ONTARIOPOWER GENERATION

News
from Ontario Power Generation

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ONTARIO POWER GENERATION REPORTS 2006 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, 2006. Net income for the three months ended September 30, 2006, was $167 million compared to net income of $181 million for the same period in 2005. For the nine months ended September 30, 2006, net income was $509 million compared to $206 million for the same period last year.

"Our third quarter and year to date results continue to reflect strong generating asset performance. Despite lower Ontario electricity demand in the second and third quarter, our year to date electricity production was essentially equal to that of 2005 due to an increase in low marginal cost nuclear production. Third quarter earnings were unfavourably impacted by lower average sales prices for electricity generation not receiving a fixed regulated price due to lower Ontario spot market electricity prices. Ontario spot market prices were almost fifty per cent lower than during the third quarter of 2005. During the quarter, we continued to make notable progress on a number of generation projects aimed at increasing Ontario's electricity supply," said President and CEO Jim Hankinson.

Net income for the three months ended September 30, 2006, of $167 million was lower compared to the same period in 2005 as a result of a decrease in gross margin from electricity sales primarily due to lower Ontario spot market prices, and by an increase in pension and other post employment benefit costs due to changes in economic assumptions used to measure the costs. Third quarter earnings were favourably affected by a decrease in depreciation expense as a result of extending the service lives of OPG's coal-fired generating stations and the Pickering A and B nuclear generating stations, for purposes of calculating depreciation.

Net income for the nine months ended September 30, 2006, of $509 million increased compared to the same period in 2005 as a result of an increase in gross margin from electricity sales due primarily to higher nuclear production, and a decrease in depreciation expense. The improved gross margin was partially offset by higher pension and other post employment benefit costs.

Net income during the nine months ended September 30, 2005, was unfavourably affected by a number of one-time charges including impairment charges of $202 million related to OPG's Lennox generating station and $63 million related to Units 2 and 3 of the Pickering A nuclear generating station. In addition, as part of the transition to a rate regulated environment in 2005, OPG eliminated a net future income tax asset of $74 million and recorded a corresponding one-time extraordinary loss.

Electricity generated in the third quarter of 2006 was 27.0 terawatt hours (TWh) compared to 27.1 TWh for the third quarter of 2005. Nuclear production increased by over eight per cent primarily as a result of the return to service of Unit 1 at the Pickering A nuclear generating station. Both regulated and unregulated hydroelectric generation increased due to higher water levels. Fossil generation declined primarily as a result of lower Ontario electricity demand and higher nuclear generation.

For the nine months ended September 30, 2006, total production from OPG's generating stations was 80.9 TWh compared to 81.4 TWh for the same period in 2005. This marginal decrease was primarily due to lower fossil-fuelled generation caused by lower electricity demand, partially offset by higher nuclear and hydroelectric generation. The higher nuclear generation was primarily due to the return to service of Unit 1 at the Pickering A generating station late in 2005.

During the third quarter, OPG continued to make progress on a number of electricity generation projects aimed at increasing Ontario's electricity supply, including the following:

- Excavation of a new water diversion tunnel, using a tunnel boring machine, to increase the amount of water flowing to existing turbines at the Sir Adam Beck generating stations in Niagara began in early September;
- Construction of a new 12.5 megawatt (MW) Lac Seul hydroelectric generating station on the English River that started during the first quarter of 2006 is expected to be completed in the fourth quarter of 2007;
- In September, Portlands Energy Centre ("PEC"), a 550 MW gas-fired, combined cycle station near downtown Toronto, signed a 20 year Accelerated Clean Energy Supply contract with the Ontario Power Authority. PEC is a limited partnership between OPG and TransCanada Energy Ltd.;
- OPG will proceed with an environmental assessment as part of its business case study for the potential refurbishment and life extension of its Pickering B nuclear generating station;
- OPG initiated a federal approvals process with the Canadian Nuclear Safety Commission in September by filing an Application for a Site Preparation Licence for new nuclear generating units at OPG's Darlington nuclear generating site;
- The definition phase for a 450 MW hydroelectric development, which includes the replacement and expansion of certain hydroelectric generating stations located on the Lower Mattagami River, is proceeding. OPG is identifying Environmental Assessment requirements and detailing technical project specifications; and
- OPG is exploring the potential development of a gas-fuelled electricity generation station at its Lakeview site and is continuing with the decommissioning and demolition of the Lakeview coal-fired generating station.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	**2006**	**2005**	**2006**	**2005**
Earnings				
Revenue after revenue limit and Market Power Mitigation Agreement rebates	**1,435**	1,571	**4,288**	4,302
Fuel expense	**310**	384	**831**	983
Gross margin	**1,125**	1,187	**3,457**	3,319
Operations, maintenance and administration	**634**	627	**1,967**	1,830
Other expenses	**273**	285	**832**	858
Impairment of long-lived assets	**-**	-	**-**	265
Income tax expenses (recoveries)	**51**	94	**149**	86
Extraordinary item	**-**	-	**-**	74
Net income	**167**	181	**509**	206
Cash flow				
Cash flow provided by operating activities	**307**	382	**306**	755
Electricity Generation (TWh)				
Regulated – Nuclear	**12.9**	11.9	**36.8**	33.3
Regulated – Hydroelectric	**4.6**	4.4	**13.5**	14.0
Unregulated – Hydroelectric	**2.2**	2.0	**11.0**	10.2
Unregulated – Fossil-Fuelled	**7.3**	8.8	**19.6**	23.9
Total electricity generation	**27.0**	27.1	**80.9**	81.4
Average electricity sales price [1] (¢/kWh)				
Regulated – Nuclear [2]	**4.9**	4.9	**4.9**	4.7
Regulated – Hydroelectric [2]	**3.6**	4.2	**3.5**	4.1
Unregulated – Hydroelectric [3]	**4.6**	6.0	**4.7**	5.0
Unregulated – Fossil-Fuelled [3]	**4.8**	6.6	**4.8**	5.5
OPG's average sales price	**4.7**	5.4	**4.6**	4.9
Nuclear unit capability factor (per cent)				
Darlington	**94.5**	98.2	**89.8**	90.9
Pickering A	**82.9**	78.8	**86.1**	60.1
Pickering B	**87.5**	85.0	**79.2**	80.7
Equivalent forced outage rate (per cent)				
Unregulated– Fossil-Fuelled	**11.7**	16.6	**12.5**	15.8
Availability (per cent)				
Regulated – Hydroelectric	**95.9**	92.5	**93.1**	92.2
Unregulated – Hydroelectric	**89.2**	90.0	**92.9**	93.6

1 Prior to the inception of rate regulation on April 1, 2005, OPG's electricity generation received the Ontario spot electricity market price net of the Market Power Mitigation Agreement rebate.

2 After April 1, 2005, electricity generation from stations in the Regulated – Nuclear segment received a fixed price of 4.95¢/kWh. During the same period, 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.

3 During the period from April 1, 2005 to April 30, 2006, 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. Starting May 1, 2006 the revenue limit decreased to 4.6¢/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 as at and for the three and nine months ended September 30, 2006, 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.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

UNAUDITED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

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, 2006. For a complete description of OPG's corporate strategies, risk management, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A 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, 2005. 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 16, 2006.

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 does not indicate that a statement is not forward-looking.

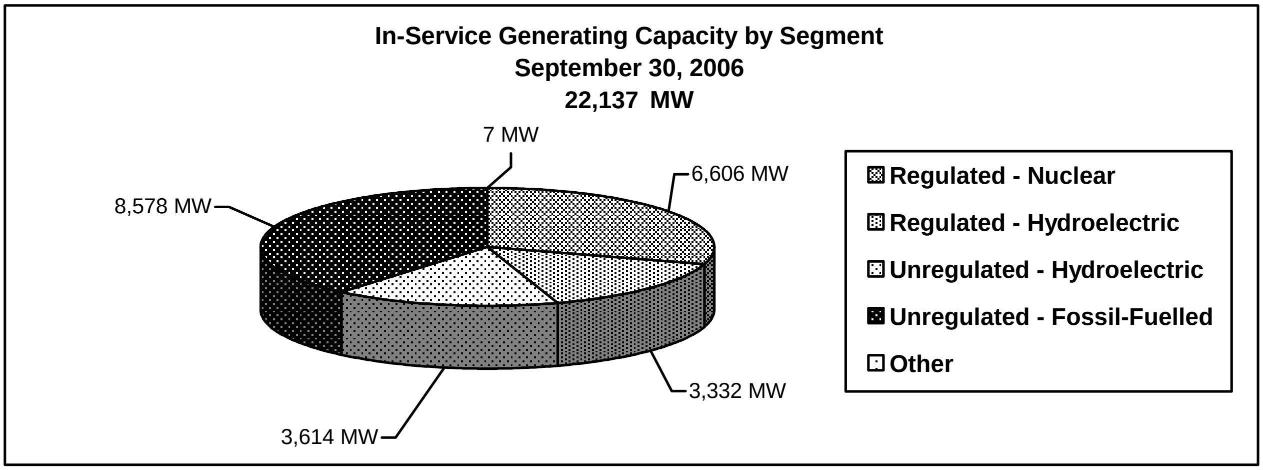
All forward-looking statements involve inherent assumptions, risks and uncertainties and, therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's fuel costs and availability, nuclear decommissioning and waste management, closure of coal-fired generating stations, refurbishment of existing facilities, development and construction of new facilities, 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 forward-looking statements included in this MD&A are made only as of the date of this MD&A. OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events or otherwise.

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, 2006, OPG's electricity generating portfolio had an in-service capacity of 22,137 megawatts ("MW"). OPG's electricity generating portfolio consists 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). 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 operated by OPG 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 on the majority of this output. With the introduction of rate regulation, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. Since the second quarter of 2005, OPG reported its business segments as Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. Beginning in the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments, identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods have been reclassified accordingly.



RATE REGULATION

A regulation was introduced pursuant to the *Electricity Restructuring Act, 2004* (Ontario), which provides that, effective April 1, 2005, OPG receives regulated prices for electricity generated from most of its baseload hydroelectric and all of the nuclear facilities that it operates. This comprises electricity generated from the 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 electricity production during peak demand periods, any production from these regulated hydroelectric facilities above 1,900 MWh in any hour receives the 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 and forward sales as of January 1, 2005, is subject to a revenue limit. Also, the output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets are excluded from the output covered by the revenue limit. In addition, until the Transition – Generation Corporation Designated Rate Options ("TRO") expired on April 30, 2006, volumes sold under such options were excluded from the revenue limit rebate. The revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit will return to 4.7¢/kWh and increase to 4.8¢/kWh effective May 1, 2008. In addition, beginning May 1, 2006, volumes sold under a Pilot Auction administered by the Ontario Power Authority ("OPA") are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Furthermore, the Pilot Auction revenue limit will increase by 0.1¢/kWh on May 1, 2007 and again on May 1, 2008. Revenues above these limits are returned to the Independent Electricity System Operator ("IESO") for the benefit of consumers.

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.

From 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 terawatt hours ("TWh") on an annual basis.

Revenue from OPG's nuclear generating stations is favourably impacted by the introduction of regulated prices that reflect the projected production and costs of operations, including an allowed return on equity, and the corresponding elimination of the Market Power Mitigation Agreement rebate. Revenue from OPG's regulated hydroelectric generating stations is negatively impacted by the regulatory changes. While a significant portion of OPG's output from its unregulated assets is subject to the revenue limit, this limit is higher than the limit that was prescribed under the Market Power Mitigation Agreement.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. A detailed discussion of OPG's performance by reportable business segment is included under the heading, *Discussion of Operating Results by Business Segment*.

(millions of dollars)	Three Months Ended September 30 2006	Three Months Ended September 30 2005	Nine Months Ended September 30 2006	Nine Months Ended September 30 2005
Revenue				
Revenue before revenue limit and Market Power Mitigation Agreement rebates	**1,494**	1,907	**4,436**	5,191
Revenue limit rebate	**(59)**	(336)	**(148)**	(477)
Market Power Mitigation Agreement rebate	**-**	-	**-**	(412)
	1,435	1,571	**4,288**	4,302
Earnings				
Income before impairment of long-lived assets, income tax expenses (recovery) and extraordinary item	**218**	275	**658**	631
Impairment of long-lived assets	**-**	-	**-**	(265)
Income before income taxes and extraordinary item	**218**	275	**658**	366
Income tax expenses	**51**	94	**149**	86
Income before extraordinary item	**167**	181	**509**	280
Extraordinary item	**-**	-	**-**	74
Net income	**167**	181	**509**	206
Electricity production (TWh)	**27.0**	27.1	**80.9**	81.4
Cash flow				
Cash flow provided by operating activities	**307**	382	**306**	755

Net income for the three months ended September 30, 2006 was $167 million compared to $181 million in the three months ended September 30, 2005, a decrease of $14 million. Income before income taxes for the three months ended September 30, 2006 was $218 million compared to $275 million for the three months ended September 30, 2005, a decrease of $57 million.

Net income for the nine months ended September 30, 2006 was $509 million compared to $206 million during the same period in 2005, an increase of $303 million. Income before income taxes for the nine months ended September 30, 2006 was $658 million compared to income before income taxes and the extraordinary item for the same period last year of $366 million, an increase of $292 million.

The following is a summary of the factors impacting OPG's results for the three and nine months ended September 30, 2006 compared to results for the same periods in 2005, on a before-tax basis:

(millions of dollars – before tax)	**Three Months**	**Nine Months**
Income before income taxes and extraordinary item for the periods ended September 30, 2005	**275**	**366**
Changes in gross margin		
Decrease in electricity sales prices after revenue limit and Market Power Mitigation Agreement rebates	(94)	(9)
Change in electricity generation by segment:		
Regulated – Nuclear	47	171
Regulated – Hydroelectric	3	(15)
Unregulated – Hydroelectric	13	40
Unregulated – Fossil-Fuelled	(53)	(135)
Trading revenue	27	58
Other changes in gross margin	(5)	28
	(62)	138
Increase in pension and other post employment benefit costs	(41)	(130)
Amortization of Pickering A Return to Service deferral account balance	(6)	(21)
Write-off of excess inventory related to Pickering A Units 2 and 3 in 2005	22	22
Decrease in earnings on nuclear fixed asset removal and nuclear waste management funds	(14)	(5)
Decrease in depreciation expense primarily due to extension of service lives of the coal-fired generating stations, Pickering B station and Unit 4 of the Pickering A station	33	62
Other changes	11	(39)
(Decrease) increase in income before income taxes, excluding impairment of long-lived assets	**(57)**	**27**
Impairment of long-lived assets	-	265
Income before income taxes for the periods ended September 30, 2006	**218**	**658**

Earnings for the Three Months Ended September 30, 2006

Earnings for the three months ended September 30, 2006 were unfavourably impacted by a decrease in gross margin from electricity sales. The decrease was primarily due to lower average sales prices for electricity generation not receiving a fixed regulated price. The impact of higher nuclear and hydroelectric generation was largely offset by lower fossil-fuelled generation.

Operations, maintenance and administration ("OM&A") expenses for the three months ended September 30, 2006 were $634 million compared to $627 million during the same period in 2005. The higher OM&A expenses were primarily due to an increase in pension and OPEB costs mainly due to changes in economic assumptions used to measure the costs. In 2006, OM&A expenses also included amortization of the Pickering A return to service costs, which were previously deferred in accordance with a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario). Amortization commenced late in 2005 with the return to service of Unit 1 at the Pickering nuclear generating station. During the three months ended September 30, 2005, OM&A expenses were impacted by a write-off of excess inventory acquired for the anticipated return to service of Units 2 and 3 at the Pickering A nuclear generating station.

Earnings were favourably impacted by a decrease in depreciation expense of $33 million. Effective July 1, 2006, OPG extended, for purposes of calculating depreciation, the remaining service life of all coal-fired generating stations as a result of delays in the plan to replace coal-fired generation. In addition, in late 2005 and early 2006, OPG extended the remaining service life of the Pickering A and B nuclear generating stations for purposes of calculating depreciation. This reduction was partially offset by an increase in depreciation expense due to the return to service of Unit 1 at the Pickering A nuclear generating station.

During the second quarter of 2006, the federal government passed legislation which eliminated the Large Corporations Tax and reduced future income tax rates. These measures reduced income taxes for the three months ended September 30, 2006 by $7 million, compared to the same period last year.

Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under this method, future income tax assets and liabilities associated with these segments are not recognized where those future income taxes are expected to be recovered in the regulated rates charged to customers in the future. As a result, OPG did not record a future tax expense of $24 million and $57 million for the rate regulated segments during the three months ended September 30, 2006 and September 30, 2005, respectively, 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, 2006

Earnings for the nine months ended September 30, 2006 were favourably impacted by an increase in gross margin from electricity sales. An increase in electricity generation from OPG's nuclear generating stations contributed to this increase, but was partly offset by lower generation at OPG's fossil-fuelled stations due to lower electricity demand in Ontario and the higher nuclear generation. In addition, higher trading and other revenue contributed to an increase in gross margin.

Earnings were also favourably impacted by a decrease in depreciation expense of $62 million during the nine months ended September 30, 2006 compared to the same period in 2005. The decrease in depreciation expense was due to a service life extension, for accounting purpose, of the Nanticoke generating station during the third quarter of 2005, the subsequent extension of the service lives of all of the coal-fired generating stations during the third quarter of 2006, and the changes in depreciation of the nuclear generating stations.

For the nine months ended September 30, 2006, OM&A expenses were $1,967 million compared to $1,830 million during the same period in 2005. In 2006, pension and OPEB costs have increased significantly compared to the same period last year mainly due to changes in economic assumptions used to measure the costs. In addition, OM&A expenses included the amortization of a portion of the previously deferred Pickering A return to service costs.

OPG recorded an impairment charge of $202 million related to its Lennox generating station in the first quarter of 2005, which contributed to higher earnings in 2006 relative to 2005. It was determined that the Lennox generating station, as a relatively high variable cost plant, would not be able to recover its carrying value from the wholesale electricity market in the future. Earnings were also reduced in 2005 as a result of the impairment charge of $63 million related to 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. The impairment charge represented the carrying value, including construction in progress of these two units.

The recently passed legislation eliminating the Large Corporations Tax and reducing future income tax rates increased earnings by $40 million for the nine months ended September 30, 2006 compared to the same period in 2005.

Net income during the nine months ended September 30, 2006 reflected the impact of accounting for income taxes for the regulated segments of the business using the taxes payable method for the entire period. Net income for the nine months ended September 30, 2005 reflected the impact the taxes payable method for only six months, as this method was adopted upon inception of rate regulation on April 1, 2005. For the nine months ended September 30, 2006, OPG did not record a future tax expense of $42 million, which would have been recorded had OPG accounted for income taxes for the regulated segments using the liability method. Net income for the nine months ended September 30, 2005 reflected the impact of not recording a future income tax expense of $110 million. In the second quarter of 2005, as part of the transition to rate regulated accounting, OPG eliminated a net future income tax asset balance of $74 million related to rate regulated segments and recorded a corresponding one-time extraordinary loss.

Average Sales Prices

The weighted average Ontario spot electricity market price and OPG's average sales prices by reportable business segment, net of the revenue limit rebate for the period from April 1, 2005 to September 30, 2006, and net of the Market Power Mitigation Agreement rebate up to the inception of rate regulation on April 1, 2005, were as follows:

	Three Months Ended September 30		**Nine Months Ended September 30**	
(¢/kWh)	**2006**	**2005**	**2006**	**2005**
Weighted average hourly Ontario spot electricity market price	**4.9**	9.2	**5.0**	7.1
Regulated – Nuclear	**4.9**	4.9	**4.9**	4.7
Regulated – Hydroelectric [1]	**3.6**	4.2	**3.5**	4.1
Unregulated – Hydroelectric [2]	**4.6**	6.0	**4.7**	5.0
Unregulated – Fossil-Fuelled [2]	**4.8**	6.6	**4.8**	5.5
OPG's average sales price	**4.7**	5.4	**4.6**	4.9

[1] During the period from April 1, 2005 to September 30, 2006, electricity generated 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, 2005 to September 30, 2006, 85 per cent of the electricity generated 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. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh.

OPG's average sales price for the three months ended September 30, 2006 was 4.7¢/kWh compared to 5.4¢/kWh for the same period in 2005. The decrease was primarily due to lower Ontario spot electricity prices during the third quarter of 2006. Spot market prices were lower as a result of a decrease in demand reflecting more moderate temperatures during the third quarter of 2006 compared to the same period last year, lower natural gas prices, and an increase in production from low marginal cost generation in Ontario. In addition, during the third quarter of 2005, the Ontario market experienced significantly higher spot market prices due to a prolonged period of hot weather that increased the demand for electricity and required the use of higher marginal cost gas-fired generation.

