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RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2002

MAY 9, 2003

HYDRO ONE INC.

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2002

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Except where otherwise indicated, all information presented herein is as at December 31, 2002.

CORPORATE STRUCTURE

Hydro One Inc. was incorporated as Ontario Hydro Services Company Inc. by articles of incorporation dated December 1, 1998 under the *Business Corporations Act* (Ontario). On May 1, 2000, we changed our name to Hydro One Inc.

Our registered office is located at 483 Bay Street, 10th Floor, Toronto, Ontario, M5G 2P5.

The following are our principal subsidiaries, each of which is wholly-owned by us and is incorporated under the laws of Ontario:

- Hydro One Networks Inc. — carries on all business relating to our ownership, operation and management of electricity transmission and distribution systems and facilities;

- Hydro One Brampton Inc. — carries on the business relating to our ownership, operation and management of electricity distribution systems and facilities in Brampton, Ontario, through its wholly-owned subsidiary, Hydro One Brampton Networks Inc.;

- Hydro One Remote Communities Inc. — carries on all business relating to our ownership, operation, maintenance and construction of generating and distribution assets used in the supply of electricity to remote communities throughout northern Ontario; and

- Hydro One Telecom Inc. — carries on all of our business relating to leasing dark fibre and providing lit telecommunications capacity to other telecommunication carriers, large corporations, government, healthcare, and education institutions.

For convenience, in this Annual Information Form:

"Hydro One", "our company", "we", "us", and "our" refer to Hydro One Inc. and its subsidiaries and predecessors, except where the context requires otherwise;

"IMO" refers to the Independent Electricity Market Operator;

"OEB" refers to the Ontario Energy Board;

"Ontario" refers to the Province of Ontario as a geographical area;

"Open Access" refers to the opening of Ontario's wholesale and retail electricity markets to competition which officially occurred on May 1, 2002; and

"Province" refers to the Government of the Province of Ontario.

GENERAL DEVELOPMENT OF THE BUSINESS

Our industry has undergone significant restructuring initiated by the Province over the past several years. Until April 1, 1999, and, since 1906, Ontario Hydro was the primary provider of both electricity generation and transmission services as well as a major provider of distribution services, in Ontario. Under the *Electricity Act, 1998*, as of April 1, 1999, the businesses of Ontario Hydro were restructured into five separate corporations, including our company, which, through wholly-owned subsidiaries, operates as the successor to Ontario Hydro's electricity transmission, distribution and energy services businesses. This restructuring was undertaken in anticipation of Open Access.

On Open Access, Ontario's electricity generators were required to compete with suppliers, from both within and outside Ontario, to sell electricity to the large purchasers of bulk power that comprise the wholesale market, consisting of distributors and large customers. These purchasers are responsible, either directly or through an intermediary, for making their own arrangements for buying electricity through bidding in the spot market administered by the IMO. In addition, market participants are permitted to enter into bilateral contracts under which the parties may either buy or sell a specified quantity of electricity for delivery at an agreed price at an agreed time or agree to make a payment to one party or the other based on agreed to financial arrangements. Customers are free to select the electricity supplier of their choice, but distributors, including our company, must continue to serve those customers that have not elected to buy their electricity from competing retail suppliers through the provision of standard supply service. Distribution companies pass through the cost of providing this standard supply service in the manner approved by the OEB to those distribution customers who do not choose to sign contracts with competitive retailers. Such competing retailers must be licensed by the OEB and may include affiliates of existing local distribution companies or of our company, electricity generators and gas marketers.

On April 30, 2002, we sold certain aspects of our business previously conducted by Ontario Hydro Energy Inc. to Union Energy Inc., a wholly-owned subsidiary of EPCOR Utilities Inc., pursuant to an asset purchase agreement. The assets sold to Union Energy Inc. included our retail electric water heater tank contract, our retail electricity customer contracts and our retail natural gas customer contracts. In addition, pursuant to a trade-mark licence agreement entered into at the same time as the completion of the asset purchase, Ontario Hydro Energy Inc. granted an exclusive licence to Union Energy Inc. of both the Ontario Hydro Energy name and trade-mark for a term of five years. The total consideration received by Ontario Hydro Energy Inc. in connection with the asset purchase and the trade-mark licence agreements was $48.2 million, subject to adjustments. With the sale of these assets, we are no longer engaged in the competitive retail sale of energy and related services.

The *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998* were significantly amended by the Province during 2002. The *Reliable Energy and Consumer Protection Act, 2002*, which received Royal Assent in June 2002, clarifies the Province's ability to dispose of its interest in Hydro One through a variety of disposition options and provided for ownership of the transmission corridor lands to be transferred from Hydro One to the Province in exchange for a statutory right to use the land for transmission and distribution purposes, effective December 31, 2002. On January 20, 2003, the Premier of Ontario announced that the Province had decided to retain full ownership of Hydro One.

On December 9, 2002, the *Electricity Pricing, Conservation and Supply Act, 2002* was enacted. As a result of this Act, energy prices for low volume and designated customers are fixed at 4.3 cents per kWh retroactive to May 1, 2002. In addition, transmission and distribution rates are capped at levels in effect on November 11, 2002 until at least April 30, 2006. Further, effective December 1, 2002, the price paid by distributors to the IMO for wholesale market charges other than energy is fixed at 0.62 cents. The enactment of this Act also effectively capped distribution rates for our customers in remote communities and Brampton.

NARRATIVE DESCRIPTION OF THE BUSINESS

Overview

We are the leading electricity transmission and distribution company in Ontario. We own and operate substantially all of Ontario's electricity transmission system, accounting for approximately 97% of

Ontario's transmission capacity as measured by revenues for the year ended December 31, 2002. Our transmission system is one of the largest in North America based on assets as at December 31, 2002. Our distribution system is the largest in Ontario based on assets as at December 31, 2002 and spans approximately 75% of Ontario, serving approximately 1.2 million customers.

Our transmission business, which represented approximately $6.6 billion of our assets as at December 31, 2002, transmits electricity through an approximately 28,500 circuit-kilometre high-voltage network. We transmit electricity from generators to our own distribution network, 51 local distribution companies and 67 large industrial customers directly connected to our transmission system. We also own and operate 26 facilities that inter-connect our transmission system with systems in neighbouring provinces and states.

Our distribution business, which represented approximately $4.7 billion of our assets as at December 31, 2002, distributes electricity through our approximately 122,000 circuit-kilometre low-voltage distribution system to municipalities and in rural areas. Customers of our distribution business include 41 local distribution companies that are not directly connected to our transmission system, 47 large industrial customers and approximately 1.2 million rural and urban customers. Hydro One Brampton Inc. is an urban distribution company, serving approximately 96,400 customers in the Greater Toronto Area with approximately 4,140 circuit-kilometres of lines. We also operate small, regulated generation and distribution systems in 19 remote communities across Northern Ontario that are not connected to Ontario's electricity grid.

We market surplus fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. The assets of these businesses constituted $90 million of our total assets of $11.4 billion as at December 31, 2002.

The OEB regulates our transmission and distribution businesses and issues rate orders to establish the revenue requirements required to cover the approved costs of these businesses plus a specified rate of return. The OEB has approved a performance based regulatory framework for Ontario's electricity distributors distribution business and is expected to implement a similar framework for our transmission business. The distribution framework for performance based regulation is not fully implemented due to the *Electricity Pricing, Conservation and Supply Act, 2002*'s suspension of the transition of rates toward a market based rate of return. Performance based regulation is a form of rate setting that provides financial incentives to reduce costs below the levels used by the OEB in establishing rates that apply for a specified period of time. Under performance based regulation, regulated utilities have greater incentives to improve their operating efficiency as they can participate in savings beyond certain thresholds established by the regulator.

BUSINESS

Recent Developments

OEFC Debt

Hydro One incurred debt, on behalf of Hydro One and some of our subsidiaries, in connection with the acquisition as of April 1, 1999 of substantially all of the assets, liabilities, rights and obligations of Ontario Hydro's electricity transmission, distribution and energy services businesses. The aggregate principal amount of this debt outstanding as at December 31, 2002 was approximately $2.5 billion and was held by Ontario Electricity Financial Corporation in the form of notes with varying interest rates and maturity dates from 2002 to 2007. On February 20, 2003, we issued $213,727,000 of additional notes to Ontario Electricity Financial Corporation pursuant to an agreement between us and Ontario Electricity Financial Corporation dated February 20, 2003 to evidence payment by us to Ontario Electricity Financial Corporation of an amount to reduce the rate of interest payable on certain of the then outstanding notes.

On March 5, 2003, Ontario Electricity Financial Corporation sold approximately $2.1 billion of these outstanding notes in a public offering in the Canadian debt capital markets. The remaining notes held by Ontario Electricity Financial Corporation mature in 2003.

Transfer of the Business of Hydro One Network Services Inc.

Effective January 1, 2003, the business of Hydro One Network Services Inc. was transferred to and is now being carried on by Hydro One Networks Inc.

Reforms to the Ontario Energy Board

On April 15, 2003, the Minister of Energy announced the Province's plans to reform the OEB. The announcement included the following proposals which are to be reflected in legislation which is currently being drafted: streamlining the hearing process to effectively eliminate the need for retroactive charges by recovering costs proactively through temporary rate adjustments; setting the terms of OEB members as initial two-year terms, with renewal terms of up to five years; the designation of the OEB as self-financing, thereby allowing it to provide competitive compensation; the creation of an OEB management committee allowing OEB members to focus their full attention on hearings; the creation of an advisory committee to review the OEB's performance annually; the establishment of a regulatory calendar with a statement of priorities to increase accountability and to ensure stringent timelines are established; the development of criteria for consumer protection support; the search for ways to harmonize the powers of the OEB to eliminate duplication and streamline the regulation of natural gas and electricity; and the enhancement of the OEB's communications role.

The Government has also announced the appointment of Mr. Howard Wetston as Chair of the OEB, effective June 30, 2003. Mr. Wetston was most recently the Vice Chair of the Ontario Securities Commission.

Our Strategy

Our goal is to be one of the leading transmission and distribution companies in Canada. We will seek to achieve this goal and to enhance our profitability by continuing to implement the following strategies:

Focusing on our core transmission and distribution businesses

Virtually all of our net income in 2002 was earned from our regulated transmission and distribution businesses which will remain our principal businesses. We intend to invest in network assets to maintain and reinforce our infrastructure and to enhance customer service and reliability.

Continuing our emphasis on reducing costs and improving productivity

The OEB has implemented a performance based regulatory framework for distribution and is expected to favour the implementation of a similar framework for transmission. Performance based regulatory frameworks will provide incentives for us to pursue cost reductions. We believe our recent financial performance reflects our ability to reduce costs and improve productivity. We have out sourced non-core functions to Inergi LP, an affiliate of Cap Gemini Ernst & Young Canada Inc., resulting in a large transfer of staff to this organization. We have reduced costs and increased productivity through the centralization of operations and new flexible work rules and practices for our lines and forestry staff, such as temporary work headquarters. We have expanded the use of hiring halls to meet intermittent and seasonal work needs. All of these activities have resulted in a reduction in regular employees from 5632 in 1999 to approximately 3929 at December 31, 2002.

We believe that cost reductions and productivity improvements can be achieved through the joint management of our transmission and distribution businesses, outsourcing of non-core functions, the realization of additional economies of scale and the consolidation of our system operations functions. We expect to consolidate our system operations functions, which are currently dispersed across Ontario, into a single operations centre by 2004, while maintaining a fully redundant back-up facility. This initiative is intended to produce lower costs and better service through the introduction of more technologically sophisticated operating systems.

Investing in new capacity in our core businesses

We plan to undertake projects to expand our existing systems and to provide for growth in our regulated rate base and earnings. For example, we are upgrading our Michigan interties by 500 MW and are exploring upgrades to our interties with Québec and New York. For protection and control of our transmission system, we are replacing our microwave telecommunications system with fibre-optic cable. We expect these and other projects to be included in our regulated rate base and to enable us to accommodate growth in the network resulting from growth in the demand for electricity in Ontario.

The Province is interested in increasing Ontario's intertie capacity with other jurisdictions, thereby enabling an increase in the amount of electricity which may be imported. We therefore intend to explore increasing the links between our system and those of neighbouring Canadian provinces and states.

Our company will not increase its share of the Ontario distribution system. We may, however, acquire and divest assets in order to facilitate the rational restructuring of the distribution sector in Ontario.

Our Transmission Business

Overview

Our transmission system operates at 500 kV, 230 kV and 115 kV and transmits electricity to customers consisting of 51 local distribution companies, our own distribution businesses and 67 large industrial companies that have loads greater than 5 MW. Electricity is also delivered to utilities in other jurisdictions through interties. Electricity is supplied by generators, both within and outside Ontario, of which 78 in Ontario are connected directly to the transmission grid. Our transmission system serves over four million customers, directly or indirectly, and transported 153.2 TWh of electricity throughout Ontario in 2002. Revenues from our transmission business accounted for approximately 36% and approximately 32% of our total revenues in 2001 and 2002, respectively.

