates pursuant to a third party study, better represents the expected remaining service life of the Lakehead system.

*Year ended December 31, 2002 compared with year ended December 31, 2001*

Operating income for 2002 was $112.1 million compared with $97.7 million for 2001. Operating income was higher in 2002 compared with 2001 primarily due to higher revenues, partially offset by higher operating expenses. Operating income for 2002 includes the full year results of the North Dakota acquisition, whereas 2001 includes the results from the date of acquisition of May 18, 2001.

Operating revenue was higher in 2002 compared with 2001 due to increased tariffs and a full year contribution from the North Dakota system, partially offset by lower deliveries on the Lakehead system. Tariffs were higher due to positive adjustments calculated under FERC regulations and agreements with customers. As well, the amount of heavy oil transported on the Lakehead system, which attracts a higher tariff, was higher in 2002 compared with 2001. Volumes delivered on the Lakehead system declined over the period as western Canadian crude oil was delivered to other markets on competing pipeline systems.

Operating and administrative expenses were higher in 2002 by $2.0 million compared with 2001. This increase was due to higher workforce costs, as well as expenses related to a Lakehead system pipeline leak in July 2002, partially offset by lower oil measurement losses and the non-recurring charge in 2001 related to the relocation of the Partnership's head office to Houston.

Depreciation expense was higher in 2002 by $1.8 million compared with 2001, due to plant additions from the prior year and a full year impact of the North Dakota system.

**Gathering and Processing**

The results of operations for the Gathering and Processing segment include the East Texas system since its acquisition date on November 30, 2001, and the remaining systems purchased as part of the Midcoast system since their acquisition on October 17, 2002. The North Texas system was purchased effective December 31, 2003, and therefore, the Partnership did not record any results of operations from this system in 2003. Comparative results for 2001 include only one month of operations from the East Texas system, and comparative results for 2002 include less than three months of operations from the Midcoast system.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (dollars in millions) | | |
| **Operating revenues** | $ 1,846.8 | $ 702.2 | $ 29.0 |
| Cost of natural gas | $(1,693.3) | $(635.2) | $(26.3) |
| Operating and administrative | (81.0) | (34.5) | (1.8) |
| Depreciation and amortization | (24.1) | (12.3) | (0.8) |
| **Expenses** | $(1,798.4) | $(682.0) | $(28.9) |
| **Operating income** | $ 48.4 | $ 20.2 | $ 0.1 |

The table below indicates the average daily volumes for each of the major systems in the Partnership's Gathering and Processing segment during each of the years ending December 31, 2003 and 2002, in million British thermal units per day. The Anadarko, Northeast Texas and South Texas systems were acquired in October 2002. The full year volume data for 2002 is shown for informational purposes and includes data from the records of the previous owner, the General Partner.

| | 2003 Average MMBtu/d | 2002 Average MMBtu/d |
|---|---|---|
| East Texas | 446,000 | 405,000 |
| Anadarko | 256,000 | 203,000 |
| Northeast Texas | 133,000 | 146,000 |
| South Texas | 38,000 | 13,000 |
| **Total** | 873,000 | 767,000 |

*Year ended December 31, 2003 compared with year ended December 31, 2002*

Gathering and Processing results of operations improved due to the full year impact of the Midcoast assets and increased volume of natural gas on the East Texas system.

Compared with 2002, natural gas volumes on the gathering and processing assets increased approximately 14% from 767,000 MMBtu/d to 873,000 MMBtu/d. Increased drilling activity by natural gas producers due to higher natural gas prices is a key contributor to volume growth. In addition, the Partnership has undertaken modest expansions of its facilities to handle increased customer volumes. The Northeast Texas system shows a modest decline in volumes partially due to low levels of natural gas drilling in its service area that are not offsetting natural production declines in the area. Drilling

near these assets is expected to increase to a level, which should result in a lesser decline or keep production levels flat in the near future.

While high natural gas prices positively impacted volumes on the Partnership's gathering and processing systems, this positive impact was largely offset by poor processing economics in 2003. The majority of the Partnership's operating income is derived from fee-based contracts, percentage of index or percentage of proceeds contracts. However, a portion of this segment's operating income is derived from keep-whole processing of natural gas. This contract structure requires the Partnership to process natural gas at times on limited volumes, when it may not be economic to do so. This can happen when natural gas prices are unusually high or natural gas liquids prices are unusually low.

Keep-whole processing for the Partnership is mostly attributable to the Anadarko and East Texas systems. The Partnership's keep-whole processing is a small but variable element of the gathering and processing segment's operating income. During 2003, operating income associated with keep-whole processing was approximately $1.9 million. This compares to operating income of $48.4 million for the gathering and processing segment as a whole.

During 2003, high natural gas prices, particularly at the beginning of the year, adversely affected processing results. In the second half of 2003, processing economics improved marginally as a result of lower natural gas prices. As levels of natural gas in storage increased through the year, natural gas prices decreased.

The Partnership estimates that a $0.05 per MMBtu change in keep-whole processing operating revenues less cost of natural gas would increase or decrease total segment operating income by approximately $4.0 million. A 50,000 MMBtu/d change in gathering volume will increase or decrease operating income by approximately $6.0 million. These estimates may vary depending upon the pipeline system to which they relate, competition, other factors and are subject to variability.

**Natural Gas Transportation**

The Natural Gas Transportation segment was established upon the acquisition of the Midcoast system on October 17, 2002, and its results of operations are included in the Partnership's results since that date. The Natural Gas Transportation segment results for 2003 reflect a full year's contribution to the Partnership compared with less than three months of results in 2002.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (dollars in millions) | | |
| **Operating revenues** | $ 117.7 | $ 19.8 | $ — |
| Cost of natural gas | $ (67.6) | $ (8.6) | $ — |
| Operating and administrative | (21.3) | (4.5) | — |
| Depreciation and amortization | (13.6) | (2.8) | — |
| **Expenses** | $(102.5) | $(15.9) | $ — |
| **Operating income** | $ 15.2 | $ 3.9 | $ — |

The table below indicates the average daily volumes for each of the major systems in Partnership's Natural Gas Transportation segment during each of the years ending December 31, 2003 and 2002, in million British thermal units per day. The UTOS, Midla, AlaTenn, KPC, Bamagas and other major

intrastate systems were acquired in October 2002. The full year volume data for 2002 is shown for informational purposes and includes data from the records of the previous owner, the General Partner.

| | 2003 Average | 2002 Average |
|---|---|---|
| | (MMBtu/d) | |
| UTOS | 213,000 | 275,000 |
| MidLa | 108,000 | 91,000 |
| AlaTenn | 61,000 | 54,000 |
| KPC | 53,000 | 40,000 |
| Bamagas | 14,000 | 16,000 |
| **Other Major Intrastates** | 182,000 | 184,000 |
| **Total** | 631,000 | 660,000 |

*Year ended December 31, 2003 compared with year ended December 31, 2002*

Results of operations for the Natural Gas Transportation segment improved in 2003 due to the full year contribution of the Midcoast assets. Performance of the Natural Gas Transportation segment depends largely upon revenues derived from reserved pipeline capacity. Natural gas transportation revenue is typically higher in the winter months due to increased pipeline rates and greater pipeline reservations; thus, the first and fourth quarter operating income is typically higher as compared with the second and third quarter operating income.

Volumes on the UTOS system have decreased 12% in 2003, as compared to the fourth quarter of 2002. This decrease is attributable to both general decline associated with volumes received into the UTOS system and stricter enforcement of gas quality specifications by pipelines downstream of the UTOS Pipeline. The full year impact to revenue in 2003 was less than $0.2 million if these 2003 volumes had remained consistent with the 2002 volumes.

As anticipated, certain customer contracts on the AlaTenn system representing approximately 20% of its capacity terminated during 2003 and were not renewed by the customers. The Partnership is exploring alternative customer connections to increase the utilization of this system. High natural gas prices have impacted the anticipated development of increased natural gas demands expected in the Tennessee River Valley area and are a factor in lower utilization of the Partnership's Bamagas system. This system connects to two new natural gas fueled power plants owned by third parties. Bamagas earns a base return whether the system is used or not because a significant portion of its capacity is contracted on a take-or-pay basis. Nonetheless, increased earnings cannot be realized until the power plants or other facilities transport more natural gas than their contracted take-or-pay levels.

**Marketing**

The Marketing segment was established upon the acquisition of the Midcoast system on October 17, 2002, and its results of operations are included in the Partnership's results since that date.

The Marketing segment's results for 2003 reflect a full year's contribution to the Partnership compared with less than three months of results in 2002.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (dollars in millions) | | |
| **Operating Revenues** | $ 863.6 | $ 129.2 | $— |
| Cost of natural gas | $(851.8) | $(126.9) | $— |
| Operating and administrative | (2.2) | (0.5) | — |
| Depreciation and amortization | (0.2) | — | — |
| **Expenses** | $(854.2) | $(127.4) | $— |
| **Operating income** | $ 9.4 | $ 1.8 | $— |

Operating income for the Marketing segment was $9.4 million for the year ended December 31, 2003, compared with $1.8 million for 2002. Colder weather during the first four months of 2003 created greater demand for natural gas, increasing the ability to optimize firm transportation contracts in competitive markets. During 2003, the volume of gas marketed by the Marketing segment was 1,068,000 MMBtu/d. Results for the Marketing segment for the year ended December 31, 2003, also include the positive impact of approximately $1.9 million due to the settlement of disputed amounts, which is included in the Consolidated Statement of Income as a reduction of cost of natural gas.

Typically, the first and fourth quarters will result in higher operating income for the Marketing segment due to colder weather in the market areas served by this segment. Colder weather generates significant incremental sales to the Partnership's wholesale customers and creates the opportunity to optimize transportation and storage agreements.

**Corporate**

Interest expense was $85.0 million in 2003 compared with $59.2 million in 2002 and $59.3 million in 2001. The $25.8 million increase in 2003 compared with 2002 reflects higher average borrowings during 2003 due to the full year impact on interest expense of the debt assumed upon the acquisition of the Midcoast system in October 2002. This was partially offset by a decrease in average borrowing rates that has occurred since the end of 2001. During 2003, the Partnership issued $400.0 million in principal amount of senior notes and repaid $311.0 million in loans from the General Partner and affiliates.

Interest expense in 2002 was approximately the same as in 2001 as higher average debt balances were more than offset by lower interest rates and higher interest capitalized on construction projects due to the Terrace expansion program in 2002.

**Liquidity and Capital Resources**

**General**

The Partnership believes that it will continue to have adequate liquidity to fund future recurring operating and investing activities. The primary cash requirements for the Partnership consist of normal operating expenses, maintenance and expansion capital expenditures, debt service payments, distributions to partners and acquisitions of new businesses. Short-term cash requirements, such as operating expenses, maintenance capital expenditures, debt service payments and quarterly distributions to partners, are expected to be funded by operating cash flows. Long-term cash requirements for expansion projects and acquisitions are expected to be funded through several sources, including cash flows from operating activities, borrowings under bank credit facilities, i-unit payment-in-kind distributions in lieu of cash and the issuance of additional debt and equity securities, including common and i-units. The Partnership's ability to complete future debt and equity offerings will depend on

various factors, including prevailing market conditions, interest rates and its financial condition and credit rating at the time.

On June 30, 2003, the Partnership filed a universal shelf registration statement with the SEC. The Partnership may offer and sell debt securities or Class A Common Units from time to time up to a total of $1.5 billion, with the amount, price and terms to be determined at the time of the sale. The Partnership expects to use the net proceeds from any future sales of securities under the universal shelf registration statement for operations and for other general corporate purposes, including repayment or refinancing of borrowings, working capital, capital expenditures or acquisitions of businesses or assets.

In December 2003 and January 2004, the Partnership issued an additional 5.45 million Class A Common Units under its universal shelf registration, which generated net proceeds of $262.0 million, net of underwriters' discounts, commissions and issuance expenses. Proceeds from this offering were used to reduce borrowings under the Partnership's 364-day credit facility, by approximately $105.0 million, to reduce borrowings under the three-year term facility of approximately $100.0 million and to pay the December 15, 2003 sinking fund payment of $31.0 million on the Partnership's First Mortgage Notes.

In January 2004, the Partnership issued $200.0 million in principal amount of 4% Senior Notes due 2009 under its universal shelf registration, from which it received net proceeds of approximately $198.4 million after offering expenses. The proceeds were used to repay a portion of the amount outstanding under the Partnership's 364-day revolving credit facility.

After giving effect to the Class A Common Unit Issuance in December 2003 and January 2004, and the debt issuance in January 2004, approximately $1,025.9 million in debt securities or Class A Common Units are available for issuance under the existing universal shelf registration statement.

**Summary of Obligations and Commitments**

The following table summarizes the Partnership's obligations and commitments at December 31, 2003:

| | Payment Due By Period | | | | |
|---|---|---|---|---|---|
| | Total | Less Than 1 Year | 1-3 Years | 3-5 Years | After 5 Years |
| | (dollars in millions) | | | | |
| **Contractual Obligations** | | | | | |
| Long-Term Debt | $1,401.8 | $246.0 | $302.0 | $62.0 | $791.8 |
| Right-of-way (1) | 54.0 | 1.8 | 3.7 | 3.5 | 45.0 |
| Operating Leases | 20.7 | 3.9 | 7.9 | 5.4 | 3.5 |
| Power and other purchase commitments | 19.1 | 12.9 | 6.2 | — | — |
| **Total Contractual Cash Obligations** | $1,495.6 | $264.6 | $319.8 | $70.9 | $840.3 |

(1) Right of way payments are estimated to be approximately $1.8 million per year for the remaining life for all pipelines. For purposes of this table, the Partnership has estimated its remaining life to be 25 years.

**Operating Activities**

Net cash provided by operating activities was $132.1 million in 2003 compared with $200.6 million in 2002. An improvement in net income in 2003 compared with 2002 of $33.6 million reflects the full year contribution by the Midcoast system as well as stronger performance on the Lakehead and East Texas systems. This was offset by the overall net decrease for changes in balances for working capital items included in operating activities of $122.1 million. The change was primarily the result of accrued gas receivables and payables changes due to the increased sales volumes and gas prices in 2003

compared with 2002, a deposit of $13.1 million made in December 2003, related to the Mid-Continent asset acquisition that closed on March 1, 2004, as well as the result of timing differences in the collection on and payment of the Partnership's current accounts.

At December 31, 2003, cash and cash equivalents totaled $64.4 million, an increase of $4.1 million from December 31, 2002. Of this amount, $55.8 million was available for cash distributions to unitholders. Of the cash available for distribution, $9.3 million was retained from i-unit holders and $0.2 million was retained from the General Partner by the Partnership for use in its business. The fourth quarter distribution to unitholders and the General Partner of $46.8 million ($0.925 per unit), which includes the effects of $0.5 million for the exercise of the over-allotment option in January 2004, was paid on February 13, 2004.

*Investing Activities*

Net cash used in investing activities was $431.0 million for the year ended December 31, 2003, compared with $557.2 million for the prior year. The $126.2 million decrease in funds utilized in investing activities was attributable to two items:

- Lower cash out flows made for strategic acquisitions in 2003 compared with 2002 of $55.0 million. During 2003, the Partnership acquired the North Texas system for cash paid of $249.7 million and paid post-closing adjustments to the General Partner related to the Midcoast acquisition of $43.8 million, compared with the acquisition of the Midcoast system during 2002 for cash paid of $344.4 million; and
- A decrease in additions to property, plant and equipment in 2003 of $85.4 million primarily due to a significant amount of construction activity during 2002 related to the Terrace Phase III expansion program.

During 2003, the Partnership spent $129.3 million for capital expenditures including core maintenance and enhancement projects. Core maintenance activities, such as the replacement of equipment and planned major maintenance activities, are undertaken to enable the Partnership's systems to operate at their maximum operating capacity. Enhancements to the systems are expected to extend the life of the systems, reduce costs or enhance revenues, and permit the Partnership to respond to developing industry and government standards and the changing service expectations of its customers. The Partnership's core maintenance capital expenditures increased to $28.8 million for 2003 compared with $14.2 million for 2002, due to the full year impact of the Midcoast system acquisition in 2003.

*Financing Activities*

Net cash provided by financing activities was $303.0 million in 2003, compared with $376.7 million in 2002. The decrease of $73.7 million from 2002 is primarily due to higher net repayments to the General Partner and affiliates and an increase in the distributions to partners. In May 2003, the Partnership issued $400.0 million in aggregate principal of senior unsecured notes and used the net proceeds to repay existing loans from Enbridge affiliates and amounts outstanding under the Partnership's credit facilities. Cash distributions to partners increased to $156.7 million in 2003 compared with $137.3 million in 2002. The increase in distributions was due to:

- an increase in the per unit cash distributions paid, from $3.60 per unit in 2002 to $3.70 per unit in 2003;
- an increase in the number of units outstanding; and
- an increase in the general partner incentive distributions, which resulted from increased cash distributions to unitholders.

During 2003, working capital decreased by $118.7 million to a working capital deficit of $179.8 million, primarily due to the inclusion of the $215.0 million balance of the Partnership's 364-day credit facility in current liabilities in 2003, compared with classifying it as long-term debt in 2002. This balance was recorded as a current liability, as the Partnership's lender granted a three-month extension to the existing maturity date of January 2004 to facilitate the credit review process and better coordinate the annual request for extension.

In December 2003, the Partnership issued 5.0 million Class A Common Units at $50.30 per unit, which generated proceeds, net of underwriters' discounts, commissions and issuance expenses, of approximately $240.3 million. Proceeds from this offering were used to reduce borrowings under the Partnership's 364-day credit facility by approximately $105.0 million, $100.0 million to reduce borrowings under the Partnership's three-year term facility and $31.0 million to pay the December 15, 2003 sinking fund payment on the First Mortgage Notes. The remainder of the net proceeds was used to fund a portion of the North Texas system acquisition. In addition to the proceeds generated from the unit issuances, the General Partner contributed $5.1 million to the Partnership to maintain its 2% general partner interest in the Partnership.

In May 2003, the Partnership issued 3.85 million Class A Common Units at $44.79 per unit, which generated proceeds, net of underwriters' discounts, commissions and issuance expenses, of approximately $165.5 million. Proceeds from this offering were used to reduce borrowings under the Partnership's 364-day credit facility by $102.4 million and an affiliate loan by $63.1 million. In addition to the proceeds generated from the unit issuances, the General Partner contributed $3.5 million to the Partnership to maintain its 2% general partner interest in the Partnership.

In March 2002, the Partnership issued 2.26 million Class A Common Units at $42.75 per unit. The net proceeds from the offering were $93.3 million and were used to repay indebtedness.

On October 17, 2002, the Partnership issued 9,000,000 i-units to Enbridge Management for net proceeds of $330.8 million. The Partnership used the net proceeds to repay debt owed to affiliates that was assumed in connection with the acquisition of the Midcoast system.

*Cash Distributions*

The Partnership distributes quarterly to the General Partner and the holders of its common units an amount equal to its''available cash,'' which generally is defined to mean for any calendar quarter the sum of all of the cash receipts of the Partnership plus net reductions to reserves less all of its cash disbursements and net changes to reserves. These reserves are retained to provide for the proper conduct of the Partnership's business, to stabilize distributions of cash to unitholders and the General Partner and, as necessary, to comply with the terms of any agreement or obligation of the Partnership. Enbridge Management, as the delegate of the General Partner under a Delegation of Control Agreement, computes the amount of the Partnership's available cash.

Enbridge Management, as owner of the i-units, does not receive distributions in cash. Instead, each time that the Partnership makes a cash distribution to the General Partner and the holders of its common units, the number of i-units owned by Enbridge Management and the percentage of total units in the Partnership owned by Enbridge Management increases automatically under the provisions of the Partnership Agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management's shares and voting shares that are then outstanding. The amount of this increase per i-unit is determined by dividing the cash amount distributed per common unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10-day period immediately preceding the ex-dividend date for Enbridge Management's shares. For purposes of calculating the sum of all distributions of available cash, the cash equivalent amount of the additional i-units that are issued when a distribution of cash is made to the General Partner and owners of common units is treated as distribution of available cash, even though the i-unit holder will not receive cash. The Partnership will retain and use that cash in its business.

During 2003, the Partnership distributed a total of 833,515 i-units through quarterly distributions to Enbridge Management, compared with 228,654 in 2002. The increase was the result of a full year's distributions in 2003, compared with one quarter in 2002, as the i-units were issued in October 2002. The Partnership retained $35.4 million in 2003 related to the i-unit distributions compared with $8.1 million in 2002.

**Credit Facilities and Debt**

The Partnership's credit facilities and debt consist of the following:

| | December 31, | |
|---|---|---|
| | 2003 | 2002 |
| | (dollars in millions) | |
| **Short-term debt:** | | |
| 364-day credit facility | $ 215.0 | $ — |
| Current portion of First Mortgage Notes | 31.0 | 31.0 |
| **Total short-term debt** | 246.0 | 31.0 |
| **Long-term debt:** | | |
| 364-day credit facility | — | 212.0 |
| Three-year term facility | 240.0 | 252.0 |
| First Mortgage Notes | 217.0 | 248.0 |
| 7.90% senior notes due 2012 | 100.0 | 100.0 |
| 4.75% senior notes due 2013 | 200.0 | — |
| 7.00% senior notes due 2018 | 100.0 | 100.0 |
| 7.125% senior notes due 2028 | 100.0 | 100.0 |
| 5.95% senior notes due 2033 | 200.0 | — |
| Unamortized discount | (1.2) | (0.6) |
| **Total long-term debt** | $1,155.8 | $1,011.4 |
| **Loans from Enbridge affiliates** | $ 133.1 | $ 444.1 |
| **Total debt** | $1,534.9 | $1,486.5 |

*Credit Facilities.* In January 2003, the Partnership amended and restated the terms of its two unsecured revolving credit facilities, which were originally entered into in January 2002. The facilities consist of a $300.0 million three-year term facility (the "Three-year Facility"), which matures in 2006 (subject to extension as provided in the facility) and a $300.0 million 364-day facility (the "364-day facility"), which matures in April 2004 (subject to a one-year term-out option and extension as provided in the facility). Interest is charged on amounts drawn under each of these facilities at a variable rate equal to the Base Rate or a Eurodollar rate as defined in the facility agreements. In the case of a Eurodollar rate loans an additional margin is charged which varies depending on the Partnership's credit rating and the amounts drawn under the facility. A facility fee is payable on the entire amount of each facility whether or not drawn. The facility fee varies depending on the Partnership's credit rating. As of December 31, 2003, the facility fees on the three-year and 364-day facilities were 0.20% and 0.15%, respectively. These credit facilities contain restrictive covenants that require that the Partnership maintain a minimum interest coverage ratio of 2.75 times and a maximum leverage ratio of 4.75 times, each as defined in the facility agreements. The facility agreements also place limitations on the amount of debt that may be incurred directly by the Partnership's subsidiaries. Accordingly, it is expected that the Partnership will provide debt financing to its subsidiaries as required.

As of December 31, 2003, $215.0 million was drawn on the Partnership's 364-day facility at a weighted average interest rate of 1.90% and $240.0 million was drawn on the Partnership's three-year facility at a weighted average interest rate of 1.84%.

*First Mortgage Notes.* The First Mortgage Notes are collateralized by a first mortgage on substantially all of the property, plant and equipment of the Lakehead Partnership and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. The Notes contain various restrictive covenants applicable to the Partnership, and restrictions on the incurrence of additional indebtedness, including compliance with certain debt issuance tests. The Partnership believes these issuance tests will not negatively impact its ability to finance future expansion projects. Under the First Mortgage Note Agreements, the Partnership cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash for the immediately preceding calendar quarter. If the notes were to be paid prior to their stated maturities, the First Mortgage Note Agreements provide for the payment of a redemption premium by the Partnership.

*Senior Notes.* In addition to the $300.0 million of Senior Unsecured Notes previously outstanding, on May 27, 2003, the Partnership issued $200.0 million in aggregate principal amount of its 4.75% Notes due 2013 and $200.0 million in aggregate principal amount of its 5.95% Notes due 2033 in a private placement. The Partnership used the proceeds of approximately $396.3 million, net of expenses of approximately $3.0 million, to repay loans from affiliates of the Partnership and other bank debt. The Partnership recorded a discount of $0.7 million in connection with the issuance of the Notes. On June 30, 2003, the Partnership completed a Form S-4 with the SEC, which registered the exchange of the unregistered Notes for publicly registered Notes.

All of the notes pay interest semi-annually and have varying maturities and terms as previously outlined in the table above. The senior unsecured notes do not contain any covenants restricting the issuance of additional indebtedness.

*Loans from Enbridge affiliates.* As of December 31, 2003, the Partnership had $133.1 million in debt outstanding under a note to an affiliate of the General Partner. This note relates to debt assumed by the Partnership in connection with the acquisition of the Midcoast system in October 2002. The note matures in 2007 and has cross-default provisions that are triggered by events of default under the First Mortgage Notes issued by the Partnership or defaults under the Partnership's three-year term facility and 364-day credit facility. The note is subordinate to the Partnership's credit facilities and other senior indebtedness.

**Off-Balance Sheet Arrangements**

The Partnership has no off-balance sheet arrangements.

**Credit Ratings**

In May 2003, Standard & Poor's and Moody's assigned the ratings for the Partnership's senior unsecured debt obligations of BBB and a Baa2, respectively. In May 2003, Moody's also lowered its senior unsecured debt rating of the Lakehead Partnership, a wholly-owned subsidiary of the Partnership, from A3 to Baa1. Standard & Poor's rating for the Lakehead Partnership's senior unsecured debt obligations was unchanged during 2003 at BBB+.

**Cash Requirements for Future Growth**

*Acquisitions.* The primary strategy of the Partnership is to grow cash distributions through the profitable expansion of existing assets and through development and acquisition of complementary businesses with risk profiles similar to the Partnership's current businesses. The Partnership will continue to analyze potential acquisitions, with a focus on crude oil, refined products and natural gas pipelines, terminals and related facilities. Major energy companies have sold their non-strategic assets in recent years, continuing the trend of rationalization of the energy infrastructure in the United States. The Partnership expects this trend to continue and believes it is well positioned to participate in these opportunities. The Partnership will seek opportunities throughout the United States, particularly in the

U.S. Gulf Coast area, where asset acquisitions are anticipated in and around its recently acquired natural gas gathering, processing, and transportation businesses.

The Partnership expects that the funds needed to achieve the objective of growth through acquisitions will be obtained through a combination of cash flows from operating activities, borrowings under bank credit facilities, i-unit payment-in-kind distributions in lieu of cash and the issuance of additional debt and equity securities, including common units and i-units.

The Partnership's acquisition of the North Texas system on December 31, 2003 for $249.7 million was funded with borrowings under the Partnership's 364-day revolving credit facility and three-year term facility. The additional debt will result in increased debt service costs in the future. To the extent that proceeds from future equity offerings are used to reduce the principal amount of debt, the Partnership's interest expense will be reduced. To the extent that the Partnership refinances its existing debt with new debt, its interest expense will generally be affected by differences in interest rates charged on the existing debt versus the new debt and by any fees associated with the new debt.

On December 22, 2003, the Partnership entered into definitive agreements to acquire crude oil pipeline and storage systems from Shell Pipeline Company LP and Shell Oil Products US ("Shell") for $115.0 million, excluding customary closing adjustments for working capital and other items. The asset purchase closed on March 1, 2004. The Partnership funded the acquisition through its existing credit facilities.

*Distributions.* For the year ended December 31, 2003, the declared annual distribution rate was $3.70 per unit, compared with $3.60 per unit for the year ended December 31, 2002. An increase in the Partnership's distribution rate will result in additional cash payments to existing unitholders and the General Partner. As well, an increase in the number of common units eligible for cash distributions will result in higher total distribution payments. The Partnership expects that all cash distributions will be paid out of operating cash flows over the long-term; however, from time to time, the Partnership may temporarily borrow under its credit facilities for the purpose of paying cash distributions until the full impact of operations is realized.

*Capital Spending.* At December 31, 2003, the Partnership had $3.7 million in estimated outstanding purchase commitments attributable to capital projects for the construction of assets that will be recorded as Property, Plant and Equipment.

Expenditures related to Property, Plant and Equipment are capitalized ("capital expenditures"), subject to a minimum rule, that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are extended, replaced, or improved; or (3) all land, regardless of cost. Acquisition of new assets, additions, replacements and improvements (other than land) costing less than the established minimum rules are expensed accordingly.

Capital expenditures are categorized by the Partnership as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of the existing assets and includes the replacement of system components and equipment which is worn, obsolete or completing its useful life. Enhancement expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable the Partnership to respond to governmental regulations and developing industry standards.

In 2004, the Partnership anticipates capital expenditure spending to approximate:

| | (dollars in millions) |
|---|---|
| System enhancements | $122.0 |
| Core maintenance activities | 33.0 |
| Lakehead System expansion projects | 40.0 |
| East Texas expansion | 105.0 |
| | $300.0 |

Excluding major expansion projects and acquisitions, ongoing capital expenditures are expected to average approximately $98.0 million annually (approximately 35% for core maintenance and 65% for system enhancements).

The Partnership anticipates funding the expenditures temporarily through its bank credit facilities, with permanent debt and equity funding being provided when appropriate.

The Partnership expects to incur continuing annual capital and operating expenditures for pipeline integrity measures to ensure both regulatory compliance and to maintain the overall integrity of the pipeline systems. Expenditure levels have continued to increase as pipelines age and require higher levels of inspection or maintenance; however, these are viewed to be consistent with industry trends.

Included in the anticipated capital expenditures spending for system enhancements in 2004 is approximately $25.0 million of capital expenditures to ensure regulatory compliance on the Lakehead system. This spending is for pressure testing of the Lakehead system to establish operating pressures in excess of operating limits that would otherwise be allowed under current circumstances.

**Subsequent Events**

*Class A Common Unit issuance*

In January 2004, the Partnership issued an additional 450,000 Class A Common Units to its underwriters pursuant to the exercise of the over-allotment option as part of the December 2003 Class A Common Unit issuance. This resulted in additional proceeds to the Partnership, net of underwriters' fees and discounts, commissions and issuance expenses, of approximately $21.7 million. The proceeds were used to reduce amounts outstanding under the Partnership's revolving credit facilities.

*Distribution Declaration*

On January 22, 2004, the Partnership's Board of Directors declared a distribution payable on February 13, 2004, to unitholders of record as of February 2, 2004, of its available cash of $55.8 million at December 31, 2003, or $0.925 per common unit. Of this distribution, $9.3 million was distributed in i-units to i-unit holders and $0.2 million was retained from the General Partner in respect of this i-unit distribution.

*Senior Notes offering*

In January 2004, the Partnership issued $200 million in principal amount of 4% Senior Notes due 2009, from which it received net proceeds of $198.4 million after offering expenses. The proceeds were used to repay a portion of the amount outstanding under the 364-day revolving credit facility.

*Mid-Continent Liquids System*

On December 22, 2003, the Partnership entered into definitive agreements to acquire crude oil pipeline and storage systems from Shell Pipeline Company LP and Shell Oil Products US ("Shell") for

$115.0 million, excluding customary closing adjustments for working capital and other items. The asset purchase closed on March 1, 2004. The assets acquired serve refineries in the Mid-Continent from the Cushing, Oklahoma hub, and consist of the following:

- The 433-mile Ozark pipeline that currently transports approximately 170,000 barrels of crude oil per day from Cushing to Wood River, Illinois;
- A 1.2 million barrel storage terminal located in El Dorado, Kansas;
- The 47-mile West Tulsa pipeline that currently transports approximately 55,000 barrels per day to two refineries in Oklahoma; and
- The storage terminal at Cushing, which is one of the largest terminal facilities in North America with 8.3 million barrels of storage capacity.

These systems provide cash flows primarily from toll or fee-based revenues from a combination of regulated assets and contracted unregulated assets and are expected to be accretive to the Partnership's distributable cash flow. The assets are consistent with the Partnership's core operating expertise in crude oil pipelines and the throughput originates from sources of supply different from those on its other crude oil systems, providing increased diversity in the Partnership's sources of cash flow.

Enbridge concurrently acquired Shell's Patoka West Tank Farm. These assets complement Enbridge's initiative to access new markets for Canadian crude oil. The Partnership expects to benefit from the market access initiative by facilitating throughput on the Lakehead system.

**Other Matters**

*Future Prospects*

The Partnership believes that its financial performance will continue to improve in 2004 as a result of increased capacity utilization on the Lakehead system, combined with the contributions from the recently acquired North Texas and Mid-Continent Liquids systems.

*Liquids Transportation*

Average daily crude oil deliveries on the Lakehead system are expected to increase by 100,000 bpd during 2004, from 1.354 million barrels per day in 2003 to approximately 1.45 million bpd in 2004. The majority of the growth in deliveries is expected to come from a full year's production from the AOSP project that commenced during 2003. The AOSP is sponsored by two multinational integrated oil companies and an independent oil and gas company. While start-up problems delayed the expected incremental supply from the AOSP during 2003, the Partnership anticipates production to increase significantly in 2004 to meet the AOSP sponsor's expectations. This increase in supply is expected to result in higher deliveries on the Lakehead system.

Future prospects for the Lakehead system depend upon increased crude oil production from western Canada. While conventional oil supplies in this area are declining, crude oil production from Canada's oil sands supply is increasing. Estimated recoverable crude oil reserves from the oil sands, using existing technology, represent only 10% of the volume in place, of approximately 1.6 trillion barrels. To put this in perspective, this total volume in western Canada exceeds the estimated reserves of Saudi Arabia. Therefore this resource is expected to be an important crude oil supply for North America in the coming decades. Recognizing this, a number of major oil companies have announced projects requiring investments of approximately $30 billion over the next decade. This level of investment is expected to increase production of crude oil and enhance utilization of the capacity available on the Lakehead system.

