

November 11, 2005

ONTARIO POWER GENERATION REPORTS 2005 THIRD QUARTER FINANCIAL RESULTS

[Toronto]: Ontario Power Generation Inc. ("OPG" or the "Company") today reported its financial and operating results for the third quarter and nine months ended September 30, 2005. Net income for the three months ended September 30, 2005 was \$181 million or \$0.71 per share compared to a net loss of \$15 million or \$0.06 per share for the same period in 2004. For the nine months ended September 30, 2005, net income was \$206 million or \$0.80 per share compared to \$8 million or \$0.03 per share for the same period last year.

Effective April 1, 2005, the output from OPG's baseload hydroelectric and nuclear facilities became rate regulated, while output from its remaining hydroelectric facilities, and its fossil-fuelled and wind generating stations remain unregulated. However, the majority of the generation output from these unregulated facilities is subject to a revenue limit of 4.7¢/kWh to April 30, 2006. As a result of these changes and higher average Ontario spot market prices due to a prolonged period of high temperatures in the June to September time frame and the impact of higher natural gas prices, OPG received average prices of 5.4¢/kWh and 4.9¢/kWh respectively for the output from all of its generating facilities during the three and nine months ended September 30, 2005. While this was an increase compared to OPG's realized average prices of 4.0¢/kWh and 4.2¢/kWh for the same periods last year, it was considerably less than the average hourly Ontario electricity prices (HOEP) of 8.6¢/kWh and 6.7¢/kWh for the three and nine month periods in 2005.

"Our third quarter financial results reflect higher realized electricity prices as well as increased production, compared to the third quarter of 2004. In particular, our fossil stations responded to record setting Ontario energy demand by producing 45 per cent more electricity than in the third quarter of 2004. Our year-to-date 2005 earnings exceed 2004 earnings for the same period and we expect this trend to continue to the end of 2005," said President and CEO Jim Hankinson.

Electricity production during the three months ended September 30, 2005 from OPG's generating stations was 27.1 TWh compared to 26.0 TWh during the same period in 2004. The increase in generation was primarily a result of significantly higher fossil-fuelled generation attributable to higher electricity demand especially during a period of record high temperatures in the third quarter of 2005.

For the nine months ended September 30, 2005, total production from OPG's generating stations was 81.4 TWh compared to 78.9 TWh for the same period in 2004. The increase in generation was primarily a result of higher fossil-fuelled generation in 2005, due to higher electricity demand and improved station performance, and higher nuclear generation due to improved station performance at OPG's Pickering B and Darlington generating stations. Hydroelectric generation during the first nine months of 2005 has been negatively impacted by lower water levels.

OPG's third quarter earnings were favourably impacted by an increase in gross margin from electricity sales primarily due to higher average sales prices during the third quarter of 2005 compared to the same period in 2004. Earnings were also favourably impacted by the establishment of a deferral account for non-capital costs related to the Pickering A nuclear generating station return to service project as required by a regulation pursuant to the *Electricity Restructuring Act, 2004*.

Earnings during the nine months ended September 30, 2005 were favourably impacted by an increase in gross margin during 2005 primarily as a result of higher average sales prices due to higher temperatures in the June to September period, higher nuclear and fossil generation, and the deferral of non-capital costs related to the Pickering A return to service project commencing in 2005. These favourable impacts were partly offset by an impairment loss on OPG's Lennox generating station recorded during the first quarter of 2005, and the impairment loss on Units 2 and 3 of the Pickering A nuclear generating station, recorded during the second quarter of 2005. In addition, earnings were impacted by higher nuclear maintenance and repairs related to continuing improvements in station reliability, and a one-time extraordinary loss to reflect the impact of adopting rate regulated accounting for income taxes effective April 1, 2005.

In August 2005, following consideration of the costs and risks associated with returning Units 2 and 3 of the Pickering A nuclear generating station to service, and taking into account the Company's current focus on improving the performance of its operating nuclear units, OPG's Board of Directors decided that while technically feasible, the return to service of these units was not justified on a commercial basis. Accordingly, an impairment loss representing the carrying value of these units was recorded in OPG's second quarter results. Units 2 and 3 have been maintained in a safe shutdown state since December 1997. Over the next two years, the fuel and heavy water will be removed from the units.

On September 26, 2005, Unit 1 at the Pickering A nuclear station was synchronized to the provincial electricity grid, sending electricity from the unit to Ontario consumers for the first time since December 1997. The unit was declared to be commercially available on November 3, 2005. Total costs incurred up to November 3, 2005 were \$996 million, excluding the impact on costs of feeder inspections and replacement of \$20 million, which were not included in the original scope of the project. The project represented a complex management and construction challenge, encompassing more than 1.9 million hours of work and almost 3,000 people at its peak. "The culmination of this project represents an outstanding achievement for OPG," said President and CEO Jim Hankinson.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
<i>Earnings</i>				
Revenue after Market Power Mitigation Agreement rebate and revenue limit rebate	1,571	1,212	4,302	3,703
Fuel expense	384	290	983	870
Gross margin	1,187	922	3,319	2,833
Operations, maintenance and administration	627	636	1,830	1,893
Other expenses	285	299	858	898
Impairment of long-lived assets	-	-	265	-
Income tax expenses	94	2	86	34
Extraordinary item	-	-	74	-
Net income (loss)	181	(15)	206	8
<i>Cash flow</i>				
Cash flow provided by (used in) operating activities	382	(3)	755	74
<i>Electricity Generation (TWh)</i>				
Regulated - Nuclear	11.9	11.5	33.3	31.9
Regulated - Hydroelectric	4.4	4.8	14.0	14.1
Unregulated Generation - Hydroelectric	2.0	3.7	10.2	13.2
Unregulated Generation - Fossil-fuelled	8.8	6.0	23.9	19.7
Total electricity generation	27.1	26.0	81.4	78.9
<i>Average electricity sales price (¢/kWh)</i>				
Regulated - Nuclear	4.9	4.0	4.7	4.1
Regulated - Hydroelectric ¹	4.2	4.0	4.1	4.2
Unregulated Generation - Hydroelectric ²	6.0	3.9	5.0	4.1
Unregulated Generation - Fossil-fuelled ²	6.6	4.2	5.5	4.3
OPG average sales price	5.4	4.0	4.9	4.2
<i>Nuclear unit capability factor (per cent)</i>				
Darlington	98.2	97.9	90.9	90.0
Pickering A	78.8	77.5	60.1	75.2
Pickering B	85.0	72.4	80.7	68.9
<i>Equivalent forced outage rate (per cent)</i>				
Regulated - Hydroelectric	2.7	3.4	1.3	2.5
Unregulated Generation - Hydroelectric	1.2	0.7	1.3	1.2
Unregulated Generation - Fossil-fuelled	16.6	15.2	15.8	19.1

¹ During the period from April 1 to September 30, 2005, electricity generation from stations in the Regulated – Hydroelectric segment received a fixed price of 3.3¢/kWh for the first 1,900 MWh of generation in any hour, and the Ontario spot electricity market price for generation above this level.

² During the period from April 1 to September 30, 2005, 85 per cent of the electricity generation from unregulated stations, excluding the Lennox generating station and other contract volumes, was subject to a revenue limit based on an average price of 4.7¢/kWh.

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our focus is on the efficient production and sale of electricity from our generation assets, while operating in a safe, open and environmentally responsible manner.

Ontario Power Generation Inc.'s unaudited consolidated financial statements and Management's Discussion and Analysis of financial condition and results of operations as at and for the three and nine months ended September 30, 2005 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

For further information, please contact: Investor Relations 416-592-6700
1-866-592-6700
investor.relations@opg.com

Media Relations 416-592-4008
1-877-592-4008

-30-

2005 THIRD QUARTER REPORT**CONTENTS****MANAGEMENT'S DISCUSSION AND ANALYSIS**

Forward-Looking Statements	2
The Company	2
Rate Regulation	3
Earnings Outlook	4
Highlights/Executive Summary	4
Vision, Core Business and Strategy	9
Business Segments	11
Key Generation Performance Indicators	12
Discussion of Operating Results By Business Segment	13
Statements of Cash Flows	26
Capital Resources and Funding Obligations	27
Liquidity	27
Critical Accounting Policies and Estimates	28
Risk Management	30
Continuous Disclosure	34
Supplemental Earnings Measures	35

ONTARIO POWER GENERATION INC. MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. ("OPG" or the "Company") as at and for the three and nine months ended September 30, 2005. It should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, and MD&A as at and for the year ended December 31, 2004. OPG's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. This MD&A is dated November 10, 2005.

FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could" and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression will not, however, mean that a statement is not a forward-looking statement.

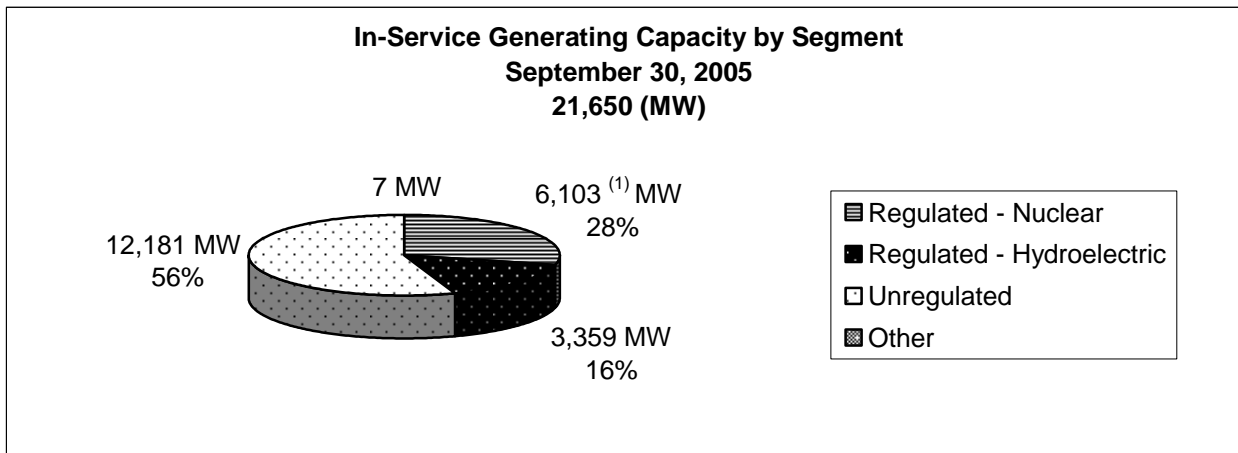
All forward-looking statements involve inherent assumptions, risks and uncertainties and, therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's fuel costs and availability, nuclear decommissioning and waste management, closure of coal-fired generating stations, pension and other post employment benefit ("OPEB") obligations, income taxes, spot market electricity prices, the ongoing evolution of the Ontario electricity industry, environmental and other regulatory requirements, and the weather. Accordingly, undue reliance should not be placed on any forward-looking statement.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the efficient production and sale of electricity from its generating assets, while operating in a safe, open and environmentally responsible manner. OPG was created under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province").

At September 30, 2005, OPG had 21,650 megawatts (MW) of in-service generating capacity. OPG's electricity generating portfolio consisted of three nuclear generating stations, five fossil-fuelled generating stations, 64 hydroelectric generating stations and three wind generating stations (which includes a 50 per cent interest in the Huron Wind joint venture). All four units of the Pickering A nuclear generating station were laid up in 1997. Unit 4 was returned to service in 2003. Unit 1 was returned to service in November 2005, adding 515 MW to OPG's in-service generating capacity. In addition, OPG, ATCO Power Canada Ltd. and ATCO Resources Ltd. co-own a gas-fired generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. ("Bruce Power").

Effective April 1, 2005, the output from most of OPG's baseload hydroelectric facilities and all of its nuclear facilities became rate regulated. OPG continues to receive the spot market price for the output from its remaining hydroelectric, fossil-fuelled and wind generating stations, subject to a revenue limit. With the introduction of rate regulation, OPG has revised its reporting segments to separately reflect the regulated and unregulated aspects of its operations. OPG's operating results are reported on a consolidated basis as well as by business segment. The business segments are: Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation.



⁽¹⁾ Excludes 515 MW from Pickering A Unit 1 returned to service in November 2005.

RATE REGULATION

A regulation was introduced pursuant to the *Electricity Restructuring Act, 2004*, which provided that, effective April 1, 2005, OPG would receive regulated prices for electricity generated from most of its baseload hydroelectric and all of its nuclear facilities. This includes electricity generated from Sir Adam Beck 1, 2 and Pump Generating Station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B, and Darlington nuclear facilities.

The regulated price received by OPG for the first 1,900 megawatt hours (MWh) of production from the regulated hydroelectric facilities in any hour is \$33.00/MWh (3.3¢/kWh). As an incentive to encourage maximum hydroelectric production during peak demand periods, any production from these regulated hydroelectric facilities above 1,900 MWh in any hour receives the unregulated Ontario electricity spot market price. The regulated price received by OPG for production from the nuclear facilities is \$49.50/MWh (4.95¢/kWh). These regulated prices were established by the Province, based on forecast production volumes and total operating costs, including the cost of capital and assuming an average five per cent return on equity. These initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time it is anticipated that the Ontario Energy Board ("OEB") will establish new regulated prices. If there are changes to the fundamental assumptions on which these regulated prices were developed, they may be amended by the Province.

The regulation directed OPG to establish variance accounts for costs incurred on or after April 1, 2005 that are associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions; changes in nuclear electricity production due to unforeseen changes to the law or to unforeseen technological changes; changes to revenues assumed for ancillary revenues from the regulated facilities; acts of God (including severe weather events); and transmission outages and transmission restrictions. In addition, the regulation directed OPG to establish a deferral account for Pickering A return to service non-capital costs incurred on or after January 1, 2005.

The production from OPG's other generating assets remains unregulated and continues to be sold at the Ontario electricity spot market price. However, 85 per cent of the generation output from OPG's other generating assets, excluding the Lennox generating station, Transition – Generation Corporation Designated Rate Options ("TRO") volumes and forward sales as of January 1, 2005, are subject to a revenue limit based on an average price of \$47.00/MWh (4.7¢/kWh). This revenue limit is in place for a period of 13 months ending April 30, 2006. Revenues above this limit will be rebated back to consumers at the end of the period.

The implementation of regulated pricing for the generation from OPG's baseload hydroelectric and nuclear facilities, as well as the revenue limit on OPG's unregulated generating assets, replaced OPG's rebate obligations under the Market Power Mitigation Agreement effective April 1, 2005.

EARNINGS OUTLOOK

Over the May 1, 2002 to March 31, 2005 period, OPG's earnings and liquidity were severely impacted by the requirement to rebate a significant portion of its revenues under the Market Power Mitigation Agreement. In total, the Market Power Mitigation Agreement rebate amounted to \$4.0 billion over this period.

OPG's earnings have improved in 2005 as a result of the implementation of the regulatory changes which took effect April 1, 2005. The improvement in earnings from OPG's regulated assets are forecast to continue as a result of the introduction of regulated rates that reflect the projected production and costs of operations, including a cost of capital with an average five per cent return on equity. While a significant portion of OPG's output from its unregulated assets is subject to the revenue limit until April 30, 2006, this limit is higher than the limit prescribed under the Market Power Mitigation Agreement. As a result, improved earnings from its unregulated assets are also forecast to continue.

OPG's future earnings are forecast to be impacted by a number of factors including the removal of the current revenue limit on its unregulated assets on April 30, 2006, the closure of its coal-fired generating stations, and the impact of the regulated prices established by the OEB.

HIGHLIGHTS/EXECUTIVE SUMMARY

This section provides an overview of OPG's consolidated operating results. A detailed review of OPG's performance by business segment is included in a later section.

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
<i>Revenue</i>				
Revenue	1,907	1,413	5,191	4,553
Market Power Mitigation Agreement rebate	-	(201)	(412)	(850)
Revenue limit rebate	(336)	-	(477)	-
	1,571	1,212	4,302	3,703
<i>Earnings</i>				
Income (loss) before impairment of long-lived assets, income taxes and extraordinary item	275	(13)	631	42
Impairment of long-lived assets	-	-	(265)	-
Income (loss) before income taxes and extraordinary item	275	(13)	366	42
Income tax expenses	94	2	86	34
Income (loss) before extraordinary item	181	(15)	280	8
Extraordinary item	-	-	74	-
Net income (loss)	181	(15)	206	8
<i>Electricity production (TWh)</i>	27.1	26.0	81.4	78.9
<i>Cash flow</i>				
Cash flow provided by (used in) operating activities	382	(3)	755	74

2005 Earnings

Net income for the three months ended September 30, 2005 was \$181 million compared to a net loss of \$15 million during the same period in 2004, an increase in earnings of \$196 million. Income before tax during the three months ended September 30, 2005 was \$275 million compared to a loss of \$13 million for the same period in 2004, an increase of \$288 million.

Net income for the nine months ended September 30, 2005 was \$206 million compared to a net income of \$8 million during the same period in 2004, an increase of \$198 million. Income before income taxes and an extraordinary item during the nine months ended September 30, 2005 was \$366 million compared to \$42 million for the same period last year, an increase of \$324 million. During the second quarter of 2005, OPG recorded a one-time extraordinary loss of \$74 million to reflect the impact of adopting rate regulated accounting for income taxes effective April 1, 2005.