Our transmission system forms an integrated transmission grid that can be divided into two components based on function. The integrated network, or bulk system, operates primarily at 500 kV or 230 kV over relatively long distances and links major sources of generation to transmission stations and larger area load centres. The area supply system operates at 230 kV or 115 kV and links the bulk system to local generators and loads, such as local distribution companies, industrial customers and our own distribution operations. Transformer stations located near load centres step down the high voltage to the level required for retail distribution systems or end-use customers connected directly to our transmission system.

Our transmission system is highly integrated and operates synchronously, or at the same phase and frequency, with the North American eastern interconnected system that is comprised of virtually all of the electric utilities east of the Continental Divide. Our transmission business owns and operates 17 synchronous interties at 345 kV, 230 kV, 115 kV and 69 kV levels with New York (9), Michigan (4), Manitoba (3) and Minnesota (1). Our transmission business also owns and operates nine non-synchronous interties with Québec. A non-synchronous intertie is an intertie that links two electricity transmission systems that do not operate at the same phase or frequency. As a result of these interties, our system has a combined import capability of approximately 3,900 MW and a combined export capability of approximately 5,800 MW. T hese capabilities are based on the installed capacities of the interties. In operation, the actual import and export capabilities may be restricted significantly by limitations within our or another jurisdiction's transmission networks, unscheduled power flows between interconnected systems and local load and generation patterns.

Our transmission system is relatively free of restrictions in its ability to supply electricity to major load centres from generating sources located across Ontario. A 500 kV system serves as the transmission "backbone" around the Greater Toronto Area with 500 kV connections to Northern Ontario, Ottawa, London and the major generating facilities.

Transmission Assets

Our transmission assets can be divided into five functional categories: transmission stations, transmission lines, transmission operations, telecommunication facilities and other transmission assets.

<u>Transmission Stations.</u> Transmission stations are required to integrate the transmission lines into a network and to transform the voltage of the electricity being transmitted, depending on the voltage requirements of the end user. These stations are frequently located at points at which power from two or more transmission lines can be combined and re-routed in different directions. Their main purpose is to transform voltage and, in most cases, to allow switching capabilities between transmission lines. In some instances, facilities with only switching facilities are required. A majority of our switching stations and a few voltage transformation facilities are located at Ontario Power Generation Inc.'s facilities.

Transmission stations can be broadly classified into two categories. The first category consists of terminal stations, including switchyards located at Ontario Power Generation Inc.'s generating facilities, which are used mainly for switching and voltage transformation between the 500 kV, 230 kV, and 115 kV systems. The second category consists of customer supply stations, which are transformer stations that deliver power from the transmission system to wholesale customers. Currently, most transmission stations used for customer supply consist of paired circuits and step-down transformers that are meant to ensure that the failure of any one element will not result in a permanent loss of supply. For smaller or remote loads, a simpler station design with a single transformer or a single circuit is used.

Our transmission system includes 273 transmission stations whose components may include high voltage power transformers, power circuit breakers, high voltage switches, capacitor and reactor banks, protection and control systems, metering and monitoring systems together with site infrastructures such as buildings and security systems.

<u>Transmission Lines.</u> Our transmission lines are classified into bulk power lines and area supply lines. Bulk power transmission lines are main lines delivering power from generating stations or interconnections to receiving terminal stations. Bulk power transmission lines are part of the integrated transmission network and generally operate at 500 kV or 230 kV, with a few at 115 kV. Area supply lines take power from the transmission network at the receiving stations and transmit it to customer supply transformer stations at customer load centres. The usual voltage levels of area supply lines are 230 kV or 115 kV. All of these lines are overhead except for approximately 272 circuit- kilometres of underground cables in urban areas.

The transmission system includes approximately 28,500 circuit-kilometres of high voltage lines whose major components consist of cables, wood or steel support structures, foundations, insulators, connecting hardware and grounding systems.

Transmission Operations. We carry out monitoring, control and real-time (i.e., instantaneous) management of our transmission system through our Transmission Operations Management Centre in Toronto, Ontario and three other transmission operating centres located across Ontario. The Transmission Operations Management Centre is our link to the IMO regarding the operation of our transmission assets. The IMO manages the electricity marketplace and directs the operation of Ontario's integrated transmission network. Based on directions received from the IMO, the Transmission Operations Management Centre oversees the operations of our other transmission operating centres which physically switch and control transmission. Switching is performed to provide reliable transmission service and acceptable power quality to our customers, protect our transmission assets, isolate equipment to facilitate maintenance, ensure the safety of maintenance personnel and restore equipment to service. We are currently in the process of rationalizing these operating centres together with our Distribution Operations Management Centre in Markham, Ontario into one centre in Barrie, Ontario which we believe will reduce our costs substantially. We will maintain our Transmission Operations Management Centre in Toronto, Ontario in order to provide a fully redundant back-up to our new centre in Barrie.

Telecommunications Facilities for Transmission. Our requirements for telecommunications include services for administrative data, voice and power system protection and operation. These requirements are met through the use of a wide range of our own facilities and services acquired from other telecommunications service providers. The reliability and availability of telecommunication services used in the protection and operation of our transmission system are vital to meeting our interconnection obligations and our customers' reliability expectations. Historically, if telecommunications service providers were not able or willing to provide the required services at an appropriate cost, we installed our own telecommunication facilities. These owned facilities include microwave radio, fibre-optic cable, power line carrier and mobile radio systems. The microwave radio system is nearing the end of its useful life and is being replaced by a fibre-optic system.

Other Transmission Assets. Other assets include those supporting the ongoing maintenance and operation of the transmission system, such as office and service buildings, transportation and work equipment and other office and information technology assets.

Projects Under Development

Québec. We are planning a new two-circuit 230 kV intertie with the Province of Québec that would increase our intertie capacity by 1,250 MW. This would consist of direct current facilities in Québec that would permit our transmission system to connect to Hydro Québec in a synchronous manner. We have obtained the necessary regulatory approvals. Hydro Québec has informed us, however, that it has not yet been able to obtain its required regulatory approvals. Accordingly, we have received from the OEB, an extension until December 31, 2003 to our approval for leave to construct this facility. Should this project proceed, we would seek recovery of the cost through rates in a future rate application.

Michigan. Two of our interties with the State of Michigan are currently being upgraded with the installation of three phase-shifting transformers and an autotransformer. Part of this installation has been completed but there are ongoing technical issues requiring resolution by the supplier of the equipment. As a result, the in-service date of the facilities is uncertain. This equipment is intended to provide us with greater control over the use of our Michigan interties so as to better control transactions directly across the Ontario-Michigan border and indirectly across the Ontario-New York border. We will bear the estimated $40 million cost of the facilities in Ontario. We will seek recovery of the costs associated with this investment through rates in a future rate application. This project is also intended to increase our export capacity by 1,000 MW and our import capacity by 500 MW.

Our Distribution Business

Overview

Our distribution system provides customers with electricity distribution services through a low voltage distribution network. In 2002, 27.1 TWh of electricity were delivered through the distribution system to approximately 1.2 million customers located in rural and urban areas (including approximately 96,400 urban retail customers located in Brampton, Ontario). The distribution system also serves 41 local distribution companies that are not connected directly to our transmission system and 43 customers with loads exceeding 5 MW. The distribution system comprises approximately 123,000 circuit-kilometres of lines operating mainly at voltages of 50 kV or less and 1,017 distribution and regulating stations. Our distribution system distributes electricity from our transmission system and 96 small embedded generators. Unlike the systems found in densely populated areas that are designed to include built-in redundancy, our distribution system supplies mainly rural areas with low population densities. To provide a cost-effective service to these areas, the distribution system is configured as a largely radial system, meaning that it is configured in straight lines, rather than loops, so that an outage at any point along the line causes all customers further down the line to lose power. As a result, component failures require immediate repair or replacement prior to service restoration. Revenues from our distribution business accounted for approximately 62% and approximately 66% of our total revenues in 2001 and 2002, respectively**.**

Distribution Assets

The electricity distribution system is made up of three components: (i) low voltage lines connecting our transmission stations to our distribution stations and to some industrial customers and local distribution companies; (ii) distribution and regulating stations; and (iii) our distribution lines connecting the low voltage side of the distribution stations to industrial, commercial, farm, and residential customers as well as embedded local distribution companies. The three components include plant such as poles, conductors, transformers, reclosers, protection devices and switches. Other assets include service centres and equipment, such as our transportation fleet, computing equipment and service and construction equipment

Remote Communities

We operate 19 regulated generation and distribution systems in 19 remote communities across Northern Ontario that are not connected to Ontario's electricity grid, the facilities of which are owned either by us or by Ontario Electricity Financial Corporation. These remote communities include a total of approximately 3,600 customers. Electricity used by these remote communities is produced by 59 diesel generators owned by us, which are supplemented by small amounts of wind or hydroelectric generation. Pursuant to Regulation 199/02 under the *Electricity Act, 1998*, we are required, through one or more of our subsidiaries, to operate and maintain existing generation and distribution assets in, and supply electricity to, these remote communities. Regulation 19/02 exempted Hydro One's remote distribution facilities from Open Access. Pursuant to the *Electricity Pricing, Conservation and Supply Act, 2002*, customer rates in remote communities were capped at the levels in place on November 11, 2002. See "Rate Orders for Remote Communities".

Our Telecommunications Business

Our telecommunications business markets dark and lit fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements. This business also markets co-location space on our microwave towers to wireless service providers.

Employees

On December 31, 2002, we had 3,753 regular (i.e., permanent) employees comprised of 309 non-represented Executive and Managerial staff, 2,697 employees represented by the Power Workers' Union and 747 employees represented by the Society of Energy Professionals. In addition, our Hydro One Brampton subsidiary had 40 non-represented regular staff, 99 employees represented by the Canadian Auto Workers and 37 employees represented by the International Brotherhood of Electrical Workers.

We also had 725 non-regular (i.e., temporary) employees comprised of 10 Executive and Managerial staff, 292 employees represented by the Power Workers' Union, 37 employees represented by the Society of Energy Professionals and 386 employees represented by a combination of the Canadian Union of Skilled Workers (an electrical trade union) and the 16 construction building trade unions that have collective agreements with the Electrical Power Sector Construction Association, of which Hydro One is a key member.

In 2002, we negotiated five renewal collective agreements. We signed an agreement with the Power Workers' Union for a two year period which will end on March 31, 2005. We signed three year agreements with the Canadian Auto Workers and the International Brotherhood of Electrical Workers in Brampton, both of which expire on March 31, 2005, and a three year agreement with the Canadian Union of Skilled Workers which expires on April 30, 2005. Finally, we received an arbitrated award that provides for a 27 month collective agreement with the Society of Energy of Professionals which expires on March 31, 2005.

Outsourcing Arrangement with Inergi LP

Through our subsidiary, Hydro One Networks Inc., we entered into an outsourcing services agreement with Inergi LP as of December 28, 2001. The provision of services by Inergi LP commenced on March 1, 2002. Inergi LP is an affiliate of Cap Gemini Ernst & Young Canada Inc. Under the agreement, Inergi LP provides us with customer service operations and settlements as well as supply management services, pay operations services, enterprise technology and finance and accounting services. As part of the agreement with Inergi LP, 906 of our unionized and non-unionized employees (including 770 regular and 136 non-regular employees) were transferred to Inergi LP on March 1, 2002. Under the agreement, we will continue to make available, for use by the transferred employees, the assets used by them prior to the transfer of their employment, with refurbishments as needed.

The agreement has a ten-year term and has base service fees of approximately $1 billion over the term of the agreement. Fees are subject to decreases based on external benchmarking analysis every three years. Cap Gemini Ernst & Young US LLC has provided a financial guarantee as well as a performance guarantee of the obligations of Inergi LP. The performance guarantee covers the first two years of the agreement.

The agreement provides for rights of termination for each of the parties, including, on the part of our company, rights of early termination for convenience and upon the occurrence of specified business events. In such cases, we are obliged under the agreement to pay specified termination fees, as well as to contribute to resulting severance and other costs. In addition, upon expiration of the agreement, we have an obligation to contribute to employee severance costs, if any, up to a maximum amount of $10 million.

Pension Plan

The Hydro One Pension Plan was established on December 31, 1999. In accordance with an asset transfer agreement dated March 29, 2001 among the five successor corporations to Ontario Hydro, the assets and liabilities of the Ontario Electricity Financial Corporation Plan (formerly the Ontario Hydro

Pension and Insurance Plan) were transferred in proportionate shares to new pension plans established by the successors to Ontario Hydro in accordance with the provisions of the *Electricity Act, 1998*. The transfer was approved by the Superintendent of Financial Services and commenced on June 29, 2001. Our company's portion of these assets and liabilities is now managed and invested by our company as plan sponsor and administrator of the Hydro One Inc. Pension Plan. As of December 31, 2002, there were 3,809 active members and 7,870 pensioners and disabled and deferred members.

Effective December 31, 1999, we established the Hydro One Inc. Supplementary Pension Plan to provide supplementary pension benefits on the same terms as provided pursuant to the supplementary plan previously maintained by Ontario Hydro. On October 30, 2001, this plan was amended to require the establishment of a trust for the purpose of creating security for payment of the supplementary pension benefits provided for therein. This trust was constituted as a Retirement Compensation Arrangement under the provisions of the *Income Tax Act* (Canada), and security was issued in the form of a letter of credit.

