RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages are made by comparison of the three and six months ended June 30, 2005 to the three and six months ended June 30, 2004.

Revenues

	Three months ended June 30				Six months ended June 30			
(Canadian dollars in millions)	2005	2004	$ Change	% Change	2005	2004	$ Change	% Change
Transmission	307	301	6	2	635	618	17	3
Distribution	706	655	51	8	1,567	1,435	132	9
Other	5	4	1	25	10	8	2	25
	1,018	960	58	6	2,212	2,061	151	7
Average Ontario 60-minute peak demand *(MW)*[1]	21,502	21,134	368	2	22,319	22,097	222	1
Distribution - units distributed to customers *(TWh)*[1]	6.6	6.3	0.3	5	15.1	14.6	0.5	3

[1]System-related statistics are preliminary

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

Transmission

Transmission revenues consist predominantly of our transmission tariff, which is based on the monthly peak demand for electricity across our high-voltage network. The level of peak demand is primarily influenced by weather conditions. Transmission revenues also include a minor amount of ancillary revenues which is primarily attributable to maintenance services provided to generators and secondary land use related to rights of way.

The Ontario peak demand reached 26,157MW during June 2005 due to higher than normal temperatures, surpassing the previous record of 25,414MW set in August 2002. This peak demand, partially offset by lower peak demand in April and May compared to last year, resulted in higher transmission tariff revenues in the quarter. The average peak demand for the first quarter was also higher than last year, further contributing to increased revenue on a year-to-date basis. Ancillary transmission revenues were slightly lower this year, both in the quarter and year-to-date periods.

Distribution

Distribution revenues include our distribution tariff, which is based on Ontario Energy Board (OEB) approved rates and recovery of 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 telecommunication and cable industries, and miscellaneous charges such as late payment charges.

Distribution revenues increased in the second quarter and in the first six months of 2005 compared to the same periods last year, primarily due to the recovery of higher purchased power costs of $29 million and $107 million, respectively. These increases primarily reflect the implementation of the interim price structure for fixed-price customers on April 1, 2004, and a subsequent increase on April 1, 2005, as well as increased demand for electricity as described below under “Purchased Power”. The remaining increases reflect the recognition of revenue related to low-voltage services in the quarter and year-to-date periods consistent with the OEB’s December 2004 decision regarding the prudence of distribution-related deferral account balances. Revenues for the second quarter also reflect the OEB-approved distribution tariff rate increase effective April 1, 2005, which was originally scheduled to be effective March 1, 2003, and subsequently suspended for all LDCs by the *Electricity Pricing, Conservation and Supply Act, 2002*.

Other

Other revenues were higher compared to the same periods last year due to increased lit fibre revenue within our telecommunications business.

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 electricity, the Independent Electricity System Operator's (IESO) wholesale market service charges, and transmission charges levied by the IESO. Prior to April 1, 2004, for certain low volume and designated customers, the commodity price of electricity was fixed at 4.3 cents per kWh. On April 1, 2004, this fixed rate was replaced by an interim two-tiered pricing structure of 4.7 cents per kWh for the first 750 kWhs consumed each month and 5.5 cents per kWh for any additional consumption. On April 1, 2005, the interim pricing structure was replaced by the OEB's Regulated Price Plan (RPP) which consists of a two-tiered pricing structure of 5.0 cents per kWh for the first 750 kWhs consumed each month and 5.8 cents per kWh for any additional consumption. Customers who are not eligible for the RPP continue to pay market prices for electricity, adjusted for the difference between the market price and set prices paid to regulated generators under the *Electricity Restructuring Act, 2004*.

Purchased power costs increased by $29 million to $484 million in the second quarter, and by $107 million to $1,102 million during the first six months of 2005 as compared to the same periods last year. These increases primarily reflect higher commodity costs of $15 million and $74 million, respectively largely due to the implementation of the April 2004 and April 2005 pricing structures, as well as a higher wholesale commodity price for customers who are not eligible for the RPP. The remaining increases are primarily attributable to increased demand for electricity.