The following is a summary of the factors impacting OPG's results for 2005 compared to 2004, on a before-tax basis:

<i>(millions of dollars – before tax)</i>	Three Months	Nine Months
(Loss) income before income taxes for the periods ended September 30, 2004	(13)	42
Changes in gross margin		
Increase in electricity sales prices after Market Power Mitigation Agreement rebate and revenue limit rebate	278	432
Change in electricity generation by segment:		
Regulated – Nuclear	30	76
Regulated – Hydroelectric	(16)	(3)
Unregulated – Hydroelectric	(68)	(127)
Unregulated – Fossil-fuelled	29	82
Other changes in gross margin	12	26
	265	486
Decrease in Pickering A return to service OM&A expense due to deferral of non-capital costs in 2005 as a rate regulated asset	62	186
Increase in OM&A costs as a result of not returning Pickering A generating station Units 2 and 3 to service primarily due to write-off of inventory	(22)	(22)
Increase in nuclear maintenance and repairs	(45)	(87)
Increase in pension and other post employment benefit costs	(6)	(26)
Other net changes	34	52
Increase in income before income taxes and extraordinary item, excluding impairment of long-lived assets	288	589
Impairment of Pickering A generating station Units 2 and 3	-	(63)
Impairment of Lennox generating station	-	(202)
Income before income taxes and extraordinary item for the periods ended September 30, 2005	275	366

Earnings for the Three Months Ended September 30, 2005

Earnings for the three months ended September 30, 2005 were significantly impacted by an increase in gross margin from electricity sales due primarily to higher average sales prices compared to the same period in 2004. The increase in OPG's average sales price was due in part to higher average Ontario spot market prices which impacted revenue from OPG's unregulated generating assets. The higher spot

market prices were primarily due to higher demand resulting from a prolonged period of hot summer weather and the effect on electricity prices of higher natural gas prices. In addition, OPG's average sales price increased due to the introduction of regulated prices and other related regulatory changes effective April 1, 2005.

The increase in income during the third quarter of 2005 was also due to a decrease in operations, maintenance and administration ("OM&A") expenses resulting from the deferral of non-capital costs related to the Pickering A return to service project, commencing January 1, 2005, as required by a regulation pursuant to the *Electricity Restructuring Act, 2004*.

The favourable impact of these changes in earnings during the third quarter of 2005, was partly offset by higher nuclear maintenance and repairs related to continuing improvements in station reliability and an increase in pension and OPEB costs primarily due to changes in economic assumptions.

In August 2005, OPG decided not to proceed with the return to service of Units 2 and 3 at the Pickering A nuclear generating station. Upon consideration of the scope of the refurbishment work, the costs and the risks related to the return to service of these two units, and the Company's focus on improving the performance of its other nuclear units, OPG's Board of Directors decided that while technically feasible, the return to service of these units was not justified on a commercial basis. During the third quarter of 2005, OPG recorded OM&A expenses of \$22 million related to the write-off of excess inventory acquired for the anticipated return to service of Units 2 and 3. OPG is continuing to assess the need to provide for additional charges as a result of the decision not to proceed with the return to service, including the requirement for the write-off of additional inventory.

During the third quarter of 2005, OPG recorded an income tax charge of \$50 million to provide for a change in income tax liabilities related to certain income tax positions that the Company has taken in prior periods. OPG is responsible for making payments in lieu of corporate income and capital taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Corporations Tax Act* (Ontario), and are modified by the *Electricity Act, 1998* and related regulations.

OPG adopted regulatory accounting for the rate regulated segments of its business, effective April 1, 2005. OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method, whereby future income tax assets and liabilities associated with these segments are not recognized where those income taxes are expected to be recovered in the regulated rates charged to customers in the future. As a result, during the third quarter of 2005, OPG did not record a future tax expense for the rate regulated segments of \$57 million, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method.

Earnings for the Nine Months Ended September 30, 2005

Earnings during the nine months ended September 30, 2005 were favourably impacted by an increase in gross margin from electricity sales due primarily to higher average sales prices compared to the same period in 2004. The increase in OPG's average sales price was due in part to higher average Ontario spot market prices due to higher demand and the effect of higher natural gas prices, and the regulatory changes effective April 1, 2005. Higher electricity generation during the nine months ended September 30, 2005 due to improved station performance also contributed to the increase in gross margin compared to the same period last year. In addition, earnings were favourably impacted by the deferral of non-capital costs related to the Pickering A return to service project commencing in 2005.

The favourable impact of these changes was partly offset by the impairment loss on OPG's Lennox generating station of \$202 million before tax, which was recorded during the first quarter of 2005. It was determined that the Lennox generating station, as a relatively high variable cost plant, would not be able to recover its fixed operating costs and carrying value from the wholesale electricity market in the future. OPG had initiated discussions with the Province, with the expectation of entering into a contractual arrangement for the recovery of the annual fixed operating costs and the carrying value of the Lennox

generating station. OPG was subsequently advised by the Province during the first quarter of 2005 that it would continue to support OPG in negotiating an arrangement that would support the recovery of fixed operating costs, but that the Province would not support an arrangement that would allow for the recovery of the carrying value of the station. As a result of this change in circumstance, OPG recorded the impairment loss. OPG has since negotiated an arrangement with the Independent Electricity System Operator (“IESO”), pursuant to the market rules, to recover its operating costs for a one-year period ending September 30, 2006. The arrangement with the IESO is subject to approval by the OEB.

Earnings for the nine months ended September 30, 2005 were also unfavourably impacted by an impairment loss of \$63 million before tax, which was recorded during the second quarter of 2005 with respect to the decision not to return to service Units 2 and 3 of the Pickering A nuclear generating station, and the subsequent write-off of \$22 million of excess inventory related to these two units.

Earnings for the nine months ended September 30, 2005 were also impacted by higher nuclear maintenance and repairs related to continuing efforts to improve station reliability, an increase in pension and OPEB costs primarily due to changes in economic assumptions, and the income tax charge during the third quarter of 2005 to provide for a change in income tax liabilities.

As a result of adopting rate regulated accounting and the corresponding use of the taxes payable method for the rate regulated segments of its business effective April 1, 2005, OPG did not record a future tax expense of \$110 million for these rate regulated segments, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method. As part of the transition, OPG also eliminated a net future income tax asset of \$74 million and recorded a corresponding one-time extraordinary loss.

Average Sales Prices

OPG’s average sales prices by business segment, net of the revenue limit rebate for the period April 1, 2005 to September 30, 2005, and net of the Market Power Mitigation Agreement up to the inception of rate regulation on April 1, 2005 are as follows:

<i>(¢/kWh)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Regulated – Nuclear	4.9	4.0	4.7	4.1
Regulated – Hydroelectric ¹	4.2	4.0	4.1	4.2
Unregulated				
Hydroelectric ²	6.0	3.9	5.0	4.1
Fossil-fuelled ²	6.6	4.2	5.5	4.3

¹ During the period from April 1 to September 30, 2005, electricity generation from stations in the Regulated – Hydroelectric segment received a fixed price of 3.3¢/kWh for the first 1,900 MWh of generation in any hour, and the Ontario spot electricity market price for generation above this level.

² During the period from April 1 to September 30, 2005, 85 per cent of the electricity generation from unregulated stations, excluding the Lennox generating station and other contract volumes, was subject to a revenue limit based on an average price of 4.7¢/kWh.

Electricity Generation

Total production during the three months ended September 30, 2005 from OPG’s generating stations was 27.1 TWh compared to 26.0 TWh during the same period in 2004. The increase in generation was primarily a result of higher fossil-fuelled generation attributable to higher electricity demand during the summer of 2005 as a result of a prolonged period of high temperatures. The increase in generation was partly offset by a reduction in hydroelectric generation due to lower water levels.

For the nine months ended September 30, 2005, total production from OPG's generating stations was 81.4 TWh compared to 78.9 TWh for the same period in 2004. The increase in generation was primarily a result of higher fossil-fuelled generation in 2005 due to higher electricity demand and improved station performance, and higher nuclear generation. Improved performance at the Pickering B and Darlington nuclear generating stations more than offset the impact of the shutdown of Unit 4 at the Pickering A nuclear generating station during the second quarter for inspection and replacement of feeder pipes. Hydroelectric generation was negatively impacted during the first nine months of 2005 compared to the same period last year due to lower water levels.

OPG's results are impacted by changes in demand resulting from variations in seasonal weather conditions. The following table provides a comparison of heating and cooling degree days.

	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Heating Degree Days ¹				
Period	20	42	2,490	2,516
Ten-year average	64	76	2,451	2,459
Cooling Degree Days ²				
Period	390	193	542	232
Ten-year average	268	256	353	334

¹ Heating Degree Days represent the aggregate of the differences between the average daily temperatures below 18°C and 18°C for each day during the period, as measured at Pearson International Airport in Toronto.

² Cooling Degree Days represent the aggregate of the differences between the average daily temperatures above 18°C and 18°C for each day during the period, as measured at Pearson International Airport in Toronto.

Cash Flow from Operations

Cash flow provided by operating activities during the three months ended September 30, 2005 was \$382 million compared to \$3 million used in operating activities during the same period in 2004, an improvement of \$385 million. Cash flow provided by operating activities during the nine months ended September 30, 2005 was \$755 million compared to \$74 million during the same period in 2004, an improvement of \$681 million. The favourable change in cash flow for both the three and nine month periods was primarily due to higher revenue and earnings compared to the same periods in 2004. The favourable changes were partly offset by higher pension contributions during the third quarter of 2005.

Recent Developments

In October 2005, the Province and Bruce Power announced an agreement to refurbish the Bruce A nuclear generating station. Under the agreement, Bruce Power will refurbish and restart Units 1 and 2, refurbish Unit 3 when it reaches the end of its current operational life and replace the steam generators in Unit 4. The Bruce A units were taken out of service between 1995 and 1998 after a decision by the former Ontario Hydro.

In 2001, Bruce Power L.P. entered into a lease arrangement with OPG relating to the Bruce A and B nuclear generating stations, which are owned by OPG. Under the previous terms of the lease, a return to service of any of the Bruce A units would result in an annual lease payment of \$25.5 million per unit (in 2002 dollars, escalated at CPI). As part of the agreement reached in October 2005 between the Province and Bruce Power, OPG received a Shareholder Declaration from the Province instructing OPG's Board of Directors to accept certain amendments to the lease agreement. These amendments included a change to the provisions regarding the transfer of Bruce Power's interest in the site and included a reduction of the annual lease payment for three of the four refurbished Bruce A units to \$5.5 million per unit (in 2002

dollars, escalated at CPI), after the planned future refurbishments are completed. This amount represents the approximate incremental cost of long-term management and disposal of used fuel for these units. These changes to the lease agreement will impact OPG when Units 1 and 2 of the Bruce A nuclear generating station are returned to service, and when Unit 3 is refurbished at the end of its current operational life. Other changes to the existing arrangements were made to address Cameco Corporation's decision not to participate in the refurbishment of the Bruce A nuclear generating station.

VISION, CORE BUSINESS AND STRATEGY

OPG's mandate is to cost effectively produce electricity from its diversified generation assets, while operating in a safe, open and environmentally responsible manner. This core mandate was agreed upon by OPG and its sole shareholder during the third quarter of 2005, and is comprised of the following specific objectives:

- OPG will operate its existing nuclear, hydroelectric and fossil generating assets as efficiently and cost effectively as possible, within federal and provincial legislative and regulatory frameworks, and in a manner that mitigates the Province's financial and operational risk.
- OPG's key nuclear objective will be the reduction of risk exposure to the Province arising from its investment in nuclear generating stations in general and, in particular, the refurbishment of older units, while continuing to operate with a high degree of vigilance with respect to nuclear safety.
- OPG will seek continuous improvement in its nuclear generation business and internal services as well as benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.
- OPG will continue to operate its fossil fleet, including coal plants, according to normal commercial principles taking into account the Government's coal replacement policy and recognizing the role that fossil plants play in the Ontario electricity market.
- With respect to investment in new generation capacity, OPG's priority will be hydroelectric capacity. OPG will seek to expand, develop, and/or improve its hydroelectric generation capacity through expansion and redevelopment of its existing sites as well as the pursuit of new projects where feasible. OPG will undertake these investments through partnerships or on its own, as appropriate.
- OPG will operate in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility, corporate citizenship and environmental stewardship, taking into account the Government's coal replacement policy.

To accomplish its mandate and these specific objectives, OPG is concentrating its efforts on further improving generating asset performance through production efficiencies and increased reliability; adding to its generating capacity; and strengthening corporate governance.

Improving the Performance of Generating Assets

Nuclear Generating Assets

OPG's strategy with respect to its nuclear generating stations is to operate the Darlington and Pickering stations in an efficient and cost effective manner, while undertaking prudent investments to improve the reliability and predictability of these assets. OPG conducts comprehensive inspection and testing programs to ascertain the physical condition of its nuclear generation stations in order to improve the reliability and predictability of the nuclear stations. OPG is implementing steam generator inspection and rehabilitation programs; feeder pipe integrity projects; pressure tube remediation programs such as Spacer Location and Relocation (SLAR); and initiatives aimed at reducing maintenance backlogs.

Hydroelectric Generating Assets

OPG's strategy for its hydroelectric generating assets is to optimize production from its stations as well as expand, develop, and improve its hydroelectric capacity. Through capital reinvestment, station automation, efficiency improvements and effective plant maintenance, OPG has increased the productive capacity of its hydroelectric plants, extended their service lives and lowered their operating and maintenance costs. This reinvestment program is continuing, and includes an accelerated runner upgrade program aimed at increasing hydroelectric capacity by an additional 110 to 120 MW between 2005 and 2012.

Fossil-Fuelled Generating Assets

As a consequence of the Government's intention to close OPG's coal facilities, the Company's strategy, taking into account the Government's coal replacement policy, is to maintain the productive capability of these facilities, while operating them in an environmentally responsible manner. Capital investments required to maintain production and meet environmental objectives will continue. The expenditure profile of the coal plants has shifted from a 'replace' to a 'repair' strategy. In particular, maintenance programs have been modified to address the impacts of increased unit starts and maneuvering of units, in part due to the role that the fossil-fuelled plants perform as intermediate and peaking facilities.

Thunder Bay Generating Station

In October 2005, OPG received a Shareholder Declaration from the Province instructing OPG's Board of Directors to convert the Thunder Bay generating station to run on natural gas. Under the declaration, the Province will put in place appropriate cost recovery mechanisms covering initial capital and development expenditures, ongoing operating costs and an appropriate return to OPG. The cost recovery mechanisms are required to ensure that OPG is able to record the conversion costs as an asset. The project is expected to be complete by December 2007.

Adding to OPG Generating Capacity

OPG's strategy, with shareholder consent, is to continue to pursue initiatives that increase the Company's electricity generation capacity. These initiatives include the return to service of Unit 1 at the Pickering A nuclear generating station and initiatives to increase the capacity of hydroelectric stations.

Pickering A Unit 1 Return to Service

Major construction for the return to service of Unit 1 at the Pickering A nuclear generating station commenced in July 2004. The construction phase of the project was completed in July 2005, with the removal of Unit 1 from the guaranteed shutdown state. On September 26, 2005, Unit 1 was synchronized to the provincial electricity grid, sending electricity from the unit to Ontario consumers for the first time since December 1997.

On November 3, 2005, OPG declared the unit to be commercially available and informed the IESO that the unit was available for dispatch into the Ontario market, adding 515 MW of baseload capacity in Ontario. The project represented a complex construction challenge, encompassing more than 1.9 million hours of work and almost 3,000 people at its peak.

During the major construction phase of Unit 1 at the Pickering A nuclear generating station, the schedule and cost to complete the project was impacted by the discovery of feeder pipe thinning in areas not previously identified. This resulted in the need to perform additional inspections and the replacement of a feeder pipe, which was not included in the original scope of the project and the cost estimate. In addition, feeder issues resulted in the shutdown of Unit 4 at the Pickering A nuclear generating station. Resources were diverted from Unit 1 to address the Unit 4 feeder issue and to complete other outage work, which also contributed to the extension of the Unit 1 project schedule. The costs related to the feeder inspection and replacement program and the schedule extension were approximately \$20 million.

Total cumulative expenditures to September 30, 2005 were \$985 million, excluding the impact on costs of the feeder inspection and replacement, and the diversion of resources to Unit 4. The total costs incurred up to the date that the unit was declared to be commercially available on November 3, 2005, excluding the feeder related impacts, were \$996 million.

Niagara Tunnel

In June 2004, OPG announced and the Government endorsed the decision to proceed with a new water diversion tunnel that will increase the amount of water flowing to existing turbines at the Sir Adam Beck generating stations in Niagara. This tunnel will allow the Beck generating facilities to utilize available water more effectively, and is expected to increase annual generation on average by about 1.6 TWh. OPG undertook an open, competitive and international process to select the successful contractor, with three pre-qualified companies submitting detailed design-build proposals in May 2005. Following approval by OPG's Board of Directors and cabinet approval of project financing by the OEFC, OPG awarded a contract to Strabag AG in August 2005 to design and construct the 10.5 km tunnel. The value of the design-build contract is approximately \$600 million, with the total project expected to cost approximately \$985 million. Construction preparation activities started in September 2005. Project completion is expected by late 2009.

Portlands Energy Centre

OPG entered into a partnership with TransCanada Energy Ltd. ("TransCanada"), called Portlands Energy Centre L.P. ("PEC"), to pursue the development of a 550 MW gas-fired, combined cycle station on the site of the former R.L. Hearn generating station, near downtown Toronto. The generating station would help to meet the growing energy needs of Toronto's downtown core.

In September 2004, the Province issued a Request for Proposals for 2,500 MW of New Clean Generation and Demand Side Management Projects. PEC submitted a bid under this process, but was not among the six bids that were selected in April and June 2005. PEC continues to seek opportunities to develop the project under future Government procurement processes.

BUSINESS SEGMENTS

Prior to the introduction of rate regulation, OPG had two reportable business segments: Generation and Energy Marketing. A separate category, Non-Energy and Other, included revenue and certain costs not allocated to its business segments. With the introduction of rate regulation, OPG changed the definition of business segments with effect from April 1, 2005 in recognition of the different economic characteristics of the Company's operations. The business segments are: Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. In addition, OPG continues to report a separate category, Other, which includes trading activities that previously comprised the Energy Marketing business segment, and revenues and certain costs neither attributable nor allocated to its business segments.

