ONTARIO POWER GENERATION

News
from Ontario Power Generation

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ONTARIO POWER GENERATION REPORTS 2012 FINANCIAL RESULTS

[Toronto]: Ontario Power Generation Inc. ("OPG" or the "Company") today reported its financial and operating results for the year ended December 31, 2012. Net income for the year was $367 million, compared to net income of $338 million for the year ended December 31, 2011.

Tom Mitchell, President and Chief Executive Officer, said "OPG's business transformation has resulted in significant cost savings as a result of workforce reductions through attrition and productivity improvements. These cost reductions were a major factor underlying the company's financial results for 2012.

"Creating a leaner organization is key to our efforts to hold down the prices that people pay for electricity. We are proud of being Ontario's low cost electricity generator."

Mr. Mitchell added, "In addition to operating with fewer people and implementing numerous efficiency improvements, OPG had a solid year in the areas of safety, environmental stewardship, operations, and new projects. For example, our Pickering nuclear units had their best year of production reliability since 2002."

Net income of $367 million in 2012 increased from $338 million in 2011. This increase was primarily the result of higher earnings from the nuclear fixed asset removal and nuclear waste management funds ("Nuclear Funds"), and a reduction in operations, maintenance and administration ("OM&A") expenses. This increase was mainly offset by a decrease in revenues as a result of lower electricity market prices, and an increase in income tax expense.

OPG's income before interest and income taxes from the electricity generation business segments was $566 million in 2012, compared to $567 million in 2011. This marginal decrease was largely due to the impact of lower Ontario electricity prices. The average revenue that OPG received for a kilowatt hour ("kWh") of electricity in 2012 was 5.1 ¢/kWh, compared to 5.3 ¢/kWh in 2011. This was significantly below the average revenue of 8.6 ¢/kWh received by all other generators in Ontario. Income before income taxes improved as a result of headcount and other cost reductions, and the recognition of losses in 2011 due to an increase in the asset retirement obligation related to certain thermal generating stations.

The Regulated – Nuclear Waste Management business segment recorded a loss before interest and income taxes of $68 million for the year ended December 31, 2012, compared to a loss before income taxes of $194 million in 2011. This improvement primarily resulted from higher earnings from the Nuclear Funds, due to a greater increase in the market value of the securities held in the funds in 2012 compared to 2011.

In January 2013, the Ministry of Energy announced the advanced shutdown of the remaining coal-fired units at the Lambton and Nanticoke generating stations by December 31, 2013, in advance of the previous December 31, 2014 deadline. OPG plans to place the units in reserve status and to preserve the option to convert them to natural gas and/or biomass in the future, if required.

In September 2012, OPG filed an application with the Ontario Electricity Board ("OEB") requesting approval to recover balances in the authorized regulatory variance and deferral accounts as at December 31, 2012. The application requested the recovery of these balances to be reflected through new rate riders effective January 1, 2013. OPG is in continuing settlement discussions with the intervenors regarding all aspects of the rate application. If an agreement is reached, a settlement agreement will be filed with the OEB and will be subject to approval by the OEB.

Generating and Operating Performance

Total electricity generated in 2012 of 83.7 terawatt hours ("TWh") decreased slightly from generation of 84.7 TWh in 2011. The 1.0 TWh decrease was primarily due to a reduction in hydroelectric generation as a result of lower water levels on the lower Great Lakes and the Northeastern and Eastern Ontario watersheds. Nuclear production of 49.0 TWh in 2012 increased by 0.4 TWh primarily due to fewer unplanned and planned outage days at the Pickering stations. Thermal generation of 4.1 TWh in 2012 represents an increase of 0.4 TWh, compared to 2011 primarily due to lower hydroelectric generation, increased electricity demand due to warmer temperatures during the summer of 2012, and the utilization of coal inventories prior to the shutdown of the stations.

The Darlington nuclear station achieved a capability factor of 93.2 per cent in 2012, compared to 95.2 per cent in 2011. This performance was mainly due to an increase in unplanned outage days. The capability factor at the Pickering stations improved to 77.8 per cent in 2012 from 73.4 per cent in 2011. This performance reflected fewer unplanned and planned outage days.

The availability of OPG's regulated and unregulated hydroelectric stations remained at high levels in 2012. OPG's regulated hydroelectric stations achieved an availability factor of 91.4 per cent in 2012, compared to 89.7 per cent in 2011. OPG's unregulated hydroelectric stations achieved an availability factor of 91.1 per cent in 2012, compared to 91.5 per cent in 2011.

The Start Guarantee rate of the thermal generating fleet was 97.5 per cent in 2012, from 94.7 per cent in 2011. The high Start Guarantee rate reflects the ability of the thermal fleet to respond to market requirements when needed.

Generation Development

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

Nuclear

- The activities associated with the definition phase of the Darlington refurbishment project continue. Based on the Environmental Assessment ("EA") that OPG submitted in 2011, the Canadian Nuclear Safety Commission ("CNSC") and Fisheries and Oceans Canada issued a final Environmental Assessment Screening Report in September 2012. This report formed the basis for the EA public hearing, held in December 2012. The report was consistent with OPG's analysis. It concluded that, taking into account the identified mitigation measures, Darlington refurbishment and continued operations are not likely to cause adverse effects on the environment. The CNSC's decision on the EA is expected by the second quarter of 2013.

During 2012, OPG awarded a Retube and Feeder Replacement contract, which includes the planning, design and testing of tooling, design and construction of a full scale reactor mock-up facility for testing and training, and removal and replacement of major reactor components of the four reactors at the Darlington generating station. The procurement processes for the Turbine and Generator Contract, and the Defueling Contract were initiated in 2012.

Construction of the Darlington Energy Complex continued in 2012. The facility was substantially completed in January 2013.

Capital project expenditures for 2012 were $232 million and the life-to-date capital expenditures as at December 31, 2012 were $362 million. A detailed cost and schedule estimate for the refurbishment of the four units is expected to be completed in 2015. The execution phase is expected to start in 2016.

- During 2012, OPG substantially completed a coordinated set of initiatives to evaluate the continued safe and reliable operation of Pickering Units 5 to 8 for approximately an additional four to six years. OPG completed the necessary work to demonstrate with sufficient confidence that the pressure tubes will achieve the additional life, as predicted. Continued operations work related to equipment improvements and inspections will continue until the end of 2014, as planned.

- In 2012, the CNSC approved the application for the Power Reactor Site Preparation ("Licence to Prepare Site") for the new nuclear units at Darlington. Subsequently, a notice of application for a judicial review of the Licence to Prepare Site was filed by third parties. OPG is preparing its response to the application.

Hydroelectric

- All major tunnel lining activities at the Niagara Tunnel were completed in 2012, with the exception of pre-stress grouting to complete the attachment of the concrete liner with the surrounding rock. This activity had progressed to 9,525 metres as at December 31, 2012. In early March 2013, final testing is underway with water flowing through the Niagara Tunnel prior to declaring it in-service, more than nine months ahead of the approved project completion date of December 2013. Upon completion of the tunnel, the average annual generation from the Sir Adam Beck generating stations is expected to increase by approximately 1.5 TWh, depending on water flow. Life-to-date capital expenditures as at December 31, 2012 were $1.4 billion. Total costs of the project at completion are expected to be approximately $1.5 billion, compared to the approved budget of $1.6 billion.

- The Lower Mattagami River project will increase the capacity of the four generating stations on the Lower Mattagami River by 438 MW. Concrete operations continued throughout 2012 at the Little Long, Harmon, and Smoky Falls sites, with all key milestone dates being met or bettered. In December 2012, there was a breach in one section of the recently installed cofferdam at the Kipling site. All other cofferdams on the project have been inspected and it has been determined that they are safe. While the cost impact of this incident is not expected to be significant, work continues to finalize a remediation plan and to determine the impact on the completion date of the project of June 2015. Life-to-date capital expenditures were $1.4 billion as at December 31, 2012.

Thermal

- In the third quarter of 2012, OPG and the Ontario Power Authority ("OPA") executed the Atikokan Biomass Energy Supply Agreement. The converted station is expected to have a capacity of 200 MW. The conversion project has an approved cost estimate of $170 million and is expected to be completed in the first half of 2014. Life-to-date capital expenditures were $59 million as at December 31, 2012.

- OPG has suspended further work on the Thunder Bay generating station conversion to natural gas, pending an OPA review of electricity needs in Northwestern Ontario. The OPA has informed OPG that more time is required to explore other options for electricity supply in the region.

- In conjunction with the status of the conversion of the Thunder Bay generating station, OPG requested deregistration of the plant in November 2012. In January 2013, the Independent Electricity System Operator ("IESO") determined that at least one unit is required in Thunder Bay to maintain reliability of the IESO-controlled grid. Accordingly, OPG and the IESO entered into negotiations for a Reliability Must Run contract covering the period from January 1, 2013 to December 31, 2013. The contract has been executed by OPG and the IESO and is subject to OEB approval.

FINANCIAL AND OPERATIONAL HIGHLIGHTS [1]

(millions of dollars – except where noted)	**2012**	**2011**
Earnings		
Revenue	**4,732**	4,964
Fuel expense	**755**	754
Gross margin	**3,977**	4,210
Operations, maintenance and administration	**2,648**	2,781
Depreciation and amortization	**664**	694
Accretion on fixed asset removal and nuclear waste management liabilities	**725**	704
Earnings on Nuclear Funds	**(651)**	(509)
Other net expenses	**40**	75
Income before interest and income taxes	**551**	465
Net interest expense	**117**	154
Income tax expense (recovery)	**67**	(27)
Net income	**367**	338
Income before interest and income taxes		
Generating segments	**566**	567
Nuclear Waste Management segment	**(68)**	(194)
Other segment	**53**	92
Total income before interest and income taxes	**551**	465
Cash flow		
Cash flow provided by operating activities	**876**	1,179
Electricity generation (TWh)		
Regulated – Nuclear	**49.0**	48.6
Regulated – Hydroelectric	**18.5**	19.5
Unregulated – Hydroelectric	**12.1**	12.9
Unregulated – Thermal	**4.1**	3.7
Total electricity generation	**83.7**	84.7
Average sales prices and average revenue (¢/kWh)		
Regulated – Nuclear Generation	**5.5**	5.5
Regulated – Hydroelectric	**3.5**	3.5
Unregulated – Hydroelectric	**2.4**	3.2
Unregulated – Thermal	**2.6**	3.3
Average revenue for all electricity generators, excluding OPG [2]	**8.6**	8.4
Average revenue for OPG [3]	**5.1**	5.3
Nuclear unit capability factor (per cent)		
Darlington	**93.2**	95.2
Pickering	**77.8**	73.4
Availability (per cent)		
Regulated – Hydroelectric	**91.4**	89.7
Unregulated – Hydroelectric	**91.1**	91.5
Start Guarantee rate (per cent)		
Unregulated – Thermal	**97.5**	94.7 [4]
Return on equity (per cent) [5]	**4.2**	4.0
Funds from operations interest coverage (times) [5]	**2.3**	3.1

[1] OPG has adopted United States generally accepted accounting principles ("US GAAP") effective January 1, 2012. Financial information for 2011 has been adjusted to US GAAP.

[2] Revenues for other electricity generators are computed as the sum of hourly Ontario demand multiplied by the hourly Ontario electricity price ("HOEP") plus total global adjustment payments, plus the sum of hourly net exports multiplied by the HOEP, less OPG's generation revenue.

[3] Average revenue for OPG is comprised of regulated revenues, market based revenues, and other energy revenues primarily from cost recovery agreements, and revenue from Hydroelectric Energy Supply Agreements.

[4] As estimated.

[5] "Funds from operations interest coverage" and "Return on equity" are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about these measures is provided in OPG's Management's Discussion and Analysis for the year ended December 31, 2012, under the heading, *Supplementary Non-GAAP Financial Measures*.

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 audited consolidated financial statements and Management's Discussion and Analysis as at and for the year ended December 31, 2012 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 INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

DECEMBER 31, 2012

2012 YEAR-END REPORT

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MANAGEMENT'S DISCUSSION AND ANALYSIS

ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. ("OPG" or the "Company") as at and for the year ended December 31, 2012. OPG's consolidated financial statements are prepared in accordance with United States generally accepted accounting principles ("US GAAP") and are presented in Canadian dollars.

As required by Ontario Regulation 395/11, as amended, a regulation under the *Financial Administration Act* (Ontario) ("FAA"), OPG has adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. The Ontario Securities Commission has also approved OPG's adoption of US GAAP for financial years that begin on or after January 1, 2012, but before January 1, 2015. Financial information derived from the consolidated financial statements for the 2011 comparative period has been adjusted to US GAAP. Information for the comparative period that has been adjusted to US GAAP is labelled "adjusted". In addition, certain of the 2011 comparative amounts have been reclassified to conform to the 2012 presentation consistent with US GAAP. The US GAAP transition adjustments and significant accounting policies under US GAAP applied retrospectively are presented in OPG's audited consolidated financial statements as at and for the year ended December 31, 2012. Refer to the *Critical Accounting Policies and Estimates* section of this MD&A for a summary of OPG's critical accounting policies. This MD&A is dated March 7, 2013.

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, fixed asset removal and nuclear 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, electricity spot market prices, proposed new legislation, the ongoing evolution of the Ontario electricity industry, 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 was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province").

As at December 31, 2012, OPG's electricity generating portfolio had an in-service capacity of 19,051 megawatts ("MW"). 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. The income of the co-owned facilities is reflected in other income. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. ("Bruce Power"). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. These co-owned facilities and leased stations are not included in the generation portfolio statistics set out in this report.

The in-service generating capacity by business segment as of December 31 is as follows:

(MW)	**2012**	**2011**
Regulated – Nuclear Generation	**6,606**	6,606
Regulated – Hydroelectric	**3,312**	3,312
Unregulated – Hydroelectric	**3,684**	3,684
Unregulated – Thermal	**5,447** [1]	5,447
Other	**2**	2
Total	**19,051**	19,051

[1] Includes the capacity of the Atikokan generating station, which is being converted to use biomass commencing in 2014.

OPG's Reporting Structure

OPG receives a regulated price for electricity generated from most of its baseload hydroelectric facilities and all of the nuclear facilities that it operates. This comprises electricity generated from the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and the Pickering and Darlington nuclear facilities (collectively, the "Prescribed Facilities"). The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's hydroelectric facilities, the operating results are described under the Unregulated – Hydroelectric segment. The operating results from the thermal facilities are discussed in the Unregulated – Thermal segment. A description of all OPG's segments is provided under the heading, *Business Segments*.

REVENUE MECHANISMS FOR REGULATED AND UNREGULATED GENERATION

Regulated Generation

OPG's regulated prices for electricity generated from the Prescribed Facilities are determined by the OEB. In March 2011, the OEB issued its decision on OPG's application for new regulated prices, including rate riders for the recovery of approved variance and deferral account balances as at December 31, 2010 based on authorized recovery periods. 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, net of a negative rate rider of $1.65/MWh, and a new regulated price for production from OPG's nuclear facilities at $55.85/MWh, including a rate rider of

$4.33/MWh, effective March 1, 2011. 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. The existing rate riders included in the regulated prices were effective until December 31, 2012.

OPG's current application to the OEB requests approval to recover the balances in the authorized regulatory variance and deferral accounts as at December 31, 2012. The application is discussed in this MD&A under the heading, *Recent Developments.*

Unregulated Generation

The electricity generation from OPG's unregulated assets receives the Ontario electricity spot market price, except where a cost recovery or an Energy Supply Agreement ("ESA") is in place.

The Lambton and Nanticoke generating stations are subject to a Contingency Support Agreement with the Ontario Electricity Financial Corporation ("OEFC"). The agreement was enacted to enable the recovery of costs associated with these coal-fired generating stations after implementation of OPG's strategy to reduce Carbon Dioxide ("CO_2") emissions. Capacity provided by and production from, the Lennox generating station, are subject to an agreement with the Ontario Power Authority ("OPA"). Refer to section *Recent Developments – Lennox Generating Station Supply Agreement* for details.

OPG currently has Hydroelectric ESAs with the OPA for the Lac Seul and Ear Falls generating stations, the Healey Falls generating station, the Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations, and the Lower Mattagami River project. Payments under the Lower Mattagami Hydroelectric ESA will commence when the first incremental unit comes into service.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's audited 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*.

(millions of dollars – except where noted)	**2012**	**2011** *(adjusted)*
Revenue	**4,732**	4,964
Fuel expense	**755**	754
Gross margin	**3,977**	4,210
Expenses		
Operations, maintenance and administration	**2,648**	2,781
Depreciation and amortization	**664**	694
Accretion on fixed asset removal and nuclear waste management liabilities	**725**	704
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(651)**	(509)
Restructuring	**3**	21
Property and capital taxes	**47**	50
	3,436	3,741
Income before other (income) loss, interest and income taxes	**541**	469
Other (income) loss	**(10)**	4
Net interest expense	**117**	154
Income tax expense (recovery)	**67**	(27)
Net income	**367**	338
Electricity generation (TWh)	**83.7**	84.7
Cash flow		
Cash flow provided by operating activities	**876**	1,179

Net income for 2012 was $367 million, compared to $338 million for 2011, an increase of $29 million. Income before income taxes for 2012 was $434 million, compared to $311 million for 2011, an increase of $123 million.

OPG's income before income taxes from the electricity generation business segments was $566 million for 2012, compared to $567 million in 2011. This marginal decrease was primarily due to the impact of lower Ontario electricity prices, largely offset by lower operations, maintenance and administration ("OM&A") expenses, and the recognition of losses in 2011 which were due to an increase in the asset retirement obligation ("ARO") related to certain thermal generating stations.

The Regulated – Nuclear Waste Management business segment recorded a loss before income taxes of $68 million for 2012, compared to a loss before income taxes of $194 million for 2011. This improvement was primarily due to higher earnings from the Decommissioning Segregated Fund ("Decommissioning Fund"). These higher earnings were the result of a greater increase in the market value of the securities held in the Decommissioning Fund in 2012, compared to 2011.

The following is a summary of the factors affecting OPG's results for 2012, compared to results for 2011, 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 2011*(adjusted)*	**567**	**(194)**	**(62)**	**311**
Changes in gross margin:				
• Change in electricity sales price:				
Regulated generation segments	(2)	-	-	(2)
Unregulated – Hydroelectric	(98)	-	-	(98)
• Change in electricity generation by segment:				
Regulated – Nuclear Generation	22	-	-	22
Regulated – Hydroelectric	(19)	-	-	(19)
Unregulated – Hydroelectric	(21)	-	-	(21)
• Decrease in thermal gross margin due primarily to lower revenues from the contingency support agreement as a result of lower expenses related to unit closures	(84)	-	-	(84)
• Increase in the regulated hydroelectric gross margin primarily due to the impact of regulatory variance accounts related to lower water levels	25	-	-	25
• Decrease in non-electricity generation revenue, net of the impact of the Bruce Lease Net Revenues Variance Account	(23)	-	-	(23)
• Other changes in gross margin	(23)	50	(60)	(33)
	(223)	50	(60)	(233)
Changes in OM&A expenses:				
• Lower thermal expenditures primarily due to unit closures and related cost reductions, including headcount reductions	62	-	-	62
• Decrease (increase) in pension and OPEB costs largely as a result of the establishment of the Impact for USGAAP Deferral Account ("US GAAP Deferral Account") and the impact of the pension and OPEB costs variance account, partially offset by higher pension and OPEB costs primarily due to lower discount rates	51	(2)	1	50
• Reduction to OM&A expenses primarily due to headcount reductions from ongoing operations, partially offset by increases in other OM&A expenses	24	-	-	24
• Other changes in OM&A expenses	-	(47)	44	(3)
	137	(49)	45	133
Increase in earnings from the nuclear fixed asset removal and nuclear waste management funds ("Nuclear Funds")	-	246	-	246
Impact of the Bruce Lease Net Revenues Variance Account on earnings from the Nuclear Funds	-	(104)	-	(104)
Decrease in depreciation expense primarily due to the removal from service of two units at the Nanticoke generating station in 2011	27	-	-	27
Losses (gains) recognized in 2011 related to changes to the ARO for certain thermal stations	81	-	(15)	66
Decrease in income due to recognition of a reduction to an environmental provision in 2011, and other losses recognized in 2012 primarily due to the retirement of various hydroelectric assets	(29)	-	-	(29)
Increase in accretion expense primarily related to an increase in the present value of the nuclear fixed asset removal and nuclear waste management liabilities ("Nuclear Liabilities"), partially offset by the impact of the regulatory variance and deferral accounts	(4)	(17)	-	(21)
Lower interest expense primarily due to higher portion of debt related to capital projects	-	-	37	37
Decrease in restructuring expense related to coal-fired units	18	-	-	18
Other changes	(8)	-	(9)	(17)
Income (loss) before income taxes for 2012	**566**	**(68)**	**(64)**	**434**

[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 as defined under the heading, *Business Segments.*

Electricity Generation

OPG's electricity generation for 2012 and 2011 was as follows:

(TWh)	**2012**	**2011**
Regulated – Nuclear Generation	**49.0**	48.6
Regulated – Hydroelectric	**18.5**	19.5
Unregulated – Hydroelectric	**12.1**	12.9
Unregulated – Thermal	**4.1**	3.7
Total electricity generation	**83.7**	84.7

Total electricity generated during 2012 from OPG's generating stations was 83.7 terawatt hours ("TWh"), compared to 84.7 TWh in 2011. This decrease was mainly due to lower electricity generation from two segments: Regulated – Hydroelectric and Unregulated – Hydroelectric. Reduced generation in these segments was partially offset by higher generation from the Regulated – Nuclear and the Unregulated – Thermal segments.

The decrease in electricity generation from the Regulated – Hydroelectric segment during 2012 was primarily due to lower water levels on the lower Great Lakes during 2012. Lower generation from the Unregulated – Hydroelectric segment was mainly due to very low water levels, primarily on the Northeastern and Eastern Ontario watersheds.

The increase in electricity generation from the Regulated – Nuclear segment during 2012 was mainly due to higher generation at the Pickering generating stations as a result of a decrease in unplanned and planned outage days. Higher generation from the Unregulated – Thermal segment during 2012 was primarily due to lower generation from the hydroelectric stations, higher demand due to warmer temperatures during the summer of 2012, and the utilization of coal inventories prior to the shutdown of the stations.

OPG's operating results are affected by changes in demand resulting from variations in seasonal weather conditions and changes in economic conditions. Ontario's primary demand was 141.3 TWh in 2012, down slightly from 141.5 TWh for 2011.

Average Sales Prices and Average Revenue

The average sales prices and average revenue for 2012 and 2011 were as follows:

(¢/kWh)	**2012**	**2011**
Weighted average hourly Ontario electricity price ("HOEP")	**2.4**	3.1
Regulated – Nuclear Generation	**5.5**	5.5
Regulated – Hydroelectric	**3.5**	3.5
Unregulated – Hydroelectric	**2.4**	3.2
Unregulated – Thermal	**2.6**	3.3
Average revenue for all electricity generators, excluding OPG [1]	**8.6**	8.4
Average revenue for OPG [2]	**5.1**	5.3

[1] Revenues for other electricity generators are computed as the sum of hourly Ontario demand multiplied by the HOEP, plus total global adjustment payments, plus the sum of hourly net exports multiplied by the HOEP, less OPG's generation revenue.

[2] Average revenue for OPG is comprised of regulated revenues, market based revenues, and other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton and Lennox generating stations, and revenue from Hydroelectric ESAs.

The average sales prices for the Regulated – Nuclear and Regulated – Hydroelectric segments for 2012 reflect the OEB's March 2011 decision establishing new regulated prices effective March 1, 2011. These regulated prices were discussed in OPG's 2011 annual MD&A under the heading, *Revenue Mechanisms for Regulated and Unregulated Generation*.

Average sales prices for OPG's unregulated segments decreased for 2012, compared to 2011. This was primarily due to the impact of significantly lower Ontario electricity spot market prices. The decrease in the HOEP for 2012 was primarily due to lower natural gas prices, offset slightly by the impact of lower hydroelectric generation.

Cash Flow from Operations

Cash flow provided by operating activities for 2012 was $876 million, compared to $1,179 million for 2011. The decrease in operating cash flow was primarily due to lower unregulated hydroelectric generation, an increase in pension contributions, and a reduction in revenues from isotope sales and technical services provided to third parties. The decrease in operating cash flow was partially offset by a decrease in OM&A expenses and lower contributions to the Nuclear Funds.

Recent Developments

OPG's OEB Application

In September 2012, OPG filed an application with the OEB requesting approval to recover balances in the authorized regulatory variance and deferral accounts, as at December 31, 2012. This includes the balance in the US GAAP Deferral Account. This account was authorized by the OEB in a decision and order issued in March 2012. The account records the financial impacts resulting from OPG's transition to and implementation of US GAAP. The application requested the recovery of the variance and deferral account balances through new rate riders. These new rate riders would apply to production from OPG's regulated nuclear and hydroelectric facilities beginning in 2013. The existing rate riders included in the regulated prices were established by the OEB's March 2011 decision and April 2011 order, to be in effect until December 31, 2012. In the application, OPG also sought approval for the use of US GAAP for regulatory purposes.

OPG's application also sought approval on an interim basis, effective January 1, 2013, for the continuation of the existing $4.33/MWh rate rider applicable to OPG's nuclear production, and the extension of the Pension and OPEB Cost Variance Account, which is currently effective until December 31, 2012. The variance account records the difference between actual pension and OPEB costs for the regulated business and related tax impacts, and the corresponding amounts reflected in the current regulated prices. In a decision and order issued in November 2012, the OEB granted these requests. The OEB also determined that the current negative regulated hydroelectric rate rider of $1.65/MWh would be allowed to expire on December 31, 2012.

The existing nuclear rate rider became interim on January 1, 2013. This rider will continue until the implementation date of the new riders resulting from the OEB's final decision and order on OPG's application, which will factor in amounts recovered through the interim rider in the determination of the new riders. The OEB's approval of the request for an interim extension of the Pension and OPEB Cost Variance Account provides OPG with the authorization to record amounts in the account for future recovery, for the period from January 1, 2013 until the issuance of, and subject to, the OEB's final decision and order regarding the extension of the account.

OPG is in continuing settlement discussions with the intervenors regarding all aspects of the rate application. If an agreement is reached, a settlement agreement will be filed with the OEB and will be subject to approval by the OEB.

In 2013, OPG plans to file an application with the OEB for new regulated prices for production from the Prescribed Facilities. These new prices are to be effective in 2014. A discussion of the risks regarding future regulated prices is included in this MD&A under the headings, *Financial Sustainability* and *Risk Management*.

Provincial Budget 2012

In March 2012, the Ontario Minister of Finance presented the 2012 Ontario Budget (the "Budget"), which includes proposed changes that could impact OPG. In the Budget, it was recognized that OPG and Hydro One Inc. are aggressively driving greater efficiencies in their operations. The government initiated a review of the electricity sector and its various agencies, including OPG and Hydro One Inc. to benchmark the companies against comparable entities and to determine further efficiency opportunities.

The Budget also set out certain objectives regarding sustainability and affordability of the broader public sector pension plans, which could result in changes to OPG's existing pension system.

Advanced Coal Unit Shutdown

In January 2013, the Ministry of Energy announced the advanced shutdown of the remaining coal-fired units at the Lambton and Nanticoke generating stations by December 31, 2013, in advance of the previous December 31, 2014 deadline. Before finalizing the shutdown of the units, OPG expects to receive a directive from the Ministry of Energy mandating the closure of the remaining coal-fired units by the end of 2013.

As a result of the announcement, OPG expects that the Contingency Support Agreement will be amended to allow OPG to continue to recover actual costs that cannot reasonably be avoided or mitigated, during the period from the advanced shutdown date up to the end of 2014, consistent with the term of the original contract. OPG had entered into a Contingency Support Agreement with the OEFC in 2009 to ensure that these generating stations receive sufficient revenue to recover their actual direct costs and to provide reimbursement of capital expenditures through the recapture of depreciation up to December 2014.

OPG plans to place the units in reserve status and to preserve the option to convert them to natural gas and/or biomass in the future, should they be required. The early shutdown of the coal-fired units will result in staff and work program reductions and a corresponding reduction in Contingency Support Agreement payments from the OEFC. See *Core Business and Strategy – Performance Excellence, Core Business and Strategy – Project Excellence, Changes in Accounting Policies and Estimates – Thermal Materials and Supplies Obsolescence,* and *Risk Management – Operational Risks* sections*,* for further details.

Lennox Generating Station Supply Agreement

In December 2012, the OPA and OPG executed a long-term Lennox ESA for the period from January 1, 2013 to September 30, 2022. The agreement allows the station to recover its costs, including a reasonable return. The agreement replaced the Lennox Generating Station Agreement, in effect from October 1, 2009 to December 31, 2012, which allowed for the recovery of the station costs.

Land Sales at Lambton and Lennox

During 2012, the Province announced the relocation of the Greenfield South gas-fired station development from Mississauga to a small portion of the Lambton generating station site. The parties are assessing this potential sale at fair market value and are performing due diligence on the site. During the fourth quarter of 2012, OPG and TransCanada Energy Ltd. executed an agreement of purchase and sale regarding a parcel of land on the Lennox generating station site at fair market value. Other site-specific arrangements for the development of a combined cycle, natural-gas fired generating station were also included in the agreement. OPG does not have an ownership interest in either development.

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 goal is to be Ontario's low cost electricity generator of choice with a focus on three corporate strategies:

- Performance Excellence.
- Project Excellence.

- Financial Sustainability.

Performance Excellence

OPG is committed to excellence in the areas of generation, the environment, and safety.

Nuclear Generating Assets

Performance excellence at OPG's nuclear generating facilities is defined as safely and reliably generating cost-effective electricity. The four cornerstones of all nuclear activities are safety, reliability, human performance and value for money.

Nuclear practices and processes are continually benchmarked against top performing nuclear facilities around the world. This facilitates the identification, development and implementation of initiatives to further improve performance.

Employee and environmental safety are overriding priorities. The nuclear sites continue to demonstrate strong performance and continuous improvement in these areas against industry benchmarks.

OPG operates and maintains its nuclear facilities to cost-effectively optimize equipment, performance, availability, and output. Improved equipment reliability results in greater nuclear safety, reduced generation interruptions, and efficient planning and execution of outages. Programs and initiatives such as Work Order Readiness and Standard Equipment Reliability support these objectives. At Pickering, prudent investments in maintenance are aimed at ensuring reliable performance during the refurbishment of Darlington. This includes proactively identifying, planning, and executing 3,000 equipment improvements at Pickering within three years. The maintenance strategy has evolved from programs designed to improve equipment condition to initiatives that increase the reliability and predictability of performance through comprehensive life cycle management.

The successful execution of outages continues to be a high priority. OPG continues to improve the planning, execution, monitoring and reporting of outage work to reduce costs and increase generation. Nuclear inspection and testing programs are largely driven by maintenance and regulatory requirements, designed to ensure that equipment is performing reliably and safely. The planned outage programs at Pickering Units 5 to 8 over the next five years reflect OPG's objective of extending the operating lives of these units for approximately an additional four to six years.

Process and procedural compliance is monitored and managed to ensure a strong safety and performance culture at the nuclear stations. Training programs continue to be implemented to improve employee performance and promote leadership development.

Delivering solutions that provide the best combination of safety, cost, and quality, and establishing challenging financial targets based on comprehensive benchmarking continue to be integral parts of OPG's strategy to improve nuclear plant and employee performance. Staffing targets continue to be reviewed and adjusted where necessary to reduce operating costs, while ensuring safety is not compromised.

In late December 2012, the Pickering stations were granted licensing approval by the Canadian Nuclear Safety Commission ("CNSC") to proceed with a revised maintenance program that will allow for better quality and efficiency of work, while contributing to improved plant reliability.

Beginning in 2012, the Pickering stations have operated as a single six-unit site through the operational amalgamation of the Pickering A and B generating stations. OPG successfully combined the work management, maintenance and operational planning departments during the first half of 2012, fully integrating the two Pickering stations. During the third quarter of 2012, the CNSC staff reviewed the Sustainable Operations Plan, which describes the strategy for the safe operation of the Pickering site in an integrated fashion. OPG has applied to the CNSC for a single operating licence for the Pickering stations for the licence renewal effective in 2013.

In addition, OPG applied for a 22-month licence renewal for the Darlington station to allow time to complete the necessary refurbishment planning studies. Once these are completed, OPG will apply for a licence to cover the refurbishment period. The hearing on the 22-month licence renewal was held in 2012 and in February 2013 the CNSC approved the renewal for a period from March 1, 2013 to December 31, 2014.

Hydroelectric Generating Assets

The hydroelectric business segments are focused on producing electricity in a safe, reliable, cost-effective, and environmentally responsible manner.