OPG's average sales price for the nine months ended September 30, 2006 was 4.6¢/kWh compared to 4.9¢/kWh for the same period last year. A decrease in OPG's average sales price due to lower Ontario spot market prices was partially offset by the impact of the introduction of regulated prices and other related regulatory changes effective April 1, 2005.

As a result of regulated prices and the revenue limit rebate, OPG's average sales price continued to be lower than the weighted average hourly Ontario spot electricity market price.

Electricity Generation

Total electricity generation during the three months ended September 30, 2006 from OPG's generating stations was 27.0 TWh compared to 27.1 TWh during the same period in 2005. For the nine months ended September 30, 2006, total electricity generation from OPG's generating stations was 80.9 TWh compared to 81.4 TWh during the same period in 2005. Electricity generation from nuclear stations increased primarily as a result of the return to service of Unit 1 at the Pickering A generating station in November 2005. Also, during the second quarter of 2005, Unit 4 at the Pickering A nuclear generating station was shut down for the duration of the quarter due to the inspection and repair of feeder pipes. The increase in nuclear electricity generation was partly offset by lower fossil-fuelled generation. The decrease in fossil-fuelled generation was due primarily to lower electricity demand in Ontario and higher nuclear generation.

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 for the three and nine months ended September 30:

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2006	**2005**	**2006**	**2005**
Heating Degree Days [1]				
Period	**83**	20	**2,188**	2,490
Ten-year average	**64**	64	**2,392**	2,451
Cooling Degree Days [2]				
Period	**290**	390	**390**	542
Ten-year average	**280**	268	**370**	353

1 Heating Degree Days are recorded on days with an average temperature below 18^0C, and represent the aggregate of the differences between the average temperature and 18^0C for each day during the period, as measured at Pearson International Airport.

2 Cooling Degree Days are recorded on days with an average temperature above 18^0C, and represent the aggregate of the differences between the average temperature and 18^0C for each day during the period, as measured at Pearson International Airport.

Cooling Degree Days for the three months ended September 30, 2006 decreased compared to the same period in 2005. Ontario experienced higher temperatures during the period from June to September of 2005 compared to the same period in 2006, which contributed to higher demand for electricity in Ontario last year.

Heating Degree Days for the nine months ended September 30, 2006 decreased compared to the same period in 2005 due primarily to warmer weather during the winter and early spring of 2006 compared to the same period last year. The reduction in heating degree days also contributed to the decrease in Ontario electricity demand compared to the same period in 2005.

Cash Flow from Operations

Cash flow provided by operating activities for the three months ended September 30, 2006 was $307 million compared to cash flow provided by operating activities of $382 million during the same period in 2005. The decrease in cash flow from operating activities was due mainly to lower revenue before the revenue limit rebate due to the decrease in the Ontario spot electricity market prices, partially offset by a lower payment to the IESO with respect to the revenue limit rebate during the third quarter of 2006, compared to the amount of the final payment of the Market Power Mitigation Agreement rebate during the same quarter in 2005.

Cash flow provided by operating activities for the nine months ended September 30, 2006 was $306 million compared to cash flow provided by operating activities of $755 million during the nine months ended September 30, 2005. The decrease in cash flow from operating activities was primarily due to lower revenue before rebates as a result of lower Ontario spot electricity market prices, partially offset by the impact of lower expenditures on fuel, higher trading revenues and lower revenue limit rebate payments during the nine months ended September 30, 2006 compared to the amount of the Market Power Mitigation Agreement rebate payments made in 2005**.**

VISION, CORE BUSINESS AND STRATEGY

OPG's mandate is to cost effectively produce electricity from its diversified generating assets, while operating in a safe, open and environmentally responsible manner. OPG's mandate, as well as a discussion of strategies to accomplish the mandate, is outlined in the 2005 annual MD&A under the heading, *Vision, Core Business and Strategy*.

Improving the Performance of Generating Assets

Nuclear Generating Assets

OPG's strategic objective is to operate the Darlington and Pickering A and B nuclear generating stations in a safe, efficient and cost effective manner, while undertaking prudent investments to improve their reliability and predictability. To achieve this objective, programs and initiatives have been implemented to improve safety performance, reduce forced outages through improvements in equipment reliability, optimize planned outages, reduce maintenance backlogs, mitigate technological risks through comprehensive inspection and testing programs, focus on production unit energy costs, and address resource planning issues.

Pursuant to the direction from the Minister of Energy in June of 2006, OPG is undertaking a feasibility study on the refurbishment of its Pickering B and Darlington nuclear generating facilities. OPG has initiated an assessment of the feasibility for refurbishing the Pickering B nuclear generating station to support its continued operation beyond 2015. The assessment will be a systematic, thorough review of the safety, environmental, financial and logistical aspects of refurbishment and continued operation of the nuclear generating station. OPG received confirmation from the Canadian Nuclear Safety Commission ("CNSC") that a Federal Environmental Assessment ("EA") is required prior to the refurbishment of the Pickering B nuclear generating station. The CNSC intends to issue draft guidelines outlining issues to be considered and included in the EA. The results of the EA will be documented in an EA study report, which will be publicly available. It is expected that an EA report will be ready in late 2007.

Hydroelectric Generating Assets

OPG's strategic objective is to improve production from its existing hydroelectric generating assets in a cost effective and efficient manner. Programs are continuing at several stations to replace aging and obsolete equipment, accelerate runner upgrades, and improve availability through enhanced maintenance practices. During the first nine months of 2006, OPG has improved its safety, and environmental performance, and increased electricity generation compared to the first nine months of 2005. To date in 2006, hydroelectric capacity has increased by 15 MW as a result of runner upgrades at three unregulated hydroelectric generating stations. In addition, plans have been developed for approval of the conversion of Sir Adam Beck 1, Unit 7 from a 25 to 60 cycle load requirement. The conversion would increase hydroelectric generating capacity by an estimated additional 58 MW, and would be in-service for early 2009.

Fossil-Fuelled Generating Assets

OPG's strategic objective is to maintain the productive capability of its coal-fired generating facilities, while continuing to operate them in an environmentally responsible manner, taking into account the Province's coal replacement policy. To achieve this objective, programs and initiatives are in place to: address the impacts of increased unit starts and stops, in part due to the role that the fossil-fuelled plants perform as intermediate and peaking facilities, ensure continued environmental compliance, and retain competent staff to continue to operate the units until their closure.

In June 2006, the Ministry of Energy announced that, as a result of additional capacity requirements in order to maintain system reliability, further delays will be necessary in the plan to replace coal-fired generation by 2009. The Minister directed the OPA to determine how best to replace coal-fired generation in the earliest practical time frame and recommend options for cost effective measures to reduce air emissions from coal-fired generation.

Following the Minister's announcement, OPG's fossil-fuelled work programs were reviewed. Maintenance programs that were appropriate for an earlier shutdown timeframe have been re-assessed assuming longer plant operations. Several environmental initiatives have also been undertaken at both the Nanticoke and Lambton coal-fired generating stations to address a number of key issues such as particulates, heat rates, water temperatures and noise abatement. Deferral of coal-fired plant closures has resulted in a further review of staffing requirements and strategies. Fossil staff demographics and the uncertainty with respect to coal-fired plant closures, have required focused recruiting efforts to maintain plant operating capability.

Increasing OPG's Generating Capacity

OPG's strategy with respect to increasing its generating capacity is to expand, develop, and/or improve its hydroelectric generating capacity through expansion and redevelopment of its existing sites, as well as the pursuit of new projects where feasible. OPG will undertake these investments on its own or through partnerships.

Niagara Tunnel

The Niagara tunnel project will increase the amount of water flowing to existing turbines at OPG's Sir Adam Beck generating stations in Niagara, allowing the stations to utilize available water more effectively. Average annual generation is expected to increase by about 1.6 TWh.

On-site assembly of the tunnel boring machine was completed in September 2006 and boring of the tunnel commenced during the month. The project is expected to be completed in late 2009.

The project is expected to cost approximately $985 million. Capital project expenditures for the three months ended September 30, 2006 were $50 million and life-to-date capital expenditures were $199 million. The project's debt financing is through the Ontario Electricity Financial Corporation ("OEFC").

Lac Seul

OPG is constructing a new 12.5 MW hydroelectric generating station on the English River. The new Lac Seul generating station will utilize a majority of the spill currently passing the existing Ear Falls generating station, thus increasing the overall efficiency, capacity and energy generated from this location. A design-build contract was awarded and construction started during the first quarter of 2006, with the in-service date planned for the fourth quarter of 2007. Total project costs are expected to be $47 million.

Work is substantially completed on the water conveyance tunnel and the tailrace channel excavation, and continues on the intake coffer dam. The project is moving ahead on the powerhouse foundation and structural concrete, and the powerhouse erection is targeted for completion by the end of 2006. Capital project expenditures for the three months ended September 30, 2006 were approximately $5 million and life-to-date capital expenditures were $18 million. OPG has negotiated the project's debt financing with the OEFC.

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.

During the first quarter of 2006, the Province directed the OPA to negotiate an agreement with PEC for the purchase of electricity. PEC signed a 20-year Accelerated Clean Energy Supply (“ACES") contract with the OPA during the third quarter of 2006. PEC has also entered into an engineer-procure-construct (“EPC”) contract to construct the facility. PEC is expected to be operational in simple cycle mode with a capacity up to 340 MW to meet peak summer demand beginning June 1, 2008. The plant is expected to be fully completed in the second quarter of 2009, providing up to 550 MW of power in combined cycle mode. The capital cost of PEC is estimated to be $730 million excluding capitalized interest. A significant proportion of this capital cost relates to the EPC contract.

OPG’s share of capital project expenditures for the three months ended September 30, 2006 were approximately $42 million and life-to-date capital expenditures were $63 million. OPG has negotiated financing for its share of the project with the OEFC.

Lower Mattagami

In May 2006, OPG provided development alternatives to the Province to increase the generating capacity of four hydroelectric generating stations on the Lower Mattagami River. The incremental capacity associated with these alternatives ranged from approximately 140 to 450 MW.

In May 2006, OPG received a letter from the Minister of Energy, which directed OPG to proceed immediately with the definition phase for a 450 MW development which includes the replacement of the Smoky Falls generating station and the expansion of Little Long, Harmon and Kipling generating stations, all of which are located on the Lower Mattagami River. OPG was also directed to initiate discussions with Ministry staff on a power purchase agreement.

During the third quarter of 2006, OPG was engaged in consultations with the First Nations stakeholders, identification of EA requirements, discussions with Hydro One regarding transmission upgrades, and detailing the technical specifications of the project. In addition, OPG has issued a call for expressions of interest to pre-qualify design build contractors for the project.

New Nuclear Generating Units

As directed by the Minister of Energy in June of 2006, OPG initiated a federal approvals process with the CNSC in September of 2006 by filing with the CNSC an Application for a Site Preparation Licence for new nuclear generating units at OPG’s Darlington nuclear generating site. The CNSC will review OPG’s application and will determine the EA requirements.

Lakeview Site

OPG is continuing with decommissioning and demolition of the Lakeview coal-fired generating station, having closed the station in 2005 after more than 40 years of service. OPG has begun to explore the potential development of a gas-fuelled electricity generating station at the site. The construction of a new plant would proceed only after required approvals and completion of a power purchase agreement.

ONTARIO ELECTRICITY MARKET TRENDS

Ontario's electricity demand averaged approximately 17,500 MW during the third quarter of 2006 compared to approximately 18,400 MW during the same period of 2005. Ontario set a new record of 27,005 MW for peak demand on August 1, 2006, exceeding the previous record set in 2005 by more than 800 MW. For the nine months ended September 30, 2006, Ontario electricity demand averaged 17,400 MW compared to 18,100 MW for the nine months ended September 30, 2005. In its 18-Month

Outlook published in September 2006, the IESO has forecast that the winter 2006-2007 Monthly Normal peak demand is expected to be approximately 24,700 MW, while the Monthly Normal summer 2007 peak demand is forecast to be approximately 25,600 MW. The IESO forecasts that energy consumed will be 154.4 TWh in 2006, a marginal decrease over the weather corrected energy demand of 154.7 TWh in 2005. For 2007, energy consumed is forecast to be 156.7 TWh, an increase of 1.5 per cent over 2006.

The IESO initiated a Day-Ahead Commitment Process ("DACP"), which is intended to address reliability needs in Ontario's power system in 2006. The DACP was established effective May 31, 2006, and is anticipated to continue to November 30, 2006. In addition, the IESO initiated an Emergency Load Reduction Program to provide consumers with incentives to reduce their electricity consumption. This program started on June 20, 2006.

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 revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. Since the second quarter of 2005, OPG reported its business segments as Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. Beginning in the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods were reclassified to reflect the revised disclosure.

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 – Hydroelectric and Unregulated – Fossil-Fuelled generation segments after that date. Gains or losses in these hedging transactions are recognized in revenue over the terms 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. This business segment also includes revenue under the terms of a lease arrangement with Bruce Power related to the Bruce nuclear generating stations. This arrangement includes lease revenue and revenue from engineering analysis and design, technical and other services. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control/reactive support.

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 is comprised of 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 – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations that are not subject to rate regulation. The Unregulated – Hydroelectric 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.

Unregulated – Fossil-Fuelled Segment

The Unregulated – Fossil-Fuelled business segment operates in Ontario, generating and selling electricity from its fossil-fuelled generating stations, which are not subject to rate regulation. The Unregulated – Fossil-Fuelled 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 and automatic generation control, and revenues from other services.

Other

The Other category includes revenue that OPG earns 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"). 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. In addition, the Other category includes revenue from real estate rentals.

KEY GENERATION AND FINANCIAL PERFORMANCE INDICATORS

Key performance indicators that directly pertain to OPG's mandate and corporate strategies are measures of production efficiency, cost effectiveness, and environmental performance. OPG evaluates the performance of its generating stations using a number of key performance indicators, which vary depending on the generating technology. These indicators are defined in this section and are discussed in the *Discussion of Operating Results by Business Segment* section.

Nuclear Unit Capability Factor

OPG's nuclear stations operate as baseload facilities as they have low marginal costs and are not designed for fluctuating production levels to meet peaking demand. The nuclear unit capability factor is a key measure of nuclear station performance. It is the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints 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. Capability factors are primarily impacted by planned and unplanned outages. Capability factors by industry definition exclude grid-related unavailability.

Fossil-Fuelled and Hydroelectric Equivalent Forced Outage Rate ("EFOR")

OPG's fossil-fuelled stations provide a flexible source of energy and operate as baseload, intermediate and peaking facilities, depending on the characteristics of the particular stations. OPG's hydroelectric stations operate primarily as baseload facilities and provide a reliable and low-cost source of renewable energy. A key measure of the reliability of the fossil-fuelled and hydroelectric stations is their ability to be available to produce electricity when called upon. EFOR is 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.

Hydroelectric Availability

Hydroelectric availability is a measure of the reliability of a hydroelectric generating unit represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually in-service, compared to the total time for a respective period.

Nuclear Production Unit Energy Cost ("PUEC")

Nuclear PUEC is used to measure the operations-related costs of production of OPG's nuclear generating assets. Nuclear PUEC is defined as nuclear fuel, OM&A expenses including allocated corporate costs, and variable costs related to used fuel disposal and the disposal of low and intermediate level radioactive waste materials, divided by total energy produced.

Hydroelectric OM&A Expense per MWh

Hydroelectric OM&A expense per MWh is used to measure the cost effectiveness of the hydroelectric generating stations. It is defined as total hydroelectric OM&A expenses, including allocated corporate costs, divided by hydroelectric electricity generation.

Fossil-Fuelled OM&A Expense per MW

Since fossil-fuelled generating stations are primarily employed during periods of intermediate and peak demand, the cost effectiveness of these stations is measured by their total OM&A expenses, including allocated corporate costs, divided by total station nameplate capacity.

Other Key Indicators

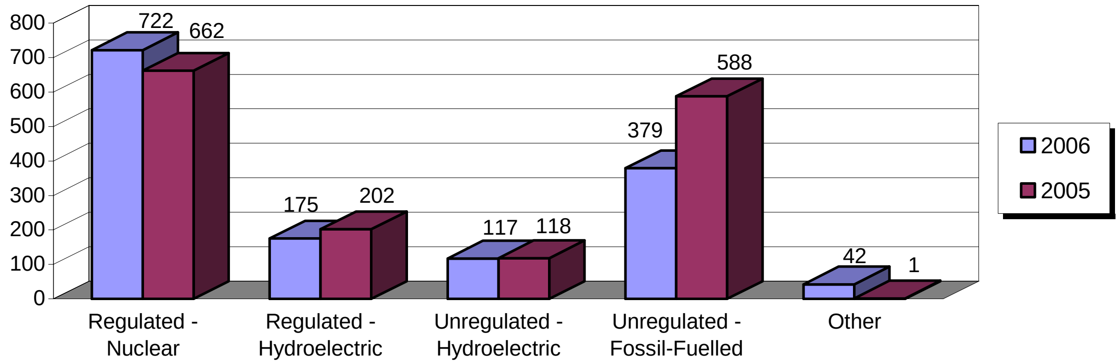
In addition to performance and cost effectiveness indicators, OPG has identified certain environmental indicators. These indicators are discussed under the heading, *Risk Management*.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

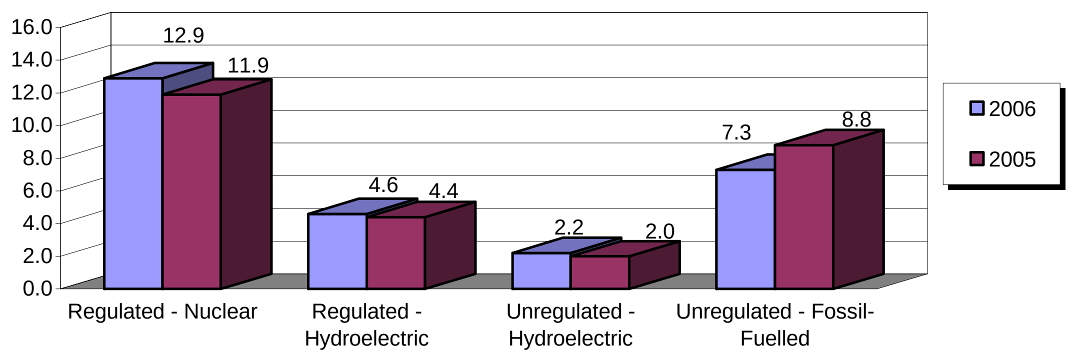
This section summarizes OPG's key results by segment for the three and nine months ended September 30, 2006 and 2005. Although the regulations pursuant to the *Electricity Restructuring Act, 2004* (Ontario), became effective commencing April 1, 2005, results for the first quarter of 2005 and the nine months ended September 30, 2005 were reclassified according to the business segment definitions. The operating results for the first quarter of 2005 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 key generation and financial performance indicators by business segment:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Revenue, net of revenue limit and Market Power Mitigation Agreement rebates				
Regulated – Nuclear	**722**	662	**2,067**	1,782
Regulated – Hydroelectric	**175**	202	**514**	609
Unregulated – Hydroelectric	**117**	118	**545**	519
Unregulated – Fossil-Fuelled	**379**	588	**1,044**	1,344
Other	**42**	1	**118**	48
	1,435	1,571	**4,288**	4,302
Income (loss) before interest, income taxes and extraordinary item				
Regulated – Nuclear	**101**	65	**193**	(50)
Regulated – Hydroelectric	**65**	96	**207**	302
Unregulated – Hydroelectric	**34**	51	**297**	306
Unregulated – Fossil-Fuelled	**39**	145	**30**	(26)
Other	**26**	(33)	**76**	(23)
	265	324	**803**	509
Electricity Generation (TWh)				
Regulated – Nuclear	**12.9**	11.9	**36.8**	33.3
Regulated – Hydroelectric	**4.6**	4.4	**13.5**	14.0
Unregulated – Hydroelectric	**2.2**	2.0	**11.0**	10.2
Unregulated – Fossil-Fuelled	**7.3**	8.8	**19.6**	23.9
Total electricity generation	**27.0**	27.1	**80.9**	81.4
Nuclear unit capability factor (per cent)				
Darlington	**94.5**	98.2	**89.8**	90.9
Pickering A	**82.9**	78.8	**86.1**	60.1
Pickering B	**87.5**	85.0	**79.2**	80.7
Equivalent forced outage rate (per cent)				
Regulated – Hydroelectric	**1.1**	2.7	**0.9**	1.3
Unregulated – Hydroelectric	**3.4**	1.2	**1.8**	1.3
Unregulated – Fossil-Fuelled	**11.7**	16.6	**12.5**	15.8
Availability (per cent)				
Regulated – Hydroelectric	**95.9**	92.5	**93.1**	92.2
Unregulated – Hydroelectric	**89.2**	90.0	**92.9**	93.6
Nuclear PUEC ($/MWh)	**35.97**	38.06	**39.16**	40.32
Regulated – Hydroelectric OM&A expense per MWh ($/MWh)	**5.43**	4.55	**5.11**	4.00
Unregulated – Hydroelectric OM&A expense per MWh ($/MWh)	**20.00**	18.50	**11.36**	9.90
Unregulated – Fossil-Fuelled OM&A expense per MW ($000/MW)	**54.1**	50.5	**58.4**	48.0