Insurance

We maintain insurance coverage, including liability, all risk property, business interruption and boiler and machinery insurance. We also maintain other insurance coverage that is required by provincial statute, which covers automobile liability, pesticide liability and aircraft liability.

Real Property

The following table sets forth summary information with respect to the principal real property used in our business operations:

Facility (1)	Total	Owned	Easement	Leased	Other(2)
Transmission corridors(3)	221,530 acres	—	221,530	—	—
Transmission stations(4)(5)	244 sites	1	212	14	17
Switching stations(4)(6)	29 sites		10	4	15
Transmission operating centres(7)	5 sites		5	—	—
Distribution stations(4)(8)	962 sites	938	—	11	13
Regulating stations(4)	73 sites	69	1	2	1
Administrative and service centres(9)	179 sites	63	66	43(7)	7

(1) On June 27, 2002, the *Reliable Energy and Consumer Protection Act, 2002* received Royal Assent. It added to the *Electricity Act, 1998* Part IX.1, which addressed the ownership and use of corridor land. Corridor land includes land in Ontario that was owned by Hydro One and was used or acquired for the purposes of the transmission system, including any abutting land. Under the Act, ownership of all corridor and abutting land was transferred to the Province and Hydro One was given the right to use the land to operate the transmission system. Hydro One also retained the obligation to incur certain ongoing expenditures related to the use of this land, including maintenance, property taxes and any future environmental remediation work that may be required by the Province. The OEB is authorized to restrict or discontinue any use of the corridor land that interferes with the transmission system. Part IX.I was proclaimed effective December 31, 2002, resulting in the ownership of transmission corridors and abutting lands with a net book value of approximately $259 million being transferred to the Province in exchange for indefinite rights of use. In addition, ownership of land assets with a net value of approximately $7 million, not currently in use, was transferred to the Province and applied as a reduction of shareholder’s equity.

(2) The Other category pertains to lands owned by Ontario Power Generation Inc. or Bruce Power, to which Hydro One has been granted access for the purposes of conducting its business. These occupations have been or will be formalized by either lease or easement.

(3) Transmission Corridor lands totalling 49,673 acres were transferred to the Province.

(4) Comprises the total number of operating stations.

(5) The total includes one Transformer Station site that is owned by Hydro One Brampton. 212 sites (lands only) were transferred to the Province pursuant to the Act.

(6) A total of 10 sites (land only) were transferred to the Province pursuant to the Act.

(7) The total number of Transmission Operating Centres is comprised of four transmission and one distribution centres. These centres will be further reduced to two facilities by May 31, 2004, which includes a backup facility. All of the centre sites (lands only) were transferred to the Province pursuant to the Act.

(8) Distribution Stations include both high and low voltage stations. There are 91 high voltage stations and the balance of the stations are low voltage. Furthermore, 18 stations sites are associated with Hydro One Brampton, 15 owned and three leased.

(9) The total number of Administrative and Service Centres includes two leases associated with the former Ontario Hydro Energy and an owned Hydro One Brampton site. A total of 66 Administrative and Service Centre sites (lands only), which includes 33 Administrative and Service Centres located within Transformer Station sites were transferred to the Province pursuant to the Act. These centres are largely independent of the transformer station function, but in some instances staff operate from buildings that serve both functions.

Environmental

Although primarily regulated at the provincial level, jurisdiction over the environment is shared by Canadian federal, provincial and local governments. As a result, we are subject to extensive federal, provincial and local regulation relating to the protection of the environment that governs, among other things, environmental assessments, discharges to water and land and the generation, storage, transportation, disposal and release of various hazardous substances.

Environmental Management System

We have an environmental management system designed to identify environmental effects of our operations and facilities and to aid in the continual improvement of our environmental performance. We continually update our environmental management system to reflect organizational changes and progress in achieving our environmental goals.

Permits, Licences and Approvals

We are required to obtain and maintain specified permits and approvals from federal, provincial and local authorities that relate to, among other things, waste disposal, drainage works and discharges to air and water.

A number of electricity projects we undertake or propose may require environmental approvals from the federal government or the use of federal lands, including reserves and other lands subject to the *Indian Act* (Canada), and will be subject to federal environmental assessment. Additional interconnection facilities with neighbouring utilities in other provinces and states require approvals and will be subject to federal regulatory review, which may include environmental assessment. Certain projects will also be subject to the provincial environmental assessment process. A significant number of our existing projects are subject to a streamlined environmental assessment process. The scope, timing and cost of environmental assessments at either the federal or provincial level depend on the type of project and its potential for environmental impact.

Releases

Federal, provincial and municipal environmental legislation operates to regulate the release of substances into the environment through the prohibition of discharges that will or may have an adverse effect on the environment. Spills and leaks of substances occur in the course of our normal operations. We could incur fines or clean-up costs in connection with these releases. Accordingly, we have a spill and leak prevention program involving the testing, replacement, repair and installation of containment systems and the regasketting of transformers. In addition, we have an emergency response capability which we believe is sufficient to minimize the environmental impact of spills and to comply with our legal obligations.

Hazardous Substances

We manage a number of hazardous substances, such as PCBs, herbicides and wood preservatives. In addition, some facilities have substances present which are designated for special treatment under occupational health and safety legislation such as asbestos, lead and mercury. We have environmental management programs in place to deal with PCBs and herbicides.

We continually remove PCB-contaminated materials from service and send PCB waste for decontamination or destruction. All high voltage electrical equipment containing PCBs at concentrations greater than 10,000 parts per million has been removed from service. Some equipment containing PCB-contaminated mineral oil continues to be in service, including an estimated 15,000 distribution transformers, as well as small electrical equipment components at transmission stations. PCB-contaminated mineral oil in small transmission equipment components is tested and retro-filled as part of station refurbishment programs. Our current estimate for future PCB expenditures is approximately $154 million as of December 31, 2002.

We use herbicides primarily for the control of incompatible vegetation on rights-of-way, along distribution lines and on station sites. We currently use an integrated management approach toward vegetation management using manual and mechanical cutting, together with the selective use of herbicides. Herbicides are applied in accordance with the *Pesticides Act*. As indicated below, the historical use of a specific herbicide has contaminated some of our properties and some nearby properties.

Wood preservatives are used in wood poles to protect the wood against fungi and insects and thereby extend their service lives. In the past, we have used poles which were impregnated with pentachlorophenol. We respond to contamination problems related to pentachlorophenol migration as they arise.

Land Assessment and Remediation

We have developed a voluntary land assessment and remediation program in order to identify and, where necessary, remediate contamination related to our transmission and distribution stations, service centres and remote generating stations. It involves the systematic identification of any contamination at or from these facilities and, where necessary the development of remediation plans for Hydro One and adjacent private properties. Potential contaminants include insulating oils, substances previously used for vegetation control such as arsenic trioxide, fuel oil, gasoline, PCBs and wood preservatives such as pentachlorophenol. Phase I assessments have been completed for most of the transmission stations, service centres and remote generating stations. Limited Phase I assessments were undertaken at distribution stations given their large number and similar operating history. Site screening involving on-site soil sampling at the areas of greatest potential for contamination have been undertaken at the majority of these sites.

The total program to the end of 2002 has involved approximately 1,470 sites. The number of sites where at least one soil or groundwater sample on site was found to be above Ministry of the Environment guideline (of at least one substance of concern) is 707. We have developed a risk-based property ranking system to assist in establishing priorities for Phase II sampling. This system is supplemented with visual inspections of the sites and nearby receptors. Remediation is occurring based on Phase II results and discussions with affected property owners and regulatory authorities. The Ministry of the Environment (at the local and head office level) and local Health Departments/Medical Officers of Health are actively involved in the program.

Future costs related to the land assessment and remediation program have been estimated at approximately $63 million over the next six to eight years.

Electric and Magnetic Fields

Electric and magnetic fields exist wherever electricity is used or transmitted, including electric power facilities such as transmission and distribution lines and substations, and within every building in Ontario that has electrical service. Based on current research, the consensus of the scientific community is that a public health risk from exposure to electric and magnetic fields has not been established. Further, the scientific community has been in agreement for some time that if a risk were to be established, it would be a low risk. We have sponsored research in the past and are now focusing on monitoring national and international developments. We also maintain a dialogue with the Province's Ministry of Health and Long Term Care regarding this issue. Partnerships with provincial and municipal agencies are in place to develop appropriate actions and communicate with the public. Electric and magnetic fields are not currently regulated by either the federal or provincial governments and we do not know of any current plans to regulate electric and magnetic fields.

Legal Proceedings

In connection with the reorganization of Ontario Hydro, we have succeeded Ontario Hydro as a party to various pending legal proceedings relating to the businesses, assets, real estate and employees transferred to us. We will also assume responsibility for future claims relating to the businesses, assets, real estate and employees acquired by us and arising out of events occurring prior to, as well as after, April 1, 1999. In addition to claims assumed by us, we are, from time to time, named as a defendant in legal actions arising in the normal course of business. The pending legal proceedings containing material claims to which we are currently a defendant are discussed below.

On September 1, 1995, Torcom Communications Inc. named Ontario Hydro as one of several defendants in a suit in the Ontario Superior Court of Justice seeking damages of $150 million, as well as specific performance of agreements and interim injunctive relief. Torcom Communications had sought to purchase telecommunication devices belonging to a bankrupt company from a court-appointed receiver. The devices had been installed on Ontario Hydro property under licence to the original owner. Torcom Communications claims that it reached an agreement with Ontario Hydro for the continued placement of the devices on Ontario Hydro property. Torcom Communications alleges Ontario Hydro breached this contract and interfered with its efforts to purchase the devices from the receiver. There has been little activity on the case since 1995 when Ontario Hydro served a demand to particularize the allegations against it. Ontario Hydro did not receive a reply to its demand for particulars and has not served a statement of defence. We believe that there are strong defences to the plaintiff's claims against Ontario Hydro and that it is unlikely that the outcome of this litigation will have a material adverse effect on our business, results of operations, financial position or prospects.

On March 29, 1999 and May 24, 2001, the Whitesand First Nation Band commenced substantially similar actions in the Ontario Superior Court of Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, Ontario Electricity Financial Corporation, Ontario Power Generation Inc. and our company. These actions seek declaratory relief, injunctive relief and damages in an unspecified amount. The Whitesand Band alleges that since at least the first half of the twentieth century Ontario Hydro has erected dams, generating stations, electrical power lines and other facilities within or affecting the band's traditional lands and that those facilities have caused damage to band members and the lands, including substantial flooding and erosion. The Whitesand Band also claims treaty rights to a share of the profits arising from the activities of these Ontario Hydro facilities, an entitlement to increases in annuity payments established by treaty and for breach of an alleged contract to reimburse the Band for negotiation costs with Ontario Hydro. The Whitesand Band asserts multiple causes of action, including trespass, breach of fiduciary duty, nuisance and negligence. To date, we have not filed a defence. We have requested particulars of the claims as have the other defendants and have recently requested further and better particulars. Following receipt of the particulars, we will be filing a defence. The flooding alleged to have been caused by Ontario Hydro is a matter for which we believe Ontario Power Generation Inc. would have responsibility pursuant to transfer orders under the *Electricity Act, 1998*. We believe that it is unlikely that the outcome of this litigation will have a material adverse effect on our business, results of operations, financial position or prospects.

On September 7, 2001, the Red Rock First Nation Band commenced an action in the Ontario Superior Court of Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, Ontario Electricity Financial Corporation, Ontario Power Generation Inc. and our company. This claim is similar in form to the claim of the Whitesands First Nation Band and the same lawyer is acting for the Red Rock Band. The Band seeks declaratory relief and claims an unspecified amount of damages for trespass, breach of fiduciary duties, public and private nuisance and unpaid lease payments relating to a transmission line or right-of-way. We have requested better particulars of the claim as against us and are in the process of investigating it. We cannot yet fully assess what the likelihood is that the outcome of this litigation will have a material adverse effect on our business, results of operations, financial position or prospects, but believe that such a result is unlikely.

Health and Safety

Hydro One considers health and safety to be of paramount importance in the operation of its business. The company is committed to creating and maintaining an injury-free workplace for its employees and contractors, to developing practices that lead to injury prevention and to minimizing the risk of injury to the public associated with its facilities and operations. Policies are in place for both employee health and safety and public safety.

Corporate safety performance indicators and targets have been developed to measure accident severity rate and lost-time injury frequency rate and are monitored by management and by the Health and Safety Committee of the Board of Directors. Employee compensation is tied, in part, to success in achieving annual safety performance targets. An effective early and safe return to work process has allowed us to ensure that, when injuries occur, employees recover and return to the workplace as soon as possible.

Several programs and practices have been implemented to improve our safety performance. In 2002, we conducted a number of compliance reviews to assess compliance with regulatory requirements and company policies. Work site inspections and effective job planning are also contributing to a safer workplace by identifying hazards and ensuring that proper barriers are in place before work is undertaken. Our incident investigation process allows us to learn as much as possible from incidents in order to develop improvements to our job planning and prevent recurrences.