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.

As a result of our actuarial valuation filed with the Financial Services Commission of Ontario (FSCO), we are required to contribute approximately $80 million to our pension plan in each of the years over the period 2004 through 2006. Such pension contribution costs are attributed to labour and are normally charged to operations, maintenance and administration expense or capitalized as part of the cost of fixed assets. However, in July 2004, the OEB approved our application requesting approval for a regulatory deferral account to include that portion of our pension contribution costs that would otherwise have been charged to the operations, maintenance and administration expense of our distribution business. As a result, commencing in July 2004, distribution pension contribution costs, plus interest from January 1, 2004 have been recognized as a regulatory asset within our distribution operations. We expect to apply for recovery of these deferred costs in our next distribution rate submission, which is expected to be filed with the OEB later this year. While the results of operations for the first six months of 2005 do not reflect such distribution-related pension contribution costs, our results of operations for the second quarter and first six months of 2004 included such costs in the amount of $9 million and $18 million, respectively. Pension contribution costs continue to be included within the operations, maintenance and administration expense of our transmission business and within the capital expenditures of both our distribution and transmission businesses.

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

	Three months ended June 30				**Six months ended June 30**			
(Canadian dollars in millions)	**2005**	**2004**	**$ Change**	**% Change**	**2005**	**2004**	**$ Change**	**% Change**
Transmission	83	103	(20)	(19)	170	188	(18)	(10)
Distribution	102	113	(11)	(10)	188	210	(22)	(10)
Other	6	6	-	-	12	10	2	20
	191	222	(31)	(14)	370	408	(38)	(9)

Transmission

Operation, maintenance and administration expenditures attributable to our transmission business were $20 million lower in the second quarter and $18 million lower on a year-to-date basis compared to the respective periods last year, primarily reflecting recoveries associated with insurance settlements and bad debts in the second quarter. Lower operating, maintenance and administration costs for the quarter also reflect cost reductions associated with the current labour disruption with the Society of Energy Professionals. In the first half of the year, these reductions were partially offset by marginally higher expenditures to sustain our high-voltage system due to the advancement of our transmission forestry program.

Distribution

Operation, maintenance and administration expenditures for our distribution business decreased by $11 million in the second quarter and $22 million in the first six months compared to the same periods in 2004. These reductions are primarily due to the regulatory treatment of pension contribution costs. Such costs were included in operation, maintenance and administration expense last year but have been deferred in a regulatory asset account since July 2004. The labour disruption also impacted costs in the quarter. In addition, a lower volume of trouble calls to restore power as a result of favourable weather conditions as well as reduced expenditures for the forestry program contributed to the reductions in the quarter and year-to-date periods. The forestry program is scheduled to increase over the last half of the year.

Other

Other operation, maintenance and administration costs were unchanged in the quarter and $2 million higher on a year-to-date basis, than in the comparative periods. These results are consistent with the higher level of lit fibre service revenue partially offset by lower market prices paid for telecommunications services and fibre within our telecommunications business.

Depreciation and Amortization

Depreciation and amortization expense increased by $4 million, or 3%, to $119 million in the second quarter and by $15 million, or 7%, to $241 million in the first six months from the same periods last year. These increases primarily result from an increase in fixed assets in service, consistent with the investments made in our electricity delivery network. Increased amortization of regulatory assets related to the OEB's December 2004 regulatory decision to allow recovery of the assets included in our regulatory asset recovery account also contributed to the increase.