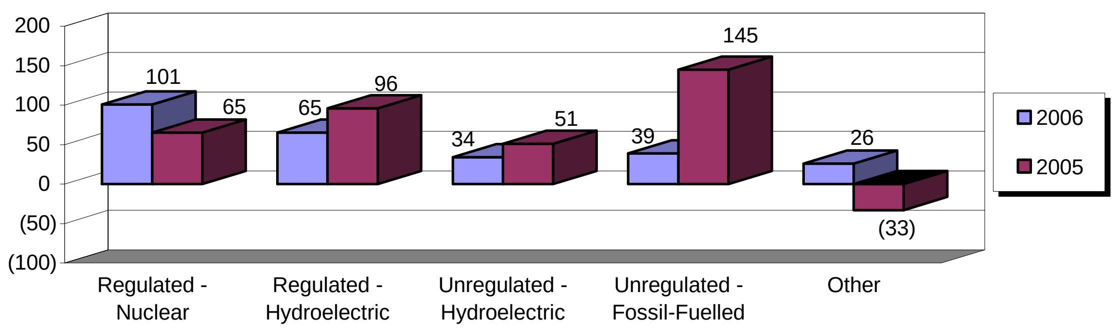
Revenue, Net of Revenue Limit Rebate by Segment
Three Months Ended September 30
(millions of dollars)



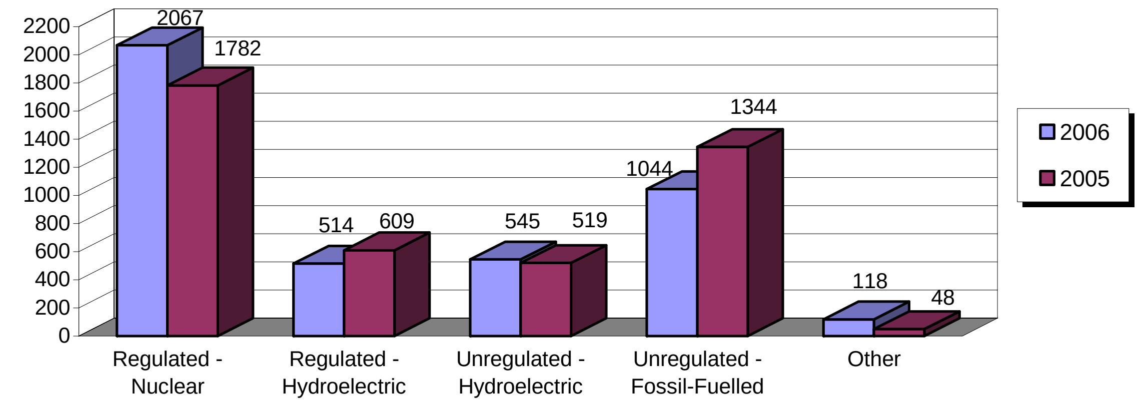
Electricity Production
Three Months Ended September 30
(TWh)



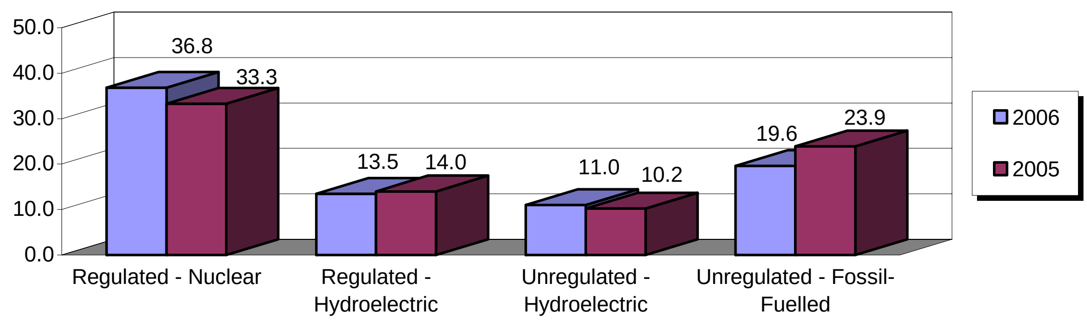
Income (Loss) Before Interest, Income Taxes and Extraordinary Item by Segment
Three Months Ended September 30
(millions of dollars)



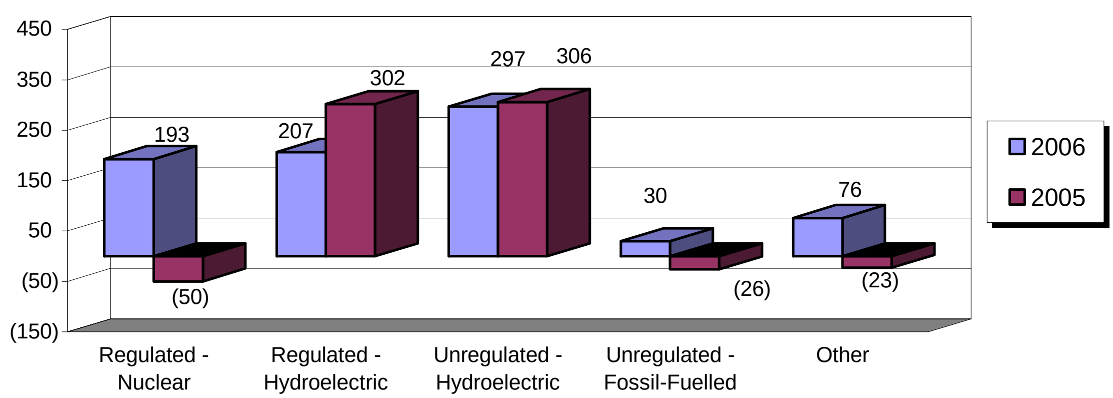
Revenue, Net of Revenue Limit and Market Power Mitigation Agreement Rebates by Segment
Nine Months Ended September 30
(millions of dollars)



Electricity Production
Nine Months Ended September 30
(TWh)



Income (Loss) Before Interest, Income Taxes and Extraordinary Item by Segment
Nine Months Ended September 30
(millions of dollars)



Regulated – Nuclear Segment

(millions of dollars)	Three Months Ended September 30 2006	2005	Nine Months Ended September 30 2006	2005
Revenue net of Market Power Mitigation Agreement rebate	**722**	662	**2,067**	1,782
Fuel expense	**34**	31	**93**	85
Gross margin	**688**	631	**1,974**	1,697
Operations, maintenance and administration	**446**	457	**1,399**	1,324
Depreciation and amortization	**85**	88	**254**	267
Accretion on fixed asset removal and nuclear waste management liabilities	**123**	117	**368**	351
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(82)**	(96)	**(274)**	(279)
Property and capital taxes	**15**	-	**34**	21
Income (loss) before impairment of long-lived asset	**101**	65	**193**	13
Impairment of long-lived asset	**-**	-	**-**	63
Income (loss) before interest and income taxes	**101**	65	**193**	(50)

Revenue

(millions of dollars)	Three Months Ended September 30 2006	2005	Nine Months Ended September 30 2006	2005
Regulated generation sales	**638**	585	**1,813**	1,046
Spot market sales, net of hedging instruments	**-**	-	**-**	662
Market Power Mitigation Agreement rebate	**-**	-	**-**	(160)
Other	**84**	77	**254**	234
Total revenue	**722**	662	**2,067**	1,782

Regulated – Nuclear revenue was $722 million for the three months ended September 30, 2006 compared to $662 million during the same period in 2005, an increase of $60 million. The increase in revenue was primarily due to higher electricity generation of 1.0 TWh compared to the same period in 2005.

Regulated – Nuclear revenue was $2,067 million for the nine months ended September 30, 2006 compared to $1,782 million during the same period in 2005. The increase in revenue of $285 million was largely due to higher electricity generation of 3.5 TWh during the first nine months of 2006 compared to the same period last year. In addition, higher sales prices related to the introduction of regulated rates effective April 1, 2005 contributed to the increase in revenue for the nine months ended September 30, 2006 compared to the same period in 2005.

Electricity Prices

Electricity generation from stations in the Regulated – Nuclear segment received a fixed price of 4.95¢/kWh since the introduction of rate regulation effective April 1, 2005. For the nine months ended September 30, 2005, OPG's Regulated – Nuclear sales price was 4.7¢/kWh, after taking into account the regulated rate for the second and third quarters of 2005 and spot market sales price, net of the Market Power Mitigation Agreement rebate for the first quarter of 2005.

Volume

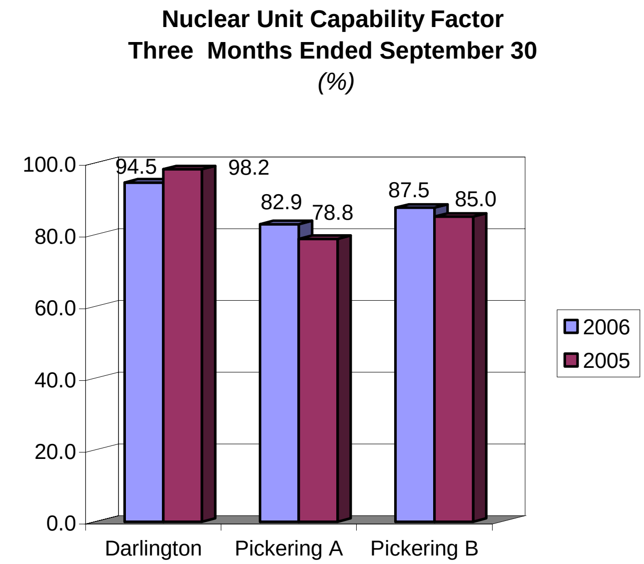
Electricity generation from stations in the Regulated – Nuclear segment for the three months ended September 30, 2006 was 12.9 TWh compared to 11.9 TWh for the same period in 2005. The increase in volume was mainly due to the return to service of Unit 1 at the Pickering A nuclear generating station.

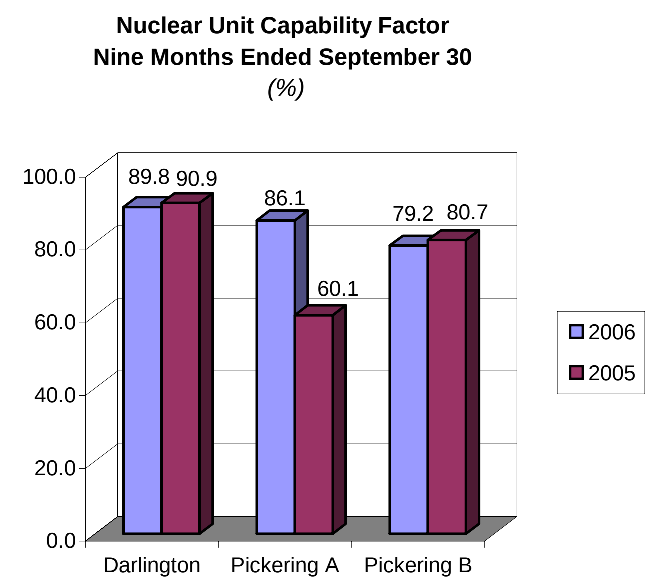
Total nuclear generation for the nine months ended September 30, 2006 increased to 36.8 TWh from 33.3 TWh for the same period in 2005. The increase in volume was mainly due to the Pickering A Unit 1 return to service. Also, in the second quarter of 2005, Unit 4 at the Pickering A nuclear generating station was shut down for the duration of the quarter due to the inspection and repair of feeder pipes. The nuclear generating stations continued to perform well during the third quarter and for the nine months ended September 30, 2006.

The Darlington nuclear generating station's unit capability factor for the three months ended September 30, 2006 was 94.5 per cent compared to 98.2 per cent for the same period in 2005. The decrease was as a result of additional unplanned outage days in the third quarter of 2006.

The Pickering A nuclear generating station's unit capability factor increased to 82.9 per cent for the three months ended September 30, 2006, from 78.8 per cent for the same period in 2005. The increase was due to strong performance of Unit 1, which was returned to service late in 2005, partly offset by forced deratings at Unit 4 in the 2006 period.

The Pickering B nuclear generating station's unit capability factor improved to 87.5 per cent for the three months ended September 30, 2006, compared with 85.0 per cent for the same period in 2005. The improvement resulted from lower planned outage days in the third quarter of 2006, partly offset by higher unplanned outages.





For the nine months ended September 30, 2006, the unit capability factor for the Darlington nuclear generating station was 89.8 per cent, compared to 90.9 per cent for the nine months ended September 30, 2005. The slight decrease was a result of higher unplanned outage days in 2006.

For the nine months ended September 30, 2006, the Pickering A nuclear generating station's unit capability factor was 86.1 per cent compared to 60.1 per cent for the nine months ended September 30, 2005. The increase was primarily due to the shutdown at Unit 4 during the second quarter of 2005 due to inspection and repair of feeder pipes.

For the nine months ended September 30, 2006, the Pickering B nuclear generating station's unit capability factor was 79.2 per cent compared to 80.7 per cent for the same period in 2005. The decrease was due to an increase in planned and unplanned outages.

Fuel Expense

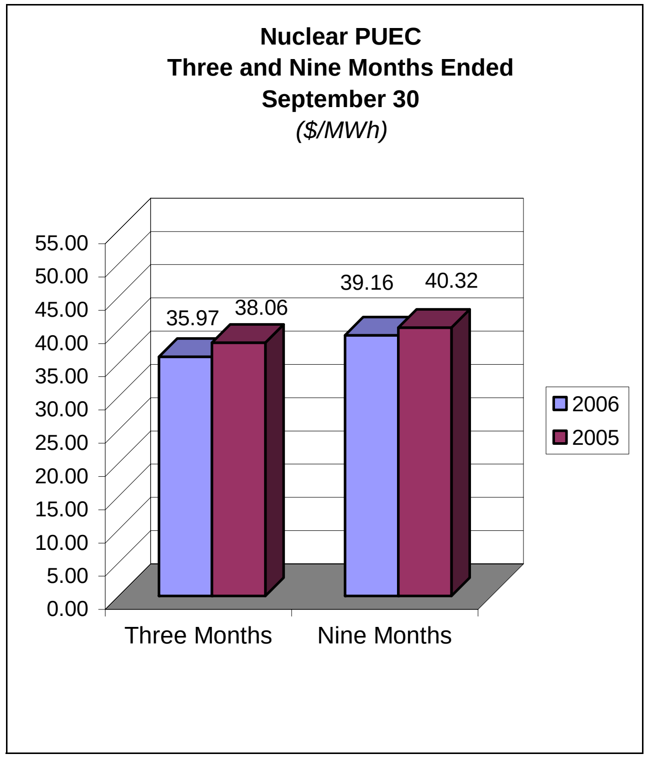
Fuel expense for the three months ended September 30, 2006 was $34 million compared to $31 million during the same period in 2005. Fuel expense for the nine months ended September 30, 2006 was $93 million compared to $85 million during the same period in 2005. The increase in fuel expense during the third quarter of 2006 and the nine months ended September 30, 2006 compared to the same periods in 2005 was primarily due to higher generation.

Operations, Maintenance and Administration

OM&A expenses for the three months ended September 30, 2006 were $446 million compared to $457 million during the same period in 2005. The decrease in OM&A expenses was primarily due to a reduction in expenditures for outages, projects, and other nuclear costs of $25 million during the third quarter of 2006, compared to the same period in 2005, and the impact of the write-off of excess inventory of $22 million in the third quarter of 2005 related to the decision not to proceed with the return to service of Units 2 and 3 at the Pickering A nuclear generating station. The impact of these factors was largely offset by an increase in pension and OPEB costs of $32 million, primarily due to changes in economic assumptions related to discount rates and inflation. In addition, OM&A expenses for the three months ended September 30, 2006, included amortization of $6 million related to Pickering A nuclear generating station return to service costs, which were previously deferred.

Effective January 1, 2005, in accordance with a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario), OPG established a balance sheet deferral account for non-capital costs associated with the return to service of Pickering A nuclear generating station units. The deferred costs are charged to operations in accordance with the terms of the regulation. Amortization of this deferral account commenced in the fourth quarter of 2005 following the return to commercial service of Unit 1 of the Pickering A nuclear generating station.

OM&A expenses were $1,399 million for the nine months ended September 30, 2006 compared to $1,324 million for the same period in 2005. The increase of $75 million was primarily due to the increase in pension and OPEB costs of $99 million and amortization of $21 million related to the Pickering A nuclear generating station return to service costs. The increase in OM&A expenses was partially offset by expenses incurred in 2005 pertaining to the write-off of excess inventory of $22 million, lower expenses for nuclear outages and projects, and other changes in OM&A expenses.



Nuclear PUEC for the three months ended September 30, 2006 was $35.97/MWh compared to $38.06/MWh during the same period in 2005. During the nine months ended September 30, 2006, nuclear PUEC was $39.16/MWh compared to $40.32/MWh. The decrease in 2006 was due to higher generation in 2006, partially offset by higher pension and OPEB costs, and other changes in OM&A expenses.

Depreciation and Amortization

Depreciation and amortization expense for the three months ended September 30, 2006 was $85 million compared to $88 million for the same period in 2005. Depreciation and amortization expense for the nine months ended September 30, 2006 was $254 million compared to $267 million for the same period last year. The decrease was primarily due to the impact of an extension of the remaining service lives of the Pickering B nuclear generating station and Unit 4 of the Pickering A nuclear generating station, for purposes of calculating depreciation. The reduction in depreciation related to the service life extension was partially offset by the impact of the return to commercial service of Unit 1 at the Pickering A station and fixed asset additions.

Accretion

Accretion expense relating to future costs for fixed asset removal and nuclear waste management was $123 million for the three months ended September 30, 2006 compared to $117 million during the third quarter of 2005. Accretion expense for the nine months ended September 30, 2006 was $368 million compared to $351 million for the same period last year. The increase in the accretion expense in 2006 was due to the higher liability base compared to last year primarily as a result of the increase in the present value of the liability due to the passage of time.

Earnings on the Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

For the three months ended September 30, 2006, OPG realized earnings of $82 million on the nuclear fixed asset removal and nuclear waste management funds, compared to $96 million during the third quarter of 2005. The decrease was primarily a result of lower earnings from the Decommissioning Fund and a lower Ontario Consumer Price Index during the third quarter of 2006 compared to the same period in 2005. The Ontario Consumer Price Index is used to determine the guaranteed rate of return in the Used Fuel Fund.

For the nine months ended September 30, 2006, OPG realized earnings of $274 million on the nuclear fixed asset removal and nuclear waste management funds, compared to $279 million during the same period of 2005. The decrease of $5 million during the nine months ended September 30, 2006 was due primarily to the impact of a lower Ontario Consumer Price Index on the Used Fuel Fund earnings when compared to the same period in 2005, and a decrease in earnings from the Decommissioning Fund. The lower earnings from the Decommissioning Fund are a result of the requirement to record an amount due to the Province, to recognize that the Fund became overfunded on a cost basis during the fourth quarter of 2005. These impacts on earnings for the nine months ended September 30, 2006 were partially offset by the effect of a higher asset base compared to the same period in 2005.

Property and Capital Taxes

Property and capital taxes for the three months ended September 30, 2006 were $15 million compared to nil during the same period in 2005. Property and capital taxes for the nine months ended September 30, 2006 were $34 million compared to $21 million during the same period last year. During the three months ended September 30, 2005, OPG received a favourable settlement from a municipal tax appeal.