There are several major oil sands projects scheduled for completion over the next few years including expansions of existing oil sands projects as well as new projects. The two original oil sands producers, Suncor and Syncrude, are both constructing projects to increase production by 2005-2006. In combination, these projects are expected to provide more than 100,000 bpd of supply. In addition to the Alberta oil sands, Canada has substantial conventional crude oil resources. Conventional crude production will remain sensitive to the price of crude oil and the level of crude oil drilling activity. For a complete discussion of supply and demand for crude oil, please see "Items 1. & 2. Business and Properties."

Recognizing the need to expand beyond the Lakehead system's traditional markets, Enbridge and the Partnership have undertaken an Oil Sands Market Study to research supply and disposition of crude oil. The findings indicate that there is demand among U.S. refiners who have not previously had access to Canadian crude oil due to a lack of pipeline infrastructure or economic tariffs. Enbridge and the Partnership are focusing on developing transportation solutions to allow PADD II refineries, and ultimately, refiners on the U.S. Gulf Coast, to gain increased or new access to western Canadian crude oil production.

Two tangible steps have already been announced under this initiative. First, Enbridge acquired a 90% stake in a pipeline that runs from Cushing, Oklahoma to Chicago and intends to reverse its flow. The pipeline will be renamed the Spearhead Pipeline and will provide capacity to deliver 200,000 bpd into the major oil hub at Cushing by 2005. The Partnership expects to benefit following the reversal, as western Canadian crude oil will be carried on the Lakehead system as far as Chicago, and then transferred to Spearhead. The second step was the Partnership's announcement in October 2003 of plans to extend the Lakehead system with a new 250,000 to 400,000 bpd pipeline to serve the large Wood River, Illinois refining center by 2007. This "Southern Access" project would intersect with Spearhead to offer customers delivery options to Cushing and Chicago, in addition to Wood River.

The Partnership closed its previously announced acquisition of Shell's Mid-Continent liquids systems, centered around the major Cushing crude oil hub, on March 1, 2004. The pipeline assets provide U.S. domestic and imported feedstock to Mid-Continent area refineries. The Partnership also acquired considerable tank storage capacity, mainly at the Cushing hub. The Cushing storage capacity in excess of operating requirements is contracted under term agreements. These assets provide basin diversification for the Partnership, because the crude oil shipped is not sourced from the western Canadian basin, as are the bulk of the Lakehead system deliveries.

*Natural Gas—Gathering and Processing, Transportation and Marketing*

The Partnership's natural gas assets are located in the Gulf Coast and Mid-Continent regions of the United States, two of the premier natural gas producing areas of the United States. As a result, there are many opportunities to connect new natural gas supplies either by installing new facilities or acquiring adjacent third-party gathering operations. Consolidation with neighboring facilities will extract efficiencies by eliminating costs, for example, by combining redundant facilities, increasing volume, and increasing processing margins. These opportunities tend to involve modest amounts of capital with attractive rates of return.

Results of the Partnership's natural gas gathering and processing business depend upon the drilling activities of natural gas producers in the areas served by the Partnership. During 2003, increased drilling in the areas where the Partnership's gathering systems are located has generally exceeded the national trend. One of the prominent areas in which this occurred was the Barnett Shale formation in north Texas, where natural gas production increased from 180 MMcf/d in 1999 to 750 MMcf/d in late 2003. The Barnett Shale is a prominent new natural gas development within the Fort Worth Basin, not previously accessed by the Partnership's system. To address this opportunity, the Partnership acquired the North Texas system in a transaction that closed on December 31, 2003. The acquired facilities will

provide approximately 220 MMcf/d of processing capacity. The Barnett Shale is being actively developed, and the Partnership anticipates that throughput on the North Texas system will increase modestly in each of the next several years.

The Partnership has announced proposed construction of a new 500 MMcf/d intrastate transmission pipeline to carry increased volumes of natural gas to the pipeline hub at Carthage, Texas. Carthage access is important to natural gas shippers because it offers a number of connections to interstate pipelines, which tend to support more favorable margins to producers. Following a successful open season for the proposed East Texas line, preliminary volume commitments were obtained from natural gas producers, and the Partnership expects to proceed with construction to bring the system on stream in mid 2005. The Partnership is pursuing options to connect production from North Texas to the new transmission line and provide Carthage access for gas producers in that area.

*Growth by Acquisitions*

Acquisitions are expected to play a role in the achievement of financial targets of the Partnership for 2004. In general, these acquisitions are expected to be in or near areas where the Partnership already operates and will present the best opportunities for consolidation savings and enhancement of the Partnership's market position. In addition to the previously announced Mid-Continent crude oil acquisition, approximately $175.0 million of capital has been budgeted for additional acquisitions in 2004.

The Partnership also will evaluate more significant acquisitions. Subject to financing capability, Enbridge plans to use the Partnership as its primary vehicle for acquiring mature energy delivery assets, particularly in the Gulf Coast region of the United States. The Partnership could make acquisitions directly from Enbridge or its subsidiaries in the future and will continue to pursue strategic acquisitions from unaffiliated parties.

*Growth in Cash Distributions*

The Partnership has modestly grown its cash distributions over the last several years. Cash distributions would likely have increased more were it not for lower utilization of the Lakehead system expansions than anticipated when the Partnership committed to the expansions in the late 1990's. Increased utilization of the Lakehead system and the approximately $415.0 million Terrace expansion program are fundamental to increasing cash distributions above the current $3.70 per unit, per year. It is anticipated that oil sands developments will provide increased utilization of the Lakehead system in the near future. It is also anticipated that oil sands development will support further expansions, such as the Southern Access project, that will grow the earnings and cash flow of the Partnership. Selected acquisitions and growth of the natural gas segments are also expected to contribute to improved near-term performance of the Partnership.

**Regulatory Matters**

*KPC System*

From 1998, when KPC became subject to the FERC jurisdiction, until November 9, 2002, when KPC's rate case rates became effective, the FERC established initial rates based upon an annual cost of service of approximately $31.0 million. Since that time, these initial rates have been the subject of various ongoing challenges that remain unresolved.

The United States Court of Appeals for the D.C. Circuit issued an order on August 12, 2003, vacating the FERC's 2001 remand order and 2002 rehearing order and remanded the issue of KPC's initial rates back to the FERC with directions that the FERC address the question of an appropriate rate refund. In prior KPC orders in this proceeding, the FERC determined that it had no authority to

impose a refund condition on initial rates. On October 3, 2003, KPC filed a pleading at the FERC requesting the issuance of an order finding that it had no refund obligation and requesting termination of the proceedings on remand. There are other actions and administrative proceedings that may be undertaken in connection with the Court's determination. The outcome of KPC's motion or any proceedings, including the amount of any refunds that may be ordered, is uncertain. If the FERC determines refunds are required, after all administrative options and court appeals are exhausted, the amount of the refunds may range from zero to $9.0 million.

*Liquids Petroleum Pipelines*

Since 1995, FERC-regulated liquid petroleum pipelines have been generally subject to an indexed ceiling rate methodology under which the annual change in the ceiling rate is the annual change in the Producers Price Index for Finished Goods minus 1% (PPI-1%). In December 2000, FERC affirmed this methodology and the existing index. The petroleum industry appealed this decision, and on February 24, 2003, the FERC issued an Order on Remand, replacing the PPI-1% index by removing the 1% reduction. During the second quarter of 2003, Flying J, Lion Oil, Sinclair Oil and Tesoro Refining and Marketing filed an appeal against this Order with the U.S. Court of Appeals for the District of Columbia Circuit. This issue has not yet been resolved.

**Recent Accounting Developments**

In April 2003, the Financial Accounting Standards Board ("FASB") issued SFAS No. 149, "*Amendment of Statement 133 on Derivative Instruments and Hedging Activities*." This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. In particular, this statement: (1) clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative discussed in paragraph 6(b) of SFAS No. 133, (2) clarifies when a derivative contains a financing component, (3) amends the definition of an underlying to conform it to language used in FASB Interpretation No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, and (4) amends certain other existing pronouncements. The new standard was adopted July 1, 2003, and did not have a significant impact on the Partnership's financial position, results of operations, or cash flows.

In January 2003, the FASB issued Interpretation No. 46, "*Consolidation of Variable Interest Entities*" ("FIN 46"). FIN 46 requires an investor with a majority of the variable interests in a variable interest entity to consolidate the entity and also requires majority and significant variable interest investors to provide certain disclosures. A variable interest entity is an entity in which the equity investors do not have a controlling interest or the equity investment at risk is insufficient to finance the entity's activities without receiving additional subordinated financial support form the other parties. In December 2003, the FASB completed deliberations of proposed modifications to FIN 46 resulting in multiple effective dates based on the nature as well as the creation date of the variable interest entity. However, the revised Interpretation must be applied no later than the first quarter of fiscal year 2004. There was no impact on the Partnership's consolidated financial position or results of operations as a result of the adoption of FIN 46.

**Item 7A. Quantitative and Qualitative Disclosures About Market Risk**

**Interest Rate and Foreign Exchange Risk**

To the extent the amounts drawn under its revolving credit facilities carry a floating rate of interest, the Partnership's earnings and cash flow are exposed to changes in interest rates. This exposure is managed through periodically refinancing floating rate bank debt with long-term fixed rate

debt and through the use of interest rate risk management hedge contracts. The Partnership does not have any material exposure to movements in foreign exchange rates as virtually all of its revenues and expenses are denominated in U.S. dollars. To the extent that a material foreign exchange exposure arises, the Partnership intends to hedge such exposure using forward or other financial derivative contracts.

The table below summarizes, as of December 31, 2003, the Partnership's derivative financial instruments and other financial instruments that are sensitive to changes in interest rates, including interest rate swaps and debt obligations. For debt obligations, the table presents principal cash flows and related weighted average interest rates by expected maturity dates. For interest rate swaps, the table presents notional amounts and weighted average interest paid rates by expected (contractual) maturity dates. Notional amounts are used to calculate the contractual payments to be exchanged under the contract.

**Expected Maturity Date**

| | 2004 | 2005 | 2006 | 2007 | 2008 | There-after | Total | Fair Value |
|---|---|---|---|---|---|---|---|---|
| | (dollars in millions) | | | | | | | |
| **Liabilities** | | | | | | | | |
| Fixed Rate: | | | | | | | | |
| First Mortgage Notes | $ 31.0 | $31.0 | $ 31.0 | $ 31.0 | $31.0 | $ 93.0 | $248.0 | $303.0 |
| Interest Rate . . . . . | 9.15% | 9.15% | 9.15% | 9.15% | 9.15% | 9.15% | — | — |
| Senior Unsecured Notes . . . . . | — | — | — | — | — | $ 700.0 | $700.0 | $739.0 |
| Average Interest Rate . . . . . | — | — | — | — | — | 6.20% | — | — |
| Variable Rate: | | | | | | | | |
| Revolving Credit Facility . . . . . | $215.0 | — | $240.0 | — | — | — | $455.0 | $455.0 |
| Average Interest Rate . . . . . | 1.90% | — | 1.84% | — | — | — | — | — |
| *Interest Rate Derivatives* | | | | | | | | |
| Interest Rate Swaps: | | | | | | | | |
| Variable to Fixed . . . | $150.0 | — | — | — | — | — | $150.0 | — |
| Average Pay Rate . . | 1.36% | — | — | — | — | — | — | — |
| Fixed to Variable . . . | — | — | — | — | — | $ 125.0 | $125.0 | $ 4.2 |
| Average Pay Rate . . | — | — | — | — | — | Libor—0.22% | — | — |
| Treasury Lock . . . . . | $104.0 | — | — | — | — | — | $104.0 | $ 1.0 |
| Pay Rate . . . . . | 3.19% | — | — | — | — | — | — | — |

**Commodity Price Risk**

The Partnership's earnings and cash flows associated with its liquids transportation systems are not significantly impacted by changes in commodity prices, as the Partnership does not own the crude oil and NGLs it transports. However, the Partnership has commodity risk related to degradation losses associated with fluctuating differentials between the price of heavy crude oil relative to light crude oil. Commodity prices have a significant impact on the underlying supply of, and demand for, crude oil and NGLs that the Partnership transports.

A portion of the Partnership's earnings and cash flows in its natural gas segments are exposed to movements in the prices of natural gas and NGLs. The Partnership has entered into hedge transactions to substantially mitigate exposure to movements in these prices. Pursuant to policies approved by the Board of Directors of the General Partner, the Partnership may not enter into derivative instruments for speculative purposes. All financial derivative transactions must be undertaken with creditworthy

counterparties. As at December 31, 2003, all financial counterparties were rated at least "A" by all major credit rating agencies.

*Natural Gas Transportation and Marketing*

Natural gas derivative transactions are entered into by the Partnership in order to hedge the forecasted purchases or sales of natural gas. The following table details the outstanding derivatives at December 31, 2003 and 2002:

| System | Maturity Dates | Notional MMBtu | Fair Value 2003 | Fair Value 2002 |
|---|---|---|---|---|
| | | | (dollars in millions) | |
| East Texas system | 2004-2011 | 26,000 | $(19.9) | $ (6.1) |
| Northeast Texas system | 2004-2012 | 42,000 | $(44.9) | $(19.1) |
| Midcoast system | 2004 | 600 | $ (0.7) | $ (0.3) |
| Marketing | 2004-2007 | 38,000 | $ 2.0 | $ 2.1 |

A limited number of natural gas derivative transactions, which mitigate economic exposures arising from underlying natural gas purchases and sales, do not qualify for hedge accounting treatment under SFAS No. 133. As such, the change in fair market value (from the last quarter-end) of these derivative instruments is booked to the income statement. For the years ended December 31, 2003 and 2002, the Partnership recorded losses of $0.3 million and zero, respectively, in the Consolidated Statements of Income as part of the cost of natural gas expense, to account for changes in the fair value related to these basis swaps in mark to market changes related to the Marketing segment.

**Natural Gas Liquids**

NGL derivative transactions are entered into by the Partnership to hedge the forecasted sales of NGLs. The following table details the outstanding derivatives at December 31, 2003 and 2002:

| System | Maturity Date | Notional Barrels | Fair Value 2003 | Fair Value 2002 |
|---|---|---|---|---|
| | | (in millions) | (dollars in millions) | |
| Northeast Texas system | 2004 | 0.5 | $(2.4) | $(2.5) |
| Midcoast system | 2004 | 0.1 | $(0.2) | $(0.1) |
| East Texas system | 2004 | 0.5 | $(0.8) | $ — |
| North Texas system | 2004 | 0.8 | $(1.1) | $ — |

**Item 8. Financial Statements and Supplementary Data**

The consolidated financial statements of the Partnership, together with the notes thereto and the independent auditors' report thereon, and unaudited supplementary information, appear on pages F-2 through F-20 of this Report, and are incorporated by reference. Reference should be made to the "Index to Financial Statements, Supplementary Information and Financial Statement Schedules" on page F-1 of this Report.

**Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

None.

**Item 9A. Controls and Procedures**

The Partnership and Enbridge maintain systems of disclosure controls and procedures designed to provide reasonable assurance that the Partnership is able to record, process, summarize and report the information required in the Partnership's annual and quarterly reports under the Securities Exchange Act of 1934. Management of the Partnership has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2003. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures are effective to accomplish their purpose. In conducting this assessment, management of the Partnership relied on similar evaluations conducted by employees of Enbridge affiliates who provide certain treasury, accounting and other services on behalf of the Partnership. No significant changes were made to our internal controls or other factors that could significantly affect these controls subsequent to the date of their evaluation, nor were any corrective actions with respect to significant deficiencies and material weaknesses necessary subsequent to that date.

## PART III

### Item 10. Directors and Executive Officers of the Registrant

*(a) Directors and Executive Officers of the Registrant*

The Partnership is a limited partnership and has no officers or directors of its own. Set forth below is certain information concerning the directors and executive officers of the General Partner and of Enbridge Management, the delegate of the General Partner under a Delegation of Control Agreement among the Partnership, the General Partner and Enbridge Management. All directors of the General Partner are elected annually by, and may be removed by, Enbridge Pipelines, as the sole stockholder of the General Partner. All directors of Enbridge Management are elected annually by, and may be removed by, the General Partner, as the sole holder of the Enbridge Management's voting shares. All officers of the General Partner and Enbridge Management serve at the discretion of the respective boards of directors of the General Partner and Enbridge Management. All directors and officers of the General Partner hold identical positions in Enbridge Management.

| Name | Age | Position |
|---|---|---|
| J.A. Connelly | 57 | Director |
| P.D. Daniel | 57 | Director |
| E.C. Hambrook | 66 | Director |
| M.O. Hesse | 61 | Director |
| G.K. Petty | 62 | Director |
| D.C. Tutcher | 55 | President and Director |
| J.R. Bird | 54 | Group Vice President — Liquids Transportation and Director |
| G.L.Sevick | 48 | Vice President — Liquids Transportation, Operations |
| M.A. Maki | 39 | Vice President — Finance |
| T.L. McGill | 49 | Vice President — Commercial Activity & Business Development |
| A.D. Meyer | 47 | Vice President — Liquids Transportation, Technology |
| R.L. Adams | 39 | Vice President — Operations and Technology |
| L.S. Cruess | 46 | Treasurer |
| J.L. Balko | 38 | Controller |
| E.C. Kaitson | 47 | Corporate Secretary |

J.A. Connelly was elected a director of the General Partner in January 2003 and serves on its Audit, Finance & Risk Committee. Mr. Connelly served as Senior Vice President and Vice President of the Coastal Corporation from 1988 to 2001. Mr. Connelly is a business consultant providing executive management consulting services.

P.D. Daniel was elected a director of the General Partner in July 1996 and served as its President from July 1996 through October 1997. Mr. Daniel has served as President of Enbridge since September 2000 and as Chief Executive Officer of Enbridge since January 2001. Prior to that time Mr. Daniel also served as President & Chief Operating Officer—Energy Delivery of Enbridge from June 1998 to December 2000.

E.C. Hambrook was elected a director of the General Partner in January 1992 and serves on its Audit, Finance & Risk Committee. Mr. Hambrook served as Chairman of the General Partner from July 1996 until July 1999. Mr. Hambrook has served as President of Hambrook Resources, Inc. since its inception in 1991. Hambrook Resources, Inc. is a real estate investment, marketing and sales company.

M.O. Hesse was elected a director of General Partner in April 2003 and serves as a member of its Audit, Finance & Risk Committee. Ms. Hesse is President and CEO of Hesse Gas Company. She served as Chairman of the U.S. Federal Energy Regulatory Commission from 1986 to 1989. Ms. Hesse also served as Senior Vice President, First Chicago Corporation and Assistant Secretary for Management and Administration, U.S. Department of Energy. She currently serves as a director of several domestic and international public companies.

G.K. Petty was elected a director of the General Partner in February 2001 and serves on its Audit, Finance & Risk Committee. Mr. Petty has served as a director of Enbridge since January 2001. Mr. Petty served as President and Chief Executive Officer of Telus Corporation, a Canadian telecommunications company, from November 1994 to November 1999. Mr. Petty is a business consultant providing executive management consulting services to the telecommunications industry.

D.C. Tutcher was elected a director and President of the General Partner in June 2001. He also currently serves as Group Vice President, Transportation South of Enbridge. He was previously Chairman of the Board, President and Chief Executive Officer of Midcoast Energy Resources, Inc. from its formation in 1992 until it was acquired by Enbridge on May 11, 2001.

J.R. Bird served as a director of the General Partner from September 2000 to January 2003 and was reelected as a Director in October 2003. He was elected Group Vice President, Liquids Transportation of the General Partner in January 2003. He served as President from September 2000 until June 2001. He has also served as Group Vice President, Transportation North of Enbridge since May 2001 and President of Enbridge Pipelines since September 2000. Prior to that time he served as Group Vice President, Transportation from September 2000 through April 2001 and as Senior Vice President, Corporate Planning and Development of Enbridge from August 1997 through August 2000.

G.L. Sevick was elected Vice President—Liquids Transportation, Operations of the General Partner in June 2001. He has served as Vice President, Operations for Enbridge Pipelines since 1999.

M.A. Maki was elected Vice President—Finance of the General Partner in July 2002. Prior to that time, he served as Controller of the General Partner since June 2001, and prior to that, as Controller of Enbridge Pipelines since September 1999.

T.L. McGill was elected Vice President—Commercial Activity and Business Development of the General Partner in April 2002. Prior to that time, Mr. McGill was President of Columbia Gulf Transmission Company from January 1996 to March 2002.

A.D. Meyer was elected Vice President—Liquids Transportation, Technology, of the General Partner in October 2003. He also continues to serve as Vice President, Technology, Enbridge Transportation—Pipelines since his appointment in July 1999. Prior to that time he served as President, Enbridge Pipelines (Athabasca) Inc. from October 1997 to July 1999 and as Vice President, Liquids Marketing with Enbridge for the same period.

R.L. Adams was elected Vice President—Operations and Technology of the General Partner in April 2003. Prior to his current position, he was Director of Technology & Operations for the General Partner since 2001, and Director of Field Operations and Technical Services and Director of Commercial Activities for Ocensa/Enbridge in Bogota, Columbia from 1997 to 2001.

L.S. Cruess was elected Treasurer of the General Partner in April 2003. He also has served as Vice President Financial Services of Enbridge since April 2003. Prior to that time, he served as Vice President Corporate Development of Enbridge from 2000 to 2003 and Vice President, Corporate Development of Utilicorp United Inc. from 1996 to 1999.

J.L. Balko was elected Controller of the General Partner in July 2002. Prior to that time, she served as Chief Accountant of the General Partner from October 1999 to June 2002 and served in managerial positions in accounting with Enbridge Pipelines since January 1998 to September 1999.

E.C. Kaitson has served as Corporate Secretary of the General Partner since November 2001. He also currently serves as Associate General Counsel of Enbridge. He was previously Assistant Corporate Secretary and General Counsel of Midcoast Energy Resources, Inc. from 1997 until Enbridge acquired it on May 11, 2001.

*(b) Section 16(a) Beneficial Ownership Reporting Compliance*

Section 16(a) of the Exchange Act requires directors, executive officers and 10% beneficial owners to file with the SEC reports of ownership and changes in ownership of the Partnership's equity securities and to furnish the Partnership with copies of all reports filed. The Partnership is a limited partnership and has no officers or directors of its own. Based solely on the review of the reports furnished, the Partnership believes that, during fiscal year 2003, all Section 16(a) filing requirements applicable to the directors and officers of the General Partner, and greater than 10% beneficial owners of the Partnership were met, except that SEC Form 3, Initial Statement of Beneficial Ownership of Securities, for A.D. Meyer was filed late.

*(c) Governance Matters*

As the Partnership is a limited partnership, the listing standards of the NYSE do not require that the Partnership or the General Partner have a majority of independent directors or a nominating or compensation committee of the General Partner's board of directors.

***Audit, Finance & Risk Committee***

Enbridge Management has an Audit, Finance & Risk Committee (the "Audit Committee") comprised of four board members who are independent as the term is used in Section 10A of the Securities Exchange Act of 1934, as amended. The members of the Audit Committee are M.O. Hesse, E.C. Hambrook, G.K. Petty and J.A. Connelly. No member of the Audit Committee serves on the audit committee of more than three public companies. The Audit Committee provides independent oversight with respect to our internal controls, accounting policies, financial reporting, internal audit function and the independent auditors. The Audit Committee also reviews the scope and quality, including the independence and objectivity of the independent and internal auditors and the fees paid for both audit and non-audit work and makes recommendations concerning audit matters, including the engagement of the independent auditors, to the Board of Directors.

The current version of the charter of the Audit Committee is filed as an exhibit to this annual report on Form 10-K and is available on the Partnership's website at *www.enbridgepartners.com*. The Charter of the Audit Committee complies with the listing standards of the New York Stock Exchange currently applicable to the Partnership. The Charter is under review for compliance with newly adopted rules of the NYSE with which the Partnership must comply by October 31, 2004.

The Partnership's Board of Directors has determined that M.O. Hesse, E.C. Hambrook and J.A. Connelly qualify as "audit committee financial experts" as defined in Item 401(h) of SEC Regulation S-K and are independent as that term is used in Item 7(d)(3)(iv) of Schedule 14A under the Exchange Act.

The Partnership's Audit Committee has established procedures for the receipt, retention, and treatment of complaints we receive regarding accounting, internal accounting controls, or auditing matters and the confidential, anonymous submission by our employees of concerns regarding questionable accounting or auditing matters. Persons wishing to communicate with the Partnership's Audit Committee may do by writing in care of Chairman, Audit Committee, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

***Code of Ethics and Statement of Business Conduct***

The Partnership has adopted a Code of Ethics applicable to its Senior Financial Officers, including the principal executive officer, principal financial officer and principal accounting officer of Enbridge Management. A copy of the Code of Ethics for Senior Financial Officers is available on the Partnership's website at *www.enbridgepartners.com* and is included herein as Exhibit 14.1. The Partnership intends to post on its website any amendments to or waivers of its Code of Ethics for Senior Financial Officers. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

The Partnership also has a Statement of Business Conduct applicable to all employees, officers and directors of Enbridge Management. A copy of the Statement of Business Conduct is available on the Partnership's website at *www.enbridgepartners.com*. The Partnership intends to post on its website any amendments to or waivers of its Statement of Business Conduct. Additionally, this material is available in print, free of charge, to any person who requests the information. Persons wishing to obtain this printed material should submit a request to Corporate Secretary, c/o Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

***Executive Sessions of Non-Management Directors***

The non-management directors of Enbridge Management meet at regularly scheduled executive sessions without management. J.A. Connelly or E.C. Hambrook served as the presiding director at those executive sessions. Persons wishing to communicate with the Partnership's non-management directors may do so by writing in care of Chairman, Board of Directors, Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, TX 77002.

**Item 11. Executive Compensation**

The following table sets forth the total annual and long-term compensation for all services rendered in all capacities to the Partnership and Enbridge Management for the fiscal year ended December 31, 2003 and 2002, of the Chief Executive Officer and the other most highly compensated executive officers (the "Named Executive Officers"). No allocation of compensation is made between the Partnership and Enbridge Management because the Partnership bears an allocable portion of these officers' total compensation that is based approximately on the percentage of time each of these officers devotes to Enbridge Management and the Partnership. The other affiliates of Enbridge, to whom these officers also render services, bear the remainder of the compensation expenses of these officers. Compensation of the Named Executive Officers for years prior to 2002 is not provided because it was previously not reported.

**Summary Compensation Table**

| Name & Principal Position | Year | Salary | Bonus | Other Annual Compensation (1)(2) | All Other Compensation (3) | Approximate Percentage of Time Devoted to Enbridge Management and the Partnership |
|---|---|---|---|---|---|---|
| D.C. Tutcher | 2003 | $309,750 | $235,000 | $35,000 | $10,000 | 80 |
| President | 2002 | $296,250 | $ 91,000 | $40,000 | $11,625 | 80 |
| T.L. McGill | 2003 | $221,000 | $ 89,800 | $20,000 | $ 6,361 | 90 |
| Vice President—Commercial Activity & Business Development | 2002 | $182,474 | $ 34,000 | $16,886 | $ 4,193 | 90 |
| E.C. Kaitson | 2003 | $168,000 | $ 35,400 | $10,000 | $ 8,375 | 90 |
| Secretary | 2002 | $161,250 | $ 18,200 | $10,000 | $ 8,990 | 90 |
| M.A. Maki | 2003 | $161,750 | $ 71,400 | $20,000 | $ 7,100 | 90 |
| Vice President—Finance | 2002 | $136,762 | $ 55,700 | $25,978 | $ 6,950 | 90 |
| R.L. Adams | 2003 | $151,000 | $ 54,100 | $26,229 | $ 7,568 | 90 |
| Vice President—Operations and Technology | 2002 | * | * | * | * | * |

* Not elected as an officer until 2003

**Notes:**

(1) Amounts in this column include: the flexible perquisites allowance (as described in Note 2 below), flexible credits paid as additional compensation (as described in Note 2 below), reimbursements for professional financial services, one-time payments for termination benefits, and the taxable benefit from loans by Enbridge, which were granted for relocation or hiring incentive purposes (and amounts reimbursed for the payment of taxes relating to such benefit).

(2) In fiscal 2003, the Named Executive Officers were given a Flexible Perquisites Allowance to cover perquisites that may have been previously paid on behalf of each executive. Effective July 1, 2001, Enbridge adopted a flexible benefit program pursuant to which employees receive an amount of flex credits based on their family status and base salary. Flex credits can be (a) used to purchase various benefits (such as extended health or dental coverage, disability insurance and life insurance) on the same terms as are available to all employees; (b) applied as contributions to the Stock Purchase and Savings Plan (as described in Note 3 below); or (c) paid to the employee as additional compensation. In 2003, Mr. Tutcher received perquisites and other personal benefits totaling $35,000, of which $30,000 related to his Flexible Perquisites Allowance; Mr. McGill received perquisites and other personal benefits totaling $20,000, all of which related to his Flexible Perquisites Allowance; Mr. Maki received perquisites and other personal benefits totaling $20,000, all of which related to his Flexible Perquisites Allowance; Mr. Kaitson received perquisites and other personal benefits totaling $10,000, all of which related to his Flexible Perquisites Allowance, and Mr. Adams received perquisites and other personal benefits totaling $26,229, of which $17,500 related to his Flexible Perquisites Allowance.

(3) Employees in the United States participate in the Enbridge Employee Services, Inc. Savings Plan (the "401(k) Plan") under which employees may contribute up to 25% of their base salary, with employee contributions up to 5% matched by Enbridge (all subject to the contribution limits specified in the Internal Revenue Code). Enbridge's contributions are used to purchase Enbridge shares at market value and the employees' contributions may be used to purchase Enbridge shares

or nine designated funds. During 2003, Enbridge made contributions of $10,000, $6,361, $7,100, $8,375 and $7,568, respectively, to the 401(k) Plan for the benefit of Mr. Tutcher, Mr. McGill, Mr. Maki, Mr. Kaitson, and Mr. Adams.

**Compensation Committee Interlocks and Insider Participation**

Neither Enbridge Management nor the General Partner have a compensation committee, therefore, all decisions related to executive compensation matters are made by a committee of the Board of Directors of Enbridge.

Enbridge has a Human Resources & Compensation Committee (the "Committee") which is presently comprised of the following directors (the date of their appointment to the Committee is listed after their name): D.A. Arledge (January 1, 2002), E.S. Evans (May 3, 2002), W.R. Fatt (Chair) (May 3, 2002), R.L. George (April 29, 1999), R.W. Martin (February 1, 2001) and D.J. Taylor (May 2, 1996). During 2003, no member of the Committee was an officer or employee of Enbridge or any of its subsidiaries, or had any relationship with Enbridge except as director, other than D.J. Taylor, who was a non-executive officer holding the office of Chair of the Board. Effective February 24, 2004, the Board of Directors of Enbridge revised bylaw No. 1 of the corporation so that Chair of the Board is no longer an office of the corporation. Mr. Taylor continues as Chair of the Board of Enbridge, however, effective February 24, 2004, is no longer an officer of the Board.

**Stock Options**

Options to purchase shares of Enbridge may from time to time be granted by Enbridge to the Partnership's Named Executive Officers, but no portion of any such grant is attributable to services performed for the Partnership or Enbridge Management nor are any expense reimbursements made by the Partnership on account of such options.

**Employment Agreements**

Messrs. Tutcher and Kaitson have Executive Employment Agreements with Enbridge. The Agreements commenced on May 11, 2001, and continue until the earlier of (i) the date of voluntary retirement in accordance with the retirement policies established for senior employees of Enbridge (ii) the voluntary resignation which is not a constructive dismissal, or (iii) termination based on disability, death, cause or by either party. The Agreements provide that in the event of termination of employment, the executive agrees to keep confidential all information of a confidential or proprietary nature and further agrees not to use such information for personal advantage. The Agreements also provide for a base salary, annual reviews, discretionary raises, participation in short and long-term incentive plans of Enbridge, and severance payments in the amount of two years compensation in the event of termination by Enbridge.

**Director Compensation**

Enbridge employees who are members of the Board of Directors of the General Partner or Enbridge Management do not receive any additional compensation for serving in those capacities. Members of the Board of Directors of the General Partner and Enbridge Management who are not employees receive an aggregate annual fee of $20,000, paid quarterly, plus $1,000 per day for each meeting attended of the board of directors or committees of the board. In addition, each non-employee director is reimbursed for out-of-pocket expenses in connection with attending meetings of the board of directors or committees and an additional $500 for meetings requiring out of town travel. The director who serves as chairman of the audit committees is paid an additional $5,000 per year and the director who serves as chairman of the boards is paid an additional $10,000 per year, paid quarterly. The

General Partner indemnifies each director for actions associated with being a director to the full extent permitted under Delaware law and maintains errors and omissions insurance.

Mr. Hambrook served as chairman of a special committee of the Board of Directors of the General Partner in 2002 and 2003, in its capacity as General Partner of the Partnership. The special committee of the Partnership was empowered to act on behalf of the Partnership in its purchase of the Midcoast assets. As compensation, Mr. Hambrook received a fee of $20,000, plus a fee of $1,000 per committee meeting. In addition, he was reimbursed for out-of-pocket expenses in connection with attending special committee meetings and an additional $500 for each meeting requiring out of town travel.