OPG has entered into various energy and related sales contracts with its customers to hedge commodity price exposure to changes in electricity prices associated with the spot market for electricity in Ontario. Contracts that are designated as hedges of OPG's generation revenues are included with electricity production revenues in each segment up to March 31, 2005 and in the Unregulated Generation segment after that date. Gains or losses on these hedging transactions are recognized in revenue over the term of the contract when the underlying transaction occurs.

Regulated – Nuclear Segment

OPG's Regulated – Nuclear business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations.

OPG's Regulated – Nuclear business segment includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. The arrangement includes lease

revenue, interest income and revenue from engineering analysis and design, technical and other services. The Regulated – Nuclear business segment also includes revenue earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control/reactive support. These earnings are included in the Regulated - Nuclear business segment since they were included in determining the regulated price for production from the nuclear facilities.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its baseload hydroelectric generating stations. The business segment includes electricity generated by the Sir Adam Beck 1, 2 and Pump Generating Station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. The Regulated – Hydroelectric business segment also includes ancillary revenues related to these stations earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control.

Unregulated Generation Segment

OPG's Unregulated Generation business segment operates in Ontario, generating and selling electricity from its fossil-fuelled generating stations and from the hydroelectric generating stations not included in the Regulated – Hydroelectric segment. The Unregulated Generation business segment also includes ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control/reactive support, certified black start facilities and automatic generation control, and revenues from other services.

Other

OPG earns revenue from its joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Coral Energy Canada Inc. ("Coral"). In addition, the Other category includes revenue from real estate rentals.

The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses.

KEY GENERATION PERFORMANCE INDICATORS

OPG's revenue is primarily dependent upon the quantity of electricity produced by its generating stations and the price at which that electricity is sold. OPG's electricity production is dependent on electricity demand and the availability of its generating stations to contribute to meeting that demand. OPG evaluates the performance of generating stations using a number of key performance indicators, which vary depending on the generation technology. OPG has included the following two key indicators in the Discussion of Operating Results section.

- Nuclear Unit Capability Factor – the amount of energy that the unit(s) generated over a period of time, adjusted for external energy losses such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation.
- Fossil-fuelled and Hydroelectric Equivalent Forced Outage Rate (EFOR) – an index of the reliability of the generating unit measured by the ratio of time a generating unit is forced out of service, including any forced deratings, compared to the amount of time the generating unit was available to operate.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

This section summarizes OPG's key results by segment for the three months and nine months ended September 30, 2005 and 2004. Although the regulations pursuant to the *Electricity Restructuring Act, 2004* became effective commencing April 1, 2005, results for the quarters prior to April 1, 2005 have been reclassified according to the new business segment definitions. The prior period results from OPG's nuclear and hydroelectric generating stations that are now regulated have been reclassified into the Regulated – Nuclear and Regulated – Hydroelectric segments for comparative purposes. Similarly, results from OPG's unregulated generating stations have been reclassified into the Unregulated Generation segment. Accordingly, revenues reflect spot market prices received for electricity sales net of the Market Power Mitigation Agreement rebate up to the inception of rate regulation on April 1, 2005.

The operating results for the period prior to rate regulation reflect a significantly different economic environment from that introduced by rate regulation.

The following table provides a summary of revenue, earnings and operating statistics by business segment:

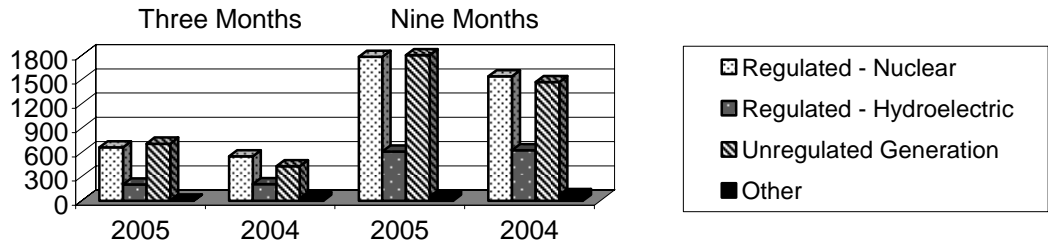
<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
<i>Revenue, net of Market Power Mitigation Agreement rebate and revenue limit rebate</i>				
Regulated – Nuclear	662	548	1,782	1,539
Regulated – Hydroelectric	202	204	609	625
Unregulated Generation	706	428	1,863	1,468
Other	1	32	48	71
	1,571	1,212	4,302	3,703
<i>Income (loss) before interest, income taxes and extraordinary item</i>				
Regulated – Nuclear	65	(71)	(50)	(297)
Regulated – Hydroelectric	96	96	302	323
Unregulated Generation	196	6	280	161
Other	(33)	4	(23)	(7)
	324	35	509	180
<i>Electricity production¹ (TWh)</i>				
Regulated – Nuclear	11.9	11.5	33.3	31.9
Regulated – Hydroelectric	4.4	4.8	14.0	14.1
Unregulated Generation – Hydroelectric	2.0	3.7	10.2	13.2
Unregulated Generation – Fossil-fuelled	8.8	6.0	23.9	19.7
Total electricity generation	27.1	26.0	81.4	78.9
<i>Nuclear unit capability factor² (per cent)</i>				
Darlington	98.2	97.9	90.9	90.0
Pickering A	78.8	77.5	60.1	75.2
Pickering B	85.0	72.4	80.7	68.9
<i>Equivalent forced outage rate (per cent)</i>				
Regulated – Hydroelectric	2.7	3.4	1.3	2.5
Unregulated Generation – Hydroelectric	1.2	0.7	1.3	1.2
Unregulated Generation – Fossil-fuelled	16.6	15.2	15.8	19.1

¹ Electricity generation is presented in accordance with OPG's business segments, with the exception of the Unregulated Generation segment, for which generation from hydroelectric and fossil-fuelled generating stations is shown separately.

² Capability factors by industry definition exclude grid-related unavailability.

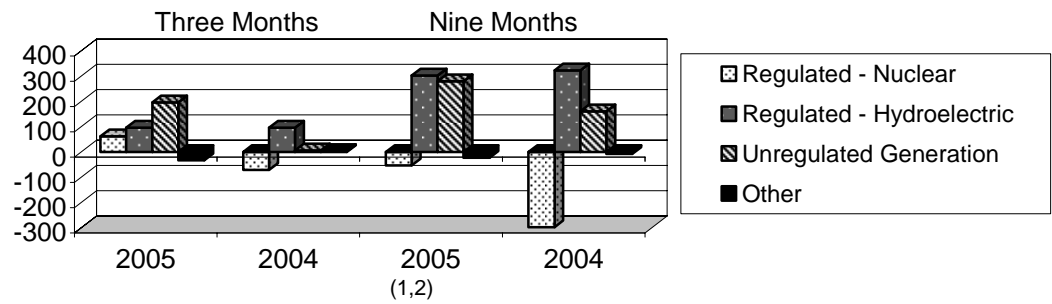
**Revenue, Net of Market Power Mitigation Agreement
Rebate and Revenue Limit Rebate by Segment**

(millions of dollars)



**Income (loss) Before Interest, Income Taxes
and Extraordinary Item by Segment**

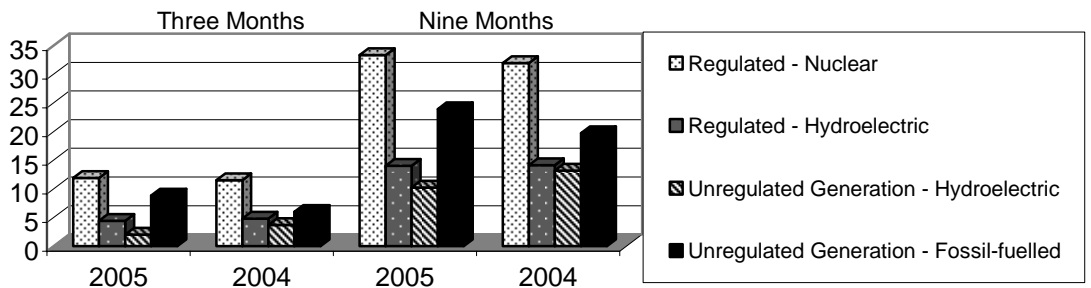
(millions of dollars)



- (1) During the second quarter of 2005, OPG recorded a \$63 million impairment loss on the Pickering A nuclear generating station Units 2 and 3.
- (2) During the first quarter of 2005, OPG recorded a \$202 million impairment loss related to its Lennox generating station.

Electricity Production

(TWh)



Regulated – Nuclear Segment

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Revenue, net of Market Power Mitigation Agreement rebate	662	548	1,782	1,539
Fuel expense	31	28	85	82
Gross margin	631	520	1,697	1,457
Operations, maintenance and administration Expenses excluding Pickering A return to service	453	399	1,312	1,195
Pickering A return to service	-	62	-	186
Depreciation and amortization	92	84	278	270
Accretion on fixed asset removal and nuclear waste management liabilities	117	111	351	334
Earnings on nuclear fixed asset removal and nuclear waste management funds	(96)	(77)	(279)	(255)
Property and capital taxes	-	12	22	24
Operating income	65	(71)	13	(297)
Impairment loss	-	-	63	-
(Loss) income before interest, income taxes and extraordinary item	65	(71)	(50)	(297)

Revenue

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Spot market sales, net of hedging instruments	-	524	662	1,572
Market Power Mitigation Agreement rebate	-	(64)	(160)	(270)
Regulated generation sales	585	-	1,046	-
Other	77	88	234	237
Total revenue	662	548	1,782	1,539

Regulated – Nuclear revenue was \$662 million for the three months ended September 30, 2005 compared to \$548 million during the same period in 2004. The increase in revenue was primarily due to higher sales prices related to the introduction of regulated rates effective April 1, 2005, which exceeded OPG's average spot market price net of the Market Power Mitigation Agreement rebate for the same period in 2004. Revenue also increased as a result of higher electricity generation of 0.4 TWh during the third quarter of 2005 compared to the same period last year.

Regulated – Nuclear revenue was \$1,782 million for the nine months ended September 30, 2005 compared to \$1,539 million during the same period in 2004. The increase in revenue was primarily related to the higher electricity sales prices in the second and third quarters of 2005 related to the introduction of rate regulation and the impact of higher electricity generation of 1.4 TWh in 2005.

Electricity Prices

Since market opening on May 1, 2002, and prior to April 1, 2005, OPG was required under its generation licence issued by the OEB to comply with prescribed market power mitigation measures, including a rebate mechanism. Under the Market Power Mitigation Agreement, OPG had been required to pay a rebate to the IESO equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for the amount of energy sales subject to the rebate mechanism for those generating stations that OPG continued to control. The IESO passed the rebate on to consumers. The amount of energy generated by OPG that was subject to the rebate mechanism was approximately 80 TWh on an annual basis.

Electricity generation from stations in the Regulated – Nuclear segment received a fixed price of 4.95¢/kWh since April 1, 2005. OPG's average sales price for the nine months ended September 30, 2005 was 4.7¢/kWh, after taking into account the regulated rate received from April 1, 2005 to September 30, 2005, and OPG's average spot market sales price, which for the first quarter was net of the Market Power Mitigation Agreement rebate. In 2004, OPG's average sales prices, after taking into account the Market Power Mitigation Agreement rebate, were 4.0¢/kWh and 4.1¢/kWh for the three and nine months ended September 30, 2004, respectively.

Volume

Electricity sales volume from the generating assets in the Regulated – Nuclear segment for the three months ended September 30, 2005 was 11.9 TWh compared to 11.5 TWh for the same period in 2004. The increase in generation volume was mainly due to fewer planned outage days at the Pickering B nuclear generating station.

Total nuclear generation for the nine months ended September 30, 2005 increased to 33.3 TWh from 31.9 TWh for the same period in 2004. The increase in volume was due to improved performance at the Pickering B and Darlington nuclear generating stations compared to the same period in 2004. Both stations experienced fewer unplanned outage days, and there were also fewer planned outage days at the Pickering B station. The higher generation at Pickering B and Darlington was partially offset by lower generation from the Pickering A nuclear generating station. Unit 4 at the Pickering A nuclear generating station was shut down on April 2, 2005 for inspection of feeder pipes. The unit was returned to service on July 19, 2005, after replacing two feeder pipes.

Fuel Expense

Fuel expense for the three months ended September 30, 2005 was \$31 million compared to \$28 million in 2004. Fuel expense for the nine months ended September 30, 2005 was \$85 million compared to \$82 million in 2004. Fuel expense for the nuclear generating stations was only marginally impacted by the changes in generation volumes in 2005 compared to 2004 due to the low marginal cost nature of nuclear generation.

Operations, Maintenance and Administration

OM&A expenses, excluding those related to the Pickering A return to service initiative, were \$453 million for the three months ended September 30, 2005 compared to \$399 million for the same period in 2004, an increase of \$54 million. The increase was partly due to the write-off of \$22 million of excess inventory as a result of not returning Pickering A generating station Units 2 and 3 to service.

As part of OPG's objective to improve the performance of its nuclear generating stations, the Company has committed additional resources in an effort to maximize the operating availability and reliability of these stations. OM&A expenses for nuclear maintenance and repairs increased by \$45 million compared to the same period in 2004. These expenditures related to improvement projects and ongoing maintenance costs to address plant condition and regulatory requirements. In addition, pension and OPEB expenses increased by \$4 million compared to the same period in 2004, primarily the result of changes in economic assumptions related to discount rates. The impact of these increases in expense was partly offset by reductions in other costs.

OM&A expenses, excluding those related to the Pickering A return to service initiative, were \$1,312 million for the nine months ended September 30, 2005 compared to \$1,195 million for the same period in 2004, an increase of \$117 million. The increase in OM&A expenses was primarily due to the higher expenses for nuclear maintenance and repairs of \$87 million, and write-off of inventory related to Pickering A Units 2 and 3. Pension and OPEB costs increased by \$19 million during the nine months ended September 30, 2005 compared to the same period in 2004, primarily due to changes in economic assumptions.

Pickering A Return to Service

Effective January 1, 2005, in accordance with a regulation pursuant to the *Electricity Restructuring Act, 2004*, OPG established a balance sheet deferral account for non-capital costs associated with the return to service of Pickering A nuclear generating station units. These deferred costs will be charged to operations in subsequent periods in accordance with the terms of the above referenced regulation. The regulation requires the OEB to ensure recovery of any balance recorded in the deferral account over a period not exceeding 15 years. This is consistent with one of the objectives of rate regulation, which is to ensure that present customers are not burdened with costs incurred for the benefit of future customers, and with generally accepted accounting principles in that the financial effects of regulation can lead to assets and liabilities that would not otherwise be recognized by a non-rate-regulated entity.

As a result of the regulation, non-capital costs related to the Pickering A return to service initiative were excluded from OM&A during the three and nine months ended September 30, 2005. Had these expenditures not been deferred, an expense of \$57 million would have been recognized in the third quarter of 2005 compared to \$62 million for the same period last year. During the nine months ended September 30, 2005, an expense of \$246 million would have been recognized compared to \$186 million during the same period in 2004. The increase in expenditures during the nine month period was primarily due to a higher level of construction activity in 2005 related to the Unit 1 return to service.

Impairment of Long-Lived Assets – Pickering A Generating Station Units 2 and 3

As a result of the decision not to proceed with the return to service of Pickering nuclear generating station Units 2 and 3, the Company recorded an impairment loss of \$63 million in the second quarter of 2005 related to the carrying amount of these two units, including construction in progress. OPG continues to assess the need to provide for additional charges as a result of the decision not to proceed with the return to service of Units 2 and 3, including the cost associated with preparing the units for safe storage, the impact on cost estimates for asset retirement obligations, and any additional inventory write-offs and any other exit costs. OPG expects that the assessment of additional charges will be completed during the fourth quarter of 2005.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended September 30, 2005 was \$92 million compared to \$84 million in the 2004 period. Depreciation and amortization expense for the nine months ended September 30, 2005 was \$278 million compared to \$270 million for the same period in 2004.

Accretion

OPG records the present value of its future costs for fixed asset removal and nuclear waste management as a long-term liability. This liability is discussed in Note 8 to the unaudited interim consolidated financial statements as at and for the three and nine months ended September 30, 2005. Accretion expense reflects the change in the present value of this liability since the end of the prior period. This expense is impacted by factors such as any changes in the estimate of the amount of the future liability for fixed asset removal and nuclear waste management, any changes to the discount rate used to determine the present value, and the change in the present value due to the passage of time.

Accretion expense for the three months ended September 30, 2005 was \$117 million compared with \$111 million for the same period in 2004. Accretion expense for the nine months ended September 30, 2005 was \$351 million compared with \$334 million for the same period last year. The increase in the accretion expense was due to the higher liability base compared to last year as a result of the increase in the present value of the liability due to the passage of time.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

OPG is responsible for the ongoing long-term management and disposal of radioactive wastes and used fuel resulting from operations and future decommissioning of its nuclear generating stations. OPG's obligations relate to the Pickering and Darlington nuclear plants that are operated by OPG, as well as the Bruce nuclear plant that is leased by OPG to Bruce Power.

Pursuant to the Ontario Nuclear Funds Agreement ("ONFA") between OPG and the Province of Ontario, OPG established the Used Fuel Fund and the Decommissioning Fund (together the "Nuclear Funds"). The Used Fuel Fund is intended to fund future expenditures associated with high-level nuclear waste disposal, while the Decommissioning Fund was established to fund future expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level waste related thereto. OPG maintains the Nuclear Funds in third party custodial accounts that are segregated from the rest of OPG's assets.

Assets in the Nuclear Funds are invested in fixed income and equity securities, which OPG records as long-term investments and accounts for at their amortized cost value. Therefore, gains and losses are recognized only upon the sale of an underlying security. As such, there may be unrealized gains and losses associated with the Nuclear Funds which OPG has not recognized in its consolidated financial statements. The balance of the Nuclear Funds, on an amortized cost basis, as at September 30, 2005 was \$6,577 million compared to \$5,976 million as at December 31, 2004.