Impairment of Long-Lived Assets

During the second quarter of 2005, OPG completed an assessment of the scope of the refurbishment work, the cost and the risks related to the return to service of Units 2 and 3 at the Pickering A nuclear generating station. OPG's Board of Directors decided that, while technically feasible, the return to service of these units was not justified on a commercial basis. As a result, the Company recorded an impairment loss of $63 million related to the carrying amount of these two units, including construction in progress.

Regulated – Hydroelectric Segment

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Revenue, net of Market Power Mitigation Agreement rebate	**175**	202	**514**	609
Fuel expense	**62**	64	**174**	186
Gross margin	**113**	138	**340**	423
Operations, maintenance and administration	**26**	20	**70**	56
Depreciation and amortization	**16**	17	**49**	51
Property and capital taxes	**6**	5	**14**	14
Income before interest and income taxes	**65**	96	**207**	302

Revenue

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Regulated generation sales[1]	**165**	187	**469**	382
Spot market sales, net of hedging instruments	**-**	-	**-**	260
Market Power Mitigation Agreement rebate	**-**	-	**-**	(65)
Variance accounts	**5**	4	**1**	-
Other	**5**	11	**44**	32
Total revenue	**175**	202	**514**	609

1 Regulated generation sales included revenue of $54 million and $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 2006 and 2005, respectively. Regulated generation sales included revenue of $123 million that OPG received at the Ontario spot market price for generation over 1,900 MWh in any hour during the nine months ended September 30, 2006. For the six month period from April 1, 2005 to September 30, 2005, OPG received $145 million in revenue for generation over 1,900 MWh in any hour.

Regulated - Hydroelectric revenue was $175 million for the three months ended September 30, 2006 compared to $202 million during the same period in 2005. The decrease of $27 million was primarily due to a significantly lower spot market price for generation in excess of 1,900 MWh in any hour.

Regulated - Hydroelectric revenue was $514 million for the nine months ended September 30, 2006 compared to $609 million during the same period in 2005. The decrease of $95 million was mainly due to lower sales prices related to the introduction of regulated prices effective April 1, 2005, lower spot market prices during the second and third quarters of 2006 that impacted revenues in excess of 1,900 MWh in any hour, and lower electricity generation.

Electricity Prices

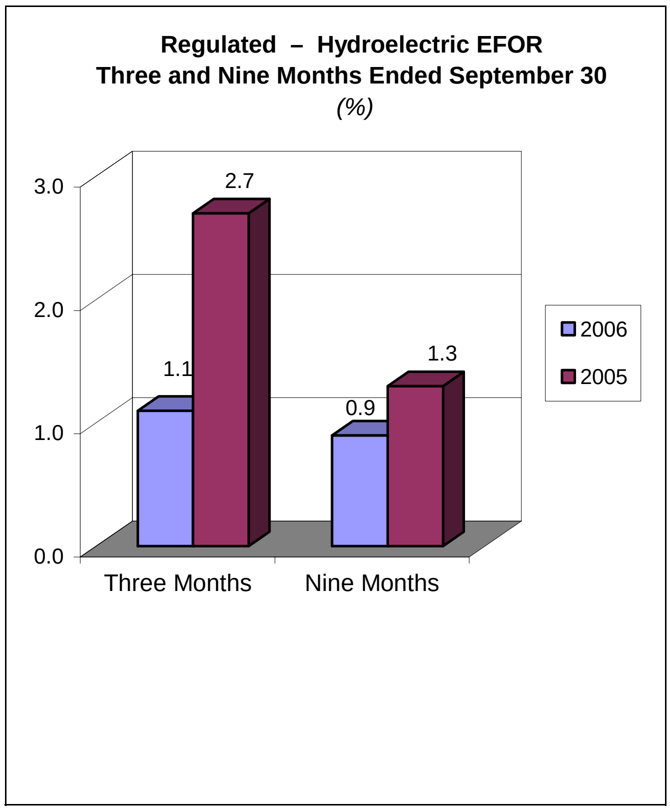
During the three months ended September 30, 2006, the average electricity sales price for the Regulated – Hydroelectric segment was 3.6¢/kWh compared to 4.2¢/kWh during the same period in 2005. The average sales price is based on the fixed price of 3.3¢/kWh for generation up to 1,900 MWh in any hour, and the spot electricity market price for generation above this level.

The average price for the nine months ended September 30, 2006 was 3.5¢/kWh compared to 4.1¢/kWh for the nine months ended September 30, 2005. The average price in 2005 reflects the regulated price for the second and third quarters and OPG's average spot market sales price net of the Market Power Mitigation Agreement rebate for the first quarter.

Volume

Electricity sales volume for the third quarter of 2006 was 4.6 TWh compared to 4.4 TWh for the third quarter of 2005. Electricity generation of 0.9 TWh and 0.8 TWh during the third quarter of 2006 and 2005 respectively, related to production levels above 1,900 MWh in any hour. The increase in electricity sales volume in the third quarter of 2006 was primarily due to higher water levels.

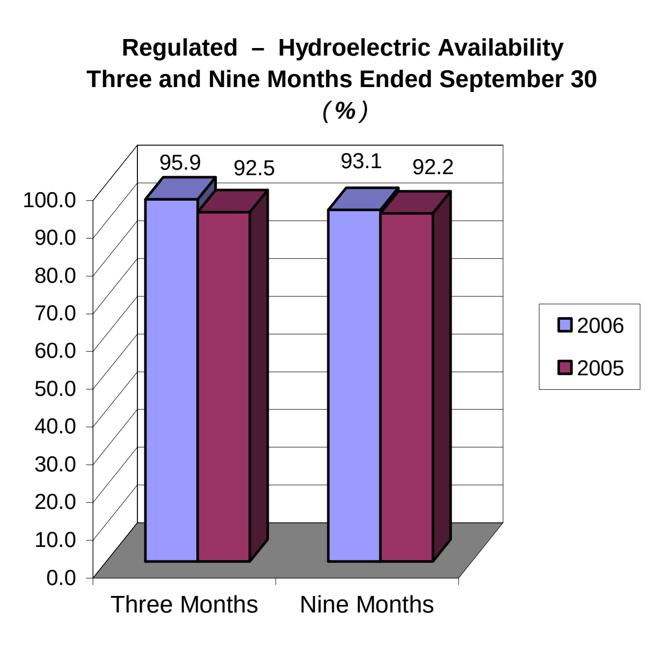
Electricity sales volume for the nine months ended September 30, 2006 was 13.5 TWh compared to 14.0 TWh during the same period in 2005. During the nine months ended September 30, 2006, electricity generation of 2.5 TWh related to production levels above 1,900 MWh in any hour. For 2005, electricity generation of 1.9 TWh related to production levels above 1,900 MWh in any hour during the period from April 1, 2005 to September 30, 2005. The decrease in electricity sales in the nine months ended September 30, 2006 was primarily due to the lower water levels in the Niagara and St. Lawrence rivers during the first and second quarters of 2006.



The equivalent forced outage rate for the Regulated – Hydroelectric stations was 1.1 per cent for the three months ended September 30, 2006 compared to 2.7 per cent during the same period in 2005. The decrease in EFOR was due to a number of forced outages and certain equipment repairs during the three months ended September 30, 2005. During the nine months ended September 30, 2006, the equivalent forced outage rate for the Regulated – Hydroelectric stations was 0.9 per cent compared to 1.3 per cent during the same period in 2005. The low EFOR reflects the continuing high reliability of these generating stations.

The availability for the Regulated – Hydroelectric stations was 95.9 per cent for the three months ended September 30, 2006 compared to 92.5 per cent in the third quarter of 2005. The increase in availability reflects lower planned outage days at the Niagara hydroelectric stations in the third quarter of 2006 compared to the third quarter of 2005.

During the nine months ended September 30, 2006, availability for the Regulated – Hydroelectric stations was 93.1 per cent compared to 92.2 per cent during the same period in 2005.



Variance Accounts

OPG is required under a regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario), to establish variance accounts for the Regulated – Hydroelectric segment to capture the impact of differences in hydroelectric electricity production due to differences between forecast and actual water conditions and differences between forecast and actual ancillary revenues. During the three months ended September 30, 2006, OPG recorded revenue of $4 million, as a result of lower ancillary revenue compared to those forecasted. During the three months ended September 30, 2006, OPG recorded revenue of $1 million, as a result of lower actual water conditions compared to those forecasted.

During the nine months ended September 30, 2006, OPG recorded a reduction in revenue of $7 million, as a result of higher ancillary revenue compared to those forecasted. During the nine months ended September 30, 2006, OPG recorded revenue of $8 million, as a result of lower actual water conditions compared to those forecasted.

Fuel Expense

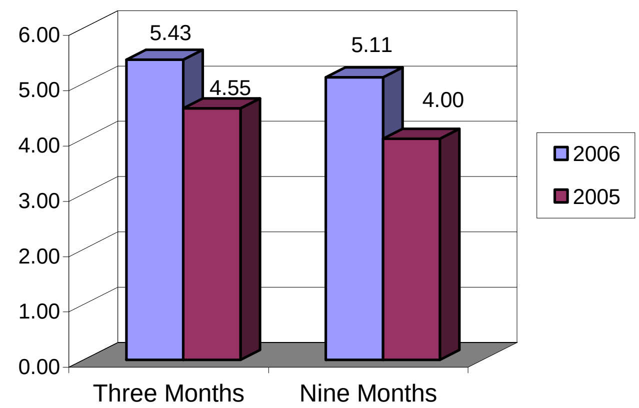
OPG pays charges to the Province and the OEFC on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue charge ("GRC") includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on 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 three months ended September 30, 2006 was $62 million compared to $64 million during the third quarter of 2005. The decrease in fuel expense during the third quarter of 2006 compared to the same period in 2005 was partly due to lower marginal GRC rates as a result of lower year-to-date generation from rate regulated hydroelectric stations. Fuel expense for the nine months ended September 30, 2006 was $174 million compared to $186 million for the nine months ended September 30, 2005. The decrease in fuel expense for the nine months ended September 30, 2006 compared to the same period last year was due primarily to lower generation volumes.

Operations, Maintenance and Administration

OM&A expenses for the three months ended September 30, 2006 were $26 million compared to $20 million during the third quarter of 2005. OM&A expenses for the nine months ended September 30, 2006 were $70 million compared to $56 million during the same period in 2005. The increase in OM&A expenses in 2006 was mainly due to higher pension and OPEB costs.

OM&A expense per MWh for the regulated hydroelectric stations increased to $5.43/MWh in the third quarter of 2006 compared to $4.55/MWh for the same period in 2005. During the nine months ended September 30, 2006, OM&A expense per MWh for the regulated hydroelectric stations was $5.11/MWh compared to $4.00/MWh in the same period in 2005. The increase in 2006 compared to 2005 mainly reflected higher OM&A expenses combined with lower generation for the nine months ended September 30, 2006.

Regulated – Hydroelectric
OM&A per MWh
Three and Nine Months Ended September 30
($/MWh)



Depreciation and Amortization

Depreciation expense for the three months ended September 30, 2006 was $16 million compared to $17 million in the same period in 2005. Depreciation expense for the nine months ended September 30, 2006 was $49 million compared to $51 million during the same period last year.

Unregulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Revenue, net of revenue limit and Market Power Mitigation Agreement rebates	**117**	118	**545**	519
Fuel expense	**15**	12	**60**	54
Gross margin	**102**	106	**485**	465
Operations, maintenance and administration	**47**	37	**128**	101
Depreciation and amortization	**17**	14	**49**	47
Property and capital taxes	**4**	4	**11**	11
Income before interest and income taxes	**34**	51	**297**	306

Revenue

(millions of dollars)	Three Months Ended September 30 2006	Three Months Ended September 30 2005	Nine Months Ended September 30 2006	Nine Months Ended September 30 2005
Spot market sales, net of hedging instruments	**121**	181	**561**	672
Revenue limit rebate	**(16)**	(71)	**(42)**	(122)
Market Power Mitigation Agreement rebate	**-**	-	**-**	(58)
Other	**12**	8	**26**	27
Total revenue	**117**	118	**545**	519

Unregulated - Hydroelectric revenue was $117 million for the three months ended September 30, 2006 compared to $118 million for the same period in 2005.

Unregulated - Hydroelectric revenue was $545 million for the nine months ended September 30, 2006 compared to $519 million for the same period in 2005. The increase of $26 million was due to higher electricity generation of 0.8 TWh, partly offset by the impact of lower Ontario spot market prices during the third quarter of 2006 compared to the same period in 2005.

Electricity Prices

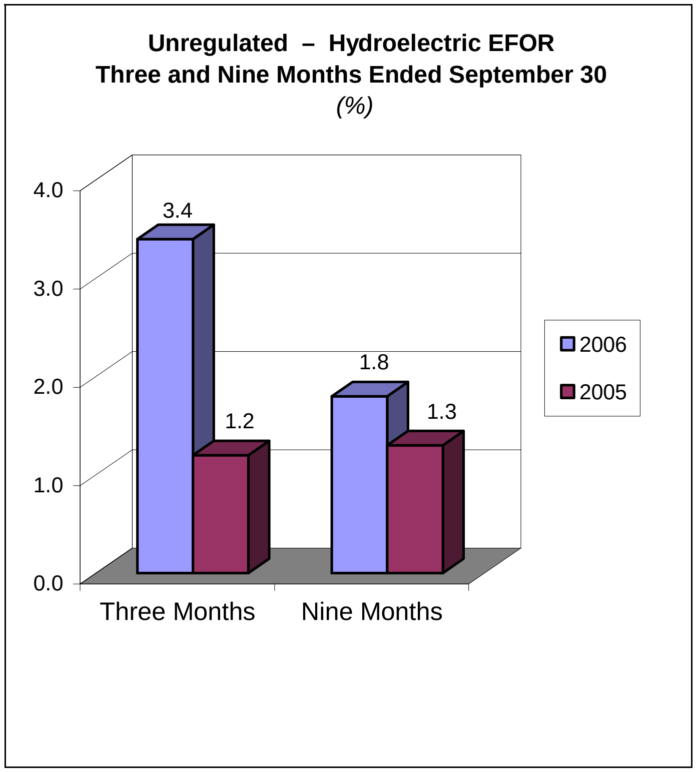
Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, TRO volumes and forward sales as of January 1, 2005, was subject to the revenue limit based on an average price of 4.7¢/kWh commencing April 1, 2005. Effective May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh.

OPG's average sales price for its unregulated hydroelectric generation for the three months ended September 30, 2006 was 4.6¢/kWh compared to 6.0¢/kWh for the same period in 2005, after taking into account the revenue limit rebate. The decrease in OPG's average sales price was due primarily to lower average Ontario spot market prices.

OPG's average sales price for its unregulated hydroelectric generation for the nine months ended September 30, 2006 was 4.7¢/kWh compared to 5.0¢/kWh in 2005. The decrease was primarily due to lower average Ontario spot market prices, partly offset by the favourable impact of the replacement of the Market Power Mitigation Agreement rebate with the revenue limit rebate effective April 1, 2005.

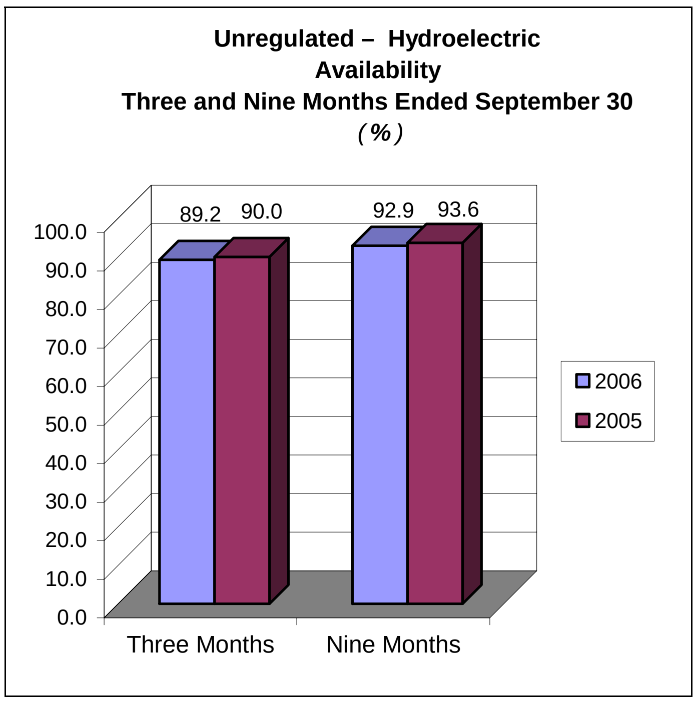
Volume

Electricity sales volume for the three months ended September 30, 2006 was 2.2 TWh compared to 2.0 TWh during the same period in 2005. For the nine months ended September 30, 2006, electricity sales volume was 11.0 TWh compared to 10.2 TWh in 2005. The increase in volume in 2006 was primarily due to higher water levels during 2006 compared to the same period in 2005.



The equivalent forced outage rate for the Unregulated – Hydroelectric stations was 3.4 per cent for the three months ended September 30, 2006 compared to 1.2 per cent during the third quarter of 2005. The increase in EFOR was due to certain equipment repairs and the forced extension of planned outages during the three months ended September 30, 2006 compared to the same period in 2005.

The equivalent forced outage rate for the Unregulated – Hydroelectric stations was 1.8 per cent for the nine months ended September 30, 2006 compared to 1.3 per cent during the same period in 2005.



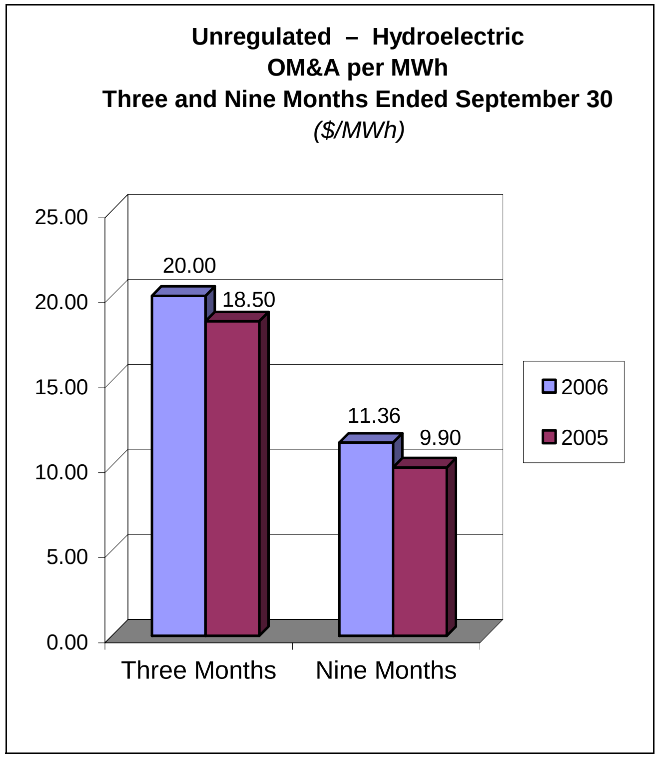
The availability for the Unregulated – Hydroelectric stations was 89.2 per cent for the three months ended September 30, 2006 compared to 90.0 per cent in the third quarter of 2005. The availability for the Unregulated – Hydroelectric stations was 92.9 per cent for the nine months ended September 30, 2006 compared to 93.6 per cent for the same period in 2005. The availability and the equivalent forced outage rate during 2006 continue to reflect the strong performance of the unregulated hydroelectric generating assets.

Fuel Expense

Fuel expense was $15 million for the three months ended September 30, 2006 compared to $12 million for the same period in 2005. Fuel expense was $60 million for the nine months ended September 30, 2006 compared to $54 million for the same period last year. The increase in fuel expense was due to higher electricity generation. Generating stations within this segment are subject to the gross revenue charge.

Operations, Maintenance and Administration

OM&A expenses for the three months ended September 30, 2006 were $47 million compared to $37 million for the same period in 2005. OM&A expenses for the nine months ended September 30, 2006 were $128 million compared to $101 million in same period in 2005. The increase in OM&A expense in 2006 was primarily due to higher expenses for plant improvement projects and pension and OPEB costs.