Messrs. Hambrook and Connelly served on pricing committees in 2003 in connection with public offerings to sell limited partnership interests in the Partnership. As compensation for serving on the pricing committees, they each received a fee of $1,000 per meeting.

**Item 12. Security Ownership of Certain Beneficial Owners and Management**

*(a) Security Ownership of Certain Beneficial Owners*

The following table sets forth information as of February 17, 2004, with respect to persons known to the Partnership to be the beneficial owners of more than 5% of either class of the Partnership's Units:

| Name and Address of Beneficial Owner | Title of Class | Amount and Nature of Beneficial Ownership | Percent Of Class |
|---|---|---|---|
| Enbridge Energy Management, L.L.C. . . . . 1100 Louisiana, Suite 3300 Houston, TX 77002 | i-units | 10,062,170 | 100.0 |
| Enbridge Energy Company, Inc. . . . . 1100 Louisiana, Suite 3300 Houston, TX 77002 | Class B Common Units | 3,912,750 | 100.0 |
| Goldman, Sachs & Co.(1) . . . . . The Goldman Sachs Group, Inc. 85 Broad St. New York, N.Y. 10004 | Class A Common Units | 1,740,639 | 4.3 |

(1) Goldman, Sachs & Co. and The Goldman Sachs Group, Inc. reported shared voting power and shared dispositive power with respects to all of such shares in its report on Form SC 13G/A filed February 12, 2004. Goldman, Sachs & Co. and The Goldman Sachs Group, Inc. each disclaim beneficial ownership of the securities beneficially owned by (a) any client accounts with respect to which Goldman, Sachs & Co. or its employees have voting or investment discretion or both, and (b) certain investment entities, of which a subsidiary of The Goldman Sachs Group, Inc. or Goldman, Sachs & Co. is the general partner, managing general partner or other manager, to the extent interests in such entities are held by persons other than The Goldman Sachs Group, Inc., Goldman, Sachs & Co. or their affiliates. The address of Goldman, Sachs & Co. and the Goldman Sachs Group, Inc. is 85 Broad Street, New York, NY 10004.

*(b) Security Ownership of Management and Directors*

The following table sets forth information as of February 17, 2004, with respect to each class of the Partnership's units beneficially owned by the Named Executive Officers, directors and nominees for

director of the General Partner and all executive officers, directors and nominees for director of the Partnership as a group:

| Name | Title of Class | Amount and Nature of Beneficial Ownership(1) | Percent Of Class |
|---|---|---|---|
| J.A. Connelly | Class A Common Units | 5,000 | * |
| P.D. Daniel | Class A Common Units | — | — |
| E.C. Hambrook | Class A Common Units | 2,000 | * |
| M.O. Hesse | Class A Common Units | — | — |
| G.K. Petty | Class A Common Units | 1,000 | * |
| D.C.Tutcher | Class A Common Units | 20,200 | * |
| J.R. Bird | Class A Common Units | — | — |
| G.L. Sevick | Class A Common Units | — | — |
| M.A. Maki | Class A Common Units | — | — |
| T.L. McGill | Class A Common Units | — | — |
| A.D. Meyer | Class A Common Units | — | — |
| R.L. Adams | Class A Common Units | — | — |
| L.S. Cruess | Class A Common Units | — | — |
| J.L. Balko | Class A Common Units | — | — |
| E.C. Kaitson | Class A Common Units | — | — |
| All Officers, directors and nominees as a group (15 persons) | Class A Common Units | 28,200 | * |

* Less than 1%

(1) Each beneficial owner has sole voting and investment power with respect to all the units attributed to him/her.

**Item 13. Certain Relationships and Related Transactions**

***Interest of the General Partner in the Partnership***

At December 31, 2003, the General Partner owned 3,912,750 Class B Common Units representing a 7.1% limited partner interest in the Partnership. In addition, the General Partner also owns 1,732,930 Listed shares or 17.2% of Enbridge Management's outstanding Listed shares, constituting an effective 3.1% limited partner interest in the Partnership. Together with the 2% general partner interest, the General Partner effectively owns a total of 12.2% of the Partnership and received $33.7 million in cash and incentive distributions.

***Interest of Enbridge Management in the Partnership***

At December 31, 2003, Enbridge Management owned 10,062,170 i-units, representing an 18.2% limited partner interest in the Partnership. The i-units are a separate class of limited partner interests in the Partnership. All of the i-units are owned by Enbridge Management and are not publicly traded. Enbridge Management's limited liability company agreement provides that the number of all of its outstanding shares, including the voting shares owned by the General Partner, at all times will equal the number of i-units that it owns. Through the combined effect of the provisions in the Partnership Agreement and the provisions of Enbridge Management's limited liability company agreement, the number of outstanding Enbridge Management shares and the number of the i-units will at all times be equal.

***Cash Distributions***

As discussed in "Part II, Item 7", the Partnership makes quarterly cash distributions of all of its available cash to the General Partner and the holders of its common units. Under the Partnership Agreement, the General Partner receives incremental incentive cash distributions on the portion of cash distributions on a per unit basis that exceed certain target thresholds as follows:

| | Unitholders | General Partner |
|---|---|---|
| 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 2003, incentive distributions paid to the General Partner were approximately $17.4 million.

***Other Related Party Transactions***

The Partnership, which has no employees, uses the services of Enbridge and its affiliates (the "Group") for management, operating and administrative services of its business.

For further discussion of this and other related party transactions, refer to "Note 10—Related Party Transactions" in the Notes to the Consolidated Financial Statements included elsewhere in this report.

**Item 14. Principal Accountant Fees and Services**

The following table sets forth the aggregate fees billed for professional services rendered by PricewaterhouseCoopers LLP, the Partnership's principal independent auditors, for each of the Partnership's last two fiscal years.

| | For the years ended December 31, | |
|---|---|---|
| | 2003 | 2002 |
| Audit fees(1) | $ 602,991 | $ 881,002 |
| Audit related fees(2) | 14,150 | — |
| Tax fees(3) | 529,520 | 537,043 |
| All other fees | — | — |
| Total | $1,146,661 | $1,418,045 |

(1) Audit fees consist of fees billed for professional services rendered for the audit of the Partnership's consolidated financial statements, reviews of the Partnership's interim consolidated financial statements, audits of various subsidiaries for statutory and regulatory filing requirements and the Partnership's debt and equity offerings.

(2) Audit related fees consist of fees billed for professional services rendered for Sarbanes-Oxley Section 404 consultation.

(3) Tax fees consist of fees billed for professional services rendered for federal and state tax compliance for Partnership tax filings and unitholder K-1's.

Engagements for services provided by PricewaterhouseCoopers LLP are subject to pre-approval by the Audit, Finance & Risk Committee of Enbridge Management's Board of Directors or services up to

$50,000 may be approved by the Chairman of the Audit, Finance & Risk Committee, under Board of Directors delegated authority.

## PART IV

### Item 15. Exhibits, Financial Statement Schedules and Reports on Form 8-K

The following documents are filed as part of this Report:

(a) As to financial statements, supplementary information and financial statement schedules, reference is made to "Index Consolidated to Financial Statements, Supplementary Information and Financial Statement Schedules" on page F-1 of this Report.

(b) The Partnership filed the following reports on Form 8-K during the fourth quarter of 2003:

- A current report on Form 8-K was filed on December 30, 2003, attaching a press release dated December 22, 2003, disclosing the intent to acquire of certain crude oil pipeline and storage systems from Shell;
- A current report on Form 8-K was filed on December 5, 2003, regarding entering into an Underwriting Agreement relating to the offering of up to 5,725,000 units (including an option to purchase up to 725,000 units) representing limited partner interests in the Partnership;
- A current report on Form 8-K was filed on November 24, 2003, attaching a press release dated November 19, 2003, disclosing the execution of a definitive purchase agreement to acquire natural gas gathering and processing assets in North Texas from Cantera Resources Inc., an affiliate of Morgan Stanley Capital Partners;
- A current report on Form 8-K was filed on October 24, 2003, attaching a press release dated October 22, 2003 regarding the financial results for the three and nine months ended September 30, 2003.

(c) Reference is made to the Index of Exhibits following the signature page, which is hereby incorporated into this Item.

**SIGNATURES**

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENBRIDGE ENERGY PARTNERS, L.P.
(Registrant)

By: Enbridge Energy Management, L.L.C.,
as delegate of the General Partner

Date: March 12, 2004

By: /s/ DAN C. TUTCHER
Dan C. Tutcher
*(President)*

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below on March 12, 2004 by the following persons on behalf of the Registrant and in the capacities indicated.

| | |
|---|---|
| /s/ D. C. TUTCHER<br>D. C. Tutcher<br>President and Director<br>(Principal Executive Officer) | /s/ M.A. MAKI<br>M.A. Maki<br>Vice President — Finance<br>(Principal Financial Officer) |
| /s/ J.A. CONNELLY<br>J.A. Connelly<br>Director | /s/ E.C. HAMBROOK<br>E.C. Hambrook<br>Director |
| /s/ G.K. PETTY<br>G.K. Petty<br>Director | /s/ P.D. DANIEL<br>P.D. Daniel<br>Director |
| /s/ M.O. HESSE<br>M.O. Hesse<br>Director | /s/ J.R. BIRD<br>J.R. Bird<br>Director |

**Index to Exhibits**

The following Exhibits (numbered in accordance with Item 601 of Regulation S-K) are filed or incorporated herein by reference as part of this Report.

| Exhibit Number | Description |
|---|---|
| 3.1 | Certificate of Limited Partnership of the Partnership (Exhibit 3.1 to the Partnership's Registration Statement No. 33-43425) |
| 3.2 | Certificate of Amendment to Certificate of Limited Partnership of the Partnership (Exhibit 3.2 to the Partnership's 2000 Form 10-K/A dated October 9, 2001) |
| 3.3 | Third Amended and Restated Agreement of Limited Partnership of the Partnership (Exhibit 3.1 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002) |
| 4.1 | Form of Certificate representing Class A Common Units (Exhibit 4.1 to the Partnership's 2000 Form 10-K/A dated October 9, 2001) |
| 10.1 | Contribution, Conveyance and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership. (Exhibit 10.10 to the Partnership's 1991 Form 10-K) |
| 10.2 | LPL Contribution and Assumption Agreement, dated December 27, 1991, among Lakehead Pipe Line Company, Inc., Lakehead Pipe Line Partners, L.P. and Lakehead Pipe Line Company, Limited Partnership and Lakehead Services, Limited Partnership. (Exhibit 10.11 to the Partnership's 1991 Form 10-K) |
| 10.3 | Contribution Agreement (Exhibit 10.1 to the Partnership's Registration Statement on Form S-3/A filed July 8, 2002) |
| 10.4 | First Amendment to Contribution Agreement (Exhibit 10.8 to the Partnership's Registration Statement on Form S-3/A filed September 24, 2002) |
| 10.5 | Second Amendment to Contribution Agreement (Exhibit 99.3 to the Partnership's Current Report on Form 8-K filed October 31, 2002) |
| 10.6 | Delegation of Control Agreement (Exhibit 10.2 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002) |
| 10.7 | Amended and Restated Treasury Services Agreement (Exhibit 10.3 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002) |
| 10.8 | Operational Services Agreement (Exhibit 10.4 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002) |
| 10.9 | General and Administrative Services Agreement (Exhibit 10.5 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002) |
| 10.10 | Omnibus Agreement (Exhibit 10.6 to the Partnership's Quarterly Report on Form 10-Q filed November 14, 2002) |
| 10.11 | Amended and Restated Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (Exhibit 10.11 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003) |
| 10.12 | Amended and Restated 364-Day Credit Agreement, dated January 24, 2003, among Enbridge Energy Partners, L.P., Bank of America, N.A., as administrative agent, and the lenders party thereto (Exhibit 10.12 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003) |
| 10.13 | Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge Hungary Liquidity Management Limited Liability Company, as lender (Exhibit 10.13 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003) |

| Exhibit Number | Description |
|---|---|
| 10.14 | Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge Hungary Liquidity Management Limited Liability Company, as lender (Exhibit 10.14 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003) |
| 10.15 | Subordinated Promissory Note, dated as of January 24, 2003, given by Enbridge Energy Partners, L.P., as borrower, to Enbridge (U.S.) Inc., as lender (Exhibit 10.15 to the Partnership's Annual Report on Form 10-K filed on March 28, 2003) |
| 10.16 | Note Agreement and Mortgage, dated December 12, 1991 (Exhibit 10.1 to the Partnership's 1991 Form 10-K) |
| 10.17 | Assumption and Indemnity Agreement, dated December 18, 1992, between Interprovincial Pipe Line Inc. and Interprovincial Pipe Line System Inc. (Exhibit 10.4 to the Partnership's 1992 Form 10-K) |
| 10.18 | Settlement Agreement, dated August 28, 1996, between Lakehead Pipe Line Company, Limited Partnership and the Canadian Association of Petroleum Producers and the Alberta Department of Energy (Exhibit 10.17 to the Partnership's 1996 Form 10-K) |
| 10.19 | Tariff Agreement as filed with the Federal Energy Regulatory Commission for the System Expansion Program II and Terrace Expansion Project (Exhibit 10.21 to the Partnership's 1998 Form 10-K) |
| 10.20 | Promissory Note, dated as of September 30, 1998, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender (Exhibit 10.19 to the Partnership's 1998 Form 10-K) |
| 10.21 | Promissory Note, dated as of March 31, 1999, given by Lakehead Pipe Line Company, Limited Partnership, as borrower, to Lakehead Pipe Line Company, Inc., as lender. (Exhibit 10.26 to the Partnership's 1999 Form 10-K) |
| 10.22 | Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.1 to the Lakehead Pipe Line Company, Limited Partnership's Form 8-K dated October 20, 1998) |
| 10.23 | First Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.2 to the Lakehead Pipe Line Company, Limited Partnership's Form 8-K dated October 20, 1998) |
| 10.24 | Second Supplemental Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.3 to the Lakehead Pipe Line Company, Limited Partnership's Form 8-K dated October 20, 1998) |
| 10.25 | Third Supplemental Indenture dated November 21, 2000, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.2 to the Lakehead Pipe Line Company, Limited Partnership's Form 8-K dated November 16, 2000) |
| 10.26 | Indenture dated September 15, 1998, between Lakehead Pipe Line Company, Limited Partnership and the Chase Manhattan Bank (Exhibit 4.4 to the Lakehead Pipe Line Company, Limited Partnership's Form 8-K dated October 20, 1998) |
| *10.27 | Executive Employment Agreement, dated May 11, 2001, between Dan C. Tutcher, as Executive, and Enbridge Inc., as corporation. |
| *10.28 | Executive Employment Agreement, dated May 11, 2001, between E. Chris Kaitson, as Executive, and Enbridge Inc., as corporation. |
| 10.29 | Indenture dated May 27, 2003, between the Partnership, as Issuer, and SunTrust Bank, as Trustee (Exhibit 4.5 to the Partnership's Registration Statement on Form S-4 filed June 30, 2003) |
| 10.30 | First Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (Exhibit 4.5 to the Partnership's Registration Statement on Form S-4 filed June 30, 2003) |

| Exhibit Number | Description |
|---|---|
| 10.31 | Second Supplemental Indenture dated May 27, 2003 between the Partnership and SunTrust Bank (Exhibit 4.5 to the Partnership's Registration Statement on Form S-4 filed June 30, 2003) |
| 10.32 | Third Supplemental Indenture dated January 9, 2004 between the Partnership and SunTrust Bank (Exhibit 99.3 to the Partnership's Form 8-K filed January 9, 2004) |
| 14.1 | Code of Ethics for Senior Financial Officers |
| 21.1 | Subsidiaries of the Registrant |
| 23.1 | Consent of PricewaterhouseCoopers LLP |
| 31.1 | Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 |
| 32.1 | Certification of Chief Executive Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2 | Certification of Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 99.1 | Charter of the Audit, Finance & Risk Committee of Enbridge Energy Management, L.L.C. |

All Exhibits listed above (with the exception of Exhibits 14.1, 21.1, 23.1, 31.1, 31.2, 32.1, 32.2, and 99.1 which are filed herewith) are incorporated herein by reference to the documents identified in parentheses.

Copies of Exhibits may be obtained upon written request of any Unitholder to Investor Relations, Enbridge Energy Partners, L.P., 1100 Louisiana, Suite 3300, Houston, Texas 77002.

* Management Compensation or Incentive Plan

## INDEX TO CONSOLIDATED FINANCIAL STATEMENTS, SUPPLEMENTARY INFORMATION AND CONSOLIDATED FINANCIAL STATEMENT SCHEDULES

## ENBRIDGE ENERGY PARTNERS, L.P.

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### FINANCIAL STATEMENT SCHEDULES

Financial statement schedules not included in this Report have been omitted because they are not applicable or the required information is shown in the consolidated financial statements or notes thereto.

**Report of Independent Auditors**

To the Partners of
Enbridge Energy Partners, L.P.

In our opinion, the accompanying consolidated statements of financial position and the related consolidated statements of income, of comprehensive income, of cash flows and of partners' capital present fairly, in all material respects, the consolidated financial position of Enbridge Energy Partners, L.P. and its subsidiaries (the "Partnership") at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Partnership's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about 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, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the consolidated financial statements, the Partnership changed its method of accounting for goodwill and intangible assets effective January 1, 2002.

PricewaterhouseCoopers LLP

Houston, Texas
January 27, 2004, except for
the first two paragraphs of Note 15, as to which the date is
March 1, 2004

**ENBRIDGE ENERGY PARTNERS, L.P.**

**CONSOLIDATED STATEMENTS OF INCOME**

| | Year ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (dollars and units in millions, except per unit amounts) | | |
| Operating revenue | $3,172.3 | $1,185.5 | $342.3 |
| Expenses | | | |
| Cost of natural gas | 2,612.7 | 770.7 | 26.3 |
| Operating and administrative | 211.8 | 144.2 | 104.5 |
| Power | 56.1 | 52.7 | 49.9 |
| Depreciation and amortization | 97.4 | 79.9 | 63.8 |
| | 2,978.0 | 1,047.5 | 244.5 |
| Operating income | 194.3 | 138.0 | 97.8 |
| Interest expense | (85.0) | (59.2) | (59.3) |
| Other income (expense) | 2.4 | (0.2) | 0.9 |
| Minority interest | — | (0.5) | (0.5) |
| Net income | $ 111.7 | $ 78.1 | $ 38.9 |
| Net income allocable to common and i-units | $ 92.1 | $ 65.0 | $ 29.8 |
| Net income per common and i-unit (Note 4) | $ 1.93 | $ 1.76 | $ 0.98 |
| Weighted average units outstanding | 47.7 | 36.7 | 30.2 |
| Cash distributions paid per unit | $ 3.70 | $ 3.60 | $ 3.50 |

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

**ENBRIDGE ENERGY PARTNERS, L.P.**

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

| | Year ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (dollars in millions) | | |
| Net income | $111.7 | $ 78.1 | $38.9 |
| Unrealized (loss) gain on derivative financial instruments | (47.7) | (28.2) | 11.9 |
| Comprehensive income | $ 64.0 | $ 49.9 | $50.8 |

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

**ENBRIDGE ENERGY PARTNERS, L.P.**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | Year ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (dollars in millions) | | |
| Cash provided from operating activities | | | |
| Net income | $ 111.7 | $ 78.1 | $ 38.9 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization | 97.4 | 79.9 | 63.8 |
| Other | (0.4) | (2.9) | 0.3 |
| Changes in operating assets and liabilities, net of acquired working capital: | | | |
| Receivables, trade and other | (21.0) | 46.0 | (22.7) |
| Due from General Partner and affiliates | (7.2) | — | — |
| Accrued gas receivables | (59.2) | (162.0) | — |
| Other current assets | (24.8) | 18.7 | (9.4) |
| Due to General Partner and affiliates | (8.7) | 12.5 | — |
| Accounts payable and other | (34.1) | (3.6) | 54.3 |
| Accrued gas purchases | 76.6 | 136.4 | — |
| Interest payable | (0.2) | (1.2) | 0.3 |
| Property and other taxes payable | 2.0 | (1.3) | (0.2) |
| Net cash provided by operating activities | $ 132.1 | $ 200.6 | $ 125.3 |
| Cash used in investing activities | | | |
| Additions to property, plant and equipment | (129.3) | (214.7) | (35.0) |
| Change in construction payable | (7.5) | 6.7 | (2.1) |
| Asset acquisitions, net of cash acquired (Note 3) | (294.2) | (349.2) | (265.0) |
| Net cash used in investing activities | $ (431.0) | $ (557.2) | $(302.1) |
| Cash provided by financing activities | | | |
| Proceeds from unit issuances, net (Note 10) | 414.4 | 424.1 | 171.3 |
| Distributions to partners | (156.7) | (138.1) | (113.8) |
| Borrowings under debt agreements | 2,653.3 | 2,939.0 | 452.0 |
| Repayments of debt | (2,297.0) | (2,643.0) | (505.0) |
| Borrowings from General Partner and affiliates | 16.0 | 1,074.7 | 176.2 |
| Repayments to the General Partner and affiliates | (327.0) | (1,279.1) | — |
| Other | — | (0.9) | (0.9) |
| Net cash provided by financing activities | $ 303.0 | $ 376.7 | $ 179.8 |
| Net increase in cash and cash equivalents | 4.1 | 20.1 | 3.0 |
| Cash and cash equivalents at beginning of year | 60.3 | 40.2 | 37.2 |
| Cash and cash equivalents at end of year | $ 64.4 | $ 60.3 | $ 40.2 |

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

## ENBRIDGE ENERGY PARTNERS, L.P.
## CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

| | December 31, 2003 | December 31, 2002 |
|---|---|---|
| | (dollars in millions) | |
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ 64.4 | $ 60.3 |
| Receivables, trade and other, net of allowance for doubtful accounts of $2.9 in 2003 and $3.7 in 2002 | 46.3 | 27.4 |
| Due from General Partner and affiliates | 7.2 | — |
| Accrued gas receivables | 249.7 | 190.5 |
| Other current assets | 41.2 | 19.3 |
| | 408.8 | 297.5 |
| Property, plant and equipment, net (Note 5) | 2,465.6 | 2,253.3 |
| Other assets | 22.9 | 12.6 |
| Goodwill (Note 6) | 257.3 | 241.1 |
| Intangibles, net (Note 7) | 77.2 | 30.4 |
| | $3,231.8 | $2,834.9 |
| **LIABILITIES AND PARTNERS' CAPITAL** | | |
| Current liabilities | | |
| Due to General Partner and affiliates | $ 1.8 | $ 63.1 |
| Accounts payable and other | 85.1 | 87.2 |
| Accrued gas purchases | 230.6 | 154.0 |
| Interest payable | 6.8 | 7.0 |
| Property and other taxes payable | 18.3 | 16.3 |
| Current maturities and short-term debt (Note 8) | 246.0 | 31.0 |
| | 588.6 | 358.6 |
| Long-term debt (Note 8) | 1,155.8 | 1,011.4 |
| Loans from General Partner and affiliates (Note 10) | 133.1 | 444.1 |
| Commitments, contingencies and environmental liabilities (Note 11) | 7.9 | 5.6 |
| Deferred credits | 33.1 | 23.2 |
| Minority interest | — | 0.4 |
| | 1,918.5 | 1,843.3 |
| Partners' capital (Note 9) | | |
| Class A common units (Units issued — 40,166,134 in 2003 and 31,313,634 in 2002) | 914.9 | 604.8 |
| Class B common units (Units issued — 3,912,750 in 2003 and 2002) | 64.2 | 48.7 |
| i-units (Units issued — 10,062,170 in 2003 and 9,228,655 in 2002) | 370.7 | 335.6 |
| General Partner | 27.5 | 18.8 |
| Accumulated other comprehensive loss | (64.0) | (16.3) |
| | 1,313.3 | 991.6 |
| | $3,231.8 | $2,834.9 |

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

**ENBRIDGE ENERGY PARTNERS, L.P.**
**CONSOLIDATED STATEMENTS OF PARTNERS' CAPITAL**

| | Years ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 2003 | | 2002 | | 2001 | |
| | Units | Amount | Units | Amount | Units | Amount |
| | | | (dollars in millions) | | | |
| **Class A common units:** | | | | | | |
| Beginning balance | 31,313,634 | $ 604.8 | 29,053,634 | $ 577.0 | 24,990,000 | $488.6 |
| Net income allocation | — | 64.9 | — | 52.3 | — | 24.4 |
| Allocation of proceeds and issuance costs from unit issuance | 8,852,500 | 368.2 | 2,260,000 | 86.2 | 4,063,634 | 154.6 |
| Distributions to partners | — | (123.0) | — | (110.7) | — | (90.6) |
| Ending balance | 40,166,134 | 914.9 | 31,313,634 | 604.8 | 29,053,634 | 577.0 |
| **Class B common units:** | | | | | | |
| Beginning balance | 3,912,750 | 48.7 | 3,912,750 | 48.8 | 3,912,750 | 42.1 |
| Net income allocation | — | 8.3 | — | 7.9 | — | 5.4 |
| Allocation of proceeds and issuance costs from unit issuance | — | 21.7 | — | 6.1 | — | 15.0 |
| Distributions to partner | — | (14.5) | — | (14.1) | — | (13.7) |
| Ending balance | 3,912,750 | 64.2 | 3,912,750 | 48.7 | 3,912,750 | 48.8 |
| **i-units:** | | | | | | |
| Beginning balance | 9,228,655 | 335.6 | — | — | — | — |
| Net income allocation | — | 18.9 | — | 4.8 | — | — |
| Allocation of proceeds and issuance costs from unit issuance | — | 16.2 | 9,000,001 | 330.8 | — | — |
| Distributions to partner | 833,515 | — | 228,654 | — | — | — |
| Ending balance | 10,062,170 | 370.7 | 9,228,655 | 335.6 | — | — |
| **General Partner:** | | | | | | |
| Beginning balance | | 18.8 | | 6.5 | | 5.2 |
| Net income allocation | | 19.6 | | 13.1 | | 9.1 |
| Allocation of proceeds and issuance costs from unit issuance | | (0.3) | | 1.0 | | 1.7 |
| General Partner contribution | | 8.6 | | 11.5 | | — |
| Distributions to partner | | (19.2) | | (13.3) | | (9.5) |
| Ending balance | | 27.5 | | 18.8 | | 6.5 |
| **Accumulated other comprehensive (loss) income:** | | | | | | |
| Beginning balance | | (16.3) | | 11.9 | | — |
| Unrealized (loss) gain on derivative financial instruments | | (47.7) | | (28.2) | | 11.9 |
| Ending balance | | (64.0) | | (16.3) | | 11.9 |
| Partners' capital at December 31, | | $1,313.3 | | $ 991.6 | | $644.2 |

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

**ENBRIDGE ENERGY PARTNERS, L.P.**
**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS**

## 1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS

***General***

Enbridge Energy Partners, L.P. and its subsidiaries (the "Partnership") is a publicly-traded Delaware limited partnership that owns and operates crude oil and liquid petroleum transportation assets, as well as natural gas gathering, treating, processing, transmission and marketing assets in the United States of America. The Class A common units of the Partnership are traded on the New York Stock Exchange ("NYSE") under the symbol "EEP."

The Partnership was formed in 1991 by Enbridge Energy Company, Inc. (the "General Partner"), which is an indirect, wholly-owned subsidiary of Enbridge Inc. ("Enbridge") of Calgary, Canada. The Partnership was formed to acquire, own and operate the crude oil and liquid petroleum transportation assets of Enbridge Energy, Limited Partnership (the "Lakehead Partnership").

On December 31, 2003, the Partnership acquired the natural gas gathering and processing assets in north Texas (the "North Texas system"). On October 17, 2002, the Partnership acquired the natural gas gathering, treating, processing, transmission and marketing assets of Enbridge Midcoast Energy, Inc. (comprised of the "Midcoast system", "Northeast Texas system" and the "South Texas system") from the General Partner. During 2001, the Partnership acquired the crude oil and liquid petroleum transportation assets of Enbridge Pipelines (North Dakota) L.L.C. (the "North Dakota system") and natural gas gathering, transportation, processing and marketing assets in east Texas (the "East Texas system"). The assets acquired are held in a series of limited liability companies and limited partnerships owned, directly or indirectly, wholly-owned by the Partnership.

On October 17, 2002, in connection with the acquisition described above, the Partnership's ownership of the Lakehead Partnership was restructured such that the Lakehead Partnership is now a wholly-owned subsidiary of the Partnership. As a result of this restructuring, the General Partner holds a 2% general partner interest in the Partnership, but no longer holds a direct interest in the Lakehead Partnership.

***Enbridge Energy Management, L.L.C.***

Enbridge Energy Management, L.L.C. and its subsidiary ("Enbridge Management"), a Delaware limited liability company, was formed on May 14, 2002. The General Partner owns all of the voting shares of Enbridge Management. At December 31, 2003 and 2002, Enbridge Management owned approximately 18.2% and 20.3%, respectively, of the outstanding limited partner units of the Partnership. Enbridge Management receives its earnings from this investment.

All of the Partnership's i-units are held by Enbridge Management. As of December 31, 2003 and 2002, Enbridge Management held 10,062,170 and 9,228,655 i-units, respectively. Enbridge Management, pursuant to a delegation of control agreement, manages the business and affairs of the Partnership. The Delegation of Control Agreement provides that Enbridge Management will not amend or propose to amend the Partnership's partnership agreement, allow a merger or consolidation involving the Partnership, allow a sale or exchange of all or substantially all of the assets of the Partnership or dissolve or liquidate the Partnership without the approval of the General Partner. In accordance with its limited liability company agreement, Enbridge Management's activities are restricted to being a limited partner in, and managing the business and affairs, of the Partnership.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## 1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS—(Continued)

***Enbridge Inc.***

Enbridge, a Canadian corporation, is the indirect parent of the General Partner and is traded on the NYSE and Toronto Stock Exchange under the symbol "ENB." Enbridge is a leader in the transportation and distribution of energy, with a focus on crude oil and liquids pipelines, natural gas pipelines and natural gas distribution in North America. Enbridge also has international interests located in Western Europe and Latin America. At December 31, 2003 and 2002, Enbridge and its consolidated subsidiaries owned, through the General Partner, an approximate 12.2% and 14.1% interest, respectively, in the Partnership.

***Business Segments***

The Partnership conducts its business through four business segments: Liquids Transportation, Gathering and Processing, Natural Gas Transportation, and Marketing. These operating segments are strategic business units established by senior management to facilitate the achievement of the Partnership's long-term objectives, to aid in resource allocation decisions and to assess operational performance.

As a result of the purchase of natural gas assets in October 2002, the Partnership changed the organization of its business segments effective in the fourth quarter of 2002. Prior period segment results have been restated to conform to the Partnership's current organization. For more information on the Partnership's reportable business segments, see Note 14.

**Liquids Transportation**

Liquids Transportation includes the operations of the Lakehead system, which consists of crude oil and liquid petroleum transportation and storage assets in the Great Lakes and Midwest regions of the United States. The Lakehead system, which spans approximately 1,900 miles, has been in operation for over 50 years and is the primary transporter of crude oil and liquid petroleum from western Canada to the United States. The Lakehead system serves all the major refining centers in the Great Lakes and Midwest regions of the United States and the Province of Ontario, Canada. Liquids Transportation also includes the operations of the North Dakota system, which consists of crude oil gathering lines connected to a transportation line that interconnects directly with the Lakehead system in the state of Minnesota.

**Gathering and Processing**

The Gathering and Processing segment includes the East Texas, Midcoast, Northeast Texas, South Texas and the newly acquired North Texas systems. The East Texas system includes natural gas gathering and transmission pipelines, four natural gas treating plants and three natural gas processing plants. The Midcoast system consists of 35 gathering and processing/treating systems, as well as trucks, trailers, and rail cars used for transporting natural gas liquids ("NGLs"), crude oil and carbon dioxide. The Northeast Texas system includes natural gas gathering pipelines, nine natural gas treating plants and three natural gas processing plants. The South Texas system includes natural gas gathering pipelines, a hydrogen sulfide treating plant and a natural gas processing plant. The North Texas system includes natural gas gathering pipelines and nine natural gas processing plants.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## 1. PARTNERSHIP ORGANIZATION AND NATURE OF OPERATIONS—(Continued)

### Natural Gas Transportation

The Natural Gas Transportation segment consists of four Federal Energy Regulatory Commission ("FERC") regulated natural gas transmission pipeline systems and 35 intrastate natural gas transmission and wholesale customer pipeline systems located in the Mid-Continent and Gulf Coast regions of the United States. These pipeline systems form part of the Midcoast System assets that were acquired from the General Partner in 2002, see Note 3.

### Marketing

The Marketing segment primarily provides natural gas supply, transmission storage and sales services for producers and wholesale customers on the Partnership's pipelines as well as other interconnected natural gas pipeline systems. Natural gas marketing activities are primarily undertaken to increase pipeline utilization, realize incremental margins on gas purchased at the wellhead, and provide value added services to customers.

## 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements of the Partnership are prepared in accordance with accounting principles generally accepted in the United States of America. The preparation of consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and the disclosure of contingent assets and liabilities. Management evaluates these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods considered reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on the consolidated financial statements resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

### *Basis of Presentation and Principles of Consolidation*

The financial statements include the accounts of the Partnership and its wholly-owned subsidiaries on a consolidated basis. All significant intercompany items have been eliminated in consolidation.

### *Regulation*

The Partnership's Liquids Transportation, Gathering and Processing and certain of its Natural Gas Transportation activities are subject to regulation by the FERC and various state authorities. Regulatory bodies exercise statutory authority over matters such as construction, rates and underlying accounting practices, and ratemaking agreements with customers.