Financing Charges

Financing charges remained consistent with the second quarter of 2004 at $83M and decreased by $5 million, or 3%, to $163 million in the first six months compared to the respective period last year. The reduction over the first six months reflects the refinancing of our debt at lower average interest rates compared to the effective rates on the maturing debt as well as interest capitalized on our regulatory assets as a result of the December 2004 OEB decision. These reductions were partially offset by the impact of a higher average level of debt outstanding in 2005 than in the comparative periods. Over the comparative quarters, these impacts fully offset.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes remained consistent at $26 million in the second quarter and increased by $5 million, or 6%, to $90 million in the first six months compared to the same periods in 2004. In the second quarter of 2005, we reached an agreement to settle an outstanding legal claim allowing for the dissolution of one of our subsidiaries. As a result, we recognized a tax benefit of approximately $21 million related to the accumulated tax losses of the subsidiary. The tax benefit offset the higher tax provision resulting from the higher net income level.

Net Income

Net income increased by $56 million, or 95%, in the second quarter and by $67 million, or 37%, in the first six months compared to 2004 results. These increases reflect higher tariff revenues associated with the higher peak demand on the transmission system in the early winter and summer months and higher distribution tariffs reflecting the recognition of low-voltage services revenue and the implementation of an OEB approved tariff rate increase effective April 1, 2005. The higher net income levels also reflect lower operating, maintenance and administration costs, including the OEB's July 2004 decision allowing deferral of pension contribution costs for our distribution business. Our effective tax rate was also lower as a result of the recognition of tax losses from one of our subsidiaries. These increases were partially offset by higher depreciation changes related to our ongoing transmission and distribution investments.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters ended September 30, 2003 through June 30, 2005. 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 includes 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)	2005		2004				2003	
Quarter ended	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sep. 30**
Total revenue[1,2]	1,018	1,194	1,074	1,018	960	1,101	1,009	949
Net income [1,2]	115	131	186[3]	133	59	120	79	93
Net income to common shareholder [1,2]	110	127	181	129	55	115	75	88

[1] Both the revenue and the net income amounts reported in the first and second quarter of 2004 have been reduced by $5 million and $6 million, respectively, to reflect a change in interperiod allocations.

[2] 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.

[3] As a result of submitted oral and written evidence, the OEB issued a ruling, on December 9, 2004, 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 in our May 31, 2004 submission. Consequently, net income for 2004 includes a regulatory recovery of $91 million.

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 resources 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

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	**2005**	**2004**	**2005**	**2004**
Operating activities	227	210	469	484
Financing activities				
Long-term debt issued	500	120	500	370
Long-term debt retired	(200)	(237)	(200)	(472)
Short-term notes payable	(30)	142	(40)	117
Dividends paid	(57)	(62)	(146)	(142)
Investing activities				
Capital expenditures	(181)	(198)	(337)	(345)
Other financing and investing activities	(17)	15	(7)	15
Net change in cash and cash equivalents	242	(10)	239	27

Operating Activities

Net cash generated from operations increased by $17 million in the second quarter and decreased by $15 million in the first six months compared to the 2004 results. Over the comparable quarter, the changes reflect higher net income levels and adjustments for non-cash items such as depreciation, partially offset by higher working capital requirements. Over the same six month period, the impact of higher working capital requirements more than offset the increased net income level. In 2004, pension payments were accrued but not paid until the third quarter, whereas in 2005, liabilities related to these funding requirements of our pension plan are accrued and paid in the subsequent month.

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 billion in short-term notes with a term to maturity of less than 365 days. The commercial paper program is supported by committed revolving credit facilities with a syndicate of banks of $750 million which matures in August 2006, with a two-year extension option. At June 30, 2005, we had no short-term notes outstanding and a cash balance of $230 million, which will be used to finance maturing debt in November 2005. The available cash, short-term liquidity under this program and anticipated levels of funding from operations should be sufficient to fund our normal operating requirements. Long-term financing is provided by our access to the debt markets, including our medium term note program. On June 24, 2005, we filed a $2.5 billion base shelf prospectus to renew our medium-term note program for another 25 months. Our notes and debentures mature between 2005 and 2043. We currently plan to refinance maturing debt principally through our medium term note program.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
Standard & Poor's Ratings Services Inc.[1]	A-1	A
Dominion Bond Rating Service Inc.	R-1 (low)	A
Moody's Investors Service Inc.[2]	Prime-1	Aa3

[1] On July 15, 2005, Standard & Poor's Ratings Services Inc. raised Hydro One's short-term debt rating to A-1 from A-2.
[2] On July 8, 2005, Moody's Investors Service Inc. raised Hydro One's long-term debt rating to Aa3 from A2 as a result of its analysis of government-related issuers.

