**Opportunity. Leadership. Innovation.**
A lot of good things come from electricity.

hydroOne

Annual Report 2008

Hydro One will be the leading electricity delivery company in North America, guided by our values of safety, stewardship, excellence and innovation.

**HYDRO ONE INC.**
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom services.

**HYDRO ONE NETWORKS INC.**
Represents the majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

**HYDRO ONE BRAMPTON NETWORKS INC.**
Distributes electricity to one of the fastest growing urban centres in Canada, just 30 kilometres outside of Toronto.

**HYDRO ONE REMOTE COMMUNITIES INC.**
Operates and maintains the generation and distribution assets used to supply electricity to 20 remote communities across northern Ontario that are not connected to the province's electricity transmission grid.

**HYDRO ONE TELECOM INC.**
Markets our fibre-optic capacity to business customers. This business represents less than 1% of our total assets.

Value means more than just what a thing costs. True value, what something is really worth, can only be shown in how important it is to a person, a family or a community – and the influence it has on choices and actions, and on what people do.

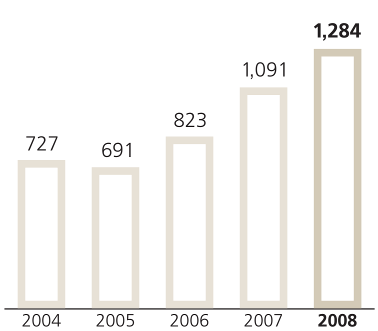
At Hydro One, there is nothing as important to us, that we value more, than keeping our commitments. As the stewards of Ontario's electricity transmission and distribution system, we are committed to the safe, reliable and cost-effective transmission and distribution of electricity to Ontario's electricity users. This commitment helps guide our plans and determine our actions; by fulfilling it, we create value for the customers we serve.

## Consolidated Financial Highlights and Statistics

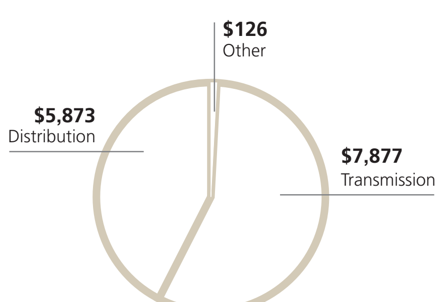
| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 | $ Change | % Change |
|---|---|---|---|---|
| Revenues | **4,597** | 4,655 | (58) | (1) |
| Purchased power | **2,181** | 2,240 | (59) | (3) |
| Operating costs | **1,513** | 1,516 | (3) | – |
| Net income | **498** | 399 | 99 | 25 |
| Net cash from operations | **1,055** | 1,141 | (86) | (8) |
| Average annual Ontario 60-minute peak demand *(MW)*[1] | **21,820** | 22,988 | (1,168) | (5) |
| Distribution – units distributed to our customers *(TWh)*[1] | **29.9** | 30.2 | (0.3) | (1) |

[1] System-related statistics include preliminary figures for December.

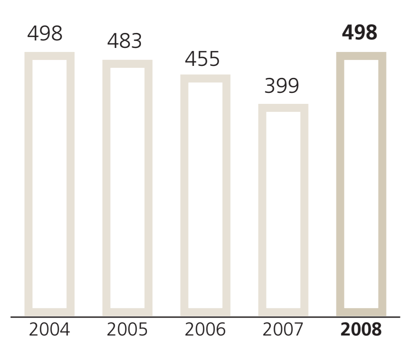
**Capital Expenditures**
*(Canadian dollars in millions)*




**Total Assets**
*December 31, 2008*
*(Canadian dollars in millions)*




**Net Income**
*(Canadian dollars in millions)*



# Letter from the Chair

**James Arnett**
Chair of the Board of Directors

The year 2008 was a good year at Hydro One Inc. Overall, I believe that the Company and its management performed well in carrying out its mandate and that the Board of Directors performed well in its oversight role.

Fundamental to our role is to ensure that Hydro One acts as a commercial enterprise and, to that end, that we build a commercial culture that increases enterprise value while we provide safe, reliable and cost-effective transmission and distribution of electricity to Ontario's electricity users.

A key accomplishment was the development and approval of a new Strategic Plan for the Company. This plan sets forth a vision of Hydro One being the leading electricity delivery company in North America. It highlights the importance of continuous innovation to ensure a smart and flexible electricity grid. I believe it has positioned the Company to rise to the challenge of the *Green Energy and Green Economy Act*, which sets out our shareholder's vision of accommodating greatly increased renewable and distributed generation.

Another significant accomplishment was the September approval by the Ontario Energy Board of our application for Leave-to-Construct our Bruce to Milton Transmission Reinforcement Project. In addition, the Company signed landmark protocol agreements with two First Nations communities and the Métis of Ontario that will facilitate their continued involvement in the Project's regulatory process and in our ultimate success with the Project.

Hydro One maintained strong credit ratings through the year which reflects prudent management of the Company's affairs. Maintaining credit quality is critical as it facilitates borrowing which will be increasingly required to finance major expansion programs in the years to come. Hydro One currently enjoys very good access to the debt capital markets and we continued to finance on a cost-effective basis during the very difficult market conditions in the last quarter of 2008. The steep decline in financial markets also had a significant impact on the Company's pension plan, an area that will continue to receive close scrutiny by the Board in 2009.

As to financial metrics, the Company's net income of $498 million was higher by $99 million, or 25%, compared to 2007 results. We paid $259 million in dividends to our shareholder, the Province of Ontario, and $145 million in payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation, also owned by the Province of Ontario.

We continue to strive for greater productivity through efficiency improvements. The Board of Directors devoted a lot of time and attention to the Cornerstone project, which is a staged process for not only replacing end-of-life Information Technology systems but also transforming our business processes. The first phase was completed in 2008 and will yield significant improvements in the period 2009–2015.

A key element of the Board's oversight responsibility is to ensure the alignment of the organization with the mandate and goals of the Company. Our monitoring includes a corporate scorecard and relatively modest short-term incentives based upon performance measures derived from that corporate scorecard. I am pleased to report that, with one exception, all such performance measures were met or exceeded. The exception related to the fatality of a worker for which, of course, we have zero tolerance.

Satisfying our customers is a key strategic goal of our Company and its employees. The Board of Directors monitors this closely, and we were very encouraged by the 86% customer satisfaction results for the year.

Overall, as I said, we had a good year, and I want to thank management and all of our employees, and all my colleagues on the Board of Directors, for their tireless efforts on behalf of both our customers and our shareholder, the Province of Ontario.

**James Arnett**
Chair of the Board of Directors
Hydro One Inc.

Hydro One maintained strong credit ratings through the year which reflects prudent management of the Company's affairs.

# Letter from the President and CEO

**Laura Formusa**
President and Chief Executive Officer

What value does our Company provide to the people of Ontario? How do we best contribute to making Ontario a great place to live and work? As stewards of the province's electricity grid, our core role is to provide safe, reliable and cost-effective electricity transmission and distribution. But how we do this in the 21st century is critical. This is a time of tremendous change, opportunity and transformation in Ontario and across North America. The challenges facing Ontario's grid are new and many. Imagine rebuilding and improving an aircraft in midflight. Our system requires massive, intelligent investment to continue to meet Ontario's needs. We believe, to deliver the most value possible to our shareholder and our customers, Hydro One must lead, not follow. By embracing technology and innovation, by forging intelligent partnerships and renewing our people as well as our infrastructure, we will deliver not only electricity but real value to Ontario.

2008 was a year of renewal and revitalization for Hydro One. We moved forward on multiple large-scale infrastructure projects. We honed our human resource strategy to ensure that we have the right people in place to continue our work for years to come.

Early in 2008, work was completed on a tunnel under the busy streets of Toronto to improve reliability to the city. We continued our work with Hydro Québec TransÉnergie Inc. to build a new high-voltage link between Québec and Ontario. This link will improve Ontario's supply of clean, renewable electricity. Leave-to-Construct, contingent on environmental assessment approval, was received from the Ontario Energy Board for the 180-km Bruce to Milton Transmission Reinforcement Project connecting renewable and nuclear power from the Bruce area to where communities and businesses need it in southern Ontario. This is one of the largest transmission projects underway in North America and we expect to bring the line into service by the end of 2011.

The Province of Ontario's smart meter initiative – to have a smart meter in every home and business by 2010 – sparked Hydro One to undertake the largest smart meter deployment initiative in North America. The installation of the meters is just a fraction of the job. The supporting communications network that Hydro One is establishing is an important step in realizing the vision of a smart grid. A smart grid will transform our relationship with our customers, allow our customers to make the smartest use of electricity and enable the connection of renewable sources of power generation like solar, wind and biomass – key to the Province's goal of increasing the amount of renewables in our system and decreasing our reliance on carbon-based fuels.

The grid of the past century was incredibly reliable at delivering power and it has served us well but it wasn't designed to allow power to flow in a diversity of directions. And in order for Hydro One to connect small, renewable sources of generation, we need the two-way flow capabilities that a smart grid will bring. Hydro One is collaborating with industry peers, universities and research organizations to transform our system.

As an employer, we are grappling with an enormous human resource challenge. Similar to others in the energy industry, many of our most skilled and experienced employees will be eligible to retire in the next few years. At all levels of our Company there is an urgent need for renewal. We are taking a proactive and aggressive approach to ensure we have the intellectual and physical human resources we need. Apprentices, technicians, technologists and engineers are joining our Company at a rate unseen in two decades. Partnerships with colleges, universities and First Nations and Métis peoples will provide us with a diversity of prospective employees.

The value that we deliver to our shareholder and the people of Ontario is real and tangible. We are listening to our customers and renewing our electricity system to enable clean and renewable sources of electricity. As we make prudent and intelligent investments in Ontario's electricity grid, I'm confident that Hydro One will continue to deliver on our promise of value in many different ways in the years ahead.

**Laura Formusa**
President and Chief Executive Officer
Hydro One Inc.

By embracing technology and innovation, by forging intelligent partnerships and renewing our people as well as our infrastructure, we will deliver not only electricity but real value to Ontario.

# Delivering value to you and your family on movie night.

A little more than a dime* is the cost of purchasing the electricity and delivering it to your house to power your television for a movie night with your family. We know you value the time you spend with your family and we operate our system so you can count on electricity to be there when you need it and for it to be affordable when it gets there.

## JUST 43% OF YOUR BILL

The towers, hydro poles, transmission lines and transformers that deliver electricity from widely dispersed generation sources to homes in Ontario account for about 43% of the average electricity bill. So, if a kilowatt-hour of electricity costs around 10 cents, Hydro One's portion of that cost is four cents – less than a nickel.

At Hydro One, we know that safe and reliable electricity is vital for Ontario. We also know that delivering affordable electricity is important to every single Ontarian.

Electricity is essential, not only for a night in with the family but for so many things in our lives. Safe, reliable and affordable electricity pours your first cup of coffee in the morning, powers your computer at work and helps cook dinner for your family.

As the stewards of both the province's transmission system and its largest distribution system, we are committed to making sure that people, communities and businesses in Ontario always have access to safe, affordable electricity.

* Based on a 40" HD LCD TV with an average consumption of 268.3 kWh/year with six hours of use per day at 13.9 cents per kWh (which includes the cost of electricity and delivery).

## 1,400 WORKERS
## 250,000 RELIEVED CUSTOMERS

1,400 workers made it a Happy New Year for more than 250,000 customers who lost power during a fierce winter storm that hit Ontario in the closing days of 2008. Working around the clock while battling gale-force winds and frigid temperatures, Hydro One crews together with the help of a number of other utilities restored power to more than 90% of affected customers by December 31, 2008. The massive response demonstrates our commitment to reliable service and the dedication and professionalism of our people.

## SERVING YOU BETTER

Our overall residential and small business customer satisfaction scores increased to 86% satisfied in 2008 from 82% satisfied in 2007. These results recognize the positive impact of our reliability programs and our increased involvement in our communities.

## WE'RE MAKING OUR RED AND WHITE TRUCKS A LOT GREENER

In 2008, we began a comprehensive energy audit of all Hydro One trucks and utility vehicles. This was a first step in building a more environmentally conscious fleet. As part of an internal program called Greener Choices, Hydro One is raising environmental awareness within the Company and taking steps towards more sustainable vehicles and facilities.

# Powering Ontario's future.

Ontario's electricity system was established just over a century ago. It expanded rapidly in the boom years that followed the Second World War until the 1970s and made an essential contribution to the province's growth and prosperity. The system's durability is a testament to the vision and hard work of its builders, but we can no longer depend upon their legacy. As the stewards of the province's electricity transmission system, it is now our turn to ensure that Ontario has a system that will continue to meet its needs in the 21st century.

We are currently engaged in Hydro One's largest infrastructure renewal program in more than two decades. Our efforts go far beyond just replacing old equipment. Instead, we are redesigning and rebuilding our system to enhance performance, relieve internal congestion points and incorporate the opportunities offered by new, more sustainable sources of electricity and a range of evolving technologies.

## BUILDING A CROSS-BORDER CONNECTION

Hydro One and Hydro-Québec TransÉnergie Inc. are building a 1,250 MW interconnection between our respective transmission systems. Hydro One's investment in this connection will increase Ontario's access to competitively priced, renewable hydro-electric energy from Québec. We expect to have our components completed in 2009 and the interconnection in operation in 2010.

## 3,000
### REASONS TO INTRODUCE BRUCE TO MILTON

As Ontario's population continues to grow, Hydro One has to ensure that Ontarians have the power they need to light their homes and businesses. To meet these expanding energy needs, Hydro One is building a clean-air corridor that will transmit 3,000 MW of nuclear and renewable electricity from the Bruce Peninsula to a switching station in Milton. In 2008, we received vital approvals from the Ontario Energy Board and plan to have the line in operation by 2011.

## ONE PROVINCE
## 10 YEARS
## 150+ PROJECTS

Over the next 10 years, Hydro One plans to initiate more than 150 major infrastructure projects across the province. Unprecedented in terms of both scale and scope, this investment is essential to the continued viability of our electricity system and to Ontario's long-term future.

# MODERNIZING MIDTOWN

The midtown power corridor, which serves heavily populated neighbourhoods in Toronto's busy core, was originally built in the 1920s, and uses underground cable that was first laid in the 1950s. Hydro One and Toronto Hydro have jointly agreed that the 115-kilovolt-transmission infrastructure that serves the area needs to be refurbished. This need has been confirmed by the Ontario Power Authority and the Ontario Energy Board. The proposed refurbishment will improve service reliability for residents of the largest city in Ontario and currently has an in-service date of May 2012.

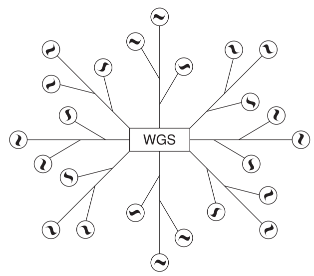
# Smart meter. Smart grid. Smart system.

Imagine if the telephone only allowed you to talk, but not to listen. The drawbacks are obvious; yet this is essentially how the province's electricity system works. It is a one-way operation that reflects the technology that existed when it was built. After years of great service, our current system needs major upgrades to accommodate all the new ways that electricity can be generated, monitored and managed. That's why Hydro One and the Province of Ontario are moving toward what is called a "smart grid."

The smart grid will help change the delivery of electricity from a one-way, point-to-point system into a thriving network in which energy and information are exchanged among electricity users, transmitters and generators. Incorporating communications and sophisticated operating and control technologies, the smart grid will allow small distributed generators, like a farmer with a bio-fuel generator, to access the grid in order to both draw and contribute electricity. The smart grid will also enable customers to better control smart appliances in homes and businesses; it will support the networking of energy management systems in smart buildings, and will help consumers manage energy use and costs more effectively by giving them access to time-of-use electricity pricing as it comes into effect.

## A POWERHOUSE HOME IMPROVEMENT PILOT

To encourage households across Ontario to tap into the power of renewable energy, the PowerHouse pilot program offered zero-interest loans or rebates on approved renewable technologies for the home. PowerHouse was offered by Hydro One Networks, Hydro One Brampton and Enersource Hydro Mississauga, and funded by the Ontario Ministry of Energy and Infrastructure. The program provided loans, rebates and information on solar water-heating systems, photovoltaic (PV) solar power systems, geothermal systems and small wind systems.




= 10 MW Wind Farm

Called a star system because the various branches resemble the rays of a star, this schematic shows 24 x 10-megawatt generators connected to a central transformer.

## WE'RE DEVELOPING OUR OWN STAR SYSTEM...

Connecting small generators to Ontario's electricity grid is a priority for Hydro One, but it is also a challenge. Our existing distribution system is set up to send electricity, not to receive it. To address this challenge, our engineers are developing solutions that are cost-effective, technically proven and can be deployed quickly – solutions like the star system. The star system is a sub-network of dedicated power lines that would gather electricity from a cluster of small generators and deliver it to a transformer station, which would convey the power to the larger grid.

## ...AND OUR OWN SOLAR SYSTEM

Solar power is potentially the cleanest, most sustainable form of power, but it needs to be harnessed, stored and distributed in ways that are economically and technically viable. Responding to the provincial government's call for the development of renewable energy, Hydro One initiated discussions with Ontario Centres of Excellence, the leading research-to-commercialization incubator in Ontario. These discussions ultimately led to the launch of a multi-million-dollar project aimed at developing technologies for integrating large-scale solar farms into electricity transmission and distribution systems.


## BY 2010 WE'LL BE 1.4 MILLION TIMES SMARTER

Hydro One installed more than 780,000 smart meters in Ontario by the end of 2008. The Company is on track to install 1.4 million smart meters in homes and small businesses by 2010. Smart meters are an essential part of building a smart grid for Ontario. Teamed with time-of-use pricing, smart meters will play a key role in establishing a culture of conservation across the province and achieving significant reductions in peak electricity demand through load shifting.

# You've heard of people power?
# We're getting more of that too.

Canada's baby boomers, the generation that has long provided our industry with talented, innovative employees, are starting to reach retirement age. By our estimates, we expect 30% of our workforce to retire in the next few years.

Simply put, the greying of our workforce precipitates the need for a proactive workforce renewal program. These are our most experienced employees, people with years of experience that they are eager to share with a new generation. We need to maximize the skill sets of two generations simultaneously and in a way that responds to their very different approaches to their work and careers. Fortunately, we have a plan.

Hydro One is building a new human resources infrastructure that includes apprenticeship programs, partnerships with community colleges and universities, and special outreach initiatives to schools, high schools and First Nations and Métis communities.

### HYDRO ONE IS GOING
## BACK TO SCHOOL

To help build its workforce for the future, Hydro One has partnered with Mohawk College in Hamilton, Algonquin College in Ottawa, Northern College in Timmins and Georgian College in Barrie to develop curricula for future employees of the electricity sector. We have also joined with Ryerson University to create a work-study program aimed at developing career-ready electrical power engineers.

Hydro One's proactive approach not only raises its profile among potential employees, it encourages talented young people to consider careers in the trades and the industrial sector.

## WE'VE BEEN
# KNIGHTED FOR DIVERSITY

For the second year in a row, Hydro One was named one of the top 10 Canadian companies in *Corporate Knights* magazine's annual Leadership Diversity Index. Out of 150 companies analyzed, Hydro One tied for sixth place. Our role within the province's electricity system demands a diverse workforce with a wide variety of education, skills, talent and training. Our repeat ranking demonstrates our commitment to reflect the communities and customers we serve.

Canadian-based *Corporate Knights* is the world's largest circulation magazine with an explicit focus on corporate responsibility.

Corporate Knights
THE CANADIAN MAGAZINE FOR RESPONSIBLE BUSINESS
corporateknights.ca

## A POWERFUL AGREEMENT

On September 30, 2008, Hydro One entered into a historic agreement with the Métis Nation of Ontario (MNO). The Engagement Protocol on Hydro One's Bruce-Milton transmission line will make it easier for the MNO to inform Métis citizens living throughout the region about the project. It will also enable the MNO to participate in the Bruce-Milton line's upcoming environmental assessment, and establishes a joint MNO-Hydro One committee to support this work. The agreement demonstrates the importance we place on building relationships with First Nations and Métis peoples.

# PUTTING POWER INTO PLAY

Hydro One recognizes that health, fitness and fun provide Ontario with another vital source of renewable energy. Now in its second year, the PowerPlay grants program helps build and refurbish children's outdoor and active play facilities in Ontario communities served by Hydro One. The program offers grants of up to $25,000 that can be used toward new facilities and the renovation of existing facilities that are open to the community at large. In 2008, we donated more than $1 million to 100 communities as part of the program.

# Hydro One Senior Management

**Laura Formusa**
President and
Chief Executive Officer,
Hydro One Inc.

**Joe Agostino**
General Counsel

**Myles D'Arcey**
Senior Vice-President,
Customer Operations

**Steve Dorey**
Vice-President,
External Relations

**John Fraser**
Vice-President,
Internal Audit and
Chief Risk Officer

**Tom Goldie**
Senior Vice-President,
Corporate Services

**Peter Gregg**
Vice-President,
Corporate and
Regulatory Affairs

**Rick Kellestine**
Vice-President and
Executive Advisor

**Carmine Marcello**
Vice-President,
Corporate Projects

**Nairn McQueen**
Vice-President,
Engineering and
Construction Services

**Geoff Ogram**
Vice-President,
Asset Management

**Wayne Smith**
Vice-President,
Grid Operations

**Ali Suleman**
Vice-President
and Treasurer

**Beth Summers***
Executive Vice-President
and Chief Financial Officer
*Resigned February 12, 2009*

* Sandy Struthers replaced Beth Summers as Chief Financial Officer in February 2009.

# Management's Discussion and Analysis

We prepare our financial statements in Canadian dollars and in accordance with accounting principles generally accepted in Canada. The following discussion is based upon our Consolidated Financial Statements for the years ended December 31, 2008 and 2007.

