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News
from Ontario Power Generation

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ONTARIO POWER GENERATION REPORTS 2011 SECOND QUARTER FINANCIAL RESULTS

[Toronto]: Ontario Power Generation Inc. ("OPG" or the "Company") today reported its financial and operating results for the three and six months ended June 30, 2011. Net income for the second quarter of 2011 was $114 million compared to a net loss of $29 million for the same period in 2010. Net income for the six months ended June 30, 2011 was $265 million compared to net income of $114 million for the same period in 2010.

Tom Mitchell, President and CEO said, the company is pleased with its operational and financial performance. "When OPG performs well, it benefits all of Ontario because OPG is owned by the people of this province."

He noted that the strong results were achieved even though OPG continued to receive comparatively low rates for its output. "Our average sales price for the first six months of this year was 4.6 cents a kilowatt hour. That is unchanged from the average price for the first six months in 2010 and considerably below prices received by other electricity generators in the province."

"The results speak to the affordability of power generated from our nuclear and hydroelectric assets as a safe, reliable and cost effective form of electricity, which has a moderating effect on Ontario's electricity prices."

Highlights

OPG's net income in the second quarter of 2011 increased by $143 million compared to the second quarter of 2010. The increase was primarily due to higher earnings from the Decommissioning and Used Fuel Segregated Funds (together the "Nuclear Funds") and lower operations, maintenance and administration ("OM&A") expenses. The higher earnings from the Nuclear Funds were largely due to an increase in the valuation levels of global financial markets compared to a decline in valuation levels during the second quarter of 2010. The lower OM&A expenses for the second quarter of 2011 compared to the same quarter of 2010 were primarily due to lower nuclear outage and project costs and lower expenditures at OPG's thermal generating stations.

The increase in net income for the second quarter of 2011 compared to the second quarter of 2010 was partially offset by an increase in income tax expense. The increase in income tax expense was primarily due to the resolution during the second quarter of 2010 of a number of tax uncertainties related to prior taxation years.

The increase in net income for the six months ended June 30, 2011 compared to the same period in 2010 was primarily due to higher earnings from the Nuclear Funds and a decrease in OM&A expenses, partially offset by an increase in income tax expense.

Total electricity generated during the three month period ended June 30, 2011 was 20.7 terawatt hours ("TWh") compared to 19.7 TWh for the same period in 2010. This increase was primarily due to an increase in nuclear generation as a result of a decrease in planned outage days at the Pickering generating stations as all six units were shutdown during the Pickering Vacuum Building Outage in the second quarter of 2010, and higher generation from OPG's Unregulated – Hydroelectric segment, partially offset by a decrease in thermal generation. Higher generation from the Unregulated – Hydroelectric segment during the second quarter of 2011 was primarily a result of higher water flows relative to the same period in 2010. The decrease in thermal generation during the second quarter of 2011 was primarily due to higher generation from hydroelectric and nuclear stations in Ontario and lower demand in Ontario.

For the six months ended June 30, 2011, OPG's electricity generation was 42.9 TWh compared to 44.2 TWh during the same period in 2010. The decrease in electricity generation was largely due to a decrease in thermal generation caused by an increase in electricity generation from other generators in Ontario and higher generation from OPG's nuclear and hydroelectric stations. The increase in electricity generation from other generators in Ontario was primarily due to lower natural gas prices relative to coal prices.

The capability factor for the Darlington nuclear station decreased during the second quarter of 2011 compared to the second quarter of 2010 as a result of a higher number of planned outage days. For the six months ended June 30, 2011, a higher capability factor at the Darlington nuclear station compared to the same period in 2010 reflected a lower number of planned outage days. Higher capability factors at the Pickering A and B nuclear generating stations for the three and six months ended June 30, 2011 were primarily due to a decrease in planned outage days.

The availability of OPG's regulated hydroelectric stations during the three and six month periods ended June 30, 2011 was slightly lower than in the same periods in 2010 primarily as a result of an increase in planned maintenance and project outages, and an increase in forced outages at the Sir Adam Beck Pump generating station. The station availability of OPG's unregulated hydroelectric generating stations increased during the three and six months ended June 30, 2011 primarily as a result of improved equipment performance.

Equivalent forced outage rates at the thermal generating stations increased for the three and six months ended June 30, 2011 compared to the same periods in 2010 primarily due to an increase in the number of unplanned outage days at the Nanticoke and Lambton stations.

Generation Development

OPG is undertaking a number of generation development projects aimed at significantly contributing to Ontario's long-term electricity supply requirements. The status of these capacity expansion or life extension projects is as follows:

Nuclear

- On June 3, 2011, the Joint Review Panel overseeing the Darlington New Nuclear Project Environmental Assessment officially stated that sufficient information has been obtained to prepare their report. This date marks the commencement of the 90-day period in which the panel will prepare their environmental assessment report for submission to the federal Minister of the Environment.

- In June 2011, OPG received responses to its Request for Proposal for the Retube and Feeder Replacement for the Darlington generating station. The selection of a contractor is targeted for late 2011. The Environmental Assessment and the Integrated Safety Review, which forms the basis of the regulatory scope of the refurbishment project, are on track for submission to the CNSC in late 2011.

Hydroelectric

- The Niagara tunnel boring machine ("TBM") mining activity has been completed and the disassembly of the TBM is in progress. As of June 30, 2011, installation in the tunnel of the lower one-third of the permanent concrete lining reached 7,625 metres. This installation work has been temporarily interrupted since July 2, 2011 to reinforce a short section of the temporary tunnel liner that was overloaded by loose rock at 6,050 metres. This interruption is not expected to delay tunnel completion. Restoration of the circular cross-section of the tunnel before installation of the upper two-thirds of the concrete lining reached 4,422 metres and was behind schedule. Installation of the upper two-thirds of the concrete lining has progressed to 3,262 metres and is ahead of schedule. The Niagara Tunnel is expected to be completed within the approved budget of $1.6 billion and the approved project completion date of December 2013. As of June 30, 2011, life-to-date capital expenditures were $1,032 million. Upon completion of the project, the average annual generation from the Sir Adam Beck generating stations will increase by approximately 1.6 TWh.

- The Lower Mattagami River project will increase the capacity of four generating stations by 438 MW. During the second quarter of 2011, the intake excavation at the Smoky Falls station was completed, rock consolidation continued and concrete operations commenced. The cofferdam at the Little Long station was installed and excavation commenced. The cofferdam installation is in progress at the Harmon site. The project is expected to be completed within the approved budget of $2.6 billion and the approved completion date of June 2015. As of June 30, 2011, life-to-date capital expenditures were $516 million.

Thermal

- OPG and the Ontario Power Authority (“OPA”) are currently negotiating an energy supply agreement for the conversion of the Atikokan generating station to biomass fuel.

- OPG is proceeding with detailed engineering for the conversion of two units at the Thunder Bay station to natural gas.

- As outlined in Ontario’s Long-Term Energy Plan and Supply Mix Directive to the OPA, OPG continues to explore the possible conversion of some units at the Lambton and Nanticoke generating stations to natural gas, if required for system reliability.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Earnings				
Revenue	**1,226**	1,210	**2,534**	2,653
Fuel expense	**183**	210	**349**	457
Gross margin	**1,043**	1,000	**2,185**	2,196
Operations, maintenance and administration expense	**686**	781	**1,398**	1,508
Depreciation and amortization	**195**	174	**353**	340
Accretion on fixed asset removal and nuclear waste management liabilities	**177**	165	**349**	330
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(164)**	(40)	**(302)**	(181)
Restructuring	**-**	-	**-**	25
Capital and property taxes	**15**	24	**23**	43
Other gains	**(4)**	(1)	**(3)**	(2)
Income before interest and income taxes	**138**	(103)	**367**	133
Net interest expense	**41**	44	**82**	89
Income tax (recoveries) expenses	**(17)**	(118)	**20**	(70)
Net income (loss)	**114**	(29)	**265**	114
Income before interest and income taxes				
Generating segments	**131**	12	**375**	244
Nuclear Waste Management segment	**(14)**	(125)	**(48)**	(149)
Other segment	**21**	10	**40**	38
Total income (loss) before interest and income taxes	**138**	(103)	**367**	133
Cash flow				
Cash flow provided by operating activities	**153**	110	**562**	328
Electricity Generation (TWh)				
Regulated – Nuclear	**11.4**	9.6	**24.0**	21.6
Regulated – Hydroelectric	**5.0**	4.6	**9.6**	9.4
Unregulated – Hydroelectric	**4.1**	2.3	**8.1**	6.2
Unregulated – Thermal	**0.2**	3.2	**1.2**	7.0
Total electricity generation	**20.7**	19.7	**42.9**	44.2
Average electricity sales price (¢/kWh)				
Regulated – Nuclear	**5.5**	5.5	**5.5**	5.5
Regulated – Hydroelectric	**3.5**	3.7	**3.6**	3.7
Unregulated – Hydroelectric	**3.1**	4.0	**3.2**	3.7
Unregulated – Thermal	**2.1**	4.1	**2.9**	3.9
OPG average sales price paid through regulated and spot market prices	**4.5**	4.6	**4.6**	4.6
Nuclear unit capability factor (percent)				
Darlington	**86.2**	93.6	**92.0**	88.0
Pickering A	**72.9**	30.3	**71.2**	48.7
Pickering B	**72.0**	41.6	**77.1**	69.4
Availability (percent)				
Regulated – Hydroelectric	**87.5**	91.8	**89.7**	92.7
Unregulated– Hydroelectric	**94.3**	93.4	**94.1**	93.7
Equivalent forced outage rate (percent)				
Unregulated – Thermal	**11.7**	7.3	**9.3**	4.8

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 six months ended June 30, 2011, 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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ONTARIO POWER GENERATION

2011 SECOND QUARTER REPORT

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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 six month periods ended June 30, 2011. For a complete description of OPG's corporate strategies, risk management, corporate governance, related parties transactions 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, 2010. Certain of the 2010 comparative amounts have been reclassified to conform to the 2011 presentation. 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 August 24, 2011.

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.

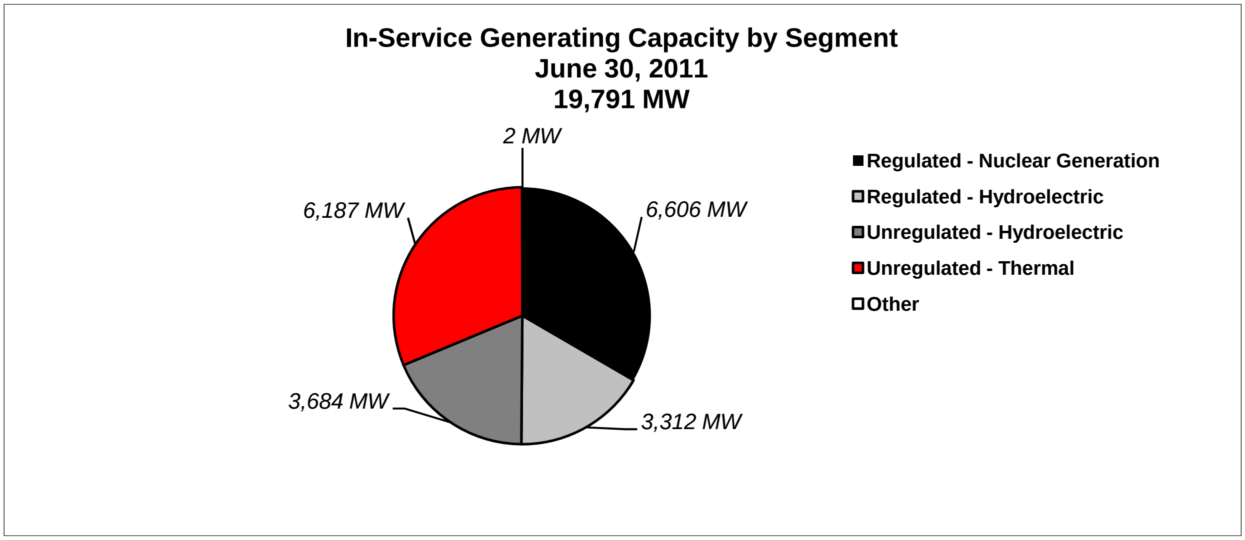
All forward-looking statements involve inherent assumptions, risks and uncertainties, including those set out under the heading *Risk Management,* and therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's fuel costs and availability, asset performance, nuclear decommissioning and waste management, closure or conversion 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 electricity market prices, the on-going evolution of the Ontario electricity industry, proposed new legislation, conversion to International Financial Reporting Standards ("IFRS"), environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, and the impact of regulatory decisions by the Ontario Energy Board ("OEB"). 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. Except as required by applicable securities laws, 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 generation and sale of electricity from its generating assets, while operating in a safe, open and environmentally responsible manner. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario.

As at June 30, 2011, OPG's electricity generating portfolio had an in-service capacity of 19,791 megawatts ("MW"), representing 57 percent of Ontario's installed electricity generating capacity. OPG operates three nuclear generating stations, five thermal generating stations, 65 hydroelectric generating stations, and two wind power turbines. In addition, OPG and TransCanada Energy Ltd. co-own the Portlands Energy Centre ("PEC") gas-fired combined cycle generating station. OPG and ATCO Power Canada Ltd. co-own the Brighton Beach gas-fired combined cycle 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"). These co-owned facilities and leased stations are incorporated into OPG's financial results, but are not included in the generation portfolio statistics set out in this report. A description of OPG's segments is provided in OPG's 2010 annual MD&A under the heading, *Business Segments*.

In May 2011, the in-service capacity of the Unregulated – Thermal segment decreased by 140 MW as a result of a reduction in the net Maximum Continuous Rating ("MCR") of the Nanticoke coal-fired generating station. The reduction in MCR reflects the decision to limit capital investments in a unit scheduled for closure in 2011. This decision was made with consideration of the forecast energy requirements from the thermal generating stations for the remainder of 2011.



Revenue Mechanisms for Regulated and Unregulated Generation

OPG receives regulated prices for 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 (collectively the "Prescribed Facilities"). In March 2011, the OEB issued its decision on OPG's application for new regulated prices. Following its decision, in its April 2011 order, the OEB established a new regulated price for production from OPG's regulated hydroelectric facilities at $34.13/MWh, and a new regulated price for production from OPG's nuclear facilities at $55.85/MWh, effective March 1, 2011. The new regulated prices include rate riders reflecting the OEB's approval for recovery or repayment of variance and deferral account balances as at December 31, 2010. The regulated hydroelectric price is net of a negative rate rider of -$1.65/MWh. The nuclear regulated price includes a rate rider of $4.33/MWh. The rate riders will remain in effect until December 31, 2012.

The following reflects the new regulated prices effective March 1, 2011 compared to those in effect prior to March 1, 2011:

($/MWh)	Effective March 1, 2011	Prior to March 1, 2011[1]
Nuclear without rate rider	**51.52**	52.98
Nuclear rate rider	**4.33**	2.00
Nuclear regulated price	**55.85**	54.98
Hydroelectric without rate rider	**35.78**	36.66
Hydroelectric rate rider	**(1.65)**	-
Hydroelectric regulated price	**34.13**	36.66

[1] Regulated prices were effective for the period April 1, 2008 to February 28, 2011.

Electricity generated from OPG's other generating assets remains unregulated and continues to receive the Ontario electricity spot market price, except where an energy supply or cost recovery agreement is in place.

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 segment is included under the heading, *Discussion of Operating Results by Business Segment*.

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of dollars – except where noted)	**2011**	**2010**	**2011**	**2010**
Revenue	**1,226**	1,210	**2,534**	2,653
Fuel expense	**183**	210	**349**	457
Gross margin	**1,043**	1,000	**2,185**	2,196
Expenses				
Operations, maintenance and administration	**686**	781	**1,398**	1,508
Depreciation and amortization	**195**	174	**353**	340
Accretion on fixed asset removal and nuclear waste management liabilities	**177**	165	**349**	330
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(164)**	(40)	**(302)**	(181)
Restructuring	**-**	-	**-**	25
Property and capital taxes	**15**	24	**23**	43
Other gains	**(4)**	(1)	**(3)**	(2)
	905	1,103	**1,818**	2,063
Income (loss) before interest and income taxes	**138**	(103)	**367**	133
Net interest expense	**41**	44	**82**	89
Income tax (recovery) expense	**(17)**	(118)	**20**	(70)
Net income (loss)	**114**	(29)	**265**	114
Electricity production (TWh)	**20.7**	19.7	**42.9**	44.2
Cash flow				
Cash flow provided by operating activities	**153**	110	**562**	328

Net income for the three months ended June 30, 2011 was $114 million compared to a net loss of $29 million for the three months ended June 30, 2010. Income before income taxes for the three months ended June 30, 2011 was $97 million compared to a loss before income taxes of $147 million for the same period in 2010.