OM&A expense per MWh for the unregulated hydroelectric stations was $20.00/MWh in the third quarter of 2006 compared to $18.50/MWh for the same period in 2005. During the nine months ended September 30, 2006, OM&A expense per MWh for the unregulated hydroelectric stations was $11.36/MWh compared to $9.90/MWh during the same period in 2005. The increases for the three and nine month periods ended September 30, 2006, compared to the same periods last year, reflect higher OM&A expenses, partially offset by higher generation.

Depreciation and Amortization

Depreciation expense for the three months ended September 30, 2006 was $17 million compared to $14 million in the same period in 2005. Depreciation expense for the nine months ended September 30, 2006 was $49 million compared to $47 million in 2005.

Unregulated – Fossil-Fuelled Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Revenue, net of revenue limit and Market Power Mitigation Agreement rebates	**379**	588	**1,044**	1,344
Fuel expense	**199**	277	**504**	658
Gross margin	**180**	311	**540**	686
Operations, maintenance and administration	**115**	107	**375**	326
Depreciation and amortization	**17**	47	**113**	158
Accretion on fixed asset removal	**2**	2	**7**	7
Property and capital taxes	**7**	6	**15**	15
Restructuring	**-**	4	**-**	4
(Loss) income before impairment of long-lived assets	**39**	145	**30**	176
Impairment of long-lived assets	**-**	-	**-**	202
(Loss) income before interest and income taxes	**39**	145	**30**	(26)

Revenue

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Spot market sales, net of hedging instruments	**398**	810	**1,055**	1,742
Revenue limit rebate	**(43)**	(265)	**(106)**	(355)
Market Power Mitigation Agreement rebate	**-**	-	**-**	(129)
Other	**24**	43	**95**	86
Total revenue	**379**	588	**1,044**	1,344

Unregulated – Fossil-Fuelled revenue was $379 million for the three months ended September 30, 2006 compared to $588 million for the same period in 2005. The decrease in revenue of $209 million was primarily due to lower electricity generation of 1.5 TWh and lower average sales prices. In addition, during the three months ended September 30, 2005, OPG received congestion management settlement revenue of $35 million. Congestion management settlement revenue is provided when Ontario electricity generation is available but transmission lines are congested due to higher Ontario electricity demand. This other revenue was caused by congestion in transmitting electricity from northwest to southern Ontario during the prolonged period of high demand for electricity in Ontario from June to September, 2005. OPG did not receive such revenue during the three months ended September 30, 2006.

Unregulated – Fossil-Fuelled revenue was $1,044 million for the nine months ended September 30, 2006 compared to $1,344 million for the same period in 2005. The decrease in revenue of $300 million in 2006 was primarily due to lower electricity generation of 4.3 TWh, lower average sales prices, and the reduction in revenue related to congestion management. This impact was partially offset by revenue from the Lennox reliability must-run ("RMR") contract and a higher margin on hedging instruments. The RMR contract, which commenced effective October 1, 2005, is a cost-based contract with the IESO that provides for regular payments, which are subject to adjustments for actual costs.

Electricity Prices

OPG's average sales price for its unregulated fossil-fuelled generation for the three months ended September 30, 2006 was 4.8¢/kWh compared to 6.6¢/kWh for the same period in 2005, after taking into account the revenue limit rebate. The decrease in OPG's average sales price was due primarily to lower average Ontario spot market prices.

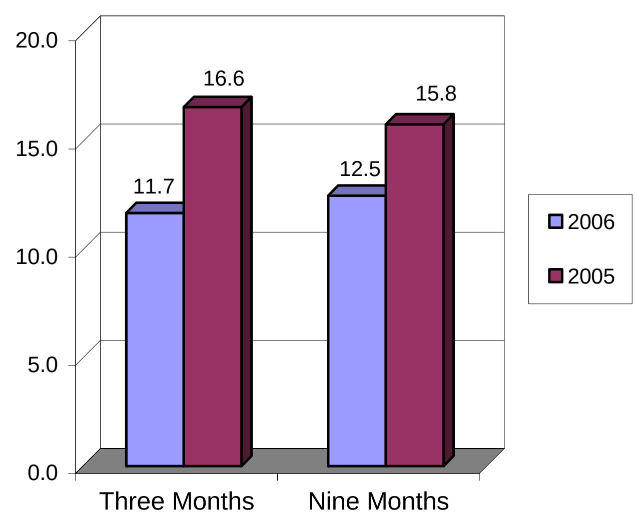
OPG's average sales price for its unregulated fossil-fuelled generation for the nine months ended September 30, 2006 was 4.8¢/kWh compared to 5.5¢/kWh in 2005. The decrease was primarily due to lower average Ontario spot market prices in 2006, partially offset by the favourable impact of the replacement of the Market Power Mitigation Agreement rebate with the revenue limit rebate effective April 1, 2005.

Volume

Electricity sales volume for the three months ended September 30, 2006 was 7.3 TWh compared to 8.8 TWh for the same period in 2005. Electricity sales volume for the nine months ended September 30, 2006 was 19.6 TWh compared to 23.9 TWh in 2005. The decrease in volume in 2006 was primarily due to lower electricity demand as a result of warmer winter weather in 2006 compared to 2005, and due to very high temperatures in the summer of 2005 which did not reoccur in 2006. In addition, higher electricity generation from nuclear generating stations also contributed to the decrease in electricity sales volume for the Unregulated Fossil-Fuelled segment in 2006.

The equivalent forced outage rate for the fossil-fuelled generating stations was 11.7 per cent during the third quarter of 2006 compared to 16.6 per cent for the same period last year. During the nine months ended September 30, 2006, the equivalent forced outage rate for the fossil-fuelled generating stations was 12.5 per cent compared to 15.8 per cent for the same period last year. EFOR improved in 2006 primarily due to improved equipment reliability of the Nanticoke fossil-fuelled generating station and the impact of closing the Lakeview generating station in April 2005.

Unregulated – Fossil-Fuelled EFOR
Three and Nine Months Ended September 30
(%)

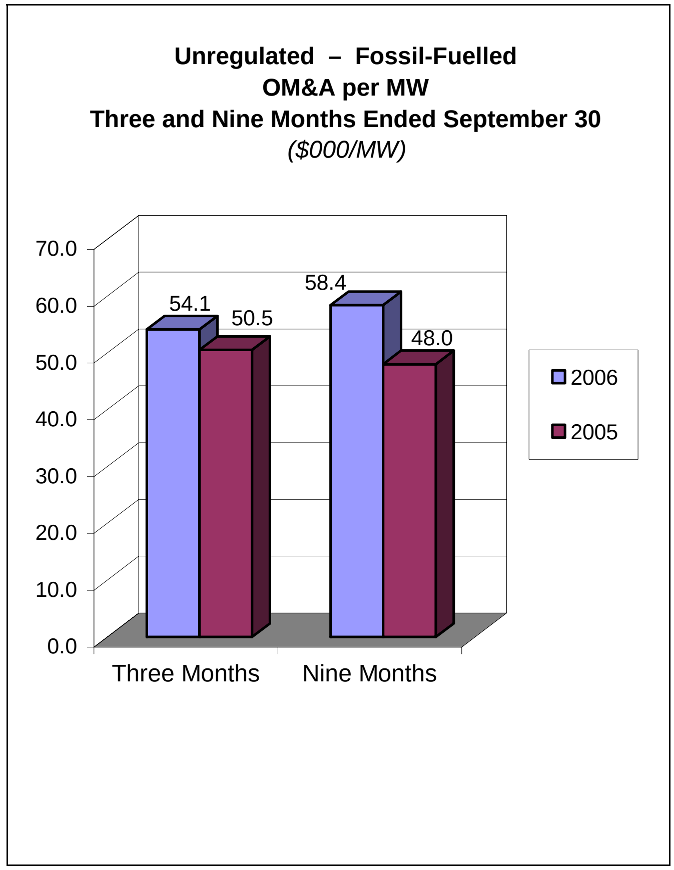


Fuel Expense

Fuel expense was $199 million for the three months ended September 30, 2006 compared to $277 million for the same period in 2005. For the nine months ended September 30, 2006, fuel expense was $504 million compared to $658 million for the same period last year. The decrease in fuel expense in 2006 was primarily due to reduced electricity generation.

Operations, Maintenance and Administration

OM&A expenses for the three months ended September 30, 2006 were $115 million compared to $107 million for the same period in 2005. For the nine months ended September 30, 2006, OM&A expenses were $375 million compared to $326 million in the 2005 period. OM&A expenses increased in 2006 mainly due to higher pension and OPEB costs, the write-off of unrecoverable costs related to the Thunder Bay generating station gas conversion project, and higher expenditures on maintenance.



OM&A expense per MW ($/MW) for the unregulated fossil-fuelled stations increased to $54,100/MW for the three months ended September 30, 2006 compared to $50,500/MW for the third quarter of 2005. During the nine months ended September 30, 2006, OM&A expenses per MW for the unregulated fossil-fuelled stations increased to $58,400/MW compared to $48,000/MW in the same period in 2005. The increase during 2006 reflected higher OM&A expenses primarily due to higher pension and OPEB costs, the unrecoverable costs related to the Thunder Bay generating station gas conversion project, and the impact of lower generation capacity due to the closure of the Lakeview generating station in April 2005.

Depreciation and Amortization

Depreciation expense for the three months ended September 30, 2006 was $17 million, compared to $47 million for the same period in 2005. For the nine months ended September 30, 2006, depreciation expense was $113 million compared to $158 million during the same period last year. The decrease in depreciation expense in 2006 was mainly due to the extension of the service life of all coal-fired generating stations, for purposes of calculating depreciation, due to the delay in the Province's coal replacement program. Furthermore, depreciation expense decreased due to a lower asset base, which resulted from the impairment charge on the Lennox generating station, which was recorded in 2005.

In the third quarter of 2005, OPG had extended, for purposes of calculating depreciation, the remaining service life of the Nanticoke generating station by one year, from 2007 to 2008, based on further details provided by the Province with respect to its coal replacement program at that time. The estimated service life for all of the coal-fired generating stations as at September 30, 2005, for purposes of calculating depreciation, was December 31, 2007, with the exception of the Nanticoke generating station. As a result of an announcement in June 2006 of delays in the plan to replace coal-fired generation, OPG extended, effective July 1, 2006, the service life for all of the coal-fired generating stations, for the purpose of calculating depreciation, to December 31, 2012. OPG will continue to assess the service life of the coal-fired stations upon release of the Ontario Integrated Power System Plan ("IPSP"), and the subsequent approval by the OEB, and other available information.

Other

(millions of dollars)	Three Months Ended September 30 2006	Three Months Ended September 30 2005	Nine Months Ended September 30 2006	Nine Months Ended September 30 2005
Revenue	**42**	1	**118**	48
Operations, maintenance and administration	**-**	6	**(5)**	23
Depreciation and amortization	**13**	15	**39**	43
Property and capital taxes	**3**	11	**8**	3
Restructuring	**-**	2	**-**	2
Income (loss) before interest and income taxes	**26**	(33)	**76**	(23)

Other revenue was $42 million for the three months ended September 30, 2006 compared to $1 million for the same period in 2005. For the nine months ended September 30, 2006, other revenue was $118 million compared to $48 million for the nine months ended September 30, 2005. The increase for both the three and nine months ended September 30, 2006 was primarily due to an increase in mark-to-market gains on interconnected sales contracts and higher margins on interconnected sales.

OM&A expenses of the generation business segments include a service fee for the use of certain property, plant and equipment of the Other category. The total service fee allocation is recorded as a reduction to the Other category's OM&A expenses. For the three months ended September 30, 2006, the service fee allocation was $7 million for Regulated – Nuclear, $1 million for Regulated – Hydroelectric, $1 million for Unregulated – Hydroelectric and $2 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $11 million for the Other category. For the nine months ended September 30, 2006, the service fee was $19 million for Regulated – Nuclear, $2 million for Regulated – Hydroelectric, $3 million for Unregulated – Hydroelectric and $6 million for Unregulated – Fossil-Fuelled, with a reduction in expenses of $30 million for the Other category. Results of the comparative periods have been reclassified to reflect the service fee. The decrease in OM&A expenses for the nine months ended September 30, 2006 as compared to the same period of 2005 was partly due to reduced activity in the Energy Markets business and an increase in the service fee allocation to other business units.

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, 2006 would have increased by $38 million (three months September 30, 2005 – $64 million), and $127 million for the nine months ended September 30, 2006 (nine months ended September 30, 2005 – $164 million), with no impact on net income.

The carrying amounts and notional quantities of derivative instruments not designated for hedging purposes are disclosed in Note 11 in the unaudited interim consolidated financial statements as at and for the three and nine months ended September 30, 2006.

Income Tax

OPG follows the liability method of tax accounting for its unregulated operations. Under the liability method, future tax assets and liabilities are determined based on differences between the accounting and tax bases 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. Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes relating to the rate regulated segments of its business to the extent those future income taxes are expected to be recovered in the regulated rates charged to future customers.

Income tax expense for the three and nine months ended September 30, 2006 reflected the impact of accounting for income taxes for the regulated segments of the business using the taxes payable method for the entire periods. Income tax expense for the nine months ended September 30, 2005 reflected the impact of the taxes payable method for six months, as this method was adopted upon inception of the rate regulation on April 1, 2005.

Income tax expense for the three months ended September 30, 2006 was $51 million compared to $94 million in the same period last year. 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. The decrease in income tax expense was also due to lower earnings and the elimination of Large Corporations Tax. During the three months ended September 30, 2006 and 2005, the income tax expense was lower than what would otherwise have been recorded had OPG accounted for income tax for the regulated segment using the liability method by $24 million and $57 million, respectively.

For the nine months ended September 30, 2006, income tax expense was $149 million compared to $86 million for the nine months ended September 30, 2005. The increase in the income tax expense was primarily due to higher taxable income in the nine months ended September 30, 2006. The increase was partially offset by the elimination of the Large Corporations Tax and the reduction in the future income tax rates enacted from the Federal Budget of 2006. In addition, during the third quarter of 2005, OPG recorded the income tax charge of $50 million to provide for a change in income tax liabilities. For the nine months ended September 30, 2006 and 2005, the tax expense was lower than what would otherwise have been recorded had OPG accounted for income tax for the regulated segment using the liability method by $42 million and $110 million, respectively.

During the second quarter of 2005, as a result of the adoption of the taxes payable method for the rate regulated segments on April 1, 2005, OPG eliminated the net future income tax asset balance of $74 million related to the rate regulated segments and recognized the amount as a one-time extraordinary loss in determining net income.

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* (Ontario) and tax related regulations are relatively new and it has therefore been necessary for OPG, since its inception, to take certain filing positions in calculating the amount of its income tax provision. Certain filing positions may be challenged on audit and some of them possibly disallowed, resulting in a potential significant increase in OPG's tax provision upon reassessment.

OPG has recently received a preliminary communication from the Provincial Tax Auditors with respect to their initial findings from their audit of OPG's 1999 taxation year. OPG is in the process of meeting with the Provincial Tax Auditors to obtain further clarification. There is uncertainty as to how these matters will be resolved.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, and credit facilities provided by OPG's shareholder. These resources are required for continued investment in plant and technologies, and to meet other significant funding obligations including contributions to the pension fund, the Used Fuel Fund and Decommissioning Segregated Fund ("Decommissioning Fund") (the "Nuclear Funds"), and to service and repay long-term debt and revenue limit rebate obligations.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Cash and cash equivalents, beginning of the period	**360**	411	**908**	2
Cash flow provided by operating activities	**307**	382	**306**	755
Cash flow (used in) investing activities	**(191)**	(243)	**(435)**	(674)
Cash flow (used in) provided by financing activities	**(301)**	(1)	**(604)**	466
Net (decrease) increase	**(185)**	138	**(733)**	547
Cash and cash equivalents, end of the period	**175**	549	**175**	549

Operating Activities

Cash flow provided by operating activities for the three months ended September 30, 2006 was $307 million compared to $382 million during the same period in 2005. The decrease in cash flow from operating activities was due mainly to lower revenue before the revenue limit rebate due to the decrease in the Ontario spot electricity market prices, partially offset by the lower payment to the IESO with respect to the revenue limit rebate during the third quarter of 2006, compared to the amount of the final payment of the Market Power Mitigation Agreement rebate during the same quarter in 2005.

Cash flow provided by operating activities for the nine months ended September 30, 2006 was $306 million compared to $755 million during the nine months ended September 30, 2005. The decrease in cash flow from operating activities was primarily due to lower revenue before rebates as a result of lower Ontario spot electricity market prices, partially offset by lower expenditures on fuel, higher trading revenues and lower revenue limit rebate payments during the nine months ended September 30, 2006 compared to the amount of the Market Power Mitigation Agreement rebate payments made in 2005.

During the nine months ended September 30, 2006, OPG made revenue limit rebate payments of $802 million, compared to a payment of $851 million for Market Power Mitigation Agreement rebate payments during the nine months ended September 30, 2005.

OPG made contributions of $65 million to the pension plan during the three months ended September 30, 2006 compared to $84 million during the same period in 2005. For the nine months ended September 30, 2006, OPG made contributions of $195 million compared to $162 million during the same period last year. Pension contributions were increased in the last half of 2005 to reflect the higher funding requirements based on the January 1, 2005 actuarial valuation.

As required under the ONFA between the Province and OPG, OPG made contributions to the nuclear fixed asset removal and nuclear waste management funds of $113 million during the three months ended September 30, 2006 and 2005. For the nine months ended September 30, 2006 and 2005, OPG made contributions of $340 million.

Investing Activities

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, invest in new generating stations and to maintain and improve service, reliability, safety and environmental performance.

Capital expenditures during the three months ended September 30, 2006 were $188 million compared with $114 million during the same period in 2005. The increase in capital expenditures of $74 million was primarily due to OPG's increased investment in the Niagara Tunnel project and Portlands Energy Centre during the three months ended September 30, 2006 compared to the same period in 2005.

For the nine months ended September 30, 2006, capital expenditures were $422 million compared with $353 million for the nine months ended September 30, 2005. The increase in capital expenditures of $69 million was primarily due to OPG's increased investment in the Niagara Tunnel project, Portlands Energy Centre, the Lac Seul project and the Pickering B nuclear generating station auxiliary power system. The impact of these expenditures was largely offset by a lower investment at the Pickering A Unit 1 nuclear generating station during the nine months ended September 30, 2006 compared to the same period in 2005, with the return to service of Unit 1 in November 2005.

OPG's anticipated capital expenditures for 2006 are approximately $690 million, which include amounts for the Niagara Tunnel project, Portlands Energy Centre, and the Lac Seul project.

Included in the investing activity is OPG's investment in deferred regulatory assets of $1 million in the third quarter of 2006 compared to $60 million during the same period in 2005. For the nine months ended September 30, 2006, OPG's investment in deferred regulatory assets was $13 million compared to $251 million in the same period in 2005. The lower investment in deferred regulatory assets during 2006 was primarily due to the return to service of Unit 1 at the Pickering A nuclear generating station in 2005.

Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility which is divided into two tranches – a $500 million 364-day term tranche maturing May 22, 2007 and a $500 million three-year term tranche maturing May 22, 2009. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. OPG has not been required to borrow under its commercial paper program since April 2005. As at September 30, 2006, OPG had no other outstanding borrowing under its bank credit facility.

OPG also maintains $26 million (December 31, 2005 – $26 million) in short-term uncommitted overdraft facilities as well as $240 million (December 31, 2005 – $215 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 Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the OEB's Retail Settlement Code. At September 30, 2006, there were a total of $175 million (December 31, 2005 – $157 million) of Letters of Credit issued, which includes $159 million for the supplementary pension plans and $14 million related to the construction of the Portlands Energy Centre.

To finance the Niagara Tunnel project, OPG negotiated an agreement with the OEFC to finance the project for up to $1 billion over the duration of the project. The funding will be advanced in the form of 10-year notes, on commercial terms and conditions. Advances under this facility are expected to commence in the fourth quarter of 2006. Similarly, financing has been negotiated for OPG's interest in the Portlands Energy Centre and Lac Seul projects for up to $400 million and $50 million, respectively. Advances under these facilities are also expected to commence in the fourth quarter of 2006, pending final approval by the OEFC.