## OVERVIEW

We are wholly owned by the Province of Ontario (the Province), and our Transmission and Distribution Businesses are regulated by the Ontario Energy Board (OEB). Our mandate is to provide the safe, reliable and cost-effective transmission and distribution of electricity to Ontario electricity users. We operate as a commercial enterprise with an independent Board of Directors. Our strategy is driven by our values: safety, stewardship, excellence and innovation. We work in an environment that can be hazardous for both workers and the public, where safety is of the utmost importance. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing these assets in a manner that is commercial and transparent and values our customers. We strive for excellence by being trained, prepared and equipped to deliver high quality and affordable service. We value innovation because it allows us to find better ways to meet the needs of our customers. In 2008, we continued our focus on our core businesses, substantially maintained and improved our performance in various key areas of the business, and made important contributions to the rebuilding of Ontario's core infrastructure.

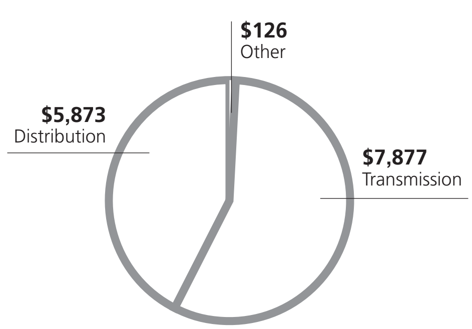
### Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our company. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre. Our system operates over relatively long distances and links major sources of generation to transmission stations and larger area load centres. In 2008, we earned total transmission revenues of $1,212 million primarily by transmitting approximately 149 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and is linked to five adjoining jurisdictions through 26 interconnections. Through these interconnections, we can accommodate imports of about 4,000 MW and exports of approximately 5,800 MW of electricity. In terms of assets, our Transmission Business is our largest business segment, representing approximately 57% of our total assets.

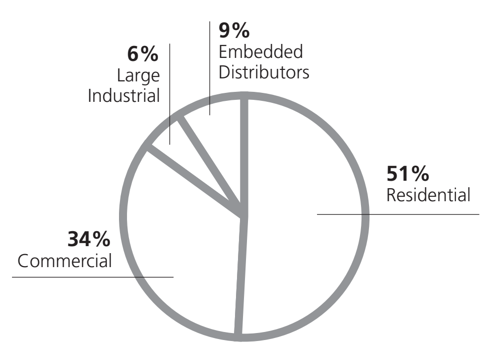
### Distribution

Our distribution system is the largest in Ontario and spans roughly 75% of the province, serving approximately 1.3 million rural and urban customers, local distribution companies (LDCs) connected to the distribution system, and 47 large industrial customers. We also operate small, regulated generation and distribution systems in a number of remote communities across Northern Ontario that are not connected to Ontario's electricity grid. We earned total distribution revenues in 2008 of $3,334 million. As illustrated in the accompanying chart, about half of our distribution revenues are earned from our residential customers.

**Total Assets**
*December 31, 2008 (Cdn $ millions)*




**2008 Distribution Revenues**



### Other

Our other business segment contributed revenues of $51 million in 2008 and has assets of about $126 million, which constitute slightly less than 1% of our total assets. This segment primarily represents the operations of our wholly owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements.

### Our Strategy

Our corporate strategy is based on our mandate, vision and values. Our vision is to be the leading electricity delivery company in North America. Our values include safety, stewardship, excellence and innovation. We are committed to providing innovation and leadership in renewing Ontario's power grid. To that end, we have identified eight strategic objectives:

*Creating an injury-free workplace and maintaining public safety:* We continue to focus on creating a passion for preventing workplace injuries and ensuring public safety.

*Satisfying our customers:* In order to satisfy our customers, we focus on the reliability and quality of power delivery, delivering on our commitments we make to our customers, providing value for money, partnering with communities we serve, communicating effectively with our customers and building our reputation as a trusted steward of provincial transmission and distribution assets.

*Continuous innovation:* We are committed to identifying and providing innovative solutions that improve the reliability and efficiency of electricity delivery and allow our customers more capability to manage their power costs. We will invest in distribution and transmission infrastructure to accommodate new distributed generation.

*Building and maintaining reliable, cost-effective power delivery systems:* Our transmission strategy is to provide a robust and reliable provincial grid that can accommodate the province's emerging generation profile and demand requirements. Our distribution strategy entails providing greater visibility, increased control and improved customer service through smart grid technology, while continuing to provide reliable service at an affordable cost over a wide range of geography and climate.

*Protecting and sustaining the environment:* We play a central role in reducing Ontario's carbon footprint, both through the delivery of clean and renewable energy and through measures that allow our consumers to manage and reduce their energy use.

*Skill development and knowledge retention:* We are addressing our demographic challenges through a comprehensive program of recruitment, training in core competencies, staff development and knowledge transfer.

*Maintenance of a commercial culture that increases value for our shareholder:* We are committed to operating on a financially sustainable basis and to increasing the value of our assets.

*Productivity improvement and cost-effectiveness:* To achieve our vision as the leading electricity delivery company in North America, we constantly strive to be the most productive through efficiency improvements and effective management of costs. Our goal is to be top quartile in key unit cost metrics relative to our North American electricity industry peer group.

We recognize the pivotal role innovation will play in building a smart electricity grid that supports high quality jobs and a clean environment for Ontario. We are committed to becoming the industry leader in putting innovative solutions to work for the well-being of the Ontario economy and its citizens.

## Performance Measures and Targets

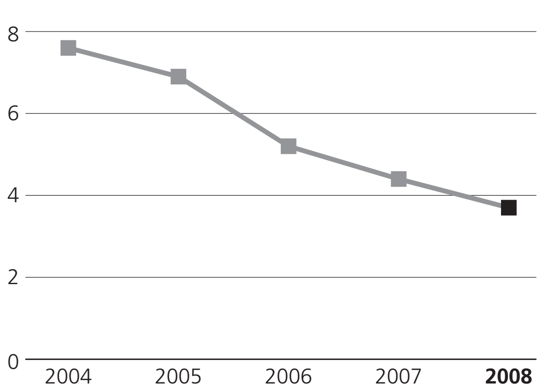
We measure and target our performance to ensure that we recognize the needs of all of our key stakeholders. Overall, we met our challenging 2008 objectives, improving in a number of areas over 2007, and are moving towards achieving our strategic goals.

The potentially hazardous nature of our business requires a strong focus on safety. Our people underpin everything we do, and as a result, their safety is paramount. Overall we met our challenging 2008 objectives, we did however experience an employee fatality at one of our construction sites. This unfortunate occurrence is a painful reminder of the workplace hazards we deal with on a daily basis. Our goal continues to be the elimination of serious injuries. Accordingly, we measure our Serious Incident Rate to identify possible situations that may increase the risk of injury. These incidents include electrical contacts, preventable motor vehicle accidents and work equipment operations. As shown in the accompanying chart, we had 3.7 serious incidents per million hours worked in 2008, which is 16% lower than 2007, 29% lower than 2006, and 46% lower than 2005. Going forward, we will continue to strengthen our already strong safety culture and ensure that all staff are appropriately trained and equipped for the hazards they will encounter and the work they will do. This involves continued coaching and mentoring, building on our learning and experience over the last few years, and achieving a better understanding of human behaviour to provide critical insight into injury prevention and performance improvement. Planned initiatives include utilizing the best knowledge and science for workplace improvement and risk reduction, ensuring employee development and competence at all levels, cultivating formal and informal learning and teaching and developing leaders and champions.

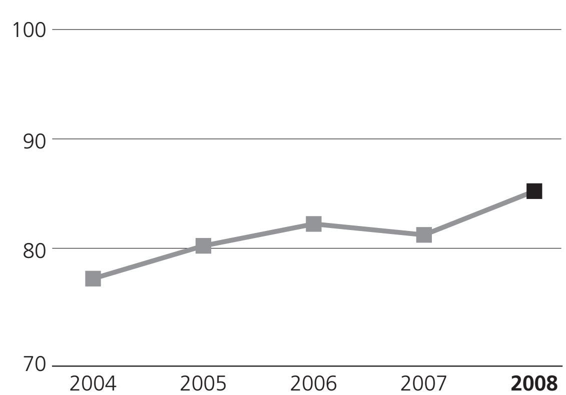
Customer satisfaction is also vital to our success. In 2008, we exceeded our overall target for customer satisfaction levels. As shown in the accompanying chart, our Residential and Small Business Customer Satisfaction Survey results improved from 82% to 86% satisfied, a 5% increase. We also continue to be conscious of the needs of our large transmission customers and survey results show an overall satisfaction level of 92%, slightly lower than our 2007 results. In 2008, we achieved an overall increase in our generator customer satisfaction results. Within this category, we improved our satisfaction results for transmission connected and distribution connected generators by 4% and 7%, respectively, compared to 2007. In 2009, we will continue to focus on improvements to customers' satisfaction by making our customers a focus in all planning discussions, effectively communicating and coordinating across all lines of business and implementing targeted strategies designed to meet the unique needs of our customer segments.

We aim to retain and build public confidence and trust in our operations, as stewards of the province's electricity grid. In 2008, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for our customers in a safe, reliable and efficient fashion. We are conscious that businesses of all sizes require reliable service and consequently, we focus on achieving top-quartile reliability in relation to other comparable systems. In 2008, we met our annual reliability targets, remaining consistent with our 2007 achievements. As stewards of significant electricity assets, we also implemented a number of environmental initiatives including the launch of our Greener Choices initiative aimed at instilling environmental and energy awareness and action within our corporate culture. Through this program, we focused on our fleet utilization with the aim to reduce carbon emissions and implemented energy efficiency audits and improvements at a number

**Serious Incident Rate**
*(Per million hours worked)*




**Residential and Small Business Customer Satisfaction**
*(Percentage)*



of our facilities. Our continued commitment to the people of Ontario has been recognized by *Corporate Knights*, an independent media company focused on promoting and reinforcing sustainable development in Canada. We were named one of Canada's Top 50 Corporate Citizens, ranking first among utilities. The ranking recognized us as having successfully managed our specific environmental, social and governance performance. In addition, *Corporate Knights* selected us as one of Canada's Top 10 Most Diverse Companies, based on achieving the greatest visible minority and female representation among Board members and senior executives.

Given the retirement profile of our employees, we are entering a period of significant demographic change. This change is taking place across the electricity sector and we have taken a leadership role to address the transition. We have embarked on an aggressive workforce renewal program. In addition to our partnership with four community colleges of applied art and technology, we strengthened our association with various Canadian universities as part of a comprehensive strategy to meet our staffing needs well into the future. An example of this association is our partnership with Ryerson University, to create a work-study program aimed at developing career-ready power engineers. The Hydro One Fellowship Program gives selected Ryerson electrical and computer engineering students the opportunity to spend summers with our company, putting their skills to work while benefiting from additional hands-on training.

In 2008, we remained focused on workplace productivity by monitoring a number of business productivity initiatives, including the achievement of our smart meter installations target, the release and implementation of work program commitments, and improved coordination of planned outages to carry out our capital and maintenance programs. Our continued focus on productivity contributes to the cost-effectiveness of our work programs, and enhances our financial performance. In 2008, we exceeded our operating results target. Our financial performance and the business environment in which we operate are taken into consideration in the setting of both our short-term and long-term credit ratings. In June 2008, Standard & Poor's Rating Services Inc. (S&P) upgraded our long-term debt rating to "A+" from "A", and affirmed our "A-1" short-term rating. Our outlook has been revised to stable from positive following the rating upgrade. This rating action reflects a stable energy policy in Ontario and consistent, independent regulation. To date, we have been able to successfully secure sufficient and cost-effective debt financing in the face of current economic conditions. Our current credit ratings facilitate ongoing access to debt markets at a reasonable cost to fund the infrastructure requirements of our system.

## REGULATION

Our electricity Transmission and Distribution Businesses are licensed and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the uniform province-wide transmission rates approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our Distribution Business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers to recover the blended cost of electricity over time based on a two-tiered electricity pricing structure with seasonal consumption thresholds. Unexpected shortfalls or overpayments associated with the RPP are financed by the Ontario Power Authority (OPA). Prices are reviewed every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period. Customers who are not eligible for the RPP, and wholesale customers, pay the market price for electricity adjusted for the difference between market prices and prices paid to generators under the *Electricity Restructuring Act, 2004.* The Independent Electricity System Operator (IESO) is responsible for overseeing and operating the wholesale market, as well as ensuring the reliability of the integrated power system.

In addition to the oversight role of the OEB, and the market monitoring and coordination role of the IESO, the OPA was created through the *Electricity Restructuring Act, 2004* to ensure the long-term supply of electricity, facilitate load management and conservation, and assist with the stability of rates for RPP customers, among others. As part of its mandate, and consistent with the Province's direction regarding supply mix, the OPA developed the Integrated Power System Plan (IPSP), which was submitted for OEB review and approval on August 29, 2007. On September 17, 2008, the Province directed the OPA to review a portion of its proposed IPSP focusing on renewable energy and conservation. The OPA is expected to file a revised IPSP by mid-2009.

The OPA is also responsible for coordinating the delivery and funding of conservation and demand management (CDM) programs. This coordination furthers initiatives undertaken by individual LDCs, including the Distribution Businesses of our subsidiaries Hydro One Networks Inc. (Hydro One Networks) and Hydro One Brampton Networks Inc. (Hydro One Brampton), as a result of OEB program requirements associated with the third phase Market Adjusted Rate of Return (MARR). Our CDM programs funded through the OPA in 2008 amounted to approximately $8 million compared to $6 million in 2007. In 2008 we completed our OEB program requirements associated with the third phase of MARR, which amounted to approximately $43 million since 2005. The overall goal of CDM programs, under the IPSP, is to reduce provincial demand by 6,300 MW by 2025.

The *Energy Conservation Responsibility Act, 2006* furthers the broad objectives of CDM by providing the framework for the installation of smart meters in all homes and small businesses in Ontario by December 31, 2010. These meters will be capable of measuring and reporting usage over predetermined periods, being read remotely, and when combined with communications systems, will be capable of providing customers with access to information about their consumption. In 2007, the Province appointed the IESO as the smart meter entity that will oversee the collection and management of data. LDCs, including our Distribution Businesses, are accountable for the deployment of smart meter infrastructure and related technology for communications to meet minimum requirements as defined in regulations, as well as the implementation of time of use rates that are presently voluntary. In 2008, we deployed over 496,000 smart meters, exceeding our 2008 target of approximately 405,000 meters, and bringing the cumulative number of installations under our Smart Meter Program to more than 780,000. We are continuing the deployment of smart meters and the associated communications network (see Future Capital Expenditures).

**Transmission Rates**

The IESO facilitates payments to us based on the Ontario Uniform Transmission Rates (UTRs) approved by the OEB for all transmitters across Ontario.

As part of an OEB-initiated proceeding to review our transmission rates and revenue requirements for 2006, 2007, and 2008 based on cost of service regulation, in 2006 the OEB announced its decision to apply an earnings sharing mechanism (ESM) to equally share, between our shareholder and customers, any transmission earnings in excess of the approved rate of return of 9.88%. Consequently, 50% of our excess earnings recovered from customers in 2006 were deferred as a regulatory liability. Also, on March 30, 2007, the OEB issued a decision approving the concept of establishing a new revenue difference deferral account (RDDA) to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year, for the period commencing January 1, 2007.

On August 16, 2007, the OEB issued its decision in respect of our 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, showed confidence in our work programs by approving all of our operating and capital expenditures for 2007 and 2008. However, the decision resulted in an estimated 8% annual reduction in transmission rates primarily due to a reduction in the approved return on equity from 9.88% to 8.35%, based on a formula used by the OEB in the regulation of LDCs. Further, the OEB approved final amounts and disposition treatments for certain regulatory accounts including the RDDA, ESM and export and wheeling fees liabilities, as well as the transmission market ready regulatory asset. The RDDA and ESM were refunded to customers over the 14-month period from November 1, 2007 to December 31, 2008, while the export and wheeling fees liability and transmission market ready regulatory asset is factored into rates over the four-year period ending December 31, 2010.

As part of a joint proceeding involving all transmitters in Ontario on October 17, 2007, the OEB approved UTRs for implementation on November 1, 2007, through to December 31, 2008. The new rates reflected the approved changes to our revenue requirement and charge determinants. The new rates resulted in an approximate 1% decrease in the average customer's total electricity bill.

On May 30, 2008, we submitted an application to the OEB to adjust UTRs for our Transmission Business effective January 1, 2009. On August 28, 2008, the OEB approved our application reflecting the 2008 OEB-approved revenue requirement given the completion of repayment to customers of the ESM and RDDA to customers as at December 31, 2008. This resulted in an average increase of approximately 9% in our revenue requirement allocation from UTRs, and an approximate 1% increase on an average customer's total bill.

To achieve the necessary funding in support of required infrastructure, we submitted a transmission rate application for 2009 to 2010 rates in September 2008. The application seeks OEB approval for revenue requirements of approximately $1,233 million and $1,341 million, based on a return on equity of 8.53% and 9.35% for 2009 and 2010, respectively. This represents an estimated increase on an average customer's total bill of approximately 0.5% and 1% in 2009 and 2010, respectively. The oral hearing is scheduled to commence on February 19, 2009, and a decision is anticipated in the summer of 2009.

### Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for approved distribution rates, purchased power costs, and other approved regulatory charges.

*Distribution Tariffs*

In 2006, the OEB initiated a process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process included a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. Our subsidiaries, Hydro One Networks and Hydro One Brampton, applied for distribution rate adjustments in February 2007, based on an OEB-approved formula that considers inflation and efficiency targets. In April 2007, the OEB approved our submissions and the revised rates were implemented effective May 1, 2007.

Our subsidiary, Hydro One Networks, submitted the revenue requirement portion of its 2008 cost of service application in accordance with the OEB's multi-year distribution rate-setting plan in 2007. This application sought the approval of a revenue requirement of $1,067 million based on a rate of return of 8.64% for 2008. We requested a distribution rate increase amounting to a net average increase of less than 1% on the average customer's total bill. The application included a plan to reduce the number of customer rate classes and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes.

On December 18, 2008, the OEB issued a decision approving substantially all of our work program expenditures, effective May 1, 2008 and for implementation on February 1, 2009. The OEB also approved recovery of our smart meter expenditures made prior to the end of 2007, including those related to excess functionality. Subsequent expenditures will continue to be tracked in deferral accounts for future recovery. The decision approved the establishment of the Revenue Recovery Account (RRA) to record the revenue differential between existing distribution rates and new rates from May 1, 2008. The RRA will be recovered over a 27-month period, commencing February 1, 2009, and ending April 30, 2011. In addition, certain other regulatory accounts were approved for recovery over the same period.

In September 2008, the OEB finalized the third generation IRM formula, which adjusts rates by considering inflation, productivity targets, significant events outside the control of management and a capital adjustment mechanism to recover costs for new incremental capital coming in-service beyond a prescribed threshold. Our subsidiary, Hydro One Networks, filed its incentive regulation application for 2009 rates in late 2008. An update was submitted in January 2009 to reflect the impact of the 2008 distribution rate decision. The application seeks an approximate 4% increase in 2009 distribution rates, effective May 1, 2009. These increases are expected to impact an average residential customer's total bill by less than 1.5%, assuming non-distribution charges remain unchanged.

On November 1, 2007, our subsidiary Hydro One Brampton filed its application for 2008 rates on the basis of the OEB's cost of capital and second-generation IRM policies. On March 19, 2008, the OEB released its decision regarding the 2008 rate application approving our submission on the basis of its cost of capital and second-generation IRM policies. The revised rates, including the continuation of an amount of $0.67 cents per month per metered customer for smart meters, were approved with an implementation date of May 1, 2008. The overall impact on an average residential customer's total bill is a decrease of about 3%. On January 29, 2009, the OEB issued a letter proposing that the distribution rates of Hydro One Brampton be rebased in 2011.

On September 8, 2008, the OEB issued a letter acknowledging receipt of a 2009 cost of service distribution rate application submitted on August 29, 2008 for our subsidiary Hydro One Remote Communities Inc. The cost of service application proposes an increase of about $10 million over the 2006 approved revenue requirement as a result of increased fuel costs. The proposed average increase for customers is approximately 4%.

*Smart Meter Program*

In April 2007, as part of its decision regarding the 2007 distribution rate applications made by Hydro One Networks and Hydro One Brampton, the OEB approved an amount of $0.93 cents and $0.67 cents, respectively, per month per metered customer as a charge for smart meters, for implementation effective May 1, 2007.

On August 8, 2007, the OEB issued a decision on its combined proceeding to determine recoverability of expenditures incurred by distributors. Expenditures associated with the approved minimum functionality for advanced metering infrastructure incurred by our subsidiaries Hydro One Networks and Hydro One Brampton were approved for recovery. As a result of this decision, smart meter expenditures are no longer deferred as regulatory assets, and instead, are now classified as capital or are charged to results of operations. As part of the December 18, 2008 decision on Hydro One Networks' 2008 distribution rates, the OEB approved the continuance of the $0.93 cents per month charge per metered customer and inclusion of smart meter expenditures incurred up to December 31, 2007, in the 2008 rate base. Hydro One Brampton will bring its smart meter expenditures forward in its 2011 cost of service application.

## RESULTS OF OPERATIONS

### Revenues

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 | $ Change | % Change |
|---|---|---|---|---|
| Transmission | **1,212** | 1,242 | (30) | (2) |
| Distribution | **3,334** | 3,382 | (48) | (1) |
| Other | **51** | 31 | 20 | 65 |
| | **4,597** | 4,655 | (58) | (1) |
| Average annual Ontario 60-minute peak demand *(MW)*[1] | **21,820** | 22,988 | (1,168) | (5) |
| Distribution – units distributed to customers *(TWh)*[1] | **29.9** | 30.2 | (0.3) | (1) |

[1] System-related statistics include preliminary figures for December.

*Transmission*

Transmission revenues predominantly consist of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand, which is primarily influenced by weather and economic conditions. Transmission revenues also include minor amounts of ancillary revenues, which are primarily attributable to maintenance services provided to generators and secondary use of our land rights-of-way.