Hydro One is currently integrating the management of health and safety into a single health, safety and environment management system. Effective risk assessment and management are key elements to the successful minimization of risk and safety performance improvement. Within the organization, hazards have been identified and controls implemented to mitigate these risks.

REGULATION
The Statutory and Operating Framework

General

Two of the five schedules of the *Energy Competition Act, 1998,* the *Electricity Act, 1998* and the *Ontario Energy Board Act, 1998,* primarily establish the broad legislative framework for Ontario's competitive electricity market. The *Electricity Act, 1998* implements the fundamental principles of the restructuring of Ontario's electricity industry, enabling the implementation of open non-discriminatory access to transmission and distribution systems. The *Ontario Energy Board Act, 1998* expanded the jurisdiction and mandate of the OEB to include regulation of the electricity and natural gas markets. Both statutes have been amended by the *Reliable Energy and Consumer Protection Act, 2002,* which received Royal Assent on June 27, 2002, and the *Electricity Pricing, Conservation and Supply Act, 2002* which received Royal Assent on December 9, 2002. See "The *Electricity Pricing, Conservation and Supply Act, 2002*".

Since May 1, 2002, the date of Open Access, the prices of electricity in Ontario began to be determined by market forces in the wholesale electricity market administered by the IMO. The IMO is the centralized independent electricity system co-ordinator responsible for maintaining the security and reliability of electricity supply in Ontario and for directing the operations of the IMO-controlled grid. The IMO itself is licensed by the OEB and funded through fees which are approved by the OEB and levied on all market participants. See Contractual Arrangements, Codes and Licences – Hydro One Inc.'s Relationship with the IMO."

Market participants may buy and sell electricity from the wholesale spot markets, administered by the IMO. Alternatively, they may contract such transactions with each other, albeit with the obligation to schedule these transactions with the IMO.

Electricity consumers in the retail market also have a choice of suppliers. They may contract with any retailer of their choice or they may continue to be provided with standard supply service by their incumbent distributor. In either case, the distributor is obliged to continue to deliver electricity to them as long as they are connected to that distribution system. See – "General Development of the Business" and "Contractual Arrangements, Codes and Licences – Electricity Industry Codes."

Each distributor, including our company, continues to have an obligation to connect and supply customers in accordance with the *Electricity Act, 1998* and the conditions of its distribution licences and rate orders. On May 1, 2002, we began to provide customers connected to our distribution system who did not choose a competitive retailer (our standard supply customers), with electricity in accordance with the provisions of the OEB's Standard Supply Service Code. See "- Contractual Arrangements, Codes and Licences – Electricity Industry Codes". As a result of the *Electricity Pricing, Conservation and Supply Act, 2002* and associated regulations, we continue to provide this service to low volume and designated consumers at a fixed price of 4.3 cents per kWh.

The *Electricity Pricing, Conservation and Supply Act, 2002*

Critical Features of the Electricity Pricing, Conservation and Supply Act, 2002 for the Businesses of Hydro One

The features of the *Electricity Pricing, Conservation and Supply Act, 2002* which have an impact on the transmission and distribution businesses of Hydro One include the following:

- Effective December 1, 2002 until at least April 30, 2006, the electricity commodity price is set at 4.3 cents per kWh for specified groups of customers ("low volume and designated consumers").

It also requires distributors, including our company, to refund the difference between the 4.3 cent per kWh price and the prices paid by low volume and designated customers retroactively to May 1, 2002. We have refunded or are in the process of refunding to customers in accordance with the *Electricity Pricing, Conservation and Supply Act*, *2002* and the regulations. Low volume and designated consumers include:

- Consumers using not more than 250,000 kWh annually; and
- Municipalities, farms, universities, schools, hospitals and registered charities, and certain social service and cultural organizations designated by regulation.

- Distributors, retailers and the IMO are entitled to compensation for the refunds made to low volume and designated consumers and for the difference between the price paid for the commodity and the price sold at 4.3 cents per kWh. Our distribution business has been reimbursed for refunds made to date.

- The *Electricity Pricing, Conservation and Supply Act*, *2002* freezes the prices that all consumers pay for transmission and distribution of electricity at the levels in effect on November 11, 2002, to apply to electricity used on or after December 1, 2002 until at least April 30, 2006, unless those rates are replaced or amended. Accordingly, some of our rate orders which had been approved but not put into effect by November 11, 2002 will not be implemented. This applies to Hydro One's rates for low voltage customers, which the OEB had approved on August 30, 2002, but which we had not yet come into effect. See -"Rate Orders and Related Issues for Hydro One Inc.'s Businesses -- Distribution - Implications of the *Electricity Pricing, Conservation and Supply Act, 2002* for our Distribution Revenues."

- Reviews of rate applications which had not resulted in an OEB order before December 9, 2002 were discontinued and all rates in effect which had been given interim approval by the OEB were deemed to be final until April 30, 2006. This affected our pending application for new rates for our remote customers. Their rates for 2002, which had been given interim approval, therefore, became final. The approved changes to Hydro One's rates for 87 of our acquired municipal utilities were also affected. The rates for these customers were frozen at 2001 levels. Distribution rates for our subsidiary, Hydro One Brampton Networks Inc., had already been approved for 2002. See - "Rate Orders and Related Issues for Hydro One Inc.'s Businesses - Distribution - Implications of the *Electricity Pricing, Conservation and Supply Act, 2002* for our Distribution Revenues" and "Rate Orders for Remote Communities."

- Distributors and transmitters may not apply to the OEB for changes in rate orders without the approval of the Minister of Energy.

- Electricity consumers were not allowed to be disconnected for failure to pay their bills until April 1, 2003.

Implications of the Electricity Pricing, Conservation and Supply Act, 2002 for the OEB's Rate-Setting Authority

The *Electricity Pricing, Conservation and Supply Act, 2002* revised certain aspects of the OEB's rate-setting authority until April 30, 2006. The OEB now may not begin rate proceedings on its own motion. An application for a new rate order may proceed to the OEB only following the written approval of the Minister of Energy. Such approval would be granted only for certain circumstances set out in the Act. The OEB may not review its own decisions on transmission and distribution rate-related matters. Appeals to a rate order in effect on November 11, 2002 and petitions to the Lieutenant Governor in

Council in respect of such an order commenced before December 9, 2002 were discontinued. The Minister also has the authority to direct the OEB to review and amend rate orders, including those in effect on November 11, 2002. The *Electricity Pricing, Conservation and Supply Act, 2002* also permits the Minister to require that electricity invoices for low-volume and designated consumers be in a form approved by the Minister, but these provisions have not yet been proclaimed in force. See "Recent Developments – The Minister's Review of Electricity Bills".

Implications of the Electricity Pricing, Conservation and Supply Act, 2002 for the IMO's Rule-Making Authority

The *Electricity Pricing, Conservation and Supply Act, 2002* revised the authority of the IMO by changing the process governing the making and changing of market rules. The Minister of Energy must now approve new market rules and changes to existing rules. The Minister may revoke amendments if they are determined to unduly and adversely affect consumers' interests with respect to prices or electricity service reliability or quality.

Contractual Arrangements, Codes and Licences

Operating Agreement with the IMO

Under the *Electricity Act, 1998*, the IMO is required to enter into agreements with transmitters giving it the authority to direct the operations of the transmitters' systems. On June 8, 2001, we signed our 10 year operating agreement with the IMO, which sets out the specific responsibilities of both parties relating to the provision of transmission service. The agreement, among other things, identifies our facilities that will be included in the IMO-controlled grid; provides that the IMO will direct the operation of the facilities of our subsidiary, Hydro One Networks Inc.; defines the respective obligations of Hydro One Networks Inc. and the IMO regarding the operation of these facilities; provides for coordination between Hydro One Networks Inc. and the IMO of modifications or additions to our transmission facilities; establishes the terms and conditions relating to information sharing and confidentiality, monitoring and telecommunications facilities, and the delineation of accountabilities for protection systems; and addresses issues of liability and indemnification obligations.

By contrast, the distribution portion of the Ontario's network is not directed by the IMO and remains subject to the operational control of local distribution companies in accordance with the regulatory framework.

Hydro One's Relationships With Other Market Participants

Generators, local distribution companies and customers directly connected to our transmission system must enter into agreements with us to ensure reliable connection service in conformity with the Transmission System Code established by the OEB.

Some market participants, such as generators and large load customers embedded within distribution systems, are connected to the wholesale market through lines and facilities that are defined as "distribution" and owned by local distribution companies. At a minimum, under the *Electricity Act, 1998*, local distribution companies must provide non-discriminatory access for eligible generators and customers to the wholesale markets administered by the IMO. The local distribution companies must advise the IMO of any conditions in their distribution system that may affect the ability of embedded generators and loads to participate in the broader IMO-administered markets.

Electricity Industry Codes

The OEB has approved the Affiliate Relationships Code for Electricity Distributors and Transmitters, the Standard Supply Service Code, the Distribution System Code, the Transmission System Code, the Retail Settlement Code and the Code of Conduct for Electricity Retailers. These Codes and requirements prescribe minimum standards of conduct and standards of service for transmitters, distributors and retailers in the competitive electricity market.

The Affiliate Relationships Code for Electricity Distributors and Transmitters became effective on October 1, 1999. This Code establishes the standards and conditions for the interaction between electricity distributors or transmitters and their affiliated companies. Accordingly, our subsidiaries through which we transmit and distribute electricity are subject to this Code. Among its primary purposes, this Code is intended to minimize the potential for a distributor or transmitter to cross-subsidize competitive or non-monopoly activities. The OEB has granted us temporary exemptions from certain provisions of this Code.

The Standard Supply Service Code became effective upon May 1, 2002. This Code governs the conduct of distributors, including our company, in their provision of standard supply service pursuant to the *Electricity Act, 1998* and the terms of their distribution licences. Under the Standard Supply Service Code, a distributor's rates for standard supply service are approved and fixed by the OEB and consist of the price for electricity and an administrative charge which is intended to allow the distributor to cover its costs of providing the service. Our rates for standard supply service were approved by the OEB. However, the aspects of this Code which address rates for standard supply service to certain customers are temporarily over-ridden by the requirement to provide electricity at 4.3 cents per kWh to low volume and designated consumers until at least April 30, 2006.

Each of the Transmission System Code and the Distribution System Code sets the minimum conditions that a transmitter or distributor, respectively, must meet in carrying out its obligations to transmit or distribute electricity under its licence and the *Electricity Act, 1998*.

The Transmission System Code applies to all transactions and interactions between a transmitter and distributors, generators and consumers of electricity directly connected to the transmission system. The Code came into force upon May 1, 2002. On June 14, 2002, the OEB initiated a two-phase process to review the Transmission System Code and related matters. The OEB's decision on the first phase, to determine the principles governing issues relating to transmission system by-pass, available capacity, cost responsibility, economic evaluation and contestability, is now pending. The incorporation of the principles, along with other issues such as cost responsibility, dispute resolution and reporting and monitoring, will be addressed in the second phase of the OEB's review.

The Distribution System Code came into force upon May 1, 2002, with the exception of those provisions relating to connections, expansions and responsibilities to generators, which had already been in effect.

The Retail Settlement Code outlines the obligations of a distributor with respect to its relationships with other retail market participants and its role as retail market settlements administrator. This Code is designed to ensure that, subject to credit risk, distributors will not make or lose money in their role as retail market settlement administrators. In particular, the distributors served by our company's distribution system may have the option of receiving electricity from us rather than purchasing from the wholesale market participants. In this event, we would require increased working capital to cover accounts receivable and increased ongoing costs and would expect to recover these costs through our distribution rate order.

Electricity Industry Licences

Our transmission and distribution licences expired on March 31, 2003, but the terms of these licences were extended by the OEB on their current terms and conditions until December 21, 2003 or until the OEB issues new licences. It is expected that any new transmission or distribution licence issued by the OEB will have a 20 year term and will incorporate the reporting and record-keeping requirements in accordance with the Electricity Reporting and Record Keeping Requirements which the OEB issued in October 2002.

The OEB had issued a retail licence to our competitive retail subsidiary, Ontario Hydro Energy Inc. The licence was cancelled upon the sale of this company's assets to Union Energy Inc. effective April 30, 2002.

Transmission Licence

The following are the key conditions of our transmission licence:

- ***Amendments, Suspension or Revocation*** —The OEB may amend this licence on the application of any person, or unilaterally, if it considers the amendment to be necessary in order to implement a governmental policy directive or in the public interest having regard to its objectives and the purposes of the *Electricity Act, 1998.* The licence may be suspended or revoked if the OEB considers us to be in contravention of the *Ontario Energy Board Act, 1998* or the *Electricity Act, 1998* or any regulation thereunder or our licence, if we are no longer in a position to operate in conformity with those statutes or our licence or if we have been negligent or made fraudulent representations in carrying on our transmission business.

- ***Information Disclosure*** — We are required to provide the OEB with any information required to monitor compliance with the conditions of the licence, industry codes or any other legislative or regulatory requirements.