During the second quarter of 2005, we issued $500 million in long-term debt under our medium term note program and we repaid $200 million in maturing long-term debt. We also decreased our short-term notes by $30 million. In comparison, during the second quarter of 2004 we issued $120 million in debt under our medium term note program, repaid $237 million in maturing long-term debt and increased our short-term notes by $142 million. On a year-to-date basis, we have issued $500 million and have retired $200 million in long-term debt compared to issuance of $370 million and retirements of $472 million in 2004. The year-to-date net decrease in short-term notes totaled $40 million compared to net increase of $117 million last year.

In the second quarter of 2005, we paid dividends to the Province of Ontario in the amount of $57 million, consisting of $52 million in common dividends and $5 million in preferred dividends. In the comparative period during 2004, we paid common dividends of $57 million and preferred dividends of $5 million. Year-to-date, we have paid common and preferred dividends totaling $146 million, compared to $142 million in 2004.

Investing Activities

Cash used for investing activities primarily represents capital expenditures for each of our three business segments as follows:

	Three months ended June 30				**Six months ended June 30**			
(Canadian dollars in millions)	**2005**	**2004**	**$ Change**	**% Change**	**2005**	**2004**	**$ Change**	**% Change**
Transmission	87	117	(30)	(26)	176	198	(22)	(11)
Distribution	94	79	15	19	160	143	17	12
Other	-	2	(2)	(100)	1	4	(3)	(75)
	181	198	(17)	(9)	337	345	(8)	(2)

Transmission

Transmission capital expenditures decreased by $30 million in the second quarter and by $22 million on a year-to-date basis compared to the same periods last year. Capital expenditure to expand and reinforce our transmission system were lower by $43 million in the quarter and $39 million in the first six months due to the substantial completion of the Parkway Transformation Station this year. This project was initiated last year in response to growing loads and the planned closure of the Lakeview Generating Station. In 2004, we also completed our Ontario Grid Control Centre. These reductions were partially offset by higher expenditures to sustain our transmission lines and stations and to maintain reliability, as well as an increased level of investments in information management infrastructure.

Distribution

Distribution capital expenditures increased by $15 million this quarter and by $17 million on a year-to-date basis compared to the same periods in 2004. These increases are due primarily to increased investments in transportation and work equipment, as well as information management infrastructure, to support our distribution network. Capital expenditures to sustain and develop the low-voltage system were consistent in both periods compared to last year.

Other

Other capital expenditures decreased by $2 million in the second quarter and by $3 million in the first six months. These reductions reflect the completion of the capital program for ongoing equipment upgrades for our telecom business commensurate with demand.

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.

June 30, 2005 (Canadian dollars in millions)	**Total**	**2005[1]**	**2006/2007**	**2008/2009**	**After 2009**
Contractual Obligations *(due by year)*					
Short-term notes payable	-	-	-	-	-
Long-term debt	5,532	339	1,093	900	3,200
Inergi LP outsourcing agreement[2]	658	54	208	197	199
Operating lease commitments	28	3	12	12	1
Total Contractual Obligations	6,218	396	1,313	1,109	3,400
Other Commercial Commitments *(by year of expiry)*					
Bank line[3]	750	-	750	-	-
Letters of credit[4]	103	83	20	-	-
Guarantees[4]	275	275	-	-	-
Pension[5]	126	38	88	-	-
Total Other Commercial Commitments	1,254	396	858	-	-

[1] The amounts disclosed represent the balance due over the period July 1, 2005 to December 31, 2005.