Under ONFA, the Province guarantees the annual rate of return in the Used Fuel Fund at 3.25 per cent plus the change in the Ontario Consumer Price Index ("committed return") over the long-term. OPG recognizes the committed return on the Used Fuel Fund and includes it in earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the assets, which includes realized and unrealized returns, is due to or from the Province. Since OPG accounts for the investments in the Nuclear Funds on an amortized cost basis, the amount due to or due from the Province recorded in the consolidated financial statements is the difference between the committed return and the actual return based on realized returns only. At September 30, 2005, the Used Fuel Fund included an amount due from the Province of \$1 million (December 31, 2004 – due to the Province of \$4 million). If the investments in the Used Fuel Fund were accounted for at fair market value in the interim consolidated financial statements, at September 30, 2005, there would be an amount due to the Province of \$289 million (December 31, 2004 – \$156 million). In addition, under ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 per cent compared to the value of the associated liabilities.

Under ONFA, the Decommissioning Fund has a long-term target rate of return of 5.75 per cent per annum. OPG bears the risk and liability for cost estimate increases and fund earnings associated with the Decommissioning Fund. At September 30, 2005, based on the estimate of costs to complete under the current approved ONFA Reference Plan (currently the 1999 Reference Plan), the Decommissioning Fund was fully funded on a market value basis and almost fully funded on an amortized cost basis. In the event that realized gains result in the Decommissioning Fund becoming overfunded in the future, OPG will limit the earnings it recognizes in its consolidated financial statements, through a charge to the fund with a corresponding payable to the Province, such that the amortized cost balance of the fund would equal the cost estimate of the liability based on the 1999 Reference Plan. These realized gains may be recognized in subsequent periods provided the fund balance declines below the then currently approved cost estimate.

At September 30, 2005, the Decommissioning Fund asset value on an amortized cost basis was \$4,038 million with a market value of \$4,462 million, the difference representing net unrealized gains totalling \$424 million. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the approved ONFA Reference Plan, are at least 120 per cent funded, OPG may direct up to 50 per cent of the surplus over 120 per cent as a contribution to the Used Fuel Fund, and the OEFC is entitled to a distribution of an identical amount. Any overfunding of the liability is payable to the Province on termination of the Decommissioning Fund. If the investments in the Decommissioning Fund were accounted for at fair market value in the interim consolidated financial statements at September 30, 2005, and the Decommissioning Fund was terminated under the ONFA, there would be an amount due to the Province of \$419 million (December 31, 2004 – \$249 million).

Realized earnings on the Nuclear Funds for the three months ended September 30, 2005 were \$96 million compared to \$77 million for the same period last year, an increase of \$19 million. The higher earnings were primarily a result of an increase in Decommissioning Fund returns during the third quarter of 2005 compared to the same period in 2004 as a result of favourable market conditions and a larger investment base.

Realized earnings on the Nuclear Funds for the nine months ended September 30, 2005 were \$279 million compared to \$255 million for the same period last year, an increase of \$24 million. The higher earnings in 2005 were primarily due to higher earnings in the Used Fuel Fund as a result of a larger asset base during the period due to growth through a combination of earnings and contributions, partly offset by the impact on earnings of a lower Ontario CPI compared to the same period in 2004. The higher earnings realized on the Decommissioning Fund during the third quarter of 2005 were partly offset by lower earnings in the Decommissioning Fund in the first quarter of 2005 compared to the same period last year. During the first quarter of 2004, earnings were higher as a result of additional realized returns in the fund due to the sale of investments related to asset mix rebalancing.

Regulated – Hydroelectric Segment

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Revenue, net of Market Power Mitigation Agreement rebate and variance accounts	202	204	609	625
Fuel expense	64	68	186	183
Gross margin	138	136	423	442
Operations, maintenance and administration	19	19	55	54
Depreciation and amortization	18	17	52	50
Property and capital taxes	5	4	14	15
Income before interest, income taxes and extraordinary item	96	96	302	323

Revenue

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Spot market sales, net of hedging instruments	-	230	260	727
Market Power Mitigation Agreement rebate	-	(34)	(65)	(140)
Regulated generation sales ¹	187	-	382	-
Variance accounts	4	-	-	-
Other	11	8	32	38
Total revenue	202	204	609	625

¹ Regulated generation sales includes revenue of \$76 million that OPG received at the Ontario spot market price for generation over 1,900 MWh in any hour during the third quarter of 2005. For the six months since regulated pricing was introduced, OPG received \$145 million in revenue for generation over 1,900 MWh in any hour.

Regulated – Hydroelectric revenue was \$202 million for the three months ended September 30, 2005 compared to \$204 million during the same period in 2004. The decrease in revenue was primarily due to lower electricity generation in 2005 of 0.4 TWh, largely offset by marginally higher prices in 2005 due to the introduction of regulated rates and related changes effective April 1, 2005.

Regulated – Hydroelectric revenue for the nine months ended September 30, 2005 was \$609 million compared to \$625 million during the same period in 2004. The decrease in revenue was primarily related to marginally lower prices in 2005 compared to 2004, and lower electricity generation of 0.1 TWh in 2005.

Electricity Prices

During the three months ended September 30, 2005, the average electricity sales price for the Regulated – Hydroelectric segment was 4.2¢/kWh. The average sales price is based on the fixed price of 3.3¢/kWh for generation up to 1,900 MWh in any hour, and the average spot electricity market price for generation above this level. The average price for the nine months ended September 30, 2005, was 4.1¢/kWh, after taking into account the regulated rate from April 1, 2005 to September 30, 2005, and OPG's average spot market sales price, which for the first quarter was net of the Market Power Mitigation Agreement rebate. After taking into account the Market Power Mitigation Agreement rebate, the average spot market sales prices for the three and nine months ended September 30, 2004 respectively were 4.0¢/kWh and 4.2¢/kWh.

Volume

Electricity sales volume for the three months ended September 30, 2005 was 4.4 TWh compared to 4.8 TWh for the same period in 2004, of which 0.8 TWh in 2005 related to production levels above 1,900 MWh in any hour. Electricity sales volume for the nine months ended September 30, 2005 was 14.0 TWh compared to 14.1 TWh for the same period in 2004. During the period from April 1, 2005 to September 30, 2005, electricity generation of 1.9 TWh related to production levels above 1,900 MWh in any hour. The decrease in sales volume was due to decreased water flows on the Niagara and St. Lawrence during the third quarter of 2005 compared to the same period in 2004.

Variance Accounts

OPG is required under the regulations pursuant to the *Electricity Restructuring Act, 2004* to establish variance accounts to capture the impact of certain items during the interim period. One of these items that applies specifically to the Regulated - Hydroelectric segment requires OPG to capture the impact of differences in hydroelectric electricity production due to differences between forecast and actual water conditions. OPG's liability as at September 30, 2005 of \$4 million, primarily reflected water conditions that were favourable to those forecasted for the second quarter of 2005. During the third quarter of 2005, OPG recorded an asset of \$4 million for ancillary revenues unfavourable to those forecasted.

Fuel Expense

Fuel expense for the three months ended September 30, 2005 was \$64 million compared to \$68 million in 2004. Fuel expense for the nine months ended September 30, 2005 was \$186 million compared to \$183 million in 2004. OPG pays charges to the Province and the OEFC on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on provincial Crown lands, in addition to graduated rate charges applicable to all hydroelectric stations. GRC costs are included in fuel expense. Fuel expense for the third quarter of 2005 was lower compared to 2004 due to lower generation volumes. Fuel expense and generation volumes for the nine months ended September 30, 2005 was essentially unchanged compared to the same period in 2004.

Operations, Maintenance and Administration

OM&A expenses were \$19 million for the three months ended September 30, 2005 and 2004. OM&A expenses were \$55 million for the nine months ended September 30, 2005 compared to \$54 million for the same period in 2004.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended September 30, 2005 was \$18 million compared to \$17 million for the same period in 2004. Depreciation and amortization expense for the nine months ended September 30, 2005 was \$52 million compared to \$50 million in the 2004 period.

Unregulated Generation Segment

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Revenue, net of Market Power Mitigation Agreement rebate and revenue limit	706	428	1,863	1,468
Fuel expense	289	194	712	605
Gross margin	417	234	1,151	863
Operations, maintenance and administration	142	142	421	419
Depreciation and amortization	63	72	211	226
Accretion on fixed asset removal	2	2	7	6
Property and capital taxes	10	12	26	35
Restructuring	4	-	4	16
Operating income	196	6	482	161
Impairment loss	-	-	202	-
Income before interest, income taxes and extraordinary item	196	6	280	161

Revenue

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Spot market sales, net of hedging instruments	991	503	2,414	1,821
Market Power Mitigation Agreement rebate	-	(103)	(187)	(440)
Revenue limit rebate	(336)	-	(477)	-
Other	51	28	113	87
Total revenue	706	428	1,863	1,468

Unregulated Generation revenue was \$706 million for the three months ended September 30, 2005 compared to \$428 million during the same period in 2004. The increase in revenue was primarily related to higher average sales prices and higher electricity generation in the third quarter of 2005 compared to the same period in 2004. In addition, higher market prices during the third quarter resulted in increased revenue received for operating in accordance with the IESO system constraints.

Unregulated Generation revenue for the nine months ended September 30, 2005 was \$1,863 million compared to \$1,468 million during the same period in 2004. The increase in revenue was primarily due to higher average prices during the nine months ended September 30, 2005 and higher generation of electricity of 1.2 TWh compared to the same period in 2004.

Electricity Prices

Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, TRO volumes and forward sales as of January 1, 2005, are subject to a revenue limit based on an average price of \$47.00/MWh during the period April 1, 2005 to April 30, 2006. Prior to April 1, 2005, OPG received the average electricity spot market sales price, but revenue was reduced by the Market Power Mitigation Agreement rebate.

OPG's average sales price for its unregulated generation for the three months ended September 30, 2005 was 6.5¢/kWh, after taking into account the impact of the revenue limit rebate. The average price for the nine months ended September 30, 2005 was 5.4¢/kWh, after taking into account the rebates for the appropriate periods. The average spot market sales prices for the three and nine months ended September 30, 2004 were 4.1¢/kWh and 4.2¢/kWh respectively, net of the Market Power Mitigation Agreement rebate.

The higher prices during the third quarter and nine months ended September 30, 2005 compared to the same periods in 2004 were due to higher average spot market sales prices during 2005 compared to 2004 and the replacement of the Market Power Mitigation Agreement rebate with the revenue limit effective April 1, 2005.

During the period June to September 2005, the Ontario market experienced significantly higher spot market prices which arose from the interaction of a variety of factors. The prolonged period of hot weather experienced during this period resulted in increased demand for electricity which required the use of higher marginal cost gas-fired generation. The cost of this gas-fired generation was in turn influenced by the increasing price of natural gas on world energy markets. Lower water levels reduced the energy supply from lower marginal cost hydroelectric resources, thereby further increasing the energy to be supplied by higher marginal cost sources.

As a result of the uncertainty being experienced in world energy markets, OPG expects natural gas and residual fuel oil prices to be volatile going forward. This fuel price volatility will have a corresponding effect on the Ontario market energy prices for this generation source, thereby presenting future uncertainty over market prices to be received for non-regulated and unhedged generation.

Volume

Electricity sales volume for the three months ended September 30, 2005 was 10.8 TWh compared to 9.7 TWh for the same period in 2004. The increase in volume was due to higher generation from the fossil-fuelled generating stations to meet increased demand in Ontario during the prolonged period of record high temperatures in 2005. Strong performance from the fossil-fuelled generating stations during the third quarter of 2005 enabled OPG to generate electricity in response to this increased demand. The increase was partly offset by lower volumes from the unregulated hydroelectric facilities due to lower water levels, especially in the Ottawa and northeast regions.

Electricity sales volume for the nine months ended September 30, 2005 was 34.1 TWh compared to 32.9 TWh for the same period in 2004. Higher generation from the fossil-fuelled generating stations during the June to September period in 2005 compared to 2004, was partly offset by the impact of lower hydroelectric generation due to lower water levels during the nine months ended September 30, 2005 compared to the same period last year.

Fuel Expense

Fuel expense for the three months ended September 30, 2005 was \$289 million compared to \$194 million in 2004. Fuel expense for the nine months ended September 30, 2005 was \$712 million compared to \$605 million in 2004. Fuel expense for the Unregulated Generation segment includes the cost of fossil fuels and charges on gross revenue derived from the hydroelectric generating stations. The increase in fuel expense during the 2005 period was primarily due to the higher production from the fossil-fuelled generating stations.

Operations, Maintenance and Administration

OM&A expenses were \$142 million for the three months ended September 30, 2005 and 2004. OM&A expenses were \$421 million for the nine months ended September 30, 2005 compared to \$419 million for the same period in 2004.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended September 30, 2005 was \$63 million compared to \$72 million during the same period in 2004. Depreciation and amortization expense for the nine months ended September 30, 2005 was \$211 million compared to \$226 million during the same period last year.

In June 2005, the Province provided further detail on its coal replacement plan. Specific to the Nanticoke generating station, the Province indicated its expectation that the units will be closed through 2008 with the last unit to close in early 2009. As a result, OPG has extended, for purposes of calculating depreciation, the remaining service life of the Nanticoke generating station by one year, from 2007 to 2008. This reduces depreciation expense by approximately \$40 million annually.

Impairment of Long-Lived Assets – Lennox Generating Station

The Lennox generating station has available generating capacity in excess of 2,000 MW, is available to provide operating reserve, and has dual fuel capability with natural gas and oil. The Lennox generating station has annual fixed operating costs of about \$60 million. Since the formation of OPG in 1999, revenue earned from electricity generated at the Lennox station was generally not sufficient to cover the fixed operating costs and annual depreciation charge related to the station. However, up until 2004, OPG expected that in the future, demand for new electricity supply requirements in Ontario would require the development of a capacity market or higher market prices sufficient for new entrants to cover their costs

and provide a return on investment. As a result, revenues associated with the Lennox station were expected to be sufficient to cover all costs, including a recovery of the carrying value.

In 2004, the Government issued a "Request for Information/Request for Proposal for 2,500 MW of New Clean Generation and Demand Side Management Projects" under which new generators would be allowed to recover fixed costs and an agreed upon rate of return on investment through contractual arrangements. By recovering these costs through contractual arrangements with the Ontario Power Authority, new entrants would need to recover only fuel and other variable operating costs from the wholesale market. These contracts are expected to result in lower than anticipated future revenue from the wholesale electricity market.

As a relatively high cost plant, the Lennox generating station likely will not be able to recover its fixed operating costs and the carrying value from the wholesale market in the future. Given these factors, and the precedent established under the Request for Information/Request for Proposal for 2,500 MW, OPG had initiated discussions with the Province, with the intention of entering into a contractual arrangement for the recovery of the annual fixed operating costs of about \$60 million and the carrying value of the Lennox station over its remaining estimated useful life of \$17 million per year.

OPG followed up on the discussions with the Province concerning the Lennox generating station situation by engaging in discussions with the IESO during the first quarter of 2005. OPG expected that it would be able to negotiate an arrangement that would provide for the recovery of all costs. Subsequently, OPG was advised by the Province that it would continue to support OPG in the negotiations with the IESO regarding the recovery of fixed operating costs, but that the Province would not support an arrangement that would allow for the recovery of costs related to the carrying value of the Lennox station. As a result of the change in circumstance, OPG recorded an impairment loss of \$202 million during the first quarter of 2005, which was the amount of the carrying value of the generating station before the impairment loss. OPG has since negotiated an arrangement with the IESO pursuant to the market rules to recover its operating costs for a one-year period ending September 30, 2006. The arrangement with the IESO is subject to approval by the OEB.

Other

<i>(millions of dollars)</i>	Three Months Ended		Nine Months Ended	
	September 30 2005	2004	September 30 2005	2004
Revenue	1	32	48	71
Operations, maintenance and administration	13	14	42	39
Depreciation and amortization	8	9	25	22
Property and capital taxes	11	5	2	17
Restructuring	2	-	2	-
(Loss) income before interest and income taxes and extraordinary item	(33)	4	(23)	(7)

Revenue

Non-Energy revenue was \$1 million during the three months ended September 30, 2005 compared to \$32 million for the same period in 2004. Non-Energy revenue was \$48 million during the nine months ended September 30, 2005 compared to \$71 million for the same period in 2004. The reductions of \$31 million and \$23 million in the 2005 periods compared to the same periods last year were primarily related to a reduction in trading revenue.

Trading losses for the three months ended September 30, 2005 were \$8 million compared to trading revenue of \$10 million during the same period in 2004. Trading revenue for the nine months ended September 30, 2005 was nil compared to \$34 million during the same period in 2004. The decreases of \$18 million during the three months ended September 30, 2005 and \$34 million during the nine months ended September 30, 2005 compared to the same periods last year were primarily due to mark-to-market losses on long-term contracts arranged by OPG's predecessor company, Ontario Hydro. During the nine months ended September 30, 2005 a decrease in realized trading margin also contributed to lower trading revenue compared to the same period in 2004.

Interconnected purchases and sales (including those to be physically settled) and mark-to-market gains and losses (realized and unrealized) on energy trading contracts are disclosed on a net basis in the consolidated statements of income. If disclosed on a gross basis, revenue and power purchases for the three months ended September 30, 2005 would have increased by \$64 million (three months ended September 30, 2004 – \$41 million), with no impact on net income. Revenue and power purchases for the nine months ended September 30, 2005, if disclosed on a gross basis, would have increased by \$164 million (nine months ended September 30, 2004 – \$136 million), with no impact on net income.

Net Interest Expense

Net interest expense for the three months ended September 30, 2005 was \$49 million compared to \$48 million for the same period in 2004. Net interest expense for the nine months ended September 30, 2005 was \$143 million compared to net interest expense of \$138 million during the same period in 2004.