- ***Obligation to Enter into Agreement with the IMO***— We are required to enter into the operating agreement with the IMO, providing for the direction by it of the operation of our transmission system. On June 8, 2001, we signed our operating agreement with the IMO. See "Contractual Arrangements, Codes and Licences Hydro One Inc.'s Relationship with the IMO".

- ***Non-discriminatory Access*** — If a generator, distributor, retailer, wholesale supplier, wholesale buyer or customer requests that we convey electricity using our transmission system, subject to capacity constraints, we must make an offer to convey electricity on behalf of the applicant consistent with the applicable Market Rules and the Transmission System Code.

- ***Obligation to Connect*** — We may not refuse an offer to connect to our transmission system which has been made in accordance with the terms of our transmission rate order, the Market Rules and the Transmission System Code unless we are permitted to do so by the OEB, the legislation or any codes, standards or rules with which we are obligated to comply as a condition of our licence.

- ***Obligation to Comply with Codes and Rules*** — We are obligated to comply with the Market Rules, the Transmission System Code and the Affiliate Relationships Code for Electricity Distributors and Transmitters and must maintain our transmission system to the standards established in our agreement with the Independent Electricity Market Operator, the Market Rules and any other recognized industry operating or planning standard which has been specified by the OEB.

- ***Separation of Business Activity*** — Our subsidiary that holds the transmission licence and operates our transmission business must ensure organizational, structural and financial separation of its transmission and distribution businesses from all of its other businesses as required by the OEB or specified in the Affiliate Relationships Code for Electricity Distributors and Transmitters.

- ***Transmission Rates*** — We may not impose charges for the transmission of electricity or connection to our transmission system except in accordance with our transmission rate order.

- ***Expansion of the Transmission System*** — We may not expand or reinforce our transmission system except in accordance with the standards established in the Transmission System Code and certain expansions will be subject to OEB approval. The OEB may require us to expand or reinforce our transmission system if it determines that there is a threat to security, reliability or integrity of the system.

- ***Intertie Expansion*** — Subject to obtaining all necessary regulatory approvals, we must use our best efforts to expand our interconnection capacity to neighbouring provinces and states by approximately 2,000 MW within 36 months after the commencement of Open Access. See "Rate Orders and Related Issues for Hydro One Inc.'s Businesses – Transmission – Inter-ties."

- ***Disposal of Assets*** — We are prohibited without obtaining leave of the OEB from selling, leasing or otherwise disposing of all or substantially all our transmission system or that part of our transmission system that is necessary in serving the public.

Distribution Licences

The terms and conditions of our three distribution licences are similar to the terms and conditions of our transmission licence described above. In addition, the licences:

- require the distribution business to keep its financial records separate from the financial records of the transmission business;

- create an obligation to charge rates in accordance with an order of the OEB and in accordance with the methods or techniques set out in the Electricity Distribution Rate Handbook, the Distribution System Code, the Standard Supply Service Code and the Retail Settlement Code;

- require compliance with the Retail Settlement Code and the Affiliate Relationships Code for Electricity Distributors and Transmitters;

- prescribe the manner by which we must pass through any rebates from Ontario Power Generation Inc. to customers; and

- impose the obligation on our distribution business to connect a building to our distribution system under prescribed circumstances, and to sell electricity or ensure electricity is supplied to every person connected to our distribution system, in accordance with our distribution rate orders and the Standard Supply Service Code, and to sell electricity to consumers consistent with the terms and conditions of these instruments.

Rate Orders and Related Issues for Hydro One's Businesses

Transmission

Current Rate Orders and Review of the Existing Transmission Rate Structure

The OEB approves both the revenue requirements of and the rates charged in our transmission business. The rates are designed to permit our transmission business to recover the allowed costs and to earn a specified annual rate of return on the average common equity.

For 2000, the rate order issued by the OEB for our transmission business (effective on April 1, 2000) approved an annual revenue requirement of $1.2 billion. In determining the revenue requirements, the OEB approved a utility rate base of $5.7 billion, a level of net costs and expenses of $549 million, and a level of payments in lieu of corporate income tax of $139 million for 2000.

The term "utility rate base" refers to the investment in regulated operations (consisting of gross plant in service, less accumulated depreciation, plus necessary working capital and excluding construction work in process). Utility rate base is used to determine the capital structure for our regulated businesses, enabling a determination of approved financing charges and return on common equity for them. The OEB accordingly approved a capital structure for our regulated businesses of 60% debt with a weighted average cost of approximately 7.7%, 4% preferred equity with a 5.5% dividend rate and 36% common equity and a rate of return on deemed common equity of 9.88%.

On January 15, 2001, the OEB issued its rate order, which included approved transmission rates for our company. Subsequently, it decided to establish a process involving all electricity transmitters within Ontario to develop uniform transmission rates that would apply to all transmission customers. On April 30, 2002, the OEB approved transmission rates that apply uniformly to the hourly peak demand at any transmission delivery point in the province. Our approved revenue requirement and load forecast remain unchanged as a result of the adoption of uniform rates. In addition, the OEB's adoption of the uniform transmission rate reduces the financial incentive for customers to seek an alternative transmission provider.

Prior to May 1, 2002, these transmission rates were charged as part of a single bundled rate for the operation, transmission and distribution of electricity. As of May 1, 2002, the rates charged to customers were unbundled and load customers are now charged in a transparent manner for their use of the transmission system based on the approved transmission rate. The IMO collects transmission revenues for our company and remits these to us on a monthly basis.

Transmission rates are based on the fully allocated cost associated with providing each of the following three transmission service elements:

- ***Network services*** — the transmission network is the integrated part of our high voltage transmission system that is shared by all users and includes all 500 kV facilities, the 230 kV and the 115 kV facilities that can be classified as commonly used;

- ***Line connection services*** — connection facilities are the radial parts of our high voltage transmission system, which are dedicated to serving a single customer or generator or a group of customers or generators. Transmission line connection facilities are the radial high voltage transmission lines connecting the transformer to the network; and

- ***Transformation connection services*** — the transformation connection assets consist of the high voltage transformation facilities that step down voltages from transmission levels to distribution levels to supply customers.

In addition, electricity exports from Ontario are levied an export charge for transmission of one dollar per MWh.

Implications of the Electricity Pricing, Conservation and Supply Act, 2002 for Transmission Revenues

We are currently evaluating the implications of the *Electricity Pricing, Conservation and Supply Act, 2002* on our transmission business. See – "Critical Features of the *Electricity Pricing, Conservation and Supply Act, 2002* for the Businesses of Hydro One Inc." Through 2002, pursuant to the direction of the OEB, we had been developing a rate application and performance based regulation framework (expected by the OEB) to set transmission rates for a five-year period, and intended to submit these to the OEB in the spring of 2003. As a result of the passage of this Act, however, we have decided to suspend this application.

Competition

Under the *Ontario Energy Board Act, 1998*, any licensed competitor can apply to the OEB for approval to build transmission network facilities in Ontario. Because there is limited need for major new network investments in the short to medium term, competition is expected to pose limited risk to us. In addition, the OEB's adoption of the uniform transmission rate reduces the financial incentive for customers to seek alternative transmission. One possible short-term exception to the limited need for new network investment relates to interconnections with neighbouring utilities.

Customers historically had the option to build and own their own transmission connection facilities and thereby avoid paying our connection charge. Only a few large industrial customers and local distribution companies chose to do so, likely because of the significant costs of construction. Under the new regulatory framework, in addition to avoiding our connection charge, local distribution companies that own their transmission connection facilities can include these assets in their rate base and earn a regulated return. Customers will generally, however, continue to have the option to have their new connection facilities incorporated within our existing transmission transformation and line pools or to build and own their new connection facility. We will continue to maintain and restore our existing connection assets, as well as bid on the construction and ownership of new facilities.

By-pass

By-pass occurs when we have invested in the provision of transmission facilities to a customer which then obtains all or part of its transmission services in another manner or takes action to avoid its use of transmission services before the rates collected have paid for the investment. Recovery of the remaining costs for the stranded facilities then necessitates higher transmission rates from the remaining customers.

In its January 2001 decision respecting transmission rate design and cost allocation, the OEB addressed the issue of by-pass where a load customer installs a generator to serve all or part of its load. The OEB decided that customers would be assessed line and transformation connection charges based on their total demand for electricity, or gross load. However, given the desire to encourage new generation and the growth anticipated in the usage of the network (which would hold us harmless from the effects of stranding), customers would be assessed network charges based on their net load. In effect, customers who generate electricity on-site can save the network charges otherwise applicable to their purchase of electricity generated by third parties. The decision to assess line and transformation connection charges based on gross loads means that on-site generators bear a portion of the costs associated with Ontario's transmission infrastructure, thereby mitigating the potentially negative effect of on-site generation on our transmission business.

Since this decision, there have been a few applications that have been brought before the OEB that would, in our view, constitute a by-pass of our transmission facilities. These applications, which we have opposed, are still under review by the OEB.

On April 14, 2003, the OEB issued its principles and preliminary propositions in its review of the Transmission System Code for intervenor response. In the area of transmission bypass, the OEB appears to expand the instances where transmission bypass would be allowed. We will register with the OEB the negative concerns and implications for transmitters and transmission pool customers that would arise from expanding bypass opportunities. The OEB's decision on this matter is expected later in 2003.

Facilities Applications

Transmitters constructing facilities in Ontario are required to apply to the OEB for leave to construct, if the facilities comprise or include a transmission line that is greater than two kilometers. From time to time, we will apply to the OEB for leave to construct transmission facilities. See "Recent Developments – Other Developments."

We have begun developmental engineering work on reinforcing our transmission facilities in southwestern Ontario. This project, known as Queenston-Flow-West, would provide an improvement to the interconnection import capability at our New York inter-tie point in the Niagara area of 800 MW. This project would require regulatory approvals, including an approval from the OEB for leave to construct. If we proceed, we would seek recovery of the costs associated with this investment through rates in a future rate application.

The Reliable Energy and Consumer Protection Act, 2002

In June 2002, the Provincial Government enacted Bill 58, the *Reliable Energy and Consumer Protection Act*, 2002, which transferred the ownership of all transmission corridor and abutting lands to the Province effective December 31, 2002. Our company retains the statutory right to use and expand the use of these corridor lands for transmission and distribution purposes.

Distribution

Rate Orders and Review of the Existing Distribution Rate Structure

Our 1999 rate order, effective April 1, 1999 through to March 31, 2001, approved an annual revenue requirement of $611 million for 2000 for our distribution business. In determining this revenue requirement, the OEB approved a utility rate base of approximately $2.4 billion, net costs and expenses of $324 million, and payments in lieu of corporate income tax of $78 million. For the purposes of determining the revenue requirement, the OEB approved a capital structure for our regulated businesses of 60% debt with a weighted average cost of approximately 7.7%, 4% preferred equity with a 5.5% dividend rate and 36% common equity and a rate of return on deemed common equity of 9.88%.

On May 1, 2000, we submitted to the OEB our application for unbundled distribution rates for a period of up to 24 months from the date of commencement of Open Access in accordance with the OEB's Electricity Distribution Rate Handbook. Our application also reflected a market based rate of return. It would have resulted in an approximately 1% increase in customers' electricity bills. Local distribution companies submitted rate applications to the OEB that would have resulted in significant increases in their customers' electricity bills. The difference in the impact on customers of our application and the applications of the local distribution companies reflected the fact that local distribution companies were seeking commercial rates of return for the first time and the fact that our cost of power was lower than that of the local distribution companies. In response to these applications, on June 7, 2000, the Minister of Energy, Science and Technology issued a directive to the OEB to give primacy to the OEB's objective to protect the interests of customers with respect to prices and the reliability and quality of electricity service when approving the rates for distributing electricity submitted to it by Ontario utilities. In response to the directive, the OEB issued a decision requiring distributors to phase in their increased rates evenly over three years to lessen the impact on consumers.

As a result of this decision, all electricity distributors were required to file or refile their distribution rate applications. Following discussions with our shareholder and in an attempt to mitigate the impact of the anticipated increase in our cost of power on our customers, we filed an amended distribution rate application, which sought to limit increases paid by consumers to 4% commencing on October 1, 2001, 2.8% commencing on March 1, 2002 and 2.8% commencing on March 1, 2003. This application reflected the anticipated increase in our wholesale cost of power yet mitigated the full impact of this increase on our customers by reducing our distribution revenues. As a result, our distribution revenues were 21% lower as of October 1, 2001, 15% lower as of March 1, 2002 and are expected to be 9% lower as of March 1, 2003 than the distribution revenues in place prior to June 2001. Subsequently, pursuant to a regulation made under the *Electricity Act, 1998*, Ontario Power Generation Inc. was required to increase its wholesale cost of power to us by an additional 1.15 cents per kWh effective October 1, 2001 in order that our power costs would be consistent with the power costs of other large electricity distributors. This increase was consistent with the anticipated increase in our wholesale cost of power reflected in our amended application that was expected to be implemented upon Open Access.