Our transmission revenues were lower by $30 million, or 2%, compared to 2007 mainly due to lower average monthly peak demands experienced during the year. While the average annual Ontario 60-minute peak demand was 1,168 MW lower, the overall related load was 14,019 MW lower than last year, resulting in lower revenues of $66 million. The impact of this load reduction was partially offset by higher revenues associated with exporting electricity to other jurisdictions (export and wheeling fees) of $21 million, higher ancillary transmission revenues of approximately $9 million due to easement payments received for secondary use of our land rights-of-way and increased metering upgrade work, and higher other revenues of $6 million primarily associated with regulatory accounts.

In addition, the OEB's August 16, 2007 transmission rate decision impacted our revenues. In its decision, the OEB approved all of our work program expenditure requirements, but reduced our rate of return on equity from 9.88% to 8.35%. The impact of the OEB's decision, which was effective January 1, 2007, was recognized at the decision date. As a result of the OEB's decision to reduce our rate of return, we experienced a reduction to our transmission revenues of $128 million compared to 2007. This impact was offset by adjustments to our earned revenue by the same amount, reflecting the fact that 2008 rates include a refund of amounts that were previously recorded as revenue reductions in the ESM in 2006 and the RDDA in 2007.

On August 28, 2008, the OEB approved our application to adjust UTRs, effective January 1, 2009, to reflect the 2008 OEB-approved revenue requirement given the completion of repayment of the ESM and RDDA to customers.

*Distribution*

Distribution revenues include our distribution tariff, which is based on OEB-approved rates, as well as amounts to recover the cost of purchased power used by our customers. Accordingly, distribution revenues are primarily influenced by our distribution rates, the amount of electricity we distribute, and the cost of purchased power. Distribution revenues also include a minor amount of ancillary distribution services revenues, such as fees related to the use of our poles by the telecommunications and cable television industries, and miscellaneous charges such as those for late payments.

Distribution revenues decreased by $48 million, or 1%, in 2008 compared to last year. This change includes the recovery of lower purchased power costs of $59 million as described below under "Purchased Power." In addition, revenues associated with the recovery of a distribution-related regulatory account ceased effective March 31, 2008, which resulted in a revenue reduction of $15 million. Lower energy consumption, resulting primarily from the milder weather experienced this year, reduced our distribution revenues by a further $6 million for the year.

Revenues for the year were also affected by the successful December 18, 2008 decision received on the distribution rate application of our subsidiary Hydro One Networks. In that decision, the OEB approved substantially all our work program expenditure requirements, including all of the smart meter expenditures up to December 31, 2007. Unrecorded amounts for smart meters in respect of 2008 will continue to be recorded in a regulatory asset account. The OEB's decision was effective May 1, 2008 and new customer rates reflecting the decision are to be implemented on February 1, 2009.

As a result of the OEB decision, we recorded distribution revenues of $25 million in the fourth quarter. The new RRA regulatory asset was recorded to reflect these revenues not yet collected from customers. This account will be drawn down over the 27-month period from February 1, 2009 to April 30, 2011.

In addition, we experienced higher other revenues of $5 million during the year, as well as increased revenues of $2 million reflecting the OEB's previous decisions on both smart meters and tariff rates for our Distribution Businesses.

### Purchased Power

Purchased power costs incurred by our Distribution Business represent the cost of electricity delivered to customers within our distribution service territory and consist of the wholesale commodity cost of energy, the IESO wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's RPP, which consists of a two-tiered pricing structure with seasonal threshold amounts. Customers that are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*. A summary of the RPP affecting the two-year period of 2007 and 2008 is provided below.

### Summary of RPP

| | Tier Threshold (kWh/month) | | Tier Rates (Cents/kWh) | |
|---|---|---|---|---|
| Effective Date | Residential | Non-residential | First Tier | Second Tier |
| November 1, 2006 | 1,000 | 750 | 5.5 | 6.4 |
| May 1, 2007 | 600 | 750 | 5.3 | 6.2 |
| November 1, 2007 | 1,000 | 750 | 5.0 | 5.9 |
| May 1, 2008 | 600 | 750 | 5.0 | 5.9 |
| November 1, 2008 | 1,000 | 750 | 5.6 | 6.5 |

Purchased power costs decreased in 2008 by $59 million, or 3%, to $2,181 million compared to last year. The reduction in our purchased power costs was primarily due to lower demand for electricity of $43 million, lower costs associated with the OEB's RPP for residential and other eligible customers of $37 million, and the impact of lower charges levied by the IESO of $27 million, including transmission charges due to the OEB's August 16, 2007 transmission rate decision and wholesale market service charges. These reductions were partially offset by higher wholesale commodity prices for customers who are not eligible for the RPP of $48 million.

### Operation, Maintenance and Administration

Our operation, maintenance and administration costs are comprised primarily of labour, material, equipment and purchased services in support of the operation and maintenance of the transmission and distribution systems. These costs also include property taxes and payments in lieu thereof on our transmission and distribution lines, stations and buildings.

Operation, maintenance and administration costs for each of our three business segments were as follows:

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 | $ Change | % Change |
|---|---|---|---|---|
| Transmission | **387** | 415 | (28) | (7) |
| Distribution | **531** | 549 | (18) | (3) |
| Other | **47** | 31 | 16 | 52 |
| | **965** | 995 | (30) | (3) |

*Transmission*

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $28 million, or 7%, in 2008 compared to last year. Within our work programs, we continued our investments that support the safe and reliable operation of our transmission system that spans Ontario. Our work program expenditures were lower by $8 million compared to the prior year. These reductions were primarily attributable to lower expenditures on our planned station maintenance program, lower requirements for unplanned corrective maintenance, particularly for power equipment, lower forestry expenditures, and cost recoveries associated with an insurance settlement. The impact of these lower expenditures was partially offset by higher station-related planned corrective maintenance, particularly for power equipment, increased planned line maintenance and the impact of reassigning resources in support of our larger capital work program. In addition, we experienced a $20 million reduction in our expenditures incurred in support of the transmission system in 2008. The change included the impact of a one-time settlement credit associated with our transfer of pension assets to the Inergi LP (Inergi) pension plan following approval from the Financial Services Commission of Ontario in the first quarter of this year.

*Distribution*

Operation, maintenance and administration expenditures necessary to maintain our low-voltage distribution system decreased by $18 million, or 3%, compared to last year. Our work program expenditures increased by $3 million primarily resulting from expenditures required to respond to storm damage and trouble-call activity in particular following back-to-back storms in December and higher forestry expenditures, partially offset by lower planned line maintenance work and lower expenditures from the recognition, in the second quarter of 2007, of deferred smart meter expenditures originally incurred in 2005 and 2006. These expenditures were recognized as a result of the OEB's August 8, 2007 decision regarding the combined smart meter proceeding. Such expenditures are now recognized as incurred. We also experienced lower CDM program expenditures after satisfying OEB program spending requirements associated with accessing our third phase MARR rates. Our involvement in CDM programs is now primarily funded by the OPA. These programs include the Electricity Retrofit Incentive Program, the Peaksaver Program, and the Great Refrigerator Roundup Program. Offsetting these work expenditures were lower support costs of $21 million as compared to 2007, including the impact of the Inergi pension asset-transfer settlement in the first quarter of this year.

### Depreciation and Amortization

Depreciation and amortization expense increased by $27 million, or 5%, to $548 million this year. This increase was mainly attributable to increased depreciation expense related to the placement of new assets in service consistent with our ongoing capital work program, combined with an increase in costs to remove fixed assets associated with our capital projects. These increases were partially offset by the completion of amortization of a regulatory asset related to a distribution deferral account in the first quarter.

### Financing Charges

Financing charges decreased by $3 million, or 1%, to $292 million compared to last year. The reduction in financing charges was a result of an increase in interest capitalization on construction in progress reflecting higher construction in progress levels and higher interest capitalization rates, a $6 million interest credit related to the Inergi pension asset-transfer settlement and increased interest income reflecting a higher average level of investments. These reductions to financing charges were partially offset by an increase in interest expense reflecting a higher average level of debt.

### Provision for Payments in Lieu of Corporate Income Taxes

We make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC) in accordance with the *Electricity Act, 1998* and on the same basis as if we were subject to federal and provincial corporate taxes. In providing for payments in lieu of corporate income taxes relating to our regulated businesses, the taxes payable method is used, whereas the liability method is used in computing the tax provision for our unregulated businesses.

The provision for payments in lieu of corporate income taxes decreased by $92 million, or 45%, to $113 million compared to 2007. The year-over-year decrease results from a reduction in the statutory rate from 36.12% to 33.50% combined with the impact of increased temporary differences primarily relating to transmission amounts paid but not recognized for accounting such as the RDDA and higher capital cost allowance in excess of depreciation this year.

## Net Income

Net income of $498 million was higher by $99 million, or 25%, compared to 2007 results. This increase was primarily due to a reduction in our payments in lieu of corporate income taxes resulting from a lower effective tax rate and other net temporary differences. Also favourably impacting our net income were lower operation, maintenance and administration expenses including the pension asset-transfer settlement with our service provider Inergi following approval from the Financial Services Commission of Ontario in the first quarter. These impacts were partially offset by reduced transmission revenues resulting from lower average monthly peak demands and higher depreciation expense.

## Quarterly Results of Operations

The following table sets forth unaudited quarterly information for each of the eight quarters from March 31, 2007 through December 31, 2008. This information has been derived from our unaudited interim Consolidated Financial Statements which, in the opinion of our management, have been prepared on a basis consistent with the audited annual Consolidated Financial Statements and which 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 and should not be relied upon to predict our future performance.

| *(Canadian dollars in millions)* | | | | **2008** | | | | 2007 |
|---|---|---|---|---|---|---|---|---|
| *Quarter Ended* | **Dec. 31**[3] | **Sep. 30** | **Jun. 30** | **Mar. 31** | Dec. 31 | Sep. 30[2] | Jun. 30 | Mar. 31 |
| Total revenues[1] | **1,194** | **1,126** | **1,055** | **1,222** | 1,129 | 1,128 | 1,120 | 1,278 |
| Net income[1] | **131** | **112** | **98** | **157** | 90 | 67 | 93 | 149 |
| Net income to common shareholder[1] | **126** | **108** | **93** | **153** | 85 | 63 | 88 | 145 |

[1] The demand for electricity generally follows normal weather-related variations, and therefore our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

[2] As a result of the OEB's August 16, 2007 decision on Hydro One Networks' transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%. Revenues in the third quarter of 2007 reflect a $38 million reduction to revenues in respect of the period January 1, 2007 to August 16, 2007 and reflect the OEB's decision to reduce the rate of return and revise the capital structure of our Transmission Business.

[3] As a result of the OEB's December 18, 2008 decision on Hydro One Network's distribution rate application that was effective May 1, 2008, revenues in the fourth quarter of 2008 reflect a $25 million increase in respect of the period May 1, 2008 to December 31, 2008, reflecting growth in the work program requirements and investment in capital infrastructure.

## LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from operations, debt capital market borrowings and bank financing. These sources will be used to satisfy our capital resource requirements, which continue to include capital expenditures, servicing and repayment of our debt, payments related to our outsourcing arrangements, investing activities and dividends.

### Summary of Sources and Uses of Cash

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| **Operating activities** | **1,055** | 1,141 |
| **Financing activities** | | |
| Long-term debt issued | **1,050** | 700 |
| Long-term debt retired | **(540)** | (355) |
| Short-term notes payable | **–** | (60) |
| Dividends paid | **(259)** | (325) |
| **Investing activities** | | |
| Capital expenditures | **(1,284)** | (1,091) |
| **Other financing and investing activities** | **6** | 7 |
| **Net change in cash and cash equivalents** | **28** | 17 |

### Operating Activities

Net cash from operating activities decreased by $86 million, to $1,055 million, compared to 2007 results. The reduction is a result of the repayment to customers of amounts recorded in the RDDA, which was established following the transmission rate decision last year, offset by higher net income. In addition, we experienced higher working capital requirements, primarily associated with increases to our work program, partially offset by increases to our power purchase requirements.

### Financing Activities

Short-term liquidity is provided through funds from operations and our Commercial Paper Program, under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days. At December 31, 2008, we had no notes outstanding. Our Commercial Paper Program is supported by a $1,000 million committed revolving credit facility with a syndicate of banks maturing August 10, 2010. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements. At December 31, 2008, we had $6,125 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2009 and 2046. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note Program. The maximum authorized principal amount of medium-term notes issuable under this program until July 2009 is $2,500 million, of which $1,150 million was remaining and available as at December 31, 2008.

| Rating Agency | Rating<br>Short-term Debt | Long-term Debt |
|---|---|---|
| DBRS Limited | R-1 (middle) | A (high) |
| Moody's Investors Service Inc. | Prime-1 | Aa3 |
| S&P | A-1 | A+ |

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets and impose a negative pledge provision, subject to customary exceptions. The credit agreement related to our $1,000 million credit facility has no material adverse change clauses that could trigger default. However, the credit agreement requires that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreement also provides limitations that debt cannot exceed 75% of total capitalization and that debt issued by our subsidiaries cannot exceed 10% of the total book value of our assets. We are in compliance with all of these covenants and limitations.

During 2008, we issued $1,050 million in long-term debt under our Medium-Term Note Program. We also repaid $540 million in maturing long-term debt. In comparison, during 2007 we issued $700 million in long-term debt under our Medium-Term Note Program and we repaid $355 million in maturing long-term debt. In 2008, the amount of short term notes was unchanged year-over-year compared to a decrease of $60 million in 2007. Despite the ongoing turmoil in the financial markets, we were able to issue $500 million in long-term debt under our Medium-Term Note Program in the fourth quarter of 2008. A further $300 million was issued during the first month of 2009, leaving $850 million remaining issuable under the program as at February 11, 2009.

In 2008, we paid dividends to the Province in the amount of $259 million, consisting of $241 million in common dividends and $18 million in preferred dividends. In the comparative period, we paid common dividends of $307 million and preferred dividends of $18 million. In 2008, cash dividends per common share were $2,410 compared to $3,070 per common share in 2007. Cash dividends per preferred share were $1.375 in each of 2008 and 2007.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to the quarterly financial results are generally declared and paid in the immediately following quarter.

### Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows.

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 | $ Change | % Change |
|---|---|---|---|---|
| Transmission | **704** | 560 | 144 | 26 |
| Distribution | **570** | 511 | 59 | 12 |
| Other | **10** | 20 | (10) | (50) |
| | **1,284** | 1,091 | 193 | 18 |

*Transmission*

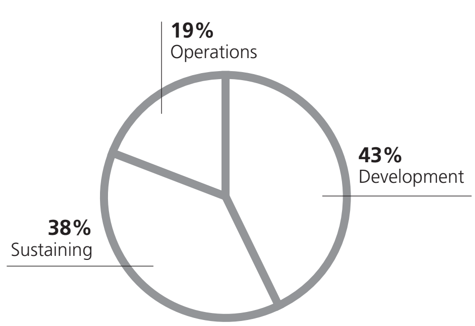
Transmission capital expenditures increased by $144 million in 2008 to $704 million, compared to 2007. Expenditures to expand and reinforce the transmission system were $302 million, representing an increase of $32 million over last year. This increase is attributable to a number of significant inter-area network upgrade projects to increase generation and local area supply projects to address growing loads, offset slightly by load and generation projects that were completed or nearing completion in the prior year. Inter-area network upgrades with significant expenditures in 2008 include the Bruce to Milton Transmission Reinforcement Project to connect redeveloped nuclear and new wind generation sources in the Huron-Grey-Bruce area, the South Western Ontario Capacitor Banks Project, which will expand transmission capacity in the Bruce area to enable the delivery of additional generation from the Bruce A nuclear plant and committed wind generation, and the Cherrywood Transformer Station to Claireville Transformer Station connection. These increases are partially offset by the substantial completion in the first part of 2008 of our construction phase of an interconnection Project with Quebec that will increase access to emission-free hydroelectric power.

Local area supply projects with significant expenditures in 2008 include our Essa Transformer Station to Stayner Transformer Station connection, which will improve the adequacy and reliability of supply to the Southern Georgian Bay region in recognition of the growing needs of our customers and our Greater Toronto Area (GTA) West Transmission Reinforcement Project, which will increase capacity in the Western GTA to ensure supply reliability in the area. These increases were offset by the completion of our Downtown Toronto Cable Project in 2007 and by the substantial completion of our Cambridge Preston Transformer Station Project. The final completion of our Niagara Reinforcement Project continues to be delayed by the aboriginal land dispute in the Caledonia area. Discussions related to the Niagara Reinforcement Project continue between the aboriginal peoples involved and various government entities and we expect to complete this project when site access becomes available.

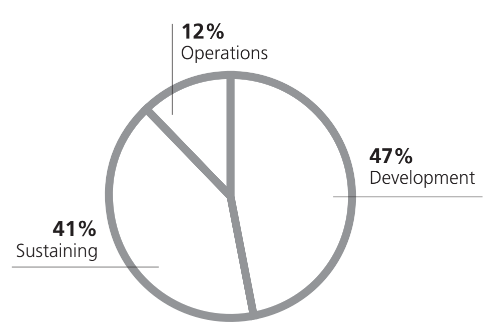
A number of significant load and generation customer connection projects were completed, or nearly completed in 2007 leading to a decrease in expenditures year over year. Work at our Whitby and London Talbot transformer stations was substantially complete last year. Reductions in expenditures on those load connection projects were partially offset by increased expenditures on our Holland and Kingston Gardiner transformer stations, as well as continued work on our Pleasant Transformer Station. Expenditures on our generation customer connection projects decreased significantly from last year due to reduced expenditures on our Lambton Transformer Station, which is expected to be completed early next year.

Expenditures to sustain our existing transmission system were $268 million, representing an increase of $46 million compared to 2007. This increase was primarily due to expenditures related to our spare transformer purchase program and to the refurbishment and replacement of end-of-life equipment at our Claireville Transformer Station to improve reliability and to meet growing demand. Our other transmission capital expenditures were $134 million in 2008, representing an increase of $66 million from the prior year. This increase was attributable to higher information technology expenditures primarily related to an entity-wide information system improvement project to replace end-of-life systems and improve productivity, for which we have completed the first phase. In addition, we incurred higher expenditures associated with information security enhancements at our Ontario Grid Control Centre and to expenditures related to the prevention of copper theft.

**2008 Transmission Capital Expenditures**




**2008 Distribution Capital Expenditures**



*Distribution*

Distribution capital expenditures increased by $59 million to $570 million in 2008, compared to the prior year. Capital expenditures to expand and reinforce our distribution network were $269 million, an increase of $24 million compared to last year. These increases primarily reflect ongoing investments in our Smart Meter Program. We have also initiated pilot programs to support the development of a smart grid that would transform the distribution network. During the year, we installed approximately 496,000 meters, bringing our cumulative program total to about 784,000 meters. The impact of these increases was partially offset by lower expenditures on new customer connections within Hydro One Brampton.

Expenditures to sustain our distribution system were $231 million, an increase of $27 million from 2007. This increase was primarily a result of higher storm-recovery expenditures and investments in transport and work equipment, combined with higher costs related to line relocation work and to engineering and construction work at our stations, partially offset by a reduction in unplanned equipment replacements as a result of our ongoing investments in assets. Our other distribution capital expenditures were $70 million in 2008, representing an increase of $8 million from last year. This increase reflects expenditures on our entity-wide information system improvement project to replace end-of-life systems and improve productivity, for which we have begun work on the second phase.

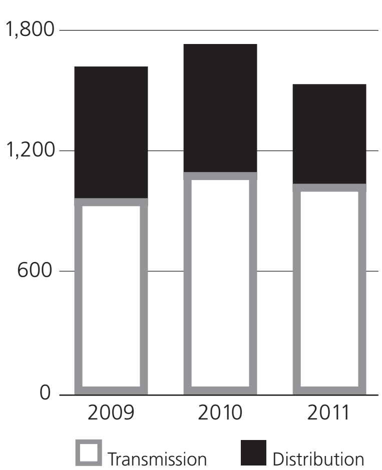
*Other*

Other capital expenditures made to enhance our telecom infrastructure decreased by $10 million to $10 million in 2008. This reduction was largely due to lower spending required to complete the balance of a dedicated network necessary to deliver on contracts providing secure, high-capacity connectivity across numerous health care locations in Ontario.

## Future Capital Expenditures

Our capital expenditures for 2009 are budgeted at approximately $1.6 billion. The 2009 capital budgets for our Transmission and Distribution Businesses are about $950 million and $650 million, respectively. Capital expenditures, as shown in the accompanying chart, are expected to exceed $1.7 billion in 2010 and $1.5 billion in 2011, primarily reflecting investments to expand, refurbish or replace transmission infrastructure, consistent with government policy, OPA planning information including the IPSP, local area supply requirements and the preventive and corrective maintenance needs to manage aging assets. These investments will facilitate an adequate and reliable supply of electricity in the public interest. These investment levels also reflect the continued mass deployment of smart meters within our Distribution Businesses that began in 2007 and which will be completed by the end of 2010. The replacement of critical information technology systems is also underway. Capital expenditures of our Other business segment are budgeted at about $7 million in 2009, reflecting sustainment of the fibre-optic network.

**Future Capital Expenditures**
*(Cdn $ millions)*




*Transmission*

Transmission system capital expenditures are anticipated to be significant over the period 2009 to 2011, amounting to about $3 billion. Our capital investment plan will address the needs of Ontario's changing generation profile, new generation development and load growth in local areas throughout the province. The transmission program also continues the focus on sustaining the performance of aging assets through maintenance and refurbishment programs and the replacement of assets that have reached end of life.