Income Tax

Commencing April 1, 2005, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method, whereby only the amount of taxes that are payable for the current taxation year are recorded. Accordingly, OPG does not recognize future income taxes relating to the rate regulated segments of its business where those income taxes are expected to be recovered in the regulated rates charged to future customers. For all other operations, the liability method of tax accounting is followed. Under the liability method, future tax assets and liabilities are determined based on differences between the accounting and tax basis of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse.

Income tax expense for the three months ended September 30, 2005 was \$94 million compared to \$2 million during the same period in 2004. Income tax for the nine months ended September 30, 2005 was \$86 million compared to income tax expense of \$34 million during the same period in 2004. During the third quarter of 2005, OPG recorded an income tax charge of \$50 million to provide for a change in income tax liabilities related to certain income tax positions that the Company has taken in prior years.

During the third quarter of 2005, the income tax expense was \$57 million lower than what would otherwise have been recorded, due to the application of the taxes payable method for the regulated segments. During the nine months ended September 30, 2005, the income tax expense was \$110 million lower than what would otherwise have been recorded due to the taxes payable method.

As a result of the adoption of rate regulated accounting for the rate regulated segments on April 1, 2005, OPG eliminated the net future income tax asset balance of \$74 million relating to the rate regulated segments and recognized the amount as a one-time extraordinary loss in determining net income.

Proxy Property Taxes

In November 2005, OPG received a letter from the Ministry of Finance indicating its intent to recommend to the Minister of Finance that an Ontario regulation covering proxy property taxes be updated retroactive to April 1, 1999 to reflect reassessments and appeal settlements of certain OPG properties since that date. Any update to the regulation, which may not occur for up to two years, is also expected to address anticipated refunds for certain OPG properties relating to prior years. OPG has not recorded any amounts relating to this anticipated regulation change.

STATEMENTS OF CASH FLOWS

Three Months ended September 30	2005	2004	Explanation
Cash and cash equivalents, beginning of period	411	149	
Cash flow provided by (used in):			
Operating activities	382	(3)	Increase in cash from operating activities primarily due to higher sales revenue and earnings in 2005 compared to the same period in 2004.
Investing activities	(243)	(153)	Increase in cash used in investing activities due to acquisition of short-term investments and the treatment of non-capital expenses related to the Pickering A return to service project as a regulatory asset in 2005, partially offset by a decrease in investment in fixed assets.
Financing activities	(1)	17	Decrease in cash from financing activities in 2005.
Net increase (decrease)	138	(139)	
Cash and cash equivalents, end of period	549	10	
Nine Months ended September 30	2005	2004	Explanation
Cash and cash equivalents, beginning of period	2	286	
Cash flow provided by (used in):			
Operating activities	755	74	Increase in cash from operating activities primarily due to higher sales revenue and earnings in 2005 compared to 2004.
Investing activities	(674)	(376)	Increase in cash used in investing activities due to the treatment of non-capital expenses related to the Pickering A return to service project as a regulatory asset in 2005 and acquisition of short-term investments, partially offset by a decrease in investment in fixed assets.
Financing activities	466	26	Increase in cash from financing activities in 2005 due to the issuance of long-term debt, partially offset by a net repayment of short-term notes.
Net increase (decrease)	547	(276)	
Cash and cash equivalents, end of period	549	10	

CAPITAL RESOURCES AND FUNDING OBLIGATIONS

OPG is in a capital-intensive business that requires continued investment in plant and technologies to improve operating efficiencies, increase generating capacity of its existing stations and to maintain and improve service, reliability, safety and environmental performance. Capital expenditures during the three months ended September 30, 2005 were \$116 million compared with \$161 million during the same period in 2004. Capital expenditures during the nine months ended September 30, 2005 were \$356 million compared with \$384 million during the same period in 2004. OPG's anticipated capital expenditures for 2005 are approximately \$550 million, including the Niagara Tunnel project.

OPG made contributions of \$84 million to the pension plan during the three months ended September 30, 2005 compared to \$38 million during the same period in 2004. OPG made contributions of \$162 million to the pension plan during the nine months ended September 30, 2005 compared to \$114 million during the same period in 2004. Pension contributions were increased in the third quarter of 2005 to reflect funding requirements based on a January 1, 2005 actuarial valuation of the pension plan.

As required under the ONFA, OPG made contributions of \$113 million to the nuclear fixed asset removal and nuclear waste management funds during the third quarter of 2005 and \$114 million during the same period in 2004. Contributions of \$340 million were made during the nine months ended September 30, 2005 and \$341 million during the same period last year.

OPG made a final Market Power Mitigation Agreement rebate payment of \$245 million during the three months ended September 30, 2005 compared to a payment of \$267 million during the same period in 2004. OPG made Market Power Mitigation Agreement rebate payments of \$851 million during the nine months ended September 30, 2005 and \$919 million during the same period in 2004. Since the Ontario market opened to competition on May 1, 2002, OPG paid rebates totalling \$4 billion up to September 30, 2005, resulting in a significant unfavourable impact on OPG's liquidity.

LIQUIDITY

OPG's current 364-day term \$1,000 million revolving committed bank credit facility was renewed on May 24, 2005. The new facility is divided into two tranches – a \$500 million 364-day term tranche maturing May 23, 2006, and a \$500 million three-year term tranche maturing May 23, 2008. The total credit facility will continue to be used primarily as support for notes issued under OPG's commercial paper program. As at September 30, 2005, OPG had no borrowings outstanding under this commercial paper program (December 31, 2004 – \$26 million). As at September 30, 2005, OPG had no other outstanding borrowing under this facility.

OPG also maintains \$26 million (December 31, 2004 – \$26 million) in short-term uncommitted overdraft facilities as well as \$215 million (December 31, 2004 – \$200 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support the supplementary pension plans, and is required to post the Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the OEB's Retail Settlement Code. At September 30, 2005, there were approximately \$179 million (December 31, 2004 – \$155 million) of Letters of Credit issued for the supplementary pension plans and collateral requirements to the LDCs.

In March 2005, the Company reached an agreement with the OEFC to obtain additional financing up to \$600 million. In accordance with the agreement, this financing is available until March 31, 2006. The financing was required to meet a forecast operating cash shortfall related to the implementation of rate regulation, including the continuing rebate obligation under the revenue limit. In April 2005, \$400 million was drawn under this facility with a seven-year term. In accordance with the OEFC Agreement, the remaining \$200 million of additional financing is available to be drawn up until March 31, 2006.

In September 2005, OPG reached an agreement with the OEFC to finance the Niagara Tunnel project. The funding, which is up to \$1 billion over the duration of the project, will be in the form of 10 year notes, which will be issued quarterly to meet the project's obligations.

At September 30, 2005, OPG's long-term credit rating is BBB+ by Standard & Poor's ("S&P") and A (low) by Dominion Bond Rating Service (DBRS). In May 2005, following a review of the new regulatory framework that OPG will operate within, DBRS changed the trend on OPG's unsecured debt from negative to stable and confirmed the rating on OPG's commercial paper at R-1 (low). In September 2005, S&P revised its outlook on OPG to positive from developing, and affirmed OPG's BBB+ long-term corporate credit rating and short-term A-2 Canadian commercial paper rating. Maintaining an investment grade credit rating is essential for corporate liquidity, and cost effective capital market access.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of future accounting pronouncements, are outlined in Note 3 to the consolidated financial statements as at and for the year ended December 31, 2004. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's consolidated financial statements, the likelihood that materially different amounts would be reported under varied conditions and estimates and the impact of changes in certain conditions or assumptions, are highlighted on pages 19 to 22 of the MD&A for the year ended December 31, 2004. With the exception of rate regulated accounting, there have not been any significant changes in OPG's critical accounting policies during the nine months ended September 30, 2005.

Rate Regulated Accounting

A regulation made pursuant to the *Electricity Restructuring Act, 2004* prescribes that OPG's nuclear and baseload hydroelectric facilities receive regulated prices for their output. Under this regulation, OPG is required to establish a deferral account in connection with non-capital costs incurred on or after January 1, 2005 that are associated with the return to service of units at the Pickering A nuclear generating station. As at September 30, 2005, the deferral account was \$251 million, consisting of non-capital costs of \$223 million relating to Unit 1, and \$21 million relating to Units 2 and 3, \$2 million of general return to service costs and interest of \$5 million accreted at the average cost of debt of 6.0 per cent. Upon OPG becoming subject to regulated prices established by the OEB in 2008, the OEB is directed by the regulation to ensure that OPG recovers any balance in the deferral account through rates charged to future customers on a straight-line basis, over a period not to exceed 15 years. OPG commenced the amortization of the deferral account associated with Unit 1 of the Pickering A nuclear generating station when the unit was returned to service in November 2005.

In addition, under the regulation, OPG is required to establish an account to record certain variances from forecast, incurred on or after April 1, 2005, associated with a number of predefined circumstances. Under the terms of the regulation, the OEB is directed to ensure that OPG recovers or returns those amounts, which have been prudently incurred or received and accurately recorded, through rates charged to future customers over a period not to exceed three years.

With the commencement of rate regulation for OPG's baseload hydroelectric and nuclear facilities on April 1, 2005, OPG recorded an extraordinary loss of \$74 million resulting from the elimination of the net future income tax asset.

Business Segments

Prior to April 1, 2005, OPG had two reportable business segments: Generation and Energy Marketing. A separate category, Other, included revenue and certain expenses that were not allocated to its business segments. With the introduction of rate regulation, OPG changed the definition of its reportable business segments in order to remain compliant with the Canadian Institute of Chartered Accountants ("CICA")

handbook, Section 1701 – Segment Disclosure. OPG reports its results on the basis of these new segments beginning April 1, 2005 and has reclassified prior period amounts accordingly.

Income Taxes

OPG is exempt from tax under the *Income Tax Act (Canada)*. However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income and capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act (Canada)* and the *Corporations Tax Act (Ontario)*, and are modified by regulations made under the *Electricity Act, 1998*.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. The *Income Tax Act (Canada)* and the *Corporations Tax Act (Ontario)* have a large body of technical interpretations and case law to help determine the Company's filing position. However, the *Electricity Act, 1998*, and tax related regulations are relatively new and it was therefore necessary for OPG to take certain filing positions in calculating the amount of the income tax provision. These filing positions may be challenged on audit and possibly disallowed, resulting in a potential significant increase in OPG's tax provision upon reassessment. Although management believes that it has adequately provided for income taxes based on all information currently available, there is uncertainty given how recently the legislation was introduced.

Commencing April 1, 2005, OPG accounts for income taxes related to the rate regulated segments of its business in accordance with paragraphs 102 to 104 inclusive of the CICA handbook, Section 3465 – Income Taxes. Accordingly, OPG will not be recognizing future income taxes related to the rate regulated segments of its business to the extent that these income taxes are expected to be recovered in the regulated rates charged to future customers.

For all other operations, OPG uses the liability method and provides future income taxes for income tax temporary differences. The process involves an estimate of OPG's actual current tax liability and an assessment of the Company's future income taxes as a result of temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value in the balance sheet. In addition, OPG has to assess whether the future tax assets can be realized and to the extent that recovery is not considered likely, a valuation allowance must be established. Judgment is required in determining the provision for income taxes, future income tax assets and liabilities and any related valuation allowance. To the extent a valuation allowance is created or revised, current period earnings will be affected.

Asset Retirement Obligations

OPG's asset retirement obligations are comprised of liabilities for nuclear fixed asset removal and nuclear waste management costs and non-nuclear fixed asset removal costs related to the decommissioning of fossil-fuelled generating stations. The liabilities associated with decommissioning the nuclear generating stations and long-term used nuclear fuel management comprise the most significant amounts of the total obligation. The estimates of the nuclear liabilities are reviewed on an annual basis as part of the ongoing, overall nuclear waste management program. Changes in the nuclear liabilities resulting from changes in assumptions or estimates that impact the amount of the originally estimated undiscounted cash flows are recorded as an adjustment to the liabilities, with a corresponding change in the related asset retirement cost capitalized as part of the carrying amount of the long-lived asset.

The estimates of nuclear fixed asset removal and nuclear waste management costs require significant assumptions in the calculations since the programs run for many years. Significant assumptions underlying operational and technical factors are used in the calculation of the accrued liabilities and are subject to periodic review. Changes to these assumptions, including changes in the timing of programs, technology employed, inflation rate, and discount rate, could result in significant changes in the value of the accrued liabilities.

The current estimate of costs to complete the nuclear fixed asset removal and nuclear waste management is in accordance with the current approved reference plan. OPG is currently performing a detailed review, which will result in an updated reference plan. It is expected that this updated reference plan will be completed and approved during 2006.

With the restart of Unit 1 and the decision to not restart Units 2 and 3 at the Pickering A nuclear generating station during the third quarter of 2005, OPG is also reviewing the impact that these events will have on the assumptions, changes in timing to programs and the estimated costs underlying the accrued nuclear fixed asset removal and nuclear waste management liability. Any resulting changes to the estimated accrual will be reflected in the updated reference plan in 2006.

RISK MANAGEMENT

OPG's portfolio of generation assets and its electricity trading and marketing operations are subject to inherent risks, including financial, operational, and strategic risks as discussed on page 23 to 27 of the MD&A as at and for the year ended December 31, 2004. To manage these risks, OPG's Board of Directors and management have implemented an integrated enterprise-wide risk management framework for the governance, identification, measurement, monitoring and reporting of risk across all of OPG and its business operations. Implementation and coordination of corporate-wide risk management activities are undertaken through a centralized risk management group, separate and independent from operational management. Risk information from the business units is independently assessed and aggregated by the risk management group, and is reported by the Chief Risk Officer to the Audit and Risk Committee of the Board of Directors on a quarterly basis. Risk based processes are incorporated into strategic and financial planning to ensure the Company's sustainability and achievement of its stated objectives.

While OPG believes it is pursuing appropriate risk management strategies, there can be no assurance that one or more of the risks outlined or other risk factors will not have a material adverse impact on OPG. In particular, the *Electricity Restructuring Act, 2004* and related regulations, the imposition of a revenue limit on the non-regulated assets excluding the Lennox generating station and volumes related to existing contracts, and changes in the future mandate of OPG in the Ontario electricity marketplace could have a material impact on OPG.

Financial Risk

Commodity Price Risk

Commodity price risk is the risk that changes in the market price of electricity or of the fuels used to produce electricity will adversely impact OPG's earnings and cash flow from operations. To manage this risk, the Company seeks to maintain a balance between the commodity price risk inherent in its electricity production and plant fuel portfolios to the extent that trading liquidity in the relevant commodities markets provides the opportunity to do so in an economically justified manner. To manage the input risk, OPG has a fuel hedging program. In addition to fixed price contracts for fossil and nuclear fuels, OPG periodically employs derivative instruments to hedge its fuel price risk.

With the recent implementation of reforms to the Ontario electricity market, the amount of expected electricity production that OPG previously had hedged through regulatory commitments and forward electricity transactions has changed materially. The Market Power Mitigation Agreement was replaced with a regulated price for baseload hydroelectric and nuclear generation. Eighty-five per cent of the remaining unregulated OPG electricity generation, excluding generation from the Lennox generating station and volumes relating to existing contracts, is subject to a revenue limit of \$47.00/MWh, in place from April 1, 2005 to April 30, 2006.

The percentages of OPG's expected generation, emission requirements and fuel requirements hedged are shown below:

	2005	2006	2007
Estimated generation output hedged ¹	92%	70%	58%
Estimated fuel requirements hedged ²	100%	93%	83%
Estimated nitric oxide (NO) emission requirement hedged ³	100%	96%	63%
Estimated sulphur dioxide (SO ₂) emission requirement hedged ³	100%	100%	100%

¹ Represents the portion of megawatt-hours of expected future generation production, including power purchases, for which the Company has sales commitments and contracts including the obligations under the transition rate option contracts, regulated price for baseload hydroelectric and nuclear generation, and revenue limit for non-prescribed assets.

² Represents the approximate portion of megawatt-hours of expected generation production (and fossil year-end inventory target) from all types of facilities (fossil, nuclear and hydroelectric) for which OPG has entered into some form of contractual arrangements or obligations in order to secure either the expected availability and/or price of fuel and/or fuel related services. Excess fuel in inventories in a given year is attributed to the next year for the purpose of measuring hedge ratios. Since production from hydroelectric facilities is primarily influenced by expected weather and weather patterns, fuel hedge ratios for hydroelectric facilities are assumed to be 100 per cent.

³ Represents the approximate portion of megawatt hours of expected fossil production for which OPG has purchased, been allocated or granted emission allowances and Emission Reduction Credits to meet OPG's obligations under Ontario Environmental Regulations 397/01.

Open trading positions are subject to measurement against Value at Risk (VaR) limits. VaR utilization ranged between \$0.7 million and \$2.9 million during the three months ended September 30, 2005, compared to \$0.4 million and \$1.7 million during the three months ended September 30, 2004. VaR utilization ranged between \$0.7 million and \$2.9 million during the nine months ended September 30, 2005, compared to \$0.4 million and \$1.7 million during the nine months ended September 30, 2004. VaR utilization is within the risk tolerance of the Company, under approved VaR limits.

Trading liquidity continues to be constrained in Ontario and interconnected markets due to broader energy market fundamentals. In addition, the revenue limit of \$47.00/MWh limits customer exposure to electricity spot market prices and further limits trading liquidity in the period to April 30, 2006.

Credit Risk

Credit risk is the financial risk of non-performance by contractual counterparties. Credit risk excludes any operational risk resulting from a third party failing to deliver a product or service as expected. OPG derives revenue from several other sources including the sale of energy products and financial risk management products to third parties. However, the majority of OPG revenues are derived from sales through the IESO administered spot market.

Credit exposure to the IESO fluctuates based on a blend of regulated and non-regulated rates as well as generated volume and is reduced each month upon settlement of the accounts. Credit exposure to the IESO peaked at \$1,146 million during the nine months ended September 30, 2005 and at \$901 million during the nine months ended September 30, 2004.