On August 30, 2002, the OEB issued its final rate order for our distribution business, approving aggregate revenues that we had requested with one exception: $12.9 million of low voltage costs were transferred from our low voltage customers to our retail customers. The approved revenue requirements totaled $646 million effective October 1, 2001, $694.0 million effective March 1, 2002 and $742.3 million effective March 1, 2003, to be collected from retail rates, miscellaneous charges and low voltage charges. In each of 2001, 2002 and 2003, low voltage rates were approved to recover revenues of $25.7 million and miscellaneous charges were set to recover $13.7 million. To address a revenue shortfall, our company embarked on a cost reduction and deferral plan to address the revenue shortfall during the transition period (2000-2003).

Implications of the *Electricity Pricing, Conservation and Supply Act, 2002* for Our Distribution Revenues

Several aspects of the *Electricity Pricing, Conservation and Supply Act, 2002* have implications for our distribution revenues.

Prior to the passage of the Act, we had contemplated a phase-in of the increase in our revenue requirement, with the last phase approved for implementation on March 1, 2003. As a result of the freeze on distribution charges at the November 11, 2002 level, this last phase (which itself did not fully address our on-going revenue requirement at market based rate of return) was not implemented. For the subsequent distribution rate period commencing in 2004, we had intended to submit a rate application that would appropriately reflect our revenue requirement. As a consequence of this Act, this work has now been suspended.

The rates approved by the OEB for our low voltage customers could not be implemented by November 11, 2002 and accordingly, anticipated annual revenues of $25.7 million cannot be recovered until at least May, 2006. Although we are permitted to establish a deferral account to record the amounts we would have recovered from customers had those charges been in effect, the extent to which we may recover the full amount has not been determined.

In preparing for an open electricity market, our distribution business has incurred transition costs. The *Electricity Pricing, Conservation and Supply Act, 2002* acknowledges such costs and provides that they be deemed regulatory assets until the OEB addresses their disposition in a rate order.

Rate Orders and Implications of the Electricity Pricing, Conservation and Supply Act, 2002 for our Acquired Customers

Applications for unbundled rates to be implemented effective March 1, 2001 for 86 of our acquired utilities were filed with the OEB. The applications were consistent with the Electricity Distribution Rate Handbook in terms of rate design and staged phase-in of a market based rate of return. The 2001 applications sought revenues which would attain the first one-third of the 9.88% of a market based rate of return. Interim approvals were granted.

In March 2002, 87 applications (now including that for Thessalon, newly acquired) were filed for the second step of a market based rate of return framework and consistent with the OEB direction included, an input price index adjustment and an adjustment for payments in lieu of corporate taxes. These applications were still under review when the *Electricity Pricing, Conservation and Supply Act, 2002* was enacted. This Act froze the interim rates and terminated the process for the second step applications. Consequently, our company is not receiving additional revenues of about $11 million which would have been realized for the second stage of a market based rate of return and low voltage revenues from our acquired customers. Further, our plan to harmonize the rates of acquired retail customers with those in our original distribution area has also been delayed.

Competition

Under the *Ontario Energy Board Act, 1998*, two or more distribution licences may be issued for the same geographic service area. Historically, in any particular region throughout Ontario, only one electricity distributor, which also provided the retail sale of electricity to each customer connected to the distribution system, existed.

Today, a competitor may obtain a licence from the OEB to own and operate a distribution system within the same geographic area as an incumbent distributor. The new or amended distribution licence will authorize the competing distributor to serve in a specific area, but will not provide exclusive distribution rights to it. The practice of a single licensed distributor to serve a single area will likely continue to serve all customers in most areas. Some competition between distributors may occur for high growth areas at the boundaries of urban utilities. The OEB recently announced that it will undertake an oral hearing to determine the principles of expansion of service areas.

Rate Orders for Remote Communities

Hydro One's Remote Communities business is exempt from a number of sections of the *Electricity Act, 1998* which relate to the competitive market. For example, it continues to apply bundled rates to its customers. Rates for our remote customers were increased on June 1, 2002, to reflect the 0.7 cent per kWh increase in the wholesale power rates applicable to the rest of Ontario on June 1, 2001. These rates will now stay in effect until at least April 30, 2006, as a result of the *Electricity Pricing, Conservation and Supply Act, 2002*.

We had applied to the OEB on March 11, 2002 to increase our remote customer rates to align with other increases in our distribution rates. We proposed to follow the intent of the Electricity Distribution Rate

Handbook and adopt a modified performance based regulatory approach. However, as the application was underway at the time that the *Electricity Pricing, Conservation and Supply Act, 2002* was passed, the proceeding was terminated. Rates which had been approved for implementation on an interim basis on June 1, 2002 became final.

Rural and Remote Rate Protection

In approving electricity rates for a distributor which delivers electricity to rural or remote consumers, the OEB is required to provide rate protection for prescribed classes of consumers, including those who received rural rate assistance prior to April 1, 1999, by reducing the rates that would otherwise apply.

From April 1, 1999 until the date of Open Access, May 1, 2002, the OEB was required to calculate the amount of rate reduction for those consumers who occupy rural residential premises in a manner that it forecast would result in the weighted average rural bill not exceeding the weighted average municipal bill by more than 15%. Our remote customers also receive protection so that the rates charged to them are no greater than the rates charged to the lowest density comparable class of our rural customers. Our distribution rate order approves the maintenance of existing subsidized rates for remote and rural customers.

From May 1, 2002 until December 31, 2004, the amount of rate reduction for rural consumers who occupy rural residential premises is $127 million per year less the specific amounts established for certain specified municipalities and distributors in three formerly remote communities.

Our remote customers received an amount of $21 million for 2002 based on the amount that they received in 2001. The amounts to be received by our remote customers for each of the years 2003 and 2004 are expected to remain at the same level of $21 million.

Under the *Ontario Energy Board Act, 1998*, a distributor is entitled to be compensated for lost revenue resulting from the rate protection regime, and all consumers are required to contribute towards the amount of any compensation to the distributors, such as our company, for rate protection. As of May 1, 2002, the amounts required to compensate the distributors were collected by the IMO and paid to us for distribution in accordance with the regulation under the *Ontario Energy Board Act, 1998*. The OEB calculates the charge to be collected by the IMO based upon the latter's forecast of the number of kWh of electricity that will be withdrawn from the IMO-controlled grid. We maintain a variance account to track any surplus or deficit in the amount received from the IMO from the $127 million and $21 million paid out to our rural and remote distribution customers.

Recent Developments

The Minister's Review of Electricity Bills

The *Electricity Pricing, Conservation and Supply Act, 2002* enables the Minister to approve the form of electricity invoices for low-volume and designated consumers, but these provisions have not yet been proclaimed into force. A review of Ontario electricity bills was undertaken and, on March 3, 2003, the Minister released a report, which makes a number of recommendations concerning bill format and rate structure. The report goes on to recommend the use of interval meters for all customers, benchmarking of our transmission costs, publication of provincial distributor statistics, a review of variance accounts, fixed charges specific to each distributor and the creation of a task force to determine how to reduce line losses.

The report suggested that the recommendations be phased in with the implementation costs recovered through rates. It is too early for us to assess the impact of the recommendations on our customers and business operations.

Other Developments

On February 28, 2003, we applied to the OEB for leave to construct a transmission line to augment the existing supply to Ottawa. This application is still before the OEB.

Transmission System Code Review

In April 2003, the OEB issued its set of principles and preliminary propositions on transmission bypass, available transmission capacity, cost responsibility, evaluation methodology and contestability to guide in decisions on amending the Transmission System Code. We have raised in our response concerns in three areas: transmission bypass, assignment of available transmission capacity and provision of financing for connection of new customers. We expect the OEB will render a final decision on its principles and propositions later this year.

RISK FACTORS

You should carefully consider the following risks before purchasing our securities. If any of the circumstances discussed below occurs, our business, results of operations, financial condition and prospects could be adversely affected, in which case the trading prices of our securities could decline.

Risks Related to our Industry

Our financial performance depends on our ability to manage our costs in accordance with our current rate orders for a longer period than originally planned.

Our electricity transmission and distribution businesses are subject to regulation, principally by the OEB. The members of the OEB are appointed by the Province and the Province has the power to issue general policy directives to the OEB. The OEB approves our revenue requirements for our transmission and distribution businesses. The *Electricity Pricing, Conservation and Supply Act, 2002* stipulates that, during the period ending April 30, 2006, an application for a new rate order may not proceed to the OEB unless written approval is received from the Minister of Energy.

Revenue requirements specify the revenues we require to cover approved costs plus a specified rate of return. By assuming levels of electricity usage, the OEB sets rates for customers of regulated businesses. As a result, we are highly dependent upon rate orders that approve our revenue requirements and the rates for customers of our core transmission and distribution businesses.

The OEB has approved rate orders for both our transmission and distribution businesses. The rate orders for our main distribution business have been implemented with the exception of the low voltage charges and third stage market based rate of return increase. The rates for the distribution customers we acquired in connection with our acquisition of 36 utilities do not include the second or third increases towards market based rate of return, nor low voltage charges. Our rate orders incorporate revenue requirements that assume we will achieve cost reductions and increased levels of productivity. If our actual costs exceed allowed costs for any reason, the actual rate of return on our common equity and our resulting net income are likely to be adversely affected. Actual costs could exceed allowed costs if, for example, we incur operation, maintenance and administration costs above budgeted amounts, capital expenditures at levels above those provided in the rate orders or debt financing charges beyond those specified in the rate orders.

In 2001, following discussions with our shareholder, which requested us to mitigate the anticipated transition to higher electricity costs for our distribution customers, we applied for lower distribution revenues than we had originally proposed. Further, any increase in revenues would be implemented in stages, with the last stage to be implemented on March 1, 2003. This revised proposal was approved, thereby comprising the final rate order for our distribution business. We had indicated to the OEB that our operation at the reduced level of revenues would be manageable through 2003, but we planned to submit an application for rates applicable in 2004 that would allow us to earn the return on equity approved for large distribution utilities.

As a result of the *Electricity Pricing, Conservation and Supply Act, 2002*, however, we were not able to complete the last stage increase as approved for implementation effective March 1, 2003. Until 2006, our revenues are, therefore, frozen at a level below that approved by the OEB. We were also not able to continue developing our application for second stage increases in rates for our acquired utilities. Accordingly, the revised distribution revenues will have a greater adverse effect on the rate of return on the common equity deemed to be allocated to our distribution business and on our resulting net revenue through a longer period than was originally anticipated.

The approved rates for our transmission business also are frozen at current levels until April 30, 2006 by the *Electricity Pricing, Conservation and Supply Act, 2002*. These rates are based on substantially the same revenue requirements as had been incorporated in the rates in effect prior to Open Access. We continue to evaluate the effect on the business of operating at the current revenue levels.

Effectively, the rate orders in place (particularly for the distribution business) now entail a continuing commitment to manage within approved cost levels and to productivity expectations over a time frame different from that envisaged by both our company and the OEB. An inability to sustain our mitigation efforts for lower than anticipated rates in the distribution business could have a material adverse effect on our net income.

We may not be allowed full recovery of our regulatory assets, which could negatively affect our profitability in future periods.

We currently record substantial regulatory assets for recovery through our future rates for our regulated transmission and distribution businesses. Our principal regulatory assets relate to future employee benefits other than pension costs, costs incurred to align our systems and practices with the requirements of the competitive electricity market in Ontario, referred to as "Market Ready" costs, retail settlement variance accounts and estimated expenditures required to remediate past environmental contamination.

The *Electricity Pricing, Conservation and Supply Act, 2002* provides that “Market Ready” costs, other costs such as Hydro One’s revenues from low-voltage customers, variances associated with retail settlements and other accounts to be prescribed by regulation are not currently collectible and provides for the recording of these costs as regulatory assets until the OEB may address their disposition.

Ordinarily, we would pursue recovery of these assets through our rates to the extent approved by the OEB in accordance with its review process. The *Electricity Pricing, Conservation and Supply Act, 2002* temporarily curtails the OEB’s authority in this regard but, at the Minister’s request, it will undertake a review of this issue in 2003. The potential scope, timing, and process of this review are not yet known.

The continuing curtailment of the authority of the OEB to allow the recovery of our regulatory assets or a determination by the OEB not to allow the recovery of our regulatory assets, or a change in its position in respect of any of these items, could have a material adverse effect on our net income.

Risks related to our company

Our financial position could be adversely affected if we fail to arrange substantial, cost-effective financing to repay maturing debt and to fund capital expenditures, dividends and other obligations.

We have substantial amounts of existing debt which mature between 2003 and 2007, including $651 million maturing in 2003 and $700 million maturing in 2004. We also plan to incur total capital expenditures of approximately $615 million in 2003. We expect our capital expenditures to continue to remain relatively stable for the next few years. In addition, we plan to pay quarterly dividends on our outstanding common shares as well as dividends on any preferred shares in accordance with their terms. The declaration and payment of dividends on our common shares will be at the discretion of our board of directors and will also be dependent on our results of operations, financial condition, cash requirements and other relevant factors.

Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our financial performance.

We could experience service disruptions and increased costs if we fail to maintain and improve our aging asset base.