These segments have the following objectives:

- Sustain and improve the existing hydroelectric assets for long-term operations.
- Operate and maintain hydroelectric facilities in an efficient and cost-effective manner.
- Seek to expand existing hydroelectric stations where economical.
- Maintain and improve reliability performance where practical and economical.
- Maintain an excellent employee safety record and ensure all worker safety laws are met.
- Strive for continuous improvement in the areas of dam and waterways, public safety, and environmental performance.
- Build and improve relationships with First Nations and Métis.

With consideration of current market conditions, OPG continues to evaluate and implement plans to increase capacity and maintain the hydroelectric generating assets. This is expected to be accomplished through refurbishment or replacement of existing turbine runners, generators, transformers, and protections and controls. This includes increasing the capacity and efficiency at certain stations by approximately 20 MW over the next five years. OPG is also planning to repair, rehabilitate, or replace a number of aging civil structures in the next five years.

During 2012, OPG continued to execute a number of projects, including overhauls at Unit 3 of the Sir Adam Beck generating station and Unit 1 of the Des Joachims generating station, refurbishment of headgates at the Arnprior and Alexander Falls generating stations, a penstock replacement at the Matabitchuan generating station and rehabilitation of the concrete dam at the Chats Falls generation station. The environmental performance of OPG's hydroelectric generating stations in 2012 was the best ever. There were minimal spills and several efficiency improvement initiatives were completed. In the area of Dam Safety, an Expert Dam Safety Review Panel concluded that OPG's Dam and Public Safety Program is meeting International Best Practice. OPG is developing a new risk-informed approach on behalf of the Province/Ontario Ministry of Natural Resources ("MNR") to prioritize the outcomes of dam safety assessments. This tool will result in significant benefits with respect to safety and costs for future upgrades to existing infrastructure.

Thermal Generating Assets

OPG's thermal stations operate as peaking facilities, depending on electricity demand. The ability of thermal units to start up and shut down on a daily basis through a wide range of their installed capacity provides Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements, and enables the electricity system to accommodate the expansion of Ontario's renewable generation portfolio. Continued operation and staffing of thermal generating units supports their role of providing capacity to the electricity system when required. OPG's coal-fired generating stations produce the required volume of electricity and ancillary services while operating within the constraints of CO_2 emission limits, in a safe, environmentally responsible, reliable, and cost-effective manner.

Consistent with Ontario's Long-Term Energy Plan (the "Energy Plan") and the Supply Mix Directive issued by the Province to the OPA, OPG removed from service two more coal-fired units at the Nanticoke generating station. This took place on December 31, 2011 in advance of the December 31, 2014 target deadline. The early closure of these coal-fired units has resulted in staff reductions at the Nanticoke generating station and reduced payments to OPG from the OEFC under the Contingency Support Agreement.

In addition, in January 2013, the Ministry of Energy announced the advanced shutdown of the remaining coal-fired units at the Lambton and Nanticoke generating stations by December 31, 2013. Before finalizing the shutdown of the units, including notifying key stakeholders, including the Society of Energy Professionals ("The Society") and the Power Workers' Union (the "PWU"), in accordance with their respective collective bargaining agreements, OPG expects to receive a directive from the Ministry of Energy mandating the closure of the remaining coal-fired units by the end of 2013. OPG is estimating the restructuring costs, including costs related to severance and relocation to other OPG sites. OPG expects to accrue the severance costs in 2013. Relocation costs will be recorded as incurred, primarily in 2014.

OPG will continue to explore options and the feasibility to convert some of the existing coal-fired units to burn alternate fuels such as natural gas and/or biomass. Converted thermal generating stations can provide Ontario's electricity system with the continued flexibility of daily start up and shut down, the load-following capability to meet changing system needs, and complement non-dispatchable renewable energy sources.

Employee and public safety continue to be the thermal business segment's highest priority. Safety programs are based on the ISO 18000 Health and Safety managed system process and engineering risk assessments of plant systems. Through these systems and assessments, OPG places a priority on investments in work planning, staff training, and at-risk equipment to mitigate and eliminate health and safety and production issues at its stations.

Environmental Performance

OPG's Environmental Policy states that "OPG shall meet all legal requirements and any environmental commitments that it makes, with the objective of exceeding these legal requirements where it makes business sense." This policy commits OPG to establish and maintain an environmental management system, work to prevent or mitigate adverse effects on the environment with a long-term objective of continual improvement, and maintain, or where it makes business sense, enhance significant natural areas and associated species at risk. Environmental performance targets also form part of OPG's annual business planning process. Performance is monitored and communicated to internal and external stakeholders.

OPG manages air emissions of Nitrogen Oxides ("NO_x") and Sulphur Dioxide ("SO_2") through the use of specialized equipment such as scrubbers, low NO_x burners, Selective Catalytic Reduction ("SCR") equipment, and the purchase of low sulphur fuel.

OPG monitors emissions into the air and water and regularly reports the results to regulators, including the Ministry of the Environment of Ontario, Environment Canada, and the CNSC. The public also receives ongoing communications regarding OPG's environmental performance. OPG has developed and implemented internal monitoring, assessment, and reporting programs to manage environmental risks. These risks include air and water emissions, discharges, spills, the treatment of radioactive emissions, and radioactive wastes. OPG also continues to address historical land contamination through a voluntary land assessment and remediation program.

OPG's environmental performance for 2012 met or outperformed targets, for all spills, infractions, energy efficiency, production of radiological waste, and dioxins/furans emissions. OPG has maintained its ISO 14001 certification for its corporate level Environmental Management System and all of its generating stations. Acid gas (SO_2 and NO_x) emissions were 16.1 gigagrams ("Gg") in 2012, compared to 17.0 Gg in 2011. The decrease in acid gas emissions resulted from utilizing lower sulphur coal and increased use of the SO_2 scrubber at the Lambton generating station. OPG's six coal-fired units with the highest acid gas emission rates were taken out of service in 2010 and 2011.

While the Federal Government passed the *Reduction of Carbon Dioxide from Coal-fired Generation of Electricity Regulations* in the third quarter of 2012, it is not expected to impact OPG as the Ministry of Energy announced in January 2013 that the remaining coal-fired units at the Lambton and Nanticoke generating stations will shut down by the end of 2013. Starting July 1, 2015, the new federal regulations impose an annual emission intensity limit of 420 Mg CO_2/GWh for coal-burning units that have reached the end of their useful life. To meet this limit, a coal-fired unit would have to be fitted with carbon-capture-and-storage technology or co-fire biomass at very high rates. This requirement is not expected to impair OPG's ability to convert coal units to burn biomass or natural gas.

In January 2013, the Ontario Ministry of the Environment released a discussion paper entitled Greenhouse Gas Emission Reductions in Ontario. The discussion paper initiates consultation on key elements of a provincial greenhouse gas ("GHG") emission reduction plan to be developed over 2013. Current provincial regulations 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 provincial GHG emission reduction plan.

To achieve further improvements in GHG emissions, OPG is implementing the use of biofuels as a partial replacement for coal. OPG also maintains a tree planting effort through its extensive biodiversity program.

Targets mandated by the Province for CO_2 emissions from OPG's coal-fired generating stations are 11.5 million tonnes per year for the period 2011 to 2014. For 2012, OPG's CO_2 emissions were 4.3 million tonnes, compared to 4.2 million tonnes for 2011.

Safety

OPG remains steadfast in its commitment to safety excellence, sustaining a strong safety culture and continuous improvement in safety management systems. Safety performance is measured using two primary indicators: the Accident Severity Rate ("ASR") and the All Injury Rate ("AIR").

OPG achieved excellent safety performance in 2011, resulting in its best ever ASR and AIR. OPG's 2012 AIR of 0.63 injuries per 200,000 hours was just slightly higher than the 2011 performance of 0.56 injuries per 200,000 hours worked. OPG's 2012 ASR of 2.4 days lost per 200,000 hours is a significant increase over the 2011 ASR of 1.10 days lost per 200,000 hours. Although 2012 performance did not match the performance of 2011, it is anticipated that OPG safety performance will continue to be one of the best amongst its comparator Canadian electrical utilities. In October 2012, the Canadian Electricity Association recognized OPG for its 2011 ranking within the top quartile of its comparator group.

Focus on continuous improvement principles, the application of lessons learned from safety incidents and proactive safety management demonstrate OPG's commitment to continuously strive to improve safety performance.

Situational awareness, which involves assessing and controlling hazards associated with changing or unexpected conditions at the work site, was integrated into the work practices as a key area of improvement in 2012. Key deliverables in this cultural improvement initiative included clear expectations from leadership and a comprehensive communication campaign to increase knowledge and skills. Business leaders challenged employees to focus on situational awareness by assessing and controlling hazards associated with changing or unexpected conditions at the work site. In 2012, emphasis continued to be placed on improving the work protection processes used to isolate equipment for maintenance activities. These improvement initiatives will help to maintain OPG's focus on reducing all injuries, including musculoskeletal injuries, and move the organization closer to reaching its goal of zero injuries.

Project Excellence

OPG is pursuing several generation development projects consistent with the Energy Plan. OPG's major projects include nuclear station refurbishment, new nuclear generation, Pickering Units 5 to 8 Continued Operations, new hydroelectric generation and plant upgrades, and the potential conversion of other coal-fired generating units to alternative fuels.

Darlington Refurbishment

The Darlington generating units, based on original design assumptions, are currently forecast to reach their nominal end of life between 2019 and 2021. The objective of the refurbishment is to extend the operating life of the station by approximately 30 years. In February 2010, OPG announced its decision to commence the definition phase for the refurbishment of the Darlington nuclear generating station. Activities in this phase include the establishment of the project organization, scope finalization, engineering, planning and estimating, procurement of long lead items, establishment of key contracts, and facilities and infrastructure upgrades. Capital project expenditures for 2012 were \$232 million and the life-to-date capital expenditures as at December 31, 2012 were \$362 million. A detailed cost and schedule estimate for the refurbishment of the four units is expected to be completed in 2015. The execution phase is expected to start in 2016.

In accordance with the CNSC regulatory requirements for Life Extension of Nuclear Power Plants, OPG must complete a series of assessments for the Darlington refurbishment project. In 2011, OPG submitted the Environmental Assessment ("EA") for refurbishment and continued operations of the Darlington nuclear generation station. Based on this EA, the CNSC and Fisheries and Oceans Canada issued a Draft Environmental Assessment Screening Report in the second quarter of 2012. This report was subject to public review. The CNSC then issued its final Environmental Assessment Screening Report in September 2012. This formed the basis for the EA public hearing. The report was consistent with OPG's analysis concluding that, taking into account the identified mitigation measures, Darlington refurbishment and continued operations are not likely to cause adverse effects on the environment. The EA public hearing was held in December 2012. The CNSC decision on the EA is expected by the second quarter of 2013. In early 2012, the CNSC completed a sufficiency review of the Integrated Safety Review ("ISR"). The CNSC found the submission sufficient to begin the detailed technical assessment. The CNSC has been actively reviewing the ISR and OPG is addressing comments and questions raised. The CNSC's detailed technical assessment of the ISR is targeted to be completed by mid-2013.

The results of the EA and ISR are incorporated in a Global Assessment Report ("GAR") which includes an Integrated Implementation Plan ("IIP"). The IIP indicates the schedule for implementing the improvements and gaps identified in the EA and ISR. The GAR and the IIP will be submitted to the CNSC in December 2013.

On March 1, 2012, OPG awarded a Retube and Feeder Replacement ("RFR") contract. The contract will be completed in two phases – a definition phase which includes the planning, design and testing of tooling, design and construction of a full scale reactor mock-up facility for testing and training, and an execution phase which includes the removal and replacement of major reactor components of the four reactors at the Darlington generating station. The contract value during the definition phase for the period to 2015 is estimated at over \$600 million. The execution phase work, which is still to be estimated and valued, includes removal and replacement of the 480 pressure tubes and calandria tubes, and 960 feeder pipes for each of the station's four reactors.

The RFR contract is one of several contracts for the refurbishment of the Darlington nuclear station. The procurement processes for the Turbine and Generator Contract and the Defueling Contract were initiated in 2012.

Construction on the Darlington Energy Complex ("Complex") continued in 2012. The facility was substantially completed in January 2013. The Complex is expected to be ready for occupancy in early summer of 2013, approximately three months ahead of plan. The Complex will house a training and calandria mock-up facility, warehouse, and office space to support the Darlington Refurbishment project.

New Nuclear Units

In May 2012, the federal government approved the Darlington New Nuclear Project Environmental Assessment. The approval of the EA provides independent review and confirmation that the project will not result in any significant adverse environmental impacts, given mitigation. The EA was subsequently challenged by way of judicial review in the Federal Court of Canada on the grounds that the Joint Review Panel report failed to comply with requirements of the *Canadian Environmental Assessment Act*, and that the hearing deprived the applicants of certain procedural rights. OPG and the federal agencies have filed their responding affidavits.

In June 2012, OPG entered into service agreements with Westinghouse and SNC Lavalin/CANDU Energy to prepare construction plans, schedules, and cost estimates for potential new nuclear units at Darlington. The service agreements provide each company with 12 months to develop reports outlining their respective positions. The completed reports will be analyzed and provided to the Province for its consideration.

In August 2012, the CNSC approved the application for the Power Reactor Site Preparation ("Licence to Prepare Site") for the new nuclear units at Darlington. Subsequently, a notice of application for a judicial review of the Licence to Prepare Site was filed by third parties on the grounds that the CNSC's issuance of the licence is invalid and does not comply with requirements of the *Canadian Environmental Assessment Act*. OPG is preparing its response to the application.

<u>Pickering Units 5 to 8 Continued Operations</u>

OPG substantially completed a coordinated set of initiatives to evaluate the continued safe and reliable operation of Units 5 to 8 at the Pickering generating stations for approximately an additional four to six years. In June 2012, OPG submitted the necessary documentation to the CNSC related to the service life extension of the pressure tubes. In the third quarter of 2012, the CNSC agreed that OPG will, through specified monitoring, the successful completion of ongoing research and development, and specified station improvements, be capable of confirming fitness-for-service of Pickering fuel channels for the duration of the proposed continued operations period to 2020. At the end of 2012, OPG completed the necessary work to demonstrate with sufficient confidence that the pressure tubes will achieve the additional life, as predicted.

The CNSC's review of Pickering Nuclear's Sustainable Operations Plan and the Continued Operations Plan did not identify any new regulatory requirements. At the end of 2012, OPG submitted its annual revision of the Continued Operations Plan to the CNSC. Continued operations work related to equipment improvements and inspections will continue until the end of 2014, as planned.

<u>Deep Geologic Repository for Low and Intermediate Level Waste</u>

In January 2012, the CNSC and the Canadian Environmental Assessment Agency announced the appointment of a three-member Joint Review Panel ("JRP") for OPG's Deep Geologic Repository ("DGR"). The JRP will examine the environmental effects of the proposed DGR to meet the requirements of the *Canadian Environmental Assessment Act*. In February 2012, the JRP announced the start of the six-month public review period on the Environmental Impact Statement, Preliminary Safety Report and Technical Support Documents. OPG received a large number of Information Requests ("IRs") from the JRP and provided responses by the end of December 2012. In December 2012, additional IRs were received from the JRP. As a result, the public review period has been extended into the first quarter of 2013.

OPG has suspended design activities pending receipt of the site preparation and construction licence from the JRP. Assuming the site preparation and construction licence is received in 2014, construction of the DGR is expected to commence in 2015.

<u>Niagara Tunnel</u>

All major tunnel lining activities at the Niagara Tunnel were completed in 2012, with the exception of pre-stress grouting to complete the attachment of the concrete liner with the surrounding rock. This activity had progressed to 9,525 metres as at December 31, 2012. Disassembly of the tunnel boring machine was completed in 2012.

In early March 2013, final testing is underway with water flowing through the Niagara Tunnel prior to declaring it in-service, more than nine months ahead of the approved project completion date of December 2013. Upon completion of the 10.2 kilometre tunnel, an additional water diversion capacity of approximately 500 cubic metres per second will increase annual generation from the Sir Adam Beck generating stations by an average of approximately 1.5 TWh, depending on water flow. The capital project expenditures for 2012 were $231 million and the life-to-date capital expenditures as at December 31, 2012 were $1.4 billion. Total costs of the project at completion are expected to be approximately $1.5 billion, compared to the approved budget of $1.6 billion.

Lower Mattagami

The Lower Mattagami River project will increase the capacity of the four generating stations on the Lower Mattagami River by 438 MW. Concrete operations continued throughout 2012 at the Little Long, Harmon and Smoky Falls sites, with all key milestone dates being met or bettered. At the Little Long site, the powerhouse steel superstructure was installed and installation of electrical and mechanical equipment is in progress. The removal of the cofferdam is also in progress at this site. In December 2012, there was a breach in one section of the recently installed cofferdam at the Kipling site. All other cofferdams on the project have been inspected and it has been determined that they are safe. While the cost impact of this incident is not expected to be significant, work continues to finalize a remediation plan and to determine the impact on the completion date of the project of June 2015.

Capital project expenditures for 2012 were $589 million and the life-to-date capital expenditures as at December 31, 2012 were $1.4 billion. The project is expected to be completed within the approved budget of $2.6 billion.

Conversion of Coal-Fired Units

The strategy to convert coal-fired units to alternative fuels is reflective of the changing energy generation portfolio for Ontario. Options for alternative fuels include biomass, natural gas, and gas-biomass dual-fuelled. Before OPG can proceed with unit conversions, a mechanism is required for recovery of capital and ongoing costs which generally requires concurrence or direction from OPG's Shareholder, the Ministry of Energy.

Atikokan Biomass Conversion

OPG is proceeding with its project to convert the Atikokan generating station from coal to biomass fuel. In the third quarter of 2012, OPG and the OPA executed the Atikokan Biomass ESA. The converted station is expected to have a capacity of 200 MW. The conversion project has an approved cost estimate of $170 million and is expected to be completed in the first half of 2014. The capital project expenditures for 2012 were $54 million and the life-to-date capital expenditures as at December 31, 2012 were $59 million.

Other Coal-Fired Units

OPG has suspended further work on the Thunder Bay generating station conversion to natural gas, pending an OPA review of electricity needs in Northwestern Ontario. The OPA has informed OPG that more time is required to explore other options for electricity supply in the northwest part of the province. Costs of $9 million that were incurred to date were written off in the fourth quarter of 2012.

In conjunction with the status of the conversion of the Thunder Bay generating station, OPG requested deregistration of the plant in November 2012. In January 2013, the Independent Electricity System Operator ("IESO") determined that at least one unit is required in Thunder Bay to maintain reliability of the IESO-controlled grid. Accordingly, OPG and the IESO entered into negotiations for a Reliability Must Run contract covering the period from January 1, 2013 to December 31, 2013. The contract has been executed by OPG and the IESO and is subject to OEB approval.

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 and/or biomass, if required for Ontario's system reliability. Without an indication that conversion will proceed, the units will continue to be made available to the system until the mandated cessation date of December 31, 2013.

Financial Sustainability

OPG's financial priority, as a commercial enterprise, is to consistently achieve a level of financial performance that will ensure its long-term financial sustainability and increase the value of its assets for its Shareholder – the Province of Ontario. Inherent in this priority are three objectives:

- Enhancing profitability by increasing revenue.
- Improving efficiency and reducing costs.
- Ensuring a strong financial position that enhances OPG's ability to finance its operations and projects.

Increasing Revenue

OPG's revenue strategy focuses on increasing revenues, while taking into account the impact on Ontario electricity ratepayers. OPG has multiple sources of revenue, including: regulated prices for the Prescribed Facilities; spot market prices for certain unregulated facilities; energy supply and cost recovery agreements for its remaining unregulated facilities; and non-generation revenues.

Electricity produced from the Prescribed Facilities, nuclear and most of its baseload hydroelectric generating stations, receives regulated prices. Under the current regulatory framework, OPG's objective is to clearly demonstrate that its regulated costs are prudently incurred and should be fully recovered, while OPG earns an appropriate return. The OEB's decision on OPG's application for new regulated prices effective March 1, 2011 established significantly lower regulated prices than submitted by OPG. As such, the regulated prices do not fully reflect the recovery of the costs of the regulated operations and do not allow these operations to earn an appropriate rate of return, thereby negatively impacting OPG's financial performance. In September 2012, OPG filed an application with the OEB requesting approval to recover balances in the authorized regulatory variance and deferral accounts as at December 31, 2012. In 2013, OPG plans to file an application with the OEB for new regulated prices for production from its Prescribed Facilities, effective in 2014. OPG is currently exploring long-term revenue options to recover its costs and earn an appropriate return, while moderating customer rates.

A portion of OPG's electricity production is unregulated and sold at the Ontario electricity spot market price. The average spot market price has declined significantly since 2008 due to factors such as low natural gas prices, increased electricity supply, and lower primary demand. As a result, based on current and forecast spot prices, OPG's unregulated revenues are insufficient to fully recover costs and earn a return. OPG is exploring options aimed at recovering costs and earning an appropriate return from its unregulated assets.

OPG has negotiated energy supply and cost recovery agreements for certain of its unregulated hydroelectric and thermal assets. OPG also earns non-electricity generation revenues through a number of sources, including: isotope and heavy water sales; the lease of the Bruce A and B nuclear stations; joint ventures associated with the PEC and the Brighton Beach gas-fired combined cycle generating stations; trading and other non-hedging activities; real estate rentals and sales; and the provision of technical and engineering services to third parties.

Improving Efficiency and Reducing Costs

OPG is aggressively pursuing opportunities to implement efficiency and productivity improvements while reducing costs. To accomplish this objective, OPG launched a multi-year business transformation initiative to create a streamlined company with a sustainable cost structure. This would allow OPG to continue to moderate consumer electricity prices and attract new generation development opportunities in support of the Energy Plan.

The business transformation includes changes to OPG's organizational structure and includes over 120 major change initiatives. These changes are designed to streamline and re-engineer many work processes and systems. A new centre-led organizational structure has been implemented to consolidate common services, leverage centres of excellence, and provide the foundation for a scalable organization model and cost structure. This will allow OPG to more effectively respond to new business opportunities in Ontario's evolving electricity sector. These business transformation initiatives have enabled OPG to achieve significant headcount reductions. Over the 2011 to the 2012 period, OPG's headcount from ongoing operations has been reduced by over 1,000, primarily through attrition. The total target headcount reduction from ongoing operations over the January 1, 2011 to December 31, 2015 period is 2,000, with an emphasis on streamlining the support functions.

Strengthening Financial Position

Successfully implementing initiatives to increase revenue, implement efficiencies, and reduce costs will serve to strengthen OPG's financial position. To operate on a financially sustainable basis and maintain the value of its assets for its Shareholder, OPG is focused on ensuring sufficient liquidity, maintaining an investment grade credit rating, ensuring that all major generation development projects are economic and provide for recovery of costs and an appropriate return, ensuring that capital is allocated in an economic and prioritized manner, and continuously evaluating its financial and operating performance.

OPG's primary sources of liquidity and capital include funds generated from operations, bank financing, credit facilities provided by the OEFC, and capital market financing. Since 2009, OPG has accessed the debt markets through private placements to finance generation development projects. In 2012, OPG issued senior notes of $425 million in support of the Lower Mattagami River project. OPG intends to continue to access capital markets in support of future generation development initiatives where it is cost effective.

Maintaining an investment grade credit rating is one of OPG's key financial objectives. OPG's current investment grade credit ratings have enabled it to secure financing at cost effective interest rates. In November 2012, however, Standard & Poor's revised the Company's outlook from stable to negative. This primarily reflected: the revision of OPG's Stand Alone Credit Profile from "bbb" to "bbb-", the negative outlook on the Province, and the exposure to the electricity spot market prices and volume related to OPG's unregulated business. In February 2013, Standard & Poor's re-affirmed OPG's long-term credit rating at A- with a negative outlook.

OPG manages its capital structure by taking into consideration the financial metrics consistent with its current credit rating, regulated prices for the regulated operations, and unregulated revenues. OPG continuously evaluates its financial performance using indicators including: Return on Equity ("ROE"), and Funds from Operations ("FFO") Interest Coverage. For further details, refer to the ROE and FFO disclosure under the heading, *Supplementary Non-GAAP Financial Measures*.

CAPABILITY TO DELIVER RESULTS

OPG's capabilities to execute its corporate strategies and deliver results are impacted by a number of areas.

Generating Assets' Reliability

OPG continues to implement specific initiatives to improve the reliability and predictability of each nuclear generating station that it operates. These initiatives are designed to address the specific technology requirements, operational experience, and mitigate risks. The Darlington nuclear generating station has converted to a three-year outage cycle to take advantage of the physical condition of the plant, the availability of backup systems, and on-power refuelling. The Pickering nuclear generating stations will continue to focus on implementing targeted reliability improvements.

OPG has increased the productive capacity of its hydroelectric stations and has made significant capital investments to replace aging equipment, upgrade runners, increase station automation, and enhance maintenance practices. Programs are in place to further improve the efficiency and availability of existing hydroelectric stations.

OPG will continue to maintain the reliability of its coal-fired generating stations to produce the electricity required until their mandated closure dates.

Project Planning and Execution

OPG is pursuing and executing a number of generation development opportunities as described under the *Core Business and Strategy* section of the MD&A. In addition, OPG continues to plan and execute maintenance and capital improvement projects related to its existing assets. To achieve its strategy of project excellence, OPG must utilize the necessary talent and experience to efficiently plan and execute projects on time and on budget. The project planning and preparation process includes establishing contingency plans to manage potential challenges, creating and maintaining comprehensive risk registers, and tracking progress against clearly established milestones at key stages of projects. In addition, project accountability is established at the appropriate level, with oversight by senior management and Board Committee.

Operating Efficiencies

OPG is continuing to focus on cost reductions and efficiencies. Progress is being achieved through a restructuring of the Company that has combined the Hydroelectric and Thermal operations, restructured commercial operations to take advantage of market opportunities, and implemented a scalable service delivery model for business support functions. OPG has moved to an integrated centre-led organization and has simplified its operational and project work processes to further streamline operations.

This significant transformation requires a strong leadership team and change agents who can achieve the necessary culture change and efficiencies, while continuing to operate OPG's generating assets in a safe and reliable manner.

People and Culture

OPG's resource strategy is to achieve its business transformation and operational objectives by accommodating attrition through the implementation of efficiency improvements to meet the future needs of the business. OPG expects to acquire and develop talent as is necessary to continue to drive change and build leadership bench strength. OPG also has an active succession planning program and continues to implement leadership development programs across the organization.

Electricity generation involves complex technologies, which demand highly skilled and trained workers. Many positions at OPG have significant educational prerequisites, as well as rigorous requirements for continuing training and periodic requalification. In addition to maintaining its extensive internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners, and educational institutions to meet the required level of qualification.

As of December 31, 2012, OPG had approximately 10,840 full-time employees and approximately 650 seasonal, casual construction, contract, and non-regular staff. The majority of OPG's full-time employees are represented by two unions:

- The PWU, representing approximately 6,300 employees.
- The Society, representing approximately 3,400 employees.

The current collective agreement between OPG and the PWU has a three-year term, which expires on March 31, 2015. The Company's collective agreement with The Society expired on December 31, 2012. OPG and The Society were unable to agree upon the terms for a renewal of the collective agreement and the dispute is currently before an arbitrator for resolution. The outcome of the arbitration will determine the terms and duration of a new collective agreement. The results of the arbitration are expected in the spring of 2013.

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. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA and have expiry dates ranging from 2013 to 2020.

ONTARIO ELECTRICITY MARKET TRENDS

In its 18-Month Outlook published on February 28, 2013, the IESO indicated that as of February 13, 2013, Ontario's installed electricity generating capacity was 35,850 MW. As of December 31, 2012, OPG's in-service electricity generating capacity was 19,051 MW, or approximately 53 percent of Ontario's capacity. The IESO reported that Ontario will continue to have adequate electricity supply. Approximately 3,200 MW of grid-connected renewable generation will be added by August 2014.

The IESO reported demand for 2012 of 141.8 TWh, and forecasted demand of 141.0 TWh for 2013. The 0.6 percent decrease in demand forecast for 2013 is primarily attributable to ongoing conservation initiatives and assets not directly connected to the IESO grid more than offsetting the effects of population growth and economic expansion. The expected peak electricity demand during the summer, under normal weather conditions, is forecast to be 23,275 MW in 2013.

Fuel prices can have a significant impact on OPG's revenue and gross margin. Natural gas prices at Henry Hub averaged United States ("US") $2.75/MMBtu in 2012, a decrease of 31 percent from the 2011 price of $4.00/MMBtu. The decrease in natural gas prices is mainly the result of a mild 2011-2012 winter and an oversupplied North American market. Eastern coal prices averaged around $60.00/tonne in 2012, a decrease of 18 percent from 2011, while Powder River Basin coal prices averaged $10.00/tonne this year, a decrease of approximately 30 percent. A more competitive coal market and ongoing natural gas displacement contributed to the significant decline in coal prices.

The nuclear fuel purchasing strategy of using a mix of spot and long-term contracts and a mix of fixed and market related pricing arrangements, together with the long cycle time between the acquisition of uranium, processing, fabrication of fuel bundles and recognition of fuel expense, tend to dampen the impact of short-term market fluctuations in uranium pricing on OPG. The industry average uranium spot market price ended the year at US $43.50 per pound which was a decrease from US $46.50 per pound at the end of the third quarter of 2012 and a significant decrease from US $52.00 per pound at the beginning of 2012. The industry average long-term uranium price ended the year at US $56.50 per pound, a decrease from US $62.00 at the beginning of 2012.

BUSINESS SEGMENTS

OPG has five reportable business segments:

- Regulated – Nuclear Generation.
- Regulated – Nuclear Waste Management.
- Regulated – Hydroelectric.
- Unregulated – Hydroelectric.
- Unregulated – Thermal.

Regulated – Nuclear Generation Segment

OPG's Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue and revenue from services such as heavy water sales and detritiation. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power and from isotope sales and ancillary services are included in the determination of the regulated prices for OPG's nuclear facilities by the OEB.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment engages in the management of used nuclear fuel and low and intermediate level waste ("L&ILW"), the decommissioning of OPG's nuclear generating stations (including the stations on lease to Bruce Power), the management of the Nuclear Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense on the Nuclear Liabilities and earnings from the Nuclear Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs variable costs related to nuclear used fuel and L&ILW generated. These costs increase the Nuclear Liabilities through the generation of additional used nuclear fuel bundles and other waste. These variable costs are charged to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy and earning revenue under the Bruce Power lease arrangement and related agreements. Since variable costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated on OPG's Consolidated Statements of Income and Balance Sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because the costs associated with the Nuclear Liabilities are included in the determination of regulated prices for production from OPG's regulated nuclear facilities by the OEB.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Ancillary revenues and other revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services. These ancillary revenues and other revenues are included in the determination of the regulated prices for these facilities by the OEB.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from the Company's hydroelectric generating stations, which are not subject to rate regulation. Ancillary revenues and other revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services.

Unregulated – Thermal Segment

The Unregulated – Thermal business segment operates in Ontario, generating and selling electricity from the Company's thermal generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, automatic generation control, and other services.

Other

The Other category includes revenue that OPG earns from its 50 percent joint venture share of Brighton Beach related to an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc. This category also includes revenue that OPG earns from its 50 percent joint venture share of the PEC gas-fired generating station, which is operated under the terms of an Accelerated Clean Energy Supply contract with the OPA. The revenue and expenses related to OPG's trading and other non-hedging activities are also reported in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in the revenue of the Other category. In addition, the Other category includes revenue from real estate rentals.

KEY GENERATION AND FINANCIAL PERFORMANCE INDICATORS

Key performance indicators that directly pertain to OPG's mandate and corporate strategies are measures of production efficiency, cost-effectiveness, environmental and safety performance. OPG evaluates the performance of its generating stations using a number of key performance indicators, which vary depending on the generating technology.

Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities, as they have low marginal costs and are not designed for fluctuating production levels to meet peaking demand. The nuclear unit capability factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints, such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. Capability factors, by industry definition, exclude grid-related unavailability and high lake water temperature losses.

Hydroelectric Availability

OPG's hydroelectric stations, which operate as baseload, intermediate, and peaking stations, provide a safe, reliable and low-cost source of renewable energy. Hydroelectric availability is a measure of the reliability of a hydroelectric generating unit. It is represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually in-service, compared to the total time for a respective period.

Thermal Start Guarantee Rate

OPG's thermal stations provide a flexible source of energy and operate as peaking facilities, depending on the demand of the market. Given continued changes in the electricity market in Ontario, the main focus of the thermal business is to ensure its generating units are available when needed. While the industry standard Equivalent Forced Outage Rate ("EFOR") measure continues to be monitored by the thermal business within the context of its business strategy, beginning in 2012, OPG also adopted the Start Guarantee rate as a key thermal reliability measure. The Start Guarantee rate represents the ratio of the number of times thermal units successfully start compared to the number of starts requested by the IESO. Start Guarantee performance was monitored in 2011 in anticipation of this change.