Net income for the six months ended June 30, 2011 was $265 million compared to $114 million for the six months ended June 30, 2010. Income before income taxes for the six months ended June 30, 2011 was $285 million compared to $44 million for the same period in 2010.

Earnings before Income Taxes for the Three Months Ended June 30, 2011

The following is a summary of the factors impacting OPG's results before income taxes for the three months ended June 30, 2011 compared to the same period in 2010, on a before-tax basis:

(millions of dollars)	Electricity Generation Segments[1]	Regulated Nuclear Waste Management Segment	Other[2]	Total
Income (loss) before income taxes for the three months ended June 30, 2010	**12**	**(125)**	**(34)**	**(147)**
Changes in gross margin:				
Change in electricity sales price:				
Regulated generation segments	2	-	-	2
Unregulated – Hydroelectric	(44)	-	-	(44)
Change in electricity generation by segment:				
Regulated – Nuclear Generation	94	-	-	94
Regulated – Hydroelectric	5	-	-	5
Unregulated – Hydroelectric	66	-	-	66
Decrease in thermal generation revenue and higher fuel-related costs primarily pertaining to favourable adjustments in thermal inventory during the second quarter of 2010 and adjustments to coal supply contracts during the second quarter of 2011, partially offset by a decrease in fuel costs primarily due to lower generation, and higher revenue related to the contingency support agreement for the Nanticoke and Lambton generating stations	(40)	-	-	(40)
Decrease in gross margin due to the cessation of additions to the Tax Loss Variance Account based on the OEB's March 2011 decision on new regulated prices	(49)	-	-	(49)
(Decrease) increase in non-electricity generation revenue, net of the impact of the regulatory variance account associated with stations on lease to Bruce Power	(13)	2	3	(8)
Other changes in gross margin	15	-	2	17
	36	2	5	43
Changes in operations, maintenance and administration ("OM&A") expenses:				
Lower expenditures related to decrease in outage and project costs, partially offset by an increase in maintenance activities at OPG's nuclear generating stations	60	-	-	60
Lower expenditures due to the continuation of vacancy and overtime management programs and reduced scope of work associated with changing operating profiles at OPG's thermal generating stations	23	-	-	23
Reduction in expenditures related to new nuclear generation development and capacity refurbishment, net of the impact of related regulatory variance accounts	13	-	-	13
Increase in pension and OPEB costs largely as a result of lower discount rates in 2011, net of the impact of the regulatory variance account	(15)	-	-	(15)
Other changes in OM&A expenses	18	(2)	(2)	14
	99	(2)	(2)	95
Increase in earnings from the Nuclear Funds	-	217	-	217
Impact of the regulatory variance account associated with stations on lease to Bruce Power on earnings from the Nuclear Funds	-	(93)	-	(93)
Increase in amortization expense due to the amortization of regulatory balances as a result of the OEB's decision effective March 1, 2011	(35)	-	-	(35)
Other changes	19	(13)	11	17
Income (loss) before income taxes for the three months ended June 30, 2011	**131**	**(14)**	**(20)**	**97**

[1] Electricity generation segments include results of the Regulated – Nuclear Generation, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal segments.

[2] Other includes results of the Other category in OPG's segmented statement of income, inter-segment eliminations, and net interest expense.

Earnings before Income Taxes for the Six Months Ended June 30, 2011

The following is a summary of the factors impacting OPG's results before income taxes for the six months ended June 30, 2011 compared the same period in 2010, on a before-tax basis:

(millions of dollars)	Electricity Generation Segments[1]	Regulated Nuclear Waste Management Segment	Other[2]	Total
Income (loss) before income taxes for the six months ended June 30, 2010	**244**	**(149)**	**(51)**	**44**
Changes in gross margin:				
Change in electricity sales price:				
Regulated generation segments	8	-	-	8
Unregulated – Hydroelectric	(54)	-	-	(54)
Change in electricity generation by segment:				
Regulated – Nuclear Generation	123	-	-	123
Regulated – Hydroelectric	1	-	-	1
Unregulated – Hydroelectric	68	-	-	68
Decrease in thermal generation revenue and higher fuel-related costs primarily pertaining to favourable adjustments in thermal inventory during the second quarter of 2010 and adjustments to coal supply contracts during the second quarter of 2011, partially offset by a decrease in fuel costs primarily due to lower generation, and higher revenue related to the contingency support agreement for the Nanticoke and Lambton generating stations	(55)	-	-	(55)
Lower revenue recognized related to an energy supply contract for the Lennox generating station	(20)	-	-	(20)
Decrease in gross margin due to the cessation of additions to the Tax Loss Variance Account based on the OEB's March 2011 decision on new regulated prices	(64)	-	-	(64)
(Decrease) increase in non-electricity generation revenue, net of the impact of the regulatory variance account associated with stations on lease to Bruce Power	(25)	3	2	(20)
Other changes in gross margin	8	-	(6)	2
	(10)	3	(4)	(11)
Changes in OM&A expenses:				
Lower expenditures related to decrease in outage and project costs, partially offset by an increase in maintenance activities at OPG's nuclear generating stations	103	-	-	103
Lower expenditures due to the continuation of vacancy and overtime management programs and reduced scope of work associated with changing operating profiles at OPG's thermal generating stations	32	-	-	32
Reduction in expenditures related to new nuclear generation development and capacity refurbishment, net of the impact of related regulatory variance accounts	19	-	-	19
(Increase) decrease in pension and OPEB costs largely as a result of lower discount rates in 2011, net of the impact of the regulatory variance account	(63)	1	-	(62)
Other changes in OM&A expenses	25	(5)	(2)	18
	116	(4)	(2)	110
Increase in earnings from the Nuclear Funds	-	201	-	201
Impact of the regulatory variance account associated with stations on lease to Bruce Power on earnings from the Nuclear Funds	-	(80)	-	(80)
Increase in amortization expense due to the amortization of regulatory balances as a result of the OEB's decision effective March 1, 2011	(30)	-	-	(30)
Severance costs related to closure of coal-fired units recognized in 2010	25	-	-	25
Other changes	30	(19)	15	26
Income (loss) before income taxes for the six months ended June 30, 2011	**375**	**(48)**	**(42)**	**285**

[1] Electricity generation segments include results of the Regulated – Nuclear Generation, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal segments.

[2] Other includes results of the Other category in OPG's segmented statement of income, inter-segment eliminations, and net interest expense.

Income Tax Expense

For the three months ended June 30, 2011, income tax recovery was $17 million compared to $118 million for the same period in 2010. The decrease in income tax recovery was primarily due to a higher reduction of income tax liabilities during the second quarter of 2010 resulting from the resolution of tax uncertainties related to prior taxation years.

For the six months ended June 30, 2011, income tax expense was $20 million compared to income tax recovery of $70 million for the same period in 2010. The increase in income tax expense was primarily due to a higher reduction of income tax liabilities during the second quarter of 2010 resulting from the resolution of tax uncertainties related to prior taxation years and higher net temporary differences, partially offset by a lower income tax component of the Bruce Lease Net Revenues Variance Account.

Electricity Generation

OPG's electricity generation for the three and six month periods ended June 30, 2011 and 2010, was as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
(TWh)	**2011**	**2010**	**2011**	**2010**
Regulated – Nuclear Generation	**11.4**	9.6	**24.0**	21.6
Regulated – Hydroelectric	**5.0**	4.6	**9.6**	9.4
Unregulated – Hydroelectric	**4.1**	2.3	**8.1**	6.2
Unregulated – Thermal	**0.2**	3.2	**1.2**	7.0
Total electricity generation	**20.7**	19.7	**42.9**	44.2

Total electricity generation during the three months ended June 30, 2011 was 20.7 TWh compared to 19.7 TWh for the same period in 2010. Electricity generation from the Regulated – Nuclear Generation segment increased by 1.8 TWh during the second quarter of 2011 compared to the second quarter of 2010 primarily due to a decrease in planned outage days at the Pickering generating stations as a result of the Pickering Vacuum Building outage in the second quarter of 2010, partially offset by lower generation at the Darlington generating station due to an increase in planned outage days and the impact of higher unplanned outage days at Pickering A. Electricity generation from the Unregulated – Hydroelectric segment increased by 1.8 TWh during the second quarter of 2011 compared to the second quarter of 2010 primarily due to higher water flows relative to the same period in 2010. The decrease in thermal generation of 3.0 TWh during the second quarter of 2011 compared to the second quarter of 2010 was primarily due to an increase in baseload generation from hydroelectric and nuclear, and lower primary demand in Ontario. Ontario primary electricity demand for the three months ended June 30, 2011 was 32.8 TWh compared to 33.4 TWh for the same period in 2010.

Total electricity generation during the six months ended June 30, 2011 was 42.9 TWh compared to 44.2 TWh for the same period in 2010. The decrease in electricity generation was largely due to a decrease in thermal generation, partially offset by higher nuclear and hydroelectric generation. Electricity generation from the Unregulated – Thermal segment decreased by 5.8 TWh during the first half of 2011 compared to the same period in 2010 primarily due to an increase in electricity generation from other generators in Ontario and higher generation from OPG's nuclear and hydroelectric generating stations. The increase in electricity generation from other generators in Ontario was primarily due to lower natural gas prices relative to coal prices. Electricity generation from the Regulated – Nuclear Generation segment increased by 2.4 TWh during the first half of 2011 compared to the same period in 2010 primarily due to a decrease in planned outage days at the Pickering generating stations and lower planned outages days at the Darlington generating station. The decrease in outage days at the Pickering generating stations was primarily a result of the Pickering Vacuum Building outage in the second quarter of 2010. The increase in generation was partially offset by the impact of higher unplanned outage days at the Pickering A nuclear generating station. Electricity generation from the Unregulated – Hydroelectric segment increased by 1.9 TWh during the first half of 2011 compared to same period in 2010 primarily due to higher water flows relative to the same period in 2010.

Average Sales Prices

The weighted average Ontario spot electricity market price and OPG's average sales prices from generation paid through the regulated prices and the hourly Ontario spot market prices, by reportable electricity segment for the three and six month periods ended June 30, 2011 and 2010, were as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
(¢/kWh)	**2011**	**2010**	**2011**	**2010**
Weighted average hourly Ontario spot electricity market price	**3.0**	3.8	**3.2**	3.6
Regulated – Nuclear Generation	**5.5**	5.5	**5.5**	5.5
Regulated – Hydroelectric	**3.5**	3.7	**3.6**	3.7
Unregulated – Hydroelectric	**3.1**	4.0	**3.2**	3.7
Unregulated – Thermal	**2.1**	4.1	**2.9**	3.9
OPG's average sales price paid through regulated and spot market prices[1]	**4.5**	4.6	**4.6**	4.6

[1] Excludes other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton, and Lennox generating stations. Had the cost recovery agreements for Nanticoke, Lambton, and Lennox generating stations been included, OPG's average sales price would have been 5.1¢/kWh for the three and six month periods ended June 30, 2011 and 5.1¢/kWh and 5.0¢/kWh, respectively, during the same periods in 2010.

The changes in average sales prices for the regulated segments for the three and six month periods ended June 30, 2011 reflect the OEB's March 2011 decision establishing new regulated prices effective March 1, 2011, as discussed under the heading, *Revenue Mechanisms for Regulated and Unregulated Generation*.

The decrease in average sales prices for the Unregulated – Hydroelectric and the Unregulated – Thermal segments for the three and six month periods ended June 30, 2011 compared to the same periods in 2010 was primarily due to the impact of lower average hourly Ontario spot electricity market prices. The decrease in the weighted average hourly Ontario spot electricity market price for the three months ended June 30, 2011 compared to the same period in 2010 was primarily due to higher hydroelectric and nuclear generation in Ontario. The decrease in the weighted average hourly Ontario spot electricity market price for the six months ended June 30, 2011 compared to the same period in 2010 was primarily due to higher hydroelectric and nuclear generation in Ontario, and lower natural gas prices.

Cash Flow from Operations

Cash flow provided by operating activities for the three months ended June 30, 2011 was $153 million compared to $110 million for the three months ended June 30, 2010. The increase in cash flow was primarily due to lower fuel purchases and tax installments in the second quarter of 2011 compared to the same period in 2010.

Cash flow provided by operating activities for the six months ended June 30, 2011 was $562 million compared to cash flow provided by operating activities of $328 million for the same period in 2010. The increase in cash flow was primarily due to lower OM&A expenditures, lower fuel purchases, a cash payment in the first half of 2010 to reflect a payment related to a derivative embedded in the Bruce lease for the 2009 calendar year, and lower tax installments compared to the same period in 2010. This increase was partially offset by lower cash receipts as a result of lower generation revenue for the six months ended June 30, 2011 compared to the same period in 2010.

Recent Developments

OPG's Motion and Appeal of the OEB's Decision

In its March 10, 2011 decision on the new regulated prices for OPG's Prescribed Facilities, the OEB did not accept OPG's proposal for a variance account related to differences between actual and forecast pension and OPEB costs and did not incorporate an updated forecast reflecting an increase in these costs submitted by OPG in September 2010. At the end of March 2011, OPG filed a motion asking the OEB to review and vary its decision with respect to the updated pension and OPEB costs and the proposed variance account. On June 23, 2011, the OEB issued a decision and order that varied the March 2011 decision in the manner requested by OPG. As requested by OPG, the OEB accepted OPG's updated forecast of September 2010 and established the Pension and OPEB Cost Variance Account effective March 1, 2011. The variance account will record the difference between actual pension and OPEB costs and related tax impacts for 2011 and 2012, and those reflected in the current regulated prices. The account is effective until December 31, 2012, and the balance will be reviewed by the OEB as part of OPG's next application for regulated prices. During the second quarter of 2011, OPG recorded a regulatory asset of $41 million related to this variance account, resulting in reductions to OM&A expenses and income tax expense of $30 million and $11 million, respectively.

In April 2011, OPG also filed a notice of appeal with the Divisional Court of Ontario related to the OEB's March 2011 decision disallowing recovery in regulated prices of a portion of OPG's nuclear compensation costs. The appeal is scheduled to be heard in late October of 2011.

Thermal Generating Stations Unit Closure

Ontario's Long-Term Energy Plan (the "Energy Plan") released in November 2010 and the Supply Mix Directive issued to the Ontario Power Authority ("OPA") in February 2011 require the safe shutdown of two additional coal-fired units at the Nanticoke coal-fired generating station in 2011. The Independent Electricity System Operator ("IESO") has confirmed that these units are not required for meeting supply adequacy and system reliability during the period from December 31, 2011 through December 31, 2014.

On March 25, 2011, OPG notified key stakeholders, including the Society of Energy Professionals ("The Society") and the Power Workers' Union ("PWU"), of the decision in accordance with their respective collective bargaining agreements. The total restructuring costs associated with the unit closures are estimated to be within the range of $22 million to $28 million and are expected to be recorded in 2011 and 2012. Additionally, costs of approximately $10 million will be incurred as a result of changes to equipment and power systems at the Nanticoke coal-fired generating station necessitated by the closure of the two additional units.

VISION, CORE BUSINESS AND STRATEGY

OPG's mandate is to reliably and cost-effectively produce electricity from its diversified portfolio of generating assets, while operating in a safe, open, and environmentally responsible manner. OPG's vision is to be a leader in clean energy generation and to have a major role in leading Ontario's transition to a more sustainable energy future. OPG is focused on three corporate strategies: performance excellence; generation development; and developing and acquiring talent.

Performance Excellence

This section provides an update to OPG's performance excellence disclosure and should be read in conjunction with OPG's 2010 annual MD&A. A detailed discussion of OPG's commitment to performance excellence in the areas of generation, safety, the environment, and fiscal performance is included in the 2010 annual MD&A under the heading, *Performance Excellence*.