Our asset base requires substantial maintenance, improvement and expansion. We acquired transmission and distribution assets from Ontario Hydro that were, in some cases, relatively old and, potentially, subject to becoming less reliable. Ontario Hydro also had deferred maintenance spending on some of these assets during the mid to late 1990s in favour of allocating funds to other business units. As a result, we have been making significant capital expenditures to maintain or improve many of these assets and to enhance our asset management and monitoring processes. We expect to make significant capital expenditures with respect to these assets for at least the next several years. Any failure to carry out these programs to maintain and improve our asset base could have a material adverse effect on our company.

Our profitability and cash flow could decline if we fail to further improve our labour productivity.

The substantial majority of our employees are represented by either the Power Workers' Union or the Society of Energy Professionals. Historically, the collective bargaining agreements with these unions have generally not provided sufficient flexibility to conduct operations in the most cost-efficient manner. Although we believe that we have achieved improved relations with these unions over the last three years, which have resulted in more flexible collective agreements, we may not be able to maintain or further improve these relations. Our rate orders incorporate revenue requirements that assume that we will achieve reduced labour costs. Accordingly, any inability on our part to continue to achieve increases in labour productivity and associated reduced costs could have a material adverse effect on our financial performance.

Our outsourcing arrangement with Inergi LP may not yield the anticipated reduction in operating costs.

Consistent with our strategy of reducing operating costs, we entered into an outsourcing services agreement in 2002 with Inergi LP, an affiliate of Cap Gemini Ernst & Young Canada Inc. Under this agreement, Inergi LP provides us with, among other things, customer service operations and supply management, pay operations, information technology and finance and accounting services over a 10-year term for aggregate base fees during that period of approximately $1 billion. These fees are subject to decreases based on benchmarking against industry standards and other adjustments. As part of this outsourcing arrangement, approximately 900 of our employees were transferred to Inergi LP on March 1, 2002. Although we believe that the outsourcing arrangement will yield cost savings over the term of the agreement, we may not, in fact, achieve all of the expected cost reductions. Cap Gemini Ernst & Young Canada Inc. and its affiliates have not previously provided the extensive range of services covered by the agreement to any other electric utility company. As a result, we cannot assure you that Inergi LP will deliver all of the agreed upon services or that such delivery will be more effective than previously provided by our own business units. If the agreement with Inergi LP is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the functions involved, which could have a material adverse effect on our financial performance.

We are controlled by the Province and may have conflicts of interest with the Province and related parties.

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and thus influence major business and corporate decisions, including, for example, financing programs and the dividend policy. We and the Province have entered into a shareholder's agreement which requires us to consult with the Province in connection with our business plans to ensure that these plans are consistent with the purposes of the *Electricity Act, 199*8, as amended by the *Reliable Energy and Consumer Protection Act, 2002,* and the *Electricity Pricing, Conservation and Supply Act, 2002*, and the objectives of the OEB under the *Ontario Energy Board Act, 199*8. These purposes and objectives, which are specifically set out in the *Electricity Act, 1998*, as amended, and the *Ontario Energy Board Act, 1998*, relate to the development of competitive electricity markets in Ontario and the protection of the interests of Ontario's electricity consumers. The shareholder's agreement also requires that we consult with the Province with respect to matters concerning our dividend policy and obtain approval from the Province in advance of any proposal to issue or transfer shares in our company or our subsidiaries, any major transaction, including the sale of assets, which would potentially have a material effect on the financial interest of the Province, or our ability to make payments to the Ontario Electricity Financial Corporation or payments in lieu of taxes under the *Electricity Act, 1998*. Finally, the Province retains the power to regulate Ontario's electricity industry.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry, the regulation of environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in Hydro One and the determination of the amount of payments to be made by us to the Province by way of dividends or to Ontario Electricity Financial Corporation in lieu of taxes. Conflicts of interest may also arise as a result of the Province's 100% ownership of Ontario Power Generation Inc. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us.

Our operations could expose us to substantial and currently undetermined environmental costs and liabilities.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply with environmental regulations could subject us to fines and other penalties. In addition, releases of hazardous or other substances on or from properties now owned, leased, occupied or used by us, or as a result of our operations, could lead to governmental orders requiring us to investigate, control and remediate the effects of these releases. The presence or release of hazardous or other substances could also lead to claims by third parties.

We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centres. It involves the systematic identification of any contamination at or from these facilities, and where necessary the development of remediation plans for Hydro One and adjacent private properties. Actual costs incurred to address remediation may be materially greater than the cost estimates used to calculate the environmental liability recognized in our financial statements. The Canadian federal government has proposed draft regulations that would require the phase-out of certain PCB equipment. We are involved in discussions on these issues with the federal government and other parties. Although the cost to comply with these draft regulations, if issued, would not have a material adverse effect on our operations and financial performance, the draft regulations may change. While we would seek approval from the OEB to recover these costs after the current rate freeze, future rate orders may not allow us to recover these costs in our rates charged to our customers. We do not have insurance coverage for these remediation costs. In addition, any contamination on our properties could limit our ability to sell these assets in the future.

Any changes in environmental regulations that affect our company, such as those relating to PCBs, or in the enforcement of these regulations, may impose material additional costs on us. In addition, obtaining governmental environmental approvals, permits or renewals of existing approvals and permits may require environmental assessment or result in the imposition of conditions, or both, which may be costly. The construction of new facilities requires environmental assessments and government approvals, which can result in delays and increase the cost of construction or operation of new facilities. In some cases, the imposition of conditions could adversely affect our planned costs to construct or operate a facility.

Scientists and public health experts in Canada, the United States and other countries are studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, litigation could result, and we could be required to take mitigation measures at our facilities. The costs of litigation and mitigation measures could be material, particularly if we were required to relocate our existing transmission and distribution facilities. Public concern over the health risks associated with electric and magnetic fields could make it difficult for us to site and build new transmission and distribution facilities.

Our facilities could be affected by severe weather, other natural disasters or catastrophic events, and we have limited insurance coverage for losses resulting from these events.

Our facilities are exposed to the effects of severe weather conditions, natural disasters and, potentially, catastrophic events, such as a major accident or incident at a generating plant of a third party to which our transmission or distribution assets are connected. Although constructed, operated and maintained to withstand occurrences of this type, our facilities may not do so in all circumstances. In addition, many of our facilities are located in remote areas, which makes access for repair of damage difficult.

We have no insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations caused by severe weather, other natural disasters or catastrophic events. In the event of a large uninsured loss, we would normally apply to the OEB for the recovery in our future rate orders of increased costs. However, as a result of the *Electricity Pricing, Conservation and Supply Act, 2002*, the application must be approved first by the Minister before proceeding to the OEB which then could decide not to approve, in whole or in part, an application by us for recovery of these costs. Losses resulting from repair costs and lost revenues could be substantial and we could be subject to claims for damages caused by the failure to transmit or distribute electricity. As a result, any major damage to our facilities could result in lost revenues, repair costs and claims that could be substantial and that could have a material adverse effect on our net income.

Our profitability and cash flow could be negatively affected by possibly significant costs to complete the transfer to us of transmission, distribution and other assets located on Indian lands.

The transfer orders by which we acquired Ontario Hydro's electricity transmission, distribution and energy services businesses as of April 1, 1999 did not transfer title to some assets located on lands held for bands or bodies of Indians under the *Indian Act* (Canada). The transfer of title to these assets did not occur because authorizations originally granted by the Canadian Minister of Indian and Northern Affairs for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant Indian bands or bodies or, in several cases, because the authorizations had either expired or had never been properly issued. These assets represent approximately 0.126% of our total assets as at December 31, 2002 and consist primarily of approximately 82 kilometres of transmission lines and approximately 1,300 kilometres of distribution lines (of which 14 kilometres of lines are used solely for serving customers off the reserves). Ontario Electricity Financial Corporation holds these assets. Under the terms of the transfer orders, we are required to manage these assets until we have obtained all consents necessary to complete the transfer of title to these assets to us.

We are seeking to obtain from the relevant Indian bands and bodies the consents necessary to complete the transfer of title to these assets. We cannot predict, however, the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. We anticipate having to pay more than the approximately $850,000 per year that we currently are paying to these Indian bands and bodies and that is the allowed cost for this matter in our rate orders. If we cannot obtain consents from the Indian bands and bodies, Ontario Electricity Financial Corporation will continue to hold these assets for an indefinite period of time. If we cannot reach a satisfactory settlement, we may have to relocate these assets from the Indian lands to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel generation facilities. We would normally apply to the OEB for reimbursement of these payments or costs in future rate orders. However, as a result of the *Electricity Pricing, Conservation and Supply Act, 2002*, the application must be approved first by the Minister before proceeding to the OEB, which then might not allow us to recover such costs. The costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them.

We may be required to make substantial contributions to our pension plan, which could negatively affect our net income.

We have a defined benefit registered pension plan for the majority of our employees. Our contributions to the pension plan are based on periodic actuarial valuations. We are currently entitled to a contribution holiday based on a valuation as at December 31, 2000 that indicated the plan had a surplus. We are required to revalue our pension plan by no later than December 31, 2003. In light of the investment performance of our pension plan since 2000, we may be required to make contributions to the plan once our next actuarial valuation is filed. Based on asset values and estimated obligations at December 31, 2001, we estimate that our contributions would be approximately $100 million per year, excluding employees transferred in connection with the Inergi LP outsourcing agreement. The actual amount of the contributions that may be required in the future will depend on future investment returns, changes in benefits or actuarial assumptions. If we are required to make contributions in the future, we intend to seek recovery of any increased expense through our rates for transmission and distribution services. Any determination by the OEB not to allow recovery of increased contributions could have a material adverse effect on our net income.

The Province has passed legislation pursuant to which it has acquired our transmission corridors which could result in additional costs and may result in a reduction of our net income.

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002* the Province acquired ownership of our owned lands underlying our transmission system, which are referred to as "transmission corridors". The acquisition of the transmission corridors by the Province may reduce the value of our regulated assets which may reduce our net income. Revenue from current and future third party uses of the transmission corridors could be affected adversely by this acquisition. Although we have the statutory right to use the transmission corridors for the purposes of our transmission, distribution and telecommunications systems, we may be limited in our ability to expand our systems in the future. Other uses of the transmission corridors, whether by the Province or others, in conjunction with the operation of transmission, distribution or telecommunications systems may increase safety or environmental risks.

Forward-looking information in this Annual Information Form is subject to risks and uncertainties.

We have included forward-looking statements in this Annual Information Form, including forward-looking statements relating to, among other things, our strategy, future rate orders and regulatory developments, planned capital expenditures and refinancings of existing debt. We have used the words "may", "will", "expect", "anticipate", "believe", "estimate", "plan" and similar expressions in this Annual Information Form to identify forward-looking statements. We have based these forward-looking statements on our current views with respect to future events and financial performance. Actual results could differ materially from those projected in the forward-looking statements. These forward-looking statements are subject to the risks, uncertainties and assumptions discussed in this "Risk Factors" section and elsewhere in this Annual Information Form. Because of these risks, uncertainties and assumptions, you should not place undue reliance on these forward-looking statements. Except to the extent required by applicable securities laws and regulations, we undertake no obligation to update or revise any of these forward-looking statements, whether to reflect new information, future events or circumstances or otherwise.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

	For the year ended December 31, (Canadian dollars in millions)			
CANADIAN GAAP **Statement of Operations Data**		**2000**	**2001**	**2002**
Total revenues		2,995	3,646	4,044
Operating costs		2,070	2,475	3,114
Financing charges		340	350	353
Payments in lieu of corporate income taxes		207	267	233
Net income		378	374	344
Basic and fully diluted earnings per common share[(1)]		3,182	3,562	3,258

(1) Earnings per share is calculated as net income during the year, after cumulative preferred dividends, divided by the weighted average number of common shares outstanding during the year. Earnings per share for 2000 reflect the issuance of common shares on March 31, 2000.

Note: This table should be read in conjunction with the consolidated financial statements.

CANADIAN GAAP Balance Sheet Data	As at December 31, (Canadian dollars in millions)			
		2000	2001	2002
Assets				
Transmission		6,477	6,693	6,635
Distribution (including retail)		3,434	4,416	4,700
Other		86	122	90
Total assets		9,997	11,231	11,425
Current liabilities (including current portion of long-term debt)		1,049	1,625	1,907
Long-term debt		3,972	4,079	3,928
Other long-term liabilities		976	1,533	1,451
Shareholder's equity				
Share capital		3,759	3,637	3,637
Retained earnings		241	357	502
Total liabilities and shareholder's equity		9,997	11,231	11,425

Note: This table should be read in conjunction with the consolidated financial statements.

The following table sets forth unaudited quarterly information for each of the eight quarters ended March 31, 2000 through December 31, 2002. This information has been derived from our unaudited consolidated financial statements which, in the opinion of our management, have been prepared on a basis consistent with the audited consolidated financial statements contained elsewhere in this Annual Information Form and include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period. You should not rely on them to predict our future performance.