Among the transmission investments required to accommodate new and evolving generation are projects to connect nuclear redeveloped generation and new wind generation in the Huron-Grey-Bruce area, including our Bruce to Milton Transmission Reinforcement Project, and voltage support equipment at existing stations. This project is referenced in the IPSP and requisite OEB approval for the 500 kV line has been obtained and approval under the *Environmental Assessment Act* is being sought. Other projects to increase transmission capability include installation of voltage-support equipment at existing stations in Northeast Ontario and a new series compensation station between Sudbury and

Barrie. This equipment will alleviate transmission congestion and accommodate new generation on the Mattagami River. The Cherrywood Transformer Station to Claireville Transformer Station Connection Project will improve reliability, enable access to emission-free hydroelectric power from Hydro Québec as the new interconnection between Ontario and Québec comes into service in early 2009, and efficiently use the new Portlands Generating Station east of downtown Toronto.

Other projects included in the transmission investment plan include local area supply transmission reinforcements in the GTA, including midtown Toronto, Southern Georgian Bay, Woodstock and Windsor.

At the local load connection level, we continue to proactively address supply needs with our customers in order to meet their load growth. For projects required to provide reliable delivery of electricity to communities, the participation and support of the affected LDCs as partners in joint planning studies and throughout the consultation and approval processes continue to be essential. Examples of projects under construction to meet the growing needs of our customers include new transformer stations to serve Essex County and Simcoe County, and expansions of transformer stations serving Brampton, Kingston, York Region, Mississauga, Hamilton, Woodstock and Red Lake. To address other future needs for local load connections, we are holding discussions with customers regarding major transmission expansions or new transformer stations and, where necessary, line connections in locations such as Mississauga, Oshawa and Brampton. Targeted investments in customer delivery point performance, power quality and our 115kV and 230kV systems are expected to lead to improved reliability.

The investment plan also includes increased program expenditures to manage the replacement and refurbishment of our aging transmission infrastructure to ensure a continued reliable supply of energy to customers throughout the province. These sustaining investments are necessary to ensure that we will continue to meet all regulatory, compliance, safety and environment objectives.

The timing of many development projects is uncertain as they are dependent upon various approvals from, as well as negotiations and consultations with, customers, neighbouring utilities and other stakeholders. We will not undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

*Distribution*

Capital expenditures for the period 2009 to 2011 are estimated to be approximately $1.8 billion, including the Smart Meter Program, and core development and sustainment programs. With approximately 1.3 million customers in our service territory, we have installed over 780,000 smart meters and anticipate installing a further 550,000 under the program. In 2009, our mass deployment of smart meters is expected to be substantially complete and we plan to have two-thirds of the provincial network installed. As the IESO recently finalized its specifications for its meter repository by building and testing the interfaces to keep the customer account and meter data synchronized and consumption data flowing between the systems. Consistent with government policy, all homes and small businesses are to have a functioning smart meter installed by the end of 2010. The deployment of smart meters can be leveraged to create a smart grid that is capable of providing a communication infrastructure to enable new smart functions and applications across our system that will support the connection of clean and renewable generation. There are currently pilots underway and the full deployment of a smart grid will be brought forward for consideration once benefits are confirmed.

Our core work will focus on preserving the performance of our aging distribution asset base in order to improve system reliability. In addition, we will continue to address the demand for new load connections, trouble calls, storm restoration and system capability reinforcement. Given initiatives to encourage renewable energy technologies, we are experiencing increased distribution generation connection activity. Connection impact assessments are undertaken to determine project feasibility. Under OEB rules, the generator will pay connection costs other than distribution upgrades that also benefit other customers. Limited provision has been included in the plan for upstream system enhancements to accommodate this growth of new distribution-generation connections. The OEB is currently reviewing its cost-connection responsibility rules. Any changes to these rules could result in us being responsible for a greater portion of the costs for this activity. The planned projects to facilitate distributed generation will not be committed until assurance of cost recovery can be established.

### Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments.

| *December 31, 2008 (Canadian dollars in millions)* | Total | 2009 | 2010/2011 | 2012/2013 | After 2013 |
|---|---|---|---|---|---|
| **Contractual obligations** *(due by year):* | | | | | |
| Long-term debt – principal repayments | 6,125 | 400 | 1,000 | 1,000 | 3,725 |
| Long-term debt – interest payments | 5,177 | 338 | 608 | 508 | 3,723 |
| Inergi outsourcing agreement[1] | 300 | 100 | 184 | 16 | – |
| Operating lease commitments | 62 | 7 | 11 | 12 | 32 |
| **Total contractual obligations**[5] | 11,664 | 845 | 1,803 | 1,536 | 7,480 |
| **Other commercial commitments** *(by year of expiry):* | | | | | |
| Bank line[2] | 1,000 | – | 1,000 | – | – |
| Letters of credit[3] | 111 | 111 | – | – | – |
| Guarantees[3] | 325 | 325 | – | – | – |
| Pension[4] | 112 | 103 | 9 | – | – |
| **Total other commercial commitments** | 1,548 | 539 | 1,009 | – | – |

[1] On March 1, 2002, Inergi LP began providing a range of services to us for a 10-year period, including information technology, customer care, supply chain and certain human resources and finance services. The agreement expires on February 29, 2012. Given the complexities involved, we have begun developing a plan of action for end-of-term.

[2] As a backstop to our commercial paper program, we have a $1,000 million revolving standby credit facility with a syndicate of banks, which matures in August 2010.

[3] We currently have bank letters of credit of $107 million outstanding relating to retirement compensation arrangements. The other $4 million included in letters of credit pertains to operating letters of credit and to surety bonds. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million. Although no letters of credit are required for prudential support, we would have to resume providing bank letters of credit if our credit rating deteriorated to below the "Aa" category. In January 2009, we issued an additional letter of credit in the amount of $10 million relating to an agreement to purchase goods.

[4] Contributions to the pension fund are made one month in arrears. Contributions for 2009 are based on an actuarial valuation filed in September 2007 and effective December 31, 2006. Our annual pension contributions for 2009 will be about $103 million. Contributions beyond 2009 will be based on an actuarial valuation effective no later than December 31, 2009, and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2009 are not estimable at this time.

[5] In addition, the Company has entered into various agreements to purchase goods or services in support of our work programs that are enforceable and legally binding. None of these are considered individually material, and the majority will result in payments by our company by December 31, 2009.

The amounts in the above table under long-term debt – principal repayments are not charged to our results of operations, but are reflected on our Balance Sheet and Statement of Cash Flows. Interest associated with this debt is recorded under financing charges on our Statement of Operations or in our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration costs on our Statement of Operations or within our capital expenditures.

## RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to the IESO, which is a related party by virtue of its status as an agency of our shareholder, the Province. The year-over-year changes related to these amounts are described more fully in our discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends, which are paid to the Province and our payments in lieu of corporate income taxes, which are paid or payable to the OEFC.

## CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

### Effect of Load on Revenue

The current economic downturn will lead to lower overall energy consumption, specifically in our industrial customer segment. The industrial sector is the most sensitive to economic changes but has the least share of our total load at 24%. The lower energy consumption from our industrial customers will negatively impact our revenues but the overall impact will be tempered by our commercial and residential customers, which make up a larger proportion of our total load at 43% and 33%, respectively. The low elasticity of demand with respect to economy in the commercial sector and a moderate elasticity in the residential sector will effectively create a floor in energy consumption and limit the impact on total revenues. On average, a 1% reduction in Gross Domestic Product (GDP) is expected to result in only a 0.3% reduction in load in the short-run.

### Effect of Interest Rates

Changes in interest rates will impact the calculation of our revenue requirements filed with the OEB. The first component impacted by interest rates is the return on equity. The OEB-approved adjustment formula for calculating return on equity will increase or decrease by 75% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 5.50%. We estimate that a 1% decrease in the forecast long-term Government of Canada bond yield used in the current OEB formula for determining our rate of return on equity would reduce our Transmission Business' results of operations by approximately $21 million and our Distribution Business' results of operations by approximately $13 million. The second component of revenue requirement which would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

### Input Costs and Commodity Pricing

In support of our ongoing work program requirements, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, blanket orders, and vendor alliances and will manage an inventory of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic procurement practices, we do not foresee any adverse impacts to our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counter-parties. Further, while we rely on such commodities as steel and copper as part of our business operations, we have not been impacted by any escalation in prices beyond what is typically experienced for such commodities.

### Debt Financing

Cash generated from operations, after the payment of expected dividends, will not be sufficient to repay existing indebtedness, fund capital expenditures and meet other obligations (see Risk Management and Risk Factors – Risk Associated with Arranging Debt Financing). We rely on debt financing through our Medium-Term Note Program and Commercial Paper Program to repay existing indebtedness and fund capital expenditures. Our Commercial Paper Program is supported by a $1 billion syndicated bank line of credit. Despite the turmoil in the credit markets and onset of current economic conditions, we have been able to arrange sufficient cost-effective debt financing through the Medium-Term Note Program and Commercial Paper Program in the Canadian debt markets to fund these requirements to date.

### Pension

During 2008, the deferred pension asset reported on our balance sheet increased by $61 million to $441 million. We contributed $101 million into our pension plan in 2008 and incurred $40 million in net periodic pension benefit cost. On an accounting basis, a 2007 funded excess of $23 million changed by $194 million, resulting in an unfunded benefit obligation of $171 million. The plan experienced negative returns of about 22.5% in the year. However, the plan was also impacted by a reduction in the accrued benefit obligation as a result of an increase in the discount rate used for accounting purposes, as well as a decrease in the implied inflation rate (see Critical Accounting Estimates – Employee Future Benefits).

Should our plan continue to incur negative returns in 2009 or fail to recover a substantial portion of the losses incurred in 2008, or if the discount rate falls sufficiently by the end of 2009, the funding deficit position at that time could lead to an increase in our contribution requirements beyond 2009. If our contribution requirements substantially increased, we would seek recovery from the OEB (see Risk Management and Risk Factors – Pension Plan Risk).

## RISK MANAGEMENT AND RISK FACTORS

We have an enterprise risk management program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic business objectives.

While our philosophy is that risk management is the responsibility of all employees, the Audit and Finance Committee of our Board of Directors annually reviews our company's risk tolerances, our risk profile and the status of our internal control framework. Our President and Chief Executive Officer has ultimate accountability for risk management. Our Leadership Team, comprising direct reports to the President and Chief Executive Officer, provides senior management oversight of risk in our company. Our Chief Risk Officer is responsible for the ongoing monitoring and review of our risk profile and practices, and our Executive Vice President and Chief Financial Officer is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. Each of our subsidiaries, as well as key specialist functions and field services, is required to complete a formal risk assessment and to develop a risk-mitigation strategy.

The Audit and Finance Committee, the President and Chief Executive Officer, and the Executive Vice President and Chief Financial Officer are supported by our Chief Risk Officer. This support includes coordinating risk policies and programs, establishing risk tolerances, preparing risk assessments and profiles and assisting line and functional managers in fulfilling their responsibilities. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk-management policies, processes and systems.

### Ownership by the Province

The Province owns all our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and thus influence our major business and corporate decisions. We have entered into a memorandum of agreement with the Province in 2008 relating to certain aspects of the governance of our company. In September 2008, pursuant to such agreement, the Province made a declaration removing certain powers from our company's directors pertaining to the off-shoring of jobs under our outsourcing arrangement with Inergi. The Province may make similar declarations in the future, some of which may have an adverse effect on our business.

Conflicts of interest may arise as a result of the Province's obligation 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 and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, the Province's ownership of Ontario Power Generation Inc. (OPG), and the determination of the amount of dividends or payments in lieu of corporate income taxes. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us.

### Risk Associated with Transmission Projects

Significant investments have been initiated to increase transmission capacity and enable the reliable delivery of power to Ontario consumers from existing and future generation sources. In many cases, initiating these investments is contingent upon one or more approvals. These can include OEB Section 92 Leave-to-Construct, expropriation and environmental approvals, as well as appropriate consultation, and where appropriate accommodation with First Nations and Métis who may be potentially affected by a project. The ability to make these investments may also be impacted by public opposition. If we are unable to make such investments, the reliability of our transmission system and our service quality could be adversely affected.

### Workforce Demographic Risk

Approximately 40% of our employees will be eligible for undiscounted retirement by February 1, 2014. We expect the skilled labour market for our industry to be highly competitive in the future. Consequently, we must continue to advance our training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, our operations could be adversely affected.

### Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain equipment performance and provide reliable service quality. Our capital and maintenance programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is dependent on external factors, including limited opportunities to remove equipment from service to accommodate construction and maintenance due to customer and generator priorities, and increased lead times for material and equipment due to increased demand and limited vendor capability. If we are unable to carry out these plans, in a timely and optimal manner, equipment performance will degrade, which could affect transmission reliability.

### Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our Transmission and Distribution Businesses that permit a reasonable opportunity to recover the estimated costs of providing service on a timely basis and to earn the approved rates of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption falls below projected levels, our rate of return for either, or both, of these businesses could be adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively impacted by successful CDM programs. Current requirements for CDM call for a 5% reduction in Ontario's projected peak electricity demand by 2010. These expectations are factored into our revenue requirements for OEB approval, to ensure that the targeted CDM accomplishments do not result in deteriorated revenues. There is a risk that our revenues would be reduced if these targets are exceeded. The OEB has recognized the need to compensate utilities for such lost revenue, but the approach, level and timing of such compensation is yet to be determined. We are also subject to risk of revenue loss from other factors.

As a transmitter, we expect to make a significant investment in the coming years in large-scale transmission infrastructure projects and to connect new third-party load and generation assets. Additionally, there is always the possibility that we could incur unexpected capital expenditures to maintain or improve our assets. The risk exists that the OEB may not allow full recovery of such investments. To the extent possible, we try to mitigate this risk by seeking from the regulator clear policy direction on cost responsibility and pre-approval of the need for capital expenditures.

The Province has passed regulations authorizing our subsidiaries, as distributors, to procure smart meters. Of the associated costs in rates, our subsidiaries Hydro One Networks and Hydro One Brampton are only currently authorized to recover $0.93 cents and $0.67 cents per metered customer per month, respectively. While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to our results of operations.

### Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency denominated debt which, however, we would be expected to hedge back to Canadian dollars, consistent with our company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic approach, which is in part based on the forecast for long-term Government of Canada bond yields. We estimate that a 1% decrease in the forecast long-term Government of Canada bond yield used in determining our rate of return would reduce our Transmission Business' results of operations by approximately $21 million and our Distribution Businesses' results of operations by approximately $13 million.

Financial assets create a risk that a counter-party will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counter-party default. We monitor and minimize credit risk through various techniques, including dealing with highly rated counter-parties, limiting total exposure levels with individual counter-parties, by entering into master agreements which enable net settlement and by monitoring the financial condition of counter-parties. We do not trade in any energy derivatives. We do, however, have interest rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's *Retail Settlements Code.*

### Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt which mature between 2009 and 2012, including $400 million maturing in 2009 and $600 million maturing in 2010. We also plan to incur capital expenditures in 2009 of approximately $1.6 billion and capital expenditures are expected to exceed $1.7 billion in 2010. 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 business.

### Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a tri-annual basis. The most recently filed valuation was prepared as at December 31, 2006, and was filed in September 2007. The next valuation is required to be prepared as at December 31, 2009. Contributions beyond 2009 will be based on an actuarial valuation effective December 31, 2009, and will depend on future investment returns, changes in benefits or actuarial assumptions. As a result of current economic uncertainty and financial market volatility, our pension plan experienced negative returns in 2008 of approximately 22.5%. Should our plan continue to incur negative returns in 2009 or fail to recover a substantial portion of the losses incurred in 2008, or if the discount rate falls sufficiently by the end of 2009, the deficit position at that time could lead to a large increase in our contribution requirements beyond 2009. The recovery of pension costs is subject to approval by the OEB. Failure to attain OEB approval could have an adverse effect on our results of operations.

### Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters and catastrophic events. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our assets located outside our transmission and distribution stations. Lost revenues, repair costs, damage and claims from third parties could be substantial. In the event of a large uninsured loss, we would apply to the OEB for recovery. However, there is no assurance that the OEB would approve such an application.

### Risk from Transfer of Assets Located on Indian Lands

The transfer orders by which we acquired certain of Ontario Hydro's 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). Currently, the OEFC 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 of these assets to us. We cannot predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required consents. However, we anticipate having to pay more than the approximately $717 thousand that we paid to these Indian bands and bodies in 2008. If we cannot obtain consents from the Indian bands and bodies, the OEFC 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. These potential costs could have a material adverse effect on our results of operations if we are unable to recover them in future rate orders.

### Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex information technology systems, which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. We continue to transition most of our financial and business processes to an integrated business and financial reporting system. At the same time we are updating our transmission operations management system. The conversion of these systems and processes may expose us to risk, including risks associated with our ability to capture data and to produce timely and accurate information and to maintain internal controls. System failures could have a material adverse effect on our company.

### Environmental Risk

Our health, safety and environmental management system ensures hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive environmental regulation and failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation program covering most of our stations and service centres. There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing our operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could mean delays and cost increases.

On September 17, 2008, Environment Canada published new final regulations, governing the management of polychlorinated biphenyl (PCB) contamination. We have recorded a liability based on our best estimate of the future expenditures required to comply with these regulations. Most of these additional expenditures are expected to be incurred in the 2013 to 2025 period. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our Consolidated Balance Sheet. We do not have insurance coverage for these environmental expenditures.

Scientists and public health experts have been 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, or governments decide to implement exposure limits, we could face litigation, be required to take costly mitigation measures, such as relocating some of our facilities, or experience difficulties in locating and building new facilities.

### Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers Union (PWU) or the Society of Energy Professionals. Our existing collective agreement with the PWU will expire on March 31, 2011, and our existing Society of Energy Professionals' collective agreement will expire on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In the event of a labour dispute, we could face operational risk related to continued compliance with our licence requirements of providing service to customers.

### Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we entered into an outsourcing services agreement in 2002 with Inergi. If this agreement is terminated for any reason, we could be required to incur significant expenses to re-establish all or some of the outsourced functions, which could have a material adverse effect on our results of operations. The agreement expires on February 29, 2012. Given the complexities involved, we have begun developing a plan of action for end-of-term.

### Risk from Provincial Ownership of Transmission Corridors

Although we have the statutory right to use provincially owned transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks.

## CRITICAL ACCOUNTING ESTIMATES

The preparation of our financial statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our financial statements.

### Regulatory Assets and Liabilities

Regulatory assets as at December 31, 2008 amounted to $355 million and principally relate to environmental costs, a regulatory asset recovery account II (RARA II), the RRA and the rural rate protection variance account. We have also recorded regulatory liabilities amounting to $607 million as at December 31, 2008. These amounts pertain primarily to deferred pension, the regulatory liability refund account, retail settlement variance accounts, export and wheeling fees and a regulatory asset recovery account I (RARA I), which is currently in a liability position. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. If management judges that it is no longer probable that the OEB will include a regulatory asset or liability in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

### Environmental Liabilities

During 2008 we recorded additional environmental liabilities and regulatory assets based on new PCB regulations published by Environment Canada on September 17, 2008. We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to satisfy obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of assets contaminated with PCB-laden mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work and make assumptions for when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express current cost estimates as estimated future expenditures. Future estimated land assessment and remediation expenditures are expected to be incurred over the period ending 2015, and are discounted using factors ranging from 4.9% to 6.25%, depending on the year of recognition. Consistent with the requirements of Environment Canada's final PCB regulations issued on September 17, 2008, estimated future PCB expenditures are expected to be incurred over the period ending 2025. The new regulations have resulted in an increase to our estimated future expenditures of approximately $265 million, which represents an increase of $195 million to environmental liabilities on a present value basis. The future expenditures for managing PCB issues are discounted using factors ranging from 5.14% to 6.25%, depending on the year of recognition.

Recording a liability now for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination, the number of assets, oil volumes and contamination levels of equipment with PCBs. All factors used in deriving our environmental liabilities represent management's best estimates based on our planned approach of meeting regulatory requirements, including the new Environment Canada regulations governing the management, storage and disposal of PCBs. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Estimate changes are accounted for prospectively.

## Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund (Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions were approximately $101 million in 2008, based on an actuarial valuation effective December 31, 2006. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009, and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the financial statements on an accrual basis. We record employee future benefit costs other than pension on an accrual basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries.

The assumed return on pension plan assets of 7.00% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was changed to 62% exposure to equities, 33% to fixed income and 5% to alternative assets consisting of hedge funds and private equity. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the fund's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. In the short term, the plan can experience aberrations in actual return. In 2008, the return on pension plan assets was lower than this long-term assumption.

The discount rate used to calculate the accrued benefit obligations is determined each year end by referring to the most recently available market interest rates based on "AA" corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2008 increased to 7.25% from 5.50% used at December 31, 2007 in conjunction with the increase in bond yields over this period. The increase in discount rates has resulted in a corresponding reduction in liabilities.

Yields on "AA" corporate bonds increased by approximately 140–200 basis points between December 31, 2007 and December 31, 2008. Based on the duration of the plan's liabilities, discount rates would be 7.50% per annum for the pension plan, 7.50% per annum for the post-retirement benefit plan and 7.16% per annum for the post employment plan. Based on current economic markets, management believes these rates are high relative to risk-free rates to be used as a long-term assumption and as such, has used a 7.25% overall discount rate for liability valuation purposes as at December 31, 2008.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has decreased from approximately 2.25% per annum as at December 31, 2007 to approximately 1.30% per annum as at December 31, 2008. While an inflation rate as low as 1.25% per annum could be used for liability valuation purposes based on December 31, 2008 bond yields, for most of 2008, the implied rate would have been over 2.00%. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current implied rate is low to be used as a long-term assumption and as such, has used a 2.00% per annum inflation rate for liability valuation purposes as at December 31, 2008.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $14 million per year and an increase in the year end obligation of about $108 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as a cost of fixed assets.

### Goodwill and Asset Impairment

In assessing the recoverability of goodwill, we must make assumptions regarding estimated future cash flows and other factors to determine the fair value of the distribution reporting unit. If these estimates or their related assumptions change in the future, we may be required to record impairment charges related to goodwill. An impairment review of goodwill was carried out during 2008, and we determined that the carrying value of our goodwill has not been impaired.