Nuclear

Nuclear Generating Assets

Following the events at the Fukushima Daiichi nuclear facilities in Japan, OPG has been engaged in a significant effort to validate its design and operational defences against events which the stations are designed to withstand ("design-basis") and against events which are beyond the design-basis of the stations. This effort also supports the World Association of Nuclear Operators ("WANO") Significant Operating Experience Report 2011-2 and Canadian Nuclear Safety Commission ("CNSC") directives.

OPG's response to this event has been to ensure that the initial facility assessments were comprehensive and that all lessons learned are implemented by using a phased approach. The initial phase is complete and involved the completion of detailed assessments. The assessment results confirmed that the risk related to both station and waste management facility operations continues to be acceptably low. In addition, OPG identified a number of areas to increase safety margins for further review and consideration.

OPG has moved forward with the strategic planning phase. The objective of this phase is to prepare implementation plans and provide an update on work in-progress to both the CNSC and WANO. On July 28, 2011, OPG submitted a report to the CNSC and WANO which details the significant progress OPG has made in evaluating the lessons learned by conducting a rigorous review of the safety preparedness of OPG's nuclear stations to deal with beyond design events. While OPG's studies confirm the nuclear stations are safe today, investments will be made as part of OPG's continuous improvement efforts to increase safety margins during these unlikely events.

Deep Geologic Repository for Low and Intermediate Level Waste

In 2010, OPG approved the commencement of the detailed design phase of the Deep Geologic Repository ("DGR") project for the long-term management of low and intermediate level waste from OPG-owned nuclear generating stations. The Environmental Impact Statement was submitted to the CNSC in April 2011 and OPG is anticipating that the Joint Review Panel will be selected in the summer of 2011. OPG has executed the Engineering, Procurement, and Construction Management Agreement for the design and construction phase of the work.

Hydroelectric Generating Assets

OPG plans to increase the capacity of existing stations by 50 MW over the next five years through the replacement of existing turbine runners, generators, transformers, and other control components with more efficient equipment. OPG is also planning to repair, rehabilitate, or replace aging civil structures.

In the second quarter of 2011, OPG completed major equipment overhauls and rehabilitation work at several stations. This included the protection and controls upgrades of Units 9 to 16 at the Saunders generating station, the replacement of the main transformer bank of Units 4, 5 and 6 at the Sir Adam Beck Pump generating station, and the headgate replacement of Unit 2 at the Little Long generating station.

Thermal Generating Assets

The closure of the two additional units at the Nanticoke generating station later in 2011 will be managed through the provisions of the collective agreements and on-going involvement and discussions with union representatives. Staffing and other operational requirements at all thermal generating stations are under review to meet the needs associated with the changing operational profiles of the stations over the next four years, taking into consideration constrained operation under carbon dioxide ("CO_2") emission caps and operations after unit conversion to alternative fuels.

Environmental Performance

During the second quarter of 2011, the federal Minister of the Environment met with the Chief Executive Officers of Canadian utilities that operate coal-fired generating stations, including OPG's President and Chief Executive Officer, regarding the greenhouse gas ("GHG") emissions regulation. The federal government's plan did not materially change from its earlier proposal to restrict CO_2 emissions from coal-fired stations based on the unit's age, starting in July 2015. The federal government's current plan indicates that coal-fired units will be permitted to operate up until 45 years from their commissioning date. After 45 years, units must meet a CO_2 emission rate standard which would prevent continued coal-fired operation without carbon capture and storage or very high rates of biomass co-firing. Since OPG will cease using coal to produce electricity after 2014, the regulation is not expected to affect OPG, including units to be converted to burn natural gas or biomass.

In the second quarter of 2011, the provincial government announced that the GHG cap-and-trade regime would be implemented after 2012, instead of in 2012 as originally planned. Provincial regulations passed in 2009 require facilities that emit 25,000 Mg of CO_2-equivalent emissions or more, to monitor, measure, and report emissions. OPG will comply with the requirements and will continue to monitor developments of the cap-and-trade regime.

For the six months ended June 30, 2011, CO_2 emissions from coal-fired stations were 1.5 million tonnes compared to 7.1 million tonnes for the same period in 2010. Acid gas (SO_2 and NO_x) emissions from coal-fired stations were 5.5 gigagrams and 30 gigagrams for the six months ended June 30, 2011 and 2010, respectively. Emissions were significantly reduced during the first half of 2011 compared to the same period in 2010 as a result of lower generation from OPG's coal-fired generating stations.

OPG's disclosures relating to environmental policies and procedures, and environmental risks are provided in the annual MD&A as at and for the year ended December 31, 2010.

Safety

OPG is committed to achieve its goal of zero injuries through further development of a strong safety culture and continuous improvement in safety management systems and risk control programs. To address two health and safety risk areas, OPG's 2011 objectives include a focus on falling object prevention and in the application of work protection (lockout/tagout) processes. Key elements of the program consist of focused senior and site management oversight, design and process improvements, and increased employee awareness of expectations. During the second quarter of 2011, communication campaigns containing messages from senior leadership were issued across OPG to increase awareness of these two risk areas.

OPG believes that partnership with its unions is an important element of its strong safety culture and has embarked on a number of safety initiatives in 2011. Further, together with its unions, OPG issued an updated young worker and new worker strategy to address health and safety issues associated with this workforce.

Generation Development

Generation development opportunities pursued by OPG include capacity expansion, life extension opportunities, and the construction of new generating stations. Pursuing opportunities to leverage existing sites and assets allows OPG to maximize benefits from these assets, and to reduce the environmental impact of meeting Ontario's electricity demands. OPG's major projects include nuclear station refurbishment, new nuclear generation, new hydroelectric generation and plant upgrades, and the conversion of selected coal-fired generating units to alternate fuels. OPG's strategy and initiatives to finance these generation development projects are discussed under the heading, *Liquidity and Capital Resources*.

New Nuclear Units

On June 3, 2011, the Joint Review Panel overseeing the Darlington New Nuclear Project Environmental Assessment officially stated that sufficient information has been obtained to prepare their report. This date marks the commencement of the 90-day period in which the panel will prepare their environmental assessment report for submission to the federal Minister of the Environment.

Darlington Refurbishment Project

The Environmental Assessment ("EA") and the Integrated Safety Review for the Darlington refurbishment project, which form the basis of the regulatory scope, are on track for submission to the CNSC in late 2011. As part of the EA process, the EA project description regarding the proposed refurbishment and continued operation of the Darlington generating station was submitted to the CNSC. Subsequently, in June 2011, the CNSC confirmed OPG's expectations that a screening federal EA is required under the Canadian Environmental Assessment Act before activities associated with the refurbishment project can be authorized by the CNSC.

In June 2011, responses were received for the Request for Proposal for the Retube and Feeder Replacement for the Darlington generating station. Evaluations are now underway with the selection of a contractor targeted for late 2011.

In July 2011, OPG broke ground to officially begin construction of the Darlington Energy Complex, which will house a training and calandria mock-up facility, a warehouse, and office space. The Darlington Energy Complex remains on track for occupancy in the fall of 2013.

Pickering B Continued Operations

OPG is undertaking a coordinated set of initiatives to evaluate the opportunity to continue safe and reliable operations of Pickering B for an additional four to six years beyond its nominal end of life. Work is progressing by incorporating incremental life cycle management inspections and maintenance into the scope, cost, and duration of the outage programs along with other plant equipment improvements. In the second quarter of 2011, OPG executed the first of several extended planned outages on Unit 5 targeted at improving the reliability of the generating station and collecting necessary inspection results to support continued operation. In addition, work associated with the fuel channel life management is proceeding as planned.

Niagara Tunnel

The tunnel boring machine ("TBM") mining activity has been completed and the TBM disassembly is in progress. As of June 30, 2011, installation in the tunnel of the lower one-third of the permanent concrete lining reached 7,625 metres. This installation work has been temporarily interrupted since July 2, 2011 to reinforce a short section of the temporary tunnel liner that was overloaded by loose rock at 6,050 metres. This interruption is not expected to delay tunnel completion. Restoration of the circular cross-section of the tunnel before installation of the upper two-thirds of the concrete lining was behind schedule at 4,422 metres on June 30, 2011, but is not expected to delay tunnel completion. Installation of the upper two-thirds of the concrete lining has progressed 3,262 metres and was ahead of schedule. Contact grouting to fill the space between the concrete lining and impermeable membrane has progressed 1,375 metres and was ahead of schedule. Pre-stress grouting to complete the attachment of the concrete liner with the surrounding rock commenced in August 2011. Some uncertainty with respect to the cost and schedule for the liner installation will continue. Notwithstanding the uncertainty, the Niagara Tunnel is expected to be completed within the approved budget of $1.6 billion and the approved project completion date of December 2013. Upon completion of the project, the average annual generation from the Sir Adam Beck generating stations will increase by approximately 1.6 TWh.

The capital project expenditures for the three and six month periods ended June 30, 2011 were $71 million and $152 million, respectively. As at June 30, 2011, the life-to-date capital expenditures were $1,032 million.

Lower Mattagami

The Lower Mattagami River project will increase the capacity of the four stations on the Lower Mattagami River by 438 MW. During the second quarter of 2011, the intake excavation at Smoky Falls was completed, rock consolidation continued, and concrete operations commenced. The cofferdam at the Little Long generating station was installed and excavation commenced. The cofferdam installation is in progress at the Harmon site. As at June 30, 2011, the life-to-date capital expenditures were $516 million. The project is expected to be completed within the approved budget of $2.6 billion and the approved completion date of June 2015.

Conversion of Coal-Fired Units

The strategy to convert coal-fired units to alternative fuels continues to advance and is reflective of the changing operating environment in Ontario, including the regulated phase-out of coal-fired generation and conversion of units to alternative fuels such as biomass, natural gas and gas-biomass dual-fuelled. Before OPG can proceed with unit conversions, a mechanism is required for recovery of capital and on-going costs. OPG is seeking opportunities for a cost recovery contract for the coal-fired units at the Atikokan and Thunder Bay generating stations for the period leading up to their potential future conversions to alternative fuels, as proposed in the Energy Plan and the Supply Mix Directive.

The conversion of the Atikokan generating station to biomass is currently in the definition phase. OPG and the OPA are continuing to negotiate the Atikokan Biomass Energy Supply Agreement. On August 17, 2011, the Minister of Energy provided clarification to a directive issued to the OPA in August 2010 regarding the conversion of the Atikokan generating station to biomass. The letter clarified that the Minister supports the OPA to enter into an agreement with OPG consistent with OPG's conversion proposal. OPG is proceeding with detailed engineering and the negotiation of the engineering, procurement, and construction contract for the conversion of the Atikokan generating station to biomass fuel. The negotiation of fuel supply contracts will be concluded after an energy supply agreement is reached with the OPA.

The conversion of two units at the Thunder Bay generating station to natural gas is currently in the definition phase and OPG is proceeding with detailed engineering. On August 17, 2011, the Minister of Energy issued a directive to the OPA to negotiate the long-term energy supply contract with OPG for the conversion of two coal-fired units at the Thunder Bay generating station to natural gas by December 31, 2011. While an energy supply agreement is still required for the conversion, OPG has been requested by the Shareholder to continue the work associated with the required gas infrastructure consistent with the Energy Plan. Union Gas has announced the start of their public process for pipeline routing to the generating station.

As outlined in the Energy Plan and Supply Mix Directive, OPG is also exploring the possible conversion of some units at the Lambton and Nanticoke generating stations to natural gas, if required for system reliability. Due to the long lead-time required for a Nanticoke gas pipeline, Union Gas has begun conducting technical and environmental studies and public consultation leading to the identification of the pipeline route to Nanticoke. Similar pipeline routing studies are being undertaken at Lambton.

Developing and Acquiring Talent

Skilled Workforce

As of June 30 2011, OPG had approximately 90 percent of its regular labour force represented by a union. The current collective agreement between OPG and the PWU has a three-year term (April 1, 2009 – March 31, 2012). The current collective agreement with The Society has a two-year term (January 1, 2011 to December 31, 2012).

In addition to the regular workforce, construction work is performed through 22 craft unions with established bargaining rights on OPG facilities. These bargaining rights are either through the Electrical Power Systems Construction Association ("EPSCA") or directly with OPG. OPG, in conjunction with

EPSCA, was actively involved in all aspects of negotiations. All of the construction agreements expired April 30, 2010 and have been re-negotiated.

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 the 2010 annual MD&A and are discussed in the *Discussion of Operating Results by Business Segment* section.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

This section summarizes OPG's key results by segment for the three and six month periods ended June 30, 2011 and 2010. The following table provides a summary of revenue, earnings and key generation by business segment:

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of dollars – except where noted)	**2011**	**2010**	**2011**	**2010**
Revenue				
Regulated – Nuclear Generation	**713**	657	**1,501**	1,450
Regulated – Nuclear Waste Management	**12**	10	**24**	21
Regulated – Hydroelectric	**190**	184	**374**	368
Unregulated – Hydroelectric	**149**	103	**298**	252
Unregulated – Thermal	**134**	233	**280**	501
Other	**39**	33	**80**	81
Elimination	**(11)**	(10)	**(23)**	(20)
	1,226	1,210	**2,534**	2,653
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**25**	(66)	**129**	23
Regulated – Nuclear Waste Management	**(14)**	(125)	**(48)**	(149)
Regulated – Hydroelectric	**87**	78	**183**	171
Unregulated – Hydroelectric	**50**	18	**115**	85
Unregulated – Thermal	**(31)**	(18)	**(52)**	(35)
Other	**21**	10	**40**	38
	138	(103)	**367**	133
Electricity generation (TWh)				
Regulated – Nuclear Generation	**11.4**	9.6	**24.0**	21.6
Regulated – Hydroelectric	**5.0**	4.6	**9.6**	9.4
Unregulated – Hydroelectric	**4.1**	2.3	**8.1**	6.2
Unregulated – Thermal	**0.2**	3.2	**1.2**	7.0
Total electricity generation	**20.7**	19.7	**42.9**	44.2

Regulated – Nuclear Generation Segment

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Regulated generation sales	**633**	522	**1,326**	1,177
Variance accounts	**4**	(8)	**29**	142
Other	**76**	143	**146**	131
Total revenue	**713**	657	**1,501**	1,450
Fuel expense	**57**	47	**119**	100
Variance accounts	**1**	(5)	**(6)**	(8)
Total fuel expense	**58**	42	**113**	92
Gross margin	**655**	615	**1,388**	1,358
Operations, maintenance and administration	**490**	569	**1,020**	1,120
Depreciation and amortization	**136**	101	**228**	193
Property and capital taxes	**7**	11	**14**	22
Income (loss) before other gains, interest and income taxes	**22**	(66)	**126**	23
Other gains	**(3)**	-	**(3)**	-
Income (loss) before interest and income taxes	**25**	(66)	**129**	23

Income before interest and income taxes from the Regulated – Nuclear generation segment was $25 million for the second quarter of 2011 compared to a loss of $66 million during the second quarter of 2010. The increase in income before interest and income taxes for the second quarter of 2011 compared to the same period in 2010 was primarily due to an increase in generation revenue and lower OM&A expenses. This increase was partially offset by higher depreciation and amortization expense.

The increase in generation revenue during the three months ended June 30, 2011 compared to the same period in 2010 was primarily due to a higher generation volume of 1.8 TWh. The higher generation volume was primarily due to a decrease in planned outage days at the Pickering generating stations as a result of the Pickering Vacuum Building outage in the second quarter of 2010, partially offset by lower generation at the Darlington generating station due to an increase in planned outage days and the impact of higher unplanned outage days at Pickering A.

The increase in revenue related to the regulatory variance accounts during the second quarter of 2011 compared to the same quarter of 2010 was primarily related to the Bruce Lease Net Revenues Variance Account. During the three months ended June 30, 2011 and 2010, OPG recognized an increase in the fair value of the derivative liability embedded in the Bruce lease of $7 million and a decrease of $57 million, respectively, as a result of changes in the expected future annual arithmetic average of the Hourly Ontario Electricity Price. Since the changes in the fair value of this derivative are recorded in non-electricity generation revenue with a corresponding change in the regulatory asset related to the Bruce Lease Net Revenues Variance Account, there is no income impact of the change in the fair value of the derivative liability. The increase in revenue was partially offset by the cessation of additions to the Tax Loss Variance Account based on the OEB's decision effective March 1, 2011.