[2] 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.

[3] As a backstop to our commercial paper program, we have a $750 million, 364-day revolving standby credit facility with a syndicate of banks that matures in August 2006, with a two-year term out option.

[4] We currently have bank letters of credit of $80 million outstanding relating to retirement compensation arrangements. We have also provided prudential support to the IESO as required by the Market Rules, using a combination of bank letters of credit of $19 million and parental guarantees of $275 million. The amount of prudential support that we provide in the form of bank letters of credit to the IESO is dependent on our long-term credit ratings from major Canadian and U.S. rating agencies. The amount of bank letters of credit provided would need to increase if our credit ratings deteriorated. For example, if our credit rating declined to BBB+, the amount of bank letters of credit required to meet our prudential support obligation would be two times our current amount, and if our credit rating declined to BB+, the amount of bank letters of credit required to meet our prudential support obligation would be four times the current amount. The remaining letters of credit pertain to operating letters of credit and to surety bonds.

[5] Contributions to the pension fund are made one-month in arrears. Contributions after 2006 will be based on an actuarial valuation as at December 31, 2006 and will depend on future investment returns, changes in benefits or actuarial assumptions. Should financial market conditions improve significantly before December 31, 2006, we have the option to file an earlier actuarial valuation.

The amounts in the above table under short-term notes payable and long-term debt 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, but these financing charges are not reflected in the above table. Payments in respect of operating leases and our outsourcing agreement with Inergi LP are recorded under operation, maintenance and administration costs on our statement of operations or in our capital programs.

RECENT DEVELOPMENTS

Replacement of Coal-fired Generation

On June 15, 2005, the Government of Ontario announced its plan to replace coal-fired generation with cleaner sources of energy and conservation. In order to ensure system reliability, and to support the replacement of coal-fired generation, transmission upgrades will be required, primarily to facilitate the closure of Nanticoke Generating Station in 2009.

Niagara Reinforcement Project

On July 8, 2005, the OEB issued a Decision and Order granting us leave to construct transmission facilities in the Niagara region. This project includes a new 76-kilometer double circuit 230 kilovolt transmission line primarily along existing rights-of-way. Cost recovery will be subject to the provision of evidence regarding the economic benefits of this project. With this decision, the OEB raised important questions about the need to clarify roles of the various organizations in the industry. We look forward to taking part in this process.

Preparation for Distribution Rate Application

During the second quarter of 2005, we continued to prepare our distribution rate application. Stakeholder consultation sessions were held to share understanding of our application and to introduce our revenue requirements. We expect to file our evidence to support our revenue requirement in August 2005. On June 24, 2005, the OEB advised all local distribution companies (LDCs) of a generic process to review cost allocation that will begin in the fall of 2005. The process will result in the submission of cost allocation studies in the fall of 2006.

Transmission System Code Review

On July 25, 2005, the OEB issued a final version of the Transmission System Code (TSC), which sets out the obligations electricity transmitters have to their customers. Under the TSC, transmission tariff revenues could be lowered as it relates to the increased opportunity for customers to qualify for net load billing and the ability to bypass transformation and connection facilities when assets become fully depreciated. Also, the TSC governs requirements for non-compliant customer equipment, and requires the filing of delivery point performance standards with the OEB for approval. The OEB has indicated that bypass could be examined when transmission rates are next reviewed.

Transmission Rates

We have provided the necessary financial information requested by the OEB with respect to the return on equity of our transmission business.

Smart Meters

Our smart meter project is currently on hold, pending a decision from the Government of Ontario as to whether the Government's initiative will be implemented centrally for all of Ontario's LDCs.

Labour Negotiations

On June 6, 2005, the Society of Energy Professionals commenced a full, ongoing strike. We have implemented our contingency plan and continue to assess the impacts of this labour disruption on our operating and capital programs with a focus on maintaining system reliability.