Within our regulated businesses, carrying costs of our other assets are recovered in our revenue requirements and are included in rate base, where they earn a return. Such assets would be tested for impairment only in the event that the OEB ordered disallowance of recovery or if such a disallowance was judged to be probable. We periodically monitor the assets of our unregulated telecom business for indications of impairment. No asset impairments have been recorded to date for any of our businesses.

## EMERGING ACCOUNTING PRONOUNCEMENTS

### Accounting for Income Taxes

In August 2007, the Canadian Accounting Standards Board (AcSB) issued a decision, effective January 1, 2009, to withdraw the temporary exemption in CICA Handbook Section 1100, *Generally Accepted Accounting Principles*, which permits the recognition and measurement of assets and liabilities arising from rate regulation. Further, CICA Handbook Section 3465, *Income Taxes*, was amended to require the recognition of future income tax liabilities and assets for regulated enterprises that were previously not subject to these provisions. Consequently, we will be required to reflect on our Consolidated Balance Sheet, the effect of applying the liability method when accounting for payments in lieu of corporate income taxes and a corresponding regulatory asset.

The new rules will apply prospectively to interim and annual financial statements relating to the 2009 fiscal year and will result in accrual accounting being followed for payments in lieu of corporate taxes. Such amounts are currently accounted for on a cash basis, consistent with specific OEB rate-setting direction. We are currently assessing the impact of the AcSB's decision on our Consolidated Balance Sheet. We do not expect these rules to impact the results of operations.

### Goodwill and Intangibles

In November 2007, the AcSB approved new CICA Handbook Section 3064, *Goodwill and Intangible Assets*. The new section is applicable to our interim and annual Consolidated Financial Statements for the 2009 fiscal year. We are currently evaluating the classification of certain of our assets to determine if they meet the definition of intangible assets. Assets that may potentially be reclassified include land rights and easements, certain software assets, telecom indefeasible rights of use and amounts contributed to other entities as capital contributions. It is not anticipated that the new section will have any impact on goodwill or on our results of operations.

**Status of Our Transition to International Financial Reporting Standards (IFRS)**

On February 13, 2008, the Canadian AcSB confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles (GAAP) for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. At this time, the impact on our future financial position and results of operations is not reasonably determinable or estimable.

We commenced our IFRS conversion project in 2007, and we have established a formal project governance structure. This structure includes a steering committee consisting of senior levels of management from finance, information technology, treasury and our operations organizations, among others. Regular reporting is provided to our senior executive management and to the Audit and Finance Committee of our Board of Directors. We have also engaged an external expert advisor.

Our project consists of four phases: diagnostic; design and planning; solution development; and implementation. We have completed the diagnostic phase, which involved a high level review of the major differences between current Canadian GAAP and IFRS. Currently, we have determined that the areas of accounting difference with the highest potential to impact our company are rate-regulated accounting, accounting for fixed assets, payments in lieu of corporate income taxes, employee future benefits as well as initial adoption of IFRS under the provisions of IFRS 1, *First-Time Adoption of IFRS.*

We are currently simultaneously engaged in the design and planning, solution development and implementation phases of our project. We are working in issue-specific teams to focus on generating options and making recommendations in the identified areas and implementing financial reports and systems solutions in our high-impact areas. We have established a regular staff communication plan, started to roll out staff training programs, and have begun to evaluate the impacts of the IFRS transition on other business activities including our subsidiaries.

In addition, we have been involved in documenting the high-impact areas identified, including an analysis of financial system impacts, the establishment of key milestones and ongoing discussions with our external auditors. Our implementation phase for our high-impact accounting and systems issues has commenced. The impact on disclosure controls and internal controls over financial reporting are also being examined. Analysis of other business impacts, such as impacts on debt covenants and performance measures, has begun.

The OEB has also begun its own IFRS project to determine the nature of any changes that should be made in regulatory reporting requirements in response to IFRS. On May 8, 2008, the OEB announced the creation of an IFRS Consultation, which will provide an opportunity for Board staff to work with industry participants to identify transition issues and suggest how those issues might be addressed. We have participated in each of the Consultation meetings and have provided comments on the OEB transition plan. We intend to closely monitor any International Accounting Standards Board initiatives with the potential to impact rate regulated accounting under IFRS and will participate in any related processes, as appropriate.

At the Canadian Public Sector Accounting Board's (PSAB) meeting on November 17 and 18, 2008, it agreed to a stakeholder request to re-evaluate an earlier conclusion that government organizations following commercial practices, such as our company, should continue to prepare their financial statements in accordance with GAAP for profit-oriented enterprises. For such enterprises that are also publicly accountable, this would become IFRS after January 1, 2011. As a result, the PSAB directed its staff to develop an Invitation to Comment, which was scheduled at a special meeting that took place in January 2009, that will seek additional input from all of PSAB's stakeholders on this issue. At this time, it is uncertain how this initiative could affect the nature or timing of our conversion to IFRS.

## DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

We are in the process of transitioning our major financial systems to a SAP enterprise-wide platform. A formal project governance structure is in place to ensure an effective transition of the information technology systems and business processes. The governance structure includes a steering committee consisting of senior levels of management, which reports to senior executive management and the Business Transformation Committee of the Board of Directors.

On June 2, 2008, we implemented the first phase of the transition including the supply chain, asset, and work management modules within SAP. A portion of the Financial Accounting and Controlling modules were also implemented to facilitate financial reporting. This implementation included both new controls over Internal Controls over Financial Reporting and replaced controls in the previous information technology system. Our process documentation has been updated and certain controls have been tested for purposes of determining whether they have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes.

The second phase of the transition, which is planned for implementation in August 2009, involves the replacement of remaining finance, human resources and pay modules with SAP.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2008, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company and that they operated effectively during the period.

## SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2006, 2007 and 2008. This information has been derived from our audited annual Consolidated Financial Statements.

### Consolidated Statement of Operations

| *Year ended December 31 (Canadian dollars in millions, except earnings per common share)* | **2008** | 2007 | 2006 |
|---|---|---|---|
| Revenues[1, 4] | **4,597** | 4,655 | 4,545 |
| Net income[1, 4] | **498** | 399 | 455 |
| Basic and fully diluted earnings per common share | **4,797** | 3,809 | 4,366 |

### Consolidated Balance Sheet

| *Year ended December 31 (Canadian dollars in millions, except cash dividends per share)* | **2008** | 2007 | 2006 |
|---|---|---|---|
| Total assets[2] | **13,876** | 12,786 | 12,210 |
| Total long-term debt[3] | **6,133** | 5,603 | 5,243 |
| Cash dividends per common share | **2,410** | 3,070 | 3,320 |
| Cash dividends per preferred share | **1.375** | 1.375 | 1.375 |

[1] As a result of the OEB's August 16, 2007 decision on Hydro One Networks' transmission rate application that was effective January 1, 2007, revenues reflect a reduced revenue requirement based on the approved rate of return of 8.35%. Previously, the rate of return was 9.88%.

[2] Total assets for 2006 reflect the reclassification of deferred debt costs in 2007, applied retroactively.

[3] Unamortized net losses relating to settled swap agreements were reclassified to AOCI on January 1, 2007 without prior year reclassification.

[4] As a result of the OEB's December 18, 2008 decision on Hydro One Network's distribution rate application that was effective May 1, 2008, revenues in the fourth quarter of 2008 reflect a $25 million increase in respect of the period May 1, 2008 to December 31, 2008, reflecting growth in the work program requirements and investment in capital infrastructure.

## OUTLOOK

To meet our vision to be the leading electricity delivery company in North America, we will continue to concentrate on our strategic objectives of safety, customer satisfaction, innovation and connecting renewable energy, reliability, protection of the environment, recruitment and knowledge retention, shareholder value, and productivity. Given the hazardous working environment our employees face, we remain resolute in our commitment to safety. A cleaner environment is also paramount as new technologies emerge and the need to connect clean and renewable generation challenge our Transmission and Distribution Businesses to recalibrate and establish a more flexible and smart electricity grid. We will continue to focus our efforts to improve customer satisfaction by maintaining operational excellence to ensure that electricity is delivered safely, reliably and affordably. As an indication of achievements, *Corporate Knights* magazine has recognized us as first among utility companies and sixth overall of Canada's Top 50 Corporate Citizens based on environmental, social and governance indicators.

Consistent with our continued commitment to the public interest and the Province's energy policies, we are planning significant investments in transmission infrastructure and the continued proactive maintenance of our assets to ensure the electricity system's reliability. Our transmission investment plan supports the achievement of the Province's renewable and nuclear objectives, facilitates the development and use of renewable energy resources, promotes system efficiency, sustains equipment performance, meets customers' service quality needs, and facilitates the integration of new supply.

In its transmission rate decision issued on August 28, 2008, the OEB approved UTR adjustments to recover our approved 2008 revenue requirement from January 1, 2009, after completion of repayment of excess earnings to customers associated with ESM and RDDA. The favourable decision expresses confidence in our ability and expertise to make an appropriate assessment of what is needed "to maintain a robust, safe, and reliable transmission system." We filed a transmission rate application for 2009 and 2010 rates in September 2008. These rates, if approved, should provide the funding required to carry out the transmission work program in these years to maintain and meet the infrastructure requirements of the transmission system in the public interest.

Our investment plan does not include spending for large-scale investments, such as an east-west transmission grid or potential long-term transmission projects identified in the IPSP. For certain long-term projects addressing generation-enabling connection lines and reliability of local area supply, the IPSP recommends that project development work (preliminary engineering, cost estimating, options assessment) and Environmental Assessment and Section 92 approvals, as required, begin upon approval of the IPSP by the OEB. As such, we are prepared to initiate project development work for these projects to enable expedited construction once a need date is confirmed by the OPA and once we have a reasonable expectation of cost recovery through rates. It is expected that the OPA will file an updated IPSP by March 16, 2009, and thereafter, the OEB will issue a Procedural Order indicating when the IPSP hearing will commence. This effective deferral in the IPSP process does not affect any of the major projects in our business plan. We expect that any decision to make major investments related to such projects will be based on appropriate assurance of recovery of the costs of such investments.

In its rate decision on the distribution application of our subsidiary Hydro One Networks issued on December 18, 2008, the OEB approved substantially all of our work program expenditures and our Smart Meter Program to the end of 2007. This firmly provides a base funding level to build upon and subsequently reduces the uncertainty of recovery of the Smart Meter Program. The increasing focus on renewable distributed generation, such as wind, solar, hydroelectric and biofuels will require development of the Smart Grid concept, which would leverage the smart meter technology to support continued reliable and safe operation of the distribution system. This technology will allow the same kind of visibility and control to distribution-connected generators that transmission-connected power producers now enjoy.

We are committed to the protection and sustainment of the environment for future generations. We can achieve this goal through distribution of clean and renewable energy by upgrading our transmission grid to support flow reversal of small, clean energy generators connected to the distribution system to the overall load. Investments in distribution and transmission infrastructure to enable major additions of distributed generation and to improve response times to these new connections at all stages will be required. However, transmission upgrades for distributed generation have been excluded from our business plan in the short term due to the uncertainty associated with cost responsibility.

We remain committed to a prudent and measured approach to distribution rationalization. In October 2006, the Province announced a two-year exemption of the electricity transfer tax. The exemption period was subsequently extended to October 2009. We have and will actively seek strategic opportunities for acquisitions or divestitures, on a voluntary and commercial basis, where they are consistent with our vision and direction from our shareholder. Our investment plan does not include any funding for any LDC acquisitions or divestitures.

Key enablers of the successful implementation of the work program are our human and material resourcing strategies. Our human resource strategy is focused on hiring through partnering with universities, colleges and our unions, as well as skills development and retention. Significant retirement projections and increasing work volumes will result in an unprecedented number of new hires in the near term. With regard to materials, we are seeing increasing lead times and costs as market shortages emerge globally. Consequently, sourcing strategies are being developed and implemented to ensure availability of materials to support the work programs.

We will continue to increase enterprise value for our shareholder through productivity improvements and effective management of costs. Initiatives in organizational alignment and process improvements together with the leveraging of our information technology strategy and new enterprise reporting system will allow us to achieve value for our customers and our shareholder.

Through the outlook period, we anticipate no changes to our role within the industry and that our financial returns will be sufficient to maintain our credit quality.

## FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to, statements about our strategy and our performance measures and targets; statements related to the IPSP and projects flowing therefrom; the anticipated impact of CDM programs; statements about smart meters including their capabilities, cost recovery and deployment and/or installation plans; expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario, including changes to codes, licences rules, rates, rate orders, cost recovery, rates of return, rate structures, revenue requirements and impacts on customers' bills in both our Transmission and Distribution Businesses; expectations regarding the timing and content of applications to and decisions from the OEB and other governing bodies; statements regarding our future liquidity and capital resources; expectations regarding our financing activities; expectations regarding the results of our ongoing and planned projects and/or initiatives and their completion dates; statements regarding future capital expenditures and our investment plans; statements regarding contractual obligations and other commercial commitments; statements regarding current economic conditions including expectations regarding load and its expected impact on revenues, the effect of interest rates on our revenue requirement and results of operations, impacts to our business in respect of the adequacy and timing of supply and credit risk of our counter-parties and expectations regarding future pension contributions; the possibility of the Province making declarations pursuant to our memorandum of agreement with them; statements regarding workforce demographics; expectations regarding asset condition; the possibility that we could in future decide to issue foreign currency denominated debt; expectations regarding our information technology infrastructure; expectations regarding the timing and amount of additional estimated future environmental expenditures; statements about our plan to address the new Environment Canada regulations governing the management, storage and disposal of PCBs; statements about the end-of-term of our outsourcing arrangement; expectations regarding anticipated expenditures associated with transferring assets located on Indian lands; statements regarding provincial ownership of our transmission corridors; statements about employee future benefit costs; statements about emerging accounting pronouncements; statements about IFRS and our conversion to IFRS; statements about the outlook period including our expectations regarding our role within the industry, our financial returns, and structural changes to our company. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "believe," "seek," "estimate," "goal," "aim," "target," and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; no unfavourable decisions from or rate structures for our Distribution and Transmission Businesses; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party sources. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the content and timing of the revised IPSP, as approved by the OEB;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- the timing and results of regulatory decisions regarding our revenue requirements, cost recovery and rates and changes to rules under OEB review;
- the potential impact of CDM programs on our load and our revenues;
- the potential impact of not being able to recover all of our project costs associated with the installation of smart meters;
- unanticipated changes in electricity demand or in our costs;
- the risks associated with changes in interest rates;
- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- future interest rates, future investment returns, inflation, changes in benefits and changes in actuarial assumptions;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the risks associated with maintaining a complex information technology systems infrastructure and transitioning most of our financial and business processes to an integrated business and financial reporting system;
- the number and volume of PCB-contaminated assets identified, the extent of asset contamination and future interest rates and inflation;
- the ability to negotiate collective agreements consistent with our rate orders or in a timely fashion and the potential for labour disputes;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi LP is terminated; and
- the impact of the ownership by the Province of lands underlying our transmission system.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail under Risk Management and Risk Factors in the 2008 annual Management's Discussion and Analysis (MD&A). You should review the section entitled Risk Management and Risk Factors in detail.

This MD&A is dated as at February 11, 2009. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

# Management's Report

The Consolidated Financial Statements, Management's Discussion and Analysis ("MD&A") and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. ("Hydro One" or the "Company"). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 11, 2009.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition internal and disclosure controls have been documented, evaluated, tested and identified consistent with National Instrument 52-109 (Bill 198). An internal audit function independently evaluates the effectiveness of these internal controls on an ongoing basis and reports its findings to management and the Audit and Finance Committee of the Hydro One Board of Directors.

The Consolidated Financial Statements have been examined by KPMG LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with accounting principles generally accepted in Canada. The Auditors' Report, which appears on page 48, outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors, and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer, and Executive Vice-President and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, related disclosure controls and procedures, and the design and effectiveness of related internal controls over financial reporting pursuant to National Instrument 52-109.

On behalf of the Hydro One Inc.'s management:

**Laura Formusa**
President and Chief Executive Officer

**Beth Summers**
Executive Vice-President and Chief Financial Officer

# Auditors' Report

**To the Shareholder of Hydro One Inc.**

We have audited the consolidated balance sheet of Hydro One Inc. (the Company) as at December 31, 2008, and the consolidated statements of operations and comprehensive income, retained earnings, accumulated other comprehensive income, and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements as at December 31, 2007 and for the year then ended were audited by other auditors, who expressed an opinion without reservation on those statements in their report, dated February 13, 2008.

KPMG LLP

**KPMG LLP**
Chartered Accountants,
Licensed Public Accountants

Toronto, Canada
February 11, 2009

# Consolidated Statements of Operations and Comprehensive Income

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| **Revenues** | | |
| Transmission (Note 14) | **1,212** | 1,242 |
| Distribution (Note 14) | **3,334** | 3,382 |
| Other | **51** | 31 |
| | **4,597** | 4,655 |
| **Costs** | | |
| Purchased power (Note 14) | **2,181** | 2,240 |
| Operation, maintenance and administration (Note 14) | **965** | 995 |
| Depreciation and amortization (Note 3) | **548** | 521 |
| | **3,694** | 3,756 |
| **Income before financing charges and provision for payments in lieu of corporate income taxes** | **903** | 899 |
| Financing charges (Note 4) | **292** | 295 |
| **Income before provision for payments in lieu of corporate income taxes** | **611** | 604 |
| Provision for payments in lieu of corporate income taxes (Notes 5 and 14) | **113** | 205 |
| **Net income** | **498** | 399 |
| Other comprehensive (loss) income | **(1)** | 3 |
| **Comprehensive income** | **497** | 402 |
| **Basic and fully diluted earnings per common share** *(Canadian dollars)* (Note 13) | **4,797** | 3,809 |

# Consolidated Statements of Retained Earnings

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| **Retained earnings, January 1** | **1,258** | 1,184 |
| Net income | **498** | 399 |
| Dividends (Note 13) | **(259)** | (325) |
| **Retained earnings, December 31** | **1,497** | 1,258 |

# Consolidated Statements of Accumulated Other Comprehensive Income

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| **Accumulated other comprehensive income, January 1** | **(9)** | (12) |
| Other comprehensive (loss) income | **(1)** | 3 |
| **Accumulated other comprehensive income, December 31** | **(10)** | (9) |

See accompanying notes to Consolidated Financial Statements.

# Consolidated Balance Sheets

| *December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | **16** | – |
| Accounts receivable (net of allowance for doubtful accounts – $23 million; 2007 – $21 million) (Note 14) | **754** | 759 |
| Regulatory assets (Note 7) | **64** | 103 |
| Materials and supplies (Note 2) | **19** | 23 |
| Other | **18** | 17 |
| | **871** | 902 |
| Fixed assets (Note 6): | | |
| Fixed assets in service | **17,604** | 16,743 |
| Less: accumulated depreciation | **6,580** | 6,220 |
| | **11,024** | 10,523 |
| Construction in progress | **963** | 622 |
| Future use land, components and spares (Note 2) | **132** | 113 |
| | **12,119** | 11,258 |
| Other long-term assets: | | |
| Deferred pension asset (Note 11) | **441** | 380 |
| Regulatory assets (Note 7) | **291** | 106 |
| Goodwill | **133** | 133 |
| Other assets | **21** | 7 |
| | **886** | 626 |
| **Total assets** | **13,876** | 12,786 |

See accompanying notes to Consolidated Financial Statements.

# Consolidated Balance Sheets (continued)

| *December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| **Liabilities** | | |
| Current liabilities: | | |
| Bank indebtedness | **–** | 12 |
| Accounts payable and accrued charges (Notes 11, 12 and 14) | **791** | 731 |
| Regulatory liabilities (Note 7) | **43** | 114 |
| Accrued interest | **64** | 55 |
| Long-term debt payable within one year (Note 8) | **400** | 540 |
| | **1,298** | 1,452 |
| Long-term debt (Note 8) | **5,733** | 5,063 |
| Other long-term liabilities: | | |
| Employee future benefits other than pension (Note 11) | **908** | 855 |
| Regulatory liabilities (Note 7) | **564** | 465 |
| Environmental liabilities (Note 12) | **237** | 52 |
| Long-term accounts payable and accrued charges | **12** | 13 |
| | **1,721** | 1,385 |
| **Total liabilities** | **8,752** | 7,900 |
| Contingencies and commitments (Notes 16 and 17) | | |
| **Shareholder's equity** (Note 13) | | |
| Preferred shares (authorized: unlimited; issued: 12,920,000) | **323** | 323 |
| Common shares (authorized: unlimited; issued: 100,000) | **3,314** | 3,314 |
| Retained earnings | **1,497** | 1,258 |
| Accumulated other comprehensive income | **(10)** | (9) |
| **Total shareholder's equity** | **5,124** | 4,886 |
| **Total liabilities and shareholder's equity** | **13,876** | 12,786 |

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

**Douglas E. Speers**
Chair

**Walter Murray**
Chair, Audit and Finance Committee

# Consolidated Statements of Cash Flow

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| **Operating activities** | | |
| Net income | **498** | 399 |
| Adjustments for non-cash items: | | |
| Depreciation and amortization (excluding removal costs) | **502** | 482 |
| Revenue difference deferral account | **(73)** | 73 |
| Regulatory liability refund account | **30** | 38 |
| Other regulatory asset and liability accounts | **(5)** | 9 |
| Revenue recovery account | **(25)** | – |
| Amortization of debt discount | **–** | 5 |
| | **927** | 1,006 |
| Changes in non-cash balances related to operations (Note 15) | **128** | 135 |
| **Net cash from operating activities** | **1,055** | 1,141 |
| **Financing activities** | | |
| Long-term debt issued | **1,050** | 700 |
| Long-term debt retired | **(540)** | (355) |
| Short-term notes payable | **–** | (60) |
| Dividends paid | **(259)** | (325) |
| Other | **9** | (1) |
| **Net cash from (used in) financing activities** | **260** | (41) |
| **Investing activities** | | |
| Capital expenditures | **(1,284)** | (1,091) |
| Other assets | **(3)** | 8 |
| **Net cash used in investing activities** | **(1,287)** | (1,083) |
| **Net change in cash and cash equivalents** | **28** | 17 |
| Cash and cash equivalents, January 1 | **(12)** | (29) |
| **Cash and cash equivalents, December 31** (Note 15) | **16** | (12) |

See accompanying notes to Consolidated Financial Statements.