	Quarter Ended							
	31-03-01	30-06-01	30-09-01	31-12-01	31-03-02	30-06-02	30-09-02	31-12-02
	(in millions, except per share data)							
Total revenue[1]	816	722	880	1,048	1,022	910	1,131	981
Net income	134	114	103	23	106	99	112	27
Net income to common shareholder	129	110	98	19	101	95	107	23

[1]Total revenues have been restated from amounts presented for the quarters subsequent to May 1, 2002 to reflect the fixed commodity price stipulated by the *Electricity Pricing, Conservation and Supply Act, 2002* of 4.3 cents per kWh for low volume and designated customers. As purchased power was revised by the same amount there was no impact on net income and net income to common shareholder.

Dividends

Our preferred shares are entitled to a total annual dividend of $18 million which is payable quarterly. In 2000, we paid dividends on our preferred shares of $31 million, which included $13 million in preferred dividends which were paid in respect of the year ended December 31, 1999. The declaration and payment of dividends on our common shares are at the sole discretion of our Board of Directors, but will be dependent upon our results of operations, financial condition, cash requirements and other relevant factors. In respect of the year ended December 31, 2002, we have paid dividends on our common shares of $174 million (2001 - $240 million; 2000 - $371). The dividends paid in 2000 on our common shares included $23 million of dividends paid in respect of the year ended December 31, 1999.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Reference is made to our 2002 Management's Discussion and Analysis which is incorporated herein by reference.

MARKET FOR SECURITIES

Our 6.94% Debentures due 2005, 7.15% Debentures due 2010, 7.35% Debentures due 2030, Series 1 Notes (6.40%) due 2011, Series 2 Notes (6.93%) due 2032, Series 3 Notes (5.77%) due 2012, Series 4 Notes (6.35%) due 2034, Series 5 Notes (6.59%) due 2043, 6.778 Notes due January 30, 2004, 3.400% Notes due March 28, 2004, 3.450% Notes due May 31, 2004, 4.00% Notes due October 31, 2005, 4.100% Notes due January 30, 2006, 4.150% Notes due April 21, 2006, 4.150% Notes due April 21, 2006, 4.200% Notes due June 1, 2006, 4.300% Notes due November 10, 2006, 4.450% Notes due May 4, 2007 and 4.550% Notes due August 10, 2007 are not listed on any exchange or similar market for securities.

DIRECTORS AND OFFICERS

Directors

The following table sets forth the name, municipality of residence and principal occupation of each of our directors, as of February 1, 2003[1].

<u>Name and Municipality of Residence</u>	**<u>Principal Occupation</u>**
Glen Wright .... St. Agatha, Ontario	Chair of the Board of Directors; Corporate Director
W. Geoffrey Beattie (1) (3) .... Toronto, Ontario	President, The Woodbridge Company Limited
Rita Burak (3) (4) (5) …………………………………… Toronto, Ontario	President and CEO, Network Executive Team, Management Consultants Inc.
Murray J. Elston (1) (4) .... Manotick, Ontario	President, Canada's Research-Based Pharmaceutical Companies
Dr. Murray B. Frum (1) (3) .... Toronto, Ontario	Chair and CEO, Frum Development Group

1 Most of our directors were first appointed as directors on June 11, 2002 following the resignation of all of the external members of our board of directors effective June 4, 2002 and the resignation as a director of Ms. Eleanor Clitheroe, our former President and Chief Executive Officer, on June 11, 2002. The resignation of the external directors on June 4, 2002 was coincident with the introduction of Bill 80, the *Hydro One Directors and Officers Act, 2002*, in the Ontario legislature which, among other things, terminated the term of office of each director who held office on June 3, 2002. On June 11, 2002, the Province, our sole shareholder, announced the appointment of eleven members to the Board of Directors to serve in an interim capacity until a more permanent Board of Directors was appointed. The Province appointed a Board of Directors to replace the interim Board of Directors on August 15, 2002.

Don MacKinnon [4] [5] .... Chatsworth, Ontario	President, Power Workers' Union
Eileen A. Mercier [1] [2] .... Toronto, Ontario	President, Finvoy Management Inc.
Tom Parkinson.. Oakville, Ontario	President and CEO, Hydro One Inc.
Hon. Bob Rae [2] [3] .... Toronto, Ontario	Partner, Goodmans LLP
Kenneth D. Taylor [4] [5] .... New York, NY USA	Chair, Taylor and Ryan Inc.
Blake Wallace [2] [3] [5] .... Toronto, Ontario	Vice President and Director, Murray & Company
Adam Zimmerman [1] [2] .... Toronto, Ontario	Corporate Director

(1) Member of the Audit and Finance Committee

(2) Member of the Corporate Governance Committee

(3) Member of the Human Resources and Public Policy Committee

(4) Member of the Regulatory and Environment Committee

(5) Member of the Health and Safety Committee

Glen Wright was appointed Chair of the Board of Directors of Hydro One Inc. on June 11, 2002. He is currently on leave of absence from his role as Chair of the Workplace Safety and Insurance Board to which he was appointed in 1996. He served as Chair of the Cowan Insurance Group Limited and is also a Director of PrinterOn Corporation, the Institute for Work and Health, a member of the Wilfrid Laurier University Foundation and a member of the Board of Governors of the Council for Canadian Unity.

W. Geoffrey Beattie is currently President and CEO of The Woodbridge Company Limited, the Thomson family holding company, to which he was appointed in March 1998. He serves on the board of The Thomson Corporation, Bell Globemedia Inc., The Royal Bank of Canada and Tm Bioscience Corporation. Mr. Beattie has been a Director of our company since June 11, 2002.

Rita Burak is currently President and CEO of the Network Executive Team, Management Consultants, Inc. She served as Secretary of the Cabinet in Ontario from 1995 to 2000. She is a Member of the Order of Ontario. Ms. Burak is the Vice Chair of the University of Guelph, and a member of the board of The Equitable Life Insurance Company of Canada. Ms. Burak was appointed Vice Chair of the Board of Directors of Hydro One Inc. in August 2002 and has been a Director of our company since June 11, 2002.

Murray J. Elston is currently President of Canada's Research-Based Pharmaceutical Companies, a national association representing over 60 research-based pharmaceutical companies, to which he was appointed in November 1998. From 1981 to 1994, he served as a Liberal MPP in the Ontario Legislature, where he held the positions of Minister of Health, Chairman of Management Board, Minister of Financial Institutions and Chairman of the Public Accounts Committee. Mr. Elston has been a Director of our company since June 11, 2002.

Dr. Murray B. Frum has served as Chair and CEO of Frum Development Group since 1972. He is also Chair of the Ontario Arts Council Foundation to which he was appointed in 1998, Chair of the Ontario Cultural Attractions Fund since 1999, and a Governor of Mount Sinai Hospital since 1992. He is a member of several other organizations and was awarded the Order of Canada in 2000. Dr. Frum has been a Director of our company since June 11, 2002.

Don MacKinnon has been President of the Power Workers' Union, an electricity industry workers union, since May 2000 and a lineman by trade since 1971. He was Vice-President of the Union for eleven years prior to being elected President. Mr. MacKinnon was appointed by the Minister of Energy, Science and Technology to the Electricity Transition Committee, and has been a member of the Board of Directors of the Electrical Safety Association and the Retail Management Board of Ontario Hydro. Mr. MacKinnon has been a Director of our company since June 11, 2002.

Eileen A. Mercier formed her own management consulting firm, Finvoy Management Inc., specializing in financial strategy, restructuring and corporate governance issues, in 1995. Prior to that time, she was Senior Vice-President and Chief Financial Officer of Abitibi-Price Inc. As an active member of the Board of Directors of several business and not for profit institutions, Mrs. Mercier’s affiliations include: CGI Group Ltd., Teekay Shipping Corporation, Quebecor World Inc., ING Bank of Canada, Winpak Limited, The University Health Network, York University and the Workplace Safety and Insurance Board. Mrs. Mercier has been a Director of our company since August 15, 2002.

Tom Parkinson was appointed the President and Chief Executive Officer of Hydro One Inc. effective January 21, 2003 after serving as our President and Chief Operating Officer since July 2002. He joined Hydro One in 2001 as President and Chief Executive Officer of Hydro One Network Services Inc. Mr. Parkinson is also a member of the Board of Directors of the IMO, representing the transmitter class of stakeholders. Mr. Parkinson is a member of the board of directors of the Canadian Electricity Association. Prior to joining Hydro One, Mr. Parkinson was President and CEO and Managing Director of NorthPower in Australia from 1995 through 2001. Mr. Parkinson was President and CEO of Oxley Electricity & Water from 1994 to 1995, and a senior executive with Illawarra Electricity from 1981 to 1994.

Honourable Bob Rae served as Ontario’s 21st Premier from 1990 to 1995. He was elected eight times to federal and provincial parliaments, and served as leader of the Ontario New Democratic Party from 1982 to 1996. He is currently a partner at Goodmans LLP and is a member of the Board of Directors of public companies and non profit organizations including Invesprint Inc., Tembec Inc., Trojan Technologies, The Toronto Symphony Orchestra, The Royal Conservatory of Music, Institute for Research in Public Policy, Canadian Unity Council and Forum of Federations. He has been a Director of our company since June 11, 2002. He also has extensive experience as a mediator and arbitrator both in Canada and internationally. He is a member of Her Majesty’s Privy Council for Canada, and an officer of the Order of Canada.

Kenneth D. Taylor is Chair, Taylor and Ryan Inc., a public affairs consulting company, and is currently Chancellor of Victoria University at the University of Toronto to which he was appointed in May 1998. He is a member of the Board of Directors of Skylink Aviation Ltd. and Devine Entertainment Corp. He is the former Canadian Ambassador to Iran and the former Canadian Consul General in New York. Mr. Taylor is the recipient of the United States Congressional Gold Medal and is an Officer of the Order of Canada. Mr. Taylor has been a Director of our company since June 11, 2002.

Blake Wallace, Q.C. is currently Vice President and Director for Murray & Company, a financial advisory services company to real estate and public-private partnerships, and has also served as Vice President and General Counsel of the company since 1972. He is also the Vice-Chair of TVOntario. Mr. Wallace has been a Director of our company since November 22, 2002.

Adam Zimmerman is a Fellow of the Institute of Chartered Accountants and has served on over 43 private sector boards during his career. Now retired, his corporate experience includes Chair of the Board of Noranda Forest Inc., and a Director of Maple Leaf Foods, Southam Inc. and The Toronto-Dominion Bank. Mr. Zimmerman was Chairman and Director of Confederation Life Insurance Company when it went into liquidation in August 1994. Mr. Zimmerman has been a Director of our company since June 11, 2002.

Each director is elected annually to serve for one year or until his or her successor is elected or appointed.

Officers

The following table sets forth the name, municipality of residence and position of each of our senior officers as of February 1, 2003:

Name and Municipality of Residence	Position with our Company
Tom Parkinson .... Oakville, Ontario	President and Chief Executive Officer
Ken Hartwick .... Milton, Ontario	Chief Financial Officer and Senior Vice President, Finance
Laura Formusa... Toronto, Ontario	General Counsel and Secretary

Tom Parkinson's biographical information is presented above under "Directors".

Ken Hartwick was appointed as Chief Financial Officer and Senior Vice President, Finance in September 2001 after serving as our Senior Vice President, Finance since October 2000. Prior to joining our company, Mr. Hartwick served as Vice President of Cap Gemini Ernst & Young Inc. and as a partner of Ernst & Young LLP.

Laura Formusa was appointed the General Counsel and Secretary of Hydro One Inc. on January 2, 2003. She joined Ontario Hydro in 1980 and has held the positions of Assistant General Counsel and General Counsel and Secretary of Hydro One Networks Inc.

The officers are appointed by our Board of Directors and hold office until their successors are appointed, subject to resignation, retirement or removal by our Board of Directors.

There is no family relationship between any director or officer and any other director or officer.

ADDITIONAL INFORMATION

We will provide to any person or company upon request to the Secretary of Hydro One at 483 Bay Street, 10th Floor, South Tower, Toronto, Ontario, M5G 2P5:

(a) when the securities of our company are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus which has been filed in respect of a distribution of our securities;

  (i) a copy of our latest Annual Information Form, together with a copy of any document, or the pertinent pages of any document, incorporated by reference in the latest Annual Information Form;

  (ii) a copy of the comparative consolidated financial statements of our company for our most recently completed financial year for which financial statements have been filed, together with the accompanying report of the auditor and a copy of the most recent interim consolidated financial statements of our company that have been filed, if any, for any period after the end of our company's most recently completed financial year;

  (iii) a copy of any annual filing of our company prepared instead of an information circular; and

  (iv) a copy of any other documents incorporated by reference into a preliminary short form prospectus or short form prospectus and are not required to be provided under clauses (i), (ii), and (iii) above; or

(b) at any other time, one copy of any documents referred to in paragraphs (a)(i), (ii) and (iii), provided that we may require the payment of a reasonable charge if the request is made by a person or company who is not a security holder of our company.

As our sole shareholder is the Province, we are not required to prepare an information circular. Information concerning remuneration and indebtedness of directors and senior officers is contained in our annual filing of a reporting issuer. Additional financial information is contained in our audited comparative consolidated financial statements for the fiscal year.