The decrease in OM&A expenses of $79 million during the second quarter of 2011 compared to the same period in 2010 was primarily due to lower planned outage and project activities, and a decrease in expenditures for new nuclear generation development and capacity refurbishment activities, net of the impact of related regulatory variance accounts. The decrease was partially offset by higher maintenance costs, and higher pension and OPEB costs net of the impact of the Pension and OPEB Cost Variance Account. The increase in pension and OPEB costs was largely as a result of lower discount rates in 2011.

The increase in depreciation and amortization expense of $35 million during the second quarter of 2011 compared to the same quarter in 2010 was primarily due to higher amortization expense related to the recovery of regulatory balances as a result of the OEB's March 2011 decision on the new regulated prices.

Income before interest and income taxes was $129 million for the six months ended June 30, 2011 compared to $23 million during the same period of 2010. The increase in income before interest and income taxes for the six months ended June 30, 2011 compared to the same period in 2010 was primarily due to higher generation revenue and lower OM&A expenses.

The increase in generation revenue was primarily due to the impact of a decrease in planned outage days at the Pickering generating stations and lower planned outage days at the Darlington generating station. The decrease in outage days at the Pickering generating stations was primarily a result of the Pickering Vacuum Building outage in the second quarter of 2010. The increase in generation was partially offset by the impact of higher unplanned outage days at the Pickering A nuclear generating station.

The decrease in OM&A expenses during the six months ended June 30, 2011 compared to the same period in 2010 was primarily due to lower planned outage and project activities, and a decrease in expenditures for new nuclear generation development and capacity refurbishment activities, net of the impact of related regulatory variance accounts. The decrease was partially offset by higher maintenance costs, and higher pension and OPEB costs net of the impact of the Pension and OPEB Cost Variance Account.

The increase in income before interest and income taxes was partially offset by lower revenue related to the cessation of additions to the Tax Loss Variance Account effective March 1, 2011, and higher depreciation and amortization expense.

The unit capability factors for each of the nuclear stations and the Production Unit Energy Cost ("PUEC") for the three and six month periods ended June 30, 2011 and 2010 are as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
	2011	**2010**	**2011**	**2010**
Unit Capability Factor *(%)*				
Darlington	**86.2**	93.6	**92.0**	88.0
Pickering A	**72.9**	30.3	**71.2**	48.7
Pickering B	**72.0**	41.6	**77.1**	69.4
Nuclear PUEC *($/MWh)*	**45.95**	59.27	**45.31**	52.32

The capability factor for the Darlington nuclear generating station decreased for the three months ended June 30, 2011 compared to the same period in 2010 due to an increase in the planned outage days. The higher capability factors at the Pickering A and B nuclear generating stations during the second quarter of 2011 compared to the same quarter in 2010 were primarily due to lower planned outage days at these stations, as all six units were shutdown during the Pickering Vacuum Building Outage in the second quarter of 2010.

The decrease in Nuclear PUEC for the three months ended June 30, 2011 compared to the same period in 2010 was primarily due to higher generation and lower OM&A expenses.

For the six months ended June 30, 2011, the higher capability factor at the Darlington nuclear generating station compared to the same period in 2010 was primarily due to a decrease in the planned outage days. The higher capability factors at the Pickering A and B nuclear generating stations during the six months ended June 30, 2011 compared to the same period in 2010 primarily reflected the lower planned outage days at these stations, as all six units were shutdown during the Pickering Vacuum Building Outage in the second quarter of 2010.

The decrease in Nuclear PUEC for the six months ended June 30, 2011 compared to the same period in 2010 was primarily due to higher generation and lower OM&A expenses.

Regulated – Nuclear Waste Management Segment

(millions of dollars)	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Revenue	**12**	10	**24**	21
Operations, maintenance and administration	**14**	12	**28**	24
Accretion on fixed asset removal and nuclear waste management liabilities	**176**	163	**346**	327
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(164)**	(40)	**(302)**	(181)
Loss before interest and income taxes	**(14)**	(125)	**(48)**	(149)

The loss before interest and income taxes for the Regulated – Nuclear Waste Management Segment was $14 million for the three months ended June 30, 2011 compared to $125 million for the same period in 2010. The loss before interest and income taxes for the six months ended June 30, 2011 was $48 million compared to $149 million for the six months ended June 30, 2010. The decrease in loss before interest and incomes taxes for the three and six month periods ended June 30, 2011 compared to the same periods in 2010 was primarily due to higher earnings from the Decommissioning Segregated Fund ("Decommissioning Fund") and the Used Fuel Segregated Fund ("Used Fuel Fund") (together "Nuclear Funds").

The earnings from the Nuclear Funds increased for the three and six month periods ended June 30, 2011 compared to the same periods in 2010 primarily due to higher income from the Decommissioning Fund. During the second quarter of 2010, there was a decline in valuation levels of global financial markets. The increase in the Nuclear Funds earnings was also due to the impact of higher guaranteed returns related to the Used Fuel Fund.

The favourable impact of higher earnings from the Nuclear Funds for the three and six month periods ended June 30, 2011 compared to the same periods in 2010 was partially offset by higher accretion expense, primarily due to an increase in the present value of the liabilities for Fixed Asset Removal and Nuclear Waste Management due to the passage of time.

Regulated – Hydroelectric Segment

(millions of dollars)	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Regulated generation sales	**172**	172	**340**	346
Variance accounts	**4**	5	**14**	5
Other	**14**	7	**20**	17
Total revenue	**190**	184	**374**	368
Fuel expense	**68**	65	**117**	115
Variance accounts	**1**	(1)	**2**	(2)
Total fuel expense	**69**	64	**119**	113
Gross margin	**121**	120	**255**	255
Operations, maintenance and administration	**25**	24	**51**	47
Depreciation and amortization	**8**	16	**22**	32
Property and capital taxes (recovery)	**1**	2	**(1)**	5
Income before interest and income taxes	**87**	78	**183**	171

For the three months ended June 30, 2011, income before interest and income taxes for the Regulated – Hydroelectric segment was $87 million compared to $78 million for the same period in 2010. The increase in income was primarily due to lower depreciation and amortization expense, an increase in ancillary and other revenues, and the impact of higher generation volume, partially offset by the impact of lower sales prices due to the OEB's March 2011 decision on the new regulated prices. The decrease in depreciation and amortization expense was primarily due to lower amortization expense related to regulatory balances as a result of the OEB's March 2011 decision.

For the six months ended June 30, 2011, income before interest and income taxes for the Regulated – Hydroelectric segment was $183 million compared to $171 million for the same period in 2010. The increase was primarily due to lower depreciation and amortization expense, higher revenue recognized related to regulatory variance accounts, and lower property and capital tax expenses resulting from a reduction in capital tax related to prior years, and the elimination of capital tax as of July 2010.

The availability, Equivalent Forced Outage Rate ("EFOR") and OM&A expense per MWh for the Regulated – Hydroelectric segment for the three and six month periods ended June 30, 2011 and 2010 are as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Availability *(%)*	**87.5**	91.8	**89.7**	92.7
EFOR *(%)*	**1.0**	0.2	**0.9**	0.3
Regulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**5.00**	5.22	**5.31**	5.00

The decrease in availability during the three and six month periods ended June 30, 2011 compared to the same periods in 2010 was primarily due to an increase in planned maintenance and project outages, and also an increase in forced outages at the Sir Adam Beck Pump generating station. The continuing high availability and low EFOR reflected the strong performance of these hydroelectric stations.

The decrease in OM&A expense per MWh in the second quarter of 2011 compared to the same quarter in 2010 was due to higher generation, partially offset by higher OM&A expenses. The increase in OM&A expense per MWh for the first half of 2011 as compared to the same period in 2010 was due to higher OM&A expenses, partially offset by higher generation.

Unregulated – Hydroelectric Segment

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Spot market sales, net of hedging instruments	**127**	94	**259**	234
Other	**22**	9	**39**	18
Total revenue	**149**	103	**298**	252
Fuel expense	**22**	13	**42**	32
Gross margin	**127**	90	**256**	220
Operations, maintenance and administration	**57**	55	**108**	101
Depreciation and amortization	**20**	15	**36**	31
Property and capital taxes (recovery)	**-**	2	**(3)**	3
Income before interest and income taxes	**50**	18	**115**	85

Income before interest and income taxes for the three and six month periods ended June 30, 2011 was $50 million and $115 million, respectively, compared to $18 million and $85 million for the same periods in 2010. The increase in income before interest and income taxes for the three and six month periods ended June 30, 2011 compared to the same periods in 2010 was primarily due to an increase in generation revenue, partially offset by higher fuel expense related to an increase in generation volume.

The increase in revenue for the three and six month periods ended June 30, 2011 compared to the same periods in 2010 was primarily due to an increase in generation volume as a result of higher water flows compared to the same periods in 2010, and revenue from an energy supply agreement related to the Upper Mattagami generating stations which were placed in service during the fourth quarter of 2010. The increase in revenue was partially offset by the impact of lower electricity prices primarily due to lower Ontario spot market prices.

The increase in fuel expense for the three and six month periods ended June 30, 2011 compared to the same periods in 2010 was primarily due to higher generation volume.

The availability, EFOR and OM&A expense per MWh for Unregulated – Hydroelectric segment for the three and six month periods ended June 30, 2011 and 2010 are as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2011	**2010**	**2011**	**2010**
Availability *(%)*	**94.3**	93.4	**94.1**	93.7
EFOR *(%)*	**1.4**	2.8	**0.9**	1.7
Unregulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**13.90**	23.91	**13.33**	16.29

EFOR decreased for the three and six month periods ended June 30, 2011 compared to the same periods in 2010 primarily as a result of improved equipment performance at the unregulated hydroelectric stations. The high availability and low EFOR reflected the continuing strong performance of these hydroelectric stations.

The decrease in OM&A expense per MWh for the three and six month periods ended June 30, 2011 compared to the same periods in 2010 was primarily due to the impact of higher generation, partially offset by higher OM&A expenses.

Unregulated – Thermal Segment

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Spot market sales, net of hedging instruments	**5**	136	**35**	274
Contingency support agreement	**106**	66	**195**	149
Other	**23**	31	**50**	78
Total revenue	**134**	233	**280**	501
Fuel expense	**34**	91	**75**	220
Gross margin	**100**	142	**205**	281
Operations, maintenance and administration	**104**	127	**202**	229
Depreciation and amortization	**22**	27	**43**	54
Accretion on fixed asset removal liabilities	**1**	2	**3**	3
Property and capital taxes	**4**	4	**8**	5
Restructuring	**-**	-	**-**	25
Loss before other losses, interest and income taxes	**(31)**	(18)	**(51)**	(35)
Other losses	**-**	-	**1**	-
Loss before interest and income taxes	**(31)**	(18)	**(52)**	(35)

The loss before interest and income taxes for the three months ended June 30, 2011 was $31 million compared to $18 million for the same period in 2010. The loss before interest and income taxes for the six months ended June 30, 2011 was $52 million compared to $35 million for the same period in 2010.

The gross margin decreased for the three and six month periods ended June 30, 2011, primarily due to a significant reduction in electricity generation volume, and higher fuel-related costs pertaining to favourable adjustments in thermal inventory during the second quarter of 2010 and adjustments to coal supply contracts during the second quarter of 2011. This decrease was partially offset by higher revenue related to the contingency support agreement for the Nanticoke and Lambton coal-fired generating stations. Electricity generation for the three and six month periods ended June 30, 2011 decreased compared to the same periods in 2010 by 3.0 TWh and 5.8 TWh, respectively.

OM&A expenses for the three and six month periods ended June 30, 2011 decreased compared to the same periods in 2010 primarily due to the continuation of the vacancy and overtime management program, and reduced scope of work associated with changing operating profiles and anticipated unit closures at Nanticoke in 2011.

The loss before interest and income taxes for the six months ended June 30, 2010 was impacted by restructuring charges of $25 million due to the recognition of severance costs related to the closure of four coal-fired units in 2010. There were no restructuring charges recorded during the three and six month periods ended June 30, 2011.

The EFOR and OM&A expense per MWh for Unregulated – Thermal segment for the three and six month periods ended June 30, 2011 and 2010 are as follows:

	Three Months Ended June 30		**Six Months Ended June 30**	
	2011	**2010**	**2011**	**2010**
EFOR *(%)*	**11.7**	7.3	**9.3**	4.8
Unregulated – Thermal OM&A expense per MW *($000/MW)*	**66.30**	62.10	**64.10**	56.00

The higher EFOR for the three and six month periods ended June 30, 2011 compared to the same periods in 2010 was primarily due to a higher number of unplanned outage days at the Nanticoke and Lambton coal-fired generating stations. The EFOR for both three and six month periods ended June 30, 2011 continued to reflect good operating performance of the thermal fleet.

The increase in OM&A expense per MW during the three and six month periods ended June 30, 2011 compared to the same periods in 2010 reflects the reduction in OPG's thermal generating capacity in late 2010 resulting from the unit closures and the reduction in capacity at Nanticoke during the second quarter of 2011, partially offset by lower OM&A expenses for the three and six month periods ended June 30, 2011.

Other

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Revenue	**39**	33	**80**	81
Operations, maintenance and administration	**7**	4	**12**	7
Depreciation and amortization	**9**	15	**24**	30
Property and capital taxes	**3**	5	**5**	8
Income before other gains, interest and income taxes	**20**	9	**39**	36
Other gains	**(1)**	(1)	**(1)**	(2)
Income before interest and income taxes	**21**	10	**40**	38

Income before interest and income taxes for the Other business segment was $21 million during the second quarter of 2011 compared to $10 million during the same period in 2010. The increase in income before interest and income taxes during the second quarter of 2011 compared to the same period in 2010 was primarily due to higher income from OPG's equity investments, an increase in net trading revenue, and a decrease in depreciation and amortization expense.

Income before interest and income taxes was $40 million during the six months ended June 30, 2011 compared to $38 million during the same period in 2010 primarily due to lower depreciation and amortization expense, and the impact of the elimination of capital tax in July 2010.

Interconnected purchases and sales, including those to be physically settled, and unrealized mark-to-market gains and losses on energy trading contracts, are disclosed on a net basis in the consolidated statements of income. For the three months ended June 30, 2011, if disclosed on a gross basis, revenue and power purchases would have increased by $10 million (three months ended June 30, 2010 – $11 million). For the six months ended June 30, 2011, if disclosed on a gross basis, revenue and power purchases would have increased by $38 million (six months ended June 30, 2010 – $33 million).

With the exception of the derivative embedded in the Bruce lease, which is reflected in the Regulated – Nuclear Generation segment, the changes in the fair value of derivative instruments not qualifying for hedge accounting are recorded in revenue, and the fair value of derivative instruments are carried on the consolidated balance sheets as assets or liabilities at fair value. The carrying amounts and notional quantities of the derivative instruments are disclosed in Note 11 of OPG's interim consolidated financial statements for the second quarter of 2011.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation ("OEFC"), and capital market financing. These sources are utilized for multiple purposes including: investments in plants and technologies; funding obligations such as contributions to the pension funds and the Nuclear Funds; and to service and repay long-term debt.

Changes in cash and cash equivalents for the three and six month periods ended June 30, 2011, and 2010 are as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Cash and cash equivalents, beginning of period	**407**	158	**280**	71
Cash flow provided by operating activities	**153**	110	**562**	328
Cash flow used in investing activities	**(255)**	(227)	**(538)**	(404)
Cash flow provided by financing activities	**349**	62	**350**	108
Net increase (decrease)	**247**	(55)	**374**	32
Cash and cash equivalents, end of period	**654**	103	**654**	103

Operating Activities

Cash flow provided by operating activities for the three months ended June 30, 2011 was $153 million compared to $110 million for the three months ended June 30, 2010. The increase in cash flow was primarily due to lower fuel purchases and tax installments in the second quarter of 2011 compared to the same period in 2010.