# Notes to Consolidated Financial Statements

## NOTE 1.
## DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the OEB.

## NOTE 2.
## SIGNIFICANT ACCOUNTING POLICIES

### Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Company and its wholly owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Inc., Hydro One Brampton Networks Inc. (Hydro One Brampton), Hydro One Telecom Inc., Hydro One Delivery Services Inc. (HODS), Hydro One Lake Erie Link Management Inc. (HOLELMI) and Hydro One Lake Erie Link Company Inc. (HOLELCo).

Hydro One Brampton Inc. was dissolved on January 30, 2007. HODS was dissolved on August 29, 2008. Effective December 13, 2007, upon approval of the resolution to apply for the dissolution of HODS, its interests in HOLELMI and HOLELCo were distributed to Hydro One.

### Basis of Accounting

The Consolidated Financial Statements are prepared in accordance with accounting principles generally accepted in Canada (Canadian GAAP).

### Rate-setting

The rates of the Company's electricity Transmission and Distribution Businesses are subject to regulation by the OEB.

*Transmission*

As part of an OEB-initiated proceeding to review Hydro One Network's transmission rates and to approve revenue requirements for 2006, 2007 and 2008, the OEB announced a decision to apply an earnings sharing mechanism (ESM) to equally share, between Hydro One's shareholder and its customers, any transmission earnings in excess of the approved rate of return of 9.88% for 2006.

On March 30, 2007, the OEB issued a decision approving the concept of establishing a new revenue difference deferral account (RDDA) to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year, for the period commencing January 1, 2007.

On August 16, 2007, the OEB issued its decision in respect of Hydro One Networks' 2007 and 2008 transmission rate application. The decision, which was effective January 1, 2007, approved all operating and capital expenditures for 2007 and 2008. However, the decision resulted in a reduction in the approved return on equity from 9.88% to 8.35%. The OEB also approved final amounts and disposition treatments for certain regulatory liabilities including: the RDDA, the ESM and export and wheeling fees, as well as the transmission market ready regulatory asset.

As part of a joint proceeding involving all transmitters in Ontario, on October 17, 2007 the OEB approved Uniform Transmission Rates (UTRs) for implementation on November 1, 2007 through to December 31, 2008. The new rates fully reflect the approved changes to our revenue requirement and charge determinants.

On May 30, 2008, Hydro One Networks submitted an application to the OEB to adjust UTRs effective January 1, 2009. On August 28, 2008, the OEB approved the application and the decision resulted in an average increase of 9% in the revenue requirement allocation from UTRs to reflect the completion of repayment to customers of the amounts recorded in the ESM and the RDDA at the end of 2008.

*Distribution*

In 2006, the OEB initiated a process of establishing an Incentive Regulation Mechanism (IRM) for the years 2007 to 2010. The process included a formulaic approach to establishing 2007 rates with a rate rebasing approach to be staggered across all Ontario distributors between 2008 and 2010. Hydro One Networks and Hydro One Brampton applied for distribution rate adjustments in February 2007, based on an OEB-approved formula that considers inflation and efficiency targets. In April 2007, the OEB approved the Company's submissions and the revised rates were implemented effective May 1, 2007.

In accordance with the OEB's multi-year distribution rate-setting plan, Hydro One Networks submitted the revenue requirement portion of its 2008 cost of service application on August 15, 2007. This application sought the approval of a revenue requirement of $1,067 million based on a rate of return of 8.64% for 2008, and included a plan to reduce the number of rate classes for its customers and consolidate or harmonize the rates for its existing rate classes to the new proposed rate classes.

On December 18, 2008, the OEB issued a decision approving substantially all work program expenditures effective May 1, 2008, for implementation on February 1, 2009. The OEB also approved recovery of our smart meter expenditures made prior to the end of 2007. Subsequent expenditures will continue to be tracked in deferral accounts for future recovery. The decision approved the establishment of the Revenue Recovery Account (RRA) to record the revenue differential between existing distribution rates and new rates. The RRA will be recovered over a 27-month period commencing February 1, 2009 and ending April 30, 2011.

On November 1, 2007, Hydro One Brampton filed an application for 2008 rates on the basis of the OEB's cost of capital and second-generation IRM policies. On March 19, 2008, the OEB released its decision and the revised rates, including an amount of 67 cents per month per metered customer for smart meters, were approved with an implementation date of May 1, 2008.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities, which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 7.

### Revenue Recognition and Allocation

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as power is transmitted and delivered to customers.

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates the monthly revenue for the period based on wholesale power purchases because customer meters are not generally read at the end of each month. Unbilled revenue included within accounts receivable as at December 31, 2008 amounted to $383 million (2007 – $413 million).

Distribution revenue also includes an amount relating to rate protection for rural residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. The current legislation provides rate protection for prescribed classes of rural residential and remote consumers by reducing the electricity rates that would otherwise apply.

Segment revenues for transmission, distribution and other also include revenue related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

### Corporate Income and Capital Taxes

Under the *Electricity Act*, 1998, Hydro One is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario) as modified by the *Electricity Act*, 1998, and related regulations.

The Company provides for payments in lieu of corporate income taxes relating to its regulated businesses using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from the customers of Hydro One at that time. The Company provides for payments in lieu of corporate income taxes relating to its unregulated businesses using the liability method.

### Materials and Supplies

Materials and supplies represent consumables, spare parts and construction material held for internal construction and maintenance of fixed assets. These assets are carried at lower of average cost or net realizable value.

Effective January 1, 2008, the Company retrospectively adopted Canadian Institute of Chartered Accountants' (CICA) Handbook Section 3031, *Inventories*, with reclassification of comparative prior period amounts. This new section requires that certain major spare parts and standby equipment be reclassified from inventory to fixed assets. The new Handbook section also allows previously recorded impairment losses taken on inventory to be reversed if there is evidence that the net realizable value has subsequently recovered.

The Company already includes certain major standby equipment as in-service fixed assets and depreciates these assets over their useful lives. Upon adoption of the new section in the first quarter of 2008, the Company reclassified asset components and equipment previously classified as materials and supplies inventory. Concurrent with the above reclassification, the Company also reclassified future use land from "fixed assets in service" to "future use land, components and spares." Future use land, components and spares are not depreciated until they are transferred to active capital projects and those projects are placed in-service.

## Fixed Assets

Fixed assets are capitalized at cost which comprises materials, labour, engineering costs, overheads, depreciation on service equipment and the OEB-approved allowance for funds used during construction applicable to capital construction activities within regulated businesses, or interest applicable to capital construction activities within unregulated businesses.

Fixed assets in service consist of transmission, distribution, communication, administration and service assets, and easements. Fixed assets also include future use assets such as land, major components and spare parts, and capitalized development costs associated with deferred capital projects.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have asset-retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its installed assets for an indefinite period, no removal date can be determined and consequently a reasonable estimate of the fair value of most asset-retirement obligations cannot be made at this time. If, at some future date, it becomes possible to estimate the fair value cost of disposing of assets that the Company is legally required to remove, a related asset-retirement obligation will be recognized at that time.

*Transmission*

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, such as transformers, circuit breakers and switches.

*Distribution*

Distribution assets comprise assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

*Communication*

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

*Administration and Service*

Administration and service assets include administrative buildings, major computer systems, personal computers, transport and work equipment, tools, vehicles and minor fixed assets.

*Easements*

Easements include statutory rights of use to transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act*, 2002, as well as other amounts related to access rights.

## Construction in Progress

Overhead costs, including corporate functions and services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology. Financing costs are capitalized on fixed assets under construction based on the OEB's approved allowance for funds used during construction (2008 – 5.32%; 2007 – 5.20%).

### Depreciation

The capital costs of fixed assets are depreciated on a straight-line basis, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically undergoes an external review of its fixed asset depreciation rates, as required by the OEB. The last review resulted in changes to rates effective January 1, 2007. A summary of depreciation rates for the various classes of assets is included below:

| | Depreciation Rates (%) | |
|---|---|---|
| | Range | Average |
| Transmission | 1%–4% | 2% |
| Distribution | 1%–13% | 2% |
| Communication | 1%–13% | 5% |
| Administration and service | 1%–20% | 8% |

Depreciation rates for easements are based on their contract life. The majority of easements are held in perpetuity and are not depreciated.

In accordance with group depreciation practices, the original cost of normal fixed asset-retirements is charged to accumulated depreciation, with no gain or loss reflected in results of operations. Gains and losses on sales of fixed assets and losses on premature retirements are charged to results of operations as adjustments to depreciation expense. Depreciation expense also includes the costs incurred to remove fixed assets.

The estimated service lives of fixed assets are subject to periodic review. Any changes arising from such a review are implemented on a remaining-service-life basis consistent with their inclusion in rates.

### Goodwill

Goodwill represents the cost of acquired local distribution companies in excess of fair value of the net identifiable assets purchased and is evaluated for impairment on an annual basis, or more frequently if circumstances require. Goodwill impairment is assessed based on a comparison of the fair value of the reporting unit to the underlying carrying value of the reporting unit's net assets, including goodwill, with any write-down of the carrying value of goodwill being charged against the results of operations. The Company has determined that goodwill is not impaired. All of the goodwill is attributable to the Distribution Business segment.

### Discounts and Premiums on Debt

Discounts and premiums are amortized over the period of the related debt using the effective interest method.

## Financial Instruments

*Comprehensive Income*

Comprehensive income is composed of the Company's net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on discontinued cash flow hedges, and the change in fair value on existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective interest method over the term of the hedged debt.

*Financial Assets and Liabilities*

All financial instruments are classified into one of the following five categories: held-to-maturity investments, loans and receivables, held-for-trading, other liabilities or available-for-sale. All financial instruments, including derivatives, are carried at fair value on the Consolidated Balance Sheet except for loans and receivables, held-to-maturity investments and other financial liabilities, which are measured at amortized cost. Held-for-trading financial instruments are measured at fair value and all gains and losses are included in financing charges in the period in which they arise. Available-for-sale financial instruments are measured at fair value with revaluation gains and losses included in OCI until the instrument is derecognized or impaired. The Company has classified its financial instruments as follows.

| | |
|---|---|
| Cash and cash equivalents | Held-for-trading |
| Accounts receivable | Loans and receivables |
| Short-term investments | Held-to-maturity/Held-for-trading |
| Fixed-to-floating interest rate swap | Not classified |
| Long-term accounts receivable | Loans and receivables |
| Bank indebtedness | Other liabilities |
| Accounts payable | Other liabilities |
| Short-term notes payable | Other liabilities |
| Long-term debt (unless otherwise specified) | Other liabilities |
| MTN Series 8 Note | Designated as held-for-trading |
| MTN Series 14 Note | Not classified |

Short-term investments are generally classified as held-to-maturity, however, the Company allows itself the possibility to classify pools of short-term investments as held-for-trading where there is not the intention of holding a pool of assets to their maturity. Documentation of the short-term investment classification is made on inception.

The MTN Series 8 Note was a step-up coupon note which matured on May 15, 2008 (See Notes 8 and 9). Where there is an economic hedge, as in the case of the MTN Series 8 Note and associated interest rate swap, the Company applied the fair value option without hedge accounting.

Where long-term debt is designated as part of a hedging relationship, as in the case of the MTN Series 14 Note, the long-term debt is not classified.

All financial instrument transactions are recorded at trade date.

*Derivatives and Hedge Accounting*

All derivative instruments, including embedded derivatives, are carried at fair value on the Consolidated Balance Sheet unless exempted from derivative treatment as a normal purchase and sale or when it is deemed that the economic characteristics and risks of the embedded derivative are not closely related to the economic characteristics and risks of the host contract. All changes in fair value are recorded in financing charges unless cash flow hedge accounting is used, in which case changes in fair value are recorded in OCI to the extent that the hedge is effective.

The Company does not engage in derivative trading or speculative activities.

The Company periodically develops hedging strategies for execution taking into account risk management objectives. At the inception of a hedging relationship, the Company documentation includes its risk management objective for establishing the hedging relationship, the identification of hedged and hedging item, the nature of the specific risk exposure being hedged and the method for assessing effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on an ongoing basis, whether the hedging items that are used are effective in offsetting changes in fair values or cash flows of the hedged items.

*Transaction Costs*

Transaction costs for financial assets and liabilities that are other than held-for-trading are added to the carrying value of the asset or liability and then amortized over the expected life of the instrument using the effective interest method.

**Financial Instrument Disclosures and Presentation**

Effective January 1, 2008, the Company adopted two new accounting standards comprising CICA Handbook Sections 3862, *Financial Instruments Disclosures* and 3863, *Financial Instruments Presentation*. The adoption of the new disclosure standard required an increased emphasis on disclosure about the risks associated with recognized and unrecognized financial instruments. These additional disclosures are provided in Note 9. The adoption of the new standard on presentation carried forward unchanged the presentation requirements from Section 3861, *Financial Instruments Disclosure and Presentation*, and therefore, adoption of this new standard did not have any impact on the Consolidated Financial Statements.

**Capital Disclosure**

Effective January 1, 2008, the Company adopted a new accounting standard comprising CICA Handbook Section 1535, *Capital Disclosures*. The adoption of the new standard required the disclosure of qualitative and quantitative information about the Company's capital and how it is managed. These disclosures are provided in Note 10.

**Employee Future Benefits**

Employee future benefits provided by Hydro One include pension, group life insurance, health care and long-term disability.

In accordance with the OEB's rate orders, pension costs are recorded when employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Actuarial valuations are conducted at least every three years. Pension costs are also calculated on an accrual basis. Pension costs are actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases, on the actuarial present value of accrued pension benefits. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are valued using fair values. Past service costs from plan amendments and all actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefits other than pension are recorded on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments and actuarial gains or losses are amortized on a straight-line basis over the expected average remaining service life of the employees covered.

Employee future benefit costs are attributed to labour and charged to operations or capitalized as part of the cost of fixed assets.

**Environmental Costs**

Hydro One recognizes a liability for estimated future expenditures associated with the assessment and remediation of contaminated lands and for the phase-out and destruction of polychlorinated biphenyl (PCB) contaminated mineral oil from electrical equipment, based on the present value of these estimated future expenditures. As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a regulatory asset has been recognized to reflect the future recovery of these costs from customers. Hydro One reviews its estimates of future environmental expenditures on an ongoing basis.

### Use of Estimates

The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses for the year. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB or the Province.

### Emerging Accounting Changes

*Income Taxes*

In August 2007, the Canadian Accounting Standards Board (AcSB) issued a decision, effective January 1, 2009, to withdraw the temporary exemption in CICA Handbook Section 1100, *Generally Accepted Accounting Principles*, which permits the recognition and measurement of assets and liabilities arising from rate regulation. Further, CICA Handbook Section 3465, *Income Taxes*, was amended to require the recognition of future income tax liabilities and assets for regulated enterprises that were previously not subject to these provisions. Consequently, the Company will be required to reflect on its Consolidated Balance Sheet, the effect of applying the liability method when accounting for payments in lieu of corporate income taxes and a corresponding regulatory asset. The Company is currently assessing the impact of the AcSB's decision on its Consolidated Balance Sheet.

*Goodwill and Intangibles*

In November 2007, the AcSB approved new CICA Handbook Section 3064, *Goodwill and Intangible Assets*. The new section is applicable to Hydro One's interim and annual Consolidated Financial Statements for the 2009 fiscal year. The Company is currently evaluating the classification of certain of its assets to determine if they meet the definition of intangible assets. Assets that may potentially be reclassified include land rights and easements, certain software assets, telecom indefeasible rights of use and amounts contributed to other entities as capital contributions. It is not anticipated that the new section will have any impact on goodwill or result in any impacts on the Company's results of operations.

## NOTE 3.
## DEPRECIATION AND AMORTIZATION

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| Depreciation of fixed assets in service | **418** | 384 |
| Fixed asset removal costs | **46** | 39 |
| Amortization of regulatory and other assets | **84** | 98 |
| | **548** | 521 |

## NOTE 4.
## FINANCING CHARGES

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| Interest on short-term notes payable | **2** | 4 |
| Interest on long-term debt payable | **331** | 308 |
| Interest accreted on regulatory accounts | **2** | – |
| Other | **–** | 7 |
| Less: Interest capitalized on construction in progress | **(36)** | (24) |
| Interest earned on investments | **(7)** | (5) |
| Amortization of debt discount | **–** | 5 |
| | **292** | 295 |

## NOTE 5.
## PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The provision for payments in lieu of corporate income taxes (PILs) differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. A reconciliation between the statutory and effective tax rates is provided as follows.

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| Income before provision for PILs | **611** | 604 |
| Federal and Ontario statutory income tax rate | **33.50%** | 36.12% |
| Provision for PILs at statutory rate | **205** | 218 |
| Increase (decrease) resulting from: | | |
| Net temporary differences: | | |
| Transmission amounts (paid) received but not recognized for accounting purposes | **(34)** | 25 |
| Capital cost allowance in excess of depreciation and amortization | **(32)** | (9) |
| Retail settlement variance accounts | **15** | 17 |
| Pension contributions in excess of pension expense | **(13)** | (13) |
| Overheads capitalized for accounting but deducted for tax purposes | **(12)** | (12) |
| Interest capitalized for accounting purposes but deducted for tax purposes | **(11)** | (9) |
| Distribution amounts paid but not recognized for accounting purposes | **(8)** | – |
| Employee future benefits other than pension expense in excess of cash payments | **6** | 7 |
| Environmental expenditures | **(5)** | (4) |
| Other | **–** | (5) |
| Net temporary differences | **(94)** | (3) |
| Net permanent differences | **2** | (10) |
| Provision for PIL | **113** | 205 |
| Effective income tax rate | **18.49%** | 33.94% |

Future income taxes relating to the regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2008, future income tax liabilities of $332 million (2007 – $253 million), based on substantively enacted income tax rates and laws that are expected to apply when the temporary differences reverse, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized using the liability method rather than the taxes payable method. As a result, the provision for PILs would have been higher by approximately $79 million (2007 – higher by $28 million), including the impact of a change in substantively enacted tax rates.

Future income tax assets relating to the non-regulated businesses have also not been recorded in the accounts as they have not met the criterion of "more likely than not" to be realized. As at December 31, 2008, future income tax assets of $4 million (2007 – $4 million), based on substantively enacted income tax rates and laws, have not been recorded.

## NOTE 6.
## FIXED ASSETS

| *December 31 (Canadian dollars in millions)* | Fixed Assets | Accumulated Depreciation | Construction in Progress | Total |
|---|---|---|---|---|
| **2008** | | | | |
| Transmission | **8,995** | **3,307** | **659** | **6,347** |
| Distribution | **6,317** | **2,266** | **165** | **4,216** |
| Communication | **773** | **342** | **54** | **485** |
| Administration and service | **1,164** | **588** | **85** | **661** |
| Easements | **487** | **77** | **–** | **410** |
| | **17,736** | **6,580** | **963** | **12,119** |
| **2007** | | | | |
| Transmission | 8,725 | 3,152 | 370 | 5,943 |
| Distribution | 5,907 | 2,133 | 115 | 3,889 |
| Communication | 739 | 305 | 58 | 492 |
| Administration and service | 1,000 | 556 | 79 | 523 |
| Easements | 485 | 74 | – | 411 |
| | 16,856 | 6,220 | 622 | 11,258 |

Financing costs are capitalized on fixed assets under construction, including allowance for funds used during construction on regulated assets and interest on unregulated assets, and were $36 million in 2008 (2007 – $24 million).

## NOTE 7.
## REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. Hydro One has recorded the following regulatory assets and liabilities.

| *December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| **Regulatory assets:** | | |
| Environmental | **253** | 65 |
| Regulatory asset recovery account II | **43** | 66 |
| Revenue recovery account | **25** | – |
| Rural and remote rate protection variance account | **17** | 4 |
| Employee future benefits other than pension | **–** | 42 |
| Regulatory asset recovery account I | **–** | 19 |
| Other | **17** | 13 |
| Total regulatory assets | **355** | 209 |
| Less: current portion | **64** | 103 |
| | **291** | 106 |

| *December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| **Regulatory liabilities:** | | |
| Deferred pension | **441** | 380 |
| Regulatory liability refund account | **73** | 43 |
| Retail settlement variance accounts | **31** | 7 |
| Export and wheeling fees | **27** | 38 |
| Regulatory asset recovery account I | **19** | – |
| Revenue difference deferral account | **–** | 73 |
| Transmission earnings sharing mechanism | **–** | 28 |
| Other | **16** | 10 |
| Total regulatory liabilities | **607** | 579 |
| Less: current portion | **43** | 114 |
| | **564** | 465 |

### Regulatory Assets

*Environmental*

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 12). Because such expenditures are expected to be recoverable in future rates, the Company has recognized an equivalent amount as a regulatory asset, including the additional amount recorded in 2008 as a result of final PCB regulations. This regulatory asset is expected to be amortized to results of operations on a basis consistent with the pattern of actual expenditures expected to be incurred up to the year 2025. The OEB has the discretion to examine and assess the prudence and the timing of recovery of all of Hydro One's future regulatory expenditures. In the absence of rate regulated accounting, operation, maintenance and administration expenses would have been higher by $195 million (2007 – $3 million). In addition, amortization expense in 2008 would have been lower by $14 million (2007 – $12 million) and financing charges would have been higher by $7 million (2007 – $4 million).