SELECTED FINANCAL HIGHLIGHTS AND RATIOS

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions) (except as otherwise noted)	**2005**	**2004**	**2005**	**2004**
Net income	115	59	246	179
Net cash from operations	227	210	469	484
Capital expenditures	181	198	337	345
Earnings per common share *(Canadian dollars)*	1,107	542	2,368	1,700
Earnings coverage ratio[1]			2.85	2.27
Net asset coverage on long-term debt[2]			1.84	1.88
Total debt to capitalization[3]			54%	54%

[1]The earnings coverage ratio has been presented for the twelve months ended June 30, 2005 and June 30, 2004, respectively and has been calculated as the sum of net income, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends. The earnings coverage ratio for the twelve months ended June 30, 2005, excluding the impact of the $91 million regulatory recovery recognized in 2004 as a result of the OEB's December 9, 2004 rate decision, was 2.60.

[2]The net asset coverage on long-term debt ratio has been presented as at June 30, 2005 and December 31, 2004 and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt including current portion.

[3]Total debt to capitalization ratio has been presented as at June 30, 2005 and December 31, 2004 and has been calculated as total debt divided by total debt plus total shareholder's equity.

FORWARD LOOKING STATEMENTS AND OTHER INFORMATION

We have included forward-looking statements in this report that are subject to risks, uncertainties and assumptions. Such information represents our current views based on information as at the date of this report. Any statement contained in this document that is not current or historical is a forward-looking statement. We have based these forward-looking statements on historical experience, current conditions and various assumptions believed to be reasonable in the circumstances. Actual results could differ materially from those projected in the forward-looking statements. Because of these risks, uncertainties and assumptions, undue reliance should not be placed on these forward-looking statements. Except to the extent required by applicable securities laws and regulations, we undertake no obligation to update or revise any of these forward-looking statements, whether to reflect new information, future events or otherwise.

This management's discussion and analysis is dated as at August 5, 2005. Additional information about our company, including our annual information form, is available on SEDAR at www.sedar.com.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2005	2004	Six months ended June 30 2005	2004
Revenues				
Transmission	307	301	635	618
Distribution	706	655	1,567	1,435
Other	5	4	10	8
	1,018	960	2,212	2,061
Costs				
Purchased power	484	455	1,102	995
Operation, maintenance and administration	191	222	370	408
Depreciation and amortization	119	115	241	226
	794	792	1,713	1,629
Income before financing charges and provision for payments in lieu of corporate income taxes	224	168	499	432
Financing charges	83	83	163	168
Income before provision for payments in lieu of corporate income taxes	141	85	336	264
Provision for payments in lieu of corporate income taxes	26	26	90	85
Net income	115	59	246	179
Basic and fully diluted earnings per common share *(Canadian dollars)*	1,107	542	2,368	1,700

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2005	2004	Six months ended June 30 2005	2004
Retained earnings, beginning of period	929	694	887	654
Net income	115	59	246	179
Dividends *(Note 2)*	(57)	(62)	(146)	(142)
Retained earnings, end of period	987	691	987	691