Cash flow provided by operating activities for the six months ended June 30, 2011 was $562 million compared to cash flow provided by operating activities of $328 million for the same period in 2010. The increase in cash flow was primarily due to lower OM&A expenditures, lower fuel purchases, a cash payment in the first half of 2010 to reflect a payment related to a derivative embedded in the Bruce lease for the 2009 calendar year, and lower tax installments compared to the same period in 2010. This increase was partially offset by lower cash receipts as a result of lower generation revenue for the six months ended June 30, 2011 compared to the same period in 2010.

An actuarial valuation of the OPG registered pension plan was completed as of January 1, 2011. Based on the actuarial valuation, OPG will increase its annual contribution to the plan from $270 million in 2010 to $300 million in 2011. The annual contributions for 2012 and 2013 will be adjusted for changes in current service costs in each year. OPG will continue to assess the requirements for contributions to the pension plan. The next actuarial valuation for funding purposes must have an effective date no later than January 1, 2014.

Investing Activities

Cash flow used in investing activities during the second quarter ended June 30, 2011 was $255 million compared to $227 million for same quarter in 2010. Cash flow used in investing activities during the six months ended June 30, 2011 was $538 million compared to $404 million for same period in 2010. The increase in cash flow used in investing activities during the three and six month periods ended June 30, 2011 compared to the same periods in 2010 was primarily due to higher capital expenditures for the Lower Mattagami project, the Niagara Tunnel project, and the Darlington Refurbishment project. This increase was partially offset by lower capital expenditures for the Upper Mattagami and Hound Chute project, which was placed in service in the fourth quarter of 2010, and other nuclear capital initiatives.

OPG's forecast capital expenditures for 2011 are approximately $1.3 billion, which includes amounts for hydroelectric development and nuclear refurbishment.

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, and a $500 million multi-year term tranche. In May 2011, OPG renewed and extended the 364-day term tranche for a four-year term to May 18, 2015. The multi-year term tranche has a maturity date of May 20, 2013. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at June 30, 2011, no commercial paper was outstanding (December 31, 2010 – nil), and OPG had no other outstanding borrowings under the bank credit facility.

During 2010, the Lower Mattagami Energy Limited Partnership ("LME") established a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami project and launched a commercial paper program. As at June 30, 2011, no commercial paper was outstanding under this program (December 31, 2010 – $155 million). In March 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami project. As at June 30, 2011, there were no outstanding borrowings under this credit facility.

On May 17, 2011, senior notes totalling $475 million were issued by the LME. The senior notes have interest rates of 4.3 percent for notes of $225 million maturing in 2021 and 5.1 percent for notes of $250 million maturing in 2041. These notes are secured by the assets of the Lower Mattagami project, including existing operating facilities and facilities being constructed.

As at June 30, 2011, OPG maintained $25 million (December 31, 2010 – $25 million) of short-term, uncommitted overdraft facilities, and $319 million (December 31, 2010 – $319 million) of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans, and for other purposes. At June 30, 2011, there was a total of $281 million of Letters of Credit issued (December 31, 2010 – $281 million), which included $254 million for the supplementary pension plans (December 31, 2010 – $254 million), $20 million for general corporate purposes (December 31, 2010 – $20 million) and $7 million related to the operation of the PEC (December 31, 2010 – $7 million).

During 2010, OPG executed an amended Niagara Tunnel project credit facility for an amount up to $1.6 billion. As at June 30, 2011, advances under this facility were $765 million, which included $35 million of new borrowing during the second quarter of 2011.

As at June 30, 2011, OPG's long-term debt outstanding with the OEFC was $3,903 million, of which $588 million must be repaid or refinanced within the next three years. To ensure that adequate financing resources were available beyond its $1 billion commercial paper program backed by the revolving committed bank credit facility, OPG reached an agreement with the OEFC in March 2011 for a $375 million credit facility to refinance notes as they mature over the period from January 2011 to December 2011. Refinancing under this agreement totalled $150 million as at June 30, 2011.

BALANCE SHEET HIGHLIGHTS

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

	As At		
(millions of dollars)	**June 30 2011**	**December 31 2010**	**Explanation of change**
Accounts receivable	**230**	270	The decrease was primarily due to lower receivables from the IESO as a result of lower electricity generation volumes in June 2011 compared to December 2010.
Nuclear fixed asset removal and nuclear waste management funds	**11,674**	11,246	The increase was primarily due to earnings on the Nuclear Funds and contributions to the Used Fuel Fund, partially offset by the reimbursement of program expenditures from the Nuclear Funds during the six months ended June 30, 2011.
Regulatory assets	**1,498**	1,559	The decrease was primarily due to the amortization of regulatory asset balances as a result of the OEB's March 2011 decision and the reduction in the regulatory asset for future income taxes. This impact was partially offset by the recognition of regulatory assets related to pension and OPEB costs pursuant to the OEB's June 2011 decision and income taxes payable as a result of the OEB's approval of recovery of certain variance and deferral accounts balances in its March 2011 decision.
Fixed asset removal and nuclear waste management liabilities	**12,992**	12,704	The increase was primarily a result of accretion expense due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.
Future and current income and capital tax liabilities (net of recoveries)	**698**	660	The change in the future and current tax balances was largely a result of the OEB's approval of recovery of certain variance and deferral account balances in its March 2011 decision.

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 in the Company's consolidated financial statements using 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 long-term fixed price contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of future accounting pronouncements, are outlined in Note 3 to the audited annual consolidated financial statements as at and for the year ended December 31, 2010. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain, and could result in materially different amounts being reported under different conditions or assumptions.

Business Combinations, Consolidated Financial Statements, and Non-controlling Interests

Effective January 1, 2011, the Company adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1582 *Business Combinations* ("Section 1582"), Section 1601 *Consolidated Financial Statements* ("Section 1601"), and Section 1602 *Non-controlling Interests* ("Section 1602"). Section 1582 specifies a number of changes, including an expanded definition of a business, a requirement to measure all business acquisitions at fair value, and a requirement to recognize acquisition-related costs as expenses. Section 1601 establishes the standards for preparing consolidated financial statements. Section 1602 specifies that non-controlling interests be treated as a separate component of equity, not as a liability or other item outside of equity. These standards shall be applied prospectively to business combinations whose acquisition date is on or after the date of adoption. As a result of adopting Section 1602, the Company has reclassified its non-controlling interests as a separate component of equity. The adoption of Section 1582 and Section 1601 did not have a material impact on the Company's consolidated financial statements for the three and six month periods ended June 30, 2011.

CONVERSION TO INTERNATIONAL FINANCIAL REPORTING STANDARDS

Introduction to Conversion Project

OPG's IFRS conversion project progressed during the second quarter of 2011, including regular communications to executive management, finance employees and other stakeholders, and the Audit and Finance Committee of the Board of Directors. This section provides an update with respect to the disclosure included in the 2010 annual MD&A and the MD&A for the first quarter of 2011 under the heading, *Conversion to International Financial Reporting Standards*.

Accounting Policy Decisions and Anticipated Impacts

During the second quarter of 2011, OPG continued to evaluate its accounting policy options under IFRS and to collect data, which will be used to report 2011 comparative information in its 2012 IFRS interim and annual consolidated financial statements. OPG continues to expect the following areas to be most impacted by its conversion to IFRS: Property, Plant and Equipment; Fixed Asset Removal and Nuclear Waste Management Liabilities; Accounts Receivable; Short-term Notes Payable; Employee Benefits; and assets and liabilities resulting from rate regulation. At this time, OPG has not concluded on all of its accounting policy choices upon transition to IFRS, and is waiting for the International Accounting Standards Board ("IASB") to finalize various accounting standards. The IASB has issued five new standards during the second quarter of 2011. Since the IASB continues to issue new accounting standards, the final accounting policy decisions of OPG will only be determined once all applicable standards are known upon the January 1, 2012 conversion date.

<u>Rate-Regulated Activities</u>

During the first quarter of 2011, OPG determined that balances in variance and deferral accounts established by the OEB, including those authorized pursuant to *Ontario Regulation 53/05,* under the *Ontario Energy Board Act, 1998,* meet the definition of a financial asset and financial liability, as defined in International Accounting Standard 32, *Financial Instruments: Presentation*. The remaining regulatory assets and liabilities currently recognized by OPG under Canadian GAAP will not be recognized upon

OPG's adoption of IFRS. As at January 1, 2011, the amount of approximately $700 million in regulatory assets related to future income tax liabilities is expected to be de-recognized.

Accounts Receivable and Short-term Notes Payable

OPG has an agreement to sell an undivided co-ownership interest in its current and future accounts receivables to an independent trust. Under Canadian GAAP, OPG de-recognizes $250 million of accounts receivable. OPG has determined that the agreement does not meet the de-recognition criteria under IFRS. The estimated amount of $250 million is expected to be recognized in the accounts receivable balance, with a corresponding recognition of a short-term notes payable, upon adoption of IFRS.

The following table provides certain elements of the changeover plan and an assessment of the progress OPG has achieved as at June 30, 2011. This information reflects OPG's most recent assumptions and expectations. Circumstances may arise, such as changes in IFRS, regulations or economic conditions, which could change these assumptions or expectations.

Selected Key Activities	Milestones/Deadlines	Progress to Date
Financial statement preparations		
Identify relevant differences between IFRS and current accounting policies and practices and design and implement solutions Evaluate and select one-time and on-going accounting policy alternatives Benchmark findings with peer companies Prepare illustrative financial statements and related note disclosures to comply with IFRS Quantify the effects of changeover to IFRS	Assessment and quantification of the significant effects of the changeover completed by approximately the third quarter of 2011 OPG has elected to defer its adoption of IFRS by one year and expects to assess and quantify the significant effects of the changeover by approximately the third quarter of 2011 Final selection of accounting policy alternatives by the changeover date	While OPG was prepared for a January 1, 2011 changeover to IFRS, it is now working within the one-year delay and assessing the impact on the following: • The 2011 transitional opening balance sheet; • Accounting policy decisions given on-going work by the IASB; and • IFRS 1, *First-time adoption of IFRS* elections. OPG has determined that balances in variance and deferral accounts established by the OEB including those authorized pursuant to *Ontario Regulation 53/05*, under the *Ontario Energy Board Act, 1998,* meet the definition of a financial asset and financial liability. The remaining regulatory assets and liabilities will be derecognized upon OPG's adoption of IFRS.
Training and communications		
Provide training to affected employees of operating units, management and the Board of Directors and relevant committees thereof, including the Audit and Finance Committee Engage subject matter experts to assist in the transition Communicate progress of changeover plan to internal and external stakeholders	Provide timely training in line with changeover milestones. Target to complete training by the end of 2011. Communicate effects of changeover by the fourth quarter of 2011	In 2010, completed detailed training for resources directly engaged in the changeover and general awareness training to a broader group of finance employees Completed specific and relevant training to 150 finance employees Continued on-going, periodic internal and external communications about OPG's progress Continued use of third-party subject matter experts to assist in the transition
IT systems		
Identify and address IFRS differences that require changes to financial systems Evaluate and select methods in 2011 to address need for dual record-keeping (i.e., IFRS and Canadian GAAP) for comparatives in 2011	Changes to significant systems and dual record-keeping process completed for the first quarter of 2010 Remaining changes to systems post-dual recordkeeping year by the fourth quarter of 2011	System changes are complete to the extent possible. Further changes to information systems would be largely dependent upon future changes to the IFRS standards. Processes and systems are in place to accumulate IFRS data to enable reporting of 2011 comparative information in 2012

Selected Key Activities	Milestones/Deadlines	Progress to Date
<u>Contractual arrangements and compensation</u>		
Identify impact of changeover on contractual arrangements, including financial covenants and employee compensation plans Make any required changes to arrangements and plans	Changes completed by the third quarter of 2010	IFRS differences with potential impacts on financial covenants and compensation plans were identified and discussed with both internal and external parties as required
<u>Internal controls</u>: Internal controls over financial reporting ("ICOFR"), disclosure controls and procedures ("DC&P") and related communications		
Revise existing internal control processes and procedures to address significant changes to existing accounting policies and practices, including the need for dual record-keeping during 2011, and changes to financial systems Design and implement internal controls with respect to one-time changeover adjustments and related communications. For changes to accounting policies and practices identified, assess the DC&P and ICOFR design and effectiveness implications	Conduct management evaluation of new or revised controls throughout 2010 and 2011 Changes will be mapped and tested to ensure that no material deficiencies exist as a result of OPG's conversion to the IFRS accounting standards	An evaluation of OPG's readiness to transition to and report under IFRS positively concluded that the project controls are adequate to support the completion of tasks to adopt IFRS IFRS compliant accounting policies and procedures continue to be developed The impact on controls continues to be evaluated and changes are made where necessary IFRS opening balance sheet adjustment controls are being evaluated and are being applied to the January 1, 2011 opening transition balance sheet

RISK MANAGEMENT

A detailed discussion of OPG's governance structure and inherent risks is included in the 2010 annual MD&A under the heading, *Risk Management*. In addition, disclosure is provided relating to the activities that OPG undertakes to identify and manage these risks. This risk management update should be read in conjunction with the *Risk Management* section included in OPG's 2010 annual MD&A. The following discussion provides an update of OPG's risk management activities since the 2010 annual disclosure.

Operational Risks

Risks Associated with Major Development Projects

The risks associated with the cost, schedule and technical aspects of the major development projects could adversely impact OPG's financial performance and ultimately, its corporate reputation.

Niagara Tunnel Project

While the TBM mining has been completed, some cost and schedule uncertainty remains with respect to the liner installation. The factors that contribute to this uncertainty include the activities to restore the tunnel profile, reinforcing the temporary tunnel liner, and challenging logistics for concrete delivery. Allowances for these factors have been included in the cost estimate and schedule. The contractor is deploying additional resources on the profile restoration and concrete delivery operations to minimize potential impact on the schedule for project completion.

Financial Risks

Commodity Markets

Changes in the market price of electricity or of the fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

OPG's revenue from its unregulated assets is also affected by changes in the market or spot price of electricity. The Company takes steps, such as executing forward sales at fixed prices, to mitigate the impact that extreme variations in the spot price could have on the gross margin.

The percentages of OPG's expected generation, emission requirements, and fuel requirements hedged are shown below. These amounts are based on yearly forecasts of generation and supply mix, and as such are subject to change as these forecasts are updated.

	2011[4]	**2012**	**2013**
Estimated generation output hedged [1]	82%	81%	81%
Estimated fuel requirements hedged [2]	65%	56%	51%
Estimated nitric oxide (NO) emission requirement hedged [3]	100%	100%	100%
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, and agreements with the IESO, OEFC, and OPA.
2 Represents the approximate portion of megawatt hours of expected generation production (and thermal year end inventory targets) from each type of facility (thermal and nuclear) for which OPG has entered into contractual arrangements or obligations in order to secure the price of fuel. Excess fuel in inventories in a given year is attributed to the next year for the purpose of measuring hedge ratios.
3 Represents the approximate portion of megawatt hours of expected thermal 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.
4 Includes forecast for the remainder of the year.

Foreign Exchange and Interest Rate Markets

OPG's earnings and cash flows can be impacted by movements in the United States dollar relative to the Canadian dollar and by prevailing interest rates on its short-term borrowings and investment programs.

The majority of OPG's existing debt is at fixed interest rates. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. The management of these risks is undertaken by using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated new financing. As at June 30, 2011, OPG had total interest rate swap contracts outstanding with a notional principal of $300 million.

Trading

OPG's financial performance could be adversely affected by its trading activities.

OPG's trading operations are closely monitored and total exposures are measured and reported to senior management on a daily basis. The metric used to measure the risk of this trading activity is known as "value at risk" or "VaR", which is defined as the potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. The VaR utilization ranged between $0.2 million and $0.3 million during the three months ended June 30, 2011 compared to $0.1 million and $0.3 million during the three months ended March 31, 2011.

Credit

Deterioration in counterparty credit and non-performance by suppliers can adversely impact OPG's earnings and cash flows from operations.

OPG manages its exposure to various suppliers or "counterparties" by evaluating the financial condition of all counterparties and ensuring that appropriate collateral or other forms of security are held by OPG. OPG's credit exposure relating to energy markets transactions as at June 30, 2011, was $380 million, including $357 million to the IESO. Over 75 percent of the remaining $23 million exposure related to investment grade counterparties.