*Regulatory Asset Recovery Account II (RARA II)*

On April 12, 2006, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The OEB ordered that the approved balances be recovered on a straight-line basis over a four-year period from May 1, 2006 to April 30, 2010. The RARA II includes retail settlement and cost-variance amounts and distribution low-voltage service amounts, plus accrued interest. In the absence of rate regulated accounting, amortization expense in 2008 would have been lower by $23 million (2007 – $23 million). In addition, related financing charges would have been higher by $2 million (2007 – $3 million).

*Revenue Recovery Account (RRA)*

On December 18, 2008, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. The approved rates are effective May 1, 2008 with an implementation date of February 1, 2009. The OEB approved the establishment of the RRA to record the revenue differential between existing distribution rates and the new rates. The OEB ordered that the approved revenue requirement be retroactively recovered, through rate riders, over a period of 27 months commencing February 1, 2009 and ending April 30, 2011.

*Rural and Remote Rate Protection Variance Account (RRRP)*

Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of Hydro One Networks who are eligible for rate protection. In 2002, the OEB approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One and the fixed entitlements defined in the regulation are tracked by the Company in the RRRP variance account to be disposed of at a later date.

### *Employee Future Benefits Other Than Pension*

Employee future benefits other than pension are recorded using the accrual method as required by Canadian GAAP. The OEB has allowed for the recovery of past service costs, which arose on the adoption of the accrual method, in the revenue requirement on a straight-line basis over a 10-year period. As a result, in 1999 Hydro One recorded a regulatory asset, with an original balance of $419 million, to reflect this regulatory treatment. This regulatory asset has been fully recovered. In 2007, it had a remaining recovery period of one year and did not earn a return. In the absence of rate regulated accounting, amortization expense in 2008 would have been lower by $42 million (2007 – $42 million).

*Regulatory Asset Recovery Account I (RARA I)*

On December 9, 2004, the OEB issued a decision on the prudence of the distribution-related deferral account balances for which recovery was sought by Hydro One in its May 31, 2004 application. Amounts for which recovery was approved represented balances incurred prior to December 31, 2003, plus associated interest. The OEB ordered that the approved amounts be aggregated into a single regulatory account to be recovered on a straight-line basis over the period ending April 30, 2008. The RARA I included distribution business low-voltage services amounts, deferred environmental expenditures incurred in 2001 and 2002, deferred market ready expenditures, retail settlement variance amounts, and other amounts primarily consisting of accrued interest. Hydro One Networks has accumulated a net liability in its RARA I account since May 1, 2008 due to continuance of the rate rider, disposition of which will be subject to a future OEB review. In the absence of rate regulated accounting, amortization expense in 2008 would have been lower by $5 million (2007 – $20 million). In addition, related financing charges would have remained the same (2007 – higher by $1 million).

**Regulatory Liabilities**

*Deferred Pension*

In accordance with the OEB's 1999 transitional rate order, pension costs are recorded in results of operations when employer contributions are paid into the pension plan. The Company's deferred pension asset represents the cumulative difference between employer contributions and pension costs and the deferred pension regulatory liability results from the Company's recognition, as the result of OEB direction, of revenues and expenses in different periods than would be the case for an unregulated enterprise. In the absence of rate regulated accounting, operating, maintenance and administration expense would have been lower by $38 million (2007 – higher by $1 million).

*Regulatory Liability Refund Account (RLRA)*

On December 18, 2008, the OEB announced its decision regarding the Company's rate application in respect of the distribution business of Hydro One Networks. As part of the decision, the OEB also approved certain distribution-related deferral account balances sought by Hydro One in its application. Amounts for which recovery was approved represented balances incurred prior to April 30, 2008, plus associated interest. The OEB ordered that the approved balances be aggregated into a single regulatory account to be recovered over a 27-month period from February 1, 2009 to April 30, 2011. The RLRA includes retail settlement variance amounts and deferred tax changes.

*Retail Settlement Variance Accounts (RSVA)*

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The OEB's December 9, 2004 decision allowed for recovery of retail settlement variance amounts accumulated prior to December 31, 2003, inclusive of interest, within the RARA I. The OEB's April 12, 2006 decision allowed for recovery of retail settlement variance amounts accumulated since January 1, 2004 and forecasted through to April 30, 2006, inclusive of interest, within the RARA II. The OEB's December 18, 2008 decision allowed for recovery of retail settlement variance amounts accumulated since May 1, 2006 through to April 30, 2008, inclusive of interest, within the RRA. The Company has accumulated a net liability in its RSVA since May 1, 2008 and anticipates that the OEB will include the net balance of this regulatory account in future rates.

*Export and Wheeling Fees*

Consistent with the IESO's Market Rules, an export and wheeling fee is collected by the IESO and remitted to Hydro One at the rate of $1 per MWh on electricity exported outside of Ontario. The amounts collected in respect of these export and wheeling fees, plus interest, were taken into consideration in the revenue requirement of Hydro One's Transmission Business as part of the Company's transmission rate application filed with the OEB in September 2006. On August 16, 2007, the OEB issued its decision in respect of the Company's transmission rate application and approved final amounts and disposition treatments for the export wheeling fees. The export wheeling fees will be factored into rates over a four-year period ending December 31, 2010.

*Revenue Difference Deferral Account (RDDA)*

On March 30, 2007, the OEB issued a decision approving the establishment of the RDDA to record the revenue differential between existing transmission rates and the new rates that were anticipated to be approved later in the year. The new deferral account was to represent the revenue differential between existing and future rates for the period commencing January 1, 2007. On August 16, 2007, in its decision on Hydro One Networks' 2007 and 2008 transmission rates, the OEB approved final amounts and disposition treatments for the RDDA liability, which was returned to customers over the 14-month period ending December 31, 2008.

*Transmission Earnings Sharing Mechanism (ESM)*

On February 21, 2006, the OEB issued a decision that established an ESM to equally share, between the Company's shareholder and ratepayers, any transmission earnings in excess of the approved rate of return of 9.88%, for the period January 1, 2006 until new transmission rates were set. Consequently, 50% of the Company's excess earnings were deferred as a regulatory liability. On March 30, 2007, the OEB issued a decision ordering that the transmission ESM cease effective December 31, 2006. The ESM was taken into consideration in setting the revenue requirement of Hydro One Networks for 2007 and 2008. On August 16, 2007, in its decision on Hydro One Networks' 2007 and 2008 transmission rates, the OEB approved final amounts and disposition treatments for the ESM which was returned to customers over a fourteen-month period ending December 31, 2008, in accordance with the decision.

## NOTE 8.
## DEBT

| *December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| **Long-term debt:** | | |
| 4.70% notes due 2008[1] | **–** | 40 |
| 4.00% notes due 2008 | **–** | 500 |
| 3.95% notes due 2009 | **400** | 400 |
| 7.15% debentures due 2010 | **400** | 400 |
| 3.89% notes due 2010 | **100** | – |
| 4.08% notes due 2011[2] | **250** | – |
| 6.40% notes due 2011 | **250** | 250 |
| 5.77% notes due 2012 | **600** | 600 |
| 5.00% notes due 2013 | **400** | – |
| 4.64% notes due 2016 | **450** | 450 |
| 5.18% notes due 2017 | **600** | 300 |
| 7.35% debentures due 2030 | **400** | 400 |
| 6.93% notes due 2032 | **500** | 500 |
| 6.35% notes due 2034 | **385** | 385 |
| 5.36% notes due 2036 | **600** | 600 |
| 4.89% notes due 2037 | **400** | 400 |
| 6.59% notes due 2043 | **315** | 315 |
| 5.00% notes due 2046 | **75** | 75 |
| | **6,125** | 5,615 |
| Add: Unrealized hedged loss[2] | **15** | – |
| Less: Long-term debt payable within one year | **(400)** | (540) |
| Net unamortized premiums | **20** | 13 |
| Unamortized debt issuance costs | **(27)** | (25) |
| Long-term debt | **5,733** | 5,063 |

[1] Step-up coupon (MTN Series 8 Note) from 4.10% to 6.40%, extendable to 2011, matured on May 15, 2008.

[2] The unrealized hedged loss relates to the MTN Series 14 Note, which is accounted for as a fair value hedge. The unrealized hedged loss is offset by the $15 million unrealized gain on the related fixed-to-floating interest rate swap agreement.

Short-term debt represents promissory notes pursuant to the Company's Commercial Paper Program. The notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. In 2008, the notes had a weighted-average interest rate of 3.0%.

Hydro One has a $1,000 million committed and unused revolving standby credit facility with a syndicate of banks maturing in August 2010. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program.

The Company issues notes for long-term financing under the Medium-Term Note (MTN) Program. On November 10, 2008, Hydro One issued new notes comprised of medium-term notes with a principal amount of $400 million having a five-year term with a coupon rate of 5.0%. The notes are due November 12, 2013. On November 19, 2008, Hydro One issued notes under the Company's Medium-Term Note Program. The issue was comprised of medium-term notes with a principal amount of $100 million having a two-year term with a coupon rate of 3.89%. The notes are due November 19, 2010.

The maximum authorized principal amount of medium-term notes issuable under this program is $2,500 million of which, as at December 31, 2008, $1,150 million was remaining.

The long-term debt is unsecured and denominated in Canadian dollars. Such debt is summarized by the number of years to maturity in Note 9.

## NOTE 9.
## CARRYING AND FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The carrying value of financial instruments as at December 31, 2008 is as follows:

| *(Canadian dollars in millions)* | Derivatives Used for Hedging | Other Financial Instruments Used for Hedging | Held-for-Trading | Loans and Receivables | Other Financial Liabilities |
|---|---|---|---|---|---|
| **Financial assets** | | | | | |
| Cash and cash equivalents | – | – | 16 | – | – |
| Accounts receivable | – | – | – | 754 | – |
| Other assets (long-term) | 15 | – | – | 6 | – |
| **Financial liabilities** | | | | | |
| Accounts payable and accrued charges[1] | – | – | – | – | 766 |
| Long-term debt | – | 265 | – | – | 5,868 |

[1] Accounts payable and accrued charges do not include income taxes payable or dividends payable.

The carrying amounts of all financial instruments, except long-term debt, approximate fair value. The fair value of derivative financial instruments reflects the estimated amount that the Company, if required to settle an outstanding contract, would have been required to pay or would be entitled to receive at year end. The fair value of long-term debt, based on year end quoted market prices for the same or similar debt of the same remaining maturities, is provided in the following table.

| *December 31 (Canadian dollars in millions)* | | **2008** | | 2007 |
|---|---|---|---|---|
| | **Carrying Value** | **Fair Value** | Carrying Fair | Fair Value |
| Long-term debt[1] | **6,125** | **6,128** | 5,615 | 6,005 |

[1] The carrying value of long-term debt represents the par value of the notes and debentures, other than the MTN Series 8 step-up note, which is marked to market and the MTN Series 14 Note which is designated as part of a hedging relationship.

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

### Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with the Company's capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although we could in the future decide to issue foreign currency denominated debt, which will be hedged back to Canadian dollars consistent with Hydro One's risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's Distribution and Transmission Businesses is derived using a formulaic approach, which is in part based on the forecast for long-term Government of Canada bond yields. The Company estimates that a 1% decrease in the forecast long-term Government of Canada bond yield used in the current OEB formula for determining the Company's rate of return on equity would reduce its Transmission Business' results of operations by approximately $21 million and its Distribution Business' results of operations by approximately $13 million.

### Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. As at December 31, 2008, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any individual customer. As at December 31, 2008, there were no significant balances of accounts receivable due from any single customer.

In the year, the Company's provision for bad debts remained relatively unchanged at $23 million (2007 – $21 million). Minor adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As at December 31, 2008, approximately 4% of the Company's accounts receivable was aged more than 60 days.

Hydro One manages its counter-party credit risk through various techniques including entering into transactions with highly rated counter-parties limiting total exposure levels with individual counter-parties consistent with the Company's Board-approved Credit Risk Policy, entering into master agreements, which enable net settlement and the contractual right of offset, and monitoring the financial condition of counter-parties. The Company's credit risk for accounts receivable is limited to the carrying amount on the Consolidated Balance Sheet.

The Company uses derivative financial instruments to manage interest rate risk. Hydro One may enter into derivative agreements such as forward starting pay fixed interest rate swap agreements, to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. No such agreements were outstanding as at December 31, 2008. Two forward starting pay fixed interest rate swaps with a notional amount of $140 million were outstanding as at December 31, 2007.

Derivative financial instruments result in exposure to credit risk since there is a risk of counter-party default. As at December 31, 2008, the only derivative instrument held by Hydro One was a $250 million fixed-to-floating interest rate swap agreement to convert the 4.08% coupon maturing March 3, 2011 into a three-month variable rate debt. The counter-party credit risk exposure on the fair value of this interest rate swap contract is $15 million as at December 31, 2008. As at December 31, 2007, the Company had a pay floating interest rate swap agreement related to a step-up coupon note issuance that was accounted for using the fair value option without hedge accounting. Counter-party credit risk exposure was insignificant in 2007.

**Liquidity Risk**

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Short-term liquidity is provided through cash and cash equivalents on hand, funds from operations, and the Company's Commercial Paper Program, under which it is authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days. The Commercial Paper Program is supported by a $1,000 million committed revolving credit facility with a syndicate of banks maturing in August 2010. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

As at December 31, 2008, accounts payable and accrued charges in the amount of $791 million are expected to be settled in cash at their carrying amounts within the next year. Long-term debt maturing over the next 12 months is $400 million. Interest payments over the next 12 months on the Company's outstanding debt amount to $338 million.

As at December 31, 2008, Hydro One has issued long-term debt in the amount of $6,125 million and the Company is required to make interest payments in the amount of $5,177 million. Principal outstanding, interest payments and related weighted-average interest rate are summarized by the number of years to maturity in the following table:

| Years to Maturity | Principal Outstanding on Notes and Debentures *(Canadian dollars in millions)* | Interest Payments *(Canadian dollars in millions)* | Weighted-average Interest Rate *(Percent)* |
|---|---|---|---|
| 1 year | 400 | 338 | 4.0 |
| 2 years | 500 | 316 | 6.5 |
| 3 years | 500 | 292 | 5.2 |
| 4 years | 600 | 271 | 5.8 |
| 5 years | 400 | 237 | 5.0 |
| | 2,400 | 1,454 | 5.4 |
| 6–10 years | 1,050 | 1,000 | 4.9 |
| Over 10 years | 2,675 | 2,723 | 6.2 |
| | 6,125 | 5,177 | 5.6 |

## NOTE 10.
## CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

The Company considers its capital structure to consist of shareholder's equity, long-term debt, and cash and cash equivalents. The Company's capital structure as at December 31, 2008 and December 31, 2007 was as follows:

| *(Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| Long-term debt payable within one year | **400** | 540 |
| Less: Cash and cash equivalents | **16** | (12) |
| | **384** | 552 |
| Long-term debt | **5,733** | 5,063 |
| Preferred shares | **323** | 323 |
| Common shares | **3,314** | 3,314 |
| Retained earnings | **1,497** | 1,258 |
| | **5,134** | 4,895 |
| **Total capital** | **11,251** | 10,510 |

For the purposes of this table and the Consolidated Statements of Cash Flows, "cash and cash equivalents" refers to the Consolidated Balance Sheet items "cash and cash equivalents" and "bank indebtedness."

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2008, Hydro One is in compliance with all of these covenants and limitations.

## NOTE 11.
## EMPLOYEE FUTURE BENEFITS

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton. Employees of Hydro One Brampton participate in the Ontario Municipal Employees Retirement System (OMERS), a multi-employer public sector pension fund. Current contributions by Hydro One Brampton are approximately $1 million annually.

### Plan Asset Mix

Hydro One's pension plan asset mix at December 31, 2008 and 2007 was as follows.

| | % of Plan Assets | |
|---|---|---|
| *December 31* | **2008** | 2007 |
| Equity securities | **62.0** | 62.5 |
| Debt securities | **33.3** | 34.1 |
| Other | **4.7** | 3.4 |
| | **100.0** | 100.0 |

### Supplementary Information

The Hydro One pension plan does not hold any direct securities of the Company, but did hold debt securities of the Province of $88 million and $90 million at December 31, 2008 and 2007, respectively.

The Company's pension plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. The measurement date used to determine plan assets and the accrued benefit obligation is December 31. Based on the actuarial valuation filed with the Financial Services Commission of Ontario on September 20, 2007, effective for December 31, 2006, the Company contributed $101 million to its pension plan in respect of 2008 (2007 – $95 million), all of which is required to satisfy minimum funding requirements. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash. Contributions after 2009 will be based on an actuarial valuation effective December 31, 2009, and will depend on future investment returns and changes in benefits or actuarial assumptions.

Total cash payments for employee future benefits made in 2008, consisting of cash contributed by the Company to its funded pension plan and cash payments directly to beneficiaries for its unfunded other benefit plans was $142 million (2007 – $137 million).

*Pension Asset Transfer*

Effective March 1, 2002, Hydro One began receiving a range of services from Inergi LP, including information technology, customer care, supply chain and certain human resources and financial services. In connection with this agreement, the Company transferred approximately 770 regular employees to Inergi LP. On March 10, 2008, the Company was granted consent from the Financial Services Commission of Ontario to transfer pension assets and related pension liabilities for affected employees from the Hydro One Pension Plan to the Inergi LP Pension Plan. Under the agreement, the Company recognized a settlement of $21 million in its results of operations for the first quarter, inclusive of a related interest credit of $6 million. The pension asset-transfer took place in the second quarter.

| | Pension | | Employee Future Benefits Other Than Pension | |
|---|---|---|---|---|
| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 | **2008** | 2007 |
| **Change in accrued benefit obligation** | | | | |
| Accrued benefit obligation, January 1 | **5,077** | 5,411 | **1,094** | 1,100 |
| Current service cost | **98** | 105 | **22** | 23 |
| Interest cost | **277** | 282 | **60** | 57 |
| Benefits paid | **(272)** | (264) | **(41)** | (42) |
| Plan amendments | **–** | – | **–** | – |
| Net actuarial gain | **(1,173)** | (457) | **(261)** | (44) |
| Accrued benefit obligation, December 31 | **4,007** | 5,077 | **874** | 1,094 |
| **Change in plan assets** | | | | |
| Fair value of plan assets, January 1 | **5,100** | 5,123 | **–** | – |
| Actual return on plan assets | **(1,121)** | 142 | **–** | – |
| Reciprocal transfers[2] | **21** | – | **–** | – |
| Benefits paid | **(272)** | (264) | **–** | – |
| Employer's contributions[1] | **101** | 95 | **–** | – |
| Employees' contributions | **20** | 17 | **–** | – |
| Administrative expenses | **(13)** | (13) | **–** | – |
| Fair value of plan assets, December 31 | **3,836** | 5,100 | **–** | – |
| **Funded status** | | | | |
| (Unfunded benefit obligation) funded excess | **(171)** | 23 | **(874)** | (1,094) |
| Unamortized net actuarial losses (gains) | **594** | 336 | **(92)** | 178 |
| Unamortized past service costs | **18** | 21 | **18** | 21 |
| Deferred pension asset (accrued benefit liability) | **441** | 380 | **(948)** | (895) |
| Less: current portion | **–** | – | **40** | 40 |
| Deferred pension asset (long-term liability) | **441** | 380 | **(908)** | (855) |

[1] In January 2009, the Company made a contribution of $10 million in respect of 2008 (2008 – $8 million in respect of 2007).

[2] In August 2008, the Hydro One Pension Plan received $21 million in reciprocal transfers, of which $19 million represents a reciprocal transfer of assets from the Inergi LP pension plan.

| | Pension | | Employee Future Benefits Other Than Pension | |
|---|---|---|---|---|
| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 | **2008** | 2007 |
| **Components of net periodic benefit cost** | | | | |
| Current service cost, net of employee contributions | **78** | 88 | **22** | 23 |
| Interest cost | **277** | 282 | **60** | 57 |
| Actual return on plan asset net of expenses | **1,113** | (129) | **–** | – |
| Actuarial gain | **(1,173)** | (457) | **(261)** | (44) |
| Plan amendments | **–** | – | **–** | – |
| Other | **–** | – | **–** | – |
| **Costs arising in the period** | **295** | (216) | **(179)** | 36 |
| Differences between costs arising in the period and costs recognized in the period in respect of: | | | | |
| Return on plan assets | **(1,465)** | (212) | **–** | – |
| Actuarial loss | **1,206** | 522 | **269** | 59 |
| Plan amendments | **4** | 3 | **4** | 4 |
| Net periodic benefit cost | **40** | 97 | **94** | 99 |
| Charged to results of operations[3] | **63** | 58 | **57** | 60 |
| **Effect of 1% increase in health care cost trends on:** | | | | |
| Accrued benefit obligation, December 31 | **–** | – | **108** | 167 |
| Service cost and interest cost | **–** | – | **14** | 12 |
| **Effect of 1% decrease in health care cost trends on:** | | | | |
| Accrued benefit obligation, December 31 | **–** | – | **(88)** | (132) |
| Service cost and interest cost | **–** | – | **(11)** | (9) |
| **Significant assumptions** | | | | |
| For net periodic benefit cost: | | | | |
| Expected rate of return on plan assets | **7.00%** | 6.75% | **–** | – |
| Weighted-average discount rate | **5.50%** | 5.25% | **5.50%** | 5.24% |
| Rate of compensation scale escalation (without merit) | **3.00%** | 3.25% | **3.00%** | 3.25% |
| Rate of cost of living increase | **2.25%** | 2.50% | **2.25%** | 2.50% |
| Average remaining service life of employees *(years)* | **10** | 10 | **11** | 9 |
| Rate of increase in health care cost trend[4] | **–** | – | **4.40%** | 4.40% |
| For accrued benefit obligation, December 31: | | | | |
| Weighted-average discount rate | **7.25%** | 5.50% | **7.25%** | 5.50% |
| Rate of compensation scale escalation (without merit) | **2.75%** | 3.00% | **2.75%** | 3.00% |
| Rate of cost of living increase | **2.00%** | 2.25% | **2.00%** | 2.25% |
| Rate of increase in health care cost trend[5] | **–** | – | **4.81%** | 4.40% |

[3] The Company follows the cash basis of accounting. During 2008, pension costs of $103 million (2007 – $95 million) were attributed to labour, of which $63 million (2007 – $58 million) was charged to operations and $40 million (2007 – $37 million) was capitalized as part of the cost of fixed assets.