Certain of the Natural Gas Transportation systems are subject to the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, *"Accounting for the Effects of Certain Types of Regulation."* Accordingly, certain assets and liabilities that result from the regulated ratemaking process are recorded that would not be recorded for non-regulated entities under accounting principles generally accepted in the United States of America. The Partnership acquired four interstate FERC-regulated natural gas transmission pipeline systems as part of the Midcoast Acquisition, see also Note 3.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## 2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)

***Revenue Recognition***

Revenues of the Liquids Transportation segment are derived from interstate transportation of crude oil and liquid petroleum under tariffs regulated by the FERC. The tariffs specify the amounts to be paid by shippers for service between receipt and delivery locations and the general terms and conditions of transportation service on the respective pipeline systems. Revenues are recorded upon delivery. The Partnership does not own the crude oil and liquid petroleum that it transports, and therefore does not assume the related commodity risk.

Revenues of the Gathering and Processing segment are derived from gathering and processing services under the following types of arrangements:

*Fee-Based Arrangements:* Under a fee-based contract, the Partnership receives a set fee for gathering, treating, processing and transmission of raw natural gas and providing other gathering services. These revenues correlate with volumes and types of service, and do not depend directly on commodity prices.

*Other Arrangements:* The Partnership also utilizes other types of arrangements in its natural gas gathering and processing business:

- Percentage-of-Index-Contracts—Under these contracts, the Partnership purchases raw natural gas at a negotiated discount to an agreed upon index. The Partnership then resells the natural gas, generally for the index price, keeping the difference as its fee.
- Percentage-of-Proceeds Contracts-Under these contracts, the Partnership receives a negotiated percentage of the natural gas it processes in the form of residue natural gas, NGLs condensate and sulfur, which it then sells at market prices.
- Keep-Whole Contracts—Under these contracts, the Partnership gathers or purchases raw natural gas from the producer for processing. A portion of the gathered or purchased gas is consumed during processing. The Partnership extracts and retains the NGLs produced during processing for its own account, which it sells at market prices. In instances where the Partnership purchases raw gas at the wellhead, it also sells for its own account the residue gas resulting from processing at market prices. In those instances when the Partnership gathers and processes raw natural gas for the account of the producer, it must return to the producer residue gas with a British Thermal Unit content equivalent to the original raw gas it received.

Some of these other arrangements expose the Partnership to commodity price risk, which is substantially mitigated by offsetting physical purchases and sales and derivative financial instruments. Revenues under all arrangements are recognized upon delivery of natural gas and natural gas liquids to customers and/or upon services rendered.

Revenues of the Natural Gas Transportation segment are generally derived from reservation fees charged for transmission of natural gas on the FERC-regulated interstate natural gas transmission pipeline systems, while revenues from intrastate pipelines are generally derived from the bundled sales of natural gas and transmission services. Customers of the FERC-regulated natural gas pipeline systems typically pay a reservation fee each month to reserve capacity plus a nominal commodity charge based on actual transmission volumes. Revenues are recognized as natural gas is delivered to customers or as transportation services are rendered.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)**

Revenues of the Marketing segment are derived from providing supply, transmission storage and sales service for producers and wholesale customers on the Partnership's natural gas gathering, transmission and customer pipelines, as well as other interconnected pipeline systems. Natural gas marketing activities are primarily undertaken to increase pipeline utilization, realize incremental margins on gas purchased at the wellhead, and provide value-added services to customers. In general, natural gas purchased and sold by the Marketing business is priced at a published daily or monthly price index. Sales to wholesale customers typically incorporate a premium for managing their transmission and balancing requirements. Higher premiums and associated margins result from transactions that involve smaller volumes or that offer greater service flexibility for wholesale customers. At the request of some customers, the Partnership will enter into long-term fixed price purchase or sale contracts with its customers and usually will enter into offsetting positions under the same or similar terms. Revenues are recognized upon delivery of natural gas and natural gas liquids to customers and/or upon services rendered.

***Cash and Cash Equivalents***

Cash equivalents are defined as all highly marketable securities with maturities of three months or less when purchased. The carrying value of cash and cash equivalents approximates fair value because of the short term to maturity of these investments.

The Partnership extinguishes liabilities when a creditor has relieved the Partnership of the obligation, which occurs when the Partnership's financial institution honors a check that the creditor has presented for payment. As such, included in Accounts Payable and Other are obligations for which the Partnership has issued check payments that have not yet been presented to the financial institution of approximately $11.9 million and $2.9 million at December 31, 2003 and 2002, respectively.

***Allowance for Doubtful Accounts***

The Partnership establishes provisions for losses on accounts receivable if it determines that it will not collect all or part of the outstanding balance. Collectibility is reviewed regularly and an allowance is established or adjusted, as necessary, using the specific identification method.

***Other Current Assets***

Other current assets include product inventory, materials and supplies inventory, and prepaid expenses. The product inventory consists of natural gas liquids and natural gas. All inventories are valued at the lower of cost or market.

***Operational Balancing Agreements and Natural Gas Imbalances***

To facilitate deliveries of natural gas and provide for operational flexibility, many natural gas transmission companies have operational balancing agreements in place with other interconnecting pipelines. These agreements ensure that the volume of gas a shipper schedules for transportation between two interconnecting pipelines equals the volume actually delivered. If natural gas moves between pipelines in volumes that are more or less than the volumes the shipper previously scheduled, a gas imbalance is created. The imbalances are settled through periodic cash payments or repaid in kind through the receipt or delivery of natural gas in the future. Gas imbalances are recorded as

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)**

current assets or current liabilities on the balance sheet using the posted index prices, which approximate market rates, or the Partnership's weighted average cost of gas.

***Property, Plant and Equipment***

Property, plant and equipment is stated at its original cost of construction or, upon acquisition, at the fair value of the assets acquired. Expenditures for system expansion and major renewals and betterments are capitalized; maintenance and repair costs are expensed as incurred.

Depreciation rates for the pipeline systems are based on the lesser of the estimated remaining useful lives of the properties or the estimated remaining life of crude oil or natural gas production in the basins served by the pipelines.

The Partnership capitalizes direct costs, such as labor and materials, and related indirect costs, such as overhead and interest at the Partnership's weighted average cost of debt, and, in its regulated businesses that apply the provisions of SFAS No. 71, an equity return component, during construction. Depreciation of property, plant and equipment is provided on a straight-line basis over estimated useful lives. For all segments, on disposition of property, plant and equipment, the cost less net proceeds is normally charged to accumulated depreciation and no gain or loss on disposal is recognized.

Expenditures related to property, plant and equipment are capitalized ("capital expenditures"), subject to a minimum rule, that have a useful life greater than one year for (1) assets purchased or constructed; (2) existing assets that are extended, replaced, or improved; or (3) all land, regardless of cost. Acquisition of new assets, additions, replacements and improvements (other than land) costing less than the established minimum rules are expensed accordingly.

Capital expenditures are categorized by the Partnership as either core maintenance or enhancement expenditures. Core maintenance expenditures are those expenditures that are necessary to maintain the service capability of the existing assets and includes the replacement of system components and equipment which is worn, obsolete or completing its useful life. Enhancement expenditures improve the service capability of the existing assets, extend asset useful lives, increase capacities from existing levels, reduce costs or enhance revenues, and enable the Partnership to respond to governmental regulations and developing industry standards.

The Partnership evaluates impairment of long-lived assets whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment loss will be recognized when the sum of estimated undiscounted future cash flows expected to result from use of the asset and its eventual disposition is less than its carrying amount. If an impairment loss will be recognized, the amount of the impairment would be calculated as the excess of the carrying amount of the asset over the fair value of the assets either through reference to similar asset sales, or by estimating the fair value using a discounted cash flow approach. There have been no impairments recorded in 2003, 2002 or 2001.

***Goodwill***

Goodwill represents the excess of the purchase price over the fair value of net assets acquired in a business combination. Goodwill is allocated to three of the Partnership's segments, Gathering and Processing, Natural Gas Transportation, and Marketing.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)**

Effective January 1, 2002, the Partnership adopted SFAS No. 142, "*Goodwill and Other Intangible Assets*". Goodwill is not amortized but is tested for impairment annually, or more frequently if impairment indicators arise that indicate the carrying value of goodwill may not be recovered. Impairment occurs when the carrying amount of a reporting unit exceeds the fair value of the reporting unit. At the time the Partnership determines that impairment has occurred, the carrying value of the goodwill is written down to its fair value.

***Intangibles, Net***

Other intangible assets consist of natural gas purchase and sale customer contracts, and natural gas opportunities, which are amortized on a straight-line basis, which approximates the effective interest method, over the weighted average useful life of the underlying reserves.

The Partnership evaluates the carrying value of the intangible assets, whenever certain events or changes in circumstances indicate that the carrying amount of these assets may not be recoverable. In assessing the recoverability of intangibles, the Partnership compares the carrying value to the undiscounted future cash flows the intangibles are expected to generate. If the total of the undiscounted future cash flows is less than the carrying amount of the intangibles, the intangibles are written down to their fair value. There have been no impairments recorded in 2003, 2002, or 2001.

***Other Assets***

Other assets primarily include deferred financing charges, which 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 on the Consolidated Statements of Income.

***Income Taxes***

The Partnership is not a taxable entity for federal and state income tax purposes. Accordingly, no recognition is given to income taxes for financial reporting purposes. The tax on Partnership net income is borne by the individual partners through the allocation of taxable income. Net income for financial statement purposes may differ significantly from taxable income of unitholders as a result of differences between the tax basis and financial reporting basis of assets and liabilities and the taxable income allocation requirements under the Partnership Agreement. The aggregate difference in the basis of the Partnership's net assets for financial and tax reporting purposes cannot be readily determined because information regarding each partner's tax attributes in the Partnership is not available.

***Derivative Financial Instruments***

Net income and cash flows are subject to volatility stemming from changes in market prices such as interest rates, natural gas prices, natural gas liquids prices and fractionation margins. In order to manage the risks to Partnership unitholders, the General Partner uses a variety of derivative financial instruments to create offsetting positions to specific commodity or interest rate exposures. Under SFAS No. 133 all derivative financial instruments are reflected in the balance sheet at their fair value. For those instruments that qualify for hedge accounting, the accounting treatment depends on each instrument's intended use and how it is designated. For those instruments that do not qualify for hedge accounting, the change in market value is recorded as cost of natural gas in the Consolidated Statement of Income.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)**

In implementing its hedging programs, the General Partner has established a formal analysis, execution and reporting framework that requires the approval of the Board of Directors of the General Partner or a committee of senior management. Derivative financial instruments are employed in connection with an underlying asset, liability and/or anticipated transaction and are not used for speculative purposes.

Derivative financial instruments qualifying for hedge accounting treatment and in use by the Partnership can generally be divided into two categories: 1) cashflow hedges, or 2) fair value hedges. Cashflow hedges are entered into to hedge the variability in cashflow(s) related to a forecasted transaction. Fair value hedges are entered into to hedge the value of a recognized asset or liability.

At inception, the Partnership formally documents the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing correlation and hedge effectiveness. The Partnership also assesses, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in its hedging transactions are highly effective in offsetting changes in cash flows or fair value of the hedged item. Furthermore, the Partnership regularly assesses the creditworthiness of the derivative counterparties to manage against the risk of default. If the Partnership determines that a derivative is no longer highly effective as a hedge, it discontinues hedge accounting prospectively by including changes in the fair value of the derivative in current earnings.

For cash flow hedges, changes in the derivative fair values, to the extent that the hedges are determined to be highly effective, are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. Any ineffective portion of a cash flow hedge's change in value is recognized immediately in earnings. For fair value hedges, the change in mark to market value of the financial instrument is determined each period and is taken into earnings. In conjunction with this, the change in the value of the hedged item is also calculated and taken into earnings. To the extent that the two valuations offset, the hedge is effective and there should not be a net earnings effect.

***Environmental Liabilities***

The Partnership expenses or capitalizes, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. Amounts for remediation of existing environmental contamination caused by past operations, which do not benefit future periods by preventing or eliminating future contamination, are expensed. Liabilities are recorded when environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of the liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by government organizations. These estimates are subject to revision in future periods based on actual costs or new circumstances and are included on the balance sheet in other current and long-term liabilities at their undiscounted amounts. The Partnership evaluates recoveries from insurance coverage separately from its liability and, when recovery is probable, it records and reports an asset separately from the associated liability in its financial statements.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)**

The Partnership recognizes liabilities for other contingencies when it has an exposure that, when fully analyzed, indicates it is either probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, the Partnership accrues the most likely amount, or at least the minimum of the range of probable loss.

***Asset Retirement Obligations***

Effective January 1, 2003, the Partnership adopted SFAS No. 143, "*Accounting for Asset Retirement Obligations*" ("SFAS No. 143"), which addresses accounting and reporting for legal asset obligations associated with the retirement of long-lived tangible assets. SFAS No. 143 requires entities to record the fair value of a liability for the retirement obligation in the period in which the liability is incurred if a reasonable estimate of fair value can be made. The associated asset retirement costs are capitalized as part of the carrying value of the asset, which is subsequently depreciated over its useful life. For offshore pipeline systems, a legal obligation exists for decommissioning requirements. However, the fair value of the asset retirement obligations cannot be reasonably estimated, as settlement dates and scope of decommissioning work are indeterminate. For a minority of onshore rights-of-way agreements, a legal obligation may be construed to exist due to the requirement to remove the pipe at final abandonment. However, the fair value of the asset retirement obligation cannot be reasonably estimated, as the settlement dates are indeterminate. In certain rate jurisdictions, the Partnership is permitted to include annual charges for cost of removal in its regulated cost of service rates charged to customers. For the year ended December 31, 2003, the Partnership recorded a $0.8 million long-term liability with a resulting increase in the related property, plant and equipment in the consolidated statement of financial position and a corresponding accretion expense of $0.1 million in the consolidated statement of net income.

***Comparative Amounts***

Certain reclassifications have been made to the prior years' reported amounts to conform to the classifications used in the 2003 consolidated financial statements. These reclassifications have no impact on net income.

***New Accounting Pronouncements***

In April 2003, the Financial Accounting Standards Board ("FASB") issued SFAS No. 149, "*Amendment of Statement 133 on Derivative Instruments and Hedging Activities*." This statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities. In particular, this statement: (1) clarifies under what circumstances a contract with an initial net investment meets the characteristic of a derivative discussed in paragraph 6(b) of SFAS No. 133, (2) clarifies when a derivative contains a financing component, (3) amends the definition of an underlying to conform it to language used in FASB Interpretation No. 45, Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others, and (4) amends certain other existing pronouncements. The new standard was adopted July 1, 2003 and did not have a significant impact on the Partnership's financial position, results of operations, or cash flows.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES—(Continued)**

In January 2003, the FASB issued Interpretation No. 46, "*Consolidation of Variable Interest Entities*" ("FIN 46"). FIN 46 requires an investor with a majority of the variable interests in a variable interest entity to consolidate the entity and also requires majority and significant variable interest investors to provide certain disclosures. A variable interest entity is an entity in which the equity investors do not have a controlling interest or the equity investment at risk is insufficient to finance the entity's activities without receiving additional subordinated financial support form the other parties. In December 2003, the FASB completed deliberations of proposed modifications to FIN 46 resulting in multiple effective dates based on the nature as well as the creation date of the variable interest entity. However, the revised Interpretation must be applied no later than the first quarter of fiscal year 2004. There was no impact on the Partnership's consolidated financial position or results if operations as a result of the adoption of FIN 46, as revised.

**3. ACQUISITIONS**

The primary strategy of the Partnership is to grow cash distributions through the profitable expansion of existing assets and through development and acquisition of complementary businesses with similar risk profiles to the Partnership's current business. During 2003 and 2002, the Partnership completed acquisitions, each of which were accounted for using the purchase method and the assets acquired and liabilities assumed were recorded at their estimated fair market values as determined by independent appraisals. The results of operations from these acquisitions are included in earnings from the effective date of acquisition.

**North Texas Acquisition**

Effective December 31, 2003, the Partnership acquired natural gas gathering and processing assets in north Texas. The gathering system, referred to as the North Texas system, primarily serves the Fort Worth Basin, including the Barnett Shale producing zone, and is complementary to the Partnership's existing natural gas systems in the area. The assets were purchased for cash of $249.7 million, which includes the buyout of a capital lease of $1.9 million and transaction costs of $1.8 million. The purchase was funded with borrowings under the Partnership's 364-day revolving credit facility and three-year term facility. The value allocated to the assets was determined by an independent appraisal. Goodwill associated with the acquisition was $23.9 million, and is allocated entirely to the Gathering and Processing segment. Intangible assets acquired of $48.1 million represents the fair value associated with the natural gas supply opportunities present in the Barnett Shale producing zone that will be shipped through the North Texas systems and is recorded in the Gathering and Processing segment. Of the $2.7 million environmental liabilities assumed, $0.5 million are included in accounts payable and other and $2.2 million are included in commitments, contingencies and environmental liabilities on the consolidated Statement of Financial Position.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**3. ACQUISITIONS—(Continued)**

The purchase price and the allocation to assets acquired and liabilities assumed was as follows:

| | (dollars in millions) |
|---|---|
| Purchase Price: | |
| Cash paid, including transaction costs | $249.7 |
| Allocation of purchase price: | |
| Current assets | $ 0.4 |
| Property, plant and equipment, including construction in progress | 181.0 |
| Intangibles | 48.1 |
| Goodwill | 23.9 |
| Current liabilities | (1.0) |
| Environmental liabilities | (2.7) |
| Total | $249.7 |

**Midcoast Acquisition**

Effective October 17, 2002, the Partnership acquired assets from the General Partner for approximately $875.5 million, including transaction costs of $4.9 million and post-closing adjustments of approximately $50.6 million. In December 2003, the Partnership paid $43.8 million, which includes $2.0 million of interest, in full settlement of post-closing adjustments from the acquisition of acquired assets. The purchase price was therefore reduced by $8.8 million, which is reflected as a decrease to Goodwill in 2003. The following assets were purchased:

***Midcoast System***

This system includes natural gas gathering and transmission pipelines, and natural gas treating and processing assets in the Mid-Continent and Gulf Coast regions of the United States, including:

- four interstate FERC-regulated natural gas transmission pipeline systems;
- intrastate natural gas transmission and wholesale customer pipeline systems;
- gathering and processing/treating systems, including four processing plants; and
- trucks, trailers and rail cars used for transporting natural gas liquids, crude oil and carbon dioxide.

***Northeast Texas System***

This system includes natural gas gathering pipelines, four active natural gas treating plants, and two active natural gas processing plants. This system is located adjacent to the Partnership's East Texas system.

***South Texas System***

This system includes natural gas gathering pipelines, a hydrogen sulfide treating plant and an inactive natural gas processing plant.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**3. ACQUISITIONS—(Continued)**

The Partnership funded this acquisition through the assumption of $472.3 million in debt related to the acquired systems, the issuance to the General Partner of an additional $8.2 million equity interest in the Partnership, $332.7 million of proceeds from the issuance of i-units to Enbridge Management and the payment to the General Partner of $11.7 million in cash, which was funded by the Partnership with borrowings under its 364-day revolving credit facility. A committee of independent members of the Board of Directors of the General Partner negotiated the purchase price and the terms of the acquisition on behalf of the Partnership and recommended that the Board of Directors of the General Partner approve the acquisition on behalf of the Partnership. The value allocated to the assets was determined by agreement between the parties and supported by an independent appraisal. Included in the acquired current assets of $51.3 million is a $3.7 million reserve for doubtful accounts. Goodwill associated with the acquisition was $226.0 million, and is allocated to the Gathering and Processing, Natural Gas Transportation, and Marketing segments. Intangible assets acquired of $16.1 million relate to customer contracts for gas purchases and sales and are recorded in the Gathering and Processing and Natural Gas Transportation segments. Other liabilities consist primarily of amounts payable for gas, NGL and interest rate swaps of $14.6 million and an environmental contingency of $5.9 million.

The purchase price and the allocation to assets acquired was as follows:

| | (dollars in millions) |
|---|---|
| Purchase Price: | |
| Debt assumed | $472.3 |
| Issuance of equity interest to the General Partner | 8.2 |
| Cash paid, including transaction costs | 344.4 |
| Working capital and other adjustments(1) | 50.6 |
| Total purchase price | $875.5 |
| Allocation of purchase price: | |
| Current assets | $ 51.3 |
| Property, plant and equipment | 626.7 |
| Goodwill(1) | 226.0 |
| Other assets and intangibles | 19.1 |
| Current liabilities | (26.4) |
| Other liabilities | (21.2) |
| Total | $875.5 |

(1) Working capital and other adjustments were settled and paid in December 2003 for $43.8 million, which includes $2.0 million of interest. As a result, Goodwill was reduced by $8.8 million.

**Pro Forma Information (Unaudited)**

The following summarized unaudited Pro Forma Consolidated Income Statement information for the twelve months ended December 31, 2003 and 2002 assumes the acquisitions described above occurred as of January 1, 2002. These unaudited Pro Forma financial results have been prepared for comparative purposes only. These unaudited Pro Forma financial results may not be indicative of the results that would have occurred if the Partnership had completed the acquisitions as of January 1,

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**3. ACQUISITIONS—(Continued)**

2002 or the results that will be attained in the future. Amounts presented below are in millions, except for the per unit amounts.

| | Pro Forma Year Ended December 31, | |
|---|---|---|
| | 2003 | 2002 |
| | (Unaudited) | |
| Revenues | $3,484.4 | $2,209.1 |
| Net Income | $ 127.4 | $ 70.7 |
| Net Income per Unit | $ 2.11 | $ 1.16 |

**4. NET INCOME PER UNIT**

Net income per unit is computed by dividing net income, after deduction of the General Partner's allocation, by the weighted average number of Class A and B common units and i-units outstanding. The General Partner's allocation is equal to an amount based upon its general partner interest, adjusted to reflect an amount equal to incentive distributions and an amount required to reflect depreciation on the General Partner's historical cost basis for assets contributed on formation of the Partnership. Net income per unit was determined as follows:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (dollars and units in millions, except per unit amounts) | | |
| Net income | $111.7 | $ 78.1 | $38.9 |
| Net income allocated to General Partner | (2.2) | (1.1) | (0.4) |
| Incentive distributions and historical cost depreciation adjustments | (17.4) | (12.0) | (8.7) |
| | (19.6) | (13.1) | (9.1) |
| Net income allocable to common units and i-units | $ 92.1 | $ 65.0 | $29.8 |
| Weighted average outstanding | 47.7 | 36.7 | 30.2 |
| Net income per common and i-unit | $ 1.93 | $ 1.76 | $0.98 |

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## 5. PROPERTY, PLANT AND EQUIPMENT

| | Depreciation Rates | December 31, 2003 | December 31, 2002 |
|---|---|---|---|
| | | (dollars in millions) | |
| Land | — | $ 12.6 | $ 10.4 |
| Rights-of-way | 0.60% — 5.71% | 222.9 | 192.5 |
| Pipeline | 0.60% — 14.29% | 1,770.1 | 1,576.1 |
| Pumping equipment, buildings and tanks | 0.20% — 20.00% | 587.9 | 520.1 |
| Compressors, meters, and other operating equipment | 1.52% — 20.00% | 167.3 | 114.5 |
| Vehicles, office furniture and equipment | 0.09% — 33.33% | 69.4 | 62.1 |
| Processing and treater plants | 4.00% | 115.2 | 96.4 |
| Construction in progress | — | 66.8 | 130.1 |
| | | $3,012.2 | $2,702.2 |
| Accumulated depreciation | | (546.6) | (448.9) |
| | | $2,465.6 | $2,253.3 |

Based on a third-party study commissioned by management, revised depreciation rates for the Lakehead system were implemented effective January 1, 2003, which represent the expected remaining service life of the pipeline system. The annual composite rate was reduced from 3.9% to 3.17% on the Lakehead System. Depreciation expense would have been approximately $109.6 million or $13.4 million higher and net income per unit would have been approximately $1.65 or $0.28 cents lower had the 2002 depreciation rates been in effect during 2003.

## 6. GOODWILL

The changes in the carrying amount of goodwill for each of the years ended December 31, 2003 and 2002 are as follows:

| | Liquids Transportation | Gathering and Processing | Natural Gas Transportation | Marketing | Corporate | Total |
|---|---|---|---|---|---|---|
| | | | (dollars in millions) | | | |
| Balance as of January 1, 2002 | $— | $ 15.1 | $ — | $ — | $— | $ 15.1 |
| Acquired during the year in conjunction with the Midcoast acquisition | — | 132.1 | 73.5 | 20.4 | — | 226.0 |
| Balance as of December 31, 2002 | $— | $147.2 | $73.5 | $20.4 | $— | $241.1 |
| Purchase price adjustments | — | 0.8 | (8.5) | — | — | (7.7) |
| Acquired during the year in conjunction with the North Texas acquisition | — | 23.9 | — | — | — | 23.9 |
| Balance as of December 31, 2003 | $— | $171.9 | $65.0 | $20.4 | $— | $257.3 |

Net income and earnings per unit, as reported for the year ending December 31, 2001, would have been unaffected by our adoption of SFAS No. 142 as the balance of goodwill at January 1, 2002 was acquired on November 30, 2001 and did not result in the recognition of material amortization expense for the year ending December 31, 2001.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**6. GOODWILL—(Continued)**

In accordance with SFAS No. 142, the Partnership completed its annual goodwill impairment test as of June 30, 2003. To estimate the fair value of the reporting units, management made estimates and judgments about future cash flows, as well as revenue, cost of sales, operating expenses, capital expenditures, and net working capital based on assumptions that are consistent with the long-range plans used to manage the business. Based on the results of the impairment analysis, the fair value of the total equity of each reporting unit was determined to exceed the respective carrying value. As a result, no goodwill impairment existed in any of its reporting units at June 30, 2003 and no events occurred or circumstances changed that would more likely than not reduce the fair value of its reporting units below the carrying amounts as of December 31, 2003.

**7. INTANGIBLES**

| | December 31, | | | |
|---|---|---|---|---|
| | 2003 | | 2002 | |
| | Gross Carrying Amount | Accumulated Amortization | Gross Carrying Amount | Accumulated Amortization |
| | (dollars in millions) | | | |
| Customer Contracts | $31.1 | $(2.0) | $31.1 | $(0.7) |
| Natural gas supply opportunities | 48.1 | — | — | — |
| | $79.2 | $(2.0) | $31.1 | $(0.7) |

Customer contracts are comprised entirely of natural gas purchase and sale contracts and are recorded in the Gathering and Processing, Natural Gas Transportation, and Marketing segments. Customer contracts are amortized over the weighted average useful life of the underlying reserves, which is approximately 25 years.

The natural gas supply opportunities were acquired in conjunction with the North Texas acquisition (see Note 3) and are recorded entirely in the Gathering and Processing segment. The value of the intangible was determined by a third party appraisal and it represents the fair value associated with growth opportunities present in the Barnett Shale producing zone. The natural gas supply opportunities are being amortized over the weighted average estimated useful life of the underlying reserves, which is approximately 25 years.

The aggregate amortization expense for the years ended December 31, 2003, 2002 and 2001, were $1.3 million, $0.7 million, and zero, respectively.

The estimated amortization expense for each of the years ended December 31, 2004, 2005, 2006, 2007, and 2008 is $3.1 million, respectively.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## 8. DEBT

| | Weighted Average Interest Rate | Maturity | December 31, 2003 | December 31, 2002 |
|---|---|---|---|---|
| | | | (dollars in millions) | |
| First Mortgage Notes | 9.15% | 2011 | $ 248.0 | $ 279.0 |
| Senior Unsecured Notes | 6.20% | 2012-2033 | 698.8 | 299.4 |
| Three-year Term Facility | 1.84% | 2006 | 240.0 | 252.0 |
| 364-Day Credit Facility | 1.90% | 2004 | 215.0 | 212.0 |
| | | | $1,401.8 | $1,042.4 |
| Current maturities and short-term debt | | | (246.0) | (31.0) |
| Long-term debt | | | $1,155.8 | $1,011.4 |

***First Mortgage Notes***

The First Mortgage Notes ("Notes") are collateralized by a first mortgage on substantially all of the property, plant and equipment of the Lakehead Partnership and are due and payable in equal annual installments of $31.0 million until their maturity in 2011. The Notes contain various restrictive covenants applicable to the Partnership, and restrictions on the incurrence of additional indebtedness, including compliance with certain debt issuance tests. The Partnership believes these issuance tests will not negatively impact its ability to finance future expansion projects. Under the Note Agreements, the Partnership cannot make cash distributions more frequently than quarterly in an amount not to exceed Available Cash (see Note 9) for the immediately preceding calendar quarter. If the notes were to be paid prior to their stated maturities, the Note Agreements provide for the payment of a redemption premium by the Partnership.

***Senior Unsecured Notes***

On May 27, 2003, the Partnership issued $200.0 million in aggregate principal amount of its 4.75% Notes due 2013 and $200.0 million in aggregate principal amount of its 5.95% Notes due 2033 (the "Notes") in a private placement. The Partnership used the proceeds of approximately $396.3 million, net of expenses of approximately $3.0 million, to repay loans from affiliates of the Partnership and other bank debt. The Partnership recorded a discount of $0.7 million in connection with the issuance of the Notes. On June 30, 2003, the Partnership completed a Form S-4 with the Securities and Exchange Commission (the "SEC"), which registered the exchange of the unregistered Notes for publicly registered Notes.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**8. DEBT—(Continued)**

All of the notes pay interest semi-annually and have varying maturities and terms as outlined below. The senior unsecured notes do not contain any covenants restricting the issuance of additional indebtedness.

| Senior Unsecured Notes | Interest Rate | December 31, 2003 | December 31, 2002 |
|---|---|---|---|
| Notes maturing in 2012 | 7.90% | $100.0 | $100.0 |
| Notes maturing in 2013 | 4.75% | 200.0 | — |
| Notes maturing in 2018 | 7.00% | 100.0 | 100.0 |
| Notes maturing in 2028 | 7.125% | 100.0 | 100.0 |
| Notes maturing in 2033 | 5.95% | 200.0 | — |
| | | $700.0 | $300.0 |
| Unamortized Discount | | (1.2) | (0.6) |
| | | $698.8 | $299.4 |

***Bank Credit Facilities***

On January 24, 2003, the Partnership amended and restated the terms of its two unsecured revolving credit facilities, which were originally entered into in January 2002. The facilities consist of a $300.0 million three-year term facility (the "Three-year Facility"), which matures in 2006 (subject to extension as provided in the facility) and a $300.0 million 364-day facility (the "364-day Facility"), which matures in April 2004 (subject to a one-year term out option and extension as provided in the facility). Interest is charged on amounts drawn under each of these facilities at a variable rate equal to the Base Rate or a Eurodollar rate as defined in the facility agreements. In the case of a Eurodollar rate loans an additional margin is charged which varies depending on the Partnership's credit rating and the amounts drawn under the facility. A facility fee is payable on the entire amount of each facility whether or not drawn. The facility fee varies depending on the Partnership's credit rating. As of December 31, 2003, the facility fees on the three-year and 364-day facilities were 0.20% and 0.15%, respectively. These credit facilities contain restrictive covenants that require that the Partnership maintain a minimum interest coverage ratio of 2.75 times and a maximum leverage ratio of 4.75 times each as defined in the facility agreements. The facilities agreements also place limitations on the amount of debt that may be incurred directly by the Partnership's subsidiaries. Accordingly, it is expected that the Partnership will provide debt financing to its subsidiaries as required.

***Interest***

In 2003, 2002, and 2001, interest expense is net of amounts capitalized of $2.2 million, $7.9 million, and $0.3 million, respectively. In 2003, 2002, and 2001, total interest paid was $85.2 million, $59.2 million, and $57.0 million, respectively.

***Debt Service Reserve***

Under the terms of the First Mortgage Notes, the Partnership is required to establish, at the end of each quarter, a debt service reserve amount. This reserve includes an amount equal to 50% of the prospective First Mortgage Note interest payments for the immediate following quarter and an amount

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**8. DEBT—(Continued)**

for First Mortgage Note sinking fund repayments. At December 31, 2003 and 2002, there was no required debt service reserve as all required interest and sinking fund payments had been made.

***Maturities of Debt***

The scheduled maturities of outstanding debt, excluding market value of interest rate swaps, at December 31, 2003, are summarized as follows:

| | (dollars in millions) |
|---|---|
| 2004 | $ 246.0 |
| 2005 | 31.0 |
| 2006 | 271.0 |
| 2007 | 31.0 |
| 2008 | 31.0 |
| Thereafter | 791.8 |
| Total | $1,401.8 |

**9. PARTNERS' CAPITAL**

The Partnership's ownership is comprised of a 2% general partner interest and 98% of limited partner interests. The limited partner ownership in the Partnership is comprised of Class A common units, Class B common units and i-units. The limited partners have limited rights of ownership as provided for under the Partnership Agreement and, as discussed below, participate in the Partnership's distributions. The General Partner manages the operations of the Partnership, subject to a Delegation of Control Agreement with Enbridge Management, and participates in the Partnership's distributions, including certain incentive income distributions.

***Class A common units***

In December 2003, the Partnership issued 5.0 million Class A common units at $50.30 per unit, which generated proceeds, net of underwriters' discounts, commissions and issuance expenses, of approximately $240.3 million. Proceeds from this offering were used to reduce borrowings under the Partnership's 364-day credit facility by approximately $105.0 million, to reduce borrowings under the three-year term facility of approximately $100.0 million and to pay the December 15, 2003 sinking fund payment of $31.0 million on the First Mortgage Notes. In addition to the proceeds generated from the unit issuance, the General Partner contributed $5.1 million to the Partnership to maintain its 2% general partner interest in the Partnership.