Nuclear Waste Obligations

The cost estimates of nuclear waste obligations are based on assumptions such as station end of life dates and nuclear waste volume that are inherently uncertain.

OPG is required by various rules and regulations to provide cost estimates associated with its nuclear waste management and decommissioning obligations. OPG is currently updating the cost estimates associated with its nuclear waste and decommissioning obligations. These cost estimates are being updated concurrently with an update to the Ontario Nuclear Funds Agreement ("ONFA") Reference Plan. OPG's costs for nuclear waste management and decommissioning, and its contribution obligations to the Nuclear Funds could significantly change as a result of updated cost estimates and the new ONFA Reference Plan.

Regulatory Risks

Rate Regulation

Significant uncertainties remain regarding the outcome of future rate proceedings, which will determine the regulated prices for OPG's rate regulated operations.

The prices for electricity generated from most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that it operates are determined by the OEB, currently on a forecast cost of service methodology. As with any regulated price established using a forecast cost of service methodology, there is an inherent risk that the prices established by the regulator may not provide for recovery of all actual costs incurred by the regulated operations, or allow the regulated operations to earn the allowed rate of return.

In March 2011, the OEB issued its decision on OPG's application for new regulated prices for 2011 and 2012. OPG has filed a notice of appeal with the Divisional Court of Ontario related to the part of the OEB's decision disallowing recovery in regulated prices of a portion of OPG's nuclear compensation costs. This matter is scheduled to be heard in late October 2011, and its outcome is uncertain.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

During the most recent interim period, there have been no changes in the Company's policies and procedures and other processes that comprise its internal control over financial reporting, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

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 – except where noted)	**June 30 2011**	**March 31 2011**	**December 31 2010**	**September 30 2010**
Revenue	**1,226**	1,308	1,324	1,396
Net income	**114**	151	202	333
Net income per share	**$0.45**	$0.59	$0.79	$1.29

(millions of dollars – except where noted)	**June 30 2010**	**March 31 2010**	**December 31 2009**	**September 30 2009**
Revenue	1,210	1,443	1,390	1,345
Net (loss) income	(29)	143	67	259
Net (loss) income per share	$(0.11)	$0.56	$0.26	$1.01

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 and cooling demands in the third quarter.

Additional items which impacted net income (loss) in certain quarters above are described below and in OPG's 2010 annual MD&A under the heading, *Quarterly Financial Highlights*.

- A decrease in gross margin during the first quarter of 2011 primarily due to lower revenue recognized related to the energy supply contract for the Lennox generating station, cessation of additions to the Tax Loss Variance Account based on the OEB's 2011 decision and order effective March 1, 2011, and a decrease in thermal generation revenue, partially offset by a decrease in fuel and fuel related costs and higher revenue related to a contingency support agreement established with the OEFC, and higher nuclear generation revenue;
- An increase in pension and OPEB costs during the first quarter of 2011, largely as a result of lower discount rates in 2011; and
- Lower expenditures related to a decrease in outage and project costs, partially offset by an increase in maintenance activities at OPG's nuclear generating stations during the first quarter of 2011.

Additional information about OPG, including its Annual Information Form, annual MD&A, and audited annual consolidated financial statements and notes thereto for the year ended December 31, 2010 can be found on SEDAR at www.sedar.com.

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 six month periods ended June 30, 2011 and 2010 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 on-going 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 fuel expense.

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

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INTERIM CONSOLIDATED STATEMENTS OF INCOME (LOSS) (UNAUDITED)

(millions of dollars – except where noted)	**Three Months Ended June 30** **2011**	**2010**	**Six Months Ended June 30** **2011**	**2010**
Revenue *(Notes 2 and 13)*	**1,226**	1,210	**2,534**	2,653
Fuel expense *(Note 13)*	**183**	210	**349**	457
Gross margin *(Note 13)*	**1,043**	1,000	**2,185**	2,196
Expenses *(Note 13)*				
Operations, maintenance and administration	**686**	781	**1,398**	1,508
Depreciation and amortization *(Note 4)*	**195**	174	**353**	340
Accretion on fixed asset removal and nuclear waste management liabilities *(Notes 5 and 8)*	**177**	165	**349**	330
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(164)**	(40)	**(302)**	(181)
Property and capital taxes	**15**	24	**23**	43
Restructuring *(Note 16)*	**-**	-	**-**	25
	909	1,104	**1,821**	2,065
Income (loss) before the following:	**134**	(104)	**364**	131
Other gains *(Note 13)*	**(4)**	(1)	**(3)**	(2)
Income (loss) before interest and income taxes	**138**	(103)	**367**	133
Net interest expense	**41**	44	**82**	89
Income (loss) before income taxes	**97**	(147)	**285**	44
Income tax (recovery) expense *(Note 9)*				
Current	**(28)**	(134)	**96**	(101)
Future	**11**	16	**(76)**	31
	(17)	(118)	**20**	(70)
Net income (loss)	**114**	(29)	**265**	114
Basic and diluted income (loss) per common share *(dollars)*	**0.45**	(0.11)	**1.04**	0.45
Common shares outstanding *(millions)*	**256.3**	256.3	**256.3**	256.3

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(millions of dollars)	**Three Months Ended June 30** **2011**	**2010**	**Six Months Ended June 30** **2011**	**2010**
Operating activities				
Net income (loss)	**114**	(29)	**265**	114
Adjust for non-cash items:				
Depreciation and amortization *(Note 4)*	**195**	174	**353**	340
Accretion on fixed asset removal and nuclear waste management liabilities *(Notes 5 and 8)*	**177**	165	**349**	330
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(164)**	(40)	**(302)**	(181)
Pension and other post employment benefit costs *(Note 10)*	**100**	85	**230**	168
Future income taxes and other accrued charges *(Note 9)*	**(12)**	(80)	**(99)**	(65)
Provision for restructuring (*Note 16)*	**-**	-	**-**	25
Mark-to-market on derivative instruments	**8**	(59)	**14**	34
Provision for used nuclear fuel and low and intermediate level waste	**11**	10	**23**	21
Regulatory assets and liabilities *(Note 5)*	**(4)**	22	**(92)**	(112)
Other	**1**	9	**1**	11
	426	257	**742**	685
Contributions to nuclear fixed asset removal and nuclear waste management funds	**(63)**	(65)	**(126)**	(137)
Expenditures on fixed asset removal and nuclear waste management *(Note 8)*	**(49)**	(49)	**(87)**	(100)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**14**	41	**27**	67
Contributions to pension funds	**(68)**	(69)	**(136)**	(137)
Expenditures on other post employment benefits and supplementary pension plans	**(24)**	(20)	**(43)**	(37)
Expenditures on restructuring *(Note 16)*	**(2)**	-	**(12)**	-
Net changes to other long-term assets and liabilities	**-**	(61)	**15**	(20)
Net changes in non-cash working capital balances *(Note 14)*	**(81)**	76	**182**	7
Cash flow provided by operating activities	**153**	110	**562**	328
Investing activities				
Investment in fixed and intangible assets	**(262)**	(227)	**(545)**	(404)
Net proceeds from sale of fixed assets	**7**	-	**7**	-
Cash flow used in investing activities	**(255)**	(227)	**(538)**	(404)
Financing activities				
Net decrease in short-term notes *(Note 7)*	**(156)**	-	**(155)**	-
Issuance of long-term debt *(Note 6)*	**507**	65	**697**	645
Repayment of long-term debt *(Note 6)*	**(2)**	(3)	**(192)**	(537)
Cash flow provided by financing activities	**349**	62	**350**	108
Net increase (decrease) in cash and cash equivalents	**247**	(55)	**374**	32
Cash and cash equivalents, beginning of period	**407**	158	**280**	71
Cash and cash equivalents, end of period	**654**	103	**654**	103

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**June 30** **2011**	**December 31** **2010**
Assets		
Current assets		
Cash and cash equivalents	**654**	280
Accounts receivable *(Note 3)*	**230**	270
Fuel inventory	**719**	734
Prepaid expenses	**36**	42
Income and capital taxes recoverable	**-**	65
Future income taxes *(Note 9)*	**67**	73
Materials and supplies	**79**	85
	1,785	1,549
Fixed assets *(Note 13)*		
Property, plant and equipment	**20,179**	19,654
Less: accumulated depreciation	**6,354**	6,099
	13,825	13,555
Intangible assets *(Note 13)*		
Intangible assets	**354**	345
Less: accumulated amortization	**305**	297
	49	48
Other long-term assets		
Deferred pension asset	**1,153**	1,146
Nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**11,674**	11,246
Long-term investments	**30**	30
Long-term materials and supplies	**394**	400
Regulatory assets *(Note 5)*	**1,498**	1,559
Long-term accounts receivable and other assets	**44**	44
	14,793	14,425
	30,452	29,577

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**June 30 2011**	**December 31 2010**
Liabilities		
Current liabilities		
Accounts payable and accrued charges	**712**	762
Income and capital taxes payable	**88**	-
Long-term debt due within one year *(Note 6)*	**599**	385
Short-term notes payable *(Note 7)*	**-**	155
Deferred revenue due within one year	**12**	12
	1,411	1,314
Long-term debt *(Note 6)*	**4,134**	3,843
Other long-term liabilities		
Fixed asset removal and nuclear waste management *(Note 8)*	**12,992**	12,704
Other post employment benefits and supplementary pension plans	**1,996**	1,908
Long-term accounts payable and accrued charges	**525**	525
Deferred revenue	**165**	152
Future income taxes *(Note 9)*	**677**	798
Regulatory liabilities *(Note 5)*	**213**	248
	16,568	16,335
Shareholder's equity		
Common shares	**5,126**	5,126
Retained earnings	**3,289**	3,024
Accumulated other comprehensive loss	**(80)**	(69)
Attributable to shareholder of Ontario Power Generation Inc.	**8,335**	8,081
Non-controlling interest *(Notes 2 and 15)*	**4**	4
	8,339	8,085
	30,452	29,577

Commitments and Contingencies *(Notes 6, 11, and 12)*

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (UNAUDITED)

Six Months Ended June 30 *(millions of dollars)*	**2011**	**2010**
Common shares	**5,126**	5,126
Retained earnings		
Balance at beginning of period	**3,024**	2,375
Net income	**265**	114
Balance at end of period	**3,289**	2,489
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of period	**(69)**	(24)
Other comprehensive loss for the period	**(11)**	(31)
Balance at end of period	**(80)**	(55)
Attributable to shareholder of Ontario Power Generation Inc.	**8,335**	7,560
Non-controlling interest *(Notes 2 and 15)*	**4**	4
	8,339	7,564

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (UNAUDITED)

	Three Months Ended June 30		**Six Months Ended June 30**	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Net income (loss)	**114**	(29)	**265**	114
Other comprehensive loss, net of income taxes				
Net loss on derivatives designated as cash flow hedges[1]	**(20)**	(17)	**(14)**	(27)
Reclassification to income of losses (gains) on derivatives designated as cash flow hedges[2]	**2**	(2)	**3**	(4)
Other comprehensive loss for the period	**(18)**	(19)	**(11)**	(31)
Comprehensive income (loss)	**96**	(48)	**254**	83

[1] Net of income tax recoveries of $1 million and $1 million for the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011 and 2010, net of income tax recoveries of $1 million and nil, respectively.

[2] Net of income tax recoveries of nil and $1 million for the three months ended June 30, 2011 and 2010, respectively. For the six months ended June 30, 2011 and 2010, net of income tax recoveries of nil and $2 million, respectively.

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2011 AND 2010 (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, and are presented in Canadian dollars. These interim consolidated financial statements do not contain all the disclosures required by Canadian generally accepted accounting principles ("GAAP") 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, 2010.

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

Certain of the 2010 comparative amounts have been reclassified from financial statements previously presented to conform to the 2011 consolidated financial statement presentation.

2. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

Changes Applicable to the Current Period

Business Combinations, Consolidated Financial Statements, and Non-controlling Interests

Effective January 1, 2011, Ontario Power Generation Inc. ("OPG" or the "Company") adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1582 *Business Combinations* ("Section 1582"), Section 1601 *Consolidated Financial Statements* ("Section 1601"), and Section 1602 *Non-controlling Interests* ("Section 1602"). Section 1582 specifies a number of changes, including an expanded definition of a business, a requirement to measure all business acquisitions at fair value, and a requirement to recognize acquisition-related costs as expenses. Section 1601 establishes the standards for preparing consolidated financial statements. Section 1602 specifies that non-controlling interests be treated as a separate component of equity, not as a liability or other item outside of equity. These new standards are harmonized with International Financial Reporting Standards ("IFRS"). These standards shall be applied prospectively to business combinations whose acquisition date is on or after the date of adoption. As a result of adopting Section 1602, the Company has reclassified its non-controlling interests as a separate component of equity. The adoption of Section 1582 and Section 1601 did not have a material impact on the Company's consolidated financial statements for the three and six month periods ended June 30, 2011.

Revenue Recognition – Generating Assets

Effective March 1, 2011, energy revenue generated from the nuclear facilities owned and operated by OPG is based on a regulated price of 5.59¢/kWh pursuant to the decision and order issued by the Ontario Energy Board ("OEB") in March and April 2011, respectively. The nuclear regulated price includes a rate rider of 0.43¢/kWh for the recovery of approved nuclear variance and deferral account balances based on recovery periods authorized by the OEB. Effective March 1, 2011, generation from OPG's regulated hydroelectric facilities receives a regulated price of 3.41¢/kWh, pursuant to the OEB's decision and order. The hydroelectric regulated price is net of a negative rate rider of -0.17¢/kWh reflecting the repayment of the approved regulated hydroelectric variance account balances. These rate riders will remain in effect until December 31, 2012.

In its decision, the OEB also approved the continuation of the existing hydroelectric incentive mechanism ("HIM"), but determined that a portion of the resulting net revenues should be shared with ratepayers effective March 1, 2011. Prior to March 1, 2011, energy revenue generated from the nuclear facilities owned and operated by OPG was based on a regulated price of 5.50¢/kWh, including a rate rider of 0.20¢/kWh for the recovery of the approved nuclear variance and deferral account balances, pursuant to the OEB's 2008 decision. Pursuant to that decision, prior to March 1, 2011, the revenue from the regulated hydroelectric generation was based on a regulated price of 3.67¢/kWh, which included the recovery of the approved regulated hydroelectric variance account balances and was subject to the HIM.

Electricity generated from OPG's other generating assets remains unregulated and continues to receive the Ontario electricity spot market price, except where an energy supply agreement is in place.

Future Changes in Accounting Policy

In February 2008, the Canadian Accounting Standards Board ("AcSB") confirmed that Publicly Accountable Enterprises will be required to transition from Canadian GAAP to IFRS, as issued by the International Accounting Standards Board ("IASB"), for interim and annual financial reporting purposes for fiscal years beginning on or after January 1, 2011. As a result of subsequent changes to Part I of the CICA Handbook – Accounting, by the AcSB, certain rate-regulated entities can defer the adoption of IFRS by one year to January 1, 2012. OPG meets the AcSB's criteria for the deferral and has chosen to adopt IFRS effective January 1, 2012.

IFRS are premised on a conceptual framework similar to Canadian GAAP, however, significant differences exist in certain matters of recognition, measurement and disclosure. In line with OPG's IFRS conversion project, an assessment has been completed to identify the key accounting differences from Canadian GAAP. OPG's assessment of the impact of IFRS is based on the IFRS standards in effect at the time of conversion on January 1, 2012 and accounting elections made. Proposed changes to the IFRS accounting standards have the potential to introduce additional significant accounting differences. OPG's interim consolidated financial statements, as currently disclosed in accordance with Canadian GAAP, will be significantly different when presented in accordance with IFRS. OPG will publish its first consolidated financial statements prepared in accordance with IFRS for the three months ending and as at March 31, 2012, and for the corresponding comparative period. The opening balance sheet as at January 1, 2011 will be disclosed in the March 31, 2012 interim consolidated financial statements.

3. SALE OF ACCOUNTS RECEIVABLE

In October 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.

During 2010, in accordance with the receivable purchase agreement, OPG renewed the agreement with a maturity date of August 31, 2013 and a commitment of $250 million.