OPG's management believes that the IESO is an acceptable credit risk due to its primary role in the Ontario market. The IESO manages its own credit risk and its ability to pay generators by mandating that all registered IESO spot market participants meet specific IESO standards for creditworthiness and collateralization. Additionally, in the event of an IESO participant default, each market participant shares the exposure pro rata. Given OPG's position in the marketplace, the Company would bear approximately 35 per cent of the exposure, residual of collateral and recovery.

OPG also monitors and reports its credit exposure with counterparties. OPG's management believes these are within acceptable limits and does not anticipate any material effect on its results of operations or cash flows arising from potential defaults.

The following table provides information on credit risk from energy sales and trading activities as at September 30, 2005:

Credit Rating ¹	Number of Counterparties ²	Potential Exposure ³ <i>(millions of dollars)</i>	Potential Exposure for Largest Counterparties	
			Number of Counterparties	Counterparty Exposure <i>(millions of dollars)</i>
AAA to AA-	36	13	0	0
A+ to A-	46	44	2	31
BBB+ to BBB-	89	21	0	0
BB+ to BB-	29	101	7	94
Below BB-	29	34	1	33
Subtotal	229	213	10	158
IESO	1	574	1	574
Total	230	787	11	732

¹ Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through guarantees and letters of credit or other security.

² OPG Counterparties are defined by each Master Agreement.

³ Potential exposure is OPG's assessment of the maximum exposure over the life of each transaction at 95 per cent confidence.

For all counterparties, OPG's contracts allow for active collateral management to mitigate credit exposures. The contracts provide for a counterparty to post performance guarantees in excess of the established threshold. OPG may employ such guarantees as a result of market price changes or upon the occurrence of credit-related events. The threshold amount represents credit limits established in accordance with the corporate credit policy. Inability to post collateral is sufficient cause to terminate a contract and liquidate all positions.

Operational Risk

Generation Risk

OPG is exposed to the financial impacts of uncertain output from its generating units. The amount of electricity generated by OPG is affected by fuel supply, equipment malfunction, maintenance requirements, and regulatory and environmental constraints. To mitigate earnings volatility due to generation risk, OPG enters into multiple short-term and long-term fuel supply agreements and long-term water use agreements, manages fuel supply inventories, and follows industry practices for maintenance and outage scheduling. In addition, OPG ensures regulatory requirements are met, particularly with respect to licensing of its nuclear facilities, and manages environmental constraints utilizing programs such as emission reduction credits.

OPG is exposed to considerable technology risk around the aging of the nuclear fleet. Technology risks that could lead to significant impacts on the production capability or operating life of these assets are not fully predictable and OPG attempts to identify and mitigate these risks through ongoing management review and assessments, internal audits and from experience of nuclear units around the world. OPG has undertaken an ongoing life cycle management program to assess the condition of major components of the nuclear units, including steam generators, fuel channels and feeder pipes, and address the active degradation mechanisms associated with these major components. Current predictions for unit end of life are based on the end of life predictions for the fuel channels.

Thinning of the carbon steel feeder pipes used to transport the hot pressurized water in the reactor to the steam generators is an industry-wide issue. Thinning of feeder pipes occurs to varying degrees at all of OPG's reactors. While this condition affects all of OPG's nuclear generating stations, it is most significant at the Darlington nuclear generating station. Mitigation options are under development by OPG which may extend feeder pipe life, reduce the thinning rate, and improve the capability to replace feeders, where required. Recent wall thickness measurements of removed feeders and field inspections at Pickering A Units 1 and 4 have indicated that the location of the thinning is different than at Darlington, and the degree of thinning is greater than originally expected. Future inspections will be required to confirm the thinning rate at Pickering A, and to determine the need for future feeder pipe replacements. Pickering B feeder pipes have been found to be less affected by thinning than those at the Darlington and Pickering A generating stations.

Cracking of feeder pipes has been experienced at two CANDU plants located outside Ontario. At those plants, the affected sections of pipe were replaced and the units were returned to service. OPG has not experienced any feeder pipe cracking at any of its nuclear facilities, but is carrying out inspections during regularly planned outages. The scale of these inspections has been increased to address the concern that the risk of cracking may be increasing in OPG's units. OPG is also participating in research and development with other CANDU operators to better understand the degradation mechanisms.

The Pickering A reactors are unique among the CANDU fleet in that the reactor is contained within an air-filled concrete enclosure called the "calandria vault". The environment is potentially corrosive to carbon steel components contained within the calandria vault structure, particularly when the atmosphere is humid. Significant degradation of the carbon steel components occurred early in life. Maintenance was carried out during the 1980s and early 1990s to mitigate the degradation and repair some of the degraded components. Equipment was added to maintain a dry vault atmosphere and thereby significantly reduce the risk of corrosion. There is limited information to determine the extent to which mitigation efforts have been successful. Further inspections are being planned.

Late in 2004, as a result of steam generator inspection activities, OPG noted the existence of a new degradation mechanism on one of the Pickering A steam generators from Unit 1. This mechanism, intergranular attack ("IGA"), is a corrosion phenomenon where the material is chemically attacked during unusual chemical conditions, and previously has not been seen in OPG's Pickering and Darlington nuclear generating stations. In combination with other degradation mechanisms, this mechanism could impact the life of the steam generator. The scope of inspections on Pickering A steam generators was expanded to determine the extent of this degradation mechanism. Inspections at Unit 1 of the Pickering A nuclear generating station have been completed and, while IGA was found to be present in some tubes, the steam generators are fit for service. The inspection of Pickering A Unit 2 confirmed extensive IGA. The inspection of Pickering A Unit 3 was partially completed and severe denting was confirmed. IGA was not observed on Pickering A Unit 4.

In 2004, inspections of Pickering A Unit 2 uncovered a single crack originating in the outer diameter of the steam generator tubing. This was the first crack observed in any of the Pickering A and B steam generator tubes and resulted in an increase in the scope of inspection for all Pickering A and B steam generators. Recent inspections on Pickering A Unit 1 and Pickering B Unit 5 have not uncovered any further cracks. However, recent inspections of Pickering A Unit 4 have confirmed a single 81 per cent through-wall crack. Operating units observed to have cracked tubes would likely require a shortened operating interval in the range of one year before inspection. Tubes which cannot be demonstrated to be fit for service can be removed from service. This will increase outage duration and costs.

Regulatory Risk

Through a regulation passed pursuant to the *Electricity Restructuring Act, 2004*, OPG receives regulated prices for its baseload hydroelectric and nuclear facilities from April 1, 2005. These prices are expected to remain in effect until at least March 31, 2008, or until such time that the OEB establishes new regulated prices. If there are changes to the fundamental assumptions on which these regulated prices were developed, the Province may amend these initial prices. Any such changes pose a risk that the return on equity factored into the existing prices could be reduced. Equally, to the extent that costs incremental to those included in the price determination process occur and no such amendments are made, these costs

may be borne by OPG and not recovered through rates charged to future customers. These costs may be necessary to maintain the reliability and safety of OPG's regulated generating assets.

The regulation also directed OPG to establish variance accounts for costs incurred on or after April 1, 2005 that are associated with certain unforeseen circumstances, and to establish a deferral account for Pickering A return to service non-capital costs incurred on or after January 1, 2005. The accuracy and prudence of any variance account balances that OPG records as a regulatory asset or liability must be demonstrated by OPG to the OEB once it establishes new regulated prices expected after March 31, 2008. Regulatory risk arises given the possibility of the OEB not approving such costs. In the event that some of these costs are disallowed by the OEB at a future date, the amounts disallowed would be reflected in results of operations in the period that the OEB decision occurs.

CONTINUOUS DISCLOSURE

Summary of Quarterly Results

The following tables set out certain unaudited interim consolidated financial statement information for each of the eight most recent quarters ended September 30, 2005. The information has been derived from OPG's unaudited interim consolidated financial statements that, in management's opinion, have been prepared on a basis consistent with the audited consolidated financial statements. These operating results are not necessarily indicative of results for any future period.

<i>(millions of dollars)</i>	2004 Quarter Ended		2005 Quarters Ended	
	December 31	March 31	June 30	September 30
Revenue after Market Power Mitigation Agreement rebate and revenue limit rebate	1,215	1,358	1,373	1,571
Net income (loss)	34	(38)	63	181
Net income (loss) per share	\$0.13	\$(0.15)	\$0.25	\$0.71

<i>(millions of dollars)</i>	2003 Quarter Ended		2004 Quarters Ended	
	December 31	March 31	June 30	September 30
Revenue after Market Power Mitigation Agreement rebate	1,228	1,350	1,141	1,212
Net (loss) income	(606) ¹	64	(41)	(15)
Net (loss) income per share	\$(2.36)	\$0.25	\$(0.16)	\$(0.06)

¹ OPG recorded an impairment loss on the coal-fired generating stations of \$473 million after tax (\$576 million before tax) due to the expected early shutdown of the coal-fired generating stations.

Off-Balance Sheet Arrangements

Securitization

In October 2003, OPG completed a revolving securitization agreement with an independent trust. Under the securitization agreement, OPG sold an undivided co-ownership interest in certain current and future accounts receivable generated in the normal course of business. The amount of the co-ownership interest sold is removed from the balance sheet with each revolving securitization. OPG also retains an undivided co-ownership interest in the receivables sold to the trust. This retained interest is accounted for at cost on OPG's balance sheet. The independent trust is not controlled by OPG, nor is OPG the primary beneficiary. As such, the results of the trust are not consolidated. The securitization provides OPG with an opportunity to obtain an alternative source of cost effective funding. For the three months ended September 30, 2005, the average all-in cost of funds was 3.0 per cent and the pre-tax charges on sales

to the trust were \$2 million. For the nine months ended September 30, 2005, the average all-in cost of funds was 2.9 per cent and the pre-tax charges on sales to the trust were \$7 million. The initial net cash proceeds from this transaction of \$300 million were used by OPG in the operation of its business. Termination of the arrangement, which in the absence of early termination, occurs in August 2006, would likely require OPG to pursue alternative liquidity arrangements to meet the ongoing operations of its business.

Guarantees

As part of normal business, OPG and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees, stand-by Letters of Credit and surety bonds.

OPG had provided limited guarantees in connection with its share of the Brighton Beach financing, whereby it was responsible for contributing its share of equity related to cost overruns associated with the construction of the generating station. As Brighton Beach commenced commercial operation in July 2004, any cost overruns are now primarily limited to settlement of construction liens registered by some contractors associated with the construction project. Brighton Beach arranged an independent third party review of the claims and is now actively negotiating final settlement of these liens.

Derivative Instruments

The majority of OPG's derivative instruments are treated as hedges, with gains or losses recognized upon settlement when the underlying transactions occur. OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity. Foreign exchange derivative instruments are used to hedge the exposure to anticipated US dollar denominated purchases. When such a derivative instrument ceases to exist or when designation of a hedging relationship is terminated, any associated deferred gains or losses are carried forward to be recognized in income in the same period as the corresponding gains or losses associated with the hedged item. When a hedged item ceases to exist, any associated deferred gains or losses are recognized in the current period's consolidated statement of income. The deferred loss on electricity derivative instruments treated as hedges was \$213 million as at September 30, 2005, compared to a deferred loss of \$71 million as at December 31, 2004. See Note 11 to the unaudited interim consolidated financial statements for more information.

All contracts not designated as hedges are recorded as assets or liabilities at fair value with changes in fair value recorded in Other revenue.

SUPPLEMENTAL EARNINGS MEASURES

In addition to providing net income in accordance with Canadian generally accepted accounting principles, OPG's Management Discussion and Analysis, financial statements for the three and nine months ended September 30, 2005 and 2004 and the notes thereto, present non-GAAP financial measures. These financial measures do not have standard definitions prescribed by Canadian generally accepted accounting principles ("Canadian GAAP") and therefore, may not be comparable to similar measures disclosed by other companies. OPG utilizes these measures in making operating decisions and assessing its performance. Readers of the MD&A, financial statements and notes thereto utilize these measures in assessing the Company's financial performance from ongoing operations. These non-GAAP financial measures have not been presented as an alternative to net income in accordance with Canadian GAAP as an indicator of operating performance. The definitions of the non-GAAP financial measures are as follows:

(1) **Gross margin** is defined as revenue less Market Power Mitigation Agreement and revenue limit rebates and fuel expense.

(2) **Restructuring** expenses are defined as costs incurred to implement a fundamental and material change to the operating and/or management structures of the Company. Restructuring expenses may include severance costs, termination benefits and related pension and OPEB expenses, professional fees, travel costs and other incremental costs directly associated with the restructuring activities.

(3) **Operating income** is defined as earnings before long-lived asset impairment charges, net interest expense, income taxes and extraordinary item.

The statement of income provides a reconciliation of operating income to Canadian GAAP net income.

For further information, please contact:

Investor Relations

416-592-6700

1-866-592-6700

investor.relations@opg.com

Media Relations

416-592-4008

1-877-592-4008

www.opg.com

www.sedar.com

CONSOLIDATED STATEMENTS OF INCOME (LOSS) (UNAUDITED)

	Three Months Ended		Nine Months Ended	
	September 30 2005	2004	September 30 2005	2004
<i>(millions of dollars except where noted)</i>				
Revenue				
Revenue before Market Power Mitigation Agreement and revenue limit rebates	1,907	1,413	5,191	4,553
Market Power Mitigation Agreement rebate <i>(note 15)</i>	-	(201)	(412)	(850)
Revenue limit rebate <i>(note 16)</i>	(336)	-	(477)	-
	1,571	1,212	4,302	3,703
Fuel expense	384	290	983	870
Gross margin	1,187	922	3,319	2,833
Expenses				
Operations, maintenance and administration	627	636	1,830	1,893
Depreciation and amortization <i>(note 4)</i>	181	182	566	568
Accretion on fixed asset removal and nuclear waste management liabilities	119	113	358	340
Earnings on nuclear fixed asset removal and nuclear waste management funds	(96)	(77)	(279)	(255)
Property and capital taxes	26	33	64	91
Restructuring	6	-	6	16
	863	887	2,545	2,653
Operating income	324	35	774	180
Impairment of long-lived assets <i>(note 4)</i>	-	-	265	-
Income (loss) before interest, income taxes and extraordinary item	324	35	509	180
Net interest expense	49	48	143	138
Income (loss) before income taxes and extraordinary item	275	(13)	366	42
Income tax (recoveries) expenses				
Current	57	7	71	13
Future <i>(note 9)</i>	37	(5)	15	21
	94	2	86	34
Income (loss) before extraordinary item	181	(15)	280	8
Extraordinary item <i>(note 9)</i>	-	-	74	-
Net income (loss)	181	(15)	206	8
Basic and diluted income (loss) per common share <i>(dollars)</i>	0.71	(0.06)	0.80	0.03
Common shares outstanding <i>(millions)</i>	256.3	256.3	256.3	256.3

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (UNAUDITED)

Nine Months Ended September 30

(millions of dollars)

	2005	2004
(Deficit), beginning of period	(105)	(147)
Net income	206	8
Retained earnings (deficit), end of period	101	(139)

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

<i>(millions of dollars)</i>	Three Months Ended		Nine Months Ended	
	September 30 2005	2004	September 30 2005	2004
Operating activities				
Net income (loss)	181	(15)	206	8
Adjust for non-cash items:				
Depreciation and amortization	181	182	566	568
Accretion on fixed asset removal and nuclear waste management liabilities	119	113	358	340
Earnings on nuclear fixed asset removal and nuclear waste management funds	(96)	(77)	(279)	(255)
Pension cost	31	23	87	69
OPEB and supplementary pension plans	49	51	140	132
Future income taxes	37	(5)	15	21
Transition rate option contracts	(9)	(8)	(27)	(34)
Provision for restructuring	6	-	6	16
Mark-to-market on energy contracts	21	-	25	5
Provision for used nuclear fuel	8	7	21	22
Impairment of long-lived assets	-	-	265	-
Extraordinary item	-	-	74	-
Other	48	18	48	24
	576	289	1,505	916
Contributions to nuclear fixed asset removal and nuclear waste management funds	(113)	(114)	(340)	(341)
Expenditures on fixed asset removal and nuclear waste management	(23)	(18)	(62)	(49)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	8	7	18	15
Contributions to pension fund	(84)	(38)	(162)	(114)
Expenditures on OPEB and supplementary pension plans	(15)	(15)	(48)	(45)
Expenditures on restructuring <i>(note 13)</i>	(8)	(4)	(17)	(47)
Net changes to other long-term assets and liabilities	(31)	(11)	(60)	(30)
Changes in non-cash working capital balances <i>(note 18)</i>	72	(99)	(79)	(231)
Cash flow provided by (used in) operating activities	382	(3)	755	74
Investing activities				
Investment in regulatory assets <i>(note 5)</i>	(60)	-	(251)	-
Investment in fixed assets	(116)	(161)	(356)	(384)
Acquisition of short-term investments	(67)	-	(67)	-
Proceeds on sale of other fixed assets	-	8	-	8
Cash flow (used in) investing activities	(243)	(153)	(674)	(376)
Financing activities				
Issuance of long-term debt <i>(note 7)</i>	-	-	495	13
Repayment of long-term debt <i>(note 7)</i>	(1)	-	(3)	(4)
Net increase (decrease) in short-term notes <i>(note 6)</i>	-	17	(26)	17
Cash flow (used in) provided by financing activities	(1)	17	466	26
Net increase (decrease) in cash and cash equivalents	138	(139)	547	(276)
Cash and cash equivalents, beginning of period	411	149	2	286
Cash and cash equivalents, end of period	549	10	549	10

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

<i>(millions of dollars)</i>	September 30 2005	December 31 2004
Assets		
Current assets		
Cash and cash equivalents	549	2
Short-term investments	67	-
Accounts receivable <i>(note 3)</i>	431	346
Future income taxes	44	44
Fuel inventory	506	569
Materials and supplies	120	92
	1,717	1,053
Fixed assets <i>(note 4)</i>		
Property, plant and equipment	15,040	15,114
Less: accumulated depreciation	3,584	3,174
	11,456	11,940
Other long-term assets		
Deferred pension asset	599	524
Nuclear fixed asset removal and nuclear waste management funds <i>(note 8)</i>	6,577	5,976
Long-term materials and supplies	281	281
Regulatory assets <i>(note 5)</i>	255	-
Long-term accounts receivable and other assets	54	56
	7,766	6,837
	20,939	19,830

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

<i>(millions of dollars)</i>	September 30 2005	December 31 2004
Liabilities		
Current liabilities		
Accounts payable and accrued charges <i>(notes 13 and 14)</i>	818	949
Market Power Mitigation Agreement rebate payable <i>(note 15)</i>	-	439
Revenue limit rebate payable <i>(note 16)</i>	477	-
Short-term notes payable <i>(note 6)</i>	-	26
Long-term debt due within one year <i>(note 7)</i>	604	5
Deferred revenue due within one year	12	12
Income and capital taxes payable	78	12
	1,989	1,443
Long-term debt <i>(note 7)</i>	3,292	3,399
Other long-term liabilities		
Fixed asset removal and nuclear waste management <i>(note 8)</i>	8,660	8,339
OPEB and supplementary pension plans	1,197	1,105
Long-term accounts payable and accrued charges	179	212
Deferred revenue	147	156
Future income taxes	244	155
Regulatory liabilities <i>(note 5)</i>	4	-
	10,431	9,967
Shareholder's equity		
Common shares	5,126	5,126
Retained earnings (deficit)	101	(105)
	5,227	5,021
	20,939	19,830

Commitments and Contingencies *(notes 1, 4, 6, 11, and 12)*

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2005 AND 2004 (UNAUDITED)

1. BASIS OF PRESENTATION

These interim consolidated financial statements were prepared following the same accounting policies and methods as in the most recent annual consolidated financial statements, except as discussed in Note 2 to the interim consolidated financial statements. However, these interim financial statements do not contain all the disclosures required by Canadian generally accepted accounting principles for annual financial statements. Accordingly, the interim consolidated financial statements should be read in conjunction with the most recently prepared annual consolidated financial statements for the year ended December 31, 2004.