In May 2003, the Partnership issued 3.85 million Class A common units at $44.79 per unit, which generated proceeds, net of underwriters' discounts, commissions and issuance expenses, of approximately $165.5 million. Proceeds from this offering were used to reduce borrowings under the Partnership's 364-day credit facility of approximately $102.4 million and an affiliate loan from Enbridge (U.S.) Inc. by $63.1 million. In addition to the proceeds generated from the unit issuance, the General Partner contributed $3.5 million to the Partnership to maintain its 2% general partner interest in the Partnership.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**9. PARTNERS' CAPITAL—(Continued)**

In March 2002, the Partnership issued 2.26 million Class A common units at $42.75 per unit, which generated proceeds, net of underwriters' discounts and commissions and issuance expenses, of approximately $93.3 million. Proceeds from this offering were used to repay indebtedness.

***Class B common units***

At December 31, 2003 and 2002, the Partnership had 3,912,750 Class B common units outstanding, which are held entirely by the General Partner. The Class B common units have rights similar to the Class A common units except that they are not eligible for trading on the NYSE.

***i-units***

In October 2002, the Partnership received net proceeds of approximately $330.8 million from Enbridge Management for the issuance of 9,000,000 i-units. The Partnership used the net proceeds to repay debt owed to affiliates that was assumed in connection with the acquisition of the Midcoast system assets.

The i-units are a separate class of limited partner interests in the Partnership. All of the i-units are owned by Enbridge Management and are not publicly traded. Enbridge Management's limited liability company agreement provides that the number of all of its outstanding shares, including the voting shares owned by the General Partner, at all times will equal the number of i-units that it owns. Through the combined effect of the provisions in the Partnership Agreement and the provisions of Enbridge Management's limited liability company agreement, the number of outstanding Enbridge Management shares and the number of the i-units will at all times be equal.

Enbridge Management, as the owner of the i-units, votes together with the holders of the common units as a single class. However, the i-units vote separately as a class on the following matters:

- Any proposed action that would cause the Partnership to be treated as a corporation for U.S. federal income tax purposes;
- Amendments to the Partnership Agreement that would have a material adverse effect on the holders of the i-units, unless, under the Partnership Agreement, the amendment could be made by the general partner of the Partnership without a vote of holders of any class of units;
- The removal of the general partner of the Partnership and the election of a successor general partner; and
- The transfer by the general partner of the Partnership of its general partner interest to a non-affiliated person that requires a vote of holders of units under the Partnership Agreement and the admission of that person as a general partner of the Partnership.

In all cases, Enbridge Management will vote or refrain from voting its i-units in the same manner that owners of Enbridge Management's shares vote or refrain from voting their shares. Furthermore, under the terms of the Partnership Agreement, the Partnership agrees that it will not, except in liquidation, make a distribution on an i-unit other than in additional i-units or a security that has in all material respects the same rights and privileges as the i-units.

In October 2002, the General Partner received an allocation of the proceeds from i-unit issuance of approximately $8.2 million. In conjunction with the restructuring of the Partnership's subsidiaries immediately following the acquisition of the Midcoast system, the Partnership contributed its 1.0101%

**9. PARTNERS' CAPITAL—(Continued)**

interest in the Lakehead Partnership to the Partnership at its carrying value of approximately $3.3 million.

***Distributions Paid***

The Partnership Agreement requires that the Partnership distribute 100% of its "Available Cash", which is generally defined in the Partnership Agreement as the sum of all cash receipts and net additions to reserves for future requirements less cash disbursements and amounts retained by the Partnership. The reserves are retained to provide for the proper conduct of the Partnership business and as necessary to comply with the terms of any agreement or obligation of the Partnership (including any reserves required under debt instruments for future principal and interest payments and for future capital expenditures). The amounts retained by the Partnership are the cash amount in respect to the i-unit distribution plus an amount equal to 2% of the i-unit distribution. The distributions are made to its partners within 45 days following the end of each calendar quarter in accordance with their respective percentage interests.

The General Partner is granted discretion by the Partnership Agreement, which discretion has been delegated to Enbridge Management, subject to the approval of the General Partner in certain cases, to establish, maintain and adjust reserves for future operating expenses, debt service, maintenance capital expenditures, and distributions for the next four quarters. These reserves are not restricted by magnitude, but only by type of future cash requirements with which they can be associated. When Enbridge Management determines the quarterly distributions, it considers current and expected reserve needs along with current and expected cash flows to identify the appropriate sustainable distribution level.

Distributions by the Partnership of its Available Cash generally are made 98.0% to the Class A and B common unitholders and the i-unitholder and 2.0% to the General Partner. The Partnership will not distribute the cash related to the i-units but instead will distribute additional i-units such that the cash is retained and used in the business. Further, the Partnership retains an additional amount equal to 2% of the i-unit distribution from the General Partner in respect of the 2% general partner interest in the i-units. Distributions are subject to the payment of incentive distributions to the General Partner to the extent that certain target levels of cash distributions to the unitholders are achieved. The incremental incentive distributions payable to the General Partner are 15.0%, 25.0% and 50.0% of all quarterly distributions of Available Cash that exceed target levels of $0.59, $0.70, and $0.99 per Class A and B common units and i-units, respectively.

Typically, the General Partner and owners of common units will receive distributions in cash. Enbridge Management, as the delegate of the General Partner under the Delegation of Control Agreement, computes the amount of the Partnership's available cash. Enbridge Management, as owner of the i-units, however, does not receive distributions in cash. Instead, each time that the Partnership makes a cash distribution to the General Partner and the holders of its common units, the number of i-units owned by Enbridge Management and the percentage of total units in the Partnership owned by Enbridge Management will increase automatically under the provisions of the Partnership's partnership agreement with the result that the number of i-units owned by Enbridge Management will equal the number of Enbridge Management's shares and voting shares that are then outstanding. The amount of this increase per i-unit is determined by dividing the cash amount distributed per common unit by the average price of one of Enbridge Management's listed shares on the NYSE for the 10-day period immediately preceding the ex-dividend date for Enbridge Management's shares. The cash equivalent

## 9. PARTNERS' CAPITAL—(Continued)

amount of the additional i-units is treated as if it had actually been distributed for purposes of determining the distributions to be made to the General Partner.

The following table sets forth the distributions, as approved by the Board of Directors for each period in the years ended December 31, 2003, 2002 and 2001.

| Distribution Declaration Date | Distribution Payment Date | Ex-Distribution Date | Distribution per Unit | Cash available for distribution | Amount of Distribution of i-units to i-unit holders | Retained from General Partner(1) | Distribution of Cash |
|---|---|---|---|---|---|---|---|
| | | | | (dollars in millions, except per unit amounts) | | | |
| **2003** | | | | | | | |
| October 22, 2003 | November 14, 2003 | November 4, 2003 | $0.925 | $ 50.5 | $ 9.2 | $0.2 | $ 41.1 |
| July 23, 2003 | August 14, 2003 | July 31, 2003 | 0.925 | 50.3 | 8.9 | 0.2 | 41.2 |
| April 24, 2003 | May 15, 2003 | April 30, 2003 | 0.925 | 46.1 | 8.7 | 0.2 | 37.2 |
| January 23, 2003 | February 14, 2003 | January 31, 2003 | 0.925 | 46.0 | 8.6 | 0.2 | 37.2 |
| | | | | $192.9 | $35.4 | $0.8 | $156.7 |
| **2002** | | | | | | | |
| October 24, 2002 | November 14, 2002 | November 5, 2002 | $ 0.90 | $ 44.1 | $ 8.1 | $0.2 | $ 35.8 |
| July 22, 2002 | August 14, 2002 | August 5, 2002 | 0.90 | 34.6 | — | — | 34.6 |
| April 25, 2002 | May 15, 2002 | May 3, 2002 | 0.90 | 34.5 | — | — | 34.5 |
| January 24, 2002 | February 14, 2002 | February 5, 2002 | 0.90 | 32.4 | — | — | 32.4 |
| | | | | $145.6 | $ 8.1 | $0.2 | $137.3 |
| **2001** | | | | | | | |
| October 25, 2001 | November 14, 2001 | October 31, 2001 | $0.875 | $ 29.3 | $ — | $ — | $ 29.3 |
| July 19, 2001 | August 15, 2001 | July 31, 2001 | 0.875 | 29.3 | — | — | 29.3 |
| April 19, 2001 | May 15, 2001 | April 30, 2001 | 0.875 | 27.6 | — | — | 27.6 |
| January 25, 2001 | February 14, 2001 | December 29, 2000 | 0.875 | 27.6 | — | — | 27.6 |
| | | | | $113.8 | $ — | $ — | $113.8 |

(1) The Partnership retains an amount equal to 2% of the i-unit distribution from the General Partner in respect of its 2% general partner interest in the i-units.

## 10. RELATED PARTY TRANSACTIONS

***Administrative and Workforce Related Services***

Enbridge and its affiliates provide management and administrative, operations and workforce related services to the Partnership. Employees of Enbridge and its affiliates are assigned to work for one or more affiliates of Enbridge, including the Partnership. Where directly attributable, the costs of all compensation, benefits expenses and employer expenses for these employees are charged directly by Enbridge to the appropriate affiliate. There is no profit or margin for these services charged by Enbridge to its affiliates.

The portion of direct workforce costs associated with the management and administrative services provided at the Partnership's Houston office and the operating and administrative services provided to support the Partnership's facilities across the United States, are charged from Enbridge and its affiliates to the Partnership.

Certain of the Partnership's operating activities associated with its Liquids Transportation segment are provided by Enbridge Pipelines Inc., a subsidiary of Enbridge, as these pipeline systems form one contiguous system with the Enbridge system in Canada. These services include control center operations, facilities management, shipper services, pipeline integrity management and other related

**10. RELATED PARTY TRANSACTIONS—(Continued)**

activities. The costs to provide these services are allocated to the Partnership from Enbridge Pipelines Inc., based on an appropriate allocation methodology consistent with Enbridge's corporate cost allocation policy, including estimated time spent and miles of pipe. The Partnership also receives costs associated with control center services for some of its Natural Gas Transportation assets from another affiliate of Enbridge.

Enbridge also allocates management and administrative costs to the Partnership pursuant to the Partnership's amended and restated limited partnership agreement ("partnership agreement") and related services agreements. These costs are allocated to the Partnership based on an appropriate allocation methodology consistent with Enbridge's corporate cost allocation policy, including estimated time spent and headcount.

During 2003, 2002 and 2001, the Partnership incurred the following costs related to these services, which are included in operating and administrative expenses.

| | Year ended December 31, | | |
|---|---|---|---|
| | 2003 | 2002 | 2001 |
| | (dollars in millions) | | |
| Direct operating and administrative costs | $75.4 | $51.2 | $22.2 |
| Liquids Transportation/Natural Gas Transportation operating costs | 9.6 | 6.5 | 8.6 |
| Allocated management and administrative costs, including insurance | 14.2 | 13.5 | 8.1 |
| | $99.2 | $71.2 | $38.9 |

***Natural Gas Sales and Purchases***

The Partnership purchases natural gas from third parties, which subsequently generates operating revenues from the sales to Enbridge and its affiliates. These transactions are entered into at the market price at the date of sale. Included in the results for the twelve months ending December 31, 2003 and 2002, are operating revenues of $30.6 million and $4.6 million, respectively, related to these sales. There were no such comparative amounts in 2001.

The Partnership also purchases natural gas from Enbridge and its affiliates for sale to third parties at market prices at the date of purchase. Included in the results for the twelve months ending December 31, 2003 and 2002, are cost of natural gas expenses of $1.2 million and $0.1 million, respectively, relating to these purchases. There were no such comparative amounts in 2001.

***Affiliate Notes***

The Partnership has various notes payable with affiliates of Enbridge that totaled $133.1 million and $444.1 million at December 31, 2003 and 2002. All loans mature in 2007. The weighted average interest rate is 6.60% and 6.03% as of December 31, 2003 and 2002.

Interest expense related to affiliate notes totaled $16.1 million, $4.6 million, and $1.3 million in 2003, 2002, and 2001, respectively. Interest payable to affiliates totaled $2.2 million and $1.3 million at December 31, 2003 and 2002, respectively. Interest paid to affiliates totaled $15.2 million, $3.3 million, and $1.3 million in 2003, 2002 and 2001, respectively.

***Incentive Income and Partnership Distributions***

Enbridge Energy Company, Inc., an affiliate of Enbridge, serves as the Partnership's general partner. Pursuant to the Partnership's partnership agreement, the General Partner owns an effective 2% ownership interest in the Partnership. The General Partner received incentive distributions for the years ended December 31, 2003, 2002 and 2001 of $17.2 million, $11.9 million, and $8.6 million, respectively.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## 10. RELATED PARTY TRANSACTIONS—(Continued)

As of December 31, 2003, the General Partner also owned 3,912,750 Class B common units, representing 7.1% ownership in the Partnership. The General Partner received cash distributions related to its ownership of Class B units for the years ended December 31, 2003, 2002 and 2001 of $14.5 million, $14.1 million and $13.7 million, respectively. See also Note 9 (Partners' Capital).

### *Conflicts of Interest*

Through a Delegation of Control Agreement with the General Partner and the Partnership, Enbridge Management makes all decisions relating to the management and control of the Partnership's business. The General Partner owns the voting shares of Enbridge Management and elects all of Enbridge Management's directors. Enbridge, through its wholly-owned subsidiary, Enbridge Pipelines Inc., owns all the common stock of the General Partner. Some of the General Partner's officers and directors are also directors and officers of Enbridge and Enbridge Management and have fiduciary duties to manage the business of Enbridge and Enbridge Management in a manner that may not be in the best interests of the Partnership's unitholders. Certain conflicts of interest could arise as a result of the relationships among Enbridge Management, the General Partner, Enbridge and the Partnership. The partnership agreement and Delegation of Control Agreement for the Partnership and its subsidiaries contain provisions that allow Enbridge Management to take into account the interest of parties in addition to the Partnership in resolving conflicts of interest, thereby limiting its fiduciary duties to the Partnership's unitholders, as well as provisions that may restrict the remedies available to unitholders for actions taken that might, without such limitations, constitute breaches of fiduciary duty.

### *Enbridge Management*

Pursuant to the Delegation of Control Agreement between Enbridge Management, the General Partner and the Partnership, and the Partnership's partnership agreement, all expenses relating to Enbridge Management are paid by the Partnership. This includes Texas franchise taxes and any other foreign, state and local taxes not otherwise paid or reimbursed pursuant to a tax indemnification agreement between Enbridge and Enbridge Management on behalf of Enbridge Management.

## 11. COMMITMENTS AND CONTINGENCIES

### *Environmental*

The Partnership is subject to federal and state laws and regulations relating to the protection of the environment. Environmental risk is inherent to liquid and gas pipeline operations and the Partnership could, at times, be subject to environmental cleanup and enforcement actions. The Partnership manages this environmental risk through appropriate environmental policies and practices to minimize any impact. To the extent that the Partnership is unable to recover environmental liabilities associated with the Lakehead system assets prior to the transfer to the Partnership in 1991, to the extent not recovered through insurance, the General Partner has agreed to indemnify the Partnership from and against any costs relating to environmental liabilities associated with the Lakehead system assets prior to the transfer to the Partnership in 1991. This excludes any liabilities resulting from a change in laws after such transfer. The Partnership continues to voluntarily investigate past leak sites on its systems for the purpose of assessing whether any remediation is required in light of current regulations, and to date no material environmental risks have been identified.

**11. COMMITMENTS AND CONTINGENCIES—(Continued)**

In connection with the Partnership's acquisition of Midcoast, Northeast Texas and South Texas systems, the General Partner has agreed to indemnify the Partnership and other related persons for certain environmental liabilities of which the General Partner has knowledge and which it did not disclose. The General Partner will not be required to indemnify the Partnership until the aggregate liabilities, including environmental liabilities, exceed $20.0 million, and the General Partner's aggregate liability, including environmental liabilities, may not exceed, with certain exceptions, $150.0 million. The Partnership will be liable for any environmental conditions related to the acquired systems that were not known to the General Partner or were disclosed.

As of December 31, 2003 and 2002, the Partnership has recorded $2.6 million and $1.1 million in current liabilities and $7.9 million and $5.6 million, respectively, in long-term liabilities to address remediation of asbestos containing materials, management of hazardous waste material disposal, and outstanding air quality measures for certain of its Liquids Transportation and Gathering and Processing assets.

***Oil and Gas in Custody***

The Partnership's Liquids Transportation assets transport crude oil and NGLs owned by its customers for a fee. The volume of liquid hydrocarbons in the Partnership's pipeline system at any one time approximates 14 million barrels, virtually all of which is owned by the Partnership's customers. Under terms of the Partnership's tariffs, losses of crude oil not resulting from direct negligence of the Partnership may be apportioned among its customers. In addition, the Partnership maintains adequate property insurance coverage with respect to crude oil and NGLs in the Partnership's custody.

Approximately 60% of the natural gas volumes on the Gathering and Processing and Natural Gas Transportation assets are transported for customers on their contract, with the remaining 40% purchased by the Partnership and sold to third parties downstream of the purchase point. At any point in time, the value of customers' natural gas in custody of the Natural Gas Transportation systems is not material to the Partnership.

***Regulatory***

From 1998, when the Kansas Pipeline system ("KPC") became subject to the FERC jurisdiction, until November 9, 2002, at which time KPC's rate case became effective, the FERC established initial rates based upon an annual cost of service of approximately $31.0 million. Since that time, these initial rates have been the subject of various ongoing challenges that remain unresolved.

The United States Court of Appeals for the D.C. Circuit issued an order on August 12, 2003 vacating the FERC's 2001 remand order and 2002 rehearing order and remanded the issue of KPC's initial rates back to the FERC with directions that the FERC address the question of an appropriate rate refund. In prior KPC orders in this proceeding, the FERC determined that it had no authority to impose a refund condition on initial rates. On October 3, 2003, KPC filed a pleading at FERC requesting the issuance of an order finding that it had no refund obligation and requesting termination of the proceedings on remand. The Missouri Public Service Commission filed an answer to KPC's pleading on October 20, 2003. The outcome of KPC's motion or any other proceedings, including the amount of any refunds that may be ordered, is uncertain. If the FERC determines refunds are required, after all administrative options and court appeals are exhausted, the amount of the refunds affecting the Partnership's earnings may range from zero to $9.0 million.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## 11. COMMITMENTS AND CONTINGENCIES—(Continued)

***Commitments***

### Right-of-Way

The Partnership, as part of its pipeline construction process, must obtain certain right-of-way agreements from landowners whose property the pipeline will cross. Right-of-way agreements that the Partnership buys are capitalized as part of Property, Plant and Equipment (Note 5). Right-of-way agreements that are leased from a third party are expensed. The Partnership recorded expenses for the leased right-of-way agreements of $1.4 million, $1.2 million, and $1.0 million during 2003, 2002, and 2001, respectively.

### Future Minimum Commitments

As of December 31, 2003, the future minimum commitments having remaining non-cancelable terms in excess of one year are as follows:

| Year ended December 31, | Power and other Purchase Commitments | Other Operating Leases | Right of Way(1) | Total |
|---|---|---|---|---|
| | (dollars in millions) | | | |
| 2004 | $12.9 | $ 3.9 | $ 1.8 | $18.6 |
| 2005 | 3.1 | 4.2 | 1.9 | 9.2 |
| 2006 | 3.1 | 3.7 | 1.8 | 8.6 |
| 2007 | — | 2.7 | 1.8 | 4.5 |
| 2008 | — | 2.7 | 1.7 | 4.4 |
| Thereafter | — | 3.5 | 45.0 | 48.5 |
| Total | $19.1 | $20.7 | $54.0 | $93.8 |

(1) Right of way payments are estimated to be approximately $1.8 million per year for the remaining life for all pipeline systems, which has been estimated to be 25 years, for purposes of calculating the amount of future minimum commitments beyond 2008.

## 12. MAJOR CUSTOMERS

At December 31, 2003 and 2002, the Partnership did not have an external customer that accounted for 10% or more of its operating revenues. The customers listed below were all attributable to the Partnership's Liquids Transportation segment. For 2001, operating revenue received from major customers was as follows:

| | Year ended December 31, 2001 |
|---|---|
| | (dollars in millions) |
| BP Canada Energy Company | $73.4 |
| ExxonMobil Canada Energy | $59.7 |
| PDV Midwest | $21.4 |
| Imperial Oil Limited | $24.0 |

## 12. MAJOR CUSTOMERS—(Continued)

The Partnership has a concentration of trade receivables from companies operating in the oil and gas industry. These receivables are collateralized by the crude oil and other products contained in the Partnership's pipeline and storage facilities.

## 13. FINANCIAL INSTRUMENTS

***Fair Value of Financial Instruments***

The carrying amounts of cash equivalents approximate fair value because of the short term to maturity of these investments.

Based on the borrowing rates currently available for instruments with similar terms and remaining maturities, the carrying value of borrowings under the 364-day credit and three-year term facilities approximates fair value.

At December 31, 2003 and 2002, the fair value of the First Mortgage Notes approximates $303.0 million and $334.0 million and the fair value of the Senior Unsecured Notes approximates $739.0 million and $326.0 million, respectively. Due to defined contractual make-whole arrangements, refinancing of the First Mortgage Notes and Senior Unsecured Notes would not result in any financial benefit to the Partnership.

The fair value of derivative financial instruments reflects the Partnership's best estimate and is based upon either exchange- traded prices, published market prices or over-the-counter market price quotations, whenever they are available. Quoted valuations may not be available due to location differences or terms that extend beyond the period for which quotations are available. Where quotes are not available, the Partnership utilizes other valuation techniques or models to estimate market values. These modeling techniques require the Partnership to make estimations of future prices, price correlation and market volatility and liquidity. The estimates also reflect factors for time value and volatility underlying the contracts, the potential impact of liquidating positions in an orderly manner over a reasonable period of time under present market conditions, modeling risk, credit risk of counter parties and operational risk.

The Partnership enters into floating rate to fixed rate (fixed rate) interest rate swaps to manage the effect of future interest rate movements on its interest costs. The Partnership also enters fixed rate to floating rate (floating rate) interest rate swaps to manage the fair value of debt issuances. The following table summarizes the interest rate financial derivatives outstanding at December 31:

| | Notional Principal | Partnership | | | Fair Value | |
|---|---|---|---|---|---|---|
| | | Pays | Receives | Maturity Date | 2003 | 2002 |
| | | (dollars in millions) | | | | |
| Fixed rate interest rate swaps: | $100.0 | 5.95% | LIBOR | October 13, 2003 | $ — | $(4.6) |
| | $ 40.0 | 4.48% | LIBOR | November 3, 2003 | $ — | $(1.2) |
| | $ 50.0 | 1.31% | LIBOR | October 6, 2004 | $ — | $ — |
| | $ 50.0 | 1.31% | LIBOR | October 7, 2004 | $ — | $ — |
| | $ 25.0 | 1.44% | LIBOR | December 29, 2004 | $ — | $ — |
| | $ 25.0 | 1.45% | LIBOR | December 24, 2004 | $ — | $ — |
| Floating rate interest rate swaps: | $ 50.0 | LIBOR — 21bps | 4.75% | June 1, 2013 | $1.7 | $ — |
| | $ 50.0 | LIBOR — 21bps | 4.75% | June 1, 2013 | $1.7 | $ — |
| | $ 25.0 | LIBOR — 25bps | 4.75% | June 1, 2013 | $0.8 | $ — |
| Treasury Lock: | $104.0 | 3.19% | N/A | January 30, 2004 | $1.0 | $ — |

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

**13. FINANCIAL INSTRUMENTS—(Continued)**

The fixed rate interest rate swaps and the treasury lock meet the criteria for hedge accounting and are accounted for as cash flow hedges.

The floating rate interest rate swaps meet the criteria for hedge accounting and are accounted for as fair value hedges.

***Commodity price risk***

The earnings and cash flows of the Partnership are sensitive to changes in the price of natural gas, NGLs, condensate, and to fractionation margins (the relative price differential between NGL sales and offsetting natural gas purchases). This market price exposure exists within the Gathering and Processing, Natural Gas Transportation and Marketing segments. To mitigate the volatility of cash flows, the exposed entity enters into derivative financial instruments to manage the purchase and sales prices of the commodities. The majority of the Partnership's commodity derivative transactions qualifies for hedge accounting under SFAS No. 133 and are accounted for as cash flow hedges.

***Natural Gas***

Natural gas derivative transactions are entered into by the Partnership in order to hedge the forecasted purchases or sales of natural gas. The following table details the outstanding derivatives at December 31:

| System | Maturity Dates | Notional MMBtu | Fair Value 2003 | Fair Value 2002 |
|---|---|---|---|---|
| | | | (dollars in millions) | |
| East Texas System | 2004-2011 | 26,000 | $(19.9) | $ (6.1) |
| Northeast Texas System | 2004-2012 | 42,000 | $(44.9) | $(19.1) |
| Midcoast System | 2004 | 600 | $ (0.7) | $ (0.3) |
| Marketing | 2004-2007 | 38,000 | $ 2.0 | $ 2.1 |

A limited number of natural gas derivative transactions, which mitigate economic exposures arising from underlying natural gas purchases and sales, do not qualify for hedge accounting treatment under SFAS No. 133. As such, the change in fair market value (from the last quarter-end) of these derivative instruments is booked to the income statement. For the years ended December 31, 2003 and 2002, $0.3 million and zero, respectively, were recorded in the Consolidated Statements of Income on the cost of natural gas expense to account mark to market changes related to the Marketing segment.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## 13. FINANCIAL INSTRUMENTS—(Continued)

***Natural Gas Liquids***

NGL derivative transactions are entered into by the Partnership to hedge the forecasted sales of NGLs. The following table details the outstanding derivatives at December 31:

| System | Maturity Date | Notional Barrels | Fair Value 2003 | Fair Value 2002 |
|---|---|---|---|---|
| | | (in millions) | (dollars in millions) | |
| Northeast Texas System | 2004 | 0.5 | $(2.4) | $(2.5) |
| Midcoast System | 2004 | 0.1 | $(0.2) | $(0.1) |
| East Texas System | 2004 | 0.5 | $(0.8) | $ — |
| North Texas System | 2004 | 0.8 | $(1.1) | $ — |

***Other***

The Partnership estimates that approximately $17.0 million of the Accumulated Other Comprehensive Loss balance on the Consolidated Statement of Financial Position of $64.0 million representing unrecognized net losses on derivative activities at December 31, 2003 is expected to be reclassified into earnings during the next twelve months.

At December 31, 2003, no material credit risk exposure existed as the Partnership enters into financial instruments only with credit worthy institutions that possess investment grade ratings.

The Partnership's hedging activities are included at the fair values in the Consolidated Statements of Financial Position as follows:

| | December 31, 2003 | December 31, 2002 |
|---|---|---|
| | (dollars in millions) | |
| Accounts receivable, trade and other | $ 2.8 | $ 3.5 |
| Other assets, net | 4.0 | — |
| Accounts payable and other | (43.7) | (13.1) |
| Deferred credits | (27.5) | (22.2) |
| | $(64.4) | $(31.8) |

## 14. SEGMENT INFORMATION

The Partnership's business is divided into operating segments, defined as components of the enterprise about which financial information is available and evaluated regularly by the Partnership's Chief Operating Decision Maker in deciding how to allocate resources to an individual segment and in assessing performance of the segment.

The Partnership's reportable segments are based on the type of business activity and management control. Each segment is managed separately because each business requires different operating strategies. The Partnership has four reportable business segments, Liquids Transportation, Gathering and Processing, Natural Gas Transportation and Marketing (see Note 1). Each segment uses accounting policies as described in the Summary of Significant Accounting Policies (see Note 2).

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## 14. SEGMENT INFORMATION—(Continued)

The following table presents certain financial information relating to the Partnership's business segments as of or for the year ended December 31, 2003 and 2002. As discussed in Note 3 to the Consolidated Financial Statements, the results from the Midcoast Acquisition were included since October 17, 2002.

| | As of and for the Year Ended December 31, 2003 | | | | | |
|---|---|---|---|---|---|---|
| | Liquids Transportation | Gathering and Processing | Natural Gas Transportation | Marketing | (1) Corporate | Total |
| | (dollars in millions) | | | | | |
| Total Revenues | $ 344.2 | $2,153.8 | $121.0 | $1,984.8 | $ — | $4,603.8 |
| Less: Intersegment revenue | — | 307.0 | 3.3 | 1,121.2 | — | 1,431.5 |
| Operating revenues | 344.2 | 1,846.8 | 117.7 | 863.6 | — | 3,172.3 |
| Cost of natural gas | — | 1,693.3 | 67.6 | 851.8 | — | 2,612.7 |
| Operating and administrative | 104.1 | 81.0 | 21.3 | 2.2 | 3.2 | 211.8 |
| Power | 56.1 | — | — | — | — | 56.1 |
| Depreciation and amortization | 59.5 | 24.1 | 13.6 | 0.2 | — | 97.4 |
| Operating income | $ 124.5 | $ 48.4 | $ 15.2 | $ 9.4 | $ (3.2) | $ 194.3 |
| Interest expense | — | — | — | — | (85.0) | (85.0) |
| Other income (expense) | — | — | — | — | 2.4 | 2.4 |
| Minority interest | — | — | — | — | — | — |
| Net income | $ 124.5 | $ 48.4 | $ 15.2 | $ 9.4 | $(85.8) | $ 111.7 |
| Total assets | $1,511.2 | $1,085.9 | $404.6 | $ 189.6 | $ 40.5 | $3,231.8 |
| Capital expenditures (excluding acquisitions) | $ 69.3 | $ 51.0 | $ 4.4 | $ 0.1 | $ 4.5 | $ 129.3 |

(1) Corporate consists of interest expense, interest income, minority interest and certain other costs such as franchise taxes, which are not allocated to the other business segments.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## 14. SEGMENT INFORMATION—(Continued)

| | As of and for the Year Ended December 31, 2002 | | | | | |
|---|---|---|---|---|---|---|
| | Liquids Transportation | Gathering and Processing | Natural Gas Transportation | Marketing | (1) Corporate | Total |
| | (dollars in millions) | | | | | |
| Total Revenues | $ 334.3 | $ 780.0 | $ 24.8 | $ 267.9 | $ — | $1,407.0 |
| Less: Intersegment revenue | — | 77.8 | 5.0 | 138.7 | — | 221.5 |
| Operating revenues | 334.3 | 702.2 | 19.8 | 129.2 | — | 1,185.5 |
| Cost of natural gas | — | 635.2 | 8.6 | 126.9 | — | 770.7 |
| Operating and administrative | 104.7 | 34.5 | 4.5 | 0.5 | — | 144.2 |
| Power | 52.7 | — | — | — | — | 52.7 |
| Depreciation and amortization | 64.8 | 12.3 | 2.8 | — | — | 79.9 |
| Operating Income | $ 112.1 | $ 20.2 | $ 3.9 | $ 1.8 | $ — | $ 138.0 |
| Interest expense | — | — | — | — | (59.2) | (59.2) |
| Other income (expense) | — | — | — | — | (0.2) | (0.2) |
| Minority interest | — | — | — | — | (0.5) | (0.5) |
| Net income | $ 112.1 | $ 20.2 | $ 3.9 | $ 1.8 | $(59.9) | $ 78.1 |
| Total Assets | $1,528.0 | $ 734.5 | $435.1 | $ 137.3 | $ — | $2,834.9 |
| Capital Expenditures (excluding acquisitions) | $ 201.8 | $ 12.2 | $ 0.7 | $ — | $ — | $ 214.7 |

(1) Corporate consists of interest expense, interest income, minority interest and certain other costs such as franchise taxes, which are not allocated to the other business segments.

| | As of and for the Year Ended December 31, 2001 | | | | | |
|---|---|---|---|---|---|---|
| | Liquids Transportation | Gathering and Processing | Natural Gas Transportation | Marketing | (1) Corporate | Total |
| | (dollars in millions) | | | | | |
| Total Revenues | $ 313.3 | $ 29.0 | $ — | $ — | $ — | $ 342.3 |
| Less: Intersegment revenue | — | — | — | — | — | — |
| Operating revenues | 313.3 | 29.0 | — | — | — | 342.3 |
| Cost of natural gas | — | 26.3 | — | — | — | 26.3 |
| Operating and administrative | 102.7 | 1.8 | — | — | — | 104.5 |
| Power | 49.9 | — | — | — | — | 49.9 |
| Depreciation and amortization | 63.0 | 0.8 | — | — | — | 63.8 |
| Operating Income | $ 97.7 | $ 0.1 | $ — | $ — | $ — | $ 97.8 |
| Interest expense | — | — | — | — | (59.3) | (59.3) |
| Other income (expense) | — | — | — | — | 0.9 | 0.9 |
| Minority interest | — | — | — | — | (0.5) | (0.5) |
| Net income | $ 97.7 | $ 0.1 | $ — | $ — | $(58.9) | $ 38.9 |
| Total Assets | $1,372.6 | $ 276.6 | $ — | $ — | $ — | $1,649.2 |
| Capital Expenditures (excluding acquisitions) | $ 34.9 | $ 0.1 | $ — | $ — | $ — | $ 35.0 |

(1) Corporate consists of interest expense, interest income, minority interest and certain other costs such as franchise taxes, which are not allocated to the other business segments.