Thermal and Hydroelectric Equivalent Forced Outage Rate

A measure of the reliability of the thermal and hydroelectric generating stations is the proportion of time they are available to produce electricity when required. EFOR is an index of the reliability of the generating unit. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

OPG continues its strategy for the thermal stations to ensure units are available when required, to optimize how coal-fired units are offered into the electricity system, and to reduce equipment damage from frequent starts and stops. In addition, OPG has optimized outage duration and scope, where warranted, in line with capped unit production due to CO_2 emission limits, reduced system demands and planned future plant operation. This strategy is to reduce maintenance related expenditures, including capital asset investments, labour and overtime. Thermal EFOR for 2012 and 2011 reflected this strategy.

Nuclear Production Unit Energy Cost (“PUEC”)

Nuclear PUEC is used to measure the cost-effectiveness of the operations-related costs of production from OPG’s nuclear generating assets. Nuclear PUEC is defined as the total cost of nuclear fuel, OM&A expenses including allocated corporate costs and the variable costs for the disposal of L&ILW, and variable costs related to used fuel disposal and storage, divided by nuclear electricity generation.

Hydroelectric OM&A Expense per Megawatt hours (“MWh”)

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

Thermal OM&A Expense per MW

Since thermal generating stations are primarily employed during periods of peak demand, the cost-effectiveness of these stations is measured by their annualized OM&A expenses for the period, including allocated corporate costs, divided by the weighted average station adjusted capacity.

Return on Equity

ROE is an indicator of OPG’s performance consistent with its objectives to operate on a financially sustainable basis and to maintain the value for the Shareholder. ROE is defined as net income divided by average shareholder’s equity excluding accumulated other comprehensive income (“AOCI”). See ROE as calculated under the heading, *Supplementary Non-GAAP Financial Measures,* for further details.

Funds from Operations Interest Coverage

FFO Interest Coverage is an indicator of OPG’s ability to meet interest obligations from operating cash flows. FFO Interest Coverage is defined as FFO Before Interest, divided by Adjusted Interest Expense. It is measured over a period of twelve months. See *Liquidity and Capital Resources – FFO Interest Coverage* and *Supplementary Non-GAAP Financial Measures – FFO Interest Coverage* sections, for further details.

ROE and FFO Interest Coverage are not measurements in accordance with US GAAP and should not be considered as alternative measures to net income or any other measure of performance under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the objectives to operate on a financially sustainable basis and to maintain the value for the Shareholder.

Other Key Indicators

In addition to performance and cost-effectiveness indicators, OPG has identified certain environmental and safety metrics. These metrics are discussed under the heading, *Core Business and Strategy*.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

This section summarizes OPG's key results by segment for 2012 and 2011. The following table provides a summary of revenue, earnings, and electricity generation by business segment:

(millions of dollars – except where noted)	**2012**	**2011** *(adjusted)*
Revenue		
Regulated – Nuclear Generation	**3,060**	3,061
Regulated – Nuclear Waste Management	**107**	57
Regulated – Hydroelectric	**724**	729
Unregulated – Hydroelectric	**373**	492
Unregulated – Thermal	**511**	608
Other	**60**	72
Elimination	**(103)**	(55)
	4,732	4,964
Income (loss) before interest and income taxes		
Regulated – Nuclear Generation	**364**	321
Regulated – Nuclear Waste Management	**(68)**	(194)
Regulated – Hydroelectric	**324**	341
Unregulated – Hydroelectric	**(10)**	107
Unregulated – Thermal	**(112)**	(202)
Other	**53**	92
	551	465
Electricity generation (TWh)		
Regulated – Nuclear Generation	**49.0**	48.6
Regulated – Hydroelectric	**18.5**	19.5
Unregulated – Hydroelectric	**12.1**	12.9
Unregulated – Thermal	**4.1**	3.7
Total electricity generation	**83.7**	84.7

Regulated – Nuclear Generation Segment

(millions of dollars)	**2012**	**2011** *(adjusted)*
Regulated generation sales	**2,719**	2,691
Variance accounts	**300**	48
Other	**41**	322
Total revenue	**3,060**	3,061
Fuel expense	**310**	256
Variance and deferral accounts	**(49)**	(13)
Total fuel expense	**261**	243
Gross margin	**2,799**	2,818
Operations, maintenance and administration	**1,930**	2,001
Depreciation and amortization	**480**	473
Property and capital taxes	**26**	26
Income before other income, interest and income taxes	**363**	318
Other income	**(1)**	(3)
Income before interest and income taxes	**364**	321

Income before interest and income taxes from the Regulated – Nuclear Generation segment was $364 million in 2012, compared to $321 million in 2011. The increase was mainly due to lower OM&A expenses, partially offset by a lower gross margin.

The $71 million decrease in OM&A expenses from 2011 to 2012 was primarily due to headcount reductions and a decrease in pension and OPEB expenses. Pension and OPEB expenses decreased primarily due to the recognition of a regulatory asset related to OPG's transition to US GAAP. Lower discount rates resulted in higher pension and OPEB costs however these high costs were offset by amounts recorded in the Pension and OPEB Cost Variance Account for future recovery. The reduction in OM&A expenses was partially offset by an increase in materials and supplies inventory obsolescence and other increases in expenses.

Gross margin decreased primarily as a result of higher fuel expense. The decrease in gross margin was partially offset by an increase in revenue due to higher generation. Fuel expense increased mainly due to higher uranium prices. Fuel expense also increased as a result of higher costs associated with used fuel storage and disposal, mainly due to the 2011 update to the Nuclear Liabilities. This increase was largely offset by the recognition of regulatory assets for the Nuclear Liability Deferral Account ("NLDA") and the Bruce Lease Net Revenues Variance Account. The Bruce Lease Net Revenues Variance Account captures the differences between actual and forecast revenues and costs related to the nuclear generating stations on lease to Bruce Power. The NLDA is discussed in the *Balance Sheet Highlights* section.

During 2012, OPG recognized a $284 million reduction in other revenue related to the Bruce Power lease agreement ("Bruce Lease"). This reduction was due to a change in the value of the derivative embedded in the Bruce Lease resulting from an extension of the useful lives of the Bruce nuclear generating stations and a decrease in the expected future annual arithmetic average HOEP ("Average HOEP"). Refer to section *Leases and Partnerships* for further details. The decrease in lease revenue was offset by the increase in a regulatory asset for the Bruce Lease Net Revenues Variance Account. For further details refer to *Changes in Accounting Policies and Estimates* section.

The unit capability factors for the Darlington and Pickering generating stations, and the Production Unit Energy Cost ("PUEC") for 2012 and 2011 are as follows:

	2012	**2011** *(adjusted)*
Unit Capability Factor *(%)*		
Darlington	**93.2**	95.2
Pickering	**77.8**	73.4
Nuclear PUEC *($/MWh)*	**43.71**	44.55

The Darlington generating station continued to perform well with a capability factor of 93.2 percent for 2012. The lower capability factor at the Darlington generating station for 2012, compared to 2011, was primarily due to an increase in unplanned outage days. For 2012, the higher capability factor at the Pickering generating stations, compared to 2011, mainly reflected fewer unplanned and planned outage days.

Nuclear PUEC decreased in 2012, primarily due to lower OM&A expenses and higher generation, partially offset by an increase in fuel and fuel-related expenses.

Regulated – Nuclear Waste Management Segment

(millions of dollars)	**2012**	**2011**
Revenue	**107**	57
Operations, maintenance and administration	**114**	65
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**712**	695
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(651)**	(509)
Loss before interest and income taxes	**(68)**	(194)

Loss before interest and income taxes for the Regulated – Nuclear Waste Management segment was $68 million for 2012, compared to $194 million for 2011. This improvement was primarily due to higher earnings from the Decommissioning Fund, as a result of a greater increase in the market value of the securities held in the funds in 2012, compared to 2011, net of the impact of the Bruce Lease Net Revenues Variance Account.

Revenue for the Regulated – Nuclear Waste Management segment for 2012 increased, compared to 2011, as a result of a higher inter-segment charge to the Regulated – Nuclear Generation segment. This increase was due to the higher variable costs related to nuclear used fuel and L&ILW resulting from the 2011 update of the Nuclear Liabilities. The increase in revenue was offset by higher OM&A expenses associated with the higher variable costs.

Regulated – Hydroelectric Segment

(millions of dollars)	**2012**	**2011**
Regulated generation sales [1]	**644**	684
Variance accounts	**55**	13
Other	**25**	32
Total revenue	**724**	729
Fuel expense	**246**	263
Variance accounts	**15**	(2)
Total fuel expense	**261**	261
Gross margin	**463**	468
Operations, maintenance and administration	**103**	108
Depreciation and amortization	**33**	38
Property and capital taxes	**(1)**	-
Income before other loss, interest and income taxes	**328**	322
Other loss (income)	**4**	(19)
Income before interest and income taxes	**324**	341

[1] The Regulated – Hydroelectric segment generation sales included revenue of $16 million in 2012 and $15 million in 2011, related to the hydroelectric incentive mechanism.

In 2012, income before interest and income taxes for the Regulated – Hydroelectric segment was $324 million, compared to $341 million in 2011. The decrease of $17 million was primarily due to the recognition of a gain in 2011 related to a reduction in an environmental provision and the recognition of a loss of $4 million in 2012. The loss in 2012 primarily related to the write-off of various bridges in the Niagara plant group that have been transferred to municipalities.

Gross margin decreased by $5 million in 2012, compared to 2011. This result was primarily due to lower generation revenue resulting from lower water levels and lower ancillary and other station revenues. The decrease was partially offset by the impact of regulatory variance accounts, related mainly to water levels.

The availability, EFOR and OM&A expense per MWh for the Regulated – Hydroelectric segment for 2012 and 2011 are as follows:

	2012	**2011**
Availability *(%)*	**91.4**	89.7
EFOR *(%)*	**2.1**	1.3
Regulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**5.57**	5.54

The availability for the regulated hydroelectric stations was 91.4 percent in 2012, compared to 89.7 percent in 2011. The increase was primarily due to fewer planned outage days in 2012. EFOR increased in 2012, compared to 2011. This was primarily due to an extension of a planned outage at Sir Adam Beck 1 generating station to repair a cracked headcover, combined with an outage at the Sir Adam Beck Pump generating station that was carried over from 2011. The high availability reflects the continuing strong performance of the regulated hydroelectric generating stations.

The OM&A expense per MWh for 2012 was $5.57/MWh, compared to $5.54/MWh for 2011. The marginal increase in OM&A expense per MWh was mainly due to lower generation.

Unregulated – Hydroelectric Segment

(millions of dollars)	**2012**	**2011**
Spot market sales	**290**	412
Other	**83**	80
Total revenue	**373**	492
Fuel expense	**71**	75
Gross margin	**302**	417
Operations, maintenance and administration	**236**	239
Depreciation and amortization	**73**	75
Property and capital taxes	**(1)**	(2)
(Loss) income before other loss, interest and income taxes	**(6)**	105
Other loss (income)	**4**	(2)
(Loss) income before interest and income taxes	**(10)**	107

Loss before interest and income taxes for the Unregulated – Hydroelectric segment in 2012 was $10 million, compared to income before interest and income taxes of $107 million in 2011. The decrease in income was primarily due to the significantly lower weighted average HOEP and the impact of lower water levels on hydroelectric generation.

The weighted average HOEP was 2.4 ¢/kWh in 2012 and 3.1 ¢/kWh in 2011. Also contributing to the decrease in income in 2012 was the recognition of a loss of $4 million in 2012 primarily related to the retirement of various assets.

OM&A expenses decreased primarily as a result of reduced work activities. This was largely offset by higher pension and OPEB costs due to lower discount rates for 2012.

The availability, EFOR and OM&A expense per MWh for Unregulated – Hydroelectric segment for 2012 and 2011 are as follows:

	2012	**2011**
Availability *(%)*	**91.1**	91.5
EFOR *(%)*	**2.0**	1.6
Unregulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**19.26**	18.14

The availability for the unregulated hydroelectric stations was 91.1 percent in 2012, compared to 91.5 percent in 2011. The decrease in availability and increase in EFOR for 2012, compared to 2011, were primarily due to an increase in unplanned outages in 2012. The high availability reflected the continuing strong performance of the unregulated hydroelectric stations.

The increase in OM&A expense per MWh for 2012 was mainly due to the impact of lower generation in 2012.

Unregulated – Thermal Segment

(millions of dollars)	**2012**	**2011** *(adjusted)*
Spot market sales	**104**	123
Contingency support agreement	**284**	363
Other	**123**	122
Total revenue	**511**	608
Fuel expense	**162**	175
Gross margin	**349**	433
Operations, maintenance and administration	**361**	419
Depreciation and amortization	**59**	88
Accretion on fixed asset removal liabilities	**13**	9
Property and capital taxes	**16**	15
Restructuring	**3**	21
Loss before other loss, interest and income taxes	**(103)**	(119)
Other loss	**9**	83
Loss before interest and income taxes	**(112)**	(202)

Loss before interest and income taxes in 2012 for the Unregulated – Thermal segment was $112 million, compared to $202 million in 2011. The improvement in income was primarily due to the recognition of a loss of $81 million in 2011 resulting from an increase in the ARO estimate. In September 2011, OPG completed a review of the ARO for most of its thermal stations which resulted in a loss of $81 million being recognized in accordance with US GAAP in the Thermal business segment, and income of $15 million in the Other segment. The 2011 review of the ARO estimate is discussed in the *Changes in Accounting Policies and Estimates* section.

Gross margin decreased by $84 million in 2012, compared to 2011. This was primarily the result of lower revenue from the Contingency Support Agreement and lower electricity sales prices, partially offset by lower fuel and fuel-related costs. The lower revenue from the Contingency Support Agreement reflected the decrease in OM&A expenses and depreciation expense related to the closure of two units at the Nanticoke generating station in December 2011, and lower fuel expense due to adjustments to coal inventory.

The reduction in OM&A expenses of $58 million in 2012, compared to 2011 was primarily due to cost reduction measures, including headcount reductions, reduced scope of work associated with changing operating profiles, and unit closures at the Nanticoke generating station in 2011. The reduction in OM&A expenses contributed to lower revenue from the Contingency Support Agreement.

Restructuring charges decreased during 2012, compared to 2011. The decrease was primarily due to the recognition of severance costs of $21 million in 2011 related to the shutdown of two units at the Nanticoke generating station that year.

The decrease in depreciation and amortization expenses in 2012, compared to 2011 was primarily due to the recognition of accelerated depreciation related to the Nanticoke unit closures in 2011.

In 2012, OPG recognized a loss of $9 million related to the write-off of costs incurred to date for the Thunder Bay conversion project.

The Start Guarantee rate, EFOR, and OM&A expense per MW for the Unregulated – Thermal segment for 2012 and 2011 are as follows:

	2012	2011
Start Guarantee rate *(%)*	**97.5**	94.7 [1]
EFOR *(%)*	**9.4**	9.2
Unregulated – Thermal OM&A expense per MW *($000/MW)*	**66.3**	67.1

[1] As estimated.

The Start Guarantee rate was 97.5 percent in 2012, compared to 94.7 percent in 2011. The high Start Guarantee rate reflects the ability of the thermal generating stations to respond to market requirements when needed.

The decrease in OM&A expense per MW in 2012, compared to 2011, reflected lower OM&A expenses as a result of reduced staff and work programs, partially offset by the reduced thermal generating capacity resulting from the unit closures at the Nanticoke generating station in 2011.

Other

(millions of dollars)	2012	2011 *(adjusted)*
Revenue	**60**	72
Operations, maintenance and administration	**7**	4
Depreciation and amortization	**19**	20
Property and capital taxes	**7**	11
Income before other income, interest and income taxes	**27**	37
Other income	**(26)**	(55)
Income before interest and income taxes	**53**	92

Income before interest and income taxes in 2012 was $53 million, compared to $92 million in 2011. The decrease was mainly due to the recognition of other income of $15 million in 2011 related to the review of the ARO estimate for the decommissioned thermal R.L. Hearn generating station. In addition, income decreased as a result of lower net trading revenue, and lower earnings in 2012 from OPG's joint ventures, compared to 2011.

The 2011 review of the ARO estimate is discussed in the *Changes in Accounting Policies and Estimates* section.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain property, plant and equipment ("PP&E"), and intangible assets held within the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. The service fee included in OM&A expenses by segment in 2012 and 2011 was as follows:

(millions of dollars)	2012	2011
Regulated – Nuclear Generation	**23**	22
Regulated – Hydroelectric	**2**	2
Unregulated – Hydroelectric	**3**	4
Unregulated – Thermal	**6**	7
Other	**(34)**	(35)

Interconnected purchases and sales, including those to be physically settled, and unrealized mark-to-market gains and losses on energy trading contracts, are reported in the results of the Other category. They are disclosed on a net basis in the Consolidated Statements of Income. In 2012, if disclosed on a gross basis, revenue and power purchases would have increased by $61 million (2011 – $69 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 values of derivative instruments not qualifying for hedge accounting are recorded in revenue in the Other category. The fair values of these derivative instruments are reported on the Consolidated Balance Sheets as assets or liabilities. The notional quantities and carrying amounts of the derivative instruments are disclosed in Note 11 and Note 12, respectively, of the audited consolidated financial statements as at and for the years ended December 31, 2012 and 2011.

Net Interest Expense

Net interest expense for 2012 was $117 million, compared to $154 million for 2011, a decrease of $37 million. The decrease was primarily due to a higher amount of interest capitalized to PP&E and intangible assets.

Income Taxes

OPG follows the liability method of tax accounting for all its business segments. The Company also records an offsetting regulatory asset or liability for the deferred taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities.

Income tax expense for 2012 was $67 million, compared to income tax recovery of $27 million for 2011. The increase in income tax expense for 2012 was primarily due to a reduction in income tax liabilities in 2011 related to the resolution of a number of tax uncertainties for certain prior years, and the recognition in 2011 of investment tax credits for eligible scientific research and experimental development expenditures related to prior years.

Return on Equity

ROE is an indicator of OPG's performance consistent with its objectives to operate on a financially sustainable basis and to maintain value for the Shareholder. ROE is measured over a 12-month period.

ROE for 2012 was 4.2 percent, compared to 4.0 percent for 2011. ROE increased in 2012 primarily due to a higher net income, partially offset by higher average shareholder's equity, excluding AOCI. OPG's ROE reflects low levels of income primarily due to low electricity spot market prices, lower regulated prices than those originally applied for, and a relatively high equity component in its capital structure.

ROE is not a measurement in accordance with US GAAP and should not be considered an alternative measure to net income, cash flows from operating activities, or any other performance measure under US GAAP. The definition of ROE can be found under the heading, *Supplementary Non-GAAP Financial Measures.*

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the 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 2012 and 2011 are as follows:

(millions of dollars)	**2012**	2011 *(adjusted)*
Cash and cash equivalents, beginning of period	**630**	269
Cash flow provided by operating activities	**876**	1,179
Cash flow used in investing activities	**(1,403)**	(1,138)
Cash flow provided by financing activities	**310**	320
Net (decrease) increase	**(217)**	361
Cash and cash equivalents, end of period	**413**	630

Operating Activities

Cash flow provided by operating activities for 2012 was $876 million, compared to $1,179 million for 2011. The decrease in operating cash flow was primarily due to lower unregulated hydroelectric generation, an increase in pension contributions, and a reduction in revenues from isotope sales and technical services provided to third parties. The decrease in operating cash flow was partially offset by a decrease in OM&A expenses and lower contributions to the Nuclear Funds.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to improve operating performance, increase generating capacity of existing stations, invest in new generating stations, and to maintain and improve service, reliability, safety and environmental performance.

Cash flow used in investing activities in 2012 was $1,403 million, compared to $1,138 million in 2011. The increase was primarily due to higher expenditures for the Darlington Refurbishment, Lower Mattagami River, and Atikokan biomass conversion projects, partially offset by lower capital expenditures for the Niagara Tunnel project.

OPG's forecast capital expenditures for 2013 are approximately $1.7 billion. This 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 $500 million multi-year term tranches. In May 2012, OPG renewed and extended both tranches to May 20, 2017. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at December 31, 2012, no commercial paper was outstanding under this program, and there were no outstanding borrowings under the bank credit facility as at December 31, 2012.

As at December 31, 2012, OPG maintained $25 million of short-term uncommitted overdraft facilities and $395 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. As at December 31, 2012, there was a total of $350 million of Letters of Credit issued. This included $329 million for the supplementary pension plans, which includes $55 million of Letters of Credit discussed below; $20 million for general corporate purposes; and $1 million related to the operation of the PEC generating station.

The Company has an agreement to sell an undivided co-ownership interest up to $250 million in its current and future accounts receivable to an independent trust. In the fourth quarter of 2012, the Company renegotiated the agreement to include the issuance of Letters of Credit, and extended the agreement from August 31, 2013 to November 30, 2014. As at December 31, 2012, there were Letters of Credit outstanding under this agreement of $55 million, which were issued in support of OPG's supplementary pension plans. As at December 31, 2011, short-term debt included $50 million outstanding under this agreement.

OPG also maintains a Niagara Tunnel project credit facility for up to $1.6 billion. As at December 31, 2012, advances under this facility were $1,025 million, including $150 million of new borrowing during 2012.

The Lower Mattagami Energy Limited Partnership ("LME") maintains a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami River project and the commercial paper program. In August 2012, the facility was divided into two tranches. The first tranche of $400 million has a maturity date of August 17, 2017 and the second tranche of $300 million has a maturity date of August 17, 2015. As at December 31, 2012, no commercial paper was outstanding under this program. In 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami River project. As at December 31, 2012, there were no outstanding borrowings under this credit facility. In April 2012, the LME issued senior notes totalling $225 million with a maturity date of 2052. The effective interest rate and coupon interest rate of these notes were 4.3 percent and 4.2 percent, respectively. In October 2012, senior notes totalling $200 million were issued by the LME. These senior notes have an effective interest rate and coupon interest rate of 2.3 percent and 2.2 percent, respectively, and mature on October 23, 2017. In February 2013, the LME issued senior notes totalling $275 million with a maturity date of 2046. The effective interest rate and coupon interest rate of these notes were 4.3 percent and 4.2 percent, respectively.

As at December 31, 2012, OPG's long-term debt outstanding was $5,114 million. OPG entered into an agreement with the OEFC in April 2012 for a $400 million refinancing credit facility. OPG refinanced $200 million of notes under this facility in the second quarter of 2012. This credit facility expired in the second quarter of 2012.

Future Pension Contributions

In December 2012, OPG applied to the government for temporary solvency relief as part of a recently announced initiative for broader public sector institutions. As a result of the economic downturn and low interest rates, many public and private sector institutions have already applied for, or are currently seeking, similar relief.

If OPG is granted temporary relief, and if the Company finds it has a solvency deficit at the time of its next actuarial valuation for funding purposes, which must have an effective date of no later than January 1, 2014, it would have the flexibility to extend the time period over which it funds the solvency deficit.

FFO Interest Coverage

FFO Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. FFO Interest Coverage was 2.3 times for 2012 and 3.1 times for 2011. The FFO Interest Coverage decreased primarily due to lower cash flows provided by operating activities.

The FFO Interest Coverage is not a measurement in accordance with US GAAP and should not be considered as an alternative measure to net income, cash flows from operating activities, or any other measure of performance under US GAAP. OPG believes that this non-GAAP financial measure is an effective indicator of performance and is consistent with the corporate strategy to operate on a financially sustainable basis. The definition and calculation of FFO Interest Coverage can be found under the heading, *Supplementary Non-GAAP Financial Measures.*

Contractual and Commercial Commitments

OPG's contractual obligations and other significant commercial commitments as at December 31, 2012, are as follows:

(millions of dollars)	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**
Contractual obligations:							
Fuel supply agreements	196	166	174	122	113	291	1,062
Contributions under the Ontario Nuclear Funds Agreement ("ONFA") [1]	211	139	143	150	163	2,899	3,705
Long-term debt repayment	5	5	593	273	1,103	3,135	5,114
Interest on long-term debt	240	239	234	220	201	1,679	2,813
Unconditional purchase obligations	104	98	97	8	-	-	307
Operating lease obligations	15	15	16	17	17	78	158
Operating licence	38	41	41	6	-	-	126
Pension contributions [2]	300	-	-	-	-	-	300
Other	31	81	32	33	36	95	308
	1,140	784	1,330	829	1,633	8,177	13,893
Significant commercial commitments:							
Niagara Tunnel	44	-	-	-	-	-	44
Lower Mattagami	477	315	116	-	-	-	908
Atikokan	65	6	-	-	-	-	71
Total	1,726	1,105	1,446	829	1,633	8,177	14,916

[1] Contributions under the ONFA are based on the 2012 ONFA Reference Plan contribution schedule approved in 2012.

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuations of the OPG registered pension plan as at January 1, 2011 and NWMO registered pension plans as at January 1, 2012. The next actuarial valuations of the OPG and NWMO plans must have effective dates no later than January 1, 2014 and 2013, respectively. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2013 for the OPG registered pension plan are excluded due to significant variability in the assumption required to project the timing of future cash flows. Funding requirements for 2013 for the NWMO registered pension plan are also excluded. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time.

CREDIT RATINGS

Maintaining an investment grade credit rating is essential for corporate liquidity and future capital market access. The cost and availability of financing are influenced by credit ratings, which are an indicator of the creditworthiness of a particular company, security or obligation. Lower ratings generally result in higher borrowing costs as well as reduced access to capital markets.

In September 2012, Dominion Bond Rating Service reaffirmed the long-term credit rating on OPG at A (low) and the commercial paper rating at R-1 (low) with a stable outlook. In November 2012, Standard & Poor's affirmed OPG's long-term corporate rating of A- and revised the outlook to negative from stable. In February 2013, Standard & Poor's re-affirmed OPG's long-term credit rating at A- with a negative outlook and the commercial paper rating at A-1 (low).

BALANCE SHEET HIGHLIGHTS

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

(millions of dollars)	2012	2011 *(adjusted)*	Explanation of change
Property, plant and equipment - net	**15,860**	14,633	The increase was primarily due fixed asset additions for the Lower Mattagami River project, the refurbishment of Darlington, the Niagara Tunnel project, and an increase in the estimate for the liability for nuclear fixed asset removal and nuclear waste management reflecting the changes in the useful lives of the Pickering and Bruce generating stations. The increase was partially offset by depreciation for 2012.
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**12,717**	11,898	The increase was primarily due to earnings on the Nuclear Funds and contributions to the Used Fuel Segregated Fund ("Used Fuel Fund").
Regulatory assets *(current and non-current portions)*	**6,478**	5,017	The increase was primarily due to the recognition of the regulatory asset related to pension and OPEB as a result of the re-measurement of the liability, as well as additions to the Pension and OPEB Cost Variance Account, the Bruce Lease Net Revenues Variance Account, the NLDA, details of which are provided below, and the US GAAP Deferral Account. This increase was partially offset by the amortization of regulatory assets based on the OEB's March 2011 decision and a decrease in the regulatory asset for deferred taxes.
Long-term debt *(including debt due within* one *year)*	**5,114**	4,744	The increase was due to the issuance of debt of $425 million for the Lower Mattagami River project and $350 million of general purpose debt. The increase was partially offset by a repayment of long-term debt of $405 million during 2012.
Fixed asset removal and nuclear waste management liabilities	**15,522**	14,392	The liability increased as a result of accretion expense due to the passage of time, and an increase in the estimate for the Nuclear Liabilities of $449 million reflecting the changes in the useful lives of the Pickering and Bruce generating stations. The increase was partially offset by expenditures on nuclear fixed asset removal and waste management activities.
Pension liabilities	**3,621**	2,847	Pension and OPEB liabilities increased primarily due to the recognition of losses as a result of the re-measurement of the liabilities at the end of 2012 using a lower discount rates than those used at the end of 2011.
Other post-employment benefit liabilities	**3,076**	2,616	

Nuclear Liability Deferral Account

In accordance with *Ontario Regulation 53/05* pursuant to the *Ontario Energy Board Act, 1998*, the OEB has authorized the NLDA in connection with changes to OPG's Nuclear Liabilities. The deferral account records the revenue requirement impact of the changes in the Nuclear Liabilities associated with the Pickering and Darlington nuclear generating stations, arising from an approved reference plan, in accordance with the terms of the ONFA.

In 2011, the estimate for OPG's Nuclear Liabilities as at December 31, 2011 was updated as a result of the ONFA Reference Plan update process. During the fourth quarter of 2011, OPG submitted the final 2012 ONFA Reference Plan, which covers the period from 2012 to 2016, to the Province for approval. During 2012, the Province approved the 2012 ONFA Reference Plan with an effective date of January 1, 2012. As a result, OPG recorded an increase of $206 million to the regulatory asset for the NLDA during 2012. The regulatory asset represents the revenue requirement impact associated with the increase in the liabilities for the nuclear facilities owned and operated by OPG arising from the approved 2012 ONFA Reference Plan for the period beginning on January 1, 2012. The revenue requirement increase included higher depreciation expense due to an increase in fixed assets at the end of 2011 to reflect an increase in the nuclear ARO. The higher revenue requirement also included an increase in nuclear used fuel and L&ILW variable costs due to an increase in variable cost rates, a higher return on rate base in accordance with the OEB approved methodology, and the corresponding tax effects of these changes. Reductions to expenses corresponding to the increase in the regulatory asset are detailed in Note 5 of the audited consolidated financial statements as at and for the year ended December 31, 2012. OPG's September 2012 application to the OEB included a request to recover the balance in this account as at December 31, 2012.

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US 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 undertaken by OPG include guarantees, which provide financial or performance assurance to third parties on behalf of certain subsidiaries, and long-term fixed price contracts.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries and joint ventures. Such agreements include guarantees, standby Letters of Credit and surety bonds. For further details on OPG's guarantees, refer to Note 14 of OPG's audited consolidated financial statements as at and for the year ended December 31, 2012.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of future accounting pronouncements, are outlined in Note 3 of OPG's 2012 audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's consolidated financial statements, the likelihood that materially different amounts would be reported under varied conditions and estimates, and the impact of changes in certain conditions or assumptions are highlighted below.

Conversion to US GAAP

OPG completed its US GAAP conversion project in 2012 and published its first consolidated financial statements prepared in accordance with US GAAP as at and for the three months ended March 31, 2012, and for the corresponding comparative period. The transitional balance sheet as at January 1, 2011 was disclosed in the March 31, 2012 unaudited interim consolidated financial statements. It is included in Note 22 to the audited consolidated financial statements as at and for the year ended December 31, 2012.

The project consisted of three phases: diagnostic, development, and implementation.

Diagnostic Phase

This phase was completed in the fourth quarter of 2011. It involved reviews of major differences between Canadian generally accepted accounting principles ("Canadian GAAP") as determined in Part V of the Canadian Institute of Chartered Accountants Handbook - Accounting and US GAAP, and OPG's significant accounting and reporting policies. OPG determined that the most significantly impacted areas included Employee Benefits, Thermal Asset Retirement Obligation, Joint Ventures, and the related impacts on regulatory assets and liabilities and income taxes.

Development and Implementation Phase

The development phase was concluded in 2012. It involved a detailed analysis of key impact areas, issue resolutions, and the preparation of illustrative financial statements. Development phase activities included the evaluation of accounting policy alternatives, investigation and development of solutions to resolve differences identified in the diagnostic phase, and identification of required changes to existing accounting policies and practices, business processes, information technology systems, and internal controls.

In the implementation phase of OPG's US GAAP conversion plan, OPG integrated changes to affected accounting policies and practices, business processes, information technology systems, financial statements, training, and internal controls as required.

A full description of the transitional adjustments can be found in Note 22 of OPG's audited consolidated financial statements as at and for the year ended December 31, 2012. Included in the transition adjustments are the impacts related to: pension and OPEB, as a result of the recognition of the funded status of the defined benefit plans, including the recognition of all actuarial gains and losses and past service costs related to long-term disability ("LTD") benefits in the income statement; and the application of equity accounting for OPG's interest in the PEC and Brighton Beach.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the Prescribed Facilities. Beginning April 1, 2008, OPG's regulated prices for these regulated facilities are determined by the OEB.

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

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required to be obtained from, or settled with, the ratepayers. When the Company assesses that there is sufficient assurance that incurred costs will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to ratepayers in the future, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through current regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB. This includes accounts authorized pursuant to *Ontario Regulation 53/05.* Variance accounts capture differences between actual costs and revenues, and the corresponding forecast amounts approved in the setting of regulated prices. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory asset and liability balances for variance and deferral accounts approved by the OEB for inclusion in regulated prices are amortized based on approved recovery periods. Disallowed balances, including associated interest, are charged to operations in the period that the OEB's decision is issued. Interest is applied to regulatory balances as prescribed by the OEB in order to recognize the cost of financing amounts to be recovered from, or repaid to, ratepayers.