[4] 8.33% in 2008 grading down to 4.40% per annum in and after 2018 (2007 – 8.69% in 2007 grading down to 4.40% per annum in and after 2018).

[5] 8.81% in 2009 grading down to 4.81% per annum in and after 2023 (2007 – 8.33% in 2008 grading down to 4.40% per annum in and after 2018).

## NOTE 12.
## ENVIRONMENTAL LIABILITIES

| *December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| Environmental liabilities, January 1 | **65** | 70 |
| Interest accretion | **7** | 4 |
| Expenditures | **(14)** | (12) |
| Revaluation adjustment | **195** | 3 |
| Environmental liabilities, December 31 | **253** | 65 |
| Less: current portion | **(16)** | (13) |
| | **237** | 52 |

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2008 and in total thereafter are as follows: 2009 – $16 million; 2010 – $11 million; 2011 – $11 million; 2012 – $12 million; 2013 – $21 million and thereafter – $263 million.

There are uncertainties in estimating future environmental costs due to potential external events such as changing regulations and advances in remediation technologies. Hydro One continuously reviews factors affecting its cost estimates as well as the environmental condition of the various properties. The actual cost of investigation or remediation may differ from current estimates.

On September 17, 2008, Environment Canada published its final regulations governing the management, storage and disposal of polychlorinated biphenyls (PCBs). These regulations were enacted under the *Canadian Environmental Protection Act*, 1999. The new regulations impose timelines for disposal of PCBs based on different types of equipment, in-use status and PCB-contamination thresholds. Under the regulations, all PCBs in concentrations of 500 parts per million (ppm) or more, except pole-top transformers and their pole-top auxiliary electrical equipment and light ballasts, must be disposed of by the end of 2009. PCBs in concentrations of 50 ppm or more in pole-top transformers and their pole-top auxiliary electrical equipment, light ballasts and other electrical equipment must be disposed of by the end of 2025. In addition, liquids with 2 ppm or more that have been removed from equipment cannot be reused.

Management judges that the Company has very limited PCB-contaminated assets in excess of 500 ppm. Priority will be given to targeting inspection and testing work toward identifying and removing PCBs in assets as quickly as operationally feasible. Assets to be disposed of primarily consist of pole and pad-mount distribution transformers and light ballasts which require disposal by 2025. Contaminated distribution and transmission station equipment will generally be decontaminated by removing PCB-contaminated insulating oil and retrofilling with less than 2 ppm oil as the liquids are removed.

Consistent with its accounting policy for environmental costs, since 2001 Hydro One has recorded a liability for the estimated future expenditures associated with the phase-out and destruction of PCB-contaminated insulating oil from electrical equipment. The Company's liability has been based on management's best estimate of the net present value of the future expenditures expected to be required to comply with existing PCB regulations.

Management's best estimate of the additional estimated future expenditures to comply with the final regulations is about $265 million. The increase in estimated future expenditures primarily relates to the inspection and testing of pole-top distribution transformers, the removal and disposal of certain transmission and distribution station equipment and the decontamination and retrofilling of station equipment found to be in excess of regulatory thresholds. These expenditures will be incurred over the period from 2009 to 2025 with the majority of the spending occurring in the 2013 to 2025 period. As a result of the final regulations and the resulting increase in future expenditures, the Company has increased its liability in the third quarter by approximately $195 million.

As the Company anticipates that the related expenditures will continue to be recoverable in future rates, a $195 million increase to the environmental regulatory asset has been recorded to reflect the probability of future recovery of these PCB expenditures from customers.

In determining the amounts to be recorded as environmental liabilities, the Company has estimated the current cost of completing mitigation work and has made assumptions as to when the future expenditures will actually be incurred to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express current cost estimates as estimated future expenditures. These future expenditures are discounted using factors ranging from 5.14% to 6.25% depending on the year the obligations were first recorded. All factors used in estimating our environmental liabilities represent management's best estimates. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation assumptions and assumed pattern of annual cash flows may differ significantly from our assumptions. In addition, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures.

Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

## NOTE 13.
## SHARE CAPITAL

### Common and Preferred Shares

On March 31, 2000, the Company issued to the Province 12,920,000 5.5% cumulative preferred shares with a redemption value of $25.00 per share, and 99,990 common shares, bringing the total number of outstanding common shares to 100,000. The Company is authorized to issue an unlimited number of preferred and common shares.

The preferred shares are entitled to an annual cumulative dividend of $18 million, which is payable on a quarterly basis. The preferred shares are redeemable at the option of the Province at a price of $25 per share, representing the stated value, plus any accrued and unpaid dividends if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of this redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

### Dividends

Common dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

In 2008, preferred dividends in the amount of $18 million (2007 – $18 million) and common dividends in the amount of $241 million (2007 – $307 million) were declared.

### Earnings per Share

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.

## NOTE 14.
## RELATED PARTY TRANSACTIONS

The Province, OEFC, IESO, OPA and Ontario Power Generation Inc. (OPG) are related parties of Hydro One. In addition the OEB is related to the Company by virtue of its status as a Provincial Crown Corporation. Transactions between these parties and Hydro One were as follows.

Hydro One received revenue for transmission services from IESO, based on uniform transmission rates approved by the OEB. Transmission revenue for 2008 includes $1,072 million (2007 – $1,203 million) related to these services.

Hydro One receives amounts for rural rate protection from the IESO. Distribution revenue for 2008 includes $127 million (2007 – $127 million) related to this program. Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenue for 2008 includes $21 million (2007 – $21 million) related to these services.

In 2008, Hydro One purchased power in the amount of $2,146 million (2007 – $2,213 million) from the IESO administered electricity market and $35 million (2007 – $27 million) from OPG.

Under the *Ontario Energy Board Act*, 1998, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters. In 2008, Hydro One incurred $9 million (2007 – $10 million) in OEB fees.

Hydro One has service level agreements with the other successor corporations. These services include field, engineering, logistics and telecommunications services. Revenues related to the provision of construction and equipment maintenance services to the other successor corporations were $12 million (2007 – $12 million), primarily for the Transmission Business. Operation, maintenance and administration costs related to the purchase of services from the other successor corporations were less than $1 million in each of 2008 and 2007.

The OPA funds some of our Conservation Demand Management (CDM) programs. The funding includes program costs, incentives, management fees and bonuses. In 2008, Hydro One received $5 million from the OPA in respect of the CDM programs (2007 – $3 million) and had a net accounts payable of $3 million (2007 – net accounts receivable of $3 million).

The provision for payments in lieu of corporate income taxes was paid or payable to the OEFC and dividends were paid or payable to the Province.

The amounts due to and from related parties as a result of the transactions referred to above are as follows.

| *December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| Accounts receivable | **103** | 97 |
| Accounts payable and accrued charges | **(260)** | (234) |

Included in accounts payable and accrued charges are amounts owing to the IESO in respect of power purchases of $225 million (2007 – $202 million).

## NOTE 15.
## CONSOLIDATED STATEMENTS OF CASH FLOWS

For the purposes of the 2007 Consolidated Statement of Cash Flows, "cash and cash equivalents" refers to the Balance Sheet item "bank indebtedness."

The changes in non-cash balances related to operations consist of the following:

| *Year ended December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| Accounts receivable decrease | **5** | 18 |
| Materials and supplies decrease (increase) | **4** | (11) |
| Accounts payable and accrued charges increase | **57** | 70 |
| Accrued interest increase | **9** | 6 |
| Long-term accounts payable and accrued charges decrease | **(1)** | (3) |
| Employee future benefits other than pension increase | **53** | 52 |
| Other | **1** | 3 |
| | **128** | 135 |
| **Supplementary information**: | | |
| Interest paid | **330** | 306 |
| Payments in lieu of corporate income taxes | **145** | 230 |

## NOTE 16.
## CONTINGENCIES

### Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows.

On March 29, 1999, the Whitesand First Nation Band commenced an action in the Ontario Court (General Division), now the Superior Court Justice, naming as defendants the Province, the Attorney General of Canada, Ontario Hydro, OEFC, OPG and the Company. On May 24, 2001, the Whitesand First Nation Band issued an almost identical claim against the same parties. The reason for the second claim is the procedural defence of the Province that proper notice of the first claim was not given under the *Proceedings Against the Crown Act* (Ontario). 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 20th century, Ontario Hydro has erected dams, generating stations 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. The May 24, 2001 case was consolidated in 2004 with a similar claim by Red Rock First Nation Band which commenced on September 7, 2001 as all procedural issues in both matters were the same. There is now one action in which the claims of both Whitesand and Red Rock are set out. The claims relating to activities of Ontario Hydro (i.e., flooding) are the matters for which OPG would have responsibility pursuant to Transfer Orders under the *Electricity Act*, 1998. In the consolidated claim, Whitesand and Red Rock seek to tie Hydro One into the flooding allegations on the alleged basis of the integrated nature of the transmission system with the entire electricity system, which includes the method of generating power. To date, Hydro One has not filed a defence. Hydro One believes that it is unlikely that the outcome of this litigation will have a material adverse effect on its consolidated financial position, results of operations or cash flows.

### Transfer of Assets

The transfer orders by which we acquired certain of Ontario Hydro's 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). Currently, OEFC holds these assets. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. However, it anticipates having to pay more than the approximately $717,000 that it paid to these Indian bands and bodies in 2008. If the Company cannot obtain consents from the Indian bands and bodies, OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it 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. The costs relating to these assets could have a material adverse effect on the Company's net income, if it is not able to recover them in future rate orders.

## NOTE 17.
## COMMITMENTS

### Agreement with Inergi

Effective March 1, 2002, Inergi LP (a wholly owned subsidiary of Cap Gemini Canada Inc.) began providing services to Hydro One. As a result of this initiative, Hydro One receives from Inergi a range of services including information technology, customer care, supply chain and certain human resources and finance services for a 10-year period. Inergi billing for these services has ranged between $93 million and $130 million per year and is subject to external benchmarking every three years to ensure Hydro One is receiving a defined competitive and continuously improved price. In connection with this agreement, on March 1, 2002 the Company transferred approximately 900 employees to Inergi, including about 130 non-regular employees.

The annual commitments under the agreement in each of the five years subsequent to December 31, 2008, and in total thereafter are as follows: 2009 – $100 million; 2010 – $94 million; 2011 – $90 million; 2012 – $16 million; 2013 – $nil and thereafter – $nil. The agreement expires on February 29, 2012.

### Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2008 and December 31, 2007, the Company provided prudential support using only parental guarantees. The IESO could draw on these guarantees if Hydro One Networks or Hydro One Brampton fails to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any bank letters of credit plus the nominal amount of the parental guarantee. If Hydro One's highest long-term credit rating deteriorated to below the "Aa" category, the Company would be required to resume providing letters of credit as prudential support. Prudential support at December 31, 2008 was provided using parental guarantees of $325 million (2007 – $325 million).

### Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The trustee is required to draw upon the letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the bank letters of credit. As at December 31, 2008, Hydro One had bank letters of credit of $107 million (2007 – $95 million) outstanding relating to retirement compensation arrangements.

### Operating Leases

The future minimum lease payments under operating leases for each of the five years subsequent to December 31, 2008 and in total thereafter are as follows: 2009 – $7 million; 2010 – $8 million; 2011 – $3 million; 2012 – $6 million; 2013 – $6 million and thereafter – $32 million.

## NOTE 18.
## SEGMENT REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- The "other" segment, which primarily consists of the telecommunications business.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2). Segment information on the above basis is as follows:

| *Year ended December 31 (Canadian dollars in millions)* | Transmission | Distribution | Other | Consolidated |
|---|---|---|---|---|
| **2008** | | | | |
| **Segment profit** | | | | |
| Revenues | 1,212 | 3,334 | 51 | 4,597 |
| Purchased power | – | 2,181 | – | 2,181 |
| Operation, maintenance and administration | 387 | 531 | 47 | 965 |
| Depreciation and amortization | 254 | 287 | 7 | 548 |
| Income (loss) before financing charges and provision for payments in lieu of corporate income taxes | 571 | 335 | (3) | 903 |
| Financing charges | | | | 292 |
| **Income before provision for payments in lieu of corporate income taxes** | | | | 611 |
| **Capital expenditures** | 704 | 570 | 10 | 1,284 |
| **2007** | | | | |
| **Segment profit** | | | | |
| Revenues | 1,242 | 3,382 | 31 | 4,655 |
| Purchased power | – | 2,240 | – | 2,240 |
| Operation, maintenance and administration | 415 | 549 | 31 | 995 |
| Depreciation and amortization | 242 | 273 | 6 | 521 |
| Income (loss) before financing charges and provision for payments in lieu of corporate income taxes | 585 | 320 | (6) | 899 |
| Financing charges | | | | 295 |
| **Income before provision for payments in lieu of corporate income taxes** | | | | 604 |
| **Capital expenditures** | 560 | 511 | 20 | 1,091 |

| *December 31 (Canadian dollars in millions)* | **2008** | 2007 |
|---|---|---|
| **Total assets** | | |
| Transmission | **7,877** | 7,273 |
| Distribution | **5,873** | 5,407 |
| Other | **126** | 106 |
| | **13,876** | 12,786 |

## NOTE 19.
## SUBSEQUENT EVENTS

On January 13, 2009, Hydro One issued $100 million in notes under the Company's MTN Program. The issue was an additional offering of 3.89% notes maturing on November 19, 2010, originally issued on November 19, 2008. The total amount outstanding for this issue is now $200 million.

On January 14, 2009 Hydro One issued $200 million in notes under the Company's MTN Program. The issue was an additional offering of 5.0% notes maturing on November 12, 2013, originally issued on November 10, 2008. The total amount outstanding for this issue is now $600 million.

## NOTE 20.
## COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2008 Consolidated Financial Statements.

# Five-Year Summary of Financial and Operating Statistics

| *Year ended December 31* *(Canadian dollars in millions)* | **2008** | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|
| **Statement of operations data** | | | | | |
| **Revenues** | | | | | |
| Transmission | **1,212** | 1,242 | 1,245 | 1,310 | 1,262 |
| Distribution | **3,334** | 3,382 | 3,273 | 3,085 | 2,874 |
| Other | **51** | 31 | 27 | 21 | 17 |
| | **4,597** | 4,655 | 4,545 | 4,416 | 4,153 |
| **Costs** | | | | | |
| Purchased power | **2,181** | 2,240 | 2,221 | 2,131 | 1,987 |
| Operation, maintenance and administration | **965** | 995 | 880 | 792 | 771 |
| Depreciation and amortization | **548** | 521 | 515 | 487 | 480 |
| | **3,694** | 3,756 | 3,616 | 3,410 | 3,238 |
| Regulatory recovery[1] | **–** | – | – | 91 | – |
| **Income before financing charges and provision for payments in lieu of corporate income taxes** | **903** | 899 | 929 | 1,006 | 1,006 |
| Financing charges | **292** | 295 | 295 | 325 | 331 |
| **Income before provision for payments in lieu of corporate income taxes** | **611** | 604 | 634 | 681 | 675 |
| Provision for payments in lieu of corporate income taxes | **113** | 205 | 179 | 198 | 177 |
| **Net income** | **498** | 399 | 455 | 483 | 498 |
| **Basic and fully diluted earnings per common share** *(Canadian dollars)* | **4,797** | 3,809 | 4,366 | 4,652 | 4,798 |

| *December 31 (Canadian dollars in millions)* | | | | | |
|---|---|---|---|---|---|
| **Balance sheet data** | | | | | |
| **Assets** | | | | | |
| Transmission | **7,877** | 7,273 | 6,950 | 6,813 | 6,771 |
| Distribution | **5,873** | 5,407 | 5,161 | 4,893 | 4,836 |
| Other | **126** | 106 | 99 | 92 | 95 |
| **Total assets** | **13,876** | 12,786 | 12,210 | 11,798 | 11,702 |
| **Liabilities** | | | | | |
| Current liabilities (including current portion of long-term debt) | **1,298** | 1,452 | 1,194 | 1,341 | 1,262 |
| Long-term debt | **5,733** | 5,063 | 4,848 | 4,443 | 4,590 |
| Other long-term liabilities | **1,721** | 1,385 | 1,347 | 1,298 | 1,326 |
| **Shareholder's equity** | | | | | |
| Share capital | **3,637** | 3,637 | 3,637 | 3,637 | 3,637 |
| Retained earnings | **1,497** | 1,258 | 1,184 | 1,079 | 887 |
| Accumulated other comprehensive income | **(10)** | (9) | – | – | – |
| **Total liabilities and shareholder's equity** | **13,876** | 12,786 | 12,210 | 11,798 | 11,702 |

# Five-Year Summary of Financial and Operating Statistics (continued)

| *Year ended December 31* *(Canadian dollars in millions)* | **2008** | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|
| **Other financial data** | | | | | |
| Capital expenditures | | | | | |
| Transmission | **704** | 560 | 402 | 349 | 432 |
| Distribution | **570** | 511 | 417 | 338 | 288 |
| Other | **10** | 20 | 4 | 4 | 7 |
| **Total capital expenditures** | **1,284** | 1,091 | 823 | 691 | 727 |
| **Ratios** | | | | | |
| Net asset coverage on long-term debt[2] | **1.84** | 1.87 | 1.92 | 1.93 | 1.88 |
| Earnings coverage ratio[3] | **2.63** | 2.67 | 2.67 | 2.69 | 2.70 |
| **Operating statistics** | | | | | |
| Transmission | | | | | |
| Units transmitted *(TWh)*[4] | **148.7** | 152.2 | 151.1 | 157.0 | 153.4 |
| Ontario 20-minute system peak demand *(MW)*[4] | **24,231** | 25,809 | 27,056 | 26,219 | 25,204 |
| Ontario 60-minute system peak demand *(MW)*[4] | **24,195** | 25,737 | 27,005 | 26,160 | 24,979 |
| Total transmission lines *(circuit-kilometres)* | **29,039** | 28,915 | 28,600 | 28,547 | 28,643 |
| Distribution | | | | | |
| Units distributed to Hydro One customers *(TWh)*[4] | **29.9** | 30.2 | 29.0 | 29.7 | 28.5 |
| Units distributed through Hydro One lines *(TWh)*[4, 5] | **44.7** | 45.7 | 44.7 | 45.6 | 44.8 |
| Total distribution lines *(circuit-kilometres)* | **123,260** | 122,933 | 122,460 | 122,118 | 121,736 |
| Customers | **1,325,745** | 1,311,714 | 1,293,396 | 1,273,768 | 1,258,925 |
| **Total regular employees** | **5,032** | 4,602 | 4,295 | 4,189 | 4,118 |

[1] As a result of the oral and written evidence submitted by Hydro One, on December 9, 2004, the OEB issued a ruling, citing prudence, and approving recovery of amounts previously delayed by the *Electricity Pricing, Conservation and Supply Act*, 2002, relating to regulatory deferral account balances sought by Hydro One in its May 31, 2004 submission. Consequently, a one-time regulatory recovery of $91 million was recorded.

[2] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[4] System-related statistics include preliminary figures for December.

[5] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

# Board of Directors (as at December 31, 2008)

**James Arnett***
Chair of the Board
of Directors
Hydro One Inc.
*Elected March 31, 2008*
*Resigned December 8, 2008*
*Re-elected February 17, 2009*

**Douglas E. Speers[2, 3, 4, 6]****
Chair of the Board of Directors
Hydro One Inc.
*Elected (on an interim basis)*
*December 8, 2008*
*Resigned February 17, 2009*
Chairman and Director,
Emco Corporation

**Sami Bébawi[2, 5, 6]**
Advisor to the President,
SNC-Lavalin Group Inc.
President, Geracon Inc.

**Kathryn A. Bouey[3, 4, 6]**
President, TBG
Strategic Services Inc.
Corporate Director

**Murray J. Elston[1, 5]**
President and CEO,
Canadian Nuclear
Association

**Laura Formusa**
President and CEO,
Hydro One Inc.

**Don MacKinnon[5, 6]**
President, Power
Workers' Union

**Michael J. Mueller[1, 2, 4]**
Corporate Director

**Walter Murray[1, 3, 4]**
Corporate Director

**Robert L. Pace[1, 3]**
President and CEO,
The Pace Group Ltd.

**Gale Rubenstein[2, 5]**
Partner, Goodmans LLP

## Board Committees

[1] **Audit and Finance Committee** The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, significant corporate risk exposures and financial compliance. The committee met five times in 2008.

[2] **Corporate Governance Committee** The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandate of the Board and each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met four times in 2008.

[3] **Human Resources and Public Policy Committee** The Human Resources and Public Policy Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President and CEO, and for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have a significant impact on us. The committee met six times in 2008.

[4] **Business Transformation Committee** The Business Transformation Committee is an advisory committee of the Board established to assist the Board in its oversight responsibility on matters related to the Company's enterprise application systems replacement strategy. The committee met seven times in 2008.

[5] **Regulatory and Environment Committee** The Regulatory and Environment Committee monitors the Company's compliance with applicable regulatory requirements and environmental legislation. The committee oversees compliance programs, policies, standards and procedures and reviews the Company's proposals for rate applications, compliance actions and reports. The committee met five times in 2008.

[6] **Health and Safety Committee** The Health and Safety Committee is responsible for reviewing occupational health and safety policies, standards, and programs and compliance with occupational health and safety legislation, policies and standards, and public health and safety issues. The committee met four times in 2008.

* *James Arnett was Chair of the Board from March 31, 2008 until December 8, 2008, when he was appointed Special Advisor to the Government of Ontario on the auto sector's restructuring. Mr. Arnett returned to his position as Chair of the Board on February 17, 2009.*

***Douglas Speers was elected Chair of the Board, on an interim basis, on December 8, 2008.*

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# Corporate Information

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Business accounts:
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**AUDITORS**
KPMG LLP

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