## 15. SUBSEQUENT EVENTS

***Mid-Continent Liquids System Acquisition***

On December 22, 2003, the Partnership entered into a definitive agreement to acquire crude oil pipeline and storage for $115.0 million, excluding customary closing adjustments for working capital and other items. The asset purchase closed on March 1, 2004. The assets acquired serve refineries in the Mid-Continent from the Cushing, Oklahoma Hub and consist of some 615 miles of active crude oil pipelines and 9.5 million barrels of storage capacity. Included are:

- The 433 mile Ozark pipeline that currently transports approximately 170,000 barrels of crude oil per day from Cushing to Wood River, Illinois;
- A 1.2 million barrel storage terminal;
- The 47-mile West Tulsa pipeline that currently transports approximately 55,000 barrels per day to two refineries in Oklahoma; and
- The Shell storage terminal at Cushing, which is one of the largest terminal facilities in North America with 8.3 million barrels of storage capacity.

These systems provide cash flows primarily from toll or fee-based revenues from a combination of regulated assets and contracted unregulated. The assets will be included in the Partnership's Liquids Transportation segment.

***Class A common unit issuance***

On January 2, 2004, the Partnership issued an additional 450,000 Class A common units pursuant to the exercise of the over-allotment option as part of the December 2003 Class A common unit issuance, resulting in additional proceeds to the Partnership, net of underwriters' fees and discounts, commissions and issuance expenses, of approximately $21.7 million. In addition to the proceeds generated from the unit issuance, the General Partner contributed $0.5 million to the Partnership to maintain its 2% general partner interest in the Partnership.

***Distribution Declaration***

On January 22, 2004, the Partnership's Board of Directors declared a distribution payable on February 13, 2004, to unitholders of record as of February 2, 2004, of its available cash of $55.8 million at December 31, 2003, or $0.925 per common unit. Of this distribution, $9.3 million was distributed in i-units to i-unit holders and $0.2 million was retained from the General Partner in respect of this i-unit distribution.

***Senior Unsecured Note Issuance***

On January 9, 2004, the Partnership issued an additional $200.0 million in aggregate principal amount of its 4.0% Senior Unsecured Notes due in 2009 in a public offering, from which it resulted in net proceeds of $198.4 million. The Partnership used the proceeds to repay a portion of its outstanding Bank Credit Facilities debt.

**ENBRIDGE ENERGY PARTNERS, L.P.**

**NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS—(Continued)**

## 16. QUARTERLY FINANCIAL DATA (unaudited)

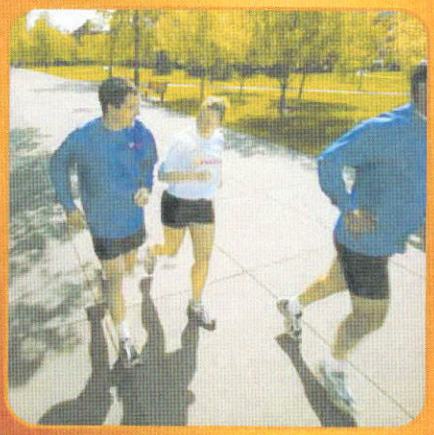
*(Dollars in millions, except per unit amounts)*

| | First | Second | Third | Fourth | Total |
|---|---|---|---|---|---|
| **2003 Quarters** | | | | | |
| Operating revenue | $896.1 | $755.3 | $760.5 | $760.4 | $3,172.3 |
| Operating income | $ 53.9 | $ 43.1 | $ 45.0 | $ 52.3 | $ 194.3 |
| Net income | $ 32.6 | $ 23.3 | $ 23.5 | $ 32.3 | $ 111.7 |
| Net income per unit(1) | $ 0.62 | $ 0.39 | $ 0.38 | $ 0.54 | $ 1.93 |

| | First | Second | Third | Fourth | Total |
|---|---|---|---|---|---|
| **2002 Quarters** | | | | | |
| Operating revenue | $181.8 | $223.1 | $237.7 | $542.9 | $1,185.5 |
| Operating income | $ 32.5 | $ 30.4 | $ 31.8 | $ 43.3 | $ 138.0 |
| Net income | $ 17.7 | $ 16.8 | $ 17.6 | $ 26.0 | $ 78.1 |
| Net income per unit(1) | $ 0.43 | $ 0.39 | $ 0.42 | $ 0.52 | $ 1.76 |

(1) The General Partner's allocation of net income has been deducted before calculating net income per unit.

ENBRIDGE



# 2003 Environment Health and Safety Report

ENBRIDGE*

## ENVIRONMENT, HEALTH AND SAFETY PERFORMANCE HIGHLIGHTS

- For the second consecutive year, in 2002 Enbridge was selected as a member of the Dow Jones Sustainability Index. The index recognizes companies from around the world that "lead their industry in terms of sustainability."
- In 2002, we conducted 37 internal reviews of pipeline operations, gate stations and gas processing and treating plants. This doubled our activity in 2001, reflecting the increasing scope of our operations.
- Total greenhouse gas emissions from our Canadian group of companies were 1.1 million tonnes of $CO_2$ in 2001, comparable to 2000 but 13% below 1990 levels.
- Employee lost-time injury frequency in 2002 was up 3% over 2001, but overall has improved 40% since 1998. Employee total recordable injury frequency improved 14% and 17% over 2001 and 1998 levels.

### SCOPE OF REPORT

The 2003 Environment, Health and Safety Report primarily covers the activities of Enbridge's three major business units: Energy Transportation North, Energy Transportation South and Energy Distribution.

We maintain statistical environment, health and safety (EH&S) data for these business units. We also provide some information on joint venture activities of Enbridge International.

This report covers the calendar year ending December 31, 2002. In some cases, we have reported on significant items in early 2003. We cover only activities for which Enbridge had operational responsibility.

Message from the President **01** Corporate Profile **02** Organization and Management Systems **04**
Environmental Performance **08** Health and Safety Performance **18** Community Relations **24**
Summary of Performance Indicators **30** Glossary — inside back cover

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## MESSAGE FROM THE PRESIDENT & CHIEF EXECUTIVE OFFICER

Safe and environmentally responsible operations are embedded in Enbridge's core values, and we work hard to live up to our stated commitment to "value the safety of our employees and the public, a clean and healthy environment and strong, vibrant communities."

That commitment is reflected throughout this, our third annual environment, health and safety report. In 2002, we continued to work harder and smarter to minimize accidents and minimize our environmental footprint.

In 2002, we made progress on a number of fronts.

- Our lost-time injury frequency rate, although marginally higher (3%) than in 2001, has improved 40% since 1998.
- We doubled the number of internal reviews and audits of pipeline operations, gate stations, and gas processing and treating plants compared with 2001.
- We expanded training for employees and held more than 60 emergency response exercises in Canada and the United States.
- And we increased the number of full-time EH&S professionals on staff to 39.

We took an active role in the climate change debate leading up to Canada's ratification of the Kyoto Protocol late last year, and we continued to work to reduce greenhouse gas emissions from our Canadian operations.

We also continued to be a leader in pipeline integrity, strengthening formal pipeline integrity programs in all three key North American business units. During the year Energy Transportation North inspected nearly 4000 kilometres (2,480 miles) of pipeline using state-of-the-art in-line inspection tools.

We work hard to ensure continued safe and reliable operation of our pipelines, but we also know that humans and machines are not infallible. Problems do occur, and when that happens Enbridge acts quickly and communicates effectively to let all affected parties know what is happening. For example, in January of this year we had an oil spill at our Superior, Wisconsin, Terminal, and some of the oil got onto the ice on the nearby Nemadji River. We responded immediately, cleaning up the spill and alerting all appropriate parties.

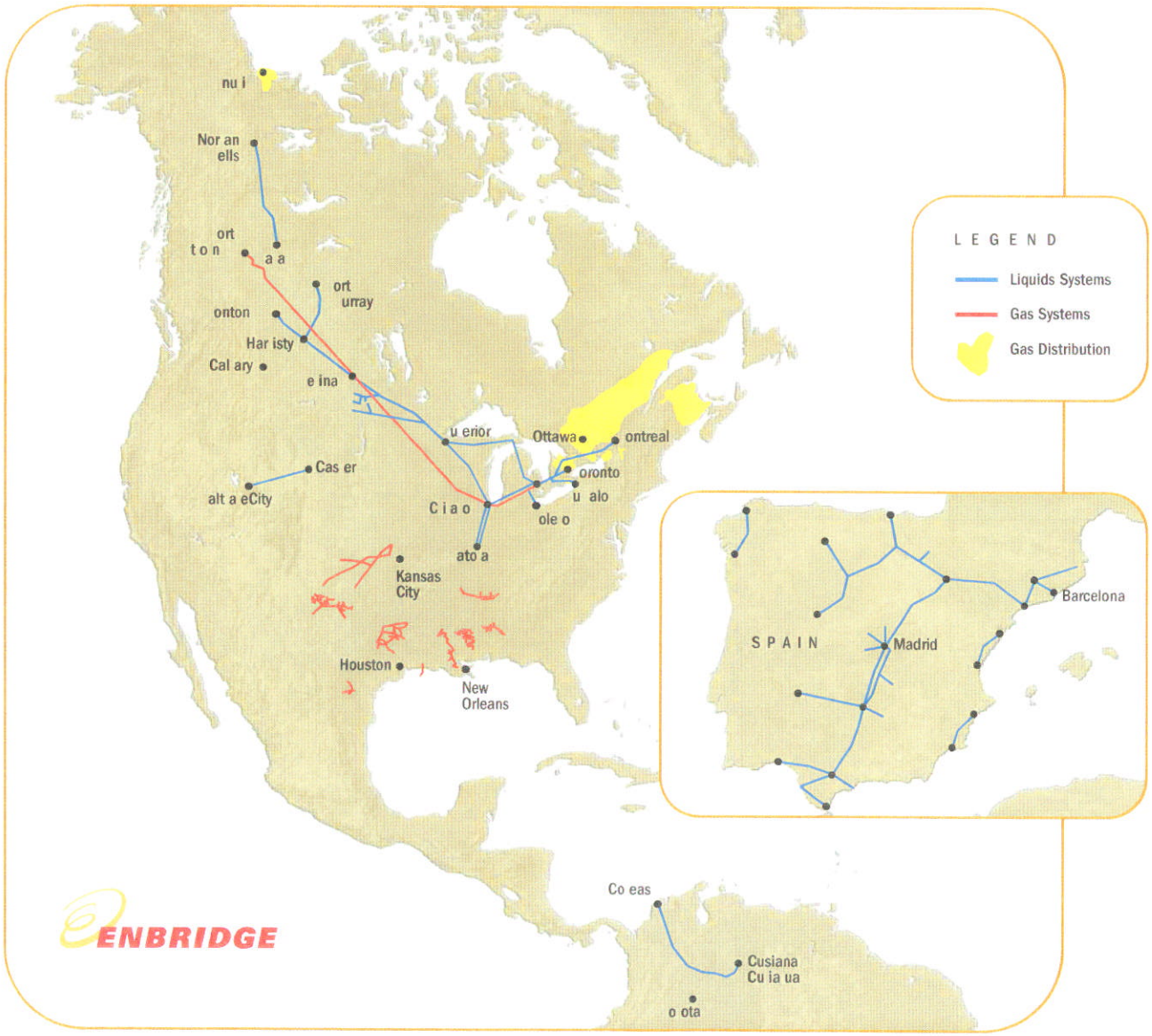
One unexpected result was an article in the Superior Daily Telegram complimenting us for our communications. In an article entitled "A little luck and honesty minimized impact of oil spill," the author stated that, "Another encouraging sign was the way Enbridge dealt with the situation ... While it would have been easy to keep the event a secret in the midst of repairs and cleanup, Enbridge can be applauded for alerting not only the public, but also all the appropriate emergency and environmental agencies in an honest and timely manner."

Those words were much appreciated, because we are committed to open and honest communication. It is an integral part of our overall commitment to social responsibility, and is in keeping with our vision of becoming the leading energy delivery company in North America. We believe, too, that being a leader in EH&S is a key part of being a leader in operational excellence and financial performance. We will continue to strive to improve our EH&S performance, and we will continue to let our key stakeholder audiences know how we are doing.

**Patrick D. Daniel**
President & Chief Executive Officer
July 7, 2003

## CORPORATE PROFILE

**Enbridge is a leading energy delivery company focused on crude oil and liquids pipelines, natural gas pipelines and natural gas distribution. Our energy delivery systems transport products that provide fuel for transportation, heat for homes and resources to manufacture different consumer products. We are active internationally, but most of our assets are in Canada and the United States. We operate the world's longest crude oil and liquids pipeline, and Canada's largest natural gas distribution company. Our head office is in Calgary, Alberta.**



| Financial performance | 2002 | 2001 |
|---|---|---|
| Earnings applicable to common shareholders (millions of Canadian dollars) | **576.5** | 458.5 |
| Earnings per common share (Canadian dollars per share) | **3.60** | 2.91 |
| Return on average common shareholders' equity | **19.9%** | 18.6% |
| Debt to debt plus shareholders' equity at year end | **64.4%** | 72.9% |
| Assets (billions of Canadian dollars) | **13.0** | 13.1 |

**We conduct our business through the following business units:**

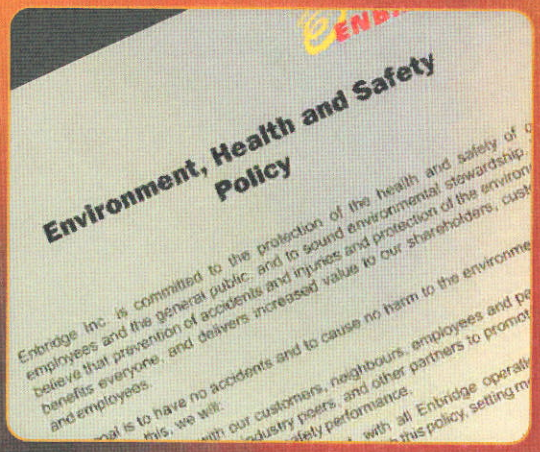
- Energy Transportation North operates our crude oil pipelines in Canada and the U.S. (the U.S. parts are the Lakehead and North Dakota systems). This group is also responsible for Enbridge's interests in the Alliance and Vector natural gas pipelines and for our midstream natural gas business in Western Canada.
- Energy Transportation South is responsible for our energy transportation businesses in the U.S. Enbridge holds a 13% interest in Houston-based Enbridge Energy Partners, L.P., which owns liquids and natural gas transportation and midstream systems. These include transmission and gathering pipelines and processing and treating businesses in the Midwest, Midcontinent and Gulf Coast areas.
- Energy Distribution owns and operates Enbridge Gas Distribution, which serves more than 1.6 million customers in parts of Ontario, Quebec and Upper New York State. We also are involved in the natural gas distribution business in Quebec through our interest in Noverco Inc., and are developing a natural gas distribution network in New Brunswick through Enbridge Gas New Brunswick.
- Enbridge International develops and coordinates Enbridge's international activities. We have a 24.7% interest in and operate the OCENSA pipeline in Colombia and have a 25% interest in Compañia Logistica de Hidrocarburos CLH, S.A., Spain's largest refined products transportation and storage business. We also provide consulting and technology transfer services internationally.

**2002 highlights**

- delivered 2.1 million barrels of crude oil and liquids each day
- distributed 410 billion cubic feet of natural gas during the year
- employed 4,000 people, mainly in Canada and the U.S.

Visit **www.enbridge.com** for more information on our businesses or to view the 2002 Enbridge Inc. Annual Report.

## ORGANIZATION AND MANAGEMENT SYSTEMS




*Enbridge's activities are diverse, but share a common commitment to promoting high standards of health, safety and environmental protection.*

We have developed systematic processes for managing EH&S issues. These processes are driven by our policies, monitored by our Board of Directors and senior management, and supported by operational procedures and employee training programs.

### POLICIES

Our corporate EH&S policy, adopted in 2000, directs our employees' decisions and actions to meet regulatory compliance and achieve EH&S excellence. Our EH&S goals are to have no incidents and cause no harm to the environment.

Some areas targeted by our policy are:

- continuous improvement in EH&S performance
- pollution prevention and resource conservation
- health and safety management
- open consultation with our stakeholders

The policy applies to all Enbridge's facilities and operations, and is communicated to our employees through our intranet site and training programs. This and other company policies are referenced in Enbridge's Statement on Business Conduct, which all employees read and agree to adhere to as a condition of employment.

### GOVERNANCE

Enbridge's activities are diverse but share a common commitment to promoting high standards of health, safety and environmental protection. This extends from our Board of Directors to all employees. As part of their corporate governance responsibilities, the Board oversees EH&S activities at a strategic level to verify they are consistent with our business objectives. The Board receives quarterly update reports on significant EH&S issues.

The Board's EH&S Committee sets EH&S directions and commitments, and reviews EH&S performance in key areas. To review performance, they receive comprehensive annual reports from the three main business units: Energy Transportation North, Energy Transportation South and Energy Distribution. This six-member committee met five times during the year to discuss a range of issues, including spills, climate change, and regulatory and legislative developments. All members are independent of management.

### ORGANIZATION

Senior management EH&S committees in the three main business units are responsible for setting and communicating EH&S policy across Enbridge.

Each business unit is supported by a dedicated EH&S department providing professional services to achieve our goal of EH&S operational excellence. These

efforts include management of EH&S programs and technical assistance and guidance on EH&S regulations, policies and issues. The departments also conduct incident investigations and EH&S reviews of facilities, and provide assessments of new business development opportunities.

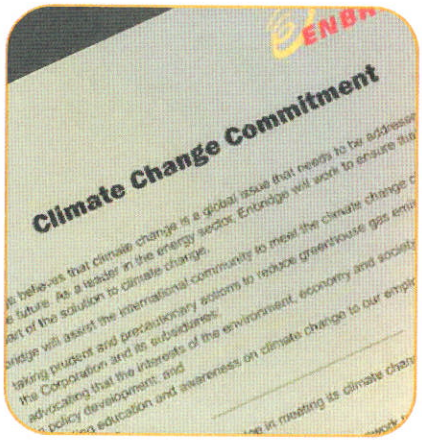
In 2002, we employed 39 full-time EH&S professionals.

### Changes in 2002

Last year, we strengthened our company's capacity to fulfill our EH&S responsibilities.

We expanded full-time EH&S professionals in Energy Transportation South from one to six, by retaining staff from recently acquired companies. Of these, three work in the Northeast and East Texas systems to support gas processing and treating operations.

We also formed the Sustainable Energy Department, based in Toronto, to identify and develop new corporate and marketing benefits from environmental programs in Enbridge Gas Distribution. This three-person group is focusing on opportunities to generate new revenue sources, enhance corporate leadership and manage environmental risks such as climate change.




### Employee forums

We believe that many of the best ideas for improving EH&S performance come from our employees. That is why we have established local and regional EH&S committees and working groups, where employees and management meet regularly to discuss local issues and opportunities.

Our local and regional EH&S committees in Energy Transportation North provide forums for sharing best practices and looking at new ways to integrate EH&S activities into our daily operations. Last year, for example, the Edmonton office EH&S committee coordinated health and wellness awareness campaigns and promoted our employee safety recognition program.

Similarly, 10 EH&S joint committees operate throughout Enbridge Gas Distribution. In 2002, committee members took an active role in reviewing EH&S issues and providing recommendations to management. This included target setting for the company's safety challenge for operations employees.

Employee working groups have also been established in Energy Transportation South's field operations to conduct safety inspections and provide input to new EH&S programs.

## MANAGEMENT SYSTEMS

We use management systems to focus our company's EH&S objectives, improve worker safety, reduce adverse impacts on health and the environment, and measure our progress. All business units apply management systems adapted to their activities and business environments.

Energy Transportation North uses separate management systems for the environment and for health and safety. Energy Transportation South and Energy Distribution apply integrated EH&S management systems.

During the year, we strengthened and updated our management systems to complement changing organizational and business needs.

Energy Transportation North developed an enhanced environmental review process, with defined timelines, protocols and record-keeping practices. These improvements will promote a more consistent approach to conducting reviews of the liquids pipeline systems in Canada and the U.S.

Energy Distribution also improved its management system by developing more detailed procedures to track and measure the progress of EH&S programs. And Energy Transportation South incorporated new business acquisitions into its management system.

### Training

Training is an important component of our company's management systems programs.

Employees who engage in work activities that may impact health and safety, or which may impact the environment, receive EH&S training.

In 2002, we provided more than 40,500 hours of EH&S training — or about 11 hours of training per field and office employee. This included classroom and hands-on training on various topics: ergonomics, driver safety, EH&S leadership, emergency preparedness, regulatory updates and management of contaminated soils.

## REVIEWS AND AUDITS

We use reviews and audits to assess each business operation's compliance against government regulations and our internal policies and management systems.

### Internal reviews

Last year, teams of EH&S professionals conducted 37 internal reviews of pipeline operations, gate stations and gas processing and treating plants. This doubled our activity over 2001, reflecting the increasing scope of our operations, with recently acquired gas processing and sulphur extraction plants in Energy Transportation South. No significant compliance issues were identified in the reviews.

We consider each review a key opportunity to continually improve our performance and share findings among staff. To carry out the review, the review team visits the site, conducts interviews and examines documentation. After the review is done, the findings are presented to local management. Management then develops an action plan to correct deficiencies.

A review team, for example, conducted an environmental review of a 1370-kilometre (850-mile) section of the Lakehead System. Although the study showed no major issues and confirmed high environmental awareness among staff, it identified opportunities to improve the handling of wastes. A corrective action plan was implemented.

### Process safety management

Process safety management (PSM), a formal review process required by U.S. regulators, is used to assess plant facilities and to promote worker and public safety.

## EH&S AWARDS AND RECOGNITION

Our strong performance trend was highlighted by EH&S awards presented to our businesses in 2002:

**ENERGY DISTRIBUTION**
***Safety Award for Distribution Companies***
Canadian Gas Association

**ENERGY TRANSPORTATION NORTH**
***Minnesota Governor's Meritorious Achievement Award in Occupational Safety***
(for better than average performance in incident rates)
Minnesota Safety Council

***Environmental Management Award***
(for excellence in corporate environmental management)
Canadian Energy Pipeline Association

***Spill Prevention Award***
(for effective detection of unplanned releases of product from an operating pipeline)
Canadian Energy Pipeline Association

***Safety Achievement Award***
(for lowest recordable injury frequency rate for large pipeline systems)
Canadian Energy Pipeline Association

**INUVIK GAS**
***Employer Recognition Award***
(for occupational health and safety activities)
Workers' Compensation Board of the Northwest Territories and Nunavut

**OCENSA**
***Emerald Cross Award***
(for EH&S performance and compliance)
Colombian Safety Council

Our PSM activities for 2002 focused on compliance reviews at 12 gas processing and sulphur extraction plants and integrating new acquisitions into our Energy Transportation South operations. Many process improvements were discovered and implemented through the year-long process.

### External audits and inspections

Environmental and safety audits and inspections of our operations also are carried out by local regulatory agencies.

In Canada, the National Energy Board (NEB) conducted an emergency preparedness audit of our NW System, which transports crude oil from Norman Wells, Northwest Territories, to Zama, Alberta. Inspecting equipment and comparing our operating practices against our policies, NEB auditors found no significant issues and commended the company on our efforts to involve communities and local response agencies in emergency deployment exercises.

The NEB also conducted a similar audit of the Niagara Gas Transmission System, which is owned and operated by Enbridge Gas Distribution. The audit identified opportunities to improve regulatory reporting, training for employees and external emergency responders, and assessment of potential hazards at facilities. Actions are under way to correct these deficiencies.

In the U.S., state and federal regulators conducted 27 EH&S compliance audits of Energy Transportation South facilities. We received a fine of US$5,600 for an air-permitting violation, which related to operations prior to acquisition by Enbridge. This facility is currently in compliance.

## REGULATORY COMPLIANCE

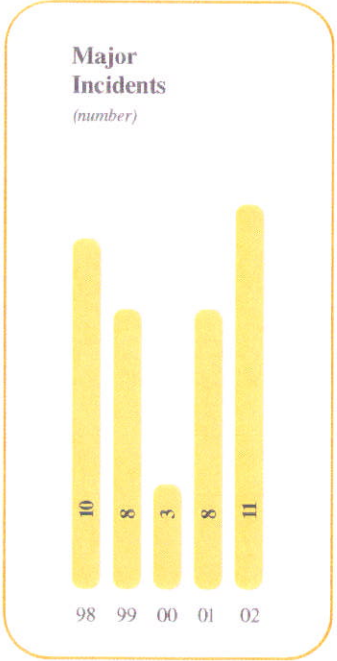
Enbridge's operations are subject to extensive local, provincial, state and federal EH&S regulations and laws. We manage compliance with these requirements through system controls and regular reviews and inspections.

Our goal is compliance with government regulations and corporate procedures. Although we generally meet these requirements, occasionally equipment failures or human errors occur that result in non-compliance. In each case, we correct the deficiencies and reinforce proper work practices among staff.

Last year, we received seven regulatory notifications for EH&S issues:

- Energy Transportation North had one notification for contaminated soil from a historic leak site along the Lakehead System near Elgin, Illinois. We submitted a remedial action plan and are continuing work to address concerns. No citations or penalties have been received.
- Energy Transportation South had three notifications for non-compliance in the East Texas System and the Anadarko System in Oklahoma. Two of the notifications related to operations before acquisition by Enbridge.
- Enbridge Gas Distribution received three orders from the Ontario Ministry of Labour. Two orders were for failing to follow safe ladder practices during a pipeline excavation, and one was for failing to inform contractors about safe operating practices near our system. Actions have been taken to address these issues, including the development of training materials to make employees aware of the dangers of improper use of ladders.

We incurred regulatory fines totaling US$16,900, compared with US$46,000 in 2001.




*Major incidents are EH&S incidents that result in a critical employee or contractor injury or fatality, significant regulatory enforcement action, a liquid spill of more than 100 barrels, or significant adverse impact to the environment.*

## ENVIRONMENTAL PERFORMANCE

*Strong environmental performance is a key indicator of successful businesses. In 2002, our efforts – everything from addressing greenhouse gas emissions to increasing energy efficiency and protecting wildlife habitat – continued to earn Enbridge a reputation for environmental leadership.*

### GREENHOUSE GASES

Climate change continued to be a key environmental issue for Enbridge's Canadian operations.

In late 2002, the Canadian government ratified the Kyoto Protocol on global climate change. Under this international agreement, Canada has agreed to reduce annual greenhouse gas emissions to 6% below 1990 levels over the period 2008 to 2012. Enbridge is assessing government plans for implementing the protocol.

Until details of the plans become clearer, we will not be able to quantify their impact on our operations. From a supply perspective, however, we are encouraged by recent responses of oil and natural gas producers, including their commitment to sustained oil sands development.

Enbridge supports the aim of reducing greenhouse gas emissions and believes that all sectors of society, including individual energy consumers, need to be involved. We continue to work with governments and other interested parties to find constructive solutions through policy development and public discussions.

We also are taking action to address the growth of greenhouse gas emissions from our wholly owned Canadian facilities. Our climate change action plan includes:

- *fugitive emission management*

  Fugitive methane emissions are released to the atmosphere from our natural gas pipelines and facilities. In our Enbridge Gas Distribution system, the use of polyethylene is a major factor in reducing these direct emissions. Since the start of this program, 773 kilometres (480 miles) of polyethylene pipe have replaced cast iron mains in Ontario. In 2001, this reduced fugitive methane emissions by 4.0 million cubic metres (140 million cubic feet), or 56 400 tonnes of $CO_2$ equivalent.

- *internal efficiencies*

  We are pursuing opportunities to increase efficiencies in our Energy Transportation North liquids pipeline system, our largest source of indirect greenhouse gas emissions. System expansions, including the use of larger diameter pipe and energy efficient equipment, saved an estimated 953 gigawatt-hours of electricity in 2001, reducing the equivalent of 470 000 tonnes of $CO_2$.

- *demand-side management*

  Enbridge Gas Distribution provides demand-side management programs that encourage and enable customers to use natural gas more efficiently. From 1995 to 2001, the programs resulted in total "avoided" emissions of 1.6 million tonnes of $CO_2$.

*alternative and renewable energy*

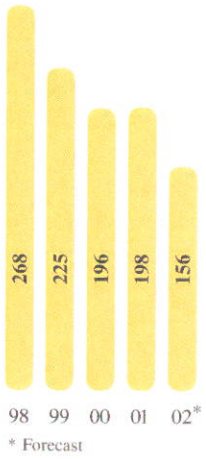
Enbridge, with Suncor, officially launched the SunBridge Wind Power Project in 2002, adding more than 11 megawatts of renewable energy to Saskatchewan's power grid. The wind farm will displace fossil fuel generating sources of electricity, resulting in "avoided" annual emissions of more than 30 000 tonnes of $CO_2$.

*Enbridge Gas Distribution operates Solarwall technology at our Toronto garage facilities. By using solar energy to provide space heating, this technology has saved about 100 tonnes of $CO_2$ equivalent since its installation in 1999.*

In 2001, total direct and indirect greenhouse gas emissions from our Canadian operations were 1.1 million tonnes of $CO_2$, nearly unchanged from 2000 levels. This was 13% below 1990 levels, even though we delivered 20% more throughput on our energy transportation and distribution systems.

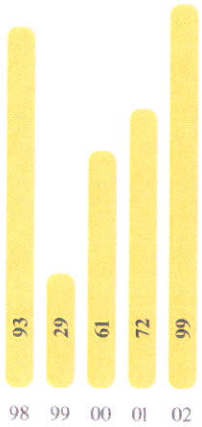
**Total Net Greenhouse Gas Emission Intensity Canadian Operations**

*(tonnes of $CO_2$ equivalent/ petajoules of energy delivered)*

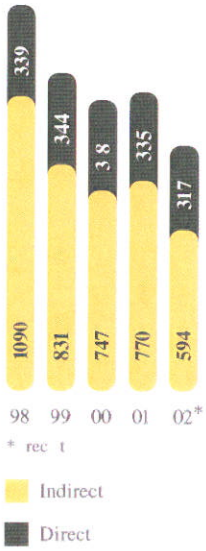



**Replacement of Cast Iron Pipe Enbridge Gas Distribution**

*(kilometres/year)*




*(thousand tonnes of $CO_2$ equivalent)*




*Based on projections for our Voluntary Challenge and Registry (VCR) Update, total greenhouse gas emissions in 2002 from our Canadian group of companies are estimated to be 29% below 1990 levels.*

*Our total net greenhouse gas emission intensity ($CO_2$ emitted for each unit of throughput) in 2002 is estimated to be 43% lower than 1990 levels.*

*Source: 2002 VCR Update Data*

*Over the last five years, Enbridge Gas Distribution has replaced 354 kilometres (219 miles) of cast iron pipe with corrosion-free polyethylene pipe, saving the equivalent of 286 400 tonnes of $CO_2$.*

### Emerging and renewable energy solutions

Our strategy is to invest in emerging and renewable energy technologies that complement our core businesses and provide environmental benefits.

With Suncor Energy, we officially launched the SunBridge Wind Power Project, generating emissions-free energy from 17 wind turbines at Gull Lake, Saskatchewan.

We also purchased shares in WindShare, a project developed by the Toronto Renewable Energy Co-operative to promote community-based wind energy initiatives. In early 2003, WindShare, in partnership with Toronto Hydro, commissioned its first wind turbine on Toronto's waterfront.

Residents of all ages from Gull Lake, Saskatchewan, were on hand to celebrate the official opening in June 2002 of the SunBridge Wind Power Project.

Besides wind power, we are focusing on emerging energy technologies that use natural gas, particularly fuel cells and micro turbines.

We support fuel cell development through our investment in Calgary-based Global Thermoelectric.

The natural gas-fuelled, solid oxide units are designed to use less fuel to produce more useful energy, ultimately reducing greenhouse gas emissions.

We are also exploring the use of natural gas-powered micro-turbine units that generate electricity and recover useful heat. In 2002, we sponsored a government-led project to test a 60-kilowatt micro-turbine unit in a federal government building in Toronto. In 2003, we will pursue other micro-turbine project opportunities that can be applied to commercial buildings.

## LOCAL AIR QUALITY

We are committed to reducing emissions from our operations that affect local air quality: sulphur dioxide ($SO_2$), nitrogen oxides ($NO_x$) and volatile organic compounds (VOCs).

### $SO_2$ and $NO_x$

Enbridge Gas Distribution operations in Ontario emit $SO_2$ and $NO_x$ from fuel use in our vehicle fleet. In 2002, these operations released 1.3 tonnes of $SO_2$ and 18.8 tonnes of $NO_x$.

### SUNBRIDGE CREATES GREEN POWER

The power of the wind is being put to good use at the SunBridge Wind Power Project, Saskatchewan's first large-scale wind power facility. Since February 2002, SunBridge has generated renewable energy from 17 turbines at Gull Lake, Saskatchewan.

SunBridge is a $22-million 50/50 partnership between Enbridge and Suncor Energy, with Enbridge serving as the project operator. Power is distributed to the power grid, with SaskPower, the province's main electricity supplier, purchasing power from the project to supply federal government buildings in Saskatchewan and other customers.

The turbines rise to the height of a 17-storey building and turn a three-blade rotor measuring 47 metres (51 yards) in diameter. They generate over 11 megawatts of electricity, or about 43 gigawatt-hours of electricity a year, enough power for 5,000 homes.

We closely monitor the project's impact on the environment. In 2002, in partnership with the Saskatchewan government and the Canadian Wildlife Service, we conducted extensive bird monitoring surveys at the site. Results of the surveys show that the turbines have little impact on migratory and nesting birds.