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

Certain of the 2004 comparative amounts have been reclassified from financial statements previously presented to conform to the 2005 financial statement presentation.

The consolidated financial statements include the accounts of Ontario Power Generation Inc. ("OPG" or the "Company") and its subsidiaries. OPG accounts for its interests in jointly controlled entities using the proportionate consolidation method. All significant intercompany transactions have been eliminated on consolidation.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Changes in Accounting Policies

Rate Regulated Accounting

In December 2004, the *Electricity Restructuring Act, 2004* (Bill 100) received Royal Assent. A regulation made pursuant to that statute in February 2005 provides that OPG receive regulated prices beginning April 1, 2005, for its baseload hydroelectric and nuclear facilities. This includes electricity generated by Sir Adam Beck 1, 2 and Pump Generating Station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B, and Darlington nuclear generating stations.

In addition, eighty-five per cent of the generation output from OPG's other generation assets, excluding the Lennox generating station and the contract volumes, are subject to a revenue limit based on an average price of \$47.00/MWh (4.7¢/kWh). This revenue limit will be in place for a period of 13 months ending April 30, 2006. Revenues above this limit will be rebated at the end of the period. Accordingly, OPG will not recognize revenue that exceeds an average price of \$47.00/MWh (4.7¢/kWh). Any such excess will be recognized and accounted for as a liability to future customers.

OPG's regulated prices were determined by the Province of Ontario (the "Province") based on total projected production and costs of operation, plus the cost of capital including an average five per cent return on equity. The initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time it is anticipated that the Ontario Energy Board ("OEB") will establish new regulated prices. If there are changes to the fundamental assumptions on which these regulated prices were developed, the Province may amend these initial prices.

The OEB is a self-financing Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Minister of Energy. It regulates all market participants in the province's natural gas and electricity industries and carries out its regulatory functions through public hearings and other more informal processes such as consultations.

Accounting standards recognize that rate regulation can create economic benefits and obligations, which are reported in the consolidated financial statements as regulatory assets and liabilities. When the regulation provides assurance that incurred costs will be recovered in the future, then OPG may defer those costs and report them as a regulatory asset. If current recovery is provided for costs expected to be incurred in the future, then OPG reports a regulatory liability. Also, if the regulation provides for lesser or greater than planned revenue to be received or returned by OPG through future rates, then OPG recognizes and reports a regulatory asset or liability, respectively.

Income Taxes

Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes related to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG will not be recognizing future income taxes related to the rate regulated segments of its business to the extent that these income taxes are expected to be recovered in the regulated rates charged to future customers. OPG continues to use the liability method of accounting for income taxes for its unregulated business.

New Accounting Recommendations

Consolidation of Variable Interest Entities

In September 2004, the CICA amended Accounting Guideline 15, *Consolidation of Variable Interest Entities*, originally issued in June 2003, to harmonize with the revised Financial Accounting Standards Board ("FASB") Interpretation No. 46, *Consolidation of Variable Interest Entities* ("FIN 46R"). The new guideline requires the consolidation of variable interest entities ("VIEs") by the primary beneficiary. A VIE is an entity where (a) its equity investment at risk is insufficient to permit the entity to finance its activities without additional subordinated support from others and/or where certain essential characteristics of a controlling financial interest are not met, and (b) it does not meet specified exemption criteria. The primary beneficiary is the enterprise that will absorb or receive the majority of the VIEs' expected losses, expected residual returns, or both.

OPG is involved with various joint venture and other arrangements and has sold trade receivables under an asset securitization arrangement. The Company assessed these arrangements in advance of the guideline becoming effective January 1, 2005. OPG concluded that the joint venture and other arrangements with which it is involved are not VIEs, and that it is not the primary beneficiary of, nor does it have a significant variable interest in, the trust to which it sold trade receivables.

3. SALE OF ACCOUNTS RECEIVABLE

On October 1, 2003, the Company signed an agreement to sell an undivided co-ownership interest in its current and future accounts receivable (the "receivables") to an independent trust. The Company also retains an undivided co-ownership interest in the receivables sold to the trust. Under the agreement, OPG continues to service the receivables. The transfer provides the trust with ownership of a share of the payments generated by the receivables, computed on a monthly basis. The trust's recourse to the Company is generally limited to its income earned on the receivables.

OPG reflected the initial transfer to the trust of the co-ownership interest, and subsequent transfers required by the revolving nature of the securitization, as sales in accordance with CICA Accounting Guideline 12, *Transfer of Receivables*. In accordance with this Guideline, the proceeds of each sale to the trust were deemed to be the cash received from the trust net of the undivided co-ownership interest retained by the Company. For the three months ended September 30, 2005, the Company has

recognized pre-tax charges of \$2 million (three months ended September 30, 2004 – \$2 million) on such sales at an average cost of funds of 3.0 per cent (three months ended September 30, 2004 – 2.4 per cent). For the nine months ended September 30, 2005, the Company has recognized pre-tax charges of \$7 million (nine months ended September 30, 2004 – \$6 million) on such sales at an average cost of funds of 2.9 per cent (nine months ended September 30, 2004 – 2.6 per cent). As at September 30, 2005, OPG had sold receivables of \$300 million from its total portfolio of \$580 million.

4. FIXED ASSETS

Depreciation and amortization expense for the three and nine months ended September 30, 2005 and 2004 consists of the following:

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Depreciation and amortization	180	180	562	563
Nuclear waste management costs	1	2	4	5
	181	182	566	568

Interest capitalized to construction in progress at 6.0 per cent during the three and nine months ended September 30, 2005 (three and nine months ended September 30, 2004 – 6.0 per cent) was \$7 million and \$24 million respectively (three and nine months ended September 30, 2004 – \$6 million and \$23 million).

Impairment of Long-Lived Assets

The accounting estimates related to asset impairment require significant management judgment to identify factors such as short and long-term forecasts for future sales prices, the supply of electricity in Ontario, inflation, fuel prices and station lives. The amount of the future cash flow that OPG will ultimately realize with respect to these assets could differ materially from the carrying values recorded in the consolidated financial statements.

Pickering A Nuclear Generating Station Units 2 and 3

OPG completed an assessment of the cost, schedule and risks related to the return to service of Units 2 and 3 at the Pickering A nuclear generating station. This included an assessment of the ability of these units to perform at an acceptable capability factor over the remaining 12 to 20 years of operations. This assessment incorporated recent findings from inspection programs with respect to feeder pipe and steam generator degradation mechanisms, and potential degradation of the calandria vault components, all of which could impact the future capability factor, operating costs and the life of the units. Upon consideration of the scope of the refurbishment work, the costs and the risks related to the return to service of these two units, and the Company's focus on improving the performance of its other nuclear units, OPG's Board of Directors decided that while technically feasible, the return to service of these units was not justified on a commercial basis. Accordingly, OPG recorded an impairment loss in the second quarter of 2005 related to the carrying amount of these two units including construction in progress, which was \$63 million at June 30, 2005.

OPG expects to recover the amounts recorded in the deferral account relating to non-capital costs incurred after January 1, 2005 associated with the return to service of Units 2 and 3. As at September 30, 2005, the deferral account relating to Units 2 and 3 was \$21 million.

As a result of the decision not to proceed with the return to service of these two units, OPG continues to assess the need to provide for any additional costs, including the cost associated with preparing the units for safe storage, any impacts on cost estimates for asset retirement obligation and any other additional

exit costs. These potential additional charges are not specifically determinable at this time, however, a detailed assessment of these associated costs will be completed during the remainder of 2005. Such charges may have a significant impact on operating results in future periods.

Lennox Generating Station

As a result of the Government's "Request for Information/Request for Proposal for 2,500 MW of New Clean Generation and Demand Side Management Projects" released in September 2004 and the related contractual arrangements, future wholesale electricity market revenue is expected to be lower than previously anticipated. As a relatively high variable cost plant, the Lennox generating station will not be able to recover its fixed operating costs and its carrying value from the wholesale electricity market in the future. Given these factors, OPG had initiated discussions with the Province, with the expectation of entering into a contractual arrangement for the recovery of the annual fixed operating costs and the carrying value of the Lennox generating station. In March 2005, OPG was advised by the Province that it would continue to support OPG in negotiating an arrangement that would allow for the recovery of fixed operating costs, but that the Province would not support an arrangement that would allow for the recovery of the carrying value of the Lennox generating station. As a result of this change in circumstance, OPG recorded the impairment loss of \$202 million in the first quarter of 2005. OPG has since negotiated an arrangement with the Independent Electricity System Operator ("IESO") pursuant to the market rules to recover its operating costs for a one-year period ending September 30, 2006. The arrangement with the IESO is subject to approval by the OEB.

5. REGULATORY ASSETS AND LIABILITIES

OPG recorded the following regulatory assets and liabilities as at September 30, 2005:

<i>(millions of dollars)</i>	September 30 2005
Regulatory assets	
Pickering A return to service costs	251
Ancillary services revenue variance account	4
Total regulatory assets	255
Regulatory liabilities	
Hydroelectric production variance account	4
Total regulatory liabilities	4

Pickering A Return to Service Costs

Effective January 1, 2005, in accordance with regulations pursuant to the *Electricity Restructuring Act, 2004*, OPG is required to establish a deferral account in connection with non-capital costs that are associated with the return to service of units at the Pickering A nuclear generating station. As a result, the change in accounting was prospectively adopted on January 1, 2005, with no retroactive adoption. As at September 30, 2005, the deferral account was \$251 million, consisting of non-capital costs of \$223 million relating to Unit 1, and \$21 million relating to Units 2 and 3, \$2 million of general return to service costs, and interest of \$5 million accreted at the average cost of debt of 6.0 per cent. Upon OPG becoming subject to regulated prices established by the OEB, expected after March 31, 2008, the OEB is directed by the regulation to ensure that OPG recovers any balance in the deferral account on a straight-line basis over a period not to exceed 15 years.

Variance Accounts

Effective April 1, 2005, in accordance with the regulations pursuant to the *Electricity Restructuring Act, 2004*, OPG was directed to establish variance accounts for costs incurred on or after April 1, 2005 that are associated with differences in hydroelectric electricity production due to differences between forecast and actual water conditions, changes in nuclear electricity production due to unforeseen changes to the law or to unforeseen technological changes, changes to revenues assumed for ancillary revenues from the regulated facilities, acts of God (including severe weather events), and transmission outages and transmission restrictions. OPG recorded an asset as at September 30, 2005 of \$4 million, reflecting ancillary services revenue that was unfavourable compared to that forecasted for the second and third quarters of 2005. OPG recorded a liability as at September 30, 2005 of \$4 million, reflecting water conditions that were favourable compared to those forecasted for the second and third quarters of 2005. Upon OPG becoming subject to regulated prices established by the OEB, expected after March 31, 2008, the OEB is directed by the regulation to ensure recovery to the extent that the OEB is satisfied that the costs recorded in the account were prudently incurred and accurately recorded. Any balances approved by the OEB will be amortized on a straight-line basis over a period not to exceed three years.

6. SHORT-TERM CREDIT FACILITIES

OPG's current 364-day term \$1,000 million revolving committed bank credit facility was renewed on May 24, 2005. The new facility is divided into two tranches – a \$500 million 364-day term tranche maturing May 23, 2006, and a \$500 million three-year term tranche maturing May 23, 2008. The total credit facility will continue to be used primarily as support for notes issued under OPG's commercial paper program. As at September 30, 2005, OPG had no borrowings outstanding under this commercial paper program (December 31, 2004 – \$26 million). As at September 30, 2005 and December 31, 2004, OPG had no other outstanding borrowing under this facility.

OPG also maintains \$26 million (December 31, 2004 – \$26 million) in short-term uncommitted overdraft facilities as well as \$215 million (December 31, 2004 – \$200 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support supplementary pension plans and is required to post the Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the OEB's Retail Settlement Code. At September 30, 2005, there were approximately \$179 million (December 31, 2004 – \$155 million) of Letters of Credit issued for the supplementary pension plans and collateral requirements to the LDCs.

7. LONG-TERM DEBT

Long-term debt consists of the following:

<i>(millions of dollars)</i>	September 30 2005	December 31 2004
Notes payable to the OEFC	3,695	3,200
Capital lease obligations	-	3
Share of non-recourse limited partnership debt	201	201
	3,896	3,404
Less: due within one year		
Notes payable to the OEFC	600	-
Capital lease obligations	-	3
Share of limited partnership debt	4	2
	604	5
Long-term debt	3,292	3,399

Holders of the senior debt are entitled to receive, in full, amounts owing in respect of the senior debt before holders of the subordinated debt are entitled to receive any payments. The Ontario Electricity Financial Corporation ("OEFC") currently holds all of OPG's outstanding senior and subordinated notes.

In December 2004, OPG reached an agreement with the OEFC to defer payment on \$500 million principal amount of senior notes maturing in March and September 2005 by extending the maturity dates by five years. The interest rates remain unchanged. In March 2005, the Company reached an agreement with the OEFC to obtain additional financing up to \$600 million, which can be drawn until March 31, 2006. In April 2005, \$400 million was drawn under this facility, with a seven-year term.

The Company also reached an agreement with the OEFC to satisfy, through the issue of additional senior notes of \$95 million and \$98 million respectively, to mature in 2010, its \$95 million interest obligation due in March 2005 and the \$98 million interest obligation due in September 2005 related to the debt owing to the OEFC of \$3.2 billion. As a result of an improved liquidity position, OPG elected to pay the interest due in September 2005 and not issue the \$98 million note.

Interest paid during the three months ended September 30, 2005 was \$114 million (three months ended September 30, 2004 – \$105 million), of which \$112 million relates to interest paid on long-term debt (three months ended September 30, 2004 – \$103 million). Interest paid during the nine months ended September 30, 2005 was \$226 million (nine months ended September 30, 2004 – \$216 million), of which \$216 million relates to interest paid on long-term debt (nine months ended September 30, 2004 – \$208 million). Interest on the notes payable to the OEFC is paid in the first and third quarters of the year.

In September 2005, OPG reached an agreement with the OEFC to provide debt financing for the Niagara Tunnel project. The funding, which is up to \$1 billion over the duration of the project, will be in the form of 10-year notes, which will be issued quarterly to meet the project's obligations. Interest will be fixed for each note issued at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on survey of market rates.

8. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT

The liability for fixed asset removal and nuclear waste management on a present value basis consists of the following:

<i>(millions of dollars)</i>	September 30 2005	December 31 2004
Liability for nuclear used fuel management	4,882	4,693
Liability for nuclear decommissioning and low and intermediate level waste management	3,588	3,457
Liability for non-nuclear fixed asset removal	190	189
Fixed asset removal and nuclear waste management liability	8,660	8,339

The change in the fixed asset removal and nuclear waste management liability for the nine months ended September 30, 2005 and year ended December 31, 2004, is as follows:

<i>(millions of dollars)</i>	September 30 2005	December 31 2004
Liability, beginning of period	8,339	7,921
Increase in liability due to accretion	358	453
Increase in liability due to nuclear used fuel and nuclear waste management variable expenses	25	35
Fixed asset removal of partnership interests	-	1
Liabilities settled by expenditures on waste management	(62)	(71)
Liability, end of period	8,660	8,339

Ontario Nuclear Funds Agreement

OPG sets aside and invests funds in a segregated custodian account specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities. The nuclear fixed asset removal and nuclear waste management funds as at September 30, 2005 and December 31, 2004, consist of the following:

<i>(millions of dollars)</i>	Amortized Cost Basis		Fair Value	
	September 30 2005	December 31 2004	September 30 2005	December 31 2004
Decommissioning Fund	4,038	3,858	4,462	4,131
Used Fuel Fund ¹	2,539	2,118	2,539	2,118
	6,577	5,976	7,001	6,249

¹ The Ontario NFWA Trust represents \$937 million as at September 30, 2005 (December 31, 2004 – \$794 million) of the Used Fuel Fund on an amortized cost basis.