Regulatory asset and liability balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, ratepayers within 12 months of the end of the reporting period, based on recovery periods established by the OEB. All other regulatory asset and liability balances are classified as long-term on the Consolidated Balance Sheets.

See Notes 3, 5, 8, 9, and 10 of OPG's 2012 audited consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Income Taxes and Investment Tax Credits

OPG is exempt from income tax under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG effectively paying taxes similar to what would be imposed under the federal and Ontario tax acts.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. OPG has taken certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If management determines that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

OPG recognizes deferred income taxes associated with its rate regulated operations and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense. OPG classifies interest and penalties associated with unrecognized tax benefits as income tax expense.

Deferred income tax assets of $5,914 million (2011 – $5,255 million) have been recorded on the Consolidated Balance Sheet at December 31, 2012. The Company believes there will be sufficient future taxable income and capital gains that will permit the use of these deductions and carry-forwards.

Deferred income tax liabilities of $6,409 million (2011 – $5,714 million) have been recorded on the Consolidated Balance Sheet as at December 31, 2012.

PP&E, Intangible Assets and Depreciation and Amortization

PP&E and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset, based on the interest rates on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are charged to OM&A expenses. Repairs and maintenance costs are also expensed when incurred.

PP&E are depreciated on a straight-line basis except for computers, and transport and work equipment. These are mostly depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis.

The accounting estimates related to asset depreciation require significant management judgment to assess the appropriate useful lives of OPG's PP&E and intangible assets including consideration of various technological and other factors.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

Various assumptions and accounting estimates are required to determine whether an impairment loss should be recognized and, if so, the value of such loss. This includes factors such as short-term and long-term forecasts of the future market price of electricity, the demand for and supply of electricity, the in-service dates of new generating stations, inflation, fuel prices, capital expenditures and station useful lives. The amount of the future net cash flow that OPG expects to receive from its fixed assets could differ materially from the net book values recorded in OPG's consolidated financial statements.

The carrying value of investments accounted for under the equity method are reviewed for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

<u>Decommissioning Fund</u>

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal, long-term L&ILW management, and a portion of used fuel storage costs after station life. Upon termination of the ONFA, the Province has a right to any excess funds in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund assets over the estimated completion costs as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial statements by recording a payable to the Province, such that the balance of the Decommissioning Fund is equal to the cost estimate of the liability based on the most recently approved ONFA Reference Plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA Reference Plan is approved with a higher estimated decommissioning liability. When the Decommissioning Fund is underfunded, the earnings on the Decommissioning Fund reflect actual fund returns based on the market value of the assets.

Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 percent plus the change in the Ontario Consumer Price Index ("CPI") for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Fund and includes it in the earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The amount due to or due from the Province represents the amount OPG would pay to or receive from the Province if the committed return were to be settled as of the balance sheet date.

As part of its regular contributions to the Used Fuel Fund, OPG was required to allocate $94 million of its 2012 contribution towards its liability associated with future fuel bundles that exceed the 2.23 million threshold (2011 – $133 million). As prescribed under the ONFA, OPG's contributions for incremental fuel bundles are not subject to the Province's guaranteed rate of return, but rather earn a return based on changes in the market value of the assets of the Used Fuel Fund.

As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the 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 these long-term liabilities and the current market value of the Used Fuel Fund and the Decommissioning 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.

The Provincial Guarantee of $1,545 million was in effect through to the end of 2012. In January 2012, OPG paid a guarantee fee of $8 million based on a Provincial Guarantee amount of $1,545 million, for the period from January 1, 2012 to December 31, 2012. In December 2012, the CNSC approved OPG's proposed 2013 - 2017 CNSC Financial Guarantee requirement. This resulted in a Provincial Guarantee amount of $1,551 million for the 2013 - 2017 period.

Pension and Other Post-Employment Benefits

The determination of OPG's pension and OPEB costs and obligations is based on accounting policies and assumptions used in calculating such amounts.

Accounting Policy

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post retirement benefits ("OPRB") including group life insurance and health care benefits, and LTD benefits. Post-employment benefit programs are also provided by the NWMO. Information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions, experience gains or losses, salary levels, inflation, and cost escalation. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Pension fund assets include equity securities and corporate and government debt securities, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The funds do not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the plan. Past service costs arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the "corridor"), is amortized over the expected average remaining service life since OPG expects to realize the associated economic benefit over that period. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes on its balance sheet the funded status of its defined benefit plans. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits that arise during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income ("OCI"), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as discussed above.

As at December 31, 2012, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $5,593 million (2011 – $4,523 million). Details of the unamortized net actuarial loss and unamortized past service costs at December 31, 2012 and 2011 are as follows:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011** *(adjusted)*
Net actuarial loss not yet subject to amortization due to use of market-related values	**91**	714	-	-	-	-
Net actuarial loss not subject to amortization due to use of the corridor	**1,367**	1,220	**30**	26	**288**	242
Net actuarial loss subject to amortization	**3,079**	1,847	**72**	51	**662**	410
Unamortized net actuarial loss	**4,537**	3,781	**102**	77	**950**	652
Unamortized past service costs	**-**	-	**-**	-	**4**	13

OPG records an offsetting regulatory asset for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery of these amounts through future regulated prices charged to customers. For the recoverable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset for the amount of the increases or decreases in OCI and for the reclassification of AOCI into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Two critical assumptions – discount rate and inflation – are important elements in the determination of benefit costs and obligations. In addition, the expected return on plan assets is a critical assumption in the determination of registered pension plan costs. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods; for LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of the AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The expected rate of return on plan assets is based on current and expected asset allocation, as well as the expected return considering long-term historical risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

The weighted average discount rate used to determine the projected pension benefit obligations as at December 31, 2012 was 4.3 percent. This represents a significant decrease, compared to the 5.1 percent discount rate that was used to determine the obligations as at December 31, 2011. The deficit for the registered pension plans increased from $2,593 million as at December 31, 2011 to $3,332 million as at December 31, 2012 largely as a result of the decrease in the discount rate.

The weighted average discount rate used to determine the projected benefit obligations for OPEB as at December 31, 2012 was 4.3 percent. This decreased significantly, compared to the 5.1 percent discount rate that was used to determine the obligations as at December 31, 2011. The projected benefit obligations increased from $2,708 million at December 31, 2011 to $3,174 million as at December 31, 2012 largely as a result of the decrease in the discount rate.

A change in assumptions, holding all other assumptions constant, would increase (decrease) 2012 costs as follows:

(millions of dollars)	**Registered Pension Plans** [1]	**Supplementary Pension Plans** [1]	**Other Post-Employment Benefits** [1]
Expected long-term rate of return			
0.25% increase	(26)	na	na
0.25% decrease	26	na	na
Discount rate			
0.25% increase	(51)	(1)	(12)
0.25% decrease	54	1	13
Inflation			
0.25% increase	91	2	-
0.25% decrease	(85)	(1)	-
Salary increases			
0.25% increase	24	4	-
0.25% decrease	(23)	(3)	-
Health care cost trend rate			
1% increase	na	na	81
1% decrease	na	na	(61)

na – change in assumption not applicable

[1] Excluding the impact of the Pension and OPEB Cost Variance Account and the US GAAP Deferral Account

Asset Retirement Obligation

As at December 31, 2012, OPG's ARO was $15,522 million (2011 – $14,392 million). OPG's ARO consists of fixed asset removal and nuclear waste management liabilities. The ARO is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating plant facilities and other facilities. The liabilities associated with decommissioning the nuclear generating stations and long-term used nuclear fuel management comprise the most significant amounts of the total obligation. Costs will be incurred for activities such as:

- Preparation for safe storage.
- Safe storage.
- Dismantling.
- Demolition and disposal of facilities and equipment.
- Remediation and restoration of sites.
- Ongoing and long-term management of nuclear used fuel and L&ILW material.

Nuclear station decommissioning consists of preparation and placement of stations into a safe state condition followed by a nominal 30-year safe store period prior to station dismantling and site restoration. Under the terms of the lease agreement with Bruce Power, OPG continues to be responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The following costs are recognized as a liability:

- The present value of the costs of decommissioning the nuclear and thermal production facilities and other facilities after the end of their useful lives.
- The present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed life of the stations.
- The present value of the variable cost portion of nuclear waste management programs taking into account actual waste volumes generated to date.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, station end of life dates, financial indicators or the technology employed may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement accuracy of the costs for these programs, which may increase or decrease over time. The estimates of the Nuclear Liabilities are reviewed on an ongoing basis as part of the overall nuclear waste management program. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount of the originally estimated undiscounted cash flows are recorded as an adjustment to the liabilities, with any resulting changes in the related asset retirement costs capitalized as part of the carrying amount of nuclear fixed assets.

For the purposes of calculating OPG's fixed asset removal and nuclear waste management liabilities, as at December 31, 2012, consistent with the current accounting end of life assumptions, nuclear and thermal plant closures are projected to occur over the next two to 41 years.

The liability for non-nuclear fixed asset removal was $345 million as at December 31, 2012 (2011 – $332 million). This liability primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. The liability is based on third party cost estimates after an in-depth review of active plant sites and an assessment of required clean-up and restoration activities. In 2011, OPG completed a review of the liability for most of its thermal generating stations. As at December 31, 2012, the estimated retirement dates of the thermal stations for the purposes of this liability are between 2014 and 2030. The undiscounted amount of estimated future cash flows associated with the non-nuclear liabilities is $491 million.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

The liability for the nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2012 was $15,177 million (2011 – $14,060 million). The undiscounted cash flows related to expenditures for OPG's nuclear fixed asset removal and nuclear waste management liabilities in 2012 dollars as at December 31, 2012 over the next five years and thereafter are as follows:

(millions of dollars)	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**
Expenditures for nuclear fixed asset removal and nuclear waste management [1]	240	270	342	473	507	31,175	33,007

[1] Most of the above expenditures are expected to be reimbursed by OPG's Nuclear Funds as established by the ONFA. The contributions required under the ONFA are not included in these undiscounted cash flows but are reflected in the table under the heading, *Contractual and Commercial Commitments*.

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 ONFA between OPG and the Province, OPG established a Used Fuel Fund and a Decommissioning Fund. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third party custodian accounts that are segregated from the rest of OPG's assets.

Environmental Liabilities

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. Environmental liabilities are recorded when it is considered likely that a liability has been incurred and the amount of the liability can be reasonably estimated at the date of the financial statements. The cost of obligations associated with current operations is provided for on an ongoing basis. Management believes it has made adequate provision in the consolidated financial statements to meet certain other environmental obligations. During 2011, a reduction of $19 million to the environmental liabilities was recognized related to the Regulated – Hydroelectric segment. As at December 31, 2012, OPG's environmental liabilities were $17 million (2011 – $19 million), the primary component of which is the land remediation program.

Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the Consolidated Balance Sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. 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. A documented assessment is made, both at the inception of a hedge 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.

Specifically for cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCI and later reclassified into net income when the underlying transaction occurs. Gains and losses on interest rate hedges are recorded as an adjustment to interest expense for the debt being hedged. Gains and losses that do not meet the effectiveness criteria are recorded in net income in the period incurred. When a derivative instrument hedge ceases to be effective as a hedge, 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 year's Consolidated Statement of Income.

Some of OPG's unregulated generation is exposed to changes in electricity prices associated with a wholesale spot market for electricity in Ontario. All derivative contracts not designated as hedges are recorded on the balance sheet as derivative assets or liabilities at fair value with changes in fair value recorded in the revenue of the Other category.

OPG utilizes emission allowances to manage emissions within the prescribed regulatory limits. Emission allowances are obtained from the Province. The historical cost of allowances is held in inventory and charged to operations at average cost as part of fuel expense, as required.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

Financial assets and liabilities, including exchange traded derivatives and other financial instruments, measured at fair value and for which quoted prices in an active market are available, are determined directly from those quoted market prices.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. This is the case for over-the-counter derivatives, which includes energy commodity derivatives, foreign exchange derivatives, and interest rate swap derivatives. 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. If the valuation technique or model is not based on observable market data, specific valuation techniques are used primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

OPG's use of financial instruments exposes the Company to various risks, including credit risk, foreign currency risk and interest rate risk. A discussion of how OPG manages these and other risks is found in the *Risk Management* section.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

Presentation of Comprehensive Income

Effective January 1, 2012, OPG adopted the amendments to Accounting Standards Codification ("ASC") Topic 220, *Comprehensive Income* ("Topic 220"). The amended standard requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. OPG continues to report the components of comprehensive income in a separate but consecutive statement.

Fair Value Measurements

Effective January 1, 2012, OPG adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures.* The amendment does not change the items measured at fair value but establishes common requirements for measuring fair value and for disclosing information about fair value measurements. The adoption did not have an impact on OPG's results of operations or financial position.

Useful Lives of Long-Lived Assets

Nuclear

OPG reviews estimated station useful lives for its generating assets on a regular basis. As part of its Pickering Continued Operations initiative, during the fourth quarter of 2012, OPG confirmed its plans for the continued operation of the Pickering stations. This confirmation resulted in a change to the useful lives for the Pickering generating stations, for the purposes of calculating depreciation, effective December 31, 2012. Consistent with the results of the Pickering Continued Operations initiative and other considerations, the useful lives, for accounting purposes, for the Bruce generating stations, were extended. These stations are currently leased to Bruce Power. Effective December 31, 2012, the changes to the estimated service lives of these generating stations have been reflected in an increase to the estimate of the Nuclear Liabilities of $451 million, which resulted in an increase in the fixed assets balance of $449 million related to the asset retirement cost and an increase in OM&A expenses of $2 million. In addition, the changes in the estimated service lives resulted in an increase in the derivative liability embedded in the Bruce lease agreement of $249 million on December 31, 2012.

The income statement impacts associated with the changes to the Nuclear Liabilities and the derivative liability are largely offset by the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB, except for the depreciation impact relating to fixed asset balances attributable to the tangible components for the Pickering generating stations.

For the fixed asset balance attributable to the tangible components, the life changes are expected to decrease depreciation expense related to existing assets for the Pickering generating stations, by $35 million in 2013 and $21 million in 2014.

Thermal

As a result of the announcement by the Ministry of Energy to advance the shutdown date of the remaining coal-fired units at the Lambton and Nanticoke generating stations, OPG has revised the end of life dates for the purposes of calculating depreciation from December 2014 to December 2013 for both generating stations. This change in estimate will increase depreciation expense in 2013 by $58 million reflecting the advancement of the 2014 expense. This increase in depreciation expense is expected to be offset by revenue from the Contingency Support Agreement with the OEFC.

Thermal Materials and Supplies Obsolescence

As a result of the revised end of life dates, OPG has revised the materials and supplies obsolescence provision for the Lambton and Nanticoke generating stations. All materials and supplies not expected to be utilized by the mandated cessation date of December 31, 2013 will be charged to obsolescence on a straight line basis during 2013. This change in estimate is expected to increase OM&A expenses by $11 million in 2013. This increase in expense in 2013 will be offset by a corresponding increase in revenue of $11 million as these costs are recoverable under the Contingency Support Agreement with the OEFC.

Thermal Asset Retirement Obligation

In September 2011, OPG completed a review of the ARO for OPG's operating thermal stations and the decommissioned R.L. Hearn generating station. As a result of the review, the ARO estimate in accordance with US GAAP increased by $171 million at September 30, 2011, primarily due to higher demolition cost estimates. The increase in the ARO resulted in the recognition of an increase in PP&E of $90 million at September 30, 2011 and other loss of $81 million during the third quarter of 2011. The other loss reflected the write-down of asset retirement costs for the Atikokan, Lennox, and Thunder Bay generating stations that were not supported by the cash flows associated with those stations.

In addition, as a result of the review, the ARO estimate in accordance with US GAAP for the R.L. Hearn generating station decreased to $18 million at September 30, 2011. The decrease in the ARO resulted in the recognition of a $3 million reduction to PP&E and other income of $15 million at September 30, 2011 for the decommissioned station.

The review of the ARO also resulted in changes to salvage value estimates for scrap metal recoveries for certain thermal stations. As a result of the ARO and salvage value estimate changes, depreciation expense for 2012 decreased by $6 million. OPG is considering the impact to the timing of the decommissioning of the thermal stations taking into account the announcement by the Province to advance the shutdown date of the Lambton and Nanticoke generating stations by the end of 2013, the placement of the units in reserve status, and the potential conversion in the future.

Recent Accounting Pronouncements

Comprehensive Income – Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

In February 2013, the Financial Accounting Standards Board issued an update to ASC Topic 220 which adds new disclosure requirements for items reclassified out of AOCI. Entities must present information about significant items reclassified out of AOCI by component either on the Consolidated Statement of Income or as a separate disclosure in the notes to the financial statements with reference to the affected line item in the Consolidated Statement of Income. OPG will apply the amendments for reporting periods beginning on or after January 1, 2013.

International Financial Reporting Standards ("IFRS")

As a result of OPG's 2011 decision to adopt US GAAP, as required by the FAA regulation, OPG's conversion to IFRS was discontinued. Prior to the adoption of US GAAP as the basis for OPG's financial reporting, the Company had planned to adopt IFRS effective January 1, 2012. OPG had substantively completed its IFRS conversion project, which included separate diagnostic, development, and implementation phases, until it suspended the project and began the evaluation of converting to US GAAP in the fourth quarter of 2011. OPG's IFRS conversion project involved, among other initiatives, a detailed assessment of the effects of IFRS on OPG's financial statements, an update of information systems to meet IFRS requirements as of January 1, 2011, an assessment of internal controls over financial reporting and disclosure controls and processes, as well as training of key finance and operational staff. If a future transition to IFRS is required, IFRS conversion work will be managed in such a way that it can effectively be restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project.

In September 2012, the International Accounting Standards Board ("IASB") decided to develop a Discussion Paper on accounting for rate regulated activities. This paper is expected to be released for comment in the second half of 2013. In addition, the IASB is expected to develop an interim standard in order to provide temporary guidance on accounting for rate-regulated activities for first-time adopters of IFRS. The IASB is targeting the completion of the exposure draft on the interim standard during the first half of 2013. OPG continues to monitor major accounting developments arising from initiatives of the international standard setter, particularly as several major projects are joint efforts with the US Financial Accounting Standards Board.

RISK MANAGEMENT

Overview

OPG faces various risks that could significantly impact the achievement of its strategic, operational, financial, environmental, and health and safety goals. The aim of risk management is to identify and mitigate these risks and preserve the value of the Shareholder's investment in OPG's assets.

Risk Governance Structure

The Risk Oversight Committee ("ROC") of the Board of Directors assists the Board to fulfill its oversight responsibilities for matters relating to identification and management of the Company's key business risks. An Executive Risk Committee, which is comprised of the business unit leaders and the Chief Risk Officer ("CRO"), assists the ROC in fulfilling its governance and oversight responsibilities related to OPG's risk management activities.

Risk Management Activities

OPG faces a wide array of risks as a result of its business operations. The Enterprise Risk Management ("ERM") framework is designed to identify and evaluate risks on the basis of their potential impact on the Company's capacity to achieve specific business plan objectives.

Risk management reporting activities are coordinated by a centralized ERM group led by the CRO. Business units identify risks that could prevent achievement of their business plan objectives. The ERM group also assesses external threats to the organization and facilitates the identification and assessment of emerging risks. OPG's senior executives identify broader strategic risks, then prioritize the operational, tactical and strategic risks to determine the top risks to the Company. 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 ERM process monitors risk management activities for identified key risks and reports significant developments in these risks quarterly to the ROC.

For the purpose of disclosure, a number of key risks are presented in five main categories, namely operational, financial, regulatory, enterprise-wide, and environmental. For each category, risks are briefly described below.

Operational Risks

Risks Associated with Existing Generating Operations

OPG is exposed to uncertain output from its existing generating stations that could adversely impact its financial performance.

Operational risks are those risks normally inherent in the operation of electricity generating facilities. These risks can lead to interruptions in the operations of generating stations or uncertainty in future production. Risks to OPG's diverse fleet of nuclear, hydroelectric, and thermal generating stations are a function of the age of the stations and the technology used.

Nuclear Generating Stations

Operating an aging nuclear fleet exposes OPG to unique risks such as unplanned outages, an increase in cost of operations and risks associated with nuclear waste management operations.

The uncertainty associated with the electricity volume generated by OPG's CANDU nuclear generating units is primarily driven by the condition of the station components and systems, which are all subject to the effects of aging. Fuel channels are expected to be the most life-limiting component affecting station end of life. Other significant factors identified to-date include degradation of primary heat transport pump motors, fuel handling performance issues, feeder pipe wall thinning, and fuel channel aging. To respond to these challenges, OPG continues to implement extensive inspection and maintenance programs to monitor performance and identify corrective actions required to operate reliably and within design parameters.

Deterioration of station components may progress in an unexpected manner, resulting in the need to increase monitoring, conduct extensive repairs, or undertake additional remedial measures. To maintain a safe operating margin, a nuclear unit could be derated. When an unexpected condition first appears, a specific monitoring program is established. The primary impact of these conditions on OPG is an increase in the long-term cost of operations. The associated mitigation may create additional outage work, thus increasing the number of outages or extending planned outages.

The process of generating electricity by nuclear generating stations produces nuclear waste. As required by the CNSC, OPG is accountable for the management of used fuel and L&ILW and decommissioning of all its nuclear facilities, including the stations on lease to Bruce Power. Currently, there is no licensed facility in Canada for the permanent disposal of nuclear used fuel or L&ILW.

To address the need for storage of L&ILW, OPG is developing a DGR for the long-term management of L&ILW from OPG-owned nuclear generating stations. Community opposition to deep geologic disposal of used fuel and L&ILW and potential community opposition to prolonged on-site used fuel storage may impede the ability of OPG, its contractors, and subcontractors to develop disposal plans acceptable to major stakeholders. Other factors impacting the residual risk around nuclear waste management operations include human performance and regulatory requirements.

The NWMO has developed a process for moving forward with Adaptive Phase Management as the long-term solution for Canada's nuclear fuel waste. In the interim, OPG is storing and managing used fuel at its nuclear generating station sites.

Pickering Continued Operations

OPG plans to continue the safe and reliable operation of Units 5 to 8 at the Pickering nuclear generating stations for approximately four to six years beyond their respective nominal end of life and then place these generating units in a safe storage stage for eventual decommissioning. Inability to achieve continued operations of these units could result in an earlier shutdown of Pickering Units 1 and 4 and lead to the advancement of station shutdown and decommissioning expenditures. Risk factors include discovery of unexpected conditions, equipment failures, and requirement for significant plant modifications. To mitigate these risks, OPG continues to undertake a number of activities which include work on fuel channel life cycle management, a regulatory strategy and economic analysis to support optimal reactor end of life dates, and modification of the operating and maintenance strategy to support Continued Operations. In the third quarter of 2012, the CNSC agreed that OPG will, through specified monitoring, the successful completion of ongoing research and development, and specified station improvements, be capable of confirming fitness-for-service of Pickering fuel channels for the duration of the proposed continued operations period to 2020.

Hydroelectric Generating Stations

OPG's hydroelectric generation is exposed to risks associated with water flows, the age of plant and equipment, and dam safety.

The extent to which OPG can operate its hydroelectric generation facilities depends upon the availability of water. Significant variances in weather or water flows, including climate change, could affect water flows. OPG manages this risk by using production forecasting models that incorporate unit efficiency characteristics, water flow conditions, and outage plans. Inputs to the models are assessed, monitored and adjusted on an ongoing basis. For the regulated hydroelectric generation, the financial impacts of variability in electricity production due to the differences between the water conditions underpinning the hydroelectric regulated prices and actual water conditions are captured by the Hydroelectric Water Conditions Variance Account authorized by the OEB. The unregulated hydroelectric generation remains fully exposed to the risk associated with uncertain water flows.

OPG's hydroelectric generating stations vary in age and the majority of the hydroelectric generating equipment is over 50 years old. The age of the equipment and civil components creates risks to reliability of some hydroelectric generating stations. OPG manages these reliability risks by performing inspection and maintenance of critical components, and conducting detailed engineering reviews and station condition assessments in order to identify future work required to sustain and, if necessary, upgrade a station.

The hydroelectric business segments operate 231 dams across the Province. Dam safety legislation does not currently exist in the Province. In August 2011, the MNR published a set of Technical Guidelines following a period of public consultation. These Technical Guidelines, which are not a regulation, represent the government standards for dam safety.

In general, OPG practices in the area of dam safety and public safety around dams exceed the minimum requirements outlined in the MNR Technical Guidelines. In addition, OPG is developing a new risk-informed approach on behalf of the MNR to prioritize the outcomes of dam safety assessments. OPG could eventually incur additional costs for certain dams that it operates, if the Dam Safety Risk Management Plan is not approved by the MNR.

OPG is required to comply with the Standards and Guidelines for Conservation of Provincial Heritage Properties which came into effect in July 2010. OPG is required to implement a heritage conservation program and certain hydroelectric generating stations and assets could be identified as heritage properties. As such, the Company may be required to incur costs to meet the requirements of the *Ontario Heritage Act*.

Thermal Generating Stations

Converting OPG's coal-fired units to run on alternate fuels will require a cost recovery mechanism.

The early closure of the Lambton and Nanticoke stations, in advance of the original December 31, 2014 deadline, will result in staff and work program reductions and reduced payments to OPG from the OEFC under the Contingency Support Agreement. After the shutdown of the units at these stations, OPG plans to place the units in reserve status and to preserve the option to convert the units to natural gas and/or biomass in the future, should they be required.

OPG's capability to convert coal-fired units to alternate fuels such as natural gas, biomass, and dual gas-biomass would depend on obtaining Shareholder approval of coal-unit conversion and achieving cost recovery agreements with the OPA. For the Lambton and Nanticoke generating stations, as a result of the announcement by the Province to advance the shutdown date by the end of 2013, OPG expects to incur costs to maintain these units in reserve status.

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.

OPG is undertaking numerous capital intensive projects that require significant investments. There may be an adverse effect on the Company if OPG is unable to: effectively manage these projects; obtain necessary approvals; borrow the necessary funds; or fully recover its capital costs in a timely manner. Major projects include the Darlington Refurbishment, possible new nuclear units at OPG's Darlington site, the Lower Mattagami River project, and other hydroelectric and thermal projects, such as the biomass conversion at the Atikokan generating station.

Darlington Refurbishment

The Darlington generating units, based on original design assumptions, are currently forecast to reach their nominal end of life between 2019 and 2021. In February 2010, OPG announced its decision to refurbish the Darlington generating station. The refurbishment of the Darlington nuclear generating station is expected to extend its operating life by approximately 30 years. Failure to achieve the objectives of the refurbishment project may result in future forced outages and more complex planned outages, potentially impacting the post-refurbishment useful life of the station. To mitigate this risk, and as part of the project front-end planning process, a component condition assessment has been performed on all critical systems within the station. This assessment has evaluated the current condition of the systems and identified required work to be performed during the refurbishment outages. Key life limiting components such as pressure tubes are included in the base refurbishment scope. Throughout 2012, various contracts have been awarded to secure specialized resources necessary to further plan and progress the project. OPG requires a mechanism to ensure recovery of its costs and to earn a return. Such a mechanism is not currently in place. OPG continues to work with its Shareholder to determine an appropriate cost recovery mechanism in connection with the project, while considering the impact to electricity consumers.

New Nuclear Units

The Government of Ontario, in its February 2011 Supply Mix Directive to the OPA, confirmed its commitment to new nuclear units at Darlington and to continue to use nuclear generation for about 50 percent of Ontario's energy supply. In the Supply Mix Directive, the Government of Ontario indicated two new nuclear units at the Darlington site would be procured provided that it can be achieved in a cost-effective manner.

In May 2012, the federal government accepted the Darlington New Nuclear Project EA and in August 2012, the Joint Review Panel, a panel of the CNSC, announced its decision to issue the Licence to Prepare Site for the Darlington New Nuclear Project. Nevertheless, legal challenges and judicial reviews could impact the project. Uncertainty with respect to the timing of a future choice of a nuclear reactor vendor also continues. The choice of a nuclear reactor vendor would allow OPG to further identify risks associated with the project.

Lower Mattagami

Construction on the Lower Mattagami River project commenced in June 2010. In December 2012, there was a breach in the recently installed cofferdam at the Kipling site. The overall impact of this event on the project schedule is currently being determined. All other cofferdams on the project have been inspected and it has been determined that they are safe. In addition, key risks to the project costs and schedule include labour productivity on concrete pours during construction, and legal challenges or blockades by groups opposed to various aspects of the project. Risk mitigation activities include hiring an experienced contractor to construct the project, installing a shelter to continue concrete operations during the winter and detailed monitoring of labour productivity.

Other Development Projects

For projects that are in initial development stages, unforeseen delays in receiving permits or approvals, which may involve various external stakeholders, could result in schedule delays or ultimately, cancellation of a project. OPG attempts to mitigate risks associated with delays in receiving permits and approvals through early involvement and regular communication with applicable government agencies, close consultation with external stakeholders, and ongoing monitoring of contractor performance relative to permits.

These projects could also be faced with increasing costs for equipment and construction that could impact their economic viability. OPG continuously monitors such trends in input costs in order to keep abreast of emerging issues. OPG seeks to manage and limit cost increases through contracting strategies, where possible.

Financial Risks

OPG is exposed to a number of discrete market-related risks that could adversely impact its financial and operating performance.

OPG is exposed to a number of financial risks, many of which arise due to OPG's exposure to volatility in commodity, equity and foreign exchange markets, and interest rate movements. Pension and OPEB costs would also be impacted by these market and interest rate movements. OPG manages this complex array of risks to reduce the uncertainty or mitigate the potential unfavourable impact on the Company's financial results.

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. A $1/MWh change in the 2013 forecast average annual spot market price of electricity would impact OPG's unregulated revenue by approximately $14 million.

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

	2013	2014	2015
Estimated generation output hedged [1]	82%	83%	81%
Estimated fuel requirements hedged [2]	66%	58%	51%
Estimated nitric oxide ("NO") emission requirement hedged [3]	100%	100%	100%
Estimated SO2 emission requirement hedged [3]	100%	100%	100%

[1] Represents the portion of megawatt-hours of: expected future generation production which is subject to regulated prices established by the OEB; agreements with the IESO, OEFC, and OPA; or other electricity contracts which are used as hedges.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and 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.

Financial Markets

The market value of investments held by OPG's Nuclear Funds and the OPG registered pension plan could be significantly affected by changes in various market factors such as equity prices, interest rates, inflation, and commodity prices.

Nuclear Funds Market Risk

The Decommissioning Fund and the Used Fuel Fund contain investment allocations to certain asset classes including fixed income securities, domestic and international equity securities, and infrastructure and Canadian real estate. These funds are managed with the objective of generating sufficient returns over time to meet the associated nuclear waste and decommissioning obligations. The rates of return earned on these segregated funds are subject to various factors including the current and future financial markets conditions, which are inherently uncertain.

For the Used Fuel Fund, the Province guarantees the annual rate of return at 3.25 percent plus the change in the Ontario CPI for the first 2.23 million fuel bundles. A change in the value of the fund, as a result of changes in capital markets related to the first 2.23 million bundles, does not impact OPG's earnings. Unlike contributions subject to the Province's rate of return guarantee, OPG assumes the market risk for investment of funds set aside for incremental bundles.

The performance of the Nuclear Funds related to stations leased to Bruce Power is subject to the Bruce Lease Net Revenues Variance Account established by the OEB. The variance account partially mitigates market risk related to the Nuclear Funds as it captures the differences between actual and forecast earnings from the Nuclear Funds as they relate to the nuclear generating stations leased to Bruce Power. Forecast earnings refer to those approved by the OEB in setting regulated nuclear prices.

Residual risk to OPG's financial results continues to exist due to volatility in the financial and commodity markets, especially risk that affects the Nuclear Funds.

Post-Employment Benefit Obligations

OPG's post-employment benefit obligations include pension, group life insurance, health care, and LTD benefits. OPG's post-employment benefit obligations and costs, and OPG's pension contributions could be materially affected in the future by numerous factors, including: changes in actuarial assumptions such as changes to discount rates; future investment returns; experience gains and losses; the current funded status of the pension and other benefit plans; changes in benefits; changes in the regulatory environment including potential changes to the *Pension*

Benefits Act (Ontario); divestitures; and the measurement uncertainty incorporated into the actuarial valuation process.

The OPG registered pension plan, which covers most employees and retirees, is a contributory defined benefit plan that is indexed to inflation. Contributions to the OPG registered pension plan are determined by actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. The most recent actuarial valuation of the OPG registered pension plan was completed as of January 1, 2011. Based on the actuarial valuation, in addition to its minimum contribution, OPG may also include voluntary contributions towards the deficit in the registered pension plan. OPG will continue to assess the requirements for contributions to the registered pension plan. The next actuarial valuation of the OPG registered plan must have an actuarial valuation date no later than January 1, 2014. OPG's OPEB obligations are not funded and the associated employee benefits are paid from cash flow provided by operating activities.