## NATURAL GAS VEHICLES — A SOLUTION FOR URBAN POLLUTION

Natural gas vehicles (NGVs) are an efficient way to reduce urban pollution. Use of NGVs cuts $SO_2$ emissions by two-thirds, $NO_x$ emissions nearly in half and $CO_2$ emissions to a quarter and eliminates almost all VOC emissions.

We provide incentives to Toronto's taxi industry to adopt NGV taxis. Since 1999, this has led to about 380 natural gas-dedicated vehicles, reducing $CO_2$ emissions by an estimated 10 200 tonnes over this three-year period.

We also work with governments and environmental groups to influence policy development that advances the use of natural gas vehicles and technologies. In 2002, Enbridge Gas Distribution and members of the Canadian Natural Gas Vehicle Alliance participated in information presentations to the Ontario Select Committee on Alternative Fuel Sources. This input, with other efforts, led to decisions by the Ontario government to further promote the purchase of environmentally friendly NGVs. In early 2003, the Ontario government doubled the provincial sales tax rebate on NGVs and introduced a new incentive for the purchase of NGV buses.

*Enbridge Gas Distribution supports the natural gas vehicle market in its Ontario franchise areas.*



In large urban areas such as Toronto, transportation fuel use accounts for roughly 40% of the smog problem. As part of the solution, Enbridge Gas Distribution actively promotes fuel efficiencies and greater use of natural gas as an environmentally preferred vehicle fuel.

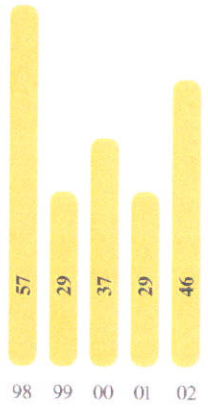
In 2002, Enbridge Gas Distribution sponsored the Enbridge Fleet Challenge in Ontario, calling on major users of fleet vehicles in the Greater Toronto Area to lower fleet fuel consumption by reducing vehicle idling.

We also continue to encourage new community strategies to reduce smog-causing emissions.

In early 2003, Enbridge Gas Distribution will participate in 20/20 The Way to Clean Air, an energy conservation program sponsored by Pollution Probe and the City of Toronto Public Health Department. The voluntary program will show Enbridge employees how to reduce energy costs and air emissions at home and while commuting.

**Natural Gas Consumption by Fleet Vehicles Enbridge Gas Distribution**

*(percentage of gasoline-equivalent fuel)*




In northern Canadian communities such as Inuvik, Northwest Territories, natural gas provides an environmentally attractive alternative to fuel oil, decreasing local air emissions and avoiding associated oil transportation emissions. In 2002, natural gas consumed by the Inuvik Gas Project displaced about 14 million litres of fuel oil, the equivalent of 350 fuel trucks.

*We opt to use natural gas in our Enbridge Gas Distribution vehicle fleet, wherever possible. The increase in the fleet's natural gas consumption between 2001 and 2002 reflects in part internal programs to encourage the use of natural gas.*

## AIR EMISSIONS REPORTING

*In 2002, we developed new reporting systems in Enbridge Gas Distribution and Energy Transportation North to track $SO_2$, $NO_x$, VOCs and other emissions. The systems will enable our company to meet new Ontario reporting regulations (called Regulation 127) and our requirements under the National Pollutant Release Inventory.*

### Volatile Organic Compounds

Sources of volatile organic compounds (VOCs) in our operations include emissions from vehicle use in Enbridge Gas Distribution, liquid spills and storage tanks in Energy Transportation North, and dehydration facilities and tanks in Energy Transportation South.

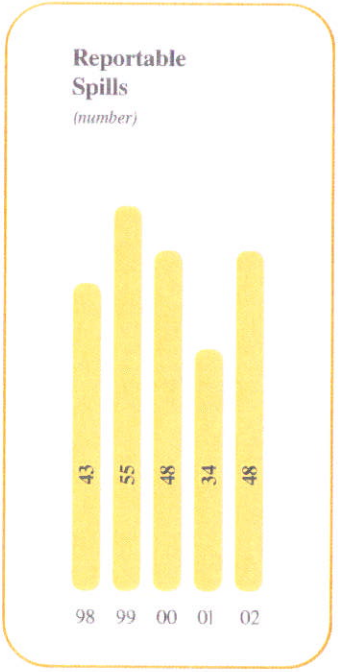
In 2002, Enbridge Gas Distribution emitted 7.4 tonnes of VOCs, compared with 15.2 tonnes in 2001 and 11.1 tonnes in 1998.

In response to new regulatory requirements, Enbridge will report VOC emissions for Canadian operations of Energy Transportation North, beginning this year. VOC emissions are currently not tracked for Energy Transportation South facilities.

## SPILLS

Our goal is to prevent all spills and leaks from our energy transportation and distribution systems. With this in mind, we carry out spill prevention and detection procedures as part of our comprehensive management of the integrity of our pipelines. Our communication programs also keep property owners and neighbors along our rights-of-way informed about our operations and enlist their help in the prevention, detection and safe response to pipeline spills.

*Reportable spills are any spill reportable to a regulatory jurisdiction.*




Despite our best efforts to prevent spills, incidents occur. In 2002, Enbridge recorded 48 reportable liquid spills from our pipeline systems in Canada and the U.S, totaling 2335 cubic metres (14,683 barrels) spilled. About 66% was recovered.

The company also recorded no reportable gas releases during the year.

In each case, we carried out prompt emergency response procedures to contain the spills and control environmental impacts. We also worked with landowners, regulatory agencies and other concerned parties to develop remediation and monitoring plans to ensure residual contaminants are appropriately managed.

Significant spills during the year included:

- *Kerrobert, Saskatchewan (January 18)*
  About 975 cubic metres (6,133 barrels) of crude oil were released from a leaking gasket on the Energy Transportation North pipeline at the Kerrobert Station. All but one barrel was contained to the industrial site, and more than 90% of the oil was recovered. About 1270 cubic metres (44,832 cubic feet) of soil were removed and used in local road repairs with government approval.
- *Glenboro, Manitoba (May 8)*
  About 95 cubic metres (598 barrels) of crude oil were released onto agricultural land after a seam failure on the Energy Transportation North pipeline. About 4330 tonnes of soil were removed for disposal at a local facility.
- *Cohasset, Minnesota (July 4)*
  About 954 cubic metres (6,000 barrels) of crude oil were released into a wetland after a pipeline rupture on the Lakehead System near Cohasset, Minnesota. A controlled

in-situ burn was carried out to eliminate much of the oil, and nearly 16 000 tonnes of contaminated soil were removed from the peat bog area. Other parts of the site will be allowed to naturally remediate under close monitoring by Enbridge and the state environmental agency. We are cooperating with regulatory agencies to conduct a natural resources damage assessment of the incident.

## SITE MONITORING AND REMEDIATION

As with any energy delivery system with many years of operating history, historic leak sites exist along our energy transportation and distribution systems.

We carry out inspections and assessments on our systems to identify and measure environmental risk from past spills, leaks and other activities. We use a risk-based process to identify and rank sites for environmental impacts, remediation and monitoring. In this way, we verify that past cleanup efforts meet today's standards and that due diligence is fulfilled.

*Enbridge conducts extensive assessments to determine the potential effects of our activities on plants, wildlife, heritage sites, water bodies and the environment.*

Throughout 2002, we demonstrated this attention to site monitoring and remediation through various activities:

- We assessed 47 historic leak sites along the Lakehead System, including a right-of-way site near Elgin, Illinois. After completing test excavations at the Illinois site, we found residual crude oil in the soil and groundwater. We are working with regulators to further investigate the site and to take corrective action, if needed.
- We inspected pump stations along the Lakehead System at Cambridge, Wisconsin, La Porte, Indiana, and Iron River, Wisconsin. No significant issues were identified.
- We inspected the site of a previous spill on our Energy Transportation North System near Herschel, Saskatchewan. No issues were found, but we are continuing to monitor the site.
- When construction activity uncovered contaminated soil from a historic leak site on our Energy Transportation North System near Hamilton, Ontario, we developed a remedial action plan and removed soil from the site. Because of further evidence of contamination, we are continuing site remediation and risk assessments of the area.
- We inspected two operating gas distribution gate stations in the Greater Toronto Area to identify the risk of possible mercury contamination from past operational practices. Soil sampling was carried out, but no remediation was required.
- We restored land at two abandoned oil wells at Tecumseh Gas Storage Operations near Sarnia, Ontario. Removing 510 tonnes of contaminated soil, we replaced topsoil and restored the land to productive agricultural use.

## LAND USE AND BIODIVERSITY

Our aim is to minimize our impacts to the land and sensitive environmental areas.

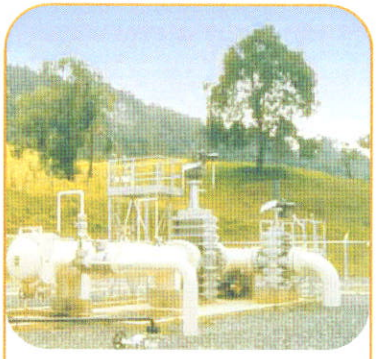
To choose pipeline routes and locations for new facilities, we conduct extensive assessments to determine the potential effects of our activities on plants, wildlife, heritage sites, water bodies and the environment. We also consult with local communities and public agencies to ensure their concerns are identified and addressed. Once facilities are in place, we restore the land and monitor our operations for potential impacts.

Examples of our efforts during the year included:

- *Wetlands in Indiana*
  We created about three hectares (eight acres) of wetlands and prairie grasslands along the Vector pipeline near Valparaiso, Indiana, to offset habitat loss during the pipeline's construction in 2000. The area will be donated to the Indiana Department of Natural Resources.

- *Merrickville, Ontario, natural gas line*
  We carried out an environmental assessment study and consulted with area residents during planning and construction of a 19-kilometre (12-mile) natural gas service line to Merrickville, Ontario. We routed the line along a roadway and used directional drilling to avoid impacts to streams and old growth trees.

- *Tree planting along OCENSA pipeline in Colombia*
  The 800-kilometre (500-mile) OCENSA crude oil pipeline traverses grasslands, forests and mountains in Colombia. The company plants trees along the pipeline right-of-way to restore forested areas disturbed during pipeline construction from 1995 to 1997. To date, more than 1550 hectares (3,830 acres) of trees have been planted.



*OCENSA plants trees along its right-of-way in Colombia as part of an ongoing commitment to restore forested areas disturbed during pipeline construction.*



## CONSULTATION AT LEECH LAKE

Many times during the past 50 years, parts of the pipeline right-of-way along the Lakehead System have been disturbed by construction. And as the years have passed and our techniques have improved, the expectations of landowners and others affected by construction have changed.

Last year, the system was expanded again. About 177 kilometres (110 miles) of new 36-inch pipeline were built between Clearbrook, Minnesota, and Superior, Wisconsin, as part of Phase III of the Terrace pipeline expansion project.

One of the sections in north central Minnesota involved construction within the boundaries of the Leech Lake Band of Ojibwe Reservation. Throughout the project, our project team consulted with Band leaders, identifying their concerns and discussing our plans to reduce the impact of our activities on the land and their community.

We worked closely with the Band and the U.S. Forest Service to reduce the clearing of old growth trees in the nearby Chippewa National Forest. Using field surveys, we modified the pipeline route and limited workspace through the forest to avoid old growth trees and rare plant species, wherever possible. In one area of the forest, several old growth trees, which could not be avoided, were cut to widen the right-of-way to accommodate new pipe. Timber was donated to the Band for use in buildings, including a ceremonial roundhouse.

During construction, we looked for other opportunities to work with the community. Garden plots along the right-of-way were cleared for Band members. We also donated eight hectares (20 acres) of culturally significant land to the Band.

## WATER MANAGEMENT

We continually evaluate facilities and procedures to verify adequate controls are in place to protect local water quality. We also implement procedures to safely manage surface water runoff at major facilities and during pipeline construction.

We use water to hydrostatically test the integrity of new pipeline facilities before putting them into service. At times we also hydrostatically test existing pipeline, as part of integrity management programs. Since existing pipeline sections have transported liquid petroleum or natural gas, we properly acquire, store and treat test water before returning it to the environment.

We also carry out tests before and after pipeline construction activities to measure our impacts on nearby domestic water wells. For example, we conducted groundwater monitoring along 19 kilometres (12 miles) of new natural gas distribution pipe near Merrickville, Ontario. No impacts resulting from our construction activities were found.

## WASTE MANAGEMENT

Enbridge's operations typically do not generate large amounts of hazardous wastes. Most of our waste volumes are non-hazardous and include paper, scrap metals, packaging materials, and construction and demolition waste.

Last year, Enbridge Gas Distribution improved its tracking system for non-hazardous wastes in its Toronto area operations. This area generated about 363 tonnes, a 23% decrease from 2001 levels. Contributing to this decrease were fewer office renovations and ongoing recycling programs that diverted about 73% of non-hazardous waste, such as office paper and cardboard, from landfills.

Energy Transportation North collected roughly 98 tonnes of recycled material, of which the largest component was office paper. We also recycle oily rags and wood pallets, but do not track the recycling of these materials.

Asbestos-containing insulation materials, found in older buildings in our operations, are classified as a non-hazardous waste under U.S. regulations. As part of ongoing site cleanup or renovations in Energy Transportation South, we remove these materials under strict guidelines to protect worker safety. Last year, we removed and disposed of 20,500 sq. feet from a gas treating plant and a dismantled sulphur recovery unit in northeast Texas.

In 2002, Enbridge Gas Distribution disposed of hazardous waste including paint solvents, PCB materials from electrical equipment, and odorant, which is added to natural gas in small quantities for public safety.

Enbridge Gas Distribution and Energy Transportation North registered their Ontario operations with the provincial government's Hazardous Waste Information Network. This system provides online information on the generation, movement and disposal of liquid industrial and hazardous wastes in the province.

### OIL SANDS MARKETS STUDY

Through our Oil Sands Markets Study, we are looking at the development of additional pipeline capacity from Fort McMurray, Alberta. Our approach is to consider all aspects of potential development, including environmental effects.

In 2002, we began environmental and regulatory evaluations of potential oil sands pipeline corridors from the area to the B.C. West Coast and different U.S. destinations. We considered the potential impacts of different routes on the environment, including water crossings, sensitive wildlife areas and heritage and archeological resources. The results of this work will be combined with information from stakeholder consultation and other economic and technical data to identify potential pipeline corridors.

## ENERGY USE

Our liquids pipeline transportation systems in Canada and the U.S. primarily use electricity, while our natural gas gathering and transmission systems mainly use natural gas as fuel. Our Enbridge Gas Distribution System in Ontario is powered by electricity and natural gas. Diesel fuel is used to drive pumps in remote locations along the Enbridge NW System.

Over the last five years, our use of energy in our liquids pipelines system has decreased because of pipeline expansions, system enhancements and conservation measures. In 2002, strategies to operate the system on the most optimum flow rates led to increased system efficiency and reduced energy consumption. This decrease has been offset partly by increased shipments of heavy crude oil on our liquids transportation system (transportation of this product increases our use of electricity per unit of throughput).

In 2002, energy use in the Energy Transportation North System in Canada and the U.S. was 2,417 gigawatt-hours.

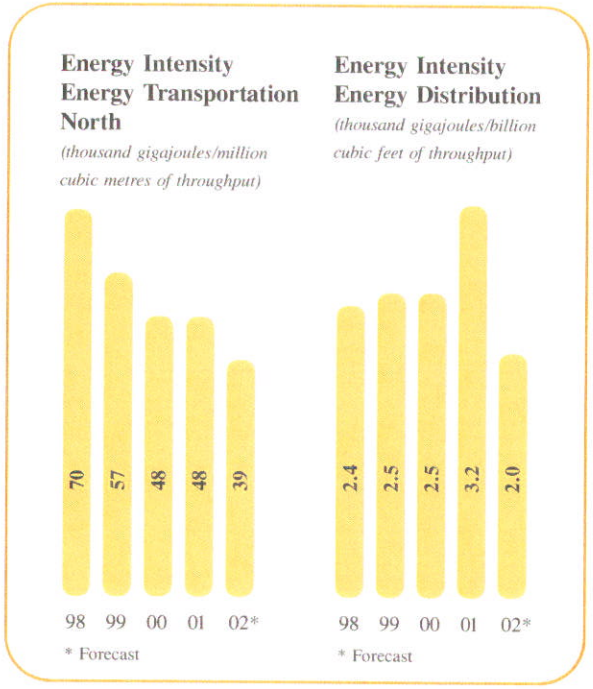
Energy reduction programs continued at Enbridge Gas Distribution with the installation of more efficient lighting at select facilities in 2002.

Extensive retrofitting of facilities, however, was not a focus during the year, due to changes in the Ontario electricity market.

## DEMAND-SIDE MANAGEMENT

Enbridge Gas Distribution's demand-side management (DSM) programs help customers to save energy and improve their environmental performance:

- We conduct energy audits of commercial and industrial customers' operations to identify opportunities to improve energy efficiency.



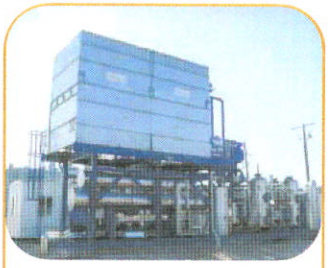

*As throughput begins to increase on the Energy Transportation North System and our recent pipeline expansions reach their capacity, it is expected that Energy Transportation North's energy intensities will return to near historical levels.*

*Energy intensity is a measure of environmental efficiency, defined as the amount of energy used per unit of throughput on energy distribution and transportation systems.*

- We partner with government, suppliers and equipment manufacturers to invest in new energy efficient technologies that benefit our ratepayers and enhance the competitiveness of our business.
- We provide financial rebates and incentives to all types of customers, from homeowners to large industrial companies, to encourage them to adopt energy-saving equipment. Over 500,000 customers participated in our DSM programs last year.

- We promote energy efficiency innovations through seminars, workshops and training programs. With Duke Energy, we sponsor an annual one-day symposium for the commercial building industry, showcasing best practices in energy efficient design and construction. About 200 industry representatives attended the event in 2002.
- We distribute energy-saving technology kits to Grade 5 students in schools in the Toronto and Durham, Ontario, regions. The students use the kits to learn about energy conservation and how to install energy-saving devices in the home. In 2002, we distributed kits to more than 5,700 students in 114 schools.

Preliminary results from our 2002 DSM programs show gas savings of about 90 million cubic metres over one year, or enough to supply about 31,000 homes. Analysis of preliminary 2002 DSM results shows that roughly 2.6 million tonnes of $CO_2$ will be reduced over the lifetime of the measures, with $NO_x$ and $SO_2$ reductions of 2148 tonnes and 21 tonnes.



*A new plant in Louisiana owned by Enbridge's Dufour Petroleum captures exhaust emissions from a nearby chemicals plant to produce food-grade $CO_2$ for use in carbonated products.*

### VEHICLE TRANSPORTATION

Our operations have two primary road transportation impacts: vehicle travel to facilities and construction sites in our energy transportation and distribution businesses in Canada and the U.S., and trucking services for natural gas liquids and petrochemical products in the U.S.

In 2002, our fleet vehicles traveled 59.7 million kilometres (37 million miles) and consumed 6.4 million litres (1.4 million gallons) of gasoline. Operation of these vehicles produced an estimated 15 800 tonnes of $CO_2$ equivalent.



### SUPPORTING THE USE OF "WASTE" GAS AND EMISSIONS

We help our partners and customers to capitalize on the use of gases and emissions that otherwise would be emitted to the atmosphere.

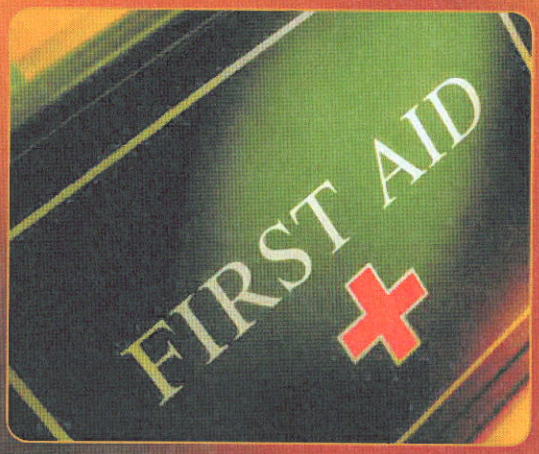
One example is pipeline construction to collect potential energy sources, such as landfill gas. When uncollected and released to the atmosphere, this gas contributes to the greenhouse effect. But after collection and processing, it provides a useful source of energy for electricity and heat.

In 2002, Enbridge Gas Distribution completed a new pipeline from a municipal landfill site to a pulp and paper operation near Thorold, Ontario. The four-kilometre (2.5-mile) line carries on average 30 000 cubic metres (1.1 million cubic feet) of recovered landfill gas each day.

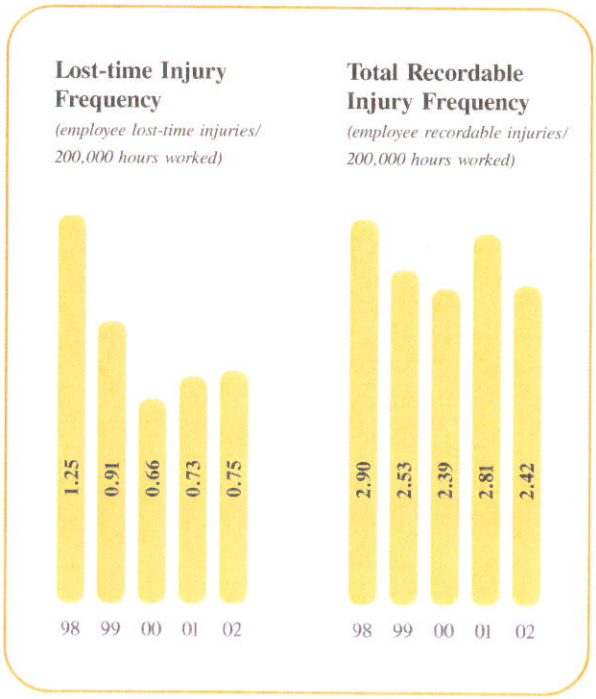
Energy Transportation South built a pipeline to connect a landfill gas plant near Kansas City, Kansas. The pipeline collects about 42 500 cubic metres (1.5 million cubic feet) of recovered gas daily for commercial customers.

Energy Transportation South also built a new plant in New Orleans, Louisiana, to capture another waste stream — $CO_2$. This prototype plant collects exhaust emissions from a nearby chemicals plant to produce food-grade $CO_2$ for manufacturing carbonated beverages. This plant is expected to recover about 250 tonnes of $CO_2$ each day.

## HEALTH AND SAFETY PERFORMANCE




*Safety is a constant focus of everything we do at Enbridge. We believe that all incidents are preventable and all employees are accountable for creating a safe and healthy workplace.*




*Employee lost-time injury frequency has improved 40% over 1998 levels.*

*Employee total recordable injury frequency has improved 17% since 1998.*

Our commitment to EH&S performance extends to all company resources, including our most valuable one — our people. Keeping our employees and contractors safe and healthy is a core value promoted throughout our organization.

### SAFETY STATISTICS

Two common statistical measures of safety performance are lost-time injury frequency (LTIF) and total recordable injury frequency (TRIF). LTIF measures work-related injuries that result in employees missing regularly scheduled work shifts per 200,000 hours worked. TRIF measures job-related injuries (lost-time and medical aid incidents) per 200,000 hours worked.

Our employee LTIF rate in 2002 was 0.75, about 3% higher than 2001. Our TRIF rate was 2.42, improving 14% from the previous year.

## HEALTH AND SAFETY REPORT TO EMPLOYEES — HIGHLIGHTS

(% of Energy Transportation North departments achieving 2002 health and safety objectives)

- specific EH&S objectives are established for all employees (75%)
- field supervisors receive critical task analysis training (100%)
- at least two critical task analyses are completed and documented by local and regional EH&S committees (89%)
- inconsistencies between documented procedures and practices are identified by local EH&S committees (100%)
- emergency preparedness objectives are developed by the Edmonton office and each operating region (100%)
- all required safety training is completed by field employees (63%)
- contractor safety management process is implemented for all significant contracts (83%)
- quarterly health and wellness campaigns are conducted across Energy Transportation North (100%)
- review of driving safety in the business is conducted by Safety and Environment, and options for improvement identified (100%)



### FATALITIES

We deeply regret that in 2002 two contractor employees were fatally injured while working at Enbridge facilities.

On January 14, a contractor was struck by a boom during construction of the Christina Lake lateral feeder pipeline, part of the Athabasca System in northern Alberta. The incident is under investigation by Alberta Workplace Health and Safety.

On May 13, a qualified contractor electrician came into contact with an energized circuit and was fatally electrocuted at the recently acquired Enbridge Pipelines (Northeast Texas) Pittsburgh Plant. The U.S. Occupational Safety and Health Administration (OSHA) and Enbridge investigated the incident.

No citations or penalties against the company have been issued in either case. We have reviewed our contractor safety management programs to ensure appropriate measures are in place to prevent similar tragic incidents from recurring.

### ACTIVITY-BASED SAFETY

Energy Transportation North's activity-based safety process plays a key role in achieving continuous health and safety improvement. The process promotes safe behaviors in a range of activities including regulatory compliance, health and wellness, assessment of workplace hazards and contractor safety. Performance improvement comes from the reinforcement of safe behaviors, with positive feedback and coaching to correct at-risk behaviors.

One of the ways we measure this process is through employee participation. Last year, we revised and expanded Energy Transportation North's safety recognition program to cover most employees. The new program encourages employees to complete three levels of safety recognition: "achieve," surpass" and "exceed." Of the 895 employees participating in the program, 19% completed "exceed" and 43% "surpass."

## HEALTH AND SAFETY TRAINING AND AWARENESS

We increase our employees' understanding of health and safety issues through training and awareness programs.

### Workplace safety

Enbridge Gas Distribution issued a safety challenge to nearly 1,000 operations employees after noticing an increase in safety incidents in the first half of 2002. Using information bulletins on previous incidents to highlight job-related safety risks, the challenge helped to significantly lower lost-time incidents as the year progressed (14 in the first half of the year compared with six in the second half).

We implemented a safety inspection process in Enbridge Gas Distribution, with managers engaging staff in regular safety "walk-throughs" at work locations. We also strengthened the company's incident investigation program, dedicating EH&S staff to carry out detailed follow-up investigations of lost-time injuries.

*Enbridge has numerous programs in place that encourage employee health and safety both on and off the job.*

In 2002, more than 80 managers and supervisors in Energy Transportation North took supervisory EH&S leadership training. The course enhanced understanding of our corporate EH&S goals, and provided a forum for identifying and resolving issues through shared experience.

The U.S. Department of Transportation (DOT) requires that pipeline operators verify the qualifications of individuals performing operations or maintenance tasks. Our approach is to not only meet these requirements, but to develop our employees' capacity to achieve operational excellence, using properly designed training and evaluation systems.

Last year, the qualifications of nearly 170 Energy Transportation South employees were confirmed through the rigorous program we developed under these rules.

### Ergonomics

We conduct ergonomic assessments and provide training, where required, to reduce the risk of discomfort or injury to our employees in their work environment in office and field locations.

In Enbridge Gas Distribution, for example, we conducted more than 300 office ergonomic evaluations. We also introduced an intranet-based questionnaire and assessment tool to educate employees on how to recognize and reduce ergonomic risks at their computer workstations.

### Contractor safety management

Our commitment to EH&S excellence extends beyond our own employees to contractors who work at our locations. Recent incidents have renewed our efforts to this commitment.

We regularly involve contractors in safety training at our field locations. All contractors must prove their commitment to safe work practices by meeting our safety performance requirements and government regulations. In Energy Transportation South, for example, contractor companies are asked to complete a formal EH&S audit document. In 2003, we plan to complete on-site EH&S audits to verify this information for selected contractors.

## EMPLOYEE HEALTH AND WELLNESS

Enbridge has many health programs that encourage employee well-being and positive lifestyles on and off the job, including:

- early-return-to-work programs that help employees who are recovering from an injury, illness or surgery to return to work in a safe and timely manner.

- employee voluntary assistance programs that offer confidential counseling services to employees and their families on a broad range of issues. Last year, about 8.8% of Enbridge Gas Distribution employees and family members used this service.
- flu immunization programs that help to safeguard employees from illness in the workplace. In 2002, more than 600 employees took advantage of this service in our different business units.
- lifestyle education for employees and their families on a variety of topics, including diabetes, addictions, heart health and stress management. Employees attended various health and wellness events, including health fairs and "lunch and learn" sessions.

Enbridge Gas Distribution trained managers in new attendance and performance management techniques for identifying absenteeism problems, and is working with employees to achieve solutions.

In 2002, field and office management in Energy Transportation North were surveyed and asked to comment on their health needs and concerns. A significant number identified ongoing work-life balance issues. We plan to study this issue further in 2003.

## PIPELINE INTEGRITY

Enbridge's pipeline integrity activities consist of comprehensive programs to ensure the safety and reliability of our pipeline systems. We endeavor to be a leader in pipeline integrity by:

- implementing rigorous preventive maintenance programs
- pursuing and supporting technological research
- participating in industry forums to share and exchange knowledge
- contributing to development of national pipeline safety standards and industry-recommended practices

By fulfilling these obligations, we maintain high standards of operating and EH&S performance and contribute to public confidence in our systems.

During 2002, we strengthened pipeline integrity in our systems:

- Energy Transportation North adopted a formal integrity management program to cover terminals and stations on the liquids pipeline system. We also inspected nearly 4000 kilometres (2,480 miles) of the system, using technologies that detect corrosion, cracking and dents.
- Enbridge Gas Distribution formed a new department to establish a formal pipeline integrity program in our natural gas business and to meet new legislation in Ontario. The business also adopted in-line inspection to further assess pipeline integrity.
- Energy Transportation South developed an integrity assessment and management plan in our ongoing effort to maintain pipeline safety and to address existing and pending federal and state regulations. The company uses a risk-based ranking process to integrate pipeline design, construction, operation, maintenance and performance data.

*Enbridge is a leader in the development of pipeline integrity programs to ensure the continued safe, reliable operation of our pipelines.*

Besides our own integrity management programs, we also furthered public education efforts that help to prevent pipeline damage by third parties. We participated in the U.S. Common Ground Alliance, a joint effort of underground utility owners and contractors to educate workers on pipeline safety and to develop industry best practices. We also supported industry efforts to add revisions to the

new U.S. Pipeline Safety Act that strengthen pipeline damage prevention programs. And we actively worked with state governments to improve pipeline damage prevention laws and enforcement.

## EMERGENCY PREPAREDNESS

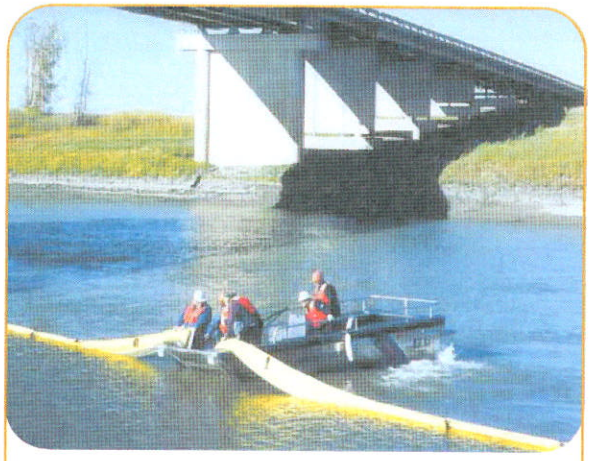
We have developed comprehensive emergency preparedness plans for each of our systems and facilities. These plans are adapted to the specific needs of the individual areas and are coordinated with the activities of local emergency response agencies.

Last year, for example, we consolidated emergency response procedures at our different pipelines, plants and gathering systems in Energy Transportation South to create an efficient, consistent and flexible plan.

Besides planning emergency procedures, we conduct training exercises to verify that our employees are constantly prepared to protect safety, property and the environment.

In 2002, we conducted 61 emergency response exercises in Canada and the U.S. These ranged from tabletop exercises, where employees discussed responses to various scenarios, to full-scale deployment exercises using equipment to practice recovery and cleanup in various terrains. We go to great lengths to include external emergency responders and members of the local community in our deployment exercises so as to stress the importance of coordinated and cooperative action during an emergency.

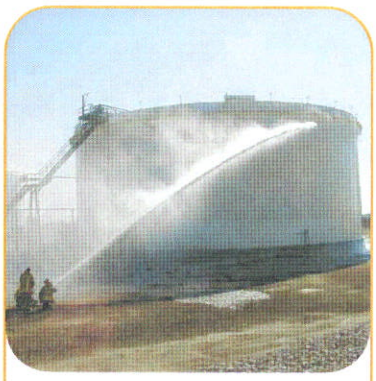
During the year, we took steps to enhance emergency preparedness in our various operations:



*Enbridge conducted more than 60 response exercises in North America in 2002 to ensure employees know their roles and responsibilities in the event of a real emergency.*

- We reviewed and revised emergency response procedures for Energy Transportation North's tank storage facilities. Although we have never experienced a fully engulfed tank fire, we recognize that a tank fire can have significant consequences, and we must be prepared. Collaborating with local fire departments, we improved tank fire emergency response procedures and planning. More than 80 employees took part in a two-day seminar on tank fire strategies and tactics. We will be conducting further training in 2003.
- We provided incident command system training to about 330 employees in Energy Transportation South and about 50 in Energy Transportation North. This system is used by regulators, company employees and local emergency responders to instill a shared understanding of the different roles and responsibilities during an emergency.
- We conducted and documented formal emergency response drills for all major facilities in Energy Transportation South.