9. INCOME TAXES

As a result of OPG accounting for income taxes related to the rate regulated segments of its business using the taxes payable method and not recognizing future income taxes, on April 1, 2005, OPG reversed the future income tax asset balance of \$74 million relating to the rate regulated segments of its business, and recognized the amount as an extraordinary loss in determining net income. The extraordinary item reduced basic and diluted earnings per share for the nine month period ended September 30, 2005 by \$0.29 per share.

Under the liability method, income taxes are recognized as a result of temporary differences arising from the difference between the tax basis of an asset or liability and its carrying value in the balance sheet, the carry-forward of unused tax losses and income tax reductions. Future income tax assets and liabilities are measured using income tax rates expected to apply in the years in which temporary differences are expected to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in income in the period the change is substantively enacted. Future income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is established.

Had OPG continued to use the liability method for the regulated business, the future tax expense for the three and nine months ended September 30, 2005 would have increased by \$57 million and \$110 million, respectively, with a corresponding increase in the future income tax liability. As at September 30, 2005, the future income tax liability would have been \$280 million under the liability method.

The amount of cash income taxes paid in the three and nine months ended September 30, 2005 was \$6 million and \$15 million (three and nine months ended September 30, 2004 – \$6 million and \$11 million).

10. BENEFIT PLANS

The post employment benefit programs include pension, group life insurance, health care and long-term disability benefits. Pension and other post employment benefit (“OPEB”) obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions and experience gains or losses. The 2005 costs are based on a measurement of the pension and OPEB obligations and the pension fund assets, at December 31, 2004.

Total benefit costs for the three and nine months ended September 30, 2005 and 2004, are as follows:

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Registered pension plan	31	23	87	69
Supplementary pension plans	4	4	13	12
OPEB	45	47	127	120

11. FINANCIAL INSTRUMENTS

Fair values of derivative instruments have been estimated by reference to quoted market prices for actual or similar instruments where available. Where quoted market prices are not available, OPG considers various factors to estimate forward prices, including market prices and price volatility in neighbouring electricity markets, market prices for fuel, and other factors.

Trading activities and liquidity in the Ontario electricity market have been limited as companies are generally entering only into short-term contracts. As a result, forward pricing information for contracts may not accurately represent the cost to enter into these contracts. For Ontario-based contracts that are not entered into for hedging purposes, OPG established liquidity reserves against the fair market value of the assets and liabilities equal to the gain or loss on these contracts. These reserves increased trading revenue by \$23 million during the nine months ended September 30, 2005 (nine months ended September 30, 2004 – increased by \$2 million). Contracts for transactions outside of Ontario continue to be carried on the consolidated balance sheets as assets or liabilities at fair value, with changes in fair value recorded in trading revenue as gains or losses.

Derivative Instruments Used for Hedging Purposes

The following table provides the estimated fair value of derivative instruments designated as hedges. The majority of OPG’s derivative instruments are treated as hedges, with gains or losses recognized upon settlement when the underlying transactions occur. OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity.

<i>(millions of dollars except where noted)</i>	Notional Quantity September 30, 2005	Terms	Fair Value	Notional Quantity December 31, 2004	Terms	Fair Value
(Loss)/gain						
Electricity derivative instruments	4.8 TWh	1-2 yrs	(213)	10.4 TWh	1-3 yrs	(71)
Foreign exchange derivative instruments	US\$45	Dec/05	(2)	US\$10	Jan/05	-

Foreign exchange derivative instruments are used to hedge the exposure to anticipated U.S. dollar denominated purchases. The weighted average fixed exchange rate for contracts outstanding at September 30, 2005 was US \$0.83 (December 31, 2004 – US \$0.81) for every Canadian dollar.

Derivative Instruments Not Used for Hedging Purposes

The carrying amount (fair value) of derivative instruments not designated for hedging purposes is as follows:

<i>(millions of dollars except where noted)</i>	Notional Quantity September 30, 2005	Fair Value	Notional Quantity December 31, 2004	Fair Value
Commodity derivative instruments				
Assets	3.5 TWh	11	7.9 TWh	12
Liabilities	1.7 TWh	(61)	1.3 TWh	(12)
		(50)		-
Ontario market liquidity reserve		16		(7)
Total		(34)		(7)

12. COMMITMENTS AND CONTINGENCIES

Litigation and Claims

Various legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of its business activities. OPG has become aware of a class action suit for \$50 billion that has been issued in an Ontario Court naming OPG and 20 U.S.-based electricity generators as defendants. Although the claim has been filed in the court office, it has not been served on OPG and, consequently, OPG is not yet a party to the litigation. The claim alleges coal-fired generation station emissions cause various adverse health effects and claims damages for all residents of Ontario. The claim alleges that it is negligent for the defendants to use coal to produce electricity and not to use cleaner coal burning technologies. The preliminary assessment is that the claim is unlikely to succeed.

In July 2004, OPG was charged with criminal negligence causing death and criminal negligence causing bodily harm in relation to a 2002 drowning accident at Barrett Chute. Also, certain First Nations have commenced actions for interference with reserve and traditional land rights. The claims by some of these First Nations total approximately \$50 million and claims by others are for unspecified amounts.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably with respect to OPG. Contingencies are provided for when they are likely to occur and are reasonably estimable. Management believes that the ultimate resolution of these matters will not have a material effect on OPG's financial position.

Guarantees

As part of normal business, OPG and certain of its subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees, standby Letters of Credit and surety bonds.

OPG had provided limited guarantees in connection with its share of the Brighton Beach financing, whereby it is responsible for contributing its share of equity related to cost overruns associated with the construction of the generating station. As Brighton Beach commenced commercial operation in July 2004, any cost overruns as at September 30, 2005 are now primarily limited to settlement of construction liens registered by some contractors associated with the construction project. Brighton Beach arranged an independent third party review of the claims and is now actively negotiating final settlement of these liens.

Contractual Commitments

In June 2004, OPG announced and the Government endorsed the decision to proceed with a new water diversion tunnel that will increase the amount of water flowing to existing turbines at the Sir Adam Beck generating stations in Niagara. OPG awarded a contract to Strabag AG in August 2005 to design and construct the 10.5 km tunnel. The value of the design-build contract is approximately \$600 million, with the total project expected to cost approximately \$985 million. Construction preparation activities started in September 2005. Project completion is expected by late 2009.

Proxy Property Taxes

In November 2005, OPG received a letter from the Ministry of Finance indicating its intent to recommend to the Minister of Finance that an Ontario regulation covering proxy property taxes be updated retroactive to April 1, 1999 to reflect reassessments and appeal settlements of certain OPG properties since that date. Any update to the regulation, which may not occur for up to two years, is also expected to address anticipated refunds for certain OPG properties relating to prior years. OPG has not recorded any amounts relating to this anticipated regulation change.

13. RESTRUCTURING

The change in the restructuring liability for termination benefits for the nine months ended September 30, 2005 and year ended December 31, 2004 is as follows:

<i>(millions of dollars)</i>	September 30 2005	December 31 2004
Liability, beginning of period	20	52
Restructuring charges	6	19
Payments	(17)	(51)
Liability, end of period	9	20

During 2004, OPG recorded restructuring charges of \$16 million, which consisted of \$15 million for termination benefits and \$1 million in related pension and OPEB expenses associated with its Lakeview generating station. OPG also recorded restructuring charges of \$4 million related to its Energy Marketing segment during 2004. During 2005, OPG recorded an additional \$6 million of restructuring charges mainly related to its Lakeview generating station and Energy Markets business.

14. TRANSITION RATE OPTION CONTRACTS

Under regulation known as Transition – Generation Corporation Designated Rate Options (“TRO”), OPG has been required to provide transitional price relief since market opening to certain power customers for up to four years based on the consumption and average price paid by each customer during a reference period of July 1, 1999 to June 30, 2000. The TRO is treated as a hedge of generation revenue. The maximum anticipated volume subject to the transitional price relief was approximately 5.4 TWh in the first year after market opening and 3.6 TWh in the second year. The maximum anticipated volume in each of the third and fourth years is 1.8 TWh. The maximum length of the program is four years, which expires April 30, 2006.

A provision of \$210 million on the TRO contracts was recorded in the first quarter of 2002 based on the estimated future loss on these contracts. The provision was determined at that time using management's best estimates of the forward price curve for electricity, wholesale electricity market fees, impact of decontrol on these contracts, interruptions of volume, and the recovery of Market Power Mitigation Agreement rebates. The provision for the TRO contracts was established based on meeting decontrol targets within three years of market opening. An additional charge of \$30 million related to the fourth year of the TRO contracts was recorded in 2003, based on OPG's expectation that the Company would not meet the decontrol targets necessary for TRO contracts to expire after three years.

The change in the TRO contracts provision for the nine months ended September 30, 2005 and year ended December 31, 2004 is as follows:

<i>(millions of dollars)</i>	September 30 2005	December 31 2004
Provision, beginning of period	48	100
Decrease of provision during the period	(27)	(52)
Provision, end of period	21	48

15. MARKET POWER MITIGATION AGREEMENT REBATE

Until April 1, 2005, OPG was required under its generating licence to comply with prescribed market power mitigation measures to address the potential for OPG to exercise market power in Ontario. The market power mitigation measures included both a rebate mechanism and the requirement to decontrol generating capacity. Under the rebate mechanism, a majority of OPG's expected energy sales in Ontario were subject to an average annual revenue cap of 3.8¢/kWh. During the term of the Market Power Mitigation Agreement, OPG was required to pay a rebate to the Independent Electricity System Operator equal to the excess, if any, of the average hourly spot energy price over 3.8¢/kWh for a 12-month settlement period, multiplied by the amount of energy subject to the rebate mechanism. The Market Power Mitigation Agreement was replaced effective April 1, 2005 by a regulated price for baseload hydroelectric and nuclear generation and a revenue limit that applies to OPG's unregulated generation assets.

In accordance with the Market Power Mitigation Agreement, the rebate is calculated after taking into account the amount of energy sales subject to the rebate mechanism for only those generating stations that OPG continues to control. Since the average hourly spot price during the three months ended March 31, 2005, when the rebate mechanism ended, exceeded the 3.8¢/kWh revenue cap, OPG provided \$412 million (three months ended March 31, 2004 – \$441 million) as a Market Power Mitigation Agreement rebate. During the three and nine months ended September 30, 2004, OPG provided \$201 million and \$850 million, respectively, as a Market Power Mitigation Agreement rebate.

The change in the Market Power Mitigation Agreement rebate liability for the nine months ended September 30, 2005 and year ended December 31, 2004 is as follows:

<i>(millions of dollars)</i>	September 30 2005	December 31 2004
Liability, beginning of period	439	409
Increase to provision during the period	412	1,154
Payments	(851)	(1,124)
Liability, end of period	-	439

16. REVENUE LIMIT REBATE

A regulation made pursuant to the *Electricity Restructuring Act, 2004* requires that 85 per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, TRO volumes and forward sales as of January 1, 2005, are subject to a revenue limit based on an average price of \$47.00/MWh (4.7¢/kWh). This revenue limit is in place for a period of 13 months ending April 30, 2006. Revenues above this limit will be rebated at the end of the period.

The change in the revenue limit rebate liability for the nine months ended September 30, 2005 is as follows:

<i>(millions of dollars)</i>	September 30 2005
Liability, beginning of period	-
Increase to provision during the year	477
Payments	-
Liability, end of period	477

17. BUSINESS SEGMENTS

A regulation made pursuant to the *Electricity Restructuring Act, 2004* provided that OPG would receive regulated prices for its baseload hydroelectric and nuclear facilities. These initial prices took effect April 1, 2005, and are expected to remain in effect until at least March 31, 2008, at which time it is anticipated that the OEB will have established new regulated prices. Given the effective date of these prices, and OPG's management approach, OPG changed its definition of business segments on April 1, 2005 from Generation and Energy Marketing to Regulated – Nuclear, Regulated – Hydroelectric and Unregulated Generation. OPG will continue to report other activities, including the previously separately presented trading activities in the Other category. As a result of this change in definition, OPG has reclassified the comparative periods to be consistent with the current presentation of business segments.

Segment Income for three months ended September 30, 2005	Regulated – Nuclear	Regulated – Hydroelectric	Unregulated Generation	Other	Total
<i>(millions of dollars)</i>					
Revenues					
Revenue	662	202	1,042	1	1,907
Market Power Mitigation Agreement rebate	-	-	-	-	-
Revenue limit rebate	-	-	(336)	-	(336)
	662	202	706	1	1,571
Fuel expense	31	64	289	-	384
Gross margin	631	138	417	1	1,187
Operations, maintenance and administration	453	19	142	13	627
Depreciation and amortization	92	18	63	8	181
Accretion on fixed asset removal and nuclear waste management liabilities	117	-	2	-	119
Earnings on nuclear fixed asset removal and nuclear waste management funds	(96)	-	-	-	(96)
Property and capital taxes	-	5	10	11	26
Restructuring	-	-	4	2	6
Income (loss) before interest, income taxes and extraordinary item	65	96	196	(33)	324

Segment Income for three months ended September 30, 2004	Regulated – Nuclear	Regulated – Hydroelectric	Unregulated Generation	Other	Total
<i>(millions of dollars)</i>					
Revenues					
Revenue	612	238	531	32	1,413
Market Power Mitigation Agreement rebate	(64)	(34)	(103)	-	(201)
	548	204	428	32	1,212
Fuel expense	28	68	194	-	290
Gross margin	520	136	234	32	922
Operations, maintenance and administration excluding Pickering A return to service	399	19	142	14	574
Pickering A return to service	62	-	-	-	62
Depreciation and amortization	84	17	72	9	182
Accretion on fixed asset removal and nuclear waste management liabilities	111	-	2	-	113
Earnings on nuclear fixed asset removal and nuclear waste management funds	(77)	-	-	-	(77)
Property and capital taxes	12	4	12	5	33
(Loss) income before interest, income taxes and extraordinary item	(71)	96	6	4	35

Segment Income for nine months ended September 30, 2005	Regulated – Nuclear	Regulated – Hydroelectric	Unregulated Generation	Other	Total
<i>(millions of dollars)</i>					
Revenues					
Revenue	1,942	674	2,527	48	5,191
Market Power Mitigation Agreement rebate	(160)	(65)	(187)	-	(412)
Revenue limit rebate	-	-	(477)	-	(477)
	1,782	609	1,863	48	4,302
Fuel expense	85	186	712	-	983
Gross margin	1,697	423	1,151	48	3,319
Operations, maintenance and administration	1,312	55	421	42	1,830
Depreciation and amortization	278	52	211	25	566
Accretion on fixed asset removal and nuclear waste management liabilities	351	-	7	-	358
Earnings on nuclear fixed asset removal and nuclear waste management funds	(279)	-	-	-	(279)
Property and capital taxes	22	14	26	2	64
Restructuring	-	-	4	2	6
Operating income (loss)	13	302	482	(23)	774
Impairment of long-lived assets	63	-	202	-	265
(Loss) income before interest, income taxes and extraordinary item	(50)	302	280	(23)	509

Segment Income for nine months ended September 30, 2004	Regulated – Nuclear	Regulated – Hydroelectric	Unregulated Generation	Other	Total
<i>(millions of dollars)</i>					
Revenues					
Revenue	1,809	765	1,908	71	4,553
Market Power Mitigation Agreement rebate	(270)	(140)	(440)	-	(850)
Revenue limit rebate	-	-	-	-	-
	1,539	625	1,468	71	3,703
Fuel expense	82	183	605	-	870
Gross margin	1,457	442	863	71	2,833
Operations, maintenance and administration excluding Pickering A return to service	1,195	54	419	39	1,707
Pickering A return to service	186	-	-	-	186
Depreciation and amortization	270	50	226	22	568
Accretion on fixed asset removal and nuclear waste management liabilities	334	-	6	-	340
Earnings on nuclear fixed asset removal and nuclear waste management funds	(255)	-	-	-	(255)
Property and capital taxes	24	15	35	17	91
Restructuring	-	-	16	-	16
(Loss) income before interest, income taxes and extraordinary item	(297)	323	161	(7)	180

Selected Balance Sheet Information	Regulated – Nuclear	Regulated – Hydroelectric	Unregulated Generation	Other	Total
<i>(millions of dollars)</i>					
September 30, 2005 Segment property, plant and equipment, net	3,185	4,037	3,633	601	11,456
December 31, 2004 Segment property, plant and equipment, net	3,305	4,015	3,986	634	11,940
Selected Cash Flow Information					
<i>(millions of dollars)</i>					
Three months ended September 30, 2005 Capital expenditures	54	29	23	10	116
Three months ended September 30, 2004 Capital expenditures	111	6	27	17	161
Nine months ended September 30, 2005 Capital expenditures	214	66	59	17	356
Nine months ended September 30, 2004 Capital expenditures	243	18	56	67	384

18. CHANGES IN NON-CASH WORKING CAPITAL BALANCES

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2005	2004	2005	2004
Accounts receivable	(34)	(18)	(85)	18
Income taxes recoverable	-	-	-	16
Fuel inventory	(10)	(37)	63	(48)
Materials and supplies	(2)	(5)	(28)	(22)
Market Power Mitigation Agreement rebate payable	(245)	(66)	(439)	(69)
Revenue limit rebate payable	336	-	477	-
Accounts payable and accrued charges	(28)	26	(133)	(134)
Income and capital taxes payable	55	1	66	8
	72	(99)	(79)	(231)

19. SEASONAL OPERATIONS

OPG's quarterly results are impacted by changes in demand resulting from variations in seasonal weather conditions. Historically, OPG's revenues are higher in the first and third quarters of a fiscal year as a result of winter heating demands in the first quarter and air conditioning/cooling demands in the third quarter. The Market Power Mitigation Agreement rebate and OPG's hedging strategies significantly reduced the impact of seasonal price fluctuations on the results of operations. Commencing April 1, 2005, regulated prices for the baseload hydroelectric and nuclear facilities and the revenue limit related to the generation from OPG's other generating assets will further reduce the impact of seasonal price fluctuations on operating results.