The accounts receivable reported and securitized by the Company are as follows:

	Principal Amount of Receivables as at	
(millions of dollars)	**June 30 2011**	**December 31 2010**
Total receivables portfolio [1]	**314**	377
Receivables sold	**250**	250
Receivables retained	**64**	127

[1] Amount represents receivables outstanding, including receivables that have been securitized, which the Company continues to service.

The pre-tax charges and average cost of funds are as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars – except where noted)	**2011**	**2010**	**2011**	**2010**
Pre-tax charges	**1**	1	**2**	2
Average cost of funds *(percent)*	**1.9**	1.3	**1.8**	1.2

4. Depreciation and Amortization

Depreciation and amortization expense for the three and six month periods ended June 30, 2011 and 2010 consists of the following:

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Depreciation	**131**	146	**265**	282
Amortization of intangible assets	**4**	3	**8**	8
Amortization of regulatory assets and liabilities *(Note 5)*	**60**	25	**80**	50
	195	174	**353**	340

Interest capitalized to construction and development in progress at an average rate of five percent during the three and six month periods ended June 30, 2011 (three and six month periods ended June 30, 2010 – six percent) was $20 million and $38 million, respectively (three and six month periods ended June 30, 2010 – $18 million and $36 million, respectively).

5. Regulatory Assets and Liabilities

The OEB's decisions issued in 2008 and 2009 authorized certain variance and deferral accounts, including those authorized pursuant to *Ontario Regulation 53/05*, a regulation under the *Ontario Energy Board Act, 1998*. During January and February 2011, the Company recorded additions to these variance and deferral accounts pursuant to the OEB's decisions.

In March 2011, the OEB issued its decision on OPG's application for new prices for OPG's regulated generation effective March 1, 2011. In that decision, the OEB approved OPG's request for the disposition of variance and deferral account balances as at December 31, 2010. The OEB also authorized the continuation of previously existing variance and deferral accounts, with the exception of the Nuclear Fuel Cost Variance Account, which was discontinued as of March 1, 2011. The OEB also established the Hydroelectric Surplus Baseload Generation ("SBG") Variance Account and the HIM Variance Account.

Effective March 1, 2011, the Company recorded additions to the variance and deferral accounts authorized by the OEB's March 2011 decision, and amortized approved regulatory balances based on recovery periods established by that decision.

In March 2011, OPG filed with the OEB a motion to review and vary the OEB's March 2011 decision with respect to pension and other post employment benefit ("OPEB") costs. In June 2011, the OEB established the Pension and OPEB Cost Variance Account in its decision and order granting OPG's motion. The variance account records the difference between actual pension and OPEB costs and related tax impacts and those reflected in the current regulated prices. The variance account is in effect for the period from March 1, 2011 to December 31, 2012. The balance in the account will be reviewed by the OEB as part of OPG's next application for regulated prices. During the second quarter of 2011, OPG recorded a regulatory asset of $41 million related to the Pension and OPEB Cost Variance Account, resulting in reductions to OM&A expenses and income tax expense of $30 million and $11 million, respectively.

OPG also recorded interest on outstanding balances in the variance and deferral accounts at the interest rate prescribed by the OEB, which was 1.47 percent per annum during the six months ended June 30, 2011. The interest rate fluctuated in the range of 0.55 percent to 1.20 percent per annum during the year ended December 31, 2010.

In March 2011, OPG recorded a regulatory asset related to the amount of income taxes payable by the Company as a result of the OEB's approval for recovery of certain variance and deferral account balances in its March 2011 decision. The regulatory asset was based on the amount of income taxes expected to be recovered through current regulated prices and is amortized as these income taxes are recovered. During the three and six month periods ended June 30, 2011, OPG recorded a reduction to income tax expense of nil and $57 million, respectively, and a charge of $7 million and $10 million, respectively, to depreciation and amortization expense related to this regulatory asset.

The regulatory assets and liabilities recorded as at June 30, 2011 and December 31, 2010 are as follows:

(millions of dollars)	**June 30 2011**	**December 31 2010**
Regulatory assets		
Future Income Taxes *(Note 9)*	**658**	711
Bruce Lease Net Revenues Variance Account	**194**	250
Tax Loss Variance Account	**486**	492
Current Income Taxes	**47**	-
Pension and OPEB Cost Variance Account	**41**	-
Other	**72**	106
Total regulatory assets	**1,498**	1,559
Regulatory liabilities		
Nuclear Development Variance Account	**93**	111
Hydroelectric Water Conditions Variance Account	**56**	70
Income and Other Taxes Variance Account	**42**	40
Other	**22**	27
Total regulatory liabilities	**213**	248

As at June 30, 2011 and December 31, 2010, other regulatory assets include the Nuclear Liability Deferral Account, the Pickering A Return to Service Deferral Account, the Nuclear Deferral and Variance Over/Under Variance Account, the Nuclear Fuel Cost Variance Account, and other regulatory asset balances. As at June 30, 2011 and December 31, 2010, other regulatory liabilities include the Hydroelectric Deferral and Variance Over/Under Variance Account, the Capacity Refurbishment Variance Account, and other regulatory liability balances.

The changes in the regulatory assets and liabilities during the six months ended June 30, 2011 and the year ended December 31, 2010 are as follows:

(millions of dollars)	**Future Income Taxes**	**Bruce Lease Net Revenues Variance**	**Tax Loss Variance**	**Current Income Taxes**	**Pension and OPEB Cost Variance**	**Nuclear Develop-ment Variance**	**Hydro-electric Water Conditions Variance**	**Income and Other Taxes Variance**	**Other (net)**
Regulatory assets (liabilities), January 1, 2010	592	328	295	-	-	(55)	(55)	(21)	140
Change during the year	119	(81)	194	-	-	(50)	(14)	(19)	34
Interest	-	3	3	-	-	(1)	(1)	-	1
Amortization during the year	-	-	-	-	-	(5)	-	-	(96)
Regulatory assets (liabilities), December 31, 2010	711	250	492	-	-	(111)	(70)	(40)	79
Change during the period	(53)	(13)	33	57	41	(1)	2	(9)	(7)
Interest	-	2	4	-	-	(1)	(1)	-	-
Amortization during the period	-	(45)	(43)	(10)	-	20	13	7	(22)
Regulatory assets (liabilities), June 30, 2011	**658**	**194**	**486**	**47**	**41**	**(93)**	**(56)**	**(42)**	**50**

The following tables summarize the income statement and other comprehensive income statement impacts of recognizing regulatory assets and liabilities:

(millions of dollars)	Three Months Ended June 30, 2011 As Stated	Three Months Ended June 30, 2011 Impact of Regulatory Assets and Liabilities	Three Months Ended June 30, 2011 Financial Statements without the Impact of Regulatory Assets and Liabilities	Three Months Ended June 30, 2010 As Stated	Three Months Ended June 30, 2010 Impact of Regulatory Assets and Liabilities	Three Months Ended June 30, 2010 Financial Statements without the Impact of Regulatory Assets and Liabilities
Revenue	**1,226**	**(8)**	**1,218**	1,210	3	1,213
Fuel expense	**183**	**(2)**	**181**	210	6	216
Operations, maintenance and administration	**686**	**32**	**718**	781	(21)	760
Depreciation and amortization	**195**	**(61)**	**134**	174	(32)	142
Accretion on fixed asset removal and nuclear waste management liabilities	**177**	**(1)**	**176**	165	3	168
(Earnings) losses on nuclear fixed asset removal and nuclear waste management funds	**(164)**	**(24)**	**(188)**	(40)	69	29
Property and capital taxes	**15**	**-**	**15**	24	(3)	21
Net interest expense	**41**	**2**	**43**	44	(2)	42
Income tax (recovery) expense	**(17)**	**25**	**8**	(118)	(22)	(140)
Other comprehensive loss	**(18)**	**5**	**(13)**	(19)	5	(14)

(millions of dollars)	As Stated	Six Months Ended June 30, 2011 Impact of Regulatory Assets and Liabilities	Financial Statements without the Impact of Regulatory Assets and Liabilities	As Stated	Six Months Ended June 30, 2010 Impact of Regulatory Assets and Liabilities	Financial Statements without the Impact of Regulatory Assets and Liabilities
Revenue	**2,534**	**(43)**	**2,491**	2,653	(147)	2,506
Fuel expense	**349**	**4**	**353**	457	10	467
Operations, maintenance and administration	**1,398**	**25**	**1,423**	1,508	(37)	1,471
Depreciation and amortization	**353**	**(86)**	**267**	340	(65)	275
Accretion on fixed asset removal and nuclear waste management liabilities	**349**	**3**	**352**	330	6	336
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(302)**	**(27)**	**(329)**	(181)	53	(128)
Property and capital taxes	**23**	**(4)**	**19**	43	(6)	37
Net interest expense	**82**	**3**	**85**	89	(2)	87
Income tax expense (recovery)	**20**	**16**	**36**	(70)	(14)	(84)
Other comprehensive loss	**(11)**	**3**	**(8)**	(31)	9	(22)

6. LONG-TERM DEBT

Long-term debt consists of the following:

(millions of dollars)	June 30 2011	December 31 2010
Notes payable to the Ontario Electricity Financial Corporation	**3,903**	3,865
UMH Energy Partnership debt	**198**	198
Lower Mattagami Energy Limited Partnership debt	**471**	-
Share of non-recourse limited partnership debt	**161**	165
	4,733	4,228
Less: due within one year		
Notes payable to the Ontario Electricity Financial Corporation	**588**	375
UMH Energy Partnership debt	**3**	2
Share of non-recourse limited partnership debt	**8**	8
	599	385
Long-term debt	**4,134**	3,843

Interest paid during the three months ended June 30, 2011 was $39 million (three months ended June 30, 2010 – $35 million), of which $36 million related to interest paid on long-term debt (three months ended June 30, 2010 – $33 million). Interest paid during the six months ended June 30, 2011 was $123 million (six months ended June 30, 2010 – $128 million), of which $118 million related to interest paid on long-term debt (six months ended June 30, 2010 – $123 million). Interest on the notes payable to the Ontario Electricity Financial Corporation ("OEFC") is paid semi-annually.

During 2010, OPG executed an amended Niagara Tunnel project credit facility for an amount up to $1.6 billion. As at June 30, 2011, advances under this facility were $765 million, which included $35 million of new borrowing during the second quarter of 2011.

OPG reached an agreement with the OEFC in the first quarter of 2011 for a $375 million credit facility to refinance notes as they mature over the period from January 2011 to December 2011. Refinancing under this agreement totalled $150 million as at June 30, 2011.

On May 17, 2011, senior notes totalling $475 million were issued by the Lower Mattagami Energy Limited Partnership ("LME"). The senior notes have interest rates of 4.3 percent for notes of $225 million maturing in 2021 and 5.1 percent for notes of $250 million maturing in 2041. These notes are secured by the assets of the Lower Mattagami project including existing operating facilities and facilities being constructed.

7. SHORT-TERM CREDIT FACILITIES

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two tranches – a $500 million 364-day term tranche, and a $500 million multi-year term tranche. In May 2011, OPG renewed and extended the 364-day term tranche for a four-year term to May 18, 2015. The multi-year term tranche has a maturity date of May 20, 2013. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at June 30, 2011, no commercial paper was outstanding (December 31, 2010 – nil), and OPG had no other outstanding borrowings under the bank credit facility.

During 2010, the LME established a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami project and launched a commercial paper program. As at June 30, 2011, no commercial paper was outstanding under this program (December 31, 2010 – $155 million). In March 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami project. As at June 30, 2011, there was no outstanding borrowing under this credit facility.

8. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT

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

(millions of dollars)	**June 30 2011**	**December 31 2010**
Liability for nuclear used fuel management	**7,720**	7,534
Liability for nuclear decommissioning and low and intermediate level waste management	**5,112**	5,013
Liability for non-nuclear fixed asset removal	**160**	157
Fixed asset removal and nuclear waste management liabilities	**12,992**	12,704

The changes in the fixed asset removal and nuclear waste management liabilities for the six months ended June 30, 2011 and the year ended December 31, 2010 are as follows:

(millions of dollars)	**June 30 2011**	**December 31 2010**
Liabilities, beginning of period	**12,704**	11,859
Increase in liabilities due to accretion	**352**	673
Increase in liabilities due to changes in assumptions related to the decision to commence the definition phase of the refurbishment of the Darlington nuclear generating station	**-**	293
Increase in liabilities due to nuclear used fuel, nuclear waste management variable expenses and other expenses	**23**	56
Liabilities settled by expenditures on fixed asset removal and waste management	**(87)**	(181)
Change in the liabilities for non-nuclear fixed asset removal	**-**	4
Liabilities, end of period	**12,992**	12,704

The cash and cash equivalents balance as at June 30, 2011 includes $5 million of cash and cash equivalents that are for the use of nuclear waste management activities (December 31, 2010 – $3 million).

Ontario Nuclear Funds Agreement

OPG sets aside and invests funds held in segregated custodian and trustee accounts specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities in accordance with the Ontario Nuclear Funds Agreement ("ONFA") and the federal Nuclear Fuel Waste Act ("NFWA").

The nuclear fixed asset removal and nuclear waste management funds ("Nuclear Funds") as at June 30, 2011 and December 31, 2010 consist of the following:

	Fair Value	
(millions of dollars)	**June 30 2011**	**December 31 2010**
Decommissioning Segregated Fund	**5,381**	5,267
Used Fuel Segregated Fund[1]	**6,463**	6,198
Due to Province – Used Fuel Segregated Fund	**(170)**	(219)
	6,293	5,979
	11,674	11,246

[1] The Ontario NFWA Trust represented $2,142 million as at June 30, 2011 (December 31, 2010 – $1,949 million) of the Used Fuel Segregated Fund on a fair value basis.

As required by the terms of the ONFA, the Province of Ontario ("Province") has provided a Provincial Guarantee to the Canadian Nuclear Safety Commission ("CNSC") since 2003, on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between the long-term liabilities and the current market value of the Used Fuel

Segregated Fund and the Decommissioning Segregated Fund, up to the value of the Provincial Guarantee. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee provided by the Province. In December 2009, the CNSC approved an increase in the amount of the Provincial Guarantee to $1,545 million effective on March 1, 2010. The value of this Provincial Guarantee will be in effect through to the end of 2012, when the next reference plan for the CNSC is required to be submitted. In January 2011, OPG paid a guarantee fee of $8 million based on a Provincial Guarantee amount of $1,545 million.

In accordance with CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement* ("Section 3855"), the investments in the Nuclear Funds and the corresponding payables to the Province are classified as held-for-trading and are measured at fair value with realized and unrealized gains and losses recognized in OPG's interim consolidated financial statements.

The earnings on the Nuclear Funds for the three and six month periods ended June 30, 2011 and 2010 are as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Decommissioning Segregated Fund	**39**	(126)	**129**	(39)
Used Fuel Segregated Fund	**149**	97	**200**	167
Bruce Lease Net Revenues Variance Account *(Note 5)*	**(24)**	69	**(27)**	53
Total earnings	**164**	40	**302**	181

9. INCOME TAXES

OPG follows the liability method of tax accounting for all its business segments and records a corresponding regulatory asset or liability for the future income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

During the three months ended June 30, 2011, OPG recorded an increase of $8 million to the future income tax liability for the future taxes relating to the regulated operations. Since these future income taxes are expected to be recovered through future regulated prices, OPG has recorded a corresponding increase to the regulatory asset for future income taxes. As a result, the future income taxes for the three months ended June 30, 2011 were not impacted.

During the six months ended June 30, 2011, OPG recorded a decrease of $53 million to the future income tax liability for the future taxes relating to the regulated operations. Since these future income taxes are expected to be refunded through future regulated prices, OPG has recorded a corresponding decrease to the regulatory asset for future income taxes. As a result, the future income taxes for the six months ended June 30, 2011 were not impacted.

The amount of cash income taxes paid during the three months ended June 30, 2011 was nil (three months ended June 30, 2010 – $25 million). For the six months ended June 30, 2011, income taxes paid were nil (six months ended June 30, 2010 – $33 million).