During September 2006, OPG's Board of Directors approved the payment of a dividend to its shareholder, the Province. The declared dividend of $128 million represents 35 per cent of OPG's 2005 net income and will be paid in November 2006.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

Selected balance sheet data	**As at**	
(millions of dollars)	**September 30 2006**	**December 31 2005**
Assets		
Accounts receivable	**252**	538
Property, plant and equipment – net	**11,333**	11,412
Nuclear fixed asset removal and nuclear waste management funds	**7,388**	6,788
Regulatory assets	**257**	266
Liabilities		
Accounts payable and accrued charges	**769**	958
Dividend payable	**128**	-
Revenue limit rebate payable	**85**	739
Fixed asset removal and nuclear waste management	**9,049**	8,759
Other post employment benefits and supplementary pension plans (long-term portion)	**1,357**	1,212

Accounts Receivable

As at September 30, 2006, accounts receivable were $252 million compared to $538 million as at December 31, 2005. The decrease of $286 million was primarily due to lower sales to the spot market**.**

Property, Plant and Equipment – Net

Net property, plant and equipment as at September 30, 2006 was $11,333 million compared to $11,412 million as at December 31, 2005. The decrease of $79 million was primarily due to depreciation expense, partially offset by OPG's investment in fixed assets.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

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

In order to fund these liabilities, OPG established and manages, jointly with the Province, a Used Fuel Fund and a Decommissioning Fund, which are funded by OPG in accordance with the ONFA. The Used Fuel Fund is intended to fund future expenditures associated with the disposal of highly radioactive used nuclear fuel bundles. The Decommissioning Fund was established to fund future expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. 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 at their amortized cost. 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 investments in the Nuclear Funds, which OPG has not recognized in its consolidated financial statements. The Nuclear Funds are referred to as the nuclear fixed asset removal and nuclear waste management funds in OPG's consolidated financial statements.

As at September 30, 2006, the Nuclear Funds on an amortized cost basis were $7,388 million compared to $6,788 million as at December 31, 2005. The increase of $600 million was due to contributions of $340 million, income earned of $274 million on the asset base, partially offset by payments of eligible program expenditures of $14 million.

Under the 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, 2006, the Used Fuel Fund included an amount due to the Province of $46 million (December 31, 2005 – $4 million). If the investments in the Used Fuel Fund were accounted for at fair market value in the unaudited interim consolidated financial statements at September 30, 2006, there would be an amount due to the Province of $387 million (December 31, 2005 – $306 million). In addition, under the 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 the 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, 2006, 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 on an amortized cost basis. When the Decommissioning Fund is overfunded on an amortized cost basis, OPG will limit the earnings it recognizes in its consolidated financial statements, through a charge to the Decommissioning Fund with a corresponding payable to the Province, such that the amortized cost balance of the Decommissioning 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 Decommissioning Fund balance declines below the then currently approved cost estimate.

At September 30, 2006, the Decommissioning Fund asset value on an amortized cost basis was $4,290 million compared to a market value of $4,804 million, the difference representing net unrealized gains of $514 million. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the then current 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 to be treated as a contribution to the Used Fuel Fund, and the OEFC is entitled to the remaining 50 per cent of such surplus. Any overfunding of the liability is payable to the Province on termination of the Decommissioning Fund. Therefore, the accounting for this overfunded position requires an adjustment to the amortized cost value of the assets in the Decommissioning Fund. This adjustment reduced the value of the assets by $21 million, to equal the value of the liabilities as defined by the current approved ONFA Reference Plan. If the investments in the Decommissioning Fund were accounted for at fair market value in the unaudited interim consolidated financial statements at September 30, 2006, and the Decommissioning Fund was terminated under the ONFA, there would be an amount due to the Province of $535 million (December 31, 2005 – $484 million).

OPG has commenced the process to review and update the cost estimates under the ONFA Reference Plan, and is targeting for an updated approved Reference Plan (the 2006 Reference Plan) under ONFA to be in place in 2006. The updated Reference Plan will likely result in a significant increase in OPG's liability for nuclear waste management and decommissioning, and a corresponding increase in the carrying value of the nuclear generating stations to which this liability relates. The primary drivers for this increase are a change in economic indices, and an increase in the volume of used fuel and low and intermediate level waste based on service life extensions.

Regulatory Assets

As at September 30, 2006, regulatory assets were $257 million compared to $266 million as at December 31, 2005. Effective January 1, 2005, in accordance with regulations pursuant to the *Electricity Restructuring Act*, *2004* (Ontario), OPG established 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. The change in regulatory assets during the nine months ended September 30, 2006 was mainly due to the amortization of $21 million of the deferred Pickering A return to service costs, partially offset by $13 million of non-capital costs that were deferred. OPG also recorded a regulatory asset of $4 million as at September 30, 2006 reflecting water conditions that were unfavourable compared to those forecasted for 2006.

Accounts Payable and Accrued Charges

Accounts payable and accrued charges as at September 30, 2006 were $769 million compared to $958 million as at December 31, 2005. The decrease of $189 million was partly due to reduced accrued interest, a reduced property tax balance, and reduced coal purchases.

Dividend Payable

In September 2006, OPG's Board of Directors approved the payment of a $128 million dividend to its shareholder, the Province.

Revenue Limit Rebate Payable

The revenue limit rebate payable as at September 30, 2006 was $85 million compared to $739 million as at December 31, 2005. Payments of $739 million and $63 million were made in the second and third quarters of 2006, respectively. The balance of $85 million as at September 30, 2006 represents the revenue limit rebate payable for the period of May 1, 2006 to September 30, 2006.

Fixed Asset Removal and Nuclear Waste Management

The liability for fixed asset removal and nuclear waste management as at September 30, 2006 was $9,049 million compared to $8,759 million as at December 31, 2005. The increase of $290 million was primarily due to accretion due to the passage of time, partially offset by expenditures on nuclear waste management activities.

OPEB and Supplementary Pension Plans

The long-term portion of the liability for OPEB and supplementary pension plans was $1,357 million as at September 30, 2006 compared to $1,212 million as at December 31, 2005. The increase of $145 million was due to costs recognized in the first nine months of 2006, net of benefit payments.

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under Canadian GAAP, are either not recorded in the Company's consolidated financial statements or are recorded on the Company's consolidated financial statements in amounts that differ from the full contract amounts. Principal off-balance sheet activities that OPG undertakes include securitization of certain accounts receivable agreements, guarantees which provide financial or performance assurance to third parties on behalf of certain subsidiaries, and certain derivative instruments and long-term fixed price contracts.

Securitization

In October 2003, OPG completed a revolving securitization agreement with an independent trust. 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, 2006, the average all-in cost of funds was 4.6 per cent and the pre-tax charges on sales to the trust were $4 million. For the nine months ended September 30, 2006, the all-in cost of funds was 4.4 per cent and the pre-tax charges on sales to the trust were $10 million. The current securitization agreement extends to August 2009. Refer to Notes 3 and 4 of OPG's 2005 annual audited consolidated financial statements for additional information.

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 provided third party financial guarantees in support of the Portlands Energy Centre project totalling $63 million.

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 United States dollar ("USD") 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 gain on electricity derivative instruments and interest rate hedges was $25 million as at September 30, 2006, compared to a deferred loss of $124 million as at December 31, 2005. For additional information, refer to Note 11 to OPG's unaudited interim consolidated financial statements as at and for the three and nine months ended September 30, 2006.

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

RISK MANAGEMENT

A detailed discussion of OPG's inherent risks, including financial, operational, and strategic risks is included in the 2005 annual MD&A under the heading, *Risk Management*. The sections which follow provide highlights of certain of these inherent risks.

Financial Risks

Market Risks

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, which includes fixed price and indexed contracts for fossil and nuclear fuels, and may include commodity derivatives.

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

	2006	2007	2008
Estimated generation output hedged [1]	93%	92%	90%
Estimated fuel requirements hedged [2]	100%	95%	81%
Estimated nitric oxide (NO) emission requirement hedged [3]	100%	100%	92%
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 regulated pricing commitments, agreements with the IESO, OPA auction sales and the revenue limit on OPG's 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.

Trading Risk

Open trading positions are subject to measurement against Value at Risk ("VaR") limits. VaR utilization ranged between $3.4 million and $2.1 million during the three months ended September 30, 2006, compared to $2.9 million and $0.7 million during the three months ended September 30, 2005. VaR utilization ranged between $3.4 million and $1.5 million during the nine months ended September 30, 2006, compared to $2.9 million and $0.7 million during the nine months ended September 30, 2005. VaR utilization is within the risk tolerance of the Company, as per approved VaR limits.

Liquidity Risk

OPG operates in a capital intensive business. Significant financial resources are required to fund capital improvement projects and maintenance at generating stations and potential expenditures necessary to comply with environmental or other regulatory requirements. In addition, the Company has other significant disbursement requirements including rebate payments associated with the revenue limit, annual funding obligations under ONFA, pension funding, and continuing debt maturities with the OEFC. A discussion of corporate liquidity is included in the Liquidity and Capital Resources section.

Foreign Exchange and Interest Rate Risk

OPG's foreign exchange exposure is attributable to two primary factors: USD denominated transactions such as the purchase of fossil fuels; and the influence of USD denominated commodity prices on Ontario electricity spot market prices, both of which impact OPG's revenues. The magnitude and direction of the exposure to the USD from OPG's operations is impacted by generation reliability and price volatility of USD denominated commodities. OPG currently manages its exposure using forwards and other derivative products to periodically hedge portions of its anticipated USD exposures according to approved risk management policies.

OPG has interest rate exposure on its short-term borrowings and investment programs. The majority of OPG's debt is fixed on a long-term basis. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. Interest rate risk may be hedged using derivative instruments. The management of these risks is undertaken by selectively hedging in accordance with approved risk management policies.

Credit Risk

Credit risk is the financial risk of non-performance by contracted counterparties. Credit risk excludes any operational risk resulting from a third party failing to deliver a product or service as expected. OPG monitors and reports its credit exposure with counterparties. OPG's management believes that the credit risk from energy sales and trading activities as at September 30, 2006 is 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, 2006:

			Potential Exposure for Largest Counterparties	
Credit Rating [1]	**Number of Counterparties [2]**	**Potential Exposure [3]**	**Number of Counterparties**	**Counterparty Exposure**
		(millions of dollars)		*(millions of dollars)*
AAA to AA-	36	2	-	-
A+ to A-	50	104	4	88
BBB+ to BBB-	87	46	4	33
BB+ to BB-	24	22	2	15
Below BB-	33	5	-	-
Subtotal	230	179	10	136
IESO [4]	1	378	1	378
Total	231	557	11	514

[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 forms of 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 a 95 per cent confidence interval.

[4] Credit exposure to the IESO peaked at $1,029 million during the nine months ended September 30, 2006 ($1,146 million during the nine months ended September 30, 2005).

Operations Risks

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. The uncertainty around the electricity generated by OPG's nuclear generating plants arises from various degradation processes affecting three key types of components: steam generators, fuel channels, and feeders. Generation risks also arise from other structures, components or systems in the nuclear generating stations such as cooling water systems, turbines and reactor structures and components. Some of the most significant risks within the nuclear generating stations are discussed below.

Thinning of the carbon steel feeders used to transport the hot pressurized water in the reactor to the steam generators is an industry-wide issue. Thinning of feeders 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. A limited replacement program will be initiated in 2006, with feeder replacements to take place at the Darlington nuclear generating station during the fall planned outage. Additional mitigation options are also pursued to extend feeder life, reduce the thinning rate, and improve the capability to replace feeders. Wall thickness measurements of removed feeders and field inspections at the Pickering A nuclear generating station Units 1 and 4 in 2005 indicated thinning in unexpected areas and to a degree greater than expected. Future inspections will be required to confirm the thinning rate at the Pickering A nuclear generating station, and to determine the extent of future feeder replacements. The feeders at the Pickering B generating station have been found to be less affected by thinning than those at the Darlington and Pickering A generating stations.

Cracking of feeders 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 cracking at any of its nuclear facilities, but is carrying out inspections during regularly planned outages. Observations of additional shallow cracks at a CANDU plant outside Ontario have increased the risk that OPG's inspection program may need to be further increased in 2007 and beyond. OPG is 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 such that calandria vault components will not become life-limiting. Further inspections are planned in 2008 and 2009.

Recent measurements at a CANDU plant outside Ontario suggest that a component of the reactor (the guide tubes) has deteriorated to an unexpected degree. Although there is no information available on the condition of these components in the OPG units, the situation is potentially generic to all CANDU plants. There may be a need to carry out inspections and possibly repairs in the OPG units. OPG is monitoring the situation closely.

In 2004, inspections of the Pickering A generating station 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. 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 may impact outage duration and outage costs. Inspection of Pickering A Unit 4 in 2005 confirmed the presence of another single crack. Prior inspection of Pickering A Unit 1 in 2004 did not uncover cracks. Inspection of Pickering B Units 5 and 6 in 2005 and Units 7 and 8 in 2006 have not uncovered any further cracks. This observation, together with improved construction methods used on the Pickering B steam generators (as compared to Pickering A steam generators), suggests that this degradation mechanism is likely not active on Pickering B. Inspection for cracks of Pickering A Unit 4 steam generator tubes is planned for the fall of 2006.

In 2005 and 2006, a few new deep tube pits were detected in the steam generators of Unit 5 and 8, at the Pickering B nuclear generating station. Inspection of Units 6 and 7 in the same time period did not uncover any new deep pits. Deep pits may be indicative of the recurrence of active tube corrosion due to deposit build-up. The impact of this degradation is an increased risk of future forced outages due to tube leaks. This is mainly an economic risk in that it would force a unit shutdown to repair the leak. An economic assessment is being conducted to determine the benefit and cost of performing a more aggressive deposit cleaning strategy to reduce the probability of a tube leak.

Pressure tubes are life limited by hydrogen concentration which impacts flaw and blister assessments. Recent measurements taken at Unit 8 of the Pickering B generating station indicate that the rate of hydrogen pickup may be faster than anticipated. In addition, movement of some garter springs post repositioning has been noted. The consequence of these findings is increased inspection and maintenance which may extend outage durations. Confirmatory measurements are being planned for the upcoming Unit 8 outage in 2008. These findings are not expected to affect the Darlington or Pickering A nuclear generating stations; however, since the Darlington nuclear generating station operates at higher temperature, pressure and flux than any other CANDU, there is a higher uncertainty as to possible evolution of the situation.

As a result of operating in a high neutron flux environment, pressure tubes experience radial and axial deformation (creep). Radial creep impacts the Safety Report analysis used to define the safe operating envelope. At other utilities in Canada, the effect of radial creep has been accommodated by derating the reactor. In 2002, OPG, working with an industry partner, embarked on the development of a new methodology to demonstrate acceptable safety margins with radially crept pressure tubes at full power operation. The new analysis was completed for the Darlington nuclear generating station earlier this year and submitted to the CNSC. There is a risk that the CNSC may not accept the new methodology in which case the Darlington nuclear generating station would be required to derate some of its units starting as early as 2007 and increasing each year. Pickering A and B nuclear generating stations are not at risk for the five-year business planning time horizon.

Strategic Risks

Environmental Risk

OPG incurs substantial capital and operating costs to comply with environmental laws. The regulatory requirements relate to discharges to the environment; construction of or modifications to our facilities; the handling, use, storage, transportation, disposal and clean-up of hazardous substances, and waste; and the decommissioning of generating facilities at the end of their useful lives.

OPG's Environmental Policy commits OPG to meet all applicable legislative requirements and voluntary environmental commitments and integrate environmental factors into business planning and decision-making. This policy also commits OPG to maintain comprehensive environmental management systems ("EMSs") at our generating facilities consistent with the ISO 14001 standard.

The Mercury Canada-Wide Standard for coal-fired generating stations was endorsed by the Canadian Council of Ministers of the Environment in October of 2006. The standard identifies provincial caps for annual mercury emissions and comes into effect in 2010. Annual caps were identified for all provinces except Ontario. OPG continues to discuss with the Ministries of Energy, Environment and Finance and the OPA mercury emission reduction scenarios and the associated costs and implementation schedules. The Ontario commitment is consistent with the overall intent of the Mercury Canada-Wide Standard and there are no immediate impacts on OPG's fossil-fuelled generating stations pending the finalization of Ontario's plan.

OPG's environmental risks, emissions monitoring and environmental risk management programs are described in detail in the Environmental Risk section of the MD&A for the year ended December 31, 2005. OPG continues to monitor the developments with respect to changes to the federal Green Plan presently being pursued by the federal government in order to assess any impact on OPG.

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. If there are changes to the fundamental assumptions on which these regulated prices were developed, the Province may amend these initial prices.

Some time after March 31, 2008, the OEB is expected to establish new regulated prices. The process of setting new regulated rates is inherently uncertain. The new rates established by the OEB may not provide for recovery of all of OPG's costs, including an appropriate rate of return. Despite the fact that some costs may not be included within the new rates, these expenditures may still 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 seeks to recover must be demonstrated to the OEB as part of the process to establish new regulated prices expected after March 31, 2008. 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.

The timing for establishing new rates is not known at this time. A delay in establishing new payment amounts beyond April 1, 2008 would result in a continuation of current rates. The current rates were established prior to April 1, 2005 based on financial information available at that time. To the extent that these rates do not reflect current costs and operating plans this could result in deteriorating financial performance.

The OEB is currently holding a consultation to determine the form of regulation for OPG. The OEB's determination on this matter can have significant implications for OPG depending on the form of regulation ultimately adopted.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

Changes in Accounting Policies and Estimates

Certain of the accounting policies disclosed in OPG's 2005 annual audited consolidated financial statements are recognized as critical by virtue of the subjective and complex judgements 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 relate to rate regulated accounting, income taxes, business segments, impairment of generating stations and other fixed assets, pension and other post employment benefits, asset retirement obligations, and depreciation. For further details, refer to the 2005 annual MD&A under the heading, *Critical Accounting Policies and Estimates*.

The accounting policies used in preparing the unaudited interim consolidated financial statements are consistent with those used in the preparation of the 2005 annual consolidated financial statements, except as disclosed in Note 2 to the unaudited interim consolidated financial statements.

The accounting estimates related to asset depreciation require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors. The Province has accepted the advice of the IESO in their June 2006 report that indicates a need for 2,500 to 3,000 MW of additional capacity to maintain system reliability. Therefore, further delays will be necessary in the plan to replace coal-fired generation by 2009. As a result of these delays, effective July 1, 2006, OPG extended the life for all of the coal-fired generating stations, for purposes of calculating depreciation, to December 31, 2012. The extension will reduce depreciation expense by $31 million over the remainder of 2006, $126 million in 2007, and $46 million in 2008. From 2009 to 2012, the depreciation expense will increase by $59 million in each year. OPG will reassess the service life of the coal-fired stations upon release of the IPSP, and subsequent approval by the OEB. Any change to the estimated service life of the coal-fired generating stations, for purposes of calculating depreciation, could have a material impact on OPG's consolidated financial statements.

Future Changes in Accounting Policies and Estimates

In 2005, the Canadian Institute of Chartered Accountants issued three new accounting standards: Financial Instruments – Recognition and Measurement, Hedges, and Comprehensive Income. These standards provide guidance on the recognition and measurement of financial assets, financial liabilities and non-financial derivatives. They also provide guidance on the classification of financial instruments and hedge accounting.

OPG is in the process of assessing the impact of these new standards on OPG's financial position and results of operations. These accounting standards will be effective for OPG on January 1, 2007.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters. This financial information has been prepared in accordance with Canadian GAAP.

(millions of dollars)	**September 30 2006**	**June 30 2006**	**March 31 2006**	**December 31 2005**
Revenue after revenue limit and Market Power Mitigation Agreement rebates	**1,435**	1,345	1,508	1,496
Net income	**167**	143	199	160
Net income per share	**$0.65**	$0.56	$0.78	$0.62

(millions of dollars)	**September 30 2005**	**June 30 2005**	**March 31 2005**	**December 31 2004**
Revenue after revenue limit and Market Power Mitigation Agreement rebates	1,571	1,373	1,358	1,215
Income (loss) before extraordinary item	181	137	(38)	34
Income (loss) before extraordinary item per share	$0.71	$0.53	$(0.15)	$0.13
Net income (loss)	181	63	(38)	34
Net income (loss) per share	$0.71	$0.25	$(0.15)	$0.13

OPG's quarterly results are impacted by changes in demand primarily 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. Since April 1, 2005, revenue has increased due to the introduction of regulated prices for OPG's baseload hydroelectric and nuclear facilities and other related regulatory changes. The revenue limit and the Market Power Mitigation Agreement rebates, regulated prices, and OPG's hedging strategies significantly reduced the impact of seasonal price fluctuations on the results of operations.