- Enbridge Gas Distribution established a new position to oversee emergency preparedness in our natural gas distribution system in Ontario. About 50 managers and supervisors in our regional offices took half-day workshops to update their knowledge of our emergency response procedures.
- OCENSA developed and implemented a training program for community and local authorities to raise awareness of the risk of oil spills from the Colombian pipeline. The company also provided firefighting and risk awareness training to more than 400 employees and contractors.



*More than 80 employees participated in training relating to tank firefighting strategies and tactics.*

The emergency preparedness of our staff and facilities was tested on several occasions during the year. The most serious was a pipeline leak near Cohasset, Minnesota. Our emergency preparedness system was successfully activated, with Enbridge employees fulfilling their responsibilities to contain the spill and prevent further damage.

## RAPID RESPONSE TO U.S. PIPELINE LEAK

Early on July 4, 2002, emergency response teams from our Lakehead System rushed to investigate a suspected pipeline leak of crude oil near Cohasset, Minnesota, following a call from our pipeline control system operators. The line was immediately shut down. Once the team confirmed the leak — 954 cubic metres (6,000 barrels) in a peat bog one mile from the Mississippi River — local crews were mobilized. They set to work over the next eight hours to secure the area, notify regulators and develop their strategy to control environmental damage. Site security procedures were set up to protect the safety of workers and the public.

With input from company experts, regulatory agencies and local responders, our emergency crews conducted a controlled burn. Referred to as "in-situ burn," this is one of the best techniques available to manage crude oil leaks when traditional mechanical oil recovery methods could damage environmentally sensitive areas. Before the burn, specially equipped airplanes dropped fire retardant around the release area to avoid the spread of fires to nearby woods.

*Enbridge worked closely with state and federal regulatory agencies to clean up a crude oil spill near Cohasset, Minnesota.*

Site cleanup continued for the next several weeks, and trucks hauled away soil to landfill and bioremediation facilities. Skimmers and other recovery equipment also picked up standing oil and hauled it to pipeline facilities for reuse. By the end of the summer, most of the remaining oil-soaked peat was removed. In the fall, land was contoured and restored as close as possible to its original state.

We are cooperating with regulatory agencies to conduct a natural resources damage assessment of this incident and will carry out further site remediation in 2003.

## COMMUNITY RELATIONS

*Enbridge invests in communities where we operate, supplying financial support and human resources. One example is the "Plugging In: Explore the Potential of Alternative Energy" program shown at left. Enbridge is a lead sponsor of this newest addition to the Science Alberta Foundation fleet of traveling science programs.*

We connect with our communities in many different ways: investing in community initiatives and institutions, sharing employee time and knowledge, and conducting public dialogue with our stakeholders on issues of mutual interest.

### COMMUNITY INVESTMENT

Our community investment program supports not-for-profit organizations through financial contributions and human resources. Last year, our program invested $3 million in charitable and non-profit organizations in Canada and the U.S. A portion of this was donated to EH&S programs and initiatives.

Besides projects mentioned elsewhere in this report, significant contributions included sponsoring:

- high school curriculum materials on climate change by FEESA, a non-profit organization promoting balanced environmental education across Alberta.
- online green learning programs by the Pembina Institute for Appropriate Development, an Alberta-based environmental organization.
- environmental education camp for school children in Hay River, Northwest Territories.
- Clean Air Campaign, in partnership with Pollution Probe, to improve local air quality in the Toronto region through public education, advocacy and special events.
- student-driven conservation program, with students leading the way to measure, monitor and reduce energy use in schools in Renfrew County, near Ottawa.
- environmental and wildlife conservation education programs at the Tiffin Centre for Conservation near Barrie, Ontario.
- construction of the Hartley Nature Centre, a non-profit environmental education center in Duluth, Minnesota.
- Caesar Kleberg Wildlife Research Institute's South Texas Initiative to develop and promote native plants on private and public lands.

***"We're Enbridge. In partnership with our communities, we deliver more than energy; we deliver on our commitment to enhance the quality of life in our communities by supporting programs in health, education, social services and the environment. Together with our employees we have the energy to make a difference."***

## EARTH WEEK ACTIVITIES

*Enbridge Gas Distribution employees helped a Toronto-area school plant about 400 trees and shrubs on Earth Day (April 22) at the Milne Dam Conservation Park.*

Battery recycling, book exchanges, composting workshops and clothing collections for charity — those were just a few of the ways employees across the company put their energy behind Earth Week in April 2002.

While employees across Enbridge took part in different activities, the theme of waste prevention and reduction was shared:

- In Fredericton, Moncton and Saint John, New Brunswick, employees collected used household batteries for recycling.
- In Estevan, Saskatchewan, employees took part in cleanups along community roadsides.
- In Calgary, employees hosted a breakfast workshop by a local environmental group providing information to staff on recycling and composting.
- In Edmonton, employees participated in a waste prevention and reduction "home fair."
- In Fort Simpson, Northwest Territories, employees visited high school students to discuss waste management.
- In Houston, employees used the proceeds from a can-recycling program to support families with sick children.

## SPONSORING TORONTO'S SMOG SUMMIT

In 2000, Toronto's Medical Officer of Health released a report on the health impacts of urban smog. This report, together with increasing smog alerts in the city, sparked public concern. When city officials and the Toronto Atmospheric Fund decided to organize a Smog Summit — an annual conference of city, provincial and federal government officials to explore solutions to the problem — Enbridge Gas Distribution joined the effort as a founding sponsor.

Since then, the annual event has grown, attracting increasing numbers of individuals, businesses and governments.

In 2002, 600 people attended six citizens' forums over May and June to discuss ways to reduce smog and greenhouse gas emissions. Regional and municipal governments committed to new initiatives to reduce air pollution in the Greater Toronto Area. And Enbridge Gas Distribution used the Summit to launch the city's first-ever Fleet Challenge to lower vehicle fuel consumption by corporations.

## RELATIONS WITH INDIGENOUS PEOPLES

Strong and productive relations with Aboriginal communities help Enbridge to reach strategic business objectives, and indigenous peoples to realize their aspirations.

Our Indigenous Peoples Policy lays out key principles for Aboriginal relations, including respect for heritage sites, land and knowledge, the environment and traditional ways. Adopted in 2002, the policy applies to all Enbridge operations, employees, contractors and suppliers.

Guided by our policy, we are striving to build sincere and open dialogue with indigenous peoples. Much of the work during the year to support our policy was focused on northern Alberta, where we are increasing our presence:

- Enbridge was one of 14 companies to sign a new long-term agreement with the Athabasca Tribal Council (ATC), which represents five First Nations in the Athabasca and Fort McMurray regions. The agreement aims to foster meaningful dialogue and collaboration among the ATC, government and industry.
- We met with First Nations and Metis communities to review construction plans for the MacKay River and Christina Lake feeder pipelines. Based on feedback, we identified job opportunities and revised pipeline routing to reduce impacts on trap lines, sacred sites and fishing and hunting areas.
- As part of our Oil Sands Markets Study, we established an Aboriginal Engagement Team to consult with Aboriginal communities on a potential oil sands pipeline in northern Alberta and British Columbia. This six-person team, comprised mostly of Aboriginal people, met with more than 120 communities to discuss project plans and learn about their concerns.

### 911 FUND ESTABLISHED

Firefighters. Police. Wardens. Sheriff's deputies. Emergency medical technicians. Hazardous materials teams. In a community emergency, they are the "first responders" — and our partners in promoting pipeline safety and environmental protection.

To recognize their contributions and to remember the heroes and victims of the September 11, 2001 tragedy, Energy Transportation South established the Enbridge Energy 911 Fund last year. The fund will provide up to $50,000 annually in grants to first responders in U.S. communities that host our operations. These grants will be for training, special projects or new equipment.

We also met with Deh Cho communities to discuss a land use permit for a section of our NW System in the Northwest Territories. The Mackenzie Valley Land and Water Board granted the permit, commending the company on our public consultation efforts.

We recognize that better education and training initiatives are in the best interests of Aboriginal communities. Last year, we donated $40,000 toward construction of an education centre for the Chipewyan Prairie First Nation near Fort McMurray. The building will be used to provide professional training to young people in the community.

## PUBLIC CONSULTATION

We strive to foster positive and constructive relationships with our stakeholders along our rights-of-way and near our facilities, including landowners, indigenous peoples, communities, governments, and environmental and other interest groups. Before new projects are constructed, we consult and discuss our plans with affected parties. Public consultation programs, based on sincere efforts to address issues and build trust, lead to increased understanding between Enbridge and our stakeholders.

Examples of our public consultation activities during the year included:

- We consulted with the Leech Lake Band of Ojibwe in north central Minnesota during Phase III of the Terrace pipeline expansion project. Project team members met with Band leaders before and during construction to discuss our plans and to develop mutually beneficial opportunities from our activities. Based on feedback, we agreed to donate eight hectares (20 acres) of culturally significant land to the community. We also revised the right-of-way clearing process and will sponsor a forest service firefighting training program for Band members.

## ENVIRONMENTAL INITIATIVE PROGRAM

Energy Transportation North's Environmental Initiative Program (EIP) is designed to help community-based groups along our Canadian pipeline rights-of-way turn environmental commitment into action. The EIP provides grants of up to $5,000 to qualifying projects that protect the environment and boost awareness of the benefits of being environmentally responsible.

Last year, the program donated more than $90,000 to support 35 environmental projects.

Since EIP's launch in 1991, we have contributed nearly $920,000 for projects ranging from interpretative trails to community recycling programs to children's outdoor education programs.

*Since 1997, Enbridge has partnered with the Canadian Wildlife Service to protect the piping plover, an endangered species whose prime habitat is close to the company's pipeline in Saskatchewan.*

## PROTECTING THE PIPING PLOVER

The shorelines of Western Canada's prairie sloughs and lakes are prime habitat to piping plovers, small beige and white birds that are an endangered species.

When rising waters at Lake Diefenbaker threatened a piping plover nesting area last year, we underwrote the efforts of government wildlife experts to rescue eggs from the habitat area in southern Saskatchewan. Our community investment program funded air transport of rescued eggs to a U.S. hatchery and the return of chicks to the province. Fifty-two young plovers were then released at Chaplin Lake, a wetland south of Lake Diefenbaker.

This project marked the latest step in our ongoing support of Canadian Wildlife Service (CWS) efforts to promote the survival of this species. Our interest in the piping plover began in 1997, when employees chose to recognize Environment Week by supporting a CWS research and recovery program focused on plover populations at Lake Diefenbaker.

## PUBLIC AWARENESS PROGRAMS

We conduct ongoing programs to raise awareness of safety issues among those who live or work near our pipelines and major facilities.

In 2002, Energy Transportation North contacted more than 12,000 stakeholders along our crude oil mainline right-of-way in Canada, including landowners, First Nations, city residents, municipalities and emergency response organizations. Through mailings and personal visits, we provided information on Enbridge's environmental programs and the location, safety and integrity of the pipeline.

Energy Transportation North and Enbridge Gas Distribution also hosted, or took part in, various community public awareness initiatives, including open houses, trade shows and safety conferences.

In the U.S., we collaborated with regulators and industry representatives to establish a recommended industry standard for developing, implementing and evaluating public awareness programs in the pipeline industry. This standard will be published in mid-2003.

We also used a mapping technology to identify stakeholders along parts of our Energy Transportation South system, improving the efficiency of our public awareness mailings.



- We carried out public and individual meetings with local residents to discuss our plans to add a 20-kilometre (12-mile) section of natural gas distribution pipe near Barrie, Ontario. We addressed public concerns by controlling traffic and modifying our construction schedule to lower disruption to the local community.
- In partnership with CCS Inc., a Calgary-based oil and gas service company, we conducted a public consultation program in Hardisty, Alberta, to support our companies' proposal to build a new crude oil underground storage facility in the area. Through an open house, information bulletins and meetings with community leaders, we established ongoing communications and sought stakeholder comments on the project.
- We met with government officials and local community representatives to identify and address stakeholder concerns for a proposed pipeline to our Griffith, Indiana, terminal.

## POLICY DEVELOPMENT

Whether we are consulting with government policy-makers or reviewing our projects with regulators and local communities, we engage in public policy discussions that support the constructive resolution of EH&S issues. We strive to offer up ideas and solutions in matters of public policy for the interests of our customers, shareholders and other stakeholders.

Our activities in 2002 included:

- We provided input to government policy-makers to develop a climate change plan that engages all Canadians. Through our membership in industry associations, we took part in discussions to develop an industry response to national targets under the Kyoto Protocol. We advocated the need for a plan that encourages Canadians to be more efficient consumers and producers of energy without reducing our competitiveness.
- We provided recommendations to the Ontario Select Committee on Alternative Fuel Sources, a government committee reviewing different energy options. We hope that the committee's

recommendations, to be implemented over the next few years, will lead to new incentives to increase the use of natural gas and alternative fuels.

- We took a leading role in a multi-stakeholder process, led by the NEB, to develop industry best practices for consulting with Aboriginal peoples.
- We joined the Regional Issues Working Group of the Regional Municipality of Wood Buffalo. This multi-stakeholder process involves government and industry in Fort McMurray, Alberta, in collaborative problem-solving to address environmental, economic and social issues resulting from industrial growth.
- We joined with other gas companies in undertaking a technical study to determine industry reporting of pollutants to meet new regulations in Ontario and under Canada's National Pollutant Release Inventory.
- We consulted with U.S. regulators and government officials on regulations that affect pipeline integrity or environmental requirements in the 19 states where we operate.

## CODE OF BUSINESS CONDUCT

Our Statement on Business Conduct outlines the expected standards of behavior and ethics for all Enbridge employees and directors. Adherence to the code is a condition of employment at the company.

In line with our commitment to corporate social responsibility, Enbridge adopted the internationally recognized Voluntary Principles on Security and Human Rights in 2002. These principles deal with responsible corporate action in "zones of conflict" and are especially relevant to our business involvement in Colombia, where we operate the OCENSA pipeline.

We added the principles to our Statement on Business Conduct, further enhancing an already strong code of conduct.

- We met with congressional members to provide input during development of the U.S. Pipeline Safety Bill. In December 2002, U.S. Congress passed the bill, which increases pipeline safety requirements.

Enbridge is a strong advocate of responsible public policy that addresses the need for long-term energy reliability, safety and security in North America. Although a U.S. Energy Policy was not passed in 2002, we continued to offer our views during each stage of policy development. We raised awareness of the energy interdependence between Canada and the U.S. and stressed the need to streamline government permitting for pipelines in ways that balance market and environmental needs.

## ASSOCIATION MEMBERSHIPS

Enbridge belongs to a number of industry and environmental associations. These organizations provide a forum where we can listen to the views of our stakeholders and participate in collaborative problem-solving to address EH&S issues.

These organizations include:

- Alberta Chamber of Resources
- American Petroleum Institute
- Association of Oil Pipe Lines
- Canadian Coalition for Responsible Environmental Solutions
- Canadian Energy Partnership for Environmental Innovation
- Canadian Energy Pipeline Association
- Canadian Gas Association
- Canadian Wind Energy Association
- Clean Air Renewable Energy Coalition
- Interstate Natural Gas Association of America
- Pipeline Research Council International

## SUMMARY OF PERFORMANCE INDICATORS
### ENERGY TRANSPORTATION NORTH [1]

| | 1998 | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|---|
| **Operations** | | | | | |
| Deliveries (thousands of barrels/day) [2,3] | 2,024 | 1,942 | 2,072 | 2,109 | 2,088 |
| Barrel miles (billions) [3,4] | 759 | 687 | 735 | 695 | 705 |
| Length of right-of-way (miles) | 5,740 | 6,109 | 6,107 | 6,115 | 6,152 |
| Number of employees | 1,205 | 1,209 | 1,178 | 1,164 | 1,129 |
| **EH&S Management** | | | | | |
| Major incidents [5] | 9 | 8 | 3 | 5 | 9 |
| Regulatory notifications [6] | 3 | 2 | 0 | 1 | 1 |
| EH&S fines and penalties (thousands of dollars) [7] | 313 | 162 | 0 | 0 | 0 |
| EH&S professionals (full-time) | 22 | 22 | 22 | 23 | 22 |
| **Environmental Performance** | | | | | |
| Greenhouse gas emissions [8] | | | | | |
| Total direct emissions (thousand tonnes of $CO_2$ equivalent) | 47 | 47 | 23 | 23 | 23[9] |
| Total indirect emissions (thousand tonnes of $CO_2$ equivalent) | 1083 | 824 | 917 | 764 | 589[9] |
| Total net emission intensity [10] (tonnes of $CO_2$ equivalent/petajoules of energy delivered) | 229 | 182 | 204 | 154 | 113[9] |
| Energy [11] | | | | | |
| Energy use (thousand gigajoules) | 8,200 | 6,600 | 5,800 | 5,900 | 5,000[9] |
| Energy intensity (thousand gigajoules/million cubic metres of throughput) | 70 | 57 | 48 | 48 | 39[9] |
| Reportable spills [12] | | | | | |
| Number of spills | 39 | 54 | 43 | 27 | 46 |
| Spill volume (barrels) | 9,830 | 28,760 | 7,480 | 25,670 | 14,680 |
| Spill volume rate (barrels/million barrels of throughput) | 12.84 | 38.80 | 9.40 | 31.60 | 17.00 |
| Waste | | | | | |
| Recycled material (tonnes) [8,13] | 66 | 96 | 105 | 88 | 98[9] |
| **Health and Safety** | | | | | |
| Employee lost-time injury frequency (lost-time injuries/200,000 hours worked) | 0.09 | 0.00 | 0.09 | 0.34 | 0.18 |
| Employee lost-time injury severity (days lost/200,000 hours worked) | 1.53 | 0.00 | 0.09 | 1.36 | 4.23 |
| Employee total recordable injury frequency (recordable injuries/200,000 hours worked) [14] | 1.19 | 1.10 | 1.04 | 1.19 | 1.10 |
| Contractor lost-time injury frequency (lost-time injuries/200,000 hours worked) [15] | 2.24 | 0.54 | 1.76 | 1.26 | 1.06 |
| Absenteeism (days absent/employee) | 2.93 | 3.44 | 3.26 | 3.13 | 2.72 |
| Motor vehicle incident frequency (incidents/million kilometres driven) [16] | 2.32 | 2.60 | 2.65 | 2.52 | 2.14 |

1 *Unless otherwise noted, data covers Enbridge Pipelines Inc., Enbridge Energy Partners, L.P., Enbridge Pipelines (NW) Inc., Enbridge Pipelines (Saskatchewan) Inc., Enbridge Pipelines (North Dakota) Inc., Enbridge Pipelines (Athabasca) Inc. and Enbridge Pipelines (Toledo) Inc.*
2 *1 barrel = 0.159 cubic metres or 42 U.S. gallons.*
3 *Includes Enbridge Pipelines Inc., Enbridge Energy Partners, L.P., Enbridge Pipelines (NW) Inc., Enbridge Pipelines (Saskatchewan) Inc. and Enbridge Pipelines (Toledo) Inc.*
4 *Barrel miles are the number of barrels delivered multiplied by the distance traveled in miles.*
5 *Major incidents are EH&S events that result in a critical employee or contractor injury or fatality, significant regulatory enforcement action, a liquid spill in excess of 100 barrels, or significant adverse impact to the environment.*
6 *Regulatory notifications are formal written notification by regulators that Enbridge may not be adhering to the law, regulation or permit requirements. Examples of notifications include formal warnings, enforcement actions, summons and charges, notices of violation, and stop and control orders. Notifications do not include field inspection reports or other informal communications. Notifications may result in fines or penalties.*
7 *EH&S fines and penalties are levied against the company as a result of regulatory notifications. Fines and penalties in a particular year often relate to activities in prior years. Reported in Canadian dollars.*
8 *Includes Enbridge Pipelines Inc., Enbridge Pipelines (NW) Inc., Enbridge Pipelines (Saskatchewan) Inc. and Enbridge Pipelines (Athabasca) Inc. Prior year emission numbers have been revised.*
9 *2002 data is projected based on data from the Enbridge 2002 VCR Update. Data not yet available.*
10 *Net emissions include greenhouse gas emission reductions from offset projects.*
11 *Includes electricity and fuel consumption in operations of Enbridge Pipelines Inc., Enbridge Pipelines (NW) Inc., Enbridge Pipelines (Saskatchewan) Inc. and Enbridge Pipelines (Athabasca) Inc.*
12 *Reportable spills are any spill reportable to a regulatory jurisdiction.*
13 *Includes office paper, aluminum, glass, metal and newspaper. Materials such as wax, waste oil, rags and batteries are recycled but not tracked.*
14 *Includes lost-time and medical aid injuries.*
15 *Contractor lost-time injury frequency rates include engineering project contractors. They do not include operations contractors, because the number of hours worked is not tracked for these contractors.*
16 *Motor vehicle incident frequency rates do not include incidents that occurred at office locations in Edmonton, Alberta, and Duluth, Minnesota, because mileage is not tracked for these locations.*

## SUMMARY OF PERFORMANCE INDICATORS
### ENERGY TRANSPORTATION SOUTH [1]

| | 2001 | 2002 |
|---|---|---|
| **Operations** | | |
| Gas transmission volume (billion cubic feet/day) [2] | 4 | 5.2 |
| Deliveries (barrels/day) [3] | 4,500 | 5,500 |
| Barrel miles [4] | 180,000 | 407,000 |
| Length of right-of-way (miles) | 2,400 | 6,400 |
| Length of pipeline (miles) [5] | 4,100 | 8,550 |
| Number of employees | 337 | 616 |
| **EH&S Management** | | |
| Major incidents [6] | 3 | 1 |
| Regulatory notifications [7] | 4 | 3 |
| EH&S fines and penalties (thousands of dollars) [8] | 46 | 16.9 |
| EH&S training (hours) | 700 | 4,600 [9] |
| EH&S professionals (full-time) | 1 | 6 |
| **Environmental Performance** [10] | | |
| Reportable spills [11] | | |
| Number of spills [12] | 5 | 1 |
| Spill volume (barrels) | 517 | 2 |
| **Health and Safety** | | |
| Employee lost-time injury frequency (lost-time injuries/200,000 hours worked) | 2.40 | 0.19 |
| Employee lost-time injury severity (days lost/200,000 hours worked) | 29.19 | 7.86 |
| Employee total recordable injury frequency (recordable injuries/200,000 hours worked) [13] | 5.63 | 1.07 |
| Preventable motor vehicle incident frequency (incidents/million miles driven) | 1.64 | 0.55 |

1 *Unless otherwise noted, data covers Enbridge Midcoast Energy, L.P.*
2 *Reflects aggregate throughput capacity of Enbridge Midcoast Energy, L.P. transmission lines.*
3 *1 barrel = 0.159 cubic metres or 42 U.S. gallons.*
4 *Barrel miles are the number of barrels delivered multiplied by the distance traveled in miles.*
5 *Includes 40 miles of crude oil pipeline and 34 miles of natural gas liquids pipeline. The remainder is pipeline for natural gas transmission and gathering.*
6 *Major incidents are EH&S events that result in a critical employee or contractor injury or fatality, significant regulatory enforcement action, a liquid spill in excess of 100 barrels, or significant adverse impact to the environment.*
7 *Regulatory notifications are formal written notification by regulators that Enbridge may not be adhering to the law, regulation or permit requirements. Examples of notifications include formal warnings, enforcement actions, summons and charges, notices of violation, and stop and control orders. Notifications do not include field inspection reports or other informal communications. Notifications may result in fines or penalties.*
8 *EH&S fines and penalties are levied against the company as a result of regulatory notifications. Fines and penalties in a particular year often relate to activities in prior years. Reported in U.S. dollars.*
9 *Includes EH&S training for plant and pipeline employees. In 2002, this consisted of safety meetings, driver safety, process safety management, incident command system training and Occupational Safety and Health Administration (OSHA) compliance.*
10 *Due to different regulatory requirements and business needs, Energy Transportation South does not track some corporate performance indicators. A key priority of this business operation is full compliance with existing regulatory requirements. The company's management system provides accountability for achieving this performance.*
11 *Reportable spills are any spill reportable to a regulatory jurisdiction.*
12 *Includes liquid spills from gas transmission and crude oil pipelines.*
13 *Includes lost-time and medical aid injuries.*

## SUMMARY OF PERFORMANCE INDICATORS
### ENERGY DISTRIBUTION [1]

| | 1998 | 1999 | 2000 | 2001 | 2002 |
|---|---|---|---|---|---|
| **Operations** | | | | | |
| Gas distribution volumes (billion cubic feet) | 397 | 402 | 421 | 427 | 410 |
| Length of pipeline (thousand kilometres) [2] | 24.3 | 25.6 | 27.0 | 28.0 | 29.0 |
| Number of employees | 4,122 | 4,000 | 1,681 | 1,780 | 2,008 |
| **EH&S Management** | | | | | |
| Major incidents [3] | 1 | 0 | 0 | 0 | 1 |
| Regulatory notifications [4] | 7 | 1 | 7 | 4 | 3 |
| EH&S fines and penalties (thousands of dollars) [5] | 0 | 0 | 0 | 0 | 0 |
| EH&S training (hours) [6] | n/a | n/a | n/a | n/a | 4,939 |
| EH&S professionals (full-time) [7] | 13 | 14 | 11 | 12 | 11 |
| **Environmental Performance** | | | | | |
| Greenhouse gas emissions [8] | | | | | |
| Total direct emissions (thousand tonnes of $CO_2$ equivalent) | 292 | 297 | 299 | 311 | 293[9] |
| Total indirect emissions (thousand tonnes of $CO_2$ equivalent) | 7 | 7 | 5 | 6 | 6[9] |
| Total net emission intensity (tonnes of $CO_2$ equivalent/petajoules of energy delivered) [10] | 745 | 739 | 697 | 682 | 698[9] |
| Energy | | | | | |
| Energy use (thousand gigajoules) [11] | 947 | 1,016 | 1,059 | 1,334 | 863[12] |
| Energy intensity (thousand gigajoules/billion cubic feet of throughput) | 2.4 | 2.5 | 2.5 | 3.2 | 2.0 |
| Reportable spills [13] | | | | | |
| Number of spills (gas) [14] | 3 | 0 | 0 | 1 | 0 |
| Number of spills (liquid) | 1 | 1 | 5 | 1 | 1 |
| Spill volume (litres of liquid) | 100 | 1,600 | 6,000 | 5 | 180 |
| Spill volume rate (barrels/billion cubic feet of throughput) | 0.25 | 3.9 | 14.2 | 0.01 | 0.45 |
| Waste | | | | | |
| Waste to offsite disposal | | | | | |
| Total non-hazardous waste (tonnes) | 2760 | 1705 | 978 | 469 | 565 |
| Total liquid Ontario Ministry of Environment registrable waste (thousand litres) | 51 | 41 | 39 | 46 | 141[15] |
| Total solid Ontario Ministry of Environment registrable waste (kilograms) | 3430 | 403 455 | 150 000 | 38 000 | 7156[15] |
| Recycled material (tonnes) | 600 | 600 | 500 | 40 | 431 |
| **Health and Safety** | | | | | |
| Employee lost-time injury frequency (lost-time injuries/200,000 hours worked) | 1.61 | 1.17 | 0.95 | 0.62 | 1.21 |
| Employee lost-time injury severity (days lost/200,000 hours worked) | 9.41 | 9.05 | 8.61 | 6.98 | 11.27 |
| Employee total recordable injury frequency (recordable injuries/200,000 hours worked) [16] | 3.44 | 2.94 | 3.07 | 3.29 | 3.42 |
| Absenteeism (days absent/employee) | 6.43 | 7.53 | 5.14 | 4.86 | 4.44 |
| Preventable motor vehicle incident frequency (incidents/million kilometres driven) | 3.02 | 2.98 | 1.71 | 2.13 | 2.04 |

*n/a = not available*

1 *Includes overall distribution system of Enbridge Gas Distribution, Gazifère, St. Lawrence Gas Company and Enbridge Gas New Brunswick.*
2 *Does not include gas services (pipe required from the main to serve residential, commercial or industrial buildings).*
3 *Major incidents are EH&S events that result in a critical employee or contractor injury or fatality, significant regulatory enforcement action or significant adverse impact to the environment.*
4 *Regulatory notifications are formal written notification by regulators that Enbridge may not be adhering to the law, regulation or permit requirements. Examples of notifications include formal warnings, enforcement actions, summons and charges, notices of violation, and stop and control orders. Notifications do not include field inspection reports or other informal communications. Notifications may result in fines or penalties.*
5 *EH&S fines and penalties are levied against the company as a result of regulatory notifications. Fines and penalties in a particular year often relate to activities in prior years. Reported in Canadian dollars.*
6 *Includes EH&S training for employees such as driver safety, pipeline excavation safety and WHMIS.*
7 *Includes vehicle safety trainers and nursing staff in the company's Wellness Centre.*
8 *Does not include customer emissions. Prior year emission numbers have been revised.*
9 *2002 data is projected based on data from the Enbridge 2002 VCR Update. Data is not yet available.*
10 *Net emissions include greenhouse gas emission reductions from offset projects.*
11 *2003 estimates.*
12 *Reflects decreased use of gas compressors at Tecumseh Gas Storage Operations.*
13 *Reportable spills are spills reportable to a regulatory jurisdiction.*
14 *Does not include fugitive emissions, planned releases or third-party incidents.*
15 *Includes wastes registered under the Ontario Hazardous Waste Information Network.*
16 *Includes lost-time and medical aid injuries.*

## GLOSSARY

**Carbon dioxide equivalent** — Measure used to compare the emissions of various greenhouse gases based on their global warming potential. Expressed in $CO_2$, a primary greenhouse gas.

**Gate station** — Point of entry for natural gas leaving the transmission system into the local distribution system.

**Greenhouse gas emission intensity** — Amount of greenhouse gas emissions per unit of energy delivered on energy transportation and distribution systems. Measures an operation's environmental efficiencies.

**Internal reviews** — Reviews conducted by trained EH&S professionals to evaluate the status of EH&S performance at company facilities. These range from monthly facility inspections to broad comprehensive system reviews every five years. The reviews are a means of assessing whether management and staff are performing their jobs in accordance with regulations, permits, operating approvals and corporate standards.

**Hydrostatic testing** — Process involving the use of water to test new or existing pipeline facilities for leaks and to prove their structural strength under safe, controlled conditions. Through this process, water is drawn from nearby water sources. The pipe or tank is filled with water and brought up to high pressure. After testing is completed, the water is treated and discharged according to regulatory requirements.

**Indirect greenhouse gas emissions** — Emissions released during electricity production for Enbridge's use.

**In-line inspection** — Use of cylinder-shaped devices, fitted with electronic sensors, that locate pipeline wall weaknesses before they can progress to the point of causing a leak.

**Lost-time injury frequency (LTIF)** — Measure of work-related injuries per 200,000 hours worked. Lost-time injuries result in employees missing regularly scheduled work shifts.

**Major incidents** — EH&S incidents that result in a critical employee or contractor injury or fatality, significant regulatory enforcement action, a liquid spill of more than 100 barrels or significant adverse impact to the environment.

**Net emissions** — Measure of the company's greenhouse gas impact on the global atmosphere after accounting for climate change actions.

**Nitrogen oxides ($NO_x$)** — Nitrogen-based and oxygen-based compounds produced by combustion processes. $NO_x$ emissions contribute to acid rain and ground-level ozone (smog).

**Polychlorinated biphenyls (PCBs)** — Chemicals formerly used as coolants in electrical equipment.

**Regulatory notification** — Formal written notification by regulators that Enbridge may not be adhering to the law, regulation or permit requirements. Examples of notifications include formal warnings, enforcement actions, summons and charges, notices of violation, and stop and control orders. Notifications do not include field inspection reports or other informal communications. Notifications may result in fines or penalties, or may be rescinded.

**Sulphur dioxide ($SO_2$)** — Gas formed by the burning of fossil fuels, including coal, fuel oil and diesel fuel, that contain small amounts of sulphur. $SO_2$ emissions can result in acidification of soils and lakes.

**Total recordable injury frequency (TRIF)** — Measure of work-related injuries per 200,000 hours worked. Includes lost-time and medical aid injuries.

**Volatile organic compounds (VOCs)** — Gases and vapors in hydrocarbon fuels. VOCs react with nitrogen oxides in sunlight to produce ground-level ozone (smog).

**For more information on organizations and topics discussed in this report, visit the following Web sites:**

- Dow Jones Sustainability Index — www.sustainability-index.com
- Enbridge EH&S policy — www.enbridge.com/about/enviro.html
- Enbridge Indigenous Peoples Policy — www.enbridge.com/about/comm.html
- Enbridge VCR Update — www.vcr-mvr.ca
- Enbridge Voluntary Principles on Security and Human Rights — www.enbridge.com/about/comm.html
- Enbridge Gas Distribution NGV Business Development — www.NGVontario.com
- Energy Transportation North Environmental Initiative Program — www.enbridge.com/pipelines/comm.html#2
- National Pollutant Release Inventory — www.ec.gc.ca./pdb/npri
- Ontario Ministry of Environment Hazardous Waste Information Network — www.hwin.ca
- Toronto Renewable Energy Co-operative WindShare Project — www.windshare.ca

Enbridge invites public comment on this report.

To share your comments, please e-mail us at webmaster@enbridge.com

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