<u>Foreign Exchange and Interest Rate Markets</u>

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

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations are primarily denominated in US dollars. In addition, the market price of electricity in Ontario is influenced by the exchange rate because of the interaction between the Ontario and neighbouring US interconnected electricity markets. The Ontario electricity spot market is also influenced by US dollars denominated commodity prices such as those for coal and natural gas which are used in electricity generation. To manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at December 31, 2012, OPG had total foreign exchange contracts outstanding with a notional value of US $63 million.

The majority of OPG's existing debt is at fixed interest rates. Interest rate risk arises with the need to refinance existing debt and/or 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 December 31, 2012, OPG had total interest rate swap contracts outstanding with a notional principal of $410 million.

<u>Trading</u>

OPG's financial performance can be 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. One of the metrics used to measure the financial risk of this trading activity is known as "Value at Risk" or "VaR". VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. During 2012, the VaR utilization ranged between nil and $0.5 million, which was unchanged from the range during 2011.

<u>Credit</u>

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

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing, and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants.

Other major components of credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that appropriate collateral or other forms of security are held by OPG.

The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2012:

			Potential Exposure for Largest Counterparties	
Credit Rating [1]	Number of Counterparties [2]	Potential Exposure [3] *(millions of dollars)*	Number of Counterparties	Counterparty Exposure *(millions of dollars)*
Investment grade	22	17	4	11
Below investment grade	2	3	1	3
IESO [4]	1	378	1	378
Total	25	398	6	392

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

2 OPG's counterparties are defined on the basis of individual master agreements.

3 Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.

4 Credit exposure to the IESO peaked at $658 million during 2012 and $686 million during 2011.

Liquidity

Rising liquidity requirements can impact OPG's capital investment projects.

OPG operates in a capital intensive business. Significant financial resources are required to fund capital improvement projects. In addition, the Company has other significant disbursement requirements including investment in new generating capacity, annual funding obligations under the ONFA, pension contributions, payments towards OPEB and other benefit plans, and debt maturities with the OEFC. OPG must ensure it has the financial capacity and sufficient access to cost-effective financing sources to fund its capital requirements. A discussion of corporate liquidity is included in the *Liquidity and Capital Resources* section.

Nuclear Waste and Decommissioning Obligations and Nuclear Funds

The cost estimates of nuclear waste obligations are based on assumptions such as station end of life dates and nuclear waste volumes that are inherently uncertain and could impact OPG's contributions to the Nuclear Funds.

OPG is responsible for the management of used nuclear fuel and L&ILW, and eventual decommissioning of all of its nuclear facilities, including the stations on lease to Bruce Power, as required by the CNSC. OPG is required by various rules and regulations to provide cost estimates associated with its nuclear waste management and decommissioning obligations. These cost estimates are based on numerous underlying assumptions that are inherently uncertain, including station end of life dates and waste volumes. To address the inherent uncertainty, OPG undertakes to review the underlying assumptions and baseline cost estimates at least once every five years. Certain underlying assumptions, such as station end of life dates and forecast for nuclear waste volumes, are reviewed and updated annually, with resulting changes assessed for their impact to the liability. Changing business decisions, such as refurbishment decisions and premature unit closures, are reviewed as they occur and OPG uses the existing baseline cost information to estimate the impacts to the nuclear liability balance. Should changing circumstances be assessed as material or significant, an early re-assessment of baseline costs could be performed before the five-year period is completed.

OPG's contributions to the Nuclear Funds are determined by ONFA reference plans, which are required to be updated at least every five years. The changes in contribution levels are determined based upon changes in the values of the Nuclear Funds as well as associated nuclear waste and decommissioning obligations. For the purposes of ONFA reference plan updates, the value of the Nuclear Funds is measured at a point in time. At such times, decreased values of the Nuclear Funds or increases in nuclear decommissioning and waste obligations could increase OPG's required contributions under the ONFA.

During 2012, OPG recorded an update to the nuclear decommissioning and waste management liability, which is described under the heading, *Critical Accounting Policies and Estimates*.

Regulatory and Legislative Risks

OPG is subject to extensive federal and provincial legislation and regulations that have an impact on OPG's operations and financial position.

OPG is subject to regulation by various entities including the OEB and the CNSC. The risks that arise from being a regulated entity include: the potential inability to receive full recovery of capital and operating costs; reductions in earnings; and increases in operating costs. These unfavourable impacts are mitigated by maintaining close contact with regulators and issuers of standards and codes to ensure early identification and discussion of issues.

Rate Regulation

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

The prices for electricity generated from the Prescribed Facilities are determined by the OEB, currently on a forecast cost of service methodology. As with any regulated price established using this 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 may not allow the regulated operations to earn the allowed rate of return.

In September 2012, OPG filed an application with the OEB requesting approval to recover balances in the authorized variance and deferral accounts as at December 31, 2012 and approval for an extension of the Pension and OPEB Cost Variance Account. OPG is in continuing settlement discussions with the intervenors regarding all aspects of the rate application. If an agreement is reached, a settlement agreement will be filed with the OEB and will be subject to approval by the OEB. OPG's financial position could be significantly affected should the OEB disallow the recovery of variance and deferral account balances and/or not approve the extension of the Pension and OPEB Cost Variance Account. This application is discussed under the heading, *Recent Developments*.

In April 2011, OPG filed a notice of appeal with the Divisional Court of Ontario (the "Court") related to the part of the OEB's March 2011 decision disallowing recovery of a portion of OPG's nuclear compensation costs in regulated prices effective March 1, 2011. In February 2012, the Court dismissed the appeal by a 2 to 1 majority. OPG was granted leave to file an appeal of the Court's decision to the Court of Appeal for Ontario. Accordingly, the Company filed an appeal, which was heard in January 2013. OPG is currently awaiting the court's decision on the matter.

Legislative Risks

OPG is subject to extensive federal and provincial legislation and regulations that have an impact on OPG's operations and financial position.

During the second quarter of 2012, legislation associated with the Ontario Provincial budget included measures that affect OPG, such as public sector pension reform, and compensation restraints for executives until Ontario ceases to have a budget deficit. These changes may adversely affect OPG's ability to retain or attract qualified employees, including those at the executive level, and as a result may affect OPG's operations.

In October 2012, the Premier of Ontario resigned, and the Legislative Assembly of Ontario (the "Legislature") was prorogued. As such, proposed legislation which may have significant implication to OPG was terminated and may be re-introduced.

The Legislature resumed in February 2013 and OPG continues to monitor future changes to legislation.

Nuclear Regulatory Requirements

An aging nuclear fleet or changes in technical codes or laws may increase the risk of additional nuclear regulatory requirements.

The uncertainty associated with nuclear regulatory requirements is primarily driven by plant aging, technology risks, and changes to technical codes. Addressing these requirements could add to the cost of operations, and in some instances, may result in a reduction or elimination of the productive capacity of a station, or in an earlier than planned replacement of a station component. Unlike most other industries, the operations of nuclear stations are often directly impacted by circumstances or events that occur at other nuclear stations across the globe. These circumstances or events may lead to CNSC regulatory changes with a significant impact on the cost and future operation of OPG's nuclear fleet.

Enterprise-Wide Risks

OPG's business prospects could be adversely affected by various enterprise-wide risks such as electricity demand and supply, human resources, health and safety, and corporate reputation. Significant risks that could have a potential enterprise-wide impact on OPG's business, reputation, financial condition, operating results and prospects are discussed below.

Ontario Electricity Market

Ontario electricity market conditions could impact OPG's revenue and operations.

During 2012, various market factors resulted in low HOEP prices in Ontario. Going forward, Ontario electricity spot market prices are expected to remain low, which will negatively impact revenue from OPG's unregulated generation.

Lower primary demand combined with increased baseload and non-dispatchable generating sources may result in occurrences of SBG conditions. To manage SBG conditions, the IESO may require OPG to spill water from hydroelectric generating units and/or reduce generation output of nuclear units. Going forward, SBG conditions could increase in frequency and magnitude due to factors such as stagnant Ontario electricity demand, return to service of the refurbished units at the Bruce nuclear generating stations, and the ongoing addition of renewable energy sources to the IESO controlled grid.

The OEB has authorized the Hydroelectric SBG Variance Account, effective March 1, 2011, which may mitigate the financial impact of regulated hydroelectric spill due to SBG conditions. There is no similar mechanism for the recovery of losses due to SBG conditions affecting OPG's unregulated hydroelectric stations or nuclear generating stations.

The structure of the Ontario electricity market is subject to regulation and market rules, changes to which may affect OPG's revenue and impact operations.

People and Culture

OPG's financial position could be affected if skilled human resources are not available or aligned with its operations.

The risk associated with the alignment and/or availability of skilled and experienced resources continues to exist for OPG in specific areas, including leadership and project management positions. In addition, OPG's business transformation process is expected to result in the reduction of approximately 2,000 employees from ongoing operations for the period January 1, 2011 to December 31, 2015. These reductions will be spread out across the Company, with an emphasis on support functions.

There is also a risk of a mismatch between attrition levels and the specific human resources requirements of OPG's declining scale of operations. To mitigate the impact of this risk, OPG has embarked upon an organization-wide workforce planning effort and has established ongoing monitoring processes to re-assess risks, issues and opportunities related to staffing on a regular basis. OPG also continues to focus on succession planning, leadership development, and knowledge retention programs to improve the capability of its workforce. OPG expects to meet the human resource needs of the business by accommodating attrition through realigning work and streamlining processes.

As of December 31, 2012, approximately 89 percent of OPG's regular labour force was represented by a union. In addition to the regular workforce, construction work is performed through 22 craft unions with established bargaining rights on OPG facilities.

Health and Safety

OPG's safety management and risk control program is designed to effectively manage safety risks in high risk areas.

OPG's operations expose employees and contractors to various occupational safety risks and hazards. The Company is committed to achieving its goal of zero injuries and continuous improvement through maintenance of formal safety management systems at the corporate and site levels. These systems serve to focus OPG on proactively managing safety risks.

Corporate Reputation

OPG is exposed to reputational risk associated with changes in the opinion of various stakeholders regarding its public profile. OPG undertakes various assurance and risk management activities to manage risks to its corporate reputation.

As a provider of a large portion of the Province's electricity requirements, maintaining a positive corporate reputation is critical for OPG. OPG focuses on building and maintaining its reputation through many practices, including corporate citizenship initiatives across the Province, appropriate and transparent governance practices, and effective communication with stakeholders. In addition, OPG undertakes continuous improvement initiatives in various assurance and risk management activities.

Transmission and Interconnection Systems

OPG could face transmission constraints, which could impact its operations and ability to supply electricity to the Ontario and interconnected electricity markets.

OPG depends on the capacity and reliability of the transmission and interconnection systems that connect its generators with customers in Ontario and interconnected markets. In Ontario, the capacity of such transmission systems is limited under certain conditions and the OEB's approval is required for system expansion.

OPG may also face transmission constraints in interconnected markets. The capacity and operating reliability of such interconnection, transmission, and distribution systems are factors beyond OPG's control. Any capacity limitations, restrictions on access, or reductions in operating reliability could affect the supply of electricity by OPG to customers in Ontario and interconnected markets. This could result in a significant loss in generation revenues and increased costs.

Ownership by the Province

OPG's commitment to maximize the return on the Shareholder's investment in OPG's assets may compete with the obligation of the Shareholder to respond to a broad range of matters.

The Province owns all of OPG's issued and outstanding common shares. Accordingly, the Province determines the composition of the OPG's Board of Directors and can directly influence major decisions including those related to project development, timing and strategy of the applications for regulated prices, asset divestitures, financing, and capital structure. OPG could be subject to Shareholder directions that require OPG to undertake activities that result in increased expenditures, or that reduce revenues or earnings, relative to the business activities or strategies that would have otherwise been undertaken. In addition, OPG's corporate interests and the wider interests of the Province may compete as a result of the obligation of the Province to respond to a broad range of matters affecting OPG's business environment.

Information Technology

OPG's ability to operate effectively is in part dependent on effectively managing its Information Technology ("IT") requirements. IT system failures may have an adverse impact on OPG.

OPG's ability to operate effectively is in part dependent upon developing or subcontracting and managing a complex IT systems infrastructure. Failure to meet IT requirements could result in future system failures, or an inability to align IT systems. In addition, OPG could be exposed to operational risks in the event of IT security breaches. To mitigate these risks, OPG closely monitors its IT systems and service requirements.

Suppliers

Non-performance by strategic suppliers or an inability to diversify the supplier base could adversely impact the financial results and reputation of OPG.

OPG's ability to operate effectively is in part dependent upon access to equipment, materials, and service suppliers. Loss of key equipment, materials, and service suppliers, particularly for the nuclear business, could affect OPG's ability to operate effectively. OPG mitigates this risk to the extent possible through effective contract negotiations, contract language, vendor monitoring, and diversification of its supplier base.

Interconnected Electricity Markets

OPG may not be able to compete successfully in interconnected markets due to various market and regulatory factors.

OPG's ability to compete in interconnected electricity markets depends upon many external factors, including: the cost to transmit electricity to these markets; the price of electricity in these markets; the competitive actions of other generators and power marketers; the state of deregulation in Ontario and the interconnected markets; currency exchange rates; new trade limitations; OPG retaining a Federal Energy Regulatory Commission licence; and costs to comply with environmental standards imposed in these markets. There can be no assurance that OPG will continue to compete successfully in interconnected markets.

Leases and Partnerships

OPG's financial performance could be affected if the risks associated with its leases and partnerships materialize.

OPG has leased its Bruce nuclear generating stations to Bruce Power and is a party to a number of partnerships related to the ownership and operation of generating stations. Each of these generating stations is subject to numerous operational, financial, regulatory, and environmental risk factors.

In addition, under the Bruce Lease, lease revenue is reduced in each calendar year where the Average HOEP falls below $30/MWh and certain other conditions are met. The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative. Derivatives are measured at fair value and changes in fair value are recognized in the Consolidated Statements of Income.

As a result of an expected decrease in future annual Average HOEP and the extension of the useful lives of the Bruce nuclear generating stations, the fair value of the derivative liability increased to $392 million at December 31, 2012, compared to $186 million at December 31, 2011. The exposure will continue until the Bruce units that are subject to this mechanism are no longer in operation, specific units are refurbished, or when the lease agreement is terminated. This exposure is mitigated as part of the OEB regulatory process, since the revenue from the lease of the Bruce generating stations is included in the determination of nuclear regulated prices and is subject to the Bruce Lease Net Revenues Variance Account.

Natural or Unexpected Events

OPG's operational continuity and the safety of its various stakeholders are exposed to the potential effects of unpredictable incidents and developments such as natural disasters and accidents.

OPG is exposed to incidents, hazards or developments, such as natural disasters or an influenza pandemic, that could threaten the safety of various stakeholders and/or the continuity of OPG's business operations. OPG may be exposed to a significant event against which it is not fully insured or indemnified, or to a party that fails to meet its indemnification obligations.

OPG's Emergency Management program is designed to ensure operational continuity and to respond to incidents or developments that could threaten the safety of stakeholders. The program goals are to protect the health and safety of employees, the public and responders, the environment, and OPG's assets and reputation. The program elements are designed to meet legal and regulatory requirements.

First Nations and Métis Communities

The outcome of negotiations with the First Nations and Métis communities in Ontario depends on many factors such as legislation and precedents created by court rulings.

OPG may be subject to claims by First Nations and Métis communities, and other Aboriginal groups and individuals stemming from generation development, the historic operations of Ontario Hydro that related to First Nations and Métis title or rights, or the absence of permits, rights-of-way, easements, or similar rights in respect of lands held for First Nation bands or bodies under the *Indian Act* (Canada) and similar past grievances.

OPG has a First Nations and Métis Relations Policy, which sets out its commitment to build and maintain positive relationships with the First Nations and Métis communities. OPG has been successful in resolving some past grievances. However, the outcome of the ongoing and future negotiations with the First Nations and Métis communities depends on a number of factors, including legislation and regulations, which are subject to change over time. Precedents created by court rulings also impact negotiations and resolution of past grievances.

Environmental Risks

OPG may be subject to fines, penalties, and claims, if it is not in compliance with the applicable environmental laws. Changes in environmental regulations can result in existing operations being in a state of non-compliance, a potential inability to comply, potential liabilities, and costs for OPG.

Changes to environmental laws could create compliance risks and result in potential liabilities that may be addressed by the installation of control technologies, the purchase of emission reduction credits, allowances or offsets, or by constraining electricity production. Further, some of OPG's activities have the potential to impair natural habitat, damage aquatic or terrestrial plant and wildlife, or cause contamination to land or water that may require remediation.

In addition, a failure to comply with applicable environmental laws may result in enforcement actions, including the potential for orders or charges.

The Province plans to develop a GHG emission reduction plan over 2013. Therefore, there is a risk of incurring material costs to purchase allowances or offsets against GHG emissions from coal, oil, and natural gas generation. For further details on OPG's environmental performance and policies refer to the *Core Business and Strategy* section.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province, Infrastructure Ontario, OPA and the other successor entities of Ontario Hydro, including Hydro One Inc. ("Hydro One"), the IESO, and the OEFC, and jointly controlled entities. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

These transactions are summarized below:

(millions of dollars)	Revenue 2012	Expenses 2012	Revenue 2011	Expenses 2011
Hydro One				
Electricity sales	**10**	**-**	16	-
Services	**-**	**14**	-	13
Province of Ontario				
Gross revenue charge, water rentals and land tax	**-**	**118**	-	122
Guarantee fee	**-**	**8**	-	8
Used Fuel Fund rate of return guarantee	**-**	**282**	266	-
Decommissioning Fund excess funding	**-**	**64**	-	-
Pension benefits guarantee fund	**-**	**2**	-	-
OEFC				
Gross revenue charge and proxy property tax	**-**	**201**	-	217
Interest expense on long-term notes	**-**	**189**	-	196
Capital tax	**-**	**(3)**	-	(10)
Income taxes, net of investment tax credits	**-**	**77**	-	(12)
Contingency support agreement	**283**	**-**	367	-
Infrastructure Ontario				
Reimbursement of expenses incurred during the procurement process for new nuclear units	**-**	**(1)**	-	(2)
IESO				
Electricity sales	**3,823**	**34**	3,956	43
Ancillary services	**56**	**-**	55	-
OPA	**92**	**-**	98	-
	4,264	**985**	4,758	575

As at December 31, 2012, receivables from related parties included $3 million (2011 – $3 million) due from Hydro One, $337 million (2011 – $333 million) due from the IESO, $84 million (2011 – $74 million) due from the OEFC, $16 million (2011 – $16 million) due from the OPA, and $2 million (2011 – nil) due from PEC. Accounts payable and accrued charges at December 31, 2012 included $2 million (2011 – $7 million) due to Hydro One, $51 million (2011 –

$53 million) due to the OEFC, $3 million (2011 – $3 million) due to the Province, and nil (2011 – $1 million) due to Infrastructure Ontario.

CORPORATE GOVERNANCE AND AUDIT AND FINANCE COMMITTEE INFORMATION

Disclosures related to Corporate Governance and Audit and Finance Committee Information are included in OPG's 2012 Annual Information Form ("AIF").

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and Chief Executive Officer ("President and CEO") and the Chief Financial Officer ("CFO"), are responsible for maintaining Disclosure Controls and Procedures ("DC&P") and Internal Controls over Financial Reporting ("ICOFR"). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

An evaluation of the effectiveness of design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2012. Management, including the President and CEO and the CFO, concluded that, as of December 31, 2012, OPG's DC&P and ICOFR (as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings, of the Canadian Securities Administrators*) were effective.

There were no material changes in OPG's ICOFR for the most recent interim period that have materially affected or are reasonably likely to materially affect OPG's ICOFR.

FOURTH QUARTER

Discussion of Results

(millions of dollars) (unaudited)	Three Months Ended December 31 2012	2011 *(adjusted)*
Regulated generation sales	**821**	837
Spot market sales, net of hedging instruments	**106**	94
Variance accounts	**272**	28
Other	**(4)**	269
Revenue	**1,195**	1,228
Fuel expense	**199**	188
Gross margin	**996**	1,040
Operations, maintenance and administration	**734**	755
Depreciation and amortization	**169**	183
Accretion on fixed asset removal and nuclear waste management liabilities	**181**	178
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(170)**	(223)
Restructuring	**-**	2
Property and capital taxes	**7**	13
Income before other income, interest, and income taxes	**75**	132
Other income	**-**	(32)
Income before interest and income taxes	**75**	164
Net interest expense	**28**	41
Income before income taxes	**47**	123
Income tax expense (recovery)	**16**	(107)
Net income	**31**	230

Revenue

Revenue was $1,195 million for the three months ended December 31, 2012, compared to $1,228 million during the same period in 2011. The decrease of $33 million was primarily due to lower revenue from the Contingency Support Agreement and lower generation from the Regulated – Hydroelectric segment, net of the impact of regulatory variance accounts, during the fourth quarter of 2012.

In addition, OPG recognized a $257 million reduction in revenue in the fourth quarter of 2012 related to the Bruce Lease. This reduction was due to a change in the value of the derivative embedded in the Bruce Lease resulting from an extension of the useful lives of the Bruce nuclear generating stations and a decrease in the Average HOEP. The decrease in other revenue was offset by the increase in a regulatory asset for the Bruce Lease Net Revenues Variance Account.

Fuel Expense

Fuel expense was $199 million for the three months ended December 31, 2012, compared to $188 million during the same period in 2011. The increase of $11 million was primarily due to higher thermal generation during the fourth quarter of 2012.

Operations, Maintenance and Administration

OM&A expenses for the three months ended December 31, 2012 were $734 million, compared to $755 million for the same quarter in 2011. The decrease of $21 million was primarily due to lower thermal expenditures as a result of staff and work program reductions, and the unit closures at the Nanticoke generating station in 2011.

Nuclear Funds Earnings

Earnings from the Nuclear Funds for the three months ended December 31, 2012 were $170 million, compared to $223 million for the same quarter in 2011. The decrease of $53 million mainly resulted from lower fixed income returns for the Decommissioning Fund and an adjustment to recognize the overfunded status of the Decommissioning Fund, net of the impact of the Bruce Lease Net Revenues Variance Account.

Other income

Other income decreased by $32 million during the fourth quarter of 2012, compared to the same period in 2011. This reduction was primarily due to the gain recognized in 2011 as a result of a reduction in an environmental provision.

Income Taxes

Income tax expense for the fourth quarter of 2012 was $16 million, compared to income tax recovery of $107 million for 2011. The increase in income tax expense was primarily due to a reduction in income tax liabilities in 2011 related to the resolution of a number of tax uncertainties for certain prior years, and the recognition in 2011 of investment tax credits for eligible scientific research and experimental development expenditures related to prior years.

Average Sales Prices and Average Revenue

The average sales prices and average revenue for the fourth quarter of 2012 and 2011 were as follows:

(¢/kWh)	**Three Months Ended December 31** **2012**	**2011**
Weighted average HOEP	**2.5**	2.8
Regulated – Nuclear Generation	**5.6**	5.5
Regulated – Hydroelectric	**3.5**	3.4
Unregulated – Hydroelectric	**2.6**	2.9
Unregulated – Thermal	**2.2**	2.3
Average revenue for all electricity generators, excluding OPG [1]	**8.4**	8.6
Average revenue for OPG [2]	**5.2**	5.4

[1] Revenues for other electricity generators are computed as the sum of hourly Ontario demand multiplied by the HOEP, plus total global adjustment payments, plus the sum of hourly net exports multiplied by the HOEP, less OPG's generation revenue.

[2] Average revenue for OPG is comprised of regulated revenues, market based revenues, and other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton and Lennox generating stations, and revenue from Hydroelectric ESAs.

The decrease in OPG's average sales prices for OPG's unregulated segments for the three months ended December 31, 2012, compared to the same quarter in 2011. This decrease was primarily due to the impact of lower Ontario electricity spot market prices.

Electricity Generation

OPG's electricity generation for the three months ended December 31, 2012 and 2011 was as follows:

(TWh)	Three Months Ended December 31 2012	2011
Regulated – Nuclear Generation	**12.0**	12.0
Regulated – Hydroelectric	**4.4**	5.0
Unregulated – Hydroelectric	**3.2**	2.8
Unregulated – Thermal	**1.0**	0.6
Total electricity generation	**20.6**	20.4

Total electricity sales volume for the three months ended December 31, 2012 was 20.6 TWh, compared to 20.4 TWh during the same period in 2011. The increase was due to higher electricity generation from OPG's unregulated hydroelectric and thermal generating stations, partially offset by lower generation from OPG's regulated hydroelectric generating stations.

During the fourth quarter of 2012 and 2011, the primary electricity demand in Ontario was 34.8 TWh and 34.3 TWh, respectively.

Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2012 was $154 million, compared to $196 million for the same period in 2011. The decrease in cash flow was primarily due to lower cash receipts resulting from a reduction in revenues from isotope sales.

Cash flow used in investing activities during the three months ended December 31, 2012 was $415 million, compared to $334 million during the same period in 2011. The increase in cash flow used in investing activities was primarily due to higher capital expenditures for the Darlington Refurbishment project and the Lower Mattagami River project, partially offset by lower capital expenditures for the Niagara Tunnel project.

Cash flow provided by financing activities during the three months ended December 31, 2012 was $83 million, compared to cash flow used in financing activities of $35 million for the same period in 2011. The increase in cash flow was primarily due to the issuance of long-term debt for the Lower Mattagami River project during the fourth quarter of 2012.

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 US GAAP for quarters beginning on or after OPG's US GAAP transition date of January 1, 2011 and in accordance with Canadian GAAP for preceding quarters.

(millions of dollars) (unaudited)	2012 Quarters Ended December 31	September 30	June 30	March 31	Total
Revenue	**1,195**	**1,213**	**1,125**	**1,199**	**4,732**
Net income	**31**	**139**	**43**	**154**	**367**
Net income per share *(dollars)*	**$0.12**	**$0.54**	**$0.17**	**$0.60**	**$1.43**

(millions of dollars) (unaudited)	December 31 (adjusted)	September 30 (adjusted)	June 30 (adjusted)	March 31 (adjusted)	Total (adjusted)
	2011 Quarters Ended				
Revenue	1,228	1,250	1,202	1,284	4,964
Net income (loss)	230	(154)	109	153	338
Net income (loss) per share *(dollars)*	$0.90	$(0.61)	$0.43	$0.60	$1.32

(millions of dollars) (unaudited)	December 31 (Canadian GAAP unadjusted)	September 30 (Canadian GAAP unadjusted)	June 30 (Canadian GAAP unadjusted)	March 31 (Canadian GAAP unadjusted)	Total (Canadian GAAP unadjusted)
	2010 Quarters Ended				
Revenue, after revenue limit rebate	1,323	1,391	1,210	1,443	5,367
Net income (loss)	202	333	(29)	143	649
Net income (loss) per share *(dollars)*	$0.79	$1.29	$(0.11)	$0.56	$2.53

Balance Sheet as at December 31

(millions of dollars)	**2012**	**2011** *(adjusted)*	**2010** *(Canadian GAAP unadjusted)*
Total assets	**37,601**	34,443	29,577
Total long-term liabilities	**28,789**	25,387	20,178
Common shares outstanding *(millions)*	**256.3**	256.3	256.3

OPG's quarterly results are affected by changes in demand primarily resulting from variations in seasonal weather conditions. Historically, OPG's revenues are higher in the first quarter of a fiscal year as a result of winter heating demands, and in the third quarter due to air conditioning and cooling demands.

Additional items which affected net income (loss) in certain quarters above are described below:

- A decrease in income of $25 million during the first quarter of 2010 resulted from the recognition of severance costs related to the decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations.
- An increase in income of $102 million during the second quarter of 2010 resulted from the decrease in income tax expense, mainly due to a reduction in income tax liabilities after the resolution of a number of tax uncertainties related to the completion of a tax audit for prior years.
- An increase in income during the third quarter of 2010 was primarily due to an increase in average sales prices for generation from the unregulated generating segments and higher earnings from the Nuclear Funds, partially offset by lower nuclear and hydroelectric generation and higher OM&A expenses.
- An increase in income during the fourth quarter of 2010 was mainly due to an increase in earnings from the Nuclear Funds of $144 million, partially offset by the reduction to the Bruce Lease Net Revenues Variance Account regulatory asset of $71 million.
- An increase in pension and OPEB costs in 2011 largely as a result of lower discount rates in 2011.
- A decrease in revenue during the first quarter of 2011 primarily due to lower revenue recognized related to the energy supply contract for the Lennox generating station and a decrease in thermal generation revenue, partially offset by higher revenue related to a Contingency Support Agreement established with the OEFC for the Nanticoke and Lambton coal-fired generating stations and higher nuclear generation revenue.
- A decrease in gross margin during 2011 primarily as a result of the cessation of additions to the Tax Loss Variance Account based on the OEB's March 2011 decision.

- In its June 2011 decision, the OEB established the Pension and OPEB Cost Variance Account effective March 1, 2011. As a result, during the second quarter of 2011, OPG recorded a regulatory asset of $41 million related to this variance account. This resulted in reductions to OM&A expenses and income tax expense of $30 million and $11 million, respectively.
- During the third quarter of 2011, OPG recognized $19 million of restructuring charges. These charges were due to severance costs related to the closure of the two coal-fired generating units at the Nanticoke generating station on December 31, 2011.
- During the third quarter of 2011, OPG completed a review of the ARO for most of its thermal stations. This resulted in a loss of $81 million being recognized in accordance with US GAAP in the Thermal business segment, and income of $15 million in the Other category.
- A decrease in revenue during the fourth quarter of 2011 primarily due to lower generation from the unregulated hydroelectric and nuclear segments, and lower sales prices.
- An increase in income in 2011 related to the resolution of a number of tax uncertainties for certain prior years, and the recognition in 2011 of investment tax credits for eligible scientific research and experimental development expenditures related to prior years.
- A decrease in gross margin during the first quarter of 2012 primarily due to lower unregulated hydroelectric generation revenue as a result of lower electricity sales prices and lower generation, and lower revenue from the Contingency Support Agreement, mainly due to the closure of Units 1 and 2 at the Nanticoke generating station for the Unregulated – Thermal segment.
- Lower OM&A expenses for the first quarter of 2012 related to the impact of the recognition of a regulatory asset related to the US GAAP Deferral Account authorized by the OEB during the first quarter of 2012.
- A decrease in gross margin during the second quarter of 2012 primarily due to lower electricity sales prices and lower unregulated hydroelectric generation revenue.
- Decrease in depreciation expense during the second quarter of 2012 mainly due to the recognition of the regulatory asset for the NLDA as a result of the 2012 ONFA Reference Plan approval in June 2012.
- Higher earnings during the third quarter of 2012 from the Nuclear Funds.

Additional information about OPG, including its Annual Information Form, and audited consolidated financial statements as at and for the year ended December 31, 2012 and notes thereto can be found on SEDAR at www.sedar.com.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income in accordance with US GAAP, OPG's MD&A, audited consolidated financial statements as at and for the year ended December 30, 2012 and 2011, and the notes thereto, present certain non-GAAP financial measures. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP. Therefore, they may not be comparable to similar measures presented by other issuers.

OPG utilizes these non-GAAP measures in making operating decisions and assessing its performance. Readers of the MD&A, consolidated financial statements and the notes thereto utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present a measure consistent with the corporate strategy to operate on a financially sustainable basis. These non-GAAP financial measures have not been presented as an alternative to net income in accordance with US GAAP, but as an indicator of operating performance. The definitions of the non-GAAP financial measures are as follows:

(1) **ROE** is defined as net income divided by average shareholder's equity excluding AOCI, for the period. ROE is measured over a 12-month period and is calculated as follows:

(millions of dollars – except where noted)	**December 31 2012**	**December 31 2011** *(adjusted)*
ROE		
Net income	**367**	338
Divided by: Average shareholder's equity excluding AOCI	**8,700**	8,354
ROE *(percent)*	**4.2**	4.0

(2) **FFO Interest Coverage** is defined as FFO before interest divided by Adjusted Interest Expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted Interest Expense includes net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest applied to regulatory assets and liabilities, and interest on pension and OPEB projected benefit obligations less expected return on plan assets for the period.

FFO Interest Coverage is measured over a 12-month period and is calculated as follows:

(millions of dollars – except where noted)	**December 31 2012**	**December 31 2011** *(adjusted)*
FFO before interest		
Cash flow provided by operating activities	**876**	1,179
Add: Interest paid	**246**	238
Less: Interest capitalized to fixed and intangible assets	**(126)**	(86)
Add: Changes to non-cash working capital balances	**(172)**	(166)
FFO before interest	**824**	1,165
Adjusted Interest Expense		
Net interest expense	**117**	154
Add: Interest income	**7**	9
Add: Interest capitalized to fixed and intangible assets	**126**	86
Add: Interest applied to regulatory assets and liabilities	**12**	9
Add: Interest on pension and OPEB projected benefit obligations less expected return on plan assets	**103**	120
Adjusted Interest Expense	**365**	378
FFO Interest Coverage *(times)*	**2.3**	3.1

(3) **Gross margin** is defined as revenue less fuel expense.