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS **(unaudited)**

(Canadian dollars in millions)	**June 30, 2005**	**December 31, 2004**
Assets		
Current assets		
Cash	230	-
Accounts receivable (net of allowance for doubtful accounts)	707	707
Materials and supplies	49	47
	986	754
Fixed assets		
Fixed assets in service	15,266	14,940
Less: accumulated depreciation	5,646	5,475
	9,620	9,465
Construction in progress	339	348
	9,959	9,813
Other long-term assets		
Deferred pension asset	490	534
Regulatory assets	438	443
Goodwill	133	133
Long-term accounts receivable and other assets	22	25
Deferred debt costs	24	23
	1,107	1,158
Total assets	12,052	11,725
Liabilities		
Current liabilities		
Bank indebtedness	-	9
Accounts payable and accrued charges	566	630
Accrued interest	47	44
Short-term notes payable	-	40
Long-term debt payable within one year *(Note 3)*	896	539
	1,509	1,262
Long-term debt *(Note 3)*	4,578	4,613
Other long-term liabilities		
Regulatory liabilities	564	576
Employee future benefits other than pension *(Note 5)*	686	654
Environmental liabilities	68	74
Long-term accounts payable and accrued charges	23	22
	1,341	1,326
Total liabilities	7,428	7,201
Shareholder's equity		
Preferred shares (authorized: unlimited; issued: 12,920,000)	323	323
Common shares (authorized: unlimited; issued: 100,000)	3,314	3,314
Retained earnings	987	887
Total shareholder's equity	4,624	4,524
Total liabilities and shareholder's equity	12,052	11,725

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)

(Canadian dollars in millions)	Three months ended June 30 2005	 2004	Six months ended June 30 2005	 2004
Operating activities				
Net income	115	59	246	179
Adjustments for non-cash items:				
Depreciation and amortization (net of removal costs)	111	104	220	208
Amortization of discount	15	15	30	33
Retail settlement variance accounts	18	7	22	16
	259	185	518	436
Changes in non-cash balances related to operations	(32)	25	(49)	48
Net cash from operations	227	210	469	484
Financing activities				
Long-term debt issued	500	120	500	370
Long-term debt retired	(200)	(237)	(200)	(472)
Termination of forward sale	(10)	-	(10)	-
Short-term notes payable	(30)	142	(40)	117
Dividends paid	(57)	(62)	(146)	(142)
Other	(2)	(1)	(1)	(2)
Net cash from (used in) financing activities	201	(38)	103	(129)
Investing activities				
Fixed assets	(181)	(198)	(337)	(345)
Other assets	(5)	16	4	17
Net cash used in investing activities	(186)	(182)	(333)	(328)
Net change in cash and cash equivalents	242	(10)	239	27
Cash and cash equivalents, beginning of period	(12)	-	(9)	(37)
Cash and cash equivalents, end of period	230	(10)	230	(10)

See accompanying notes to Consolidated Financial Statements.

1. BASIS OF PRESENTATION

The interim Consolidated Financial Statements do not conform in all respects to the disclosure requirements of Canadian generally accepted accounting principles for annual financial statements and should, therefore, be read in conjunction with the annual Consolidated Financial Statements of Hydro One Inc. (Hydro One or the Company) which includes information necessary or useful to understanding the Company's business and financial statement presentation. In particular, the Company's significant accounting policies and practices are presented as Note 2 to the annual Consolidated Financial Statements, and have been consistently applied in the preparation of these interim Consolidated Financial Statements.

2. DIVIDENDS

During the six months ended June 30, 2005, preferred dividends in the amount of $9 million (2004 - $9 million) and common dividends in the amount of $137 million (2004 - $133 million) were declared.

3. LONG-TERM DEBT

On May 19, 2005, Hydro One issued notes under the Company's medium term note program. The issues comprised a principal amount of $350 million medium term note with a 31-year term at a coupon rate of 5.36% due May 20, 2036, and a principal amount of $150 million with a coupon rate of 3.95% due on February 24, 2009.

Hydro One enters into forward pay fixed interest rate swap agreements or forward sale agreements of Government of Canada bonds to hedge against the effect of future interest rate movements on long-term fixed rate borrowing requirements. These transactions, which in 2004 included a forward interest rate swap agreement with a $100 million notional principal amount to lock in the interest rate of a future issuance planned for 2005, are accounted for as cash flow hedges of anticipated transactions. On January 21, 2005, Hydro One entered into an additional forward interest rate swap agreement to lock in a further $50 million in notional principal related to the planned 2005 issuance. On May 19, 2005, upon debt issuance, the Company paid $10 million to settle the interest rate swap agreements.