Additional items which impacted net income in certain quarters above include the following:

- Tax benefit of $93 million recorded during the fourth quarter of 2004 related to the elimination of a valuation allowance due to the introduction of rate regulation;
- Lower OM&A expenses due to the deferral of non-capital costs related to the Pickering A nuclear generating station Unit 1 return to service project, beginning January 1, 2005, as required by regulation pursuant to the *Electricity Restructuring Act, 2004* (Ontario);
- Impairment loss on the Lennox generating station of $202 million recorded during the first quarter of 2005, reflecting the amount of the carrying value of the station;
- Higher revenues as a result of a liability must-run contract between OPG and the IESO for the Lennox generating station, for the period October 1, 2005 to September 30, 2006;
- Lower income tax expense due to the use of the taxes payable method for the regulated segments commencing April 1, 2005;
- Impairment loss of $63 million related to Units 2 and 3 of the Pickering A generating station, recorded in the second quarter of 2005;

- One-time extraordinary loss of $74 million recorded in the second quarter of 2005, resulting from the adoption of rate regulated accounting and the corresponding use of the taxes payable method;
- Write-off of $22 million and $35 million of excess inventory as a result of not returning Pickering A generating station Units 2 and 3 to service recorded in the third and fourth quarters of 2005 respectively;
- Higher depreciation expense related to the return to service of Unit 1 at the Pickering A generating station in the fourth quarter of 2005;
- Decrease in depreciation expense primarily due to extension of service lives, for accounting purposes, of the Nanticoke station, Pickering B station and Unit 4 of the Pickering A station beginning in the first quarter of 2006;
- Higher pension and OPEB costs during the first three quarters of 2006 mainly due to changes in economic assumptions used to measure the costs; and
- Decrease in depreciation expense primarily due to extension of the service life, for accounting purposes, of all coal-fired generating stations to December 31, 2012, beginning in the third quarter of 2006.

SUPPLEMENTAL EARNINGS MEASURES

In addition to providing net income in accordance with Canadian GAAP, OPG's MD&A, unaudited interim consolidated financial statements as at and for the three and nine months ended September 30, 2006 and 2005 and the notes thereto, present certain non-GAAP financial measures. These financial measures do not have standard definitions prescribed by 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, consolidated 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 revenue limit and Market Power Mitigation Agreement rebates and fuel expense.

(2) **Earnings** is defined as net income.

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CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)	**Three Months Ended September 30 2006**	**Three Months Ended September 30 2005**	**Nine Months Ended September 30 2006**	**Nine Months Ended September 30 2005**
Revenue				
Revenue before revenue limit and Market Power Mitigation Agreement rebates	**1,494**	1,907	**4,436**	5,191
Revenue limit rebate *(Note 14)*	**(59)**	(336)	**(148)**	(477)
Market Power Mitigation Agreement rebate	**-**	-	**-**	(412)
	1,435	1,571	**4,288**	4,302
Fuel expense	**310**	384	**831**	983
Gross margin	**1,125**	1,187	**3,457**	3,319
Expenses				
Operations, maintenance and administration	**634**	627	**1,967**	1,830
Depreciation and amortization *(Note 4)*	**148**	181	**504**	566
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**125**	119	**375**	358
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(82)**	(96)	**(274)**	(279)
Property and capital taxes	**35**	26	**82**	64
Restructuring	**-**	6	**-**	6
	860	863	**2,654**	2,545
Income before impairment of long-lived assets	**265**	324	**803**	774
Impairment of long-lived assets *(Note 4)*	**-**	-	**-**	265
Income before interest, income taxes and extraordinary item	**265**	324	**803**	509
Net interest expense	**47**	49	**145**	143
Income before income taxes and extraordinary item	**218**	275	**658**	366
Income tax expenses				
Current	**47**	57	**93**	71
Future *(Note 9)*	**4**	37	**56**	15
	51	94	**149**	86
Income before extraordinary item	**167**	181	**509**	280
Extraordinary item *(Note 9)*	**-**	-	**-**	74
Net income	**167**	181	**509**	206
Basic and diluted income per common share before extraordinary item *(dollars)*	**0.65**	0.71	**1.99**	1.09
Basic and diluted income per common share *(dollars)*	**0.65**	0.71	**1.99**	0.80
Common shares outstanding *(millions)*	**256.3**	256.3	**256.3**	256.3

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS (DEFICIT) (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	**2006**	**2005**
Retained earnings (deficit), beginning of period	**261**	(105)
Net income	**509**	206
Dividend	**(128)**	-
Retained earnings, end of period	**642**	101

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(millions of dollars)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2006	**2005**	**2006**	**2005**
Operating activities				
Net income	**167**	181	**509**	206
Adjust for non-cash items:				
Depreciation and amortization *(Note 4)*	**148**	181	**504**	566
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**125**	119	**375**	358
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(82)**	(96)	**(274)**	(279)
Pension cost	**54**	31	**163**	87
Other post employment benefits and supplementary pension plans *(Note 10)*	**67**	49	**194**	140
Future income taxes	**4**	37	**56**	15
Transition rate option contracts	**-**	(9)	**(13)**	(27)
Provision for restructuring	**-**	6	**-**	6
Mark-to-market on energy contracts	**(4)**	21	**(21)**	25
Provision for used nuclear fuel	**7**	8	**23**	21
Impairment of long-lived assets	**-**	-	**-**	265
Regulatory assets and liabilities	**-**	-	**19**	-
Extraordinary item	**-**	-	**-**	74
Other	**2**	48	**4**	48
	488	576	**1,539**	1,505
Contributions to nuclear fixed asset removal and nuclear waste management funds	**(113)**	(113)	**(340)**	(340)
Expenditures on fixed asset removal and nuclear waste management	**(42)**	(23)	**(112)**	(62)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**3**	8	**14**	18
Contributions to pension fund	**(65)**	(84)	**(195)**	(162)
Expenditures on other post employment benefits and supplementary pension plans	**(18)**	(15)	**(49)**	(48)
Revenue limit rebate *(Note 14)*	**(63)**	-	**(802)**	-
Market Power Mitigation Agreement rebate	**-**	(245)	**-**	(851)
Expenditures on restructuring *(Note 13)*	**(1)**	(8)	**(7)**	(17)
Net changes to other long-term assets and liabilities	**(25)**	(31)	**(82)**	(60)
Changes in non-cash working capital balances *(Note 16)*	**143**	317	**340**	772
Cash flow provided by operating activities	**307**	382	**306**	755
Investing activities				
Investment in regulatory assets *(Note 5)*	**(1)**	(60)	**(13)**	(251)
Investment in fixed assets *(Notes 4 and 15)*	**(188)**	(114)	**(422)**	(353)
Acquisition of short-term investments	**-**	(67)	**-**	(67)
Net proceeds from purchase of long-term investments	**(2)**	(2)	**-**	(3)
Cash flow (used in) investing activities	**(191)**	(243)	**(435)**	(674)
Financing activities				
Issuance of long-term debt *(Note 7)*	**-**	-	**-**	495
Repayment of long-term debt *(Note 7)*	**(301)**	(1)	**(604)**	(3)
Net decrease in short-term notes *(Note 6)*	**-**	-	**-**	(26)
Cash flow (used in) provided by financing activities	**(301)**	(1)	**(604)**	466
Net (decrease) increase in cash and cash equivalents	**(185)**	138	**(733)**	547
Cash and cash equivalents, beginning of period	**360**	411	**908**	2
Cash and cash equivalents, end of period	**175**	549	**175**	549

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2006**	**December 31 2005**
Assets		
Current assets		
Cash and cash equivalents	**175**	908
Accounts receivable *(Note 3)*	**252**	538
Future income taxes *(Note 9)*	**12**	18
Fuel inventory	**617**	581
Materials and supplies	**111**	115
	1,167	2,160
Fixed assets *(Note 4)*		
Property, plant and equipment	**15,560**	15,172
Less: accumulated depreciation	**4,227**	3,760
	11,333	11,412
Other long-term assets		
Deferred pension asset	**695**	663
Nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**7,388**	6,788
Long-term materials and supplies	**317**	273
Regulatory assets *(Note 5)*	**257**	266
Long-term accounts receivable and other assets	**63**	61
	8,720	8,051
	21,220	21,623

See accompanying notes to the interim consolidated financial statements

CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2006**	**December 31 2005**
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Note 13)*	**769**	958
Dividend payable	**128**	-
Revenue limit rebate payable *(Note 14)*	**85**	739
Long-term debt due within one year *(Note 7)*	**606**	806
Deferred revenue due within one year	**12**	12
Income and capital taxes payable	**167**	81
	1,767	2,596
Long-term debt *(Note 7)*	**2,685**	3,089
Other long-term liabilities		
Fixed asset removal and nuclear waste management *(Note 8)*	**9,049**	8,759
Other post employment benefits and supplementary pension plans	**1,357**	1,212
Long-term accounts payable and accrued charges	**159**	183
Deferred revenue	**135**	144
Future income taxes *(Note 9)*	**291**	241
Regulatory liabilities *(Note 5)*	**9**	12
	11,000	10,551
Shareholder's equity		
Common shares	**5,126**	5,126
Retained earnings	**642**	261
	5,768	5,387
	21,220	21,623

Commitments and Contingencies (Notes 1, 4, 6, 7, 8, 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, 2006 AND 2005 (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 these interim consolidated financial statements. These interim financial statements do not contain all the disclosures required by Canadian generally accepted accounting principles for annual financial statements. Accordingly, these interim consolidated financial statements should be read in conjunction with the most recently prepared annual consolidated financial statements for the year ended December 31, 2005.

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 2005 comparative amounts have been reclassified from financial statements previously presented to conform to the 2006 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

Rate Regulated Accounting

In December 2004, the *Electricity Restructuring Act, 2004* received royal assent. A regulation made pursuant to that statute provides that OPG receives regulated prices beginning April 1, 2005, for most of OPG's baseload hydroelectric facilities and all of its 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, the Pickering A and B, and Darlington nuclear generating stations.

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-funding 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 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. The measurement of such regulatory assets and liabilities are subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation. See Note 5 and Note 9 to the interim consolidated financial statements for additional disclosures required under rate regulated accounting.

Long-Term Portfolio Investments

Long-term portfolio investments, other than investments owned by the Company's wholly owned subsidiary OPG Ventures Inc. ("OPGV"), are stated at amortized cost and include the nuclear fixed asset removal and nuclear waste management funds. Gains and losses on long-term investments are recognized when investments are sold. When a decline in the value of investments occurs, which is considered to be other than temporary, a provision for loss is established.

Investments owned by OPGV are recorded at fair value, and changes to the fair value of the investments are included in revenue in the period in which the change occurs. The fair values of these investments are estimated based on readily available market information or using estimation techniques based on historical performance.

Income Taxes

OPG follows the liability method of accounting for income taxes of its unregulated operations. Under the liability method, future tax assets and liabilities are determined based on differences between the accounting and tax bases 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. 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. Commencing April 1, 2005, with the introduction of rate regulation, OPG accounts for income taxes relating to the rate regulated segments of its business using the taxes payable method. Under the taxes payable method, OPG does not recognize future income taxes relating to the rate regulated segments of its business to the extent those future income taxes are expected to be recovered in the regulated rates charged to future customers.

Changes in Accounting Policies and Estimates

Depreciation of Long-Lived Assets

The accounting estimates related to the depreciation of long-lived assets require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors.

Effective January 1, 2006, following the completion of a review of the life limiting components of the Pickering B nuclear generating station, OPG revised and extended, for the purpose of calculating depreciation, the estimated remaining service life of the Pickering B nuclear generating station to 2014 from 2009.

The Province has accepted the advice of the Independent Electricity System Operator ("IESO") in their June 2006 report that indicates a need for 2,500 to 3,000 MW of additional capacity to maintain system reliability. Therefore, further delays will be necessary in the Province's plan to replace coal-fired generation by 2009. As a result of these delays, effective July 1, 2006, OPG extended the life for all of the coal-fired generating stations, for purposes of calculating depreciation, to December 31, 2012. The extension will reduce depreciation expense by $31 million over the remainder of 2006, $126 million in 2007, and $46 million in 2008. From 2009 to 2012, the depreciation expense will increase by $59 million in each year. OPG will reassess the service life of the coal-fired stations upon release of the Integrated Power System Plan, and subsequent approval by the OEB. Any change to the estimated service life the coal-fired generating stations, for purposes of calculating depreciation, could have a material impact on OPG's consolidated financial statements.

Reportable Segments

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 on the majority of this output. With the introduction of rate regulation, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. Since the second quarter of 2005, OPG reported its business segments as Regulated – Nuclear, Regulated – Hydroelectric, and Unregulated Generation. Commencing in the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments, identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods have been reclassified to reflect the revised disclosure.

Future Accounting Changes

In 2005, the Canadian Institute of Chartered Accountants ("CICA") issued three new accounting standards: Handbook Section 1530, Comprehensive Income; Handbook Section 3855, Financial Instruments – Recognition and Measurement; and Handbook Section 3865, Hedges. These standards apply to interim and annual financial statements relating to fiscal years beginning on or after October 1, 2006.

These standards will be effective for OPG beginning in 2007. OPG is in the process of assessing the impact of these standards on its consolidated financial statements. The impact of implementing these new standards on OPG's consolidated financial statements is not yet determinable as it will be dependent on outstanding positions and their fair values at the time of transition. The following provides further information on each of the three new accounting standards as they relate to OPG.

Comprehensive Income

As a result of adopting these standards, a new category, accumulated other comprehensive income, will be added to shareholder's equity in the consolidated balance sheets. Major components for this category will include unrealized gains and losses on financial assets classified as available-for-sale, changes in the fair value of the effective portion of cash flow hedging instruments, and unrealized foreign currency translation amounts, net of hedging, arising from self-sustaining foreign operations. These amounts will be recorded in the statement of other comprehensive income until the criteria for recognition in the consolidated statement of income are met.

Financial Instruments – Recognition and Measurement

Under the new standard, for accounting purposes, financial assets will be classified as one of the following: held-to-maturity, loans and receivables, held-for-trading or available-for-sale, and financial liabilities will be classified as held-for-trading or other than held-for-trading. Financial assets and liabilities held-for-trading will be measured at fair value with gains and losses recognized in net income. Financial assets held-to-maturity, loans and receivables and financial liabilities other than those held-for-trading, will be measured at amortized cost. Available-for-sale instruments will be measured at fair value with unrealized gains and losses recognized in other comprehensive income. The standard also permits designation of any financial instrument as held-for-trading upon initial recognition. All derivatives, including embedded derivatives that must be separately accounted for, generally must be classified as held-for-trading and recorded at fair value in the consolidated balance sheets.

Hedges

This new standard specifies the criteria under which hedge accounting can be applied and how hedge accounting is to be executed for each of the permitted hedging strategies: fair value hedges, cash flow hedges and hedges of a foreign currency exposure of a net investment in a self-sustaining foreign operation. In a fair value hedging relationship, the carrying value of the hedged item is adjusted by gains or losses attributable to the hedged risk and recognized in net income. This change in fair value of the hedged item, to the extent that the hedging relationship is effective, is offset by changes in the fair value of the derivative. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative will be recognized in other comprehensive income. The ineffective portion will be recognized in net income. The amounts recognized in accumulated other comprehensive income will be reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item. In hedging a foreign currency exposure of a net investment in a self-sustaining foreign operation, foreign exchange gains and losses on the hedging instruments will be recognized in other comprehensive income.

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. In December 2005, the Company extended this agreement to August 2009.

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, 2006, the Company has recognized pre-tax charges of $4 million (three months ended September 30, 2005 – $2 million) on such sales at an average cost of funds of 4.6 per cent (three months ended September 30, 2005 – 3.0 per cent). For the nine months ended September 30, 2006, the Company has recognized pre-tax charges of $10 million (nine months ended September 30, 2005 – $7 million) on such sales at an average cost of funds of 4.4 per cent (nine months ended September 30, 2005 – 2.9 per cent). As at September 30, 2006, OPG had sold receivables of $300 million (December 31, 2005 – $300 million) from its total portfolio of $373 million (December 31, 2005 – $668 million).

4. FIXED ASSETS

Depreciation and amortization expense for the three and nine months ended September 30, 2006 and 2005 consists of the following:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Depreciation and amortization	**146**	180	**500**	562
Nuclear waste management costs	**2**	1	**4**	4
	148	181	**504**	566

Interest capitalized to construction in progress at 6.0 per cent during the three and nine months ended September 30, 2006 (three and nine months ended September 30, 2005 – 6.0 per cent) was $5 million and $13 million respectively (three and nine months ended September 30, 2005 – $7 million and $24 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, in the second quarter of 2005, 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. The assessment considered results 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, OPG determined that the return to service of these two units was not justified on a commercial basis even though technically feasible. OPG 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.

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 generating station, 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 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, the Province advised OPG that it would not support an arrangement that would allow for the recovery of the carrying value of the Lennox generating station. As a result, OPG recorded an impairment loss of $202 million in the first quarter of 2005.

In March 2006, the OEB issued a decision approving a reliability must-run ("RMR") contract between OPG and the Independent Electricity System Operator ("IESO") for the Lennox generating station, for the period October 1, 2005 to September 30, 2006. Reliability must-run contracts are designed to ensure that generating stations remain available to maintain the reliability of the electricity system. In its decision, the OEB found it appropriate for OPG to recover the fixed and variable operating costs of the Lennox generating station that are not recovered through market revenues. As a result of the decision, OPG recorded $14 million in revenue in the third quarter of 2006 (nine months ended September 30, 2006 - $58 million). The RMR contract is a cost-based contract that provides for regular payments, which are subject to adjustments for actual costs. OPG negotiated a similar contract with the IESO for the period October 1, 2006 to September 30, 2007. An application seeking OEB approval for this new RMR contract was filed in August 2006. The matter is before the OEB.

5. REGULATORY ASSETS AND LIABILITIES

The changes in the regulatory assets and liabilities for the nine months ended September 30, 2006 are as follows:

(millions of dollars)	Pickering A Return to Service Costs	Ancillary Service Revenue Variance	Hydro-electric Production Variance	Other
Regulatory assets (liabilities), beginning of the period	261	5	(4)	(8)
Increase (decrease) during the period	13	(7)	8	1
Amortization during the period	(21)	-	-	-
Regulatory assets (liabilities), end of the period	**253**	**(2)**	**4**	**(7)**

The regulatory assets and liabilities as at September 30, 2006 and December 31, 2005 are as follows:

(millions of dollars)	September 30 2006	December 31 2005
Regulatory assets		
Pickering A generating station return to service costs	**253**	261
Ancillary service revenue variance	**-**	5
Hydroelectric production variance	**4**	-
Total regulatory assets	**257**	266
Regulatory liabilities		
Ancillary service revenue variance	**2**	-
Hydroelectric production variance	**-**	4
Other	**7**	8
Total regulatory liabilities	**9**	12

Pickering A Return to Service Costs

Effective January 1, 2005, in accordance with a regulation made under the *Electricity Restructuring Act, 2004*, OPG was 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, 2006, the deferral account was $253 million, consisting of non-capital costs of $232 million relating to Unit 1, $19 million relating to Units 2 and 3, $20 million of general return to service costs, and interest of $7 million. The accumulated amortization as of September 30, 2006 was $25 million.

As at December 31, 2005, the deferral account was $261 million, consisting of non-capital costs of $228 million relating to Unit 1, $19 million relating to Units 2 and 3, $11 million of general return to service costs, and interest of $7 million. The accumulated amortization as of December 31, 2005 was $4 million.

Under the regulation, the OEB is directed 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 a regulation made under 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 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 a reduction in revenue during the nine months ended September 30, 2006 of $7 million, reflecting ancillary services revenue that was favourable compared to that forecasted for 2006. OPG recorded revenue during the nine months ended September 30, 2006 of $8 million reflecting water conditions that were unfavourable compared to those forecasted for 2006. 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 over a period not to exceed three years. The amortization will commence after OPG receives a rate order from the OEB.

The other regulatory liability consists of a portion of non-regulated revenue earned by OPG's regulated assets, which will result in a reduction of future regulated rates to be established by the OEB.

Had OPG not accounted for the variances as a regulatory asset and liability, revenue for the nine months ended September 30, 2006 would have been lower by $1 million.

6. SHORT-TERM CREDIT FACILITIES

OPG's $1 billion revolving committed bank credit facility is divided into two tranches – a $500 million 364-day term tranche maturing May 22, 2007, and a $500 million three-year term tranche maturing May 22, 2009. The total credit facility will be used primarily as support for notes issued under OPG's commercial paper program. As of September 30, 2006 and December 31, 2005, OPG had no commercial paper or other outstanding borrowing under this facility.