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

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www.sedar.com

ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2012

STATEMENT OF MANAGEMENT'S RESPONSIBILITY **FOR FINANCIAL INFORMATION**

Ontario Power Generation Inc.'s ("OPG") management is responsible for the presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis ("MD&A").

The consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles ("US GAAP") and the rules and regulations of the United States Securities and Exchange Commission for annual financial statements, as required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), effective January 1, 2012. The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of financial information, we maintain and rely on a comprehensive system of internal controls and internal audit, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes: written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and accounting policies, which we regularly update. This structure ensures appropriate internal control over transactions, assets and records. We also regularly audit internal controls. These controls and audits are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), is responsible for maintaining disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICOFR"). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

An evaluation of the effectiveness of design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2012. Accordingly, we, as OPG's President and CEO and CFO, will certify OPG's annual disclosure documents filed with the OSC, which includes attesting to the design and effectiveness of OPG's DC&P and ICOFR.

The Board of Directors, based on recommendations from its Audit and Finance Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major risk areas, and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Independent Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Finance Committee, had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

Tom Mitchell (signed)
President and Chief Executive Officer

Donn W. J. Hanbidge (signed)
Chief Financial Officer

March 7, 2013

INDEPENDENT
AUDITORS' REPORT

To the Shareholder of Ontario Power Generation Inc.

We have audited the accompanying consolidated financial statements of Ontario Power Generation Inc., which comprise the consolidated balance sheets as at December 31, 2012 and 2011, and the consolidated statements of income, cash flows, changes in shareholder's equity and comprehensive income for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2012 and 2011 and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Toronto, Canada

March 7, 2013

Ernst & Young LLP (signed)

Chartered Accountants,
Licensed Public Accountants

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars except where noted)*	2012	2011 *(as adjusted – Note 22)*
Revenue *(Note 15)*	**4,732**	4,964
Fuel expense *(Note 15)*	**755**	754
Gross margin *(Note 15)*	**3,977**	4,210
Expenses *(Note 15)*		
Operations, maintenance and administration	**2,648**	2,781
Depreciation and amortization *(Note 4)*	**664**	694
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**725**	704
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(651)**	(509)
Property and capital taxes	**47**	50
Restructuring *(Note 21)*	**3**	21
	3,436	3,741
Income before other income, interest and income taxes	**541**	469
Other (income) loss *(Notes 15 and 18)*	**(10)**	4
Income before interest and income taxes	**551**	465
Net interest expense *(Note 7)*	**117**	154
Income before income taxes	**434**	311
Income tax expense (recovery) *(Note 9)*	**67**	(27)
Net income	**367**	338
Basic and diluted income per common share *(dollars)*	**1.43**	1.32
Common shares outstanding *(millions)*	**256.3**	256.3

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	**2012**	**2011** *(as adjusted – Note 22)*
Net income	**367**	338
Other comprehensive loss, net of income taxes		
Net loss on derivatives designated as cash flow hedges [1]	**(11)**	(100)
Reclassification to income of losses on derivatives designated as cash flow hedges [2]	**18**	6
Reclassification to income of amounts related to pension and other post-employment benefits [3]	**27**	17
Actuarial loss and past service costs on re-measurement of liabilities for pension and other post-employment benefits [4]	**(123)**	(246)
Other comprehensive loss for the year	**(89)**	(323)
Comprehensive income	**278**	15

1 Net of income tax recoveries of $1 million and $20 million for 2012 and 2011, respectively.
2 Net of income tax expenses of $1 million for 2012 and 2011.
3 Net of income tax expenses of $8 million and $5 million for 2012 and 2011, respectively.
4 Net of income tax recoveries of $41 million and $82 million for 2012 and 2011, respectively.

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	2012	2011 *(as adjusted – Note 22)*
Operating activities		
Net income	**367**	338
Adjust for non-cash items:		
Depreciation and amortization *(Note 4)*	**664**	694
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**725**	704
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(651)**	(509)
Pension and other post-employment benefit costs *(Note 10)*	**406**	456
Deferred income taxes and other accrued charges	**51**	(70)
Provision for other liabilities	**4**	(16)
Provision for restructuring *(Note 21)*	**-**	21
Mark-to-market on derivative instruments	**206**	24
Provision for used nuclear fuel and low and intermediate level waste	**103**	55
Regulatory assets and liabilities *(Note 5)*	**(418)**	(58)
Provision for materials and inventory	**42**	18
Other	**2**	33
	1,501	1,690
Contributions to nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(182)**	(250)
Expenditures on fixed asset removal and nuclear waste management *(Note 8)*	**(198)**	(172)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management *(Note 8)*	**70**	59
Contributions to pension funds and expenditures on other post employment benefits and supplementary pension plans *(Note 10)*	**(474)**	(390)
Expenditures on restructuring *(Note 21)*	**(20)**	(13)
Net changes to other long-term assets and liabilities	**7**	89
Net changes to non-cash working capital balances *(Note 16)*	**172**	166
Cash flow provided by operating activities	**876**	1,179
Investing activities		
Net proceeds from sale of long-term investments	**24**	-
Net proceeds from sale of property, plant and equipment	**-**	7
Investment in property, plant and equipment and intangible assets *(Notes 4 and 15)*	**(1,427)**	(1,145)
Cash flow used in investing activities	**(1,403)**	(1,138)
Financing activities		
Issuance of long-term debt *(Note 6)*	**775**	1,056
Repayment of long-term debt *(Note 6)*	**(405)**	(377)
Net decrease in short-term debt *(Note 7)*	**(60)**	(345)
Distribution to a third party on behalf of the Shareholder *(Note 14)*	**-**	(14)
Cash flow provided by financing activities	**310**	320
Net (decrease) increase in cash and cash equivalents	**(217)**	361
Cash and cash equivalents, beginning of year	**630**	269
Cash and cash equivalents, end of year	**413**	630

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	**2012**	**2011** *(as adjusted – Note 22)*
Assets		
Current assets		
Cash and cash equivalents	**413**	630
Receivables from related parties *(Note 17)*	**442**	426
Other accounts receivable and prepaid expenses	**125**	100
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 15)*	**27**	20
Fuel inventory *(Note 15)*	**505**	655
Materials and supplies *(Note 15)*	**90**	82
Regulatory assets *(Note 5)*	**-**	299
Income taxes recoverable	**63**	58
Deferred income taxes *(Note 9)*	**68**	42
	1,733	2,312
Property, plant and equipment *(Notes 4 and 15)*	**22,923**	21,110
Less: accumulated depreciation	**7,063**	6,477
	15,860	14,633
Intangible assets *(Notes 4 and 15)*	**380**	363
Less: accumulated amortization	**328**	313
	52	50
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 15)*	**12,690**	11,878
Long-term materials and supplies *(Note 15)*	**355**	380
Regulatory assets *(Note 5)*	**6,478**	4,718
Investments subject to significant influence *(Note 19)*	**373**	395
Other long-term assets	**60**	77
	19,956	17,448
	37,601	34,443

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	**2012**	**2011** *(as adjusted – Note 22)*
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Note 17)*	**891**	825
Short-term debt *(Note 7)*	**-**	60
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(Note 6)*	**5**	403
Regulatory liabilities *(Note 5)*	**-**	130
	908	1,430
Long-term debt *(Note 6)*	**5,109**	4,341
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Notes 8 and 15)*	**15,522**	14,392
Pension liabilities *(Note 10)*	**3,621**	2,847
Other post-employment benefit liabilities *(Note 10)*	**3,076**	2,616
Long-term accounts payable and accrued charges	**707**	546
Deferred revenue	**150**	120
Deferred income taxes *(Note 9)*	**563**	501
Regulatory liabilities *(Note 5)*	**41**	24
	23,680	21,046
Shareholder's equity		
Common shares *(Note 13)* [1]	**5,126**	5,126
Retained earnings	**3,757**	3,390
Accumulated other comprehensive loss	**(979)**	(890)
	7,904	7,626
	37,601	34,443

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at December 31, 2012 and 2011.

Commitments and Contingencies *(Notes 5, 6, 9, 10, 11, 12 and 14)*

See accompanying notes to the consolidated financial statements

On behalf of the Board of Directors:

Honourable Jake Epp (signed)
Chairman

M. George Lewis (signed)
Director

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Years Ended December 31 *(millions of dollars except where noted)*	**2012**	**2011** *(as adjusted – Note 22)*
Common shares *(Note 13)*	**5,126**	5,126
Retained earnings		
Balance at beginning of year	**3,390**	3,066
Net income	**367**	338
Distribution to a third party on behalf of the shareholder *(Note 14)*	**-**	(14)
Balance at end of year	**3,757**	3,390
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(890)**	(567)
Other comprehensive loss for the year	**(89)**	(323)
Balance at end of year	**(979)**	(890)
Total shareholder's equity at end of year	**7,904**	7,626

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2012 and 2011

1. DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. ("OPG" or the "Company") was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province"). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's goal is to be Ontario's low cost electricity generator of choice with a focus on three corporate strategies: performance excellence, project excellence, and financial sustainability.

2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles ("US GAAP") and the rules and regulations of the United States Securities and Exchange Commission for annual financial statements, as required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) ("FAA") effective January 1, 2012. The Ontario Securities Commission has also approved OPG's adoption of US GAAP for financial years that begin on or after January 1, 2012, but before January 1, 2015. For prior reporting periods up to and including the year ended December 31, 2011, OPG prepared its consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") as determined in Part V of the Canadian Institute of Chartered Accountants' Handbook – Accounting. Note 22 to these consolidated financial statements details the impact of OPG's transition from Canadian GAAP to US GAAP and related reconciliation information. All dollar amounts are presented in Canadian dollars.

Certain of the 2011 comparative amounts have been reclassified from financial statements previously presented to conform to the 2012 consolidated financial statement presentation. These reclassifications, along with the US GAAP reconciliations, are presented in Note 22, *US GAAP Transition*.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements of the Company include the accounts of OPG and its majority-owned subsidiaries, and a variable interest entity ("VIE") where OPG is the primary beneficiary. All significant intercompany balances and intercompany transactions have been eliminated on consolidation.

Where OPG does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. OPG co-owns the Portlands Energy Centre ("PEC") gas-fired combined cycle generating station with TransCanada Energy Ltd. and co-owns the Brighton Beach gas-fired combined cycle generating station with ATCO Power Canada Ltd. OPG accounts for its 50 percent ownership interest in each of these jointly controlled entities under the equity method.

Variable Interest Entities

OPG performs ongoing analysis to assess whether it holds any VIEs. VIEs of which OPG is deemed to be the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the Company. In circumstances where OPG is not deemed to be the primary beneficiary, the VIE is not recorded in OPG's consolidated financial statements.

In 2002, OPG and other Canadian nuclear waste producers established the Nuclear Waste Management Organization ("NWMO") in accordance with the *Nuclear Fuel Waste Act* ("NFWA"). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel. In addition to the above mandate, the NWMO provides project management services for OPG's Deep Geologic Repository project for Low and Intermediate Level Waste ("L&ILW") and other nuclear lifecycle liability management services. OPG has the majority of voting rights at the Board of Directors and members' level. In addition, the NFWA requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan. OPG currently provides approximately 90 percent of NWMO's funding, primarily towards the Adaptive Phase Management plan for the long-term management of nuclear used fuel. As a result, OPG will absorb a majority of the NWMO's expected losses through future funding in the event of any shortfall. Therefore, OPG holds a variable interest in the NWMO, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of all significant intercompany transactions, are consolidated.

Use of Management Estimates

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. Management evaluates the Company's estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefits ("OPEB"), asset retirement obligations ("AROs"), income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments. These securities are valued at the lower of cost and market.

Interest earned on cash and cash equivalents and short-term investments was $5 million in 2012 (2011 – $6 million) at an average effective rate of 1.1 percent (2011 – 1.0 percent). The interest earned was offset against interest expense in the Consolidated Statements of Income.

Inventories

Inventory, consisting of fuel and materials and supplies, is measured at the lower of cost and market. Cost is determined as weighted average cost for fuel inventory and average cost for materials and supplies.

Property, Plant and Equipment, Intangible Assets and Depreciation and Amortization

Property, plant and equipment, and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rates on OPG's long-term debt.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are charged to operations, maintenance and administration ("OM&A") expenses. Repairs and maintenance costs are also expensed when incurred.

Property, plant and equipment are depreciated on a straight-line basis except for computers, and transport and work equipment. These are mostly depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis. As at December 31, 2012, the depreciation and amortization periods of property, plant and equipment and intangible assets are as follows:

Nuclear generating stations and major components	15 to 59 years [1]
Thermal generating stations and major components	25 to 48 years
Hydroelectric generating stations and major components	10 to 100 years
Administration and service facilities	10 to 50 years
Computers, and transport and work equipment assets – declining balance	9% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] As at December 31, 2012, the end of station life for depreciation purposes for the Darlington, Pickering, and Bruce A and B nuclear generating stations ranges between 2019 and 2051. Major components are depreciated over the lesser of the station life and the life of the components. Changes to the end of station life for depreciation purposes are described under the heading *Changes in Accounting Policies and Estimates.*

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

The carrying value of investments accounted for under the equity method are reviewed for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the baseload hydroelectric facilities and all of the nuclear facilities that it operates. Beginning April 1, 2008, OPG's regulated prices for these regulated facilities are determined by the Ontario Energy Board ("OEB").

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

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required to be obtained from, or settled with, the ratepayers. When the Company assesses that there is sufficient assurance that incurred costs will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to ratepayers in the future, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through current regulated prices, the Company records a regulatory liability. Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* Variance accounts capture differences between actual costs and revenues, and the corresponding forecast amounts approved in the setting of regulated prices. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory asset and liability balances for variance and deferral accounts approved by the OEB for inclusion in regulated prices are amortized based on approved recovery periods. Disallowed balances, including associated interest, are charged to operations in the period that the OEB's decision is issued. Interest is applied to regulatory balances as prescribed by the OEB, in order to recognize the cost of financing amounts to be recovered from, or repaid to, ratepayers.

Regulatory asset and liability balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, ratepayers within 12 months of the end of the reporting period, based on recovery periods established by the OEB. All other regulatory asset and liability balances are classified as long-term on the Consolidated Balance Sheets.

See Notes 5, 8, 9, and 10 to these consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Fixed Asset Removal and Nuclear Waste Management Liabilities

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

On an ongoing basis, the liabilities for nuclear fixed asset removal and nuclear waste management ("Nuclear Liabilities") are increased by the present value of the variable cost portion for the nuclear waste generated each year, with the corresponding amounts charged to operating expenses. Variable expenses relating to low and intermediate level nuclear waste are charged to OM&A expenses. Variable expenses relating to the management and storage of nuclear used fuel are charged to fuel expense. The liabilities may also be adjusted due to any changes in the estimated amount or timing of the underlying future cash flows. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the liabilities for fixed asset removal and nuclear waste management are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets. The capitalized cost is depreciated over the remaining service life of the related fixed assets and is included in depreciation and amortization expenses.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

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

OPG's investments in the Nuclear Funds are classified as held-for-trading. The Nuclear Funds are measured at fair value based on the bid prices of the underlying equity and fixed income securities, and, in the case of the alternative investment portfolio, using appropriate valuation techniques as outlined in Note 12 to these consolidated financial statements, with gains and losses recognized in net income.

Investments in OPG Ventures

Investments owned by the Company's wholly owned subsidiary, OPG Ventures Inc., are recorded at fair value, and changes to the fair value of the investments are included in revenue in the period in which the change occurs. The fair values of these investments are estimated using a methodology that is appropriate in light of the nature, facts, and circumstances of the respective investments and considers reasonable data and market inputs, assumptions, and estimates. See Note 12 to these consolidated financial statements for additional disclosures related to OPG's investments in OPG Ventures Inc.

Revenue Recognition

All of OPG's electricity generation is offered into the real-time energy spot market administered by the Independent Electricity System Operator ("IESO"). Revenue is recognized as electricity is generated and metered to the IESO.

Revenue Recognition – Regulated Generation

Since March 1, 2011, energy revenue generated from the nuclear facilities owned and operated by OPG has been based on a regulated price of 5.59¢/kWh pursuant to the OEB's decision and order issued in March 2011 and April 2011, respectively, on the application for new regulated prices filed by OPG in May 2010. This nuclear regulated price includes a rate rider of 0.43¢/kWh for the recovery of the approved nuclear variance and deferral account balances based on recovery periods authorized by the OEB. Effective March 1, 2011, energy revenue generated from OPG's regulated hydroelectric facilities has received a regulated price of 3.41¢/kWh, pursuant to the OEB's decision and order. This regulated hydroelectric regulated price is net of a negative rider of 0.17¢/kWh reflecting the repayment of the approved regulated hydroelectric variance account balances. In its March 2011 decision and April 2011 order, the OEB determined that the rate riders would expire on December 31, 2012.

In September 2012, OPG filed an application with the OEB requesting to recover balances in authorized nuclear and regulated hydroelectric variance and deferral accounts, including the balance in the Impact for USGAAP Deferral Account, as at December 31, 2012. The application requested the recovery of these balances to be reflected in new rate riders beginning in 2013. The application also sought, on an interim basis effective January 1, 2013, approval for the continuation of the current rate rider of 0.43¢/kWh applicable to OPG's nuclear production. In its decision and order issued on November 6, 2012, the OEB granted OPG's request for the interim continuation of the nuclear rider and also determined that the negative regulated hydroelectric rider of 0.17¢/kWh would be allowed to expire on December 31, 2012. The current nuclear rate rider became interim on January 1, 2013 and will continue until the implementation date of the new riders resulting from the OEB's final decision and order on OPG's application, which will factor in amounts recovered through the interim rider into the determination of the new rider. OPG is in continuing settlement discussions with the intervenors regarding all aspects of the rate application. If an agreement is reached, a settlement agreement will be filed with the OEB and will be subject to approval by the OEB. OPG's application is also discussed in Note 5 to these consolidated financial statements.

In its March 2011 decision, the OEB also approved the continuation of the existing hydroelectric incentive mechanism ("HIM") but determined that, effective March 1, 2011, a portion of the resulting net revenues should be shared with ratepayers. As a result, the OEB established the Hydroelectric Incentive Mechanism Variance Account. Under the mechanism, OPG continues to receive the approved regulated price for the actual monthly average net energy production per hour from the regulated hydroelectric facilities, and in the hours where OPG's actual net energy production in Ontario is greater or less than the average net volume in the month, OPG's regulated hydroelectric revenues are adjusted by the difference between the average hourly net volume and OPG's actual net energy production from the regulated hydroelectric facilities multiplied by the spot market price. The Hydroelectric Incentive Mechanism Variance Account captures the net revenues from the HIM that are required to be returned to ratepayers.

For the period from April 1, 2008 to February 28, 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 and order. Pursuant to that decision and order, effective April 1, 2008, 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 accounts and, effective December 1, 2008, was subject to the HIM.

The regulated prices established by the OEB in effect prior to, and effective March 1, 2011 were determined using a forecast cost of service methodology. The forecast cost of service methodology establishes regulated prices based on a revenue requirement, taking into account a forecast of production and operating costs for the regulated facilities, and a return on rate base. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed and intangible assets and an allowance for working capital.

Revenue Recognition – Unregulated Generation and Other Revenue

The electricity generation from OPG's unregulated assets receives the Ontario electricity spot market price, except where a cost recovery or an energy supply agreement ("ESA") is in place.

The Lambton and Nanticoke generating stations are subject to a Contingency Support Agreement with the Ontario Electricity Financial Corporation ("OEFC"). The agreement was enacted to enable the recovery of costs associated with these coal-fired generating stations following implementation of OPG's Carbon Dioxide emissions reduction strategy. Capacity provided by, and production from, the Lennox generating station was subject to a Lennox Generating Station Agreement with the Ontario Power Authority ("OPA") for the period from January 1, 2011 to December 31, 2012. In December 2012, the OPA and OPG executed a long-term Lennox ESA for the period from January 1, 2013 to September 30, 2022. The Lennox ESA allows the station to recover its costs, including a reasonable return, in providing generating capacity to the Ontario electricity system over the next 10 years.

OPG currently has Hydroelectric ESAs with the OPA for the Lac Seul and Ear Falls generating stations, the Healey Falls generating station, the Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations, and the Lower Mattagami River project. Payments under the Lower Mattagami Hydroelectric ESA commence when the first incremental unit comes into service.

Revenue generated by those generating stations, which are subject to a Contingency Support Agreement or a Hydroelectric ESA, is recognized in accordance with the terms of the agreement or contract.

OPG also sells into, and purchases from, interconnected markets of other provinces and the United States ("US") northeast and midwest. All contracts that are not designated as hedges are recorded in the Consolidated Balance Sheets at market value, with gains or losses recorded in the Consolidated Statements of Income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the Consolidated Statements of Income. Accordingly, power purchases of $61 million were netted against revenue in 2012 (2011 – $69 million).

OPG derives non-energy revenue under the terms of a lease arrangement and related agreements with Bruce Power L.P. related to the Bruce nuclear generating stations. This includes lease revenue and revenue for engineering analysis and design, technical, and ancillary services. The minimum lease payments are recognized in revenue on a straight-line basis over the term of the lease.

In addition, non-energy revenue includes isotope sales and real estate rentals. Revenues from these activities are recognized as services are completed or as products are delivered.

Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the Consolidated Balance Sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. 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. A documented assessment is made, both at the inception of a hedge 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.

Specifically for cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated other comprehensive income ("AOCI") and later reclassified into net income when the underlying transaction occurs. Gains and losses on interest rate hedges are recorded as an adjustment to interest expense for the debt being hedged. Gains and losses that do not meet the effectiveness criteria are recorded in net income in the period incurred. When a derivative instrument hedge ceases to be effective as a hedge, 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 year's Consolidated Statement of Income.

Some of OPG's unregulated generation is exposed to changes in electricity prices associated with a wholesale spot market for electricity in Ontario. All derivative contracts not designated as hedges are recorded on the balance sheet as derivative assets or liabilities at fair value with changes in fair value recorded in the revenue of the Other category (refer to Note 11).

OPG utilizes emission allowances to manage emissions within the prescribed regulatory limits. Emission allowances are obtained from the Province. The historical cost of allowances is held in inventory and charged to operations at average cost as part of fuel expense, as required.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. OPG uses a fair value hierarchy, grouping financial assets and liabilities into three levels based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the highest. Refer to Note 12 for a discussion of fair value measurements and the fair value hierarchy.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian currency at exchange rates prevailing at the balance sheet date. Any resulting gain or loss is reflected in revenue.

Research and Development

Research and development costs are expensed in the year incurred. Research and development costs incurred to discharge long-term obligations, such as the nuclear waste management liabilities, for which specific provisions have already been made, are charged to the related liability.

Leases

Leases are evaluated and classified as either operating or capital leases for financial reporting purposes. Capital leases, which transfer substantially all of the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capital leases are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Leases where the lessor retains substantially all the risks and benefits incidental to ownership of the asset are classified as operating leases. Operating lease payments, other than contingent rentals, are recognized as an expense in the Consolidated Statements of Income on a straight-line basis over the lease term. Where the amount of rent expense recognized is less than the actual rental payments, the excess payment amount is recorded as deferred revenue and included in liabilities on the Consolidated Balance Sheets.

Pension and Other Post-Employment Benefits

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post-retirement benefits ("OPRB") including group life insurance and health care benefits, and long-term disability ("LTD") benefits. Post- employment benefit programs are also provided by the NWMO. Information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions, experience gains or losses, salary levels, inflation, and cost escalation.

Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Two critical assumptions – discount rate and inflation – are important elements in the determination of benefit costs and obligations. In addition, the expected return on plan assets is a critical assumption in the determination of registered pension plan costs. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods; for LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The expected rate of return on plan assets is based on current and expected asset allocation, as well as the expected return considering long-term historical risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities and corporate and government debt securities, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The funds do not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the plan. Past service costs arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets, is amortized over the expected average remaining service life since OPG expects to realize the associated economic benefit over that period. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes on its balance sheet the funded status of its defined benefit plans. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits that arise during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income ("OCI"), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as discussed above.

OPG records an offsetting regulatory asset for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery of these amounts through future regulated prices charged to customers. For the recoverable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset for the amount of the increases or decreases in OCI and for the reclassification of AOCI into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Income Taxes and Investment Tax Credits

OPG is exempt from income tax under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG effectively paying taxes similar to what would be imposed under the federal and Ontario tax acts.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If management determines that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

OPG recognizes deferred income taxes associated with its rate regulated operations and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense. OPG classifies interest and penalties associated with unrecognized tax benefits as income tax expense.

Changes in Accounting Policies and Estimates

Presentation of Comprehensive Income

Effective January 1, 2012, OPG adopted the amendments to Accounting Standards Codification ("ASC") Topic 220, *Comprehensive Income* ("ASC Topic 220"). The amended standard requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. OPG continues to report the components of comprehensive income in a separate but consecutive statement.

Fair Value Measurements

Effective January 1, 2012, OPG adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures.* The amendment does not change the items measured at fair value but establishes common requirements for measuring fair value and for disclosing information about fair value measurements. The adoption did not have an impact on OPG's results of operations or financial position.

Useful Lives of Long-Lived Assets

Nuclear

OPG reviews estimated station useful lives for its generating assets on a regular basis. As part of its Pickering Continued Operations initiative, during the fourth quarter of 2012, OPG confirmed its plans for the continued operation of the Pickering stations. This confirmation resulted in a change to the useful lives for the Pickering generating stations, for the purposes of calculating depreciation, effective December 31, 2012. Consistent with the results of the Pickering Continued Operations initiative and other considerations, the useful lives, for accounting purposes, for the Bruce generating stations, were extended. These stations are currently leased to Bruce Power L.P. Effective December 31, 2012, the changes to the estimated service lives of these generating stations have been reflected in an increase to the estimate of the Nuclear Liabilities of $451 million, which resulted in an increase in the fixed assets balance of $449 million related to the asset retirement cost and an increase in OM&A expenses of $2 million. In addition, the changes in the estimated service lives resulted in an increase in the derivative liability embedded in the Bruce Power lease agreement ("Bruce Lease") of $249 million on December 31, 2012.

The income statement impacts associated with the changes to the Nuclear Liabilities and the derivative liability are largely offset by the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB, except for the depreciation impact relating to the fixed asset balances attributable to the tangible components for the Pickering generating stations.

For the fixed asset balance attributable to the tangible components, the life changes are expected to decrease depreciation expense related to existing assets for the Pickering generating stations, by $35 million in 2013 and $21 million in 2014.

Thermal

As a result of the announcement by the Ministry of Energy to advance the shutdown date of the remaining coal-fired units at the Lambton and Nanticoke generating stations, OPG has revised the end of life dates for the purposes of calculating depreciation from December 2014 to December 2013 for both generating stations. This change in estimate will increase depreciation expense in 2013 by $58 million reflecting the advancement of the 2014 expense. This increase in depreciation expense is expected to be offset by revenue from the Contingency Support Agreement with the OEFC.

Thermal Materials and Supplies Obsolescence

As a result of the revised end of life dates, OPG has revised the materials and supplies obsolescence provision for the Lambton and Nanticoke generating stations. All materials and supplies not expected to be utilized by the mandated cessation date of December 31, 2013 will be charged to obsolescence on a straight-line basis during 2013. This change in estimate is expected to increase OM&A expenses by $11 million in 2013. This increase in expense in 2013 will be offset by a corresponding increase in revenue of $11 million as these costs are recoverable under the Contingency Support Agreement with the OEFC.

Thermal Asset Retirement Obligation

In September 2011, OPG completed a review of the ARO for OPG's operating thermal stations and the decommissioned R.L. Hearn generating station.

As a result of the review, the ARO estimate in accordance with US GAAP increased by $171 million at September 30, 2011, primarily due to higher demolition cost estimates. The increase in the ARO resulted in the recognition of an increase in property, plant and equipment of $90 million at September 30, 2011 and other loss of $81 million during the third quarter of 2011. The other loss reflected the write-down of asset retirement costs for the Atikokan, Lennox, and Thunder Bay generating stations that were not supported by the cash flows associated with those stations.

In addition, as a result of the review, the ARO estimate in accordance with US GAAP for the R.L. Hearn generating station decreased to $18 million at September 30, 2011. The decrease in the ARO resulted in the recognition of a $3 million reduction to property, plant and equipment and other income of $15 million at September 30, 2011 for the decommissioned station.

The review of the ARO also resulted in changes to salvage value estimates for scrap metal recoveries for certain thermal stations. As a result of the ARO and salvage value estimate changes, depreciation expense for 2012 decreased by $6 million. OPG is considering the impact to the timing of the decommissioning of the thermal stations taking into account the announcement by the Province to advance the shutdown date of the Lambton and Nanticoke generating stations by the end of 2013, the placement of the units in reserve status, and the potential conversion in the future.

Recent Accounting Pronouncements

Comprehensive Income – Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

In February 2013, the Financial Accounting Standards Board issued an update to ASC Topic 220, which adds new disclosure requirements for items reclassified out of AOCI. Entities must present information about significant items reclassified out of AOCI by component, either on the Consolidated Statement of Income or as a separate disclosure in the notes to the financial statements, with reference to the affected line item in the Consolidated Statement of Income. OPG will apply the amendments for reporting periods beginning on or after January 1, 2013.

4. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

Depreciation and amortization expenses for the years ended December 31 consist of the following:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Depreciation	**480**	507
Amortization of intangible assets	**15**	13
Amortization of regulatory assets and liabilities *(Note 5)*	**169**	174
	664	694

Property, plant and equipment as at December 31 consist of the following:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Nuclear generating stations	**8,809**	8,254
Regulated hydroelectric generating stations	**4,548**	4,538
Unregulated hydroelectric generating stations	**4,140**	4,096
Thermal generating stations	**1,541**	1,534
Other property, plant and equipment	**383**	371
Construction in progress	**3,502**	2,317
	22,923	21,110
Less: accumulated depreciation		
Generating stations	**6,856**	6,288
Other property, plant and equipment	**207**	189
	7,063	6,477
	15,860	14,633

Construction in progress as at December 31 consists of the following:

(millions of dollars)	**2012**	**2011**
Niagara Tunnel	**1,353**	1,122
Lower Mattagami	**1,355**	766
Darlington Refurbishment	**354**	127
Atikokan Biomass Conversion	**59**	5
Other	**381**	297
	3,502	2,317

Intangible assets as at December 31 consist of the following:

(millions of dollars)	2012	2011 (as adjusted – Note 22)
Nuclear generating stations	**112**	101
Unregulated hydroelectric generating stations	**7**	6
Thermal generating stations	**2**	2
Other intangible assets	**249**	244
Development in progress	**10**	10
	380	363
Less: accumulated amortization		
Generating stations	**95**	87
Other intangible assets	**233**	226
	328	313
	52	50

The estimated aggregate amortization expense for intangible assets currently recognized for each of the five succeeding years is as follows:

(millions of dollars)	2013	2014	2015	2016	2017
Amortization expense	13	10	8	5	1

Interest capitalized to construction and development in progress at an average rate of five percent during 2012 (2011 – five percent) was $126 million (2011 – $86 million).

5. REGULATORY ASSETS AND LIABILITIES

In its March 2011 decision and April 2011 order, the OEB approved, without adjustments, OPG's request for the disposition of balances as at December 31, 2010 in variance and deferral accounts previously authorized by the OEB's decisions and orders since April 1, 2008, including those authorized pursuant to *Ontario Regulation 53/05*. During the period from March 1, 2011 to December 31, 2012, the Company amortized these approved balances based on recovery periods authorized by the OEB in that decision and order. Any shortfall or over-recovery of the approved balances due to differences between actual and forecast production was recorded in the authorized Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Accounts to be collected from, or refunded to, ratepayers in the future.

In addition, in its March 2011 decision, the OEB authorized the continuation of the previously existing variance and deferral accounts effective March 1, 2011, with the exception of the Nuclear Fuel Cost Variance Account, which was discontinued as of that date. Effective March 1, 2011, the OEB also established the Hydroelectric Surplus Baseload Generation ("SBG") Variance Account and, as discussed in Note 3 to these consolidated financial statements, the Hydroelectric Incentive Mechanism Variance Account.

In September 2012, OPG requested approval, including approval on an interim basis effective January 1, 2013, for the Pension and OPEB Cost Variance Account to be extended while the current regulated prices, excluding rate riders, established by the OEB's March 2011 decision, remain in effect. In its November 2012 decision and order, the OEB granted OPG's request for an extension of the account on an interim basis. This approval provides OPG with authorization to record amounts in the account for future recovery for the period from January 1, 2013 until the issuance of, and subject to, the OEB's final decision and order regarding the extension of the Pension and OPEB

Cost Variance Account. Based on the OEB's March 2011 decision, OPG also continues to record amounts in other variance and deferral accounts for periods after December 31, 2012. OPG is in continuing settlement discussions with the intervenors regarding all aspects of the rate application. If an agreement is reached, a settlement agreement will be filed with the OEB and will be subject to approval by the OEB.