4. TAX LOSSES

In May 2005, Hydro One reached an agreement to settle an outstanding legal claim allowing for the dissolution of one of its subsidiaries. As a result, it is more likely than not that Hydro One will be able to access the subsidiary's accumulated tax losses and a future tax asset of approximately $21 million was recognized in the quarter.

5. EMPLOYEE FUTURE BENEFITS

Total benefit costs are as follows:

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	2005	2004	2005	2004
Pension				
Net period benefit costs	44	31	87	62
Pension fund contribution	23	27	43	54
Less: Portion attributable to labour and capitalized				
as part of the cost of fixed assets	8	12	16	23
Portion attributable to regulatory assets[1]	7	-	14	-
Charged to results of operations	8	15	13	31

[1]On July 14, 2004, the OEB issued an order approving the establishment of a regulatory deferral account for distribution-related pension contributions, as well as interest thereon. As a result, the Company subsequently recorded $16 million in the regulatory asset account, which had previously been expensed in the first six months of 2004.

	Three months ended June 30		Six months ended June 30	
(Canadian dollars in millions)	2005	2004	2005	2004
Employee Future Benefits Other than Pension				
Net period benefit cost	24	23	48	47
Less: Portion attributable to labour and capitalized as part of the cost of fixed assets	7	9	16	18
Charged to results of operations	17	14	32	29

6. SEGMENTED REPORTING

Hydro One has three reportable segments:

I. The transmission business, which comprises the core business of providing transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
II. The distribution business, which comprises the core business of delivering and selling electricity to customers; and
III. The "other" segment, which primarily consists of telecommunications.

The designation of segments is based on a combination of regulatory status and the nature of the products and services provided. Segment information on the above basis is as follows:

Three months ended June 30 (Canadian dollars in millions)	**Transmission**	**Distribution**	**Other**	**Consolidated**
2005				
Segment profit				
Revenues	307	706	5	1,018
Purchased power	-	484	-	484
Operation, maintenance and administration	83	102	6	191
Depreciation and amortization	59	59	1	119
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	165	61	(2)	224
Financing charges				83
Income before provision for payments in lieu of corporate income taxes				141
Capital expenditures	87	94	-	181
2004				
Segment profit				
Revenues	301	655	4	960
Purchased power	-	455	-	455
Operation, maintenance and administration	103	113	6	222
Depreciation and amortization	58	56	1	115
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	140	31	(3)	168
Financing charges				83
Income before provision for payments in lieu of corporate income taxes				85
Capital expenditures	117	79	2	198

Six months ended June 30 (Canadian dollars in millions)	Transmission	Distribution	Other	Consolidated
2005				
Segment profit				
Revenues	635	1,567	10	2,212
Purchased power	-	1,102	-	1,102
Operation, maintenance and administration	170	188	12	370
Depreciation and amortization	123	116	2	241
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	342	161	(4)	499
Financing charges				163
Income before provision for payments in lieu of corporate income taxes				336
Capital expenditures	176	160	1	337
2004				
Segment profit				
Revenues	618	1,435	8	2,061
Purchased power	-	995	-	995
Operation, maintenance and administration	188	210	10	408
Depreciation and amortization	115	109	2	226
Income (loss) before financing charges and provision for payments in lieu of corporate income taxes	315	121	(4)	432
Financing charges				168
Income before provision for payments in lieu of corporate income taxes				264
Capital expenditures	198	143	4	345

(Canadian dollars in millions)	June 30, 2005	December 31, 2004
Total assets		
Transmission	6,810	6,785
Distribution	4,916	4,845
Other	326	95
	12,052	11,725

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

7. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the June 30, 2005 Consolidated Financial Statements. Revenue and net income reported in the first quarter and second quarter of 2004 were adjusted by $5 million and $6 million, respectively, in order to reflect a change in interperiod allocations.