10. Pension and Other Post Employment Benefit Costs

Total benefit costs for the three and six month periods ended June 30, 2011 and 2010 are as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**
Registered pension plans	**64**	32	**129**	63
Supplementary pension plans	**6**	5	**12**	10
Other post employment benefits	**60**	48	**119**	95
Pension and OPEB Cost Variance Account *(Note 5)*	**(30)**	-	**(30)**	-
Pension and other post employment benefit costs	**100**	85	**230**	168

An actuarial valuation of the OPG registered pension plan was completed as of January 1, 2011. Based on the actuarial valuation, OPG will increase its annual contribution to the plan from $270 million in 2010 to $300 million in 2011. The annual contributions for 2012 and 2013 will be adjusted for changes in current service costs in each year. OPG will continue to assess the requirements for contributions to the pension plan. The next actuarial valuation for funding purposes must have an effective date no later than January 1, 2014.

11. Financial Instruments

The Risk Oversight Committee ("ROC") assists the Board of Directors to fulfill its oversight responsibilities for matters relating to identification and management of the Company's key business risks. Risk management activities are coordinated by a centralized Corporate Risk Management group led by the Chief Risk Officer. Risks that would prevent business units from achieving business plan objectives are identified at the business unit level. Senior management sets risk limits for the financing, procurement, and trading activities of the Company and ensures that effective risk management policies and processes are in place to ensure compliance with such limits in order to maintain an appropriate balance between risk and return. OPG's risk management process aims to continually evaluate the effectiveness of risk mitigation activities for identified key risks. The findings from this evaluation process are reported quarterly to the ROC.

OPG is exposed to risks related to changes in electricity prices associated with a wholesale spot market for electricity in Ontario, changes in interest rates, and movements in foreign currency that affect its assets, liabilities, and forecast transactions. Select derivative instruments are used to limit such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Derivatives and Hedging

At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective and its strategy for undertaking the hedge. OPG also requires a documented assessment, both at hedge inception and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

Hedge accounting is applied when the derivative instrument is designated as a hedge and is expected to be effective throughout the life of the hedged item. When such a derivative instrument hedge ceases to exist or to be effective as a hedge, or when designation of a hedging relationship is terminated, any associated deferred gains or losses are recognized in income in the current period. When a hedged item ceases to exist, any associated deferred gains or losses are recognized in the current period's consolidated statement of income.

Derivative Instruments Qualifying for Hedge Accounting

The following table provides the estimated fair value of derivative instruments designated as hedges.

(millions of dollars – except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Notional Quantity**	**Terms**	**Fair Value**
		June 30, 2011			**December 31, 2010**	
Floating-to-fixed interest rate hedges	**33**	**1–8 yrs**	**(4)**	35	1–9 yrs	(4)
Forward starting interest rate hedges	**770**	**1–13 yrs**	**(27)**	375	1–12 yrs	(21)

OPG has entered into a number of forward start interest rate swap agreements to hedge against the effect of changes in interest rates for long-term debt for the Niagara Tunnel. In the second quarter of 2011, the LME entered into forward start interest rate swaps to hedge against the effect of future changes in interest rates for long-term debt for the Lower Mattagami project.

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 the short-term floating interest rate with a fixed rate of 5.33 percent. OPG's proportionate interest in the swap is 50 percent and is accounted for as a hedge.

Net losses of $2 million and $3 million, which include the impact of income taxes, related to derivative instruments qualifying for hedge accounting, were recognized in net income during the three and six months ended June 30, 2011, respectively. Existing net losses of $7 million deferred in accumulated other comprehensive loss at June 30, 2011 are expected to be reclassified to net income within the next 12 months.

Derivative Instruments Not Qualifying for Hedge Accounting

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

(millions of dollars – except where noted)	**Notional Quantity**	**Fair Value**	**Notional Quantity**	**Fair Value**
	June 30, 2011		**December 31, 2010**	
Commodity derivative instruments				
Assets	**3.9 TWh**	**3**	1.7 TWh	3
Liabilities	**0.2 TWh**	**(1)**	0.1 TWh	-
Total		**2**		3

Under the Bruce Power lease agreement, lease revenue is reduced in each calendar year where the annual arithmetic average of the Hourly Ontario Electricity Price ("Average HOEP") falls below $30/MWh, and if certain other conditions are met. The conditional reduction to revenue included in the lease agreement is treated as a derivative according to Section 3855. OPG reported a liability of $177 million as at June 30, 2011 (December 31, 2010 – $163 million), which reflected the fair value of a derivative embedded in the Bruce Power lease agreement. This increase in the fair value of the derivative liability was primarily due to reductions in the expected future Average HOEP since the beginning of 2011. The income statement impact as a result of changes to the liability is offset by the income statement impact of the Bruce Lease Net Revenues Variance Account.

Fair Value

Fair value is the value that a financial instrument can be closed out or sold, in an arm's length transaction with a willing and knowledgeable counterparty. The fair value of financial instruments traded in active markets is based on quoted market prices at the consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the bid price.

For financial instruments which do not have quoted market prices directly available, fair values are estimated using forward price curves developed from observable market prices or rates which may include the use of valuation techniques or models based, wherever possible, on assumptions supported by observable market prices or rates prevailing at the dates of the interim consolidated balance sheets. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate.

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.

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served on OPG and Bruce Power L.P. by British Energy Limited and British Energy International Holdings Limited (together "British Energy"). The British Energy claim against OPG pertains to corrosion in the Bruce Unit 8 Steam Generators, in particular, erosion of the support plates through which the boiler tubes pass. The claim amount includes $65 million due to an extended outage to repair some of the alleged damage. The balance of the amount claimed is based on an increased probability the steam generators will have to be replaced or the unit taken out of service prematurely. OPG leased the Bruce nuclear generating stations to Bruce Power L.P. in 2001.

British Energy is involved in arbitration with the current owners of Bruce Power L.P. regarding an alleged breach of British Energy's representations and warranties to the current owners when they purchased British Energy's interest in Bruce Power L.P. (the "Arbitration"). If British Energy is successful in defending against the Arbitration claim, they will not have suffered any damages to attempt to recoup from OPG. This Arbitration commenced on April 5, 2010. The Arbitration closing arguments have been rescheduled and are anticipated to occur in the third quarter of 2011. It may take some time for the arbitrator to come to a decision after the closing arguments have been completed.

British Energy previously indicated that they did not require OPG or Bruce Power L.P. to actively defend the court action until the conclusion of the Arbitration. Although the Arbitration had not concluded, British Energy requested that OPG file a Statement of Defence. OPG and Bruce Power L.P. advised British Energy that if British Energy wishes the court action to proceed prior to the conclusion of the Arbitration, the defendants would bring a motion for a Stay of proceedings, a Dismissal of the current action or, in the alternative, a motion to extend the time for service of the Statement of Defence until the conclusion of the

Arbitration. That motion was scheduled to be heard on March 5, 2010 but was adjourned at the request of British Energy. The return date of that motion is yet to be set.

In September 2008, a certain First Nation served a Notice of Action against the Government of Canada, the Province of Ontario, OPG, and the OEFC claiming damages arising from breach of contract, fiduciary duty, trespass to property, negligence, nuisance, misrepresentation, breach of riparian rights and unlawful and unjustifiable infringement of the Aboriginal and treaty rights and \$0.5 million in special damages. This Notice of Action was followed by service of the formal Statement of Claim (the “Claim”) in June 2010 upon the same parties seeking the same relief. As well, in September 2008, the same First Nation served a Notice of Arbitration upon OPG and the OEFC (the “Arbitration”). The OEFC was subsequently released from the Arbitration proceedings. The First Nation alleges that OPG breached an agreement to use its "best efforts" to engage the Province in discussion with the First Nation concerning the sharing of benefits related to hydroelectric development. In June 2010, the arbitrator (i) ruled in favour of the First Nation regarding OPG’s failure to use “best efforts”, and (ii) deferred his determination on whether such failure gave rise to any damages to allow for settlement discussions.

During the third quarter of 2011, the Claim and the Arbitration were settled in one settlement agreement. OPG was directed by its shareholder to pay a part of the shareholder’s portion of the settlement liability on its behalf. As a result, OPG recorded a distribution of \$14 million to the First Nation, which was recorded as a reduction to retained earnings in the third quarter of 2011. This settlement does not have a material impact on the Company’s financial position.

Certain other First Nations have commenced actions against OPG for interference with their respective reserve and traditional land rights. As well, OPG has been brought into certain actions by the First Nations against other parties as a third party defendant. Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company’s belief that their resolution is not likely to have a material adverse impact on its financial position.

Environmental

Current operations are subject to regulation with respect to emissions to air, water, and land as well as 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 interim consolidated financial statements to meet certain other environmental obligations.

13. BUSINESS SEGMENTS

Segment Income (Loss) for the Three Months Ended June 30, 2011 *(millions of dollars)*	Regulated			Unregulated				
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Hydro-electric	Thermal	Other	Elimination	Total
Revenue	713	12	190	149	134	39	(11)	1,226
Fuel expense	58	-	69	22	34	-	-	183
Gross margin	655	12	121	127	100	39	(11)	1,043
Operations, maintenance and administration	490	14	25	57	104	7	(11)	686
Depreciation and amortization	136	-	8	20	22	9	-	195
Accretion on fixed asset removal and nuclear waste management liabilities	-	176	-	-	1	-	-	177
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(164)	-	-	-	-	-	(164)
Property and capital taxes	7	-	1	-	4	3	-	15
Other gains	(3)	-	-	-	-	(1)	-	(4)
Income (loss) before interest and income taxes	25	(14)	87	50	(31)	21	-	138

Segment (Loss) Income for the Three Months Ended June 30, 2010 *(millions of dollars)*	Regulated		Unregulated					
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Elimination**	**Total**
Revenue	657	10	184	103	233	33	(10)	1,210
Fuel expense	42	-	64	13	91	-	-	210
Gross margin	615	10	120	90	142	33	(10)	1,000
Operations, maintenance and administration	569	12	24	55	127	4	(10)	781
Depreciation and amortization	101	-	16	15	27	15	-	174
Accretion on fixed asset removal and nuclear waste management liabilities	-	163	-	-	2	-	-	165
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(40)	-	-	-	-	-	(40)
Property and capital taxes	11	-	2	2	4	5	-	24
Other gains	-	-	-	-	-	(1)	-	(1)
(Loss) income before interest and income taxes	(66)	(125)	78	18	(18)	10	-	(103)

Segment Income (Loss) for the Six Months Ended June 30, 2011 *(millions of dollars)*	**Regulated**			**Unregulated**				
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Elimination**	**Total**
Revenue	**1,501**	**24**	**374**	**298**	**280**	**80**	**(23)**	**2,534**
Fuel expense	**113**	**-**	**119**	**42**	**75**	**-**	**-**	**349**
Gross margin	**1,388**	**24**	**255**	**256**	**205**	**80**	**(23)**	**2,185**
Operations, maintenance and administration	**1,020**	**28**	**51**	**108**	**202**	**12**	**(23)**	**1,398**
Depreciation and amortization	**228**	**-**	**22**	**36**	**43**	**24**	**-**	**353**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**346**	**-**	**-**	**3**	**-**	**-**	**349**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(302)**	**-**	**-**	**-**	**-**	**-**	**(302)**
Property and capital taxes	**14**	**-**	**(1)**	**(3)**	**8**	**5**	**-**	**23**
Other (gains) losses	**(3)**	**-**	**-**	**-**	**1**	**(1)**	**-**	**(3)**
Income (loss) before interest and income taxes	**129**	**(48)**	**183**	**115**	**(52)**	**40**	**-**	**367**

Segment Income (Loss) for the Six Months Ended June 30, 2010 *(millions of dollars)*	**Regulated**		**Unregulated**					
	Nuclear Generation	**Nuclear Waste Manage-ment**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Elimination**	**Total**
Revenue	1,450	21	368	252	501	81	(20)	2,653
Fuel expense	92	-	113	32	220	-	-	457
Gross margin	1,358	21	255	220	281	81	(20)	2,196
Operations, maintenance and administration	1,120	24	47	101	229	7	(20)	1,508
Depreciation and amortization	193	-	32	31	54	30	-	340
Accretion on fixed asset removal and nuclear waste management liabilities	-	327	-	-	3	-	-	330
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(181)	-	-	-	-	-	(181)
Property and capital taxes	22	-	5	3	5	8	-	43
Restructuring	-	-	-	-	25	-	-	25
Other gains	-	-	-	-	-	(2)	-	(2)
Income (loss) before interest and income taxes	23	(149)	171	85	(35)	38	-	133

(millions of dollars)	Nuclear	Regulated Hydro-electric	Unregulated Hydro-electric	Thermal	Other	Total
Selected Balance Sheet Information						
As at June 30, 2011						
Segment fixed assets in service, net	**3,881**	**3,765**	**3,316**	**242**	**739**	**11,943**
Segment construction in progress	**221**	**1,036**	**587**	**17**	**21**	**1,882**
Segment property, plant and equipment, net	**4,102**	**4,801**	**3,903**	**259**	**760**	**13,825**
As at June 30, 2011						
Segment intangible assets in service, net	**14**	**-**	**6**	**1**	**16**	**37**
Segment development in progress	**6**	**-**	**-**	**-**	**6**	**12**
Segment intangible assets, net	**20**	**-**	**6**	**1**	**22**	**49**
As at December 31, 2010						
Segment fixed assets in service, net	3,963	3,750	3,324	282	759	12,078
Segment construction in progress	174	913	367	20	3	1,477
Segment property, plant and equipment, net	4,137	4,663	3,691	302	762	13,555
As at December 31, 2010						
Segment intangible assets in service, net	18	-	5	1	16	40
Segment development in progress	3	-	-	-	5	8
Segment intangible assets, net	21	-	5	1	21	48

14. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	Three Months Ended June 30 2011	Three Months Ended June 30 2010	Six Months Ended June 30 2011	Six Months Ended June 30 2010
Accounts receivable	**(45)**	61	**40**	173
Prepaid expenses	**17**	8	**6**	(17)
Fuel inventory	**(8)**	17	**15**	89
Materials and supplies	**9**	37	**6**	38
Accounts payable and accrued charges	**(40)**	27	**(38)**	(226)
Income and capital taxes payable/recoverable	**(14)**	(74)	**153**	(50)
	(81)	76	**182**	7

15. Non-Controlling Interest

OPG has entered into a partnership agreement with the Lac Seul First Nation ("LSFN") regarding the 12.5 MW Lac Seul generating station. In July 2009, OPG transferred ownership of the station to the Lac Seul LP partnership.

OPG consolidates the results of the Lac Seul LP and the non-controlling interest represents the LSFN's ownership interest in the partnership.

16. Restructuring

In September 2009, together with the Ministry of Energy and Infrastructure, OPG announced its decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations. The closures occurred on October 1, 2010. OPG conducted discussions with key stakeholders, including the Society of Energy Professionals and the Power Workers' Union, in accordance with their respective collective bargaining agreements. As determined by the collective bargaining agreements, restructuring costs of $27 million were recorded during 2010 for those employees who have elected to leave. The change in the restructuring liability for severance costs for the six months ended June 30, 2011 is as follows:

(millions of dollars)	
Liability, January 1, 2010	-
Restructuring charges during the year	27
Payments during the year	(12)
Liability, December 31, 2010	15
Payments during the period	(12)
Liability, June 30, 2011	**3**

In addition to the 2010 unit closure, Ontario's Long-Term Energy Plan released in November 2010 and the Supply Mix Directive issued in February 2011 require the safe shutdown of two coal-fired units at the Nanticoke coal-fired generating station in 2011. The Independent Electricity System Operator has confirmed that these units are not required for meeting supply adequacy and system reliability in the period from December 31, 2011 through December 31, 2014. On March 25, 2011, OPG notified key stakeholders, including the Society of Energy Professionals and the Power Workers' Union, of the decision in accordance with their respective collective bargaining agreements. The restructuring costs associated with the unit closures are estimated to be within the range of $22 million to $28 million and are expected to be recorded in 2011 and 2012.

17. Seasonal Operations

OPG's quarterly results are impacted by changes in demand resulting from variations in seasonal weather conditions. Primarily during the first and third quarters of a fiscal year, OPG's revenues are impacted as a result of winter heating demands in the first quarter and air conditioning/cooling demands in the third quarter. Regulated prices for most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that OPG operates, the contingency support agreement with the OEFC, and OPG's hedging strategies significantly reduced the impact of seasonal price fluctuations on the results of operations.