During the period from January 1, 2011 to February 28, 2011, the Company recorded additions to variance and deferral accounts as authorized by the OEB's decisions issued since April 1, 2008 and, pursuant to the OEB's 2008 decision on OPG's regulated prices, amortized account balances as at December 31, 2007, which were recorded pursuant to *Ontario Regulation 53/05*.

During 2012 and 2011, OPG recorded interest on outstanding variance and deferral account balances at the interest rate of 1.47 percent per annum prescribed by the OEB.

The regulatory assets and liabilities recorded as at December 31 are as follows:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Regulatory assets		
Variance and deferral accounts as authorized by the OEB		
Pension and OPEB Cost Variance Account	**324**	96
Bruce Lease Net Revenues Variance Account	**311**	196
Tax Loss Variance Account	**302**	425
Nuclear Liability Deferral Account	**208**	22
Impact for USGAAP Deferral Account	**63**	-
Other variance and deferral accounts	**108**	26
	1,316	765
Pension and OPEB Regulatory Asset *(Note 10)*	**4,494**	3,553
Deferred Income Taxes *(Note 9)*	**668**	699
Total regulatory assets	**6,478**	5,017
Less: current portion	**-**	299
Non-current regulatory assets	**6,478**	4,718
Regulatory liabilities		
Variance and deferral accounts as authorized by the OEB		
Income and Other Taxes Variance Account	**35**	49
Other variance and deferral accounts	**6**	105
Total regulatory liabilities	**41**	154
Less: current portion	**-**	130
Non-current regulatory liabilities	**41**	24

The changes in the regulatory assets and liabilities during 2012 and 2011 are as follows:

(millions of dollars)	Pension and OPEB Cost Variance	Bruce Lease Net Revenues Variance	Tax Loss Variance	Nuclear Liability Deferral	Impact for USGAAP Deferral	Pension and OPEB Regulatory Asset	Deferred Income Taxes	Income and Other Taxes Variance	Other Variance and Deferral (net)
Regulatory assets (liabilities), January 1, 2011 *(as adjusted – Note 22)*	-	250	492	39	-	2,254	727	(40)	(141)
Change during the year	95	56	33	-	-	1,299	(28)	(26)	18
Interest	1	3	7	1	-	-	-	(1)	(2)
Amortization during the year	-	(113)	(107)	(18)	-	-	-	18	46
Regulatory assets (liabilities), December 31, 2011 *(as adjusted – Note 22)*	96	196	425	22	-	3,553	699	(49)	(79)
Change during the year	225	248	-	206	62	941	(31)	(7)	87
Interest	3	3	5	1	1	-	-	(1)	-
Amortization during the year	-	(136)	(128)	(21)	-	-	-	22	94
Regulatory assets (liabilities), December 31, 2012	**324**	**311**	**302**	**208**	**63**	**4,494**	**668**	**(35)**	**102**

Pension and OPEB Cost Variance Account

The OEB established the Pension and OPEB Cost Variance Account in its June 2011 decision and order, granting OPG's motion to review and vary the OEB's March 2011 decision, as it related to updated pension and OPEB costs. The variance account records the difference between actual pension and OPEB costs for the regulated business, as calculated in accordance with Canadian GAAP, and related tax impacts, and the corresponding amounts reflected in the current regulated prices. The OEB's June 2011 decision and order established the account for the period from March 1, 2011 to December 31, 2012. In its September 2012 application requesting OEB's approval to recover balances in variance and deferral accounts as at December 31, 2012, OPG requested approval for the variance account to be extended while the current regulated prices, excluding rate riders, remain in effect.

Bruce Lease Net Revenues Variance Account

As per *Ontario Regulation 53/05*, OPG is required to include the difference between its revenues and costs associated with its ownership of the two nuclear stations on lease to Bruce Power L.P. in the determination of the regulated prices for production from OPG's regulated nuclear facilities. The OEB established a variance account that captures differences between actual and forecast revenues and costs related to the nuclear generating stations on lease to Bruce Power L.P. that are included in the approved nuclear regulated prices.

In its March 2011 decision, the OEB approved the recovery of the balance in the Bruce Lease Net Revenues Variance Account as at December 31, 2010 over a 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, OPG recorded amortization of the regulatory asset for this account on a straight-line basis over this period.

Tax Loss Variance Account

The Tax Loss Variance Account, authorized by the OEB in May 2009 and effective April 1, 2008, pertains to the treatment of tax losses and their use for mitigation. In accordance with the OEB's May 2009 decision on OPG's motion to review and vary the OEB's 2008 decision on OPG's regulated prices, this account recorded, up to March 1, 2011, the difference between the amount of mitigation included in the approved regulated prices established by the OEB's 2008 decision and the revenue requirement reduction available from carried forward prior period tax losses, as recalculated per the OEB's 2008 decision. Only interest and amortization are recorded in this account, effective March 1, 2011.

In its March 2011 decision, the OEB approved the recovery of the balance in the account as at December 31, 2010 over a 46-month period ending December 31, 2014. Accordingly, effective March 1, 2011, OPG recorded amortization for this account on a straight-line basis over this period.

Nuclear Liability Deferral Account

As per *Ontario Regulation 53/05*, the OEB has authorized the Nuclear Liability Deferral Account ("NLDA") in connection with changes to OPG's liabilities for nuclear used fuel management and nuclear decommissioning and L&ILW management associated with the nuclear facilities owned and operated by OPG, which are comprised of the Pickering and Darlington nuclear generating stations. The deferral account records the revenue requirement impact associated with the changes in these liabilities arising from an approved reference plan, in accordance with the terms of the ONFA.

In 2011, the estimate for OPG's nuclear used fuel management and nuclear decommissioning and L&ILW management liabilities as at December 31, 2011 was updated as a result of the ONFA

Reference Plan update process. During 2012, the Province approved the 2012 ONFA Reference Plan, covering the period from 2012 to 2016, with an effective date of January 1, 2012. As a result, OPG recorded an increase to the regulatory asset for the NLDA during 2012. The regulatory asset represents the revenue requirement impact associated with the increase in the liabilities for the nuclear facilities owned and operated by OPG arising from the approved 2012 ONFA Reference Plan for the period beginning on January 1, 2012.

During the year ended December 31, 2012, the following items have been recorded as components of the regulatory asset for the NLDA relating to the above increase in the liabilities, with reductions to corresponding expenses:

(millions of dollars)	**2012**
Fuel expense	**25**
Low and intermediate level waste management variable expenses [1]	**1**
Depreciation expense	**98**
Return on rate base [2]	**22**
Interest	**1**
Income taxes	**60**
	207

[1] Amount was recorded as a reduction to OM&A expenses.

[2] Amount was recorded as a reduction to accretion on fixed asset removal and nuclear waste management liabilities.

Prior to April 1, 2008, OPG recorded a regulatory asset for the NLDA associated with the increase in the nuclear used fuel management and nuclear decommissioning and L&ILW management liabilities recognized as at December 31, 2006, following the 2006 ONFA Reference Plan update process. The OEB's March 2011 decision authorized a 22-month recovery period, ending December 31, 2012, for the remaining balance in the NLDA as at December 31, 2010 related to this increase in the liabilities. Accordingly, effective March 1, 2011, OPG recorded amortization of the regulatory asset for the NLDA on a straight-line basis over this period.

Impact for USGAAP Deferral Account

In December 2011, OPG filed an application with the OEB for an accounting order, establishing a deferral account to record the financial impacts resulting from the transition to and implementation of US GAAP. The OEB granted OPG's request, authorizing the Impact for USGAAP Deferral Account in its decision and order issued on March 2, 2012. In the decision and order, the OEB stated that the disposition of the account is subject to the OEB's approval of OPG's use of US GAAP for regulatory purposes, for which OPG subsequently applied in its September 2012 application to the OEB.

The Impact for USGAAP Deferral Account is in effect from January 1, 2012 to the effective date of the OEB's next order establishing OPG's regulated prices. The amounts recorded in the account represent the regulated portion of the increase in the liability for certain OPEB costs, as a result of the transition to US GAAP, recognized by OPG as of January 1, 2011 and for the period from January 1, 2011 to December 31, 2012, and associated tax impacts.

Pension and OPEB Regulatory Asset

The regulated prices established by the OEB for generation from OPG's regulated facilities, using a forecast cost of service methodology, reflect amounts for pension and OPEB costs attributable to these facilities. These amounts are determined on the basis of the manner in which these costs are recognized in OPG's consolidated financial statements. Unamortized amounts, in respect of OPG's pension and OPEB plans that are recognized in AOCI, are not generally reflected in the regulated prices until these amounts are reclassified from AOCI, and recognized as amortization components of the benefit costs in respect of these plans. As such, OPG recognizes an offsetting regulatory asset for the unamortized amounts that have not yet been reclassified from AOCI to benefit costs. The regulatory asset is reversed, as underlying unamortized balances are amortized as components of the benefit costs.

The recognition of previously unamortized actuarial net losses and past service costs on transition to US GAAP is discussed in Notes 3, 10, and 21. The AOCI amounts related to pension and OPEB plans are presented in Note 10.

Deferred Income Taxes

OPG is required to recognize deferred income taxes associated with its rate regulated operations, including deferred income taxes on temporary differences related to the regulatory assets and liabilities recognized for accounting purposes. In addition, OPG is required to recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be included in future regulated prices and recovered from, or paid to, customers.

Income and Other Taxes Variance Account

The OEB authorized a variance account to record deviations in income, capital and certain other tax-related expenses for the regulated business, from those approved by the OEB in setting regulated prices, caused by changes in tax rates or rules under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by regulations made under the *Electricity Act, 1998*, as well as variances caused by reassessments. Variances resulting from reassessments of prior taxation years that have an impact on taxes payable related to the regulated business for the periods after March 31, 2008 are included in the account. In addition, the variance account captures certain changes to the property tax expense.

The OEB's March 2011 decision authorized the repayment of the balance in this variance account, as at December 31, 2010, over a 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, the amortization of this balance was recorded by OPG on a straight-line basis over this period.

Other Variance and Deferral Accounts

As at December 31, 2012, regulatory assets for other variance and deferral accounts included amounts for the Ancillary Services Net Revenue Variance Account, the Nuclear Development Variance Account, the Hydroelectric Water Conditions Variance Account and the Capacity Refurbishment Variance Account.

The Ancillary Services Net Revenue Variance Account was authorized by the OEB to capture differences between actual nuclear and regulated hydroelectric ancillary services net revenue and the forecast amounts of such revenue approved by the OEB in setting regulated prices.

The Nuclear Development Variance Account was established pursuant to *Ontario Regulation 53/05* and records differences between actual non-capital costs incurred by OPG in the course of planning and preparing for the development of proposed new nuclear facilities, and the forecast amount of these costs included in the current nuclear regulated prices.

The Hydroelectric Water Conditions Variance Account captures the impact of differences in regulated hydroelectric electricity production due to differences between forecast water conditions underlying the hydroelectric production forecast approved by the OEB in setting current regulated hydroelectric regulated prices and the actual water conditions.

The Capacity Refurbishment Variance Account was authorized by the OEB effective April 1, 2008 pursuant to *Ontario Regulation 53/05* and includes variances from forecast costs reflected in the current regulated prices related to the refurbishment of the Darlington nuclear generating station, life extension initiatives at the Pickering nuclear generating stations, the Niagara Tunnel project, and other projects.

Regulatory assets for other variance and deferral accounts as at December 31, 2012 also included amounts for the Nuclear Deferral and Variance Over/Under Recovery Variance Account and the Hydroelectric SBG Variance Account. The unamortized balance related to the Nuclear Fuel Cost Variance Account which, up to March 1, 2011, captured differences between actual nuclear fuel costs per unit of production and the forecast of these costs approved by the OEB, was also included in these regulatory assets.

The regulatory assets for other variance and deferral accounts as at December 31, 2011 included amounts for the Ancillary Services Net Revenue Variance Account, the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Hydroelectric SBG Variance Account, the Nuclear Fuel Cost Variance Account, the Nuclear Interim Period Shortfall Variance Account, and the unamortized balance of the variance account related to transmission outages and transmission restrictions. The OEB-approved balances in the Nuclear Interim Period Shortfall Variance Account and the variance account related to transmission outages and transmission restrictions, as well as that in the Hydroelectric Interim Period Shortfall Variance Account, were fully amortized by December 31, 2012, with residual unamortized amounts transferred to the Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance accounts, as applicable.

As at December 31, 2012 and 2011, regulatory liabilities for other variance and deferral accounts included amounts for the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and for the Hydroelectric Incentive Mechanism Variance Account. In addition, as at December 31, 2011, these regulatory liabilities also included amounts for the Nuclear Development Variance Account, the Hydroelectric Water Conditions Variance Account, the Capacity Refurbishment Variance Account, and the Hydroelectric Interim Period Shortfall Variance Account.

In its March 2011 decision, the OEB authorized the recovery or repayment of the other variance and deferral account balances as at December 31, 2010, with the exception of the Pickering A Return to Service ("PARTS") Deferral Account, over the 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, the amortization of these balances is being recorded by OPG on a straight-line basis over this period. The PARTS Deferral Account was authorized to be amortized over a period of 10 months ending December 31, 2011.

6. LONG-TERM DEBT

Long-term debt consists of the following as at December 31:

(millions of dollars)	2012	2011 (as adjusted – Note 22)
Long-term debt [1]		
Notes payable to the Ontario Electricity Financial Corporation		
Senior Notes [2]		
5.72% due 2012	**-**	400
3.43% due 2015	**500**	500
4.91% due 2016	**270**	270
5.35% due 2017	**900**	900
5.27% due 2018	**395**	395
5.44% due 2019	**365**	365
4.56% due 2020	**660**	660
4.28% due 2021	**185**	185
3.30% due 2022	**150**	-
5.07% due 2041	**300**	300
4.36% due 2042	**200**	-
UMH Energy Partnership debt [3]		
Senior Notes		
7.86% due to 2041	**195**	198
Lower Mattagami Energy Limited Partnership [4]		
Senior Notes		
2.59% due 2015	**94**	96
2.35% due 2017	**200**	-
4.46% due 2021	**225**	225
5.26% due 2041	**250**	250
4.26% due 2052	**225**	-
	5,114	4,744
Less: due within one year	**5**	403
Long-term debt	**5,109**	4,341

[1] The interest rates disclosed reflect the effective interest rate of the debt.

[2] OEFC senior debt is entitled to receive, in full, amounts owing in respect of the senior debt and is pari passu to the UMH Energy Partnership and the Lower Mattagami Energy Limited Partnership ("LME") senior notes.

[3] These notes are secured by the assets of the Upper Mattagami and Hound Chute project and are recourse to OPG until specified conditions have been satisfied following construction. These notes rank pari passu to the OEFC senior notes.

[4] These notes are secured by the assets of the Lower Mattagami project, including existing operating facilities and facilities being constructed, and are recourse to OPG until the recourse release date. These notes rank pari passu to the OEFC senior notes.

OPG maintains a Niagara Tunnel project credit facility for an amount up to $1.6 billion. Interest will be fixed for each note issued at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on a survey of market rates. As at December 31, 2012, advances under this facility were $1,025 million (2011 – $875 million).

OPG entered into an agreement with the OEFC in April 2012 for a $400 million refinancing credit facility to refinance notes as they mature, and refinanced $200 million of notes under this facility in the second quarter. This facility expired in the second quarter of 2012.

In February 2013, the LME issued senior notes totalling $275 million with a maturity date of 2046. The effective interest rate and coupon interest rate of these notes were 4.3 percent and 4.2 percent, respectively.

Interest paid in 2012 was $246 million (2011 – $238 million), of which $235 million (2011 – $212 million) relates to interest paid on long-term corporate debt.

The book value of the pledged assets as at December 31, 2012 was $3,099 million (2011 – $2,088 million).

A summary of the contractual maturities by year is as follows:

(millions of dollars)	
2013	**5**
2014	**5**
2015	**593**
2016	**273**
2017	**1,103**
Thereafter	**3,135**
	5,114

7. SHORT-TERM DEBT AND NET INTEREST EXPENSE

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In May 2012, OPG renewed and extended both tranches to May 20, 2017. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at December 31, 2012, no commercial paper was outstanding under this program, and there were no outstanding borrowings under the bank credit facility as at December 31, 2012.

The LME maintains a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami River project and the commercial paper program. In August 2012, the facility was divided into two tranches. The first tranche of $400 million has a maturity date of August 17, 2017 and the second tranche of $300 million has a maturity date of August 17, 2015. As at December 31, 2012, no commercial paper was outstanding under this program (2011 – $10 million). In 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami River project. As at December 31, 2012 and 2011, there were no outstanding borrowings under this credit facility.

The Company has an agreement to sell an undivided co-ownership interest up to $250 million in its current and future accounts receivable to an independent trust. The Company also retains an undivided co-ownership interest in the receivables sold to the trust. Under the agreement, OPG continues to service the receivables. The transfer provides the trust with ownership of a share of the payments generated by the receivables, computed on a monthly basis. The trust's recourse to the Company is generally limited to its income earned on the receivables. In the fourth quarter of 2012, the Company renegotiated the agreement to include the issuance of Letters of Credit, and extended the agreement from August 31, 2013 to November 30, 2014. As at December 31, 2012, there were Letters of Credit outstanding under this agreement of $55 million, which were issued in support of OPG's supplementary pension plans. As at December 31, 2011, short-term debt included $50 million outstanding under this agreement and the corresponding accounts receivable of $50 million was recognized on OPG's Consolidated Balance Sheet.

As at December 31, 2012, OPG maintained $25 million of short-term uncommitted overdraft facilities and $395 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. As at December 31, 2012, there was a total of $350 million of Letters of Credit issued. This included $329 million for the supplementary pension plans, which includes $55 million of Letters of Credit discussed above; $20 million for general corporate purposes; and $1 million related to the operation of the PEC.

In addition, as at December 31, 2012, the NWMO has issued a Letter of Credit of $3 million for its supplementary pension plan.

The following table summarizes the net interest expense for the years ended December 31:

(millions of dollars)	**2012**	**2011**
Interest on long-term debt	**256**	243
Interest on short-term debt	**11**	15
Interest income	**(7)**	(9)
Interest capitalized to property, plant and equipment and intangible assets	**(126)**	(86)
Interest applied to regulatory assets and liabilities	**(12)**	(9)
Other	**(5)**	-
Net interest expense	**117**	154

8. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis consist of the following as at December 31:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Liability for nuclear used fuel management	**9,469**	8,523
Liability for nuclear decommissioning and low and intermediate level waste management	**5,708**	5,537
Liability for non-nuclear fixed asset removal	**345**	332
Fixed asset removal and nuclear waste management liabilities	**15,522**	14,392

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31 are as follows:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Liabilities, beginning of year	**14,392**	12,718
Increase in liabilities due to accretion [1]	**774**	704
Increase in liabilities resulting from the ONFA Reference Plan update process	**-**	934
Increase in liabilities reflecting a change to the useful lives of the Pickering and Bruce generating stations	**451**	-
Increase in liabilities due to nuclear used fuel, nuclear waste management variable expenses and other expenses	**103**	55
Liabilities settled by expenditures on fixed asset removal and nuclear waste management	**(198)**	(172)
Change in the liability for non-nuclear fixed asset removal	**-**	153
Liabilities, end of year	**15,522**	14,392

[1] The increase in liabilities due to accretion for 2012 excludes the reduction to accretion expense due to the impact of the NLDA of $22 million and the Bruce Lease Net Revenues Variance Account of $27 million on accretion expense. (2011 – NLDA of nil and the Bruce Lease Net Revenues Variance Account of $1 million)

During 2012, expenditures on fixed asset removal and nuclear waste management included $57 million in funding to the NWMO related to OPG's nuclear fixed asset removal and nuclear waste management liabilities (2011 –

$53 million). OPG's cash and cash equivalents balance as at December 31, 2012 includes $5 million of cash and cash equivalents that are for the use of nuclear waste management activities (2011 – $10 million).

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear, thermal generating plant facilities, and other facilities. Costs will be incurred for activities such as preparation for safe storage, safe storage, dismantling, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel and low and intermediate level waste material.

Nuclear station decommissioning consists of preparation and placement of stations into a safe store condition, followed by a nominal 30-year safe store period prior to station dismantling and site restoration. Under the terms of the Bruce Lease, OPG continues to be primarily responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The following costs are recognized as a liability:

- The present value of the costs of decommissioning the nuclear and thermal production facilities and other facilities after the end of their useful lives.
- The present value of the fixed cost portion of nuclear waste management programs that are required, based on the total volume of waste expected to be generated over the assumed life of the stations.
- The present value of the variable cost portion of nuclear waste management programs, taking into account actual waste volumes generated to date.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions since these programs run for many years. The most recent update of the estimates for the nuclear waste management and decommissioning liabilities are contained in the approved 2012 ONFA Reference Plan. The update resulted in an increased estimate of costs mainly due to higher costs for the construction of the L&ILW underground repository, higher costs for handling and storing of used fuel and L&ILW during station operations, and changes in economic indices. The increase was partially offset by lower expected costs to decommission reactors.

For the purposes of calculating OPG's fixed asset removal and nuclear waste management liabilities, as at December 31, 2012, consistent with the current accounting end of life assumptions, nuclear and thermal plant closures are projected to occur over the next two to 41 years.

To reflect the change in estimated station useful lives for the Pickering generating stations and the Bruce generating stations leased to Bruce Power L.P., OPG recorded an increase to the estimate of the Nuclear Liabilities of $451 million at December 31, 2012.

The updated estimates for the Nuclear Liabilities included cash flow estimates for decommissioning nuclear stations for approximately 40 years after station shut down and to 2071 for placement of used fuel into the long-term disposal repository followed by extended monitoring. The undiscounted amount of estimated future cash flows associated with the liabilities is approximately $33 billion in 2012 dollars. The weighted average discount rate used to calculate the present value of the liabilities at December 31, 2012 was 5.4 percent. The increase in the liabilities recorded as at December 31, 2012, which reflects the change in estimated useful lives and is consistent with the approved 2012 ONFA Reference Plan, was determined by discounting the net incremental future cash flows at 3.5 percent. The cost escalation rates used to determine the increase in the cost estimates ranged from 1.9 percent to 3.7 percent.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, end of life dates, financial indicators, or the technology employed may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement of the costs for these programs, which may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal NFWA, proclaimed into force in 2002, requires that Canada's nuclear fuel waste owners form a nuclear waste management organization, and that each waste owner establish a trust fund for used fuel management costs. To estimate its liability for nuclear used fuel management costs, OPG has adopted a conservative approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository in-service date of 2035.

Liability for Nuclear Decommissioning and L&ILW Management Costs

The liability for nuclear decommissioning and L&ILW management represents the estimated costs of decommissioning nuclear generating stations after the end of their service lives, as well as the cost of managing low and intermediate level radioactive wastes generated by the nuclear stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include decommissioning of nuclear generating stations on a deferred dismantlement basis, where the reactors will remain in a safe storage state for a 30-year period prior to a 10-year dismantlement period.

The life cycle costs of L&ILW waste management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of ultimate long-term management of these wastes. The current assumptions used to establish the accrued L&ILW management costs include a L&ILW deep geologic repository ("L&ILW DGR"). Agreement has been reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of L&ILW adjacent to the Western Waste Management Facility. A federal environmental assessment in respect of this proposed facility is in progress.

Assuming the site preparation and construction licence is received in 2014 from the CNSC for the L&ILW DGR, construction of the deep geologic repository is expected to commence in 2015 and be in-service within six to seven years by 2021 or 2022.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. The liability is based on third party cost estimates after an in-depth review of active plant sites and an assessment of required clean-up and restoration activities. As at December 31, 2012, the estimated retirement dates of the thermal stations for the purposes of this liability are between 2014 and 2030. The discount rates range from 1.5 percent to 5.8 percent. The undiscounted amount of estimated future cash flows associated with the non-nuclear liabilities is $491 million in 2012 dollars.

In addition to the $301 million liability for active sites, OPG has an ARO of $44 million for decommissioning and restoration costs associated with plant sites that are no longer in use for electricity generation.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

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 ONFA between OPG and the Province, OPG established the Nuclear Funds. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third party custodian accounts that are segregated from the rest of OPG's assets.

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal, long-term L&ILW management and a portion of used fuel storage costs after station life. As at December 31, 2012, the Decommissioning Fund was in an overfunded position.

The Used Fuel Fund was established to fund future costs of long-term nuclear used fuel waste management. OPG is responsible for the risk and liability of cost increases for used fuel waste management, subject to graduated liability thresholds specified in the ONFA, which limit OPG's total financial exposure at approximately $12.4 billion in December 31, 2012 dollars, based on used fuel bundle projections of 2.23 million bundles, consistent with the station life assumptions included within the initial financial reference plan. The graduated liability thresholds do not apply to additional used fuel bundles beyond 2.23 million.

OPG makes quarterly payments to the Used Fuel Fund over the life of its nuclear generating stations, as specified in the ONFA. Required funding for 2012 under the ONFA was $182 million (2011 – $250 million), including a contribution to the Ontario NFWA Trust (the "Trust") of $149 million (2011 – $139 million). Included in the 2012 funding was a $94 million contribution related to future bundles over the 2.23 million threshold (2011 – $133 million). Based on the Approved ONFA Reference Plan 2012, OPG is required to contribute annual amounts to the Used Fuel Fund, ranging from $139 million to $211 million over the years 2013 to 2017 (Refer to Note 14).

The NFWA was proclaimed into force in November 2002. As required under the NFWA, OPG established the Trust in November 2002 and made an initial deposit of $500 million into the Trust. The NFWA required OPG to make annual contributions of $100 million to the Trust, until such time that the NWMO proposed funding formula, designed to address the future financial costs of implementing the Adapted Phase Management approach, was approved by the Federal Minister of Natural Resources. In 2009, this funding formula was approved. The Trust forms part of the Used Fuel Fund, and contributions to the Trust, as required by the NFWA, may be applied towards OPG's ONFA payment obligations.

As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the 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 Fund and the Decommissioning 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. The Provincial Guarantee of $1,545 million was in effect through to the end of 2012. In January 2012, OPG paid a guarantee fee of $8 million based on a Provincial Guarantee amount of $1,545 million, for the period from January 1, 2012 to December 31, 2012. In December 2012, the CNSC approved OPG's proposed 2013 - 2017 CNSC Financial Guarantee requirement, resulting in a Provincial Guarantee amount of $1,551 million for the 2013 - 2017 period.

OPG's investments in the Nuclear Funds and the corresponding payables/receivables to/from 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 Consolidated Statements of Income and Consolidated Balance Sheets.

Decommissioning Fund

Upon termination of the ONFA, the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund over the estimated completion costs, as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial by recording a payable to the Province, such that the balance of the Decommissioning Fund would equal the cost estimate of the liability based on the most recently approved ONFA Reference Plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA Reference Plan is approved with a higher estimated decommissioning liability. When the Decommissioning Fund is underfunded, the earnings on the Decommissioning Fund reflect actual fund returns based on the market value of the assets.

The Province's right to any excess funding in the Decommissioning Fund upon termination of the ONFA results in OPG capping its annual earnings at 3.25 percent plus long-term Ontario Consumer Price Index, which is the rate of growth in the liability for the estimated completion cost, as long as the Decommissioning Fund is in an overfunded status.

The Decommissioning Fund's asset value on a fair value basis was $5,707 million as at December 31, 2012, which is net of the due to the Province of $64 million as the value of the fund was higher than the liability per the approved 2012 ONFA Reference Plan. At December 31, 2011, the Decommissioning Fund's asset value on a fair value basis was $5,342 million, which was less than the liability per the approved 2006 Approved Reference Plan. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 120 percent funded, OPG may direct up to 50 percent of the surplus over 120 percent to be treated as a contribution to the Used Fuel Fund and the OEFC would be entitled to a distribution of an equal amount. Since OPG is responsible for the risks associated with liability cost increases and investment returns in the Decommissioning Fund, future contributions to the Decommissioning Fund may be required should the fund be in an underfunded position at the time of the next liability reference plan review.

The investments in the Decommissioning Fund include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in infrastructure and Canadian real estate. The Nuclear Funds are invested to fund long-term liability requirements and, as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Funds remains the primary goal.

Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 percent plus the change in the Ontario Consumer Price Index for funding related to the first 2.23 million of used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Fund and includes it in the earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The due to or due from the Province represents the amount the fund would pay to or receive from the Province if the committed return were to be settled as of the Consolidated Balance Sheet date. As part of its regular contributions to the Used Fuel Fund, OPG was required to allocate $94 million of its 2012 contribution towards its liability associated with future fuel bundles that exceed the 2.23 million threshold (2011 – $133 million). As prescribed under the ONFA, OPG's contributions for incremental fuel bundles are not subject to the Province's guaranteed rate of return, but rather earn a return based on changes in the market value of the assets of the Used Fuel Fund.

As at December 31, 2012, the Used Fuel Fund asset value on a fair value basis was $7,010 million. The Used Fuel Fund value included a due to the Province of $235 million related to the committed return adjustment. As at December 31, 2011, the Used Fuel Fund asset value on a fair value basis was $6,556 million, including a receivable from the Province of $47 million related to the committed return adjustment.

Under the ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 percent compared to the value of the associated liabilities.

The nuclear fixed asset removal and nuclear waste management funds as at December 31 consist of the following:

	Fair Value	
(millions of dollars)	**2012**	**2011**
Decommissioning Fund	**5,771**	5,342
Due to Province – Decommissioning Fund	**(64)**	-
	5,707	5,342
Used Fuel Fund [1]	**7,245**	6,509
Due (to) from Province – Used Fuel Fund	**(235)**	47
	7,010	6,556
Total Nuclear Funds	**12,717**	11,898
Less: current portion	**27**	20
Non-current Nuclear Funds	**12,690**	11,878

[1] The Ontario NFWA Trust represented $2,559 million as at December 31, 2012 (2011 – $2,296 million) of the Used Fuel Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Funds as at December 31 is as follows:

	Fair Value	
(millions of dollars)	**2012**	**2011**
Cash and cash equivalents and short-term investments	**335**	555
Alternative investments	**362**	212
Pooled funds	**2,093**	1,842
Marketable equity securities	**5,670**	4,863
Fixed income securities	**4,523**	4,345
Derivatives	**-**	2
Net receivables/payables	**41**	38
Administrative expense payable	**(8)**	(6)
	13,016	11,851
Due (to) from Province	**(299)**	47
	12,717	11,898

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31 mature according to the following schedule:

	Fair Value	
(millions of dollars)	**2012**	**2011**
1 – 5 years	**1,151**	1,153
5 – 10 years	**631**	594
More than 10 years	**2,741**	2,598
Total maturities of debt securities	**4,523**	4,345
Average yield	**2.7%**	2.8%

The change in the Nuclear Funds for the years ended December 31 is as follows:

	Fair Value	
(millions of dollars)	**2012**	**2011**
Decommissioning Fund, beginning of year	**5,342**	5,267
Increase in fund due to return on investments	**469**	108
Decrease in fund due to reimbursement of expenditures	**(40)**	(33)
Increase in due to Province	**(64)**	-
Decommissioning Fund, end of year	**5,707**	5,342
Used Fuel Fund, beginning of year	**6,556**	5,979
Increase in fund due to contributions made	**182**	250
Increase in fund due to return on investments	**584**	87
Decrease in fund due to reimbursement of expenditures	**(30)**	(26)
Increase in due (to) from Province	**(282)**	266
Used Fuel Fund, end of year	**7,010**	6,556

The earnings from the Nuclear Funds during 2012 and 2011 were impacted by the Bruce Lease Net Revenues Variance Account authorized by the OEB. The earnings on the Nuclear Funds for the years ended December 31 are as follows:

(millions of dollars)	**2012**	**2011**
Decommissioning Fund	**405**	108
Used Fuel Fund	**302**	353
Bruce Lease Net Revenues Variance Account *(Note 5)*	**(56)**	48
Total earnings	**651**	509

9. INCOME TAXES

OPG follows the liability method of tax accounting for all its business segments. The Company records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities.

During 2012, OPG recorded a decrease in the deferred income tax liability for the deferred income taxes that are expected to be recovered or refunded through regulated prices charged to customers of $31 million (2011 – $28 million). Since these deferred income taxes are expected to be recovered through future regulated prices, OPG recorded a corresponding decrease to the regulatory asset for deferred income taxes. As a result, the deferred income tax expense for 2012 and 2011 were not impacted.

The amount of tax refund received net of taxes paid during 2012 was $7 million (2011 – $23 million).