OPG also maintains $26 million (December 31, 2005 – $26 million) in short-term uncommitted overdraft facilities as well as $240 million (December 31, 2005 – $215 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 Letters of Credit as collateral with Local Distribution Companies ("LDCs") as prescribed by the OEB's Retail Settlement Code. At September 30, 2006, there was a total of $175 million (December 31, 2005 – $157 million) of Letters of Credit issued, which included $159 million relating to the supplementary pension plans (December 31, 2005 – $138 million) and $14 million (December 31, 2005 – $ nil) relating to the construction of the Portlands Energy Centre.

7. LONG-TERM DEBT

Long-term debt consists of the following:

(millions of dollars)	**September 30 2006**	**December 31 2005**
Notes payable to the Ontario Electricity Financial Corporation	**3,095**	3,695
Share of non-recourse limited partnership debt	**196**	200
	3,291	3,895
Less: due within one year		
Notes payable to the Ontario Electricity Financial Corporation	**600**	800
Share of limited partnership debt	**6**	6
	606	806
Long-term debt	**2,685**	3,089

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.

Interest paid during the three months ended September 30, 2006 was $109 million (three months ended September 30, 2005 – $114 million), of which $105 million relates to interest paid on long-term debt (three months ended September 30, 2005 – $112 million). Interest paid during the nine months ended September 30, 2006 was $235 million (nine months ended September 30, 2005 – $226 million), of which $223 million relates to interest paid on long-term debt (nine months ended September 30, 2005 – $216 million). Interest on the notes payable to OEFC is paid in the first and third quarter of the year.

8. Fixed Asset Removal and Nuclear Waste Management

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

(millions of dollars)	**September 30 2006**	**December 31 2005**
Liability for nuclear used fuel management	**5,129**	4,940
Liability for nuclear decommissioning and low and intermediate level waste management	**3,731**	3,627
Liability for non-nuclear fixed asset removal	**189**	192
Fixed asset removal and nuclear waste management liabilities	**9,049**	8,759

The change in the fixed asset removal and nuclear waste management liability for the nine months ended September 30, 2006 and the year ended December 31, 2005 are as follows:

(millions of dollars)	**September 30 2006**	**December 31 2005**
Liabilities, beginning of period	**8,759**	8,339
Increase in liabilities due to accretion	**375**	476
Increase in liabilities due to nuclear used fuel and nuclear waste management variable expenses	**27**	34
Liabilities settled by expenditures on waste management	**(112)**	(90)
Liabilities, end of period	**9,049**	8,759

OPG recognizes asset retirement obligations for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG has estimated both the amount and timing of future cash expenditures based on current plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

OPG has commenced the process to review and update the estimate of costs to complete under the ONFA Reference Plan, and is targeting for an updated approved Reference Plan (the 2006 Reference Plan) to be in place in 2006. The updated Reference Plan will likely result in a significant increase in OPG's liability for nuclear waste management and decommissioning, and a corresponding increase in the carrying value of the nuclear generating stations to which this liability relates.

Ontario Nuclear Funds Agreement

OPG sets aside and invests funds in segregated custodian accounts 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, 2006 and December 31, 2005, consist of the following:

(millions of dollars)	Amortized Cost Basis September 30 2006	Amortized Cost Basis December 31 2005	Fair Value September 30 2006	Fair Value December 31 2005
Decommissioning Fund	**4,290**	4,106	**4,804**	4,583
Due to Province – Decommissioning Fund	**(21)**	(7)	**(535)**	(484)
	4,269	4,099	**4,269**	4,099
Used Fuel Fund [1]	**3,165**	2,693	**3,506**	2,995
Due (to) from Province – Used Fuel Fund	**(46)**	(4)	**(387)**	(306)
	3,119	2,689	**3,119**	2,689
	7,388	6,788	**7,388**	6,788

[1] The Ontario NFWA Trust represents $1,087 million as at September 30, 2006 (December 31, 2005 – $1,003 million) of the Used Fuel Fund on an amortized cost basis.

9. INCOME TAXES

The following table summarizes the difference in the balance sheet amounts under the taxes payable method used by the Company to account for income taxes compared to what would have been reported had OPG applied the liability method for the regulated business as at September 30, 2006 and December 31, 2005:

(millions of dollars)	September 30, 2006 As Stated	September 30, 2006 Liability Method	December 31, 2005 As Stated	December 31, 2005 Liability Method
Future income tax assets – current	**12**	**32**	18	38
Long-term future income tax liabilities	**(291)**	**(436)**	(241)	(344)

The following table summarizes the difference in the income statement amounts under the method used by the Company to account for income taxes compared to what would have been reported had OPG applied the liability method for the regulated business for the three and nine months ended September 30, 2006 and 2005:

(millions of dollars)	Three Months Ended September 30 2006	Three Months Ended September 30 2005	Nine Months Ended September 30 2006	Nine Months Ended September 30 2005
As Stated:				
Extraordinary item	**-**	-	**-**	74
Future income tax expense	**4**	37	**56**	15
Liability Method:				
Future income tax expense	**28**	94	**98**	125

The amount of cash income taxes paid during the three months ended September 30, 2006 was $4 million (three months ended September 30, 2005 – $6 million). For the nine months ended September 30, 2006, cash income taxes paid were $18 million (nine months ended September 30, 2005 – $15 million).

During the three months ended June 30, 2005, OPG recorded a one-time extraordinary loss of $74 million as a result of the adoption of rate regulated accounting for income taxes related to the rate regulated business segments.

The Company has revised its future income tax assets and liabilities to reflect the lower federal income tax rates recently enacted.

OPG has taken certain filing positions for corporate income and capital taxes that may be challenged on audit and possibly disallowed and result in a significant increase in the tax obligation upon reassessment. There is still uncertainty around the amount of the tax provision, and Management is not able to determine the impact of that uncertainty on the consolidated financial statements.

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 2006 costs are based on a measurement of the pension and OPEB obligations and the pension fund assets, as at December 31, 2005.

Total benefit costs for the three and nine months ended September 30, 2006 and 2005 are as follows:

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2006**	**2005**	**2006**	**2005**
Registered pension plan	**54**	31	**163**	87
Supplementary pension plans	**4**	4	**11**	13
OPEB	**63**	45	**183**	127

11. FINANCIAL INSTRUMENTS

Contracts for all trading transactions are carried on the consolidated balance sheet as assets or liabilities at fair value, with changes in fair value recorded in trading revenue as gains or losses.

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.

Forward pricing information is inherently uncertain so that fair values of the derivative instruments may not accurately represent the cost to enter into these positions. To address the impact of some of this uncertainty on trading positions, OPG established liquidity reserves against the mark-to-market gains or losses of these positions. During the three months ended September 30, 2006, the liquidity reserve increased trading revenue by $3 million (three months ended September 30, 2005 – increased trading revenue by $16 million). During the nine months ended September 30, 2006, the liquidity reserves reduced trading revenue by $2 million (nine months ended September 30, 2005 – increased trading revenue by $23 million).

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.

(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Notional Quantity**	**Terms**	**Fair Value**
	September 30, 2006			**December 31, 2005**		
Gain (loss)						
Electricity derivative instruments	**4.6TWh**	**1-4 yrs**	**35**	4.1 TWh	1-2 yrs	(125)
Foreign exchange derivative instruments	**U.S. $5**	**Oct/06**	**-**	U.S. $15	Jan/06	-
Floating to fixed interest rate hedge	**46**	**1-12 yrs**	**3**	47	1-13 yrs	3
Forward start interest rate hedges	**660**	**1-14 yrs**	**(15)**	400	1-15 yrs	(7)

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, 2006 was U.S. $0.90 (December 31, 2005 – U.S. $0.87) for every Canadian dollar.

One of the Company's joint ventures is exposed to changes in interest rates. The joint venture entered into an interest rate swap to manage the risk arising from fluctuations in interest rates by swapping short-term floating interest rate with a fixed rate of 5.33 per cent. OPG's proportionate interest in the swap is 50 per cent and is accounted for as a hedge.

OPG entered into a number of forward start interest rate swap agreements to hedge against the effect of future interest rate movement based on the anticipated future borrowing requirement for the Niagara Tunnel project. These transactions are accounted for as hedges.

Derivative Instruments Not Used for Hedging Purposes

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

(millions of dollars except where noted)	**Notional Quantity**	**Fair Value**	**Notional Quantity**	**Fair Value**
	September 30, 2006		**December 31, 2005**	
Foreign exchange derivative	**-**	**-**	U.S. $3	-
Commodity derivative instruments				
Assets	**5.8TWh**	**28**	3.3 TWh	13
Liabilities	**1.8TWh**	**(27)**	1.1 TWh	(37)
		1		(24)
Liquidity reserve		**(5)**		(3)
Total		**(4)**		(27)

Foreign exchange derivative instruments that were not designated as hedges had a weighted average exchange rate of U.S. $0.85 as at December 31, 2005.

12. COMMITMENTS AND CONTINGENCIES

Litigation

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.

In July 2004, OPG and two individual OPG employees were each charged with criminal negligence causing death and criminal negligence causing bodily harm in relation to a 2002 drowning accident at Barrett Chute. Further to a recent summary application by all three, OPG was acquitted of all charges on November 14, 2006. The two employees remain defendants.

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.

On August 9, 2006, a Notice of Action and Statement of Claim in the amount of $500 million (the "Claim") was served on OPG and Bruce Power L.P. by British Energy Limited and British Energy International Holdings Limited ("British Energy"), claiming that OPG is liable to them for breach of contract and negligence. OPG leased the Bruce nuclear generating stations to Bruce Power L.P. in 2001. British Energy was an investor in Bruce Power L.P. In 2003, British Energy sold its interest in Bruce Power L.P. to a group of investors (the "Purchasers"). The Purchasers are claiming that British Energy is liable to them with respect to this purchase transaction. Their claim is currently the subject of an arbitration proceeding (the "Arbitration"). British Energy is therefore suing OPG in order to preserve any similar claim it may have against OPG pursuant to the 2001 lease transaction. British Energy has indicated that it does not require OPG to actively defend the Claim at this point in time as British Energy is defending the Arbitration commenced by the Purchasers. The Arbitration may narrow or eliminate the claims or damages British Energy has, so as to narrow or eliminate the need to continue the Claim against OPG. British Energy has reserved the right to require OPG to defend the Claim prior to the conclusion of the Arbitration should British Energy at some point believe there is some advantage of doing so.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably with respect to OPG and could have a significant effect on OPG's financial position. Management has provided for contingencies that are determined to be likely and are reasonably measurable.

Environmental

OPG was required to assume certain environmental obligations from Ontario Hydro. A provision of $76 million was established as at April 1, 1999 for such obligations. During the nine months ended September 30, 2006, expenditures of $3 million (nine months ended September 30, 2005 – $1 million) were recorded against the provision. As at September 30, 2006, the remaining provision was $53 million (December 31, 2005 – $56 million).

Current operations are subject to regulation with respect to air, soil and water quality and other environmental matters by federal, provincial and local authorities. The cost of obligations associated with current operations is provided for on an ongoing basis. Management believes it has made adequate provision in its consolidated financial statements to meet OPG's current environmental obligations.

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.

Other

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. PEC signed a 20 year Accelerated Clean Energy Supply ("ACES") contract with the OPA during the third quarter of 2006. PEC has also entered into an engineer-procure-construct ("EPC") contract to construct the facility. A significant proportion of expenditures on the project of $730 million will be made under the EPC contract. OPG provided third party financial guarantees in support of the Portlands Energy Centre project totaling $63 million.

13. RESTRUCTURING

The change in the restructuring liability for termination benefits for the nine months ended September 30, 2006 and the year ended December 31, 2005 are as follows:

(millions of dollars)	September 30 2006	December 31 2005
Liability, beginning of period	**12**	20
Restructuring charges	**-**	10
Payments	**(7)**	(18)
Liability, end of period	**5**	12

14. REVENUE LIMIT REBATE

Eighty-five per cent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station and forward sales as of January 1, 2005, is subject to a revenue limit. The output from a generating unit where there has been a fuel conversion and the incremental output from a generating station where there has been a refurbishment or expansion of these assets is also excluded from the output covered by the revenue limit. In addition, until the Transition – Generation Corporation Designated Rate Options ("TRO") expired on April 30, 2006, volumes sold under such options were also excluded from the revenue limit rebate. This revenue limit, which was originally established for a period of 13 months ending April 30, 2006, was subsequently extended for an additional three years. Starting May 1, 2006, the revenue limit decreased to 4.6¢/kWh from the previous limit of 4.7¢/kWh. On May 1, 2007, the revenue limit will return to 4.7¢/kWh and increase to 4.8¢/kWh effective May 1, 2008. In addition, beginning May 1, 2006, volumes sold under a Pilot Auction administered by the Ontario Power Authority ("OPA") are subject to a revenue limit that is 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Furthermore, the Pilot Auction revenue limit will increase by 0.1¢/kWh on May 1, 2007 and again on May 1, 2008. Revenues above these limits are returned to the IESO for the benefit of consumers.

The change in the revenue limit rebate liability for the nine months ended September 30, 2006 and the year ended December 31, 2005 are as follows:

(millions of dollars)	September 30 2006	December 31 2005
Liability, beginning of the year	**739**	-
Increase to provision during the period	**148**	739
Payments made during the period	**(802)**	-
Liability, end of period	**85**	739

15. BUSINESS SEGMENTS

Effective April 1, 2005, the output from most of OPG's baseload hydroelectric facilities and all of its nuclear facilities became rate regulated. With the introduction of rate regulation, OPG revised its reportable business segments to separately reflect the regulated and unregulated aspects of its business. In the first quarter of 2006, OPG separated the Unregulated Generation business segment into two reportable segments identified as Unregulated – Fossil-Fuelled and Unregulated – Hydroelectric, as a result of changes in the management structure of these segments. Results for the comparative periods have been reclassified to reflect the revised disclosure.

Operations, maintenance and administration ("OM&A") expenses of the generation business segments include a service fee for the use of certain property, plant and equipment of the Other category. The total service fee allocation is recorded as a reduction to the Other category's OM&A expenses. For the three months ended September 30, 2006, the service fee allocation was $7 million for Regulated – Nuclear, $1 million for Regulated – Hydroelectric, $1 million for Unregulated – Hydroelectric and $2 million for Unregulated – Fossil-Fuelled, with a corresponding reduction in OM&A expenses of $11 million for the Other category. For the nine months ended September 30, 2006, the service fee was $19 million for Regulated – Nuclear, $2 million for Regulated – Hydroelectric, $3 million for Unregulated – Hydroelectric and $6 million for Unregulated – Fossil-Fuelled, with a reduction in expenses of $30 million for the Other category. Results of the comparative periods have been reclassified to reflect the service fee.

	Regulated		**Unregulated**			
Segment Income for Three Months Ended September 30, 2006	**Nuclear**	**Hydro-electric**	**Hydro-electric**	**Fossil-Fuelled**	**Other**	**Total**
(millions of dollars)						
Revenue before revenue limit rebate	**722**	**175**	**133**	**422**	**42**	**1,494**
Revenue limit rebate	**-**	**-**	**(16)**	**(43)**	**-**	**(59)**
	722	**175**	**117**	**379**	**42**	**1,435**
Fuel expense	**34**	**62**	**15**	**199**	**-**	**310**
Gross margin	**688**	**113**	**102**	**180**	**42**	**1,125**
Operations, maintenance and administration	**446**	**26**	**47**	**115**	**-**	**634**
Depreciation and amortization	**85**	**16**	**17**	**17**	**13**	**148**
Accretion on fixed asset removal and nuclear waste management liabilities	**123**	**-**	**-**	**2**	**-**	**125**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(82)**	**-**	**-**	**-**	**-**	**(82)**
Property and capital taxes	**15**	**6**	**4**	**7**	**3**	**35**
Income before interest, income taxes and extraordinary item	**101**	**65**	**34**	**39**	**26**	**265**

Segment Income (Loss) for Three Months Ended September 30, 2005	Regulated Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Unregulated Fossil-Fuelled	Other	Total
(millions of dollars)						
Revenue before revenue limit rebate	662	202	189	853	1	1,907
Revenue limit rebate	-	-	(71)	(265)	-	(336)
	662	202	118	588	1	1,571
Fuel expense	31	64	12	277	-	384
Gross margin	631	138	106	311	1	1,187
Operations, maintenance and administration	457	20	37	107	6	627
Depreciation and amortization	88	17	14	47	15	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	4	6	11	26
Restructuring	-	-	-	4	2	6
Income (Loss) before interest, income taxes and extraordinary item	65	96	51	145	(33)	324

Segment Income for Nine Months Ended September 30, 2006	Regulated Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Unregulated Fossil-Fuelled	Other	Total
(millions of dollars)						
Revenue before revenue limit rebate	**2,067**	**514**	**587**	**1,150**	**118**	**4,436**
Revenue limit rebate	**-**	**-**	**(42)**	**(106)**	**-**	**(148)**
	2,067	**514**	**545**	**1,044**	**118**	**4,288**
Fuel expense	**93**	**174**	**60**	**504**	**-**	**831**
Gross margin	**1,974**	**340**	**485**	**540**	**118**	**3,457**
Operations, maintenance and administration	**1,399**	**70**	**128**	**375**	**(5)**	**1,967**
Depreciation and amortization	**254**	**49**	**49**	**113**	**39**	**504**
Accretion on fixed asset removal and nuclear waste management liabilities	**368**	**-**	**-**	**7**	**-**	**375**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(274)**	**-**	**-**	**-**	**-**	**(274)**
Property and capital taxes	**34**	**14**	**11**	**15**	**8**	**82**
Income before interest, income taxes and extraordinary item	**193**	**207**	**297**	**30**	**76**	**803**

Segment (Loss) Income for Nine Months Ended September 30, 2005	Regulated Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Unregulated Fossil-Fuelled	Other	Total
(millions of dollars)						
Revenue before revenue limit and Market Power Mitigation Agreement rebates	1,942	674	699	1,828	48	5,191
Revenue limit rebate	-	-	(122)	(355)	-	(477)
Market Power Mitigation Agreement rebate	(160)	(65)	(58)	(129)	-	(412)
	1,782	609	519	1,344	48	4,302
Fuel expense	85	186	54	658	-	983
Gross margin	1,697	423	465	686	48	3,319
Operations, maintenance and administration	1,324	56	101	326	23	1,830
Depreciation and amortization	267	51	47	158	43	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	21	14	11	15	3	64
Restructuring	-	-	-	4	2	6
(Loss) income before impairment of long-lived assets	13	302	306	176	(23)	774
Impairment of long-lived assets	63	-	-	202	-	265
(Loss) income before interest, income taxes and extraordinary item	(50)	302	306	(26)	(23)	509

(millions of dollars)	Regulated Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Unregulated Fossil-Fuelled	Other	Total
Selected Balance Sheet Information						
As at September 30, 2006 Segment property, plant and equipment, net	**3,025**	**4,128**	**3,076**	**466**	**638**	**11,333**
As at December 31, 2005 Segment property, plant and equipment, net	3,156	4,054	3,076	531	595	11,412
Selected Cash Flow Information						
Three months ended September 30, 2006 Investment in fixed assets	**40**	**51**	**24**	**19**	**54**	**188**
Three months ended September 30, 2005 Investment in fixed assets	54	29	12	11	8	114
Nine months ended September 30, 2006 Investment in fixed assets	**118**	**121**	**50**	**47**	**86**	**422**
Nine months ended September 30, 2005 Investment in fixed assets	214	66	27	32	14	353

16. CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	Three Months Ended September 30 2006	Three Months Ended September 30 2005	Nine Months Ended September 30 2006	Nine Months Ended September 30 2005
Accounts receivable	**37**	(34)	**308**	(85)
Fuel inventory	**12**	(10)	**(36)**	63
Materials and supplies	**(4)**	(2)	**1**	(28)
Revenue limit rebate payable	**59**	336	**148**	477
Market Power Mitigation Agreement rebate payable	**-**	-	**-**	412
Accounts payable and accrued charges	**(11)**	(28)	**(167)**	(133)
Income and capital taxes payable	**50**	55	**86**	66
	143	317	**340**	772

17. 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. Regulated prices for the baseload hydroelectric and nuclear facilities, the revenue limit related to the generation from OPG’s other generating assets and OPG’s hedging strategies significantly reduced the impact of seasonal price fluctuations on the results of operations.