The following table summarizes the deferred income tax liabilities recorded for the rate regulated operations that are expected to be recovered through future regulated prices:

(millions of dollars)	2012	2011 *(as adjusted – Note 22)*
January 1:		
Deferred income tax liabilities on temporary differences related to regulated operations	**538**	559
Deferred income tax liabilities resulting from the regulatory asset for deferred income taxes	**161**	168
	699	727
Changes during the year:		
Decrease in deferred income tax liabilities on temporary differences related to regulated operations	**(23)**	(21)
Decrease in deferred income tax liabilities resulting from the regulatory asset for deferred income taxes	**(8)**	(7)
Balance at December 31	**668**	699

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	2012	2011 *(as adjusted – Note 22)*
Income before income taxes	**434**	311
Combined Canadian federal and provincial statutory enacted income tax rates	**26.5%**	28.0%
Statutory income tax rates applied to accounting income	**115**	87
(Decrease) increase in income taxes resulting from:		
Income tax components of the regulatory variance and deferral accounts	**(17)**	24
Non-taxable income items	**(5)**	(13)
Change in income tax positions	**(11)**	(64)
Regulatory asset for deferred income taxes	**15**	41
Scientific Research and Experimental Development investment tax credits	**(28)**	(55)
Adjustment to prior years' current income taxes	**-**	(21)
Other	**(2)**	(26)
	(48)	(114)
Income tax expense (recovery)	**67**	(27)
Effective rate of income taxes	**15.4%**	(8.7%)

Significant components of the income tax expense (recovery) are presented in the table below:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Current income tax expense (recovery):		
Current payable	**21**	65
Change in income tax positions	**(11)**	(64)
Income tax components of the regulatory variance and deferral accounts	**23**	34
Scientific Research and Experimental Development investment tax credits	**(28)**	(55)
Other	**-**	(23)
	5	(43)
Deferred income tax expense:		
Change in temporary differences	**87**	(15)
Income tax components of the regulatory variance and deferral accounts	**(40)**	(10)
Regulatory asset for deferred income taxes	**15**	41
	62	16
Income tax expense (recovery)	**67**	(27)

The income tax effects of temporary differences that give rise to deferred income tax assets and liabilities as at December 31 are as follows:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Deferred income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**3,871**	3,589
Other liabilities and assets	**2,006**	1,653
Future recoverable Ontario minimum tax	**37**	13
	5,914	5,255
Deferred income tax liabilities:		
Property, plant and equipment and intangible assets	**(1,497)**	(1,400)
Nuclear fixed asset removal and nuclear waste management funds	**(3,179)**	(2,974)
Other liabilities and assets	**(1,733)**	(1,340)
	(6,409)	(5,714)
Net deferred income tax liabilities	**(495)**	(459)
Represented by:		
Current portion – asset	**68**	42
Long-term portion – liability	**(563)**	(501)
	(495)	(459)

The tax benefit associated with an income tax position is recognized only when it is more likely than not that such a position will be sustained by the taxing authorities based on the technical merits of the position. The current and deferred income tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(millions of dollars)	**2012**	**2011**
Opening balance, January 1	**68**	130
Additions based on tax positions related to the current year	**29**	5
Additions for tax positions of prior years	**-**	11
Reductions for tax positions of prior years	**(15)**	(26)
Decreases due to lapse of statute of limitations	**-**	(40)
Settlements	**-**	(4)
Other	**-**	(8)
Closing balance, December 31	**82**	68

As at December 31, 2012, OPG's unrecognized tax benefits were $82 million (2011 – $68 million), excluding interest and penalties, all of which, if recognized, would affect OPG's effective tax rate. Changes in unrecognized tax benefits over the next 12 months cannot be predicted with certainty.

OPG recognizes interest and penalties related to unrecognized tax benefits as income tax expense. As at December 31, 2012, OPG has recorded interest on unrecognized tax benefits of $7 million (2011 – $31 million). OPG considers its significant tax jurisdiction to be Canada. OPG remains subject to income tax examination for years after 2005.

10. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

Fund Assets

The OPG registered pension fund investment guidelines are stated in an approved Statement of Investment Policies and Procedures ("SIPP"). The SIPP is reviewed and approved by OPG's Audit and Finance Committee at least annually and includes a discussion regarding investment objectives and expectations, asset mix and rebalancing, and the basis for measuring the performance of the pension fund assets.

In accordance with the SIPP, investment allocation decisions are made with a view to achieve OPG's objective to meet obligations of the plan as they come due. The pension fund assets are invested in two categories of asset classes. The first category is liability hedging assets, which are intended, over the long run, to hedge the inflation and interest rate sensitivity of the plan liabilities. The second category is return enhancing assets, which are intended, over the long run, to obtain higher investment returns compared to the returns expected for liability hedging assets.

To achieve the above objective, OPG has adopted the following long-term asset mix and allowable ranges:

	Minimum	**Target**	**Maximum**
Asset Class			
Fixed income securities	26%	34%	46%
Equity securities	44%	54%	64%
Alternative investments	0%	12%	20%

The plan may enter into derivative securities, such as interest rate swaps and forward foreign exchange contracts, for risk management purposes, where such activity is consistent with its investment objective.

Significant Concentrations of Risk in Fund Assets

The assets of the pension fund are diversified to limit the impact of any individual investment. The pension fund is diversified across multiple asset classes. Fixed income securities are diversified among Canadian structured, real return, and corporate bonds, and an interest rate overlay hedging program. Equity securities are diversified across

Canadian, US, and non-North American stocks. There are also real estate and infrastructure portfolios that are less than three percent of the total pension fund assets. Investments in the above asset classes are further diversified across funds, investment managers, strategies, vintages, sectors and geographies, depending on the specific characteristics of each asset class.

Credit risk with respect to the pension fund's fixed income securities is governed by the SIPP, which requires that fixed income securities comply with various investment constraints that ensure prudent diversification and prescribed minimum required credit rating quality. Credit risk, as it relates to the pension fund's derivatives, is managed through the use of International Swap and Derivatives Association ("ISDA") documentation and counterparty management performed by the fund's investment managers.

Risk Management

Risk management oversight with respect to the pension fund includes but is not limited to the following activities:

- Periodic asset/liability management and strategic asset allocation studies;
- Monitoring of funding levels and funding ratios;
- Monitoring compliance with asset allocation guidelines and investment management agreements;
- Monitoring asset class performance against asset class benchmarks; and
- Monitoring investment manager performance against benchmarks.

Expected Rate of Return on Plan Assets

The expected rate of return on plan assets is based on current and expected asset allocation, as well as the expected return considering long-term historical risks and returns associated with each asset class within the plan portfolio. The asset management decisions consider the economic liabilities of the plan.

Fair Value Measurements

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. Refer to Note 12 for a detailed discussion of fair value measurements and the fair value hierarchy.

The following tables present pension plan assets measured at fair value in accordance with the fair value hierarchy:

	December 31, 2012			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	**81**	**116**	**-**	**197**
Short-term investments	**-**	**5**	**-**	**5**
Fixed income				
Corporate debt securities	**-**	**308**	**-**	**308**
Non-US government bonds	**-**	**1,601**	**-**	**1,601**
Equities				
Canadian	**1,988**	**-**	**-**	**1,988**
US	**1,664**	**-**	**-**	**1,664**
Foreign	**1,907**	**-**	**-**	**1,907**
Pooled funds	**8**	**2,396**	**8**	**2,412**
Infrastructure	**-**	**-**	**160**	**160**
Real estate	**-**	**-**	**72**	**72**
Other	**-**	**5**	**-**	**5**
	5,648	**4,431**	**240**	**10,319** [1]

[1] The table above exclude pension fund receivables and payables.

(millions of dollars)	December 31, 2011 Level 1	Level 2	Level 3	Total
Cash and cash equivalents	132	92	-	224
Short-term investments	-	6	-	6
Fixed income				
Corporate debt securities	-	277	-	277
Non-US government bonds	-	2,301	-	2,301
Equities				
Canadian	1,841	-	-	1,841
US	1,552	-	-	1,552
Foreign	1,572	-	-	1,572
Pooled funds	3	1,664	7	1,674
Infrastructure	-	-	86	86
Real estate	-	-	52	52
Other	-	3	-	3
	5,100	4,343	145	9,588 [1]

[1] The table above exclude pension fund receivables and payables.

The following tables present the changes in the fair value of financial instruments classified in Level 3:

(millions of dollars)	For the year ended December 31, 2012 Pooled Funds	Infrastructure	Real Estate	Total
Opening balance, January 1, 2012	**7**	**86**	**52**	**145**
Total realized and unrealized gains	**1**	**74**	**7**	**82**
Purchases, sales, and settlements	**-**	**-**	**13**	**13**
Closing balance, December 31, 2012	**8**	**160**	**72**	**240**

(millions of dollars)	For the year ended December 31, 2011 Pooled Funds	Infrastructure	Real Estate	Total
Opening balance, January 1, 2011	-	39	3	42
Total realized and unrealized gains	-	6	-	6
Purchases, sales, and settlements	7	41	49	97
Closing balance, December 31, 2011	7	86	52	145

During the year ended December 31, 2012 and 2011, there were no transfers between Level 1 and Level 2. During 2011, a $9 million transfer occurred from Level 1 to Level 3 as an investment was no longer actively traded.

Plan Costs and Liabilities

Details of OPG's pension and OPEB obligations, pension fund assets and costs are presented in the following tables:

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2012	**2011**	**2012**	**2011**
Weighted Average Assumptions – Benefit Obligations at Year-End				
Rate used to discount future benefits	**4.30%**	5.10%	**4.32%**	5.07%
Salary schedule escalation rate	**2.50%**	3.00%	**-**	-
Rate of cost of living increase to pensions	**2.00%**	2.00%	**-**	-
Initial health care trend rate	**-**	-	**6.38%**	6.48%
Ultimate health care trend rate	**-**	-	**4.38%**	4.38%
Year ultimate health care trend rate reached	**-**	-	**2030**	2030
Rate of increase in disability benefits	**-**	-	**2.00%**	2.00%

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2012	**2011**	**2012**	**2011**
Weighted Average Assumptions – Costs for the Year				
Expected return on plan assets, net of expenses	**6.50%**	6.50%	**-**	-
Rate used to discount future benefits	**5.10%**	5.80%	**5.07%**	5.67%
Salary schedule escalation rate	**3.00%**	3.00%	**-**	-
Rate of cost of living increase to pensions	**2.00%**	2.00%	**-**	-
Initial health care trend rate	**-**	-	**6.48%**	6.53%
Ultimate health care trend rate	**-**	-	**4.38%**	4.69%
Year ultimate health care trend rate reached	**-**	-	**2030**	2030
Rate of increase in disability benefits	**-**	-	**2.00%**	2.00%
Expected average remaining service life for employees (years)	**12**	12	**13**	11

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011** *(adjusted)*
Components of Cost Recognized						
Current service costs	**264**	210	**9**	9	**78**	76
Interest on projected benefit obligation	**618**	603	**14**	13	**139**	133
Expected return on plan assets, net of expenses	**(668)**	(629)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	10	**-**	-	**2**	2
Amortization of net actuarial loss [1]	**144**	66	**4**	2	**31**	22
Recognition of LTD net actuarial loss	**-**	-	**-**	-	**10**	13
Cost recognized [2]	**358**	260	**27**	24	**260**	246

[1] The amortization of past service costs and net actuarial loss is recognized as an increase to OCI. This increase is partially offset by the impact of the Pension and OPEB Regulatory Asset as discussed in Note 5.

[2] These pension and OPEB costs exclude the reduction of costs resulting from the recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account and the Impact for USGAAP Deferral Account. The Pension and OPEB Cost Variance Account and the Impact for USGAAP Deferral Account are discussed in Note 5.

Total benefit costs, including the impact of the Pension and OPEB Cost Variance Account and Impact for USGAAP Deferral Account, for the years ended December 31 are as follows:

(millions of dollars)	**2012**	**2011** *(adjusted)*
Registered pension plans	**358**	260
Supplementary pension plans	**27**	24
Other post-employment benefits	**260**	246
Pension and OPEB Cost Variance Account *(Note 5)*	**(192)**	(74)
Impact for USGAAP Deferral Account *(Note 5)*	**(47)**	-
Pension and other post-employment benefit costs	**406**	456

The pension and OPEB obligations and the pension fund assets, measured as at December 31 are as follows:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Change in Plan Assets						
Fair value of plan assets at beginning of year	**9,604**	9,118	**-**	-	**-**	-
Contributions by employer	**375**	302	**16**	8	**83**	80
Contributions by employees	**77**	80	**-**	-	**-**	-
Actual return on plan assets, net of expenses	**898**	586	**-**	-	**-**	-
Benefit payments	**(617)**	(482)	**(16)**	(8)	**(83)**	(80)
Fair value of plan assets at end of year	**10,337**	9,604	**-**	-	**-**	-
Change in Projected Benefit Obligations						
Projected benefit obligations at beginning of year	**12,197**	10,375	**261**	219	**2,708**	2,341
Employer current service costs	**264**	210	**9**	9	**78**	76
Contributions by employees	**77**	80	**-**	-	**-**	-
Interest on projected benefit obligation	**618**	603	**14**	13	**139**	133
Benefit payments	**(617)**	(482)	**(16)**	(8)	**(83)**	(80)
Past service (credits) costs	**-**	-	**-**	-	**(7)**	1
Net actuarial loss	**1,130**	1,411	**29**	28	**339**	237
Projected benefit obligations at end of year	**13,669**	12,197	**297**	261	**3,174**	2,708
Funded status – deficit at end of year	**(3,332)**	(2,593)	**(297)**	(261)	**(3,174)**	(2,708)

The following table provides the pension and OPEB liabilities and their classification on the Consolidated Balance Sheets as at December 31:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2012**	**2011** *(adjusted)*	**2012**	**2011** *(adjusted)*	**2012**	**2011** *(adjusted)*
Current liabilities	**-**	-	**(8)**	(7)	**(98)**	(92)
Non-current liabilities	**(3,332)**	(2,593)	**(289)**	(254)	**(3,076)**	(2,616)
Total liabilities	**(3,332)**	(2,593)	**(297)**	(261)	**(3,174)**	(2,708)

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2012 are $12,366 million and $242 million, respectively (2011 – $11,029 million and $216 million, respectively). The accumulated benefit obligation differs from the projected benefit obligation in that the accumulated benefit obligation includes no assumption about future compensation levels.

The following table provides the components of OPG's OCI related to pension and OPEB plans and the offsetting Pension and OPEB Regulatory Asset as discussed in Note 5 for the years ended December 31:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Changes in plan assets and benefit obligations recognized in OCI						
Current year past service (credits) costs	**-**	-	**-**	-	**(7)**	1
Current year net actuarial loss	**900**	1,454	**29**	28	**329**	224
Amortization of past service costs	**-**	(10)	**-**	-	**(2)**	(2)
Amortization of net actuarial loss	**(144)**	(66)	**(4)**	(2)	**(31)**	(22)
Total decrease in OCI	**756**	1,378	**25**	26	**289**	201
Less: Increase in Pension and OPEB Regulatory Asset *(Note 5)*	**675**	1,114	**21**	21	**245**	164
Net decrease in OCI	**81**	264	**4**	5	**44**	37

The following table provides the components of OPG's AOCI and the offsetting Pension and OPEB Regulatory Asset that have not yet been recognized as components of benefit costs as at December 31:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Unamortized amounts recognized in AOCI						
Past service costs	**-**	-	**-**	-	**4**	13
Net actuarial loss	**4,537**	3,781	**102**	77	**950**	652
Total recognized in AOCI	**4,537**	3,781	**102**	77	**954**	665
Less: Pension and OPEB Regulatory Asset *(Note 5)*	**3,645**	2,970	**82**	61	**767**	522
Net recognized in AOCI	**892**	811	**20**	16	**187**	143

The following table provides the components of OPG's AOCI and the offsetting Pension and OPEB Regulatory Asset as at December 31 (included in the table above) that are expected to be amortized as components of benefit costs and recognized as increases to OCI and reductions in the Pension and OPEB Regulatory Asset in 2013:

(millions of dollars)	**Registered Pension Plans**	**Supplementary Pension Plans**	**Other Post-Employment Benefits**
Past service costs	**-**	**-**	**1**
Net actuarial loss	**244**	**6**	**49**
Total increase in AOCI	**244**	**6**	**50**
Less: Estimated decrease in Pension and OPEB Regulatory Asset	**196**	**5**	**40**
Net increase in AOCI	**48**	**1**	**10**

Based on the most recently filed actuarial valuation of the OPG registered pension plan, as at January 1, 2011, there was an unfunded liability on a going-concern basis of $555 million and a deficiency on a wind-up basis of $5,663 million. In the previously filed actuarial valuation, as at January 1, 2008, there was an unfunded liability on a going-concern basis of $239 million and a deficiency on a wind-up basis of $2,846 million. The funded status to be determined in the next filed funding valuation, which must have an effective date no later than January 1, 2014, could be significantly different. For 2013, OPG's contribution to its registered pension plan is expected to be $300 million. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time. OPG will continue to assess the requirements for contributions to the pension plan.

Based on the most recently filed actuarial valuation of the NWMO registered pension plan, as at January 1, 2012, there was a surplus on a going-concern basis of $8 million and a deficiency on a wind-up basis of $15 million. In the previously filed actuarial valuation, as at January 1, 2011, there was a surplus on a going-concern basis of $6 million and a deficiency on a wind-up basis of $5 million. The next filed funding valuation must have an effective date no later than January 1, 2013.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $332 million as at December 31, 2012 (2011 – $290 million).

Estimated future benefit payments to participants in the pension and OPEB plans based on the assumptions used to measure the benefit obligations as at December 31, 2012 are as follows:

(millions of dollars)	**Registered Pension Plans**	**Supplementary Pension Plans**	**Other Post-Employment Benefits**
2013	587	8	98
2014	590	8	103
2015	599	9	108
2016	625	10	113
2017	672	11	119
2018 through 2021	3,788	73	687

A one percent increase or decrease in the health care trend rate would result in an increase in the current service and interest components of the 2012 OPEB cost recognized of $48 million (2011 – $41 million) or a decrease in the service and interest components of the 2012 OPEB cost recognized of $36 million (2011 – $31 million). A one percent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation at December 31, 2012 of $604 million (2011 – $478 million) or a decrease in the projected OPEB obligation at December 31, 2012 of $456 million (2011 – $369 million).

11. DERIVATIVES

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

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to undertake new financing and with the 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 financing.

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 project. The LME has 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 River project.

Electricity price risk for the Company is the potential for adverse movements in the market price of electricity. Exposure to electricity price risk is reduced as a result of regulated prices and other contractual arrangements for a significant portion of OPG's business.

The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative. Assumptions related to future electricity prices impact the valuation of the derivative liability embedded in the Bruce Lease.

OPG's foreign exchange exposure is attributable to two primary factors: US dollar denominated transactions such as the purchase of fuels; and the influence of US dollar denominated commodity prices on Ontario electricity market prices.

OPG enters into foreign exchange derivatives and agreements with major financial institutions, when necessary, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO-administered spot market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at December 31, 2012 was $1 million.

The following is a summary of OPG's derivative instruments:

(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Balance Sheet Line Item**
As at December 31, 2012				
Commodity derivative instruments	**4.3 TWh**	**1 - 2 years**	**7**	Other accounts receivable and prepaid expenses
Foreign exchange derivative instruments	**63**	**within 1 year**	**(1)**	Accounts payable and accrued charges
Commodity derivative instruments	**2.0 TWh**	**1 - 2 years**	**(4)**	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	**410**	**1 - 12 years**	**(66)**	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	**n/a**	**7 years**	**(392)**	Long-term accounts payable and accrued charges
Total derivatives			**(456)**	

(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Balance Sheet Line Item**
As at December 31, 2011 *(as adjusted – Note 22)*				
Commodity derivative instruments	2.3 TWh	2 - 3 years	3	Other accounts receivable and prepaid expenses
Commodity derivative instruments	0.2 TWh	2 - 3 years	(1)	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	760	1 - 13 years	(115)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	n/a	3 years	(186)	Long-term accounts payable and accrued charges
Total derivatives			(299)	

The following table shows the amount related to derivatives recorded in AOCI and income for the years ended December 31:

(millions of dollars)	**2012**	**2011**
Cash flow hedges		
Loss in OCI	**(12)**	(120)
Reclassification of losses to net interest expense	**19**	7
Commodity derivatives		
Realized gains in revenue	**-**	1
Unrealized (losses) gains in revenue	**(1)**	2
Embedded derivative		
Unrealized losses in revenue[1]	**(284)**	(23)

[1] Excludes the impact of the Bruce Lease Net Revenues Variance Account.

Existing net losses of $14 million deferred in AOCI as at December 31, 2012 are expected to be reclassified to net income within the next 12 months.

12. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. The level within which the financial asset or liability is classified is determined based on the attribute of significance to the inputs to the fair value measurement. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

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 current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. 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. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. 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. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The Company is required to determine the fair value of all its financial instruments. The following is a summary of OPG's financial instruments as at December 31:

(millions of dollars except where noted)	**Fair Value**	**Carrying Value** [1]	**Balance Sheet Line Item**
As at December 31, 2012			
Commodity derivative instruments	**7**	**7**	Other accounts receivable and prepaid expenses
Investments in OPG Ventures Inc.	**10**	**10**	Other long-term assets
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	**12,717**	**12,717**	Nuclear fixed asset removal and nuclear waste management funds
Foreign exchange derivative instruments	**(1)**	**(1)**	Accounts payable and accrued charges
Commodity derivative instruments	**(4)**	**(4)**	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	**(66)**	**(66)**	Long-term accounts payable and accrued charges
Payable related to cash flow hedges	**(24)**	**(24)**	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	**(392)**	**(392)**	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(5,751)**	**(5,114)**	Long-term debt
As at December 31, 2011 *(as adjusted – Note 22)*			
Commodity derivative instruments	3	3	Other accounts receivable and prepaid expenses
Investments in OPG Ventures Inc.	32	32	Other long-term assets
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	11,898	11,898	Nuclear fixed asset removal and nuclear waste management funds
Commodity derivative instruments	(1)	(1)	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	(115)	(115)	Long-term accounts payable and accrued charges
Payable related to cash flow hedges	(4)	(4)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	(186)	(186)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	(5,273)	(4,744)	Long-term debt

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other accounts receivable and prepaid expenses, and accounts payable and accrued charges approximate their fair value due to the immediate or short-term maturity of these financial instruments.

The fair value of long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve, and term to maturity. These inputs are considered Level 2 inputs.

The following tables present financial assets and liabilities measured at fair value in accordance with the fair value hierarchy:

	December 31, 2012			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	**2,596**	**2,948**	**163**	**5,707**
Used Fuel Fund	**212**	**6,785**	**13**	**7,010**
Commodity derivative instruments	**2**	**2**	**3**	**7**
Investment in OPG Ventures Inc.	**-**	**-**	**10**	**10**
Total	**2,810**	**9,735**	**189**	**12,734**
Liabilities				
Derivative embedded in the Bruce Lease	**-**	**-**	**(392)**	**(392)**
Forward start interest rate swaps	**-**	**(66)**	**-**	**(66)**
Commodity derivative instruments	**(3)**	**(1)**	**-**	**(4)**
Foreign exchange derivative instruments	**-**	**(1)**	**-**	**(1)**
Total	**(3)**	**(68)**	**(392)**	**(463)**
Net assets (liabilities)	**2,807**	**9,667**	**(203)**	**12,271**

	December 31, 2011 *(as adjusted – Note 22)*			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	2,294	2,950	98	5,342
Used Fuel Fund	131	6,419	6	6,556
Commodity derivative instruments	-	1	2	3
Investment in OPG Ventures Inc.	16	-	16	32
Total	2,441	9,370	122	11,933
Liabilities				
Derivative embedded in the Bruce Lease	-	-	(186)	(186)
Forward start interest rate swaps	-	(115)	-	(115)
Commodity derivative instruments	-	(1)	-	(1)
Total	-	(116)	(186)	(302)
Net assets (liabilities)	2,441	9,254	(64)	11,631

During the year ended December 31, 2012, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into and out of Level 3.

The following tables present the changes in OPG's assets and liabilities measured at fair value based on Level 3:

(millions of dollars)	For the year ended December 31, 2012				
	Decom-missioning Fund	**Used Fuel Fund**	**Investments in OPG Ventures Inc.**	**Derivative Embedded in the Bruce Lease [1]**	**Commodity Derivative Instruments**
Opening balance, January 1, 2012	**98**	**6**	**16**	**(186)**	**2**
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds[1]	**11**	**1**	**-**	**-**	**-**
Unrealized losses included in revenue	**-**	**-**	**(5)**	**(284)**	**(1)**
Realized losses included in revenue	**-**	**-**	**-**	**-**	**(5)**
Purchases	**58**	**6**	**-**	**-**	**7**
Sales	**(2)**	**-**	**-**	**-**	**-**
Settlements	**(2)**	**-**	**(1)**	**78**	**-**
Closing balance, December 31, 2012	**163**	**13**	**10**	**(392)**	**3**

[1] Total gains (losses) exclude the impact of regulatory assets and liabilities.

(millions of dollars)	For the year ended December 31, 2011				
	Decom-missioning Fund	**Used Fuel Fund**	**Investments in OPG Ventures Inc.**	**Derivative Embedded in the Bruce Lease [1]**	**Commodity Derivative Instruments**
Opening balance, January 1, 2011	29	1	17	(163)	2
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds [1]	3	-	-	-	-
Unrealized gains (losses) included in revenue	-	-	3	(23)	-
Purchases	73	5	-	-	-
Settlements	(8)	-	(4)	-	-
Transfers into Level 3	1	-	-	-	-
Closing balance, December 31, 2011	98	6	16	(186)	2

[1] Total gains (losses) exclude the impact of regulatory assets and liabilities.

Derivative Embedded in the Bruce Lease

The revenue from the Bruce Lease is reduced in each calendar year where the expected future annual arithmetic average hourly Ontario electricity price falls below $30/MWh and certain other conditions are met. The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative.

Due to an unobservable input used in the pricing model of the Bruce Lease embedded derivative, the measurement of the liability is classified within Level 3.

The following table presents the quantitative information about the Level 3 fair value measurement of the Bruce Lease embedded derivative as at December 31, 2012:

(millions of dollars except where noted)	**Fair Value**	**Valuation Technique**	**Unobservable Input**	**Range**
Derivative embedded in the Bruce Lease	(392)	Option model	Risk premium [1]	0% - 30%

[1] Represents the range of premiums used in the valuation analysis that OPG has determined market participants would use when pricing the derivative.

The term related to the derivative embedded in the Bruce Lease is based on the remaining service lives, for accounting purposes, for certain units of the Bruce generating stations. In 2012, the service life of these Bruce units was extended to 2019. The service life extension accounted for $249 million of the total increase in the derivative liability during 2012. OPG's exposure to changes in the fair value of the Bruce Lease embedded derivative is mitigated as part of the OEB regulatory process, since the revenue from the lease of the Bruce generating stations is included in the determination of regulated prices and is subject to the Bruce Lease Net Revenues Variance Account. As such, the pre-tax income statement impact, as a result of changes in the derivative liability, is offset by the pre-tax income statement impact of the Bruce Lease Net Revenues Variance Account.

Decommissioning Fund and Used Fuel Fund

Nuclear Funds investments classified as Level 3 consist of real estate and infrastructure investments within the alternative investment portfolio. The fair value of the investments within the Nuclear Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, reference to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity, or other discount premiums on the investments are considered in the determination of fair value.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for the investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Funds that are reported on the basis of net asset value as at December 31, 2012:

(millions of dollars)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Infrastructure	240	118	n/a	n/a
Real Estate	122	525	n/a	n/a
Pooled Funds				
Short-term Investments	24	-	Daily	1 - 5 days
Fixed Income	772	-	Daily	1 - 5 days
Equity	1,297	-	Daily	1 - 5 days
Total	2,455	643		

The fair value of the above investments is classified as either Level 2 or Level 3.

Infrastructure

This class includes investments in infrastructure funds whose investment objective is to generate a combination of long-term capital appreciation and current income, generally through investments in energy, transportation, and utilities.

The fair values of investments in this class have been estimated using the Nuclear Funds' ownership interest in partners' capital and/or underlying investments held by subsidiaries of an infrastructure fund.

The investments can never be redeemed with the respective infrastructure funds. However, the Nuclear Funds may transfer any of its partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets of the infrastructure funds will be liquidated, however, the infrastructure funds have a maturity end period ranging from 2019 to 2023.

Real Estate

This class includes investment in institutional-grade real estate property located in Canada. The investment objective is to provide a stable level of income with the opportunity for long-term capital appreciation.

The fair values of the investments in this class have been estimated using the net asset value of the Nuclear Funds' ownership interest in these investments.

The partnership investments can never be redeemed. However, the Nuclear Funds may transfer any of its partnership interests to another party, as stipulated in the partnership agreement, with prior written consent of the other limited partners. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this class will be liquidated.

Pooled Funds

This class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations and diversified portfolios of US and Emerging Market listed equity and fixed income securities. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios.

The fair value of the investments in this class has been estimated using the net asset value per share of the investments.

There are no significant restrictions on the ability to sell investments in this class.

Investment in OPG Ventures Inc.

Significant Level 3 inputs used in the fair value measurement of the OPG Ventures Inc. investments include recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors. Significant increases (decreases) in any of those inputs in isolation would result in significantly higher (lower) fair value measurement.

13. COMMON SHARES

As at December 31, 2012 and 2011, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder.

14. 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 defending an arbitration commenced by some of the current owners of Bruce Power L.P. regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power L.P. (the "Arbitration"). In the second quarter of 2012, the arbitrator released an interim award. The arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The arbitrator determined what elements of the claim British Energy was liable for, but did not award a specific amount in damages as it was found that further evidence from the parties is necessary to quantify the exact amount of the damages. If the parties to the Arbitration cannot agree on the quantum of damages, there will be further proceedings before the arbitrator to determine the amount. British Energy counsel has indicated that the damages payable to the claimants will likely be less than $70 million.

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 Defense. 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 Defense 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.

During 2011, OPG settled a claim and arbitration with a certain First Nation 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 2011. This settlement did not have a material impact on the Company's financial position.

Certain 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 the consolidated financial statements to meet certain other environmental obligations. During 2011, a reduction of

$19 million to the environmental liabilities was recognized related to the Regulated – Hydroelectric segment. As at December 31, 2012, OPG's environmental liabilities were $17 million (2011 – $19 million).

Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at December 31, 2012, the total amount of guarantees OPG provided to these entities was $73 million. OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2028. The potential impact of the fair value of these guarantees to income has been estimated as at December 31, 2012 to be negligible. As at December 31, 2012, OPG does not expect to make any payments associated with these guarantees.

Contractual and Commercial Commitments

The Company's contractual obligations and other significant commercial commitments as at December 31, 2012 are as follows:

(millions of dollars)	2013	2014	2015	2016	2017	Thereafter	Total
Contractual obligations:							
Fuel supply agreements	196	166	174	122	113	291	1,062
Contributions under the ONFA [1]	211	139	143	150	163	2,899	3,705
Long-term debt repayment	5	5	593	273	1,103	3,135	5,114
Interest on long-term debt	240	239	234	220	201	1,679	2,813
Unconditional purchase obligations	104	98	97	8	-	-	307
Operating lease obligations	15	15	16	17	17	78	158
Operating licence	38	41	41	6	-	-	126
Pension contributions [2]	300	-	-	-	-	-	300
Other	31	81	32	33	36	95	308
	1,140	784	1,330	829	1,633	8,177	13,893
Significant commercial commitments:							
Niagara Tunnel	44	-	-	-	-	-	44
Lower Mattagami	477	315	116	-	-	-	908
Atikokan Biomass Conversion	65	6	-	-	-	-	71
Total	1,726	1,105	1,446	829	1,633	8,177	14,916

[1] Contributions under the ONFA are based on the 2012 ONFA Reference Plan contribution schedule approved in 2012.

[2] The pension contributions include ongoing funding requirements, and additional funding requirements towards the deficit, in accordance with the actuarial valuations of the OPG registered pension plan as at January 1, 2011 and NWMO registered pension plans as at January 1, 2012. The next actuarial valuations of the OPG and NWMO plans must have effective dates no later than January 1, 2014 and 2013, respectively. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2013 for the OPG registered pension plan are excluded due to significant variability in the assumption required to project the timing of future cash flows. Funding requirements for 2013 for the NWMO registered pension plan are also excluded. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time.

Niagara Tunnel

All major tunnel lining activities at the Niagara Tunnel were completed in 2012, with the exception of pre-stress grouting to complete the attachment of the concrete liner with the surrounding rock. Disassembly of the tunnel boring machine was completed in 2012. In early March 2013, final testing is underway with water flowing through the Niagara Tunnel prior to declaring it in-service, more than nine months ahead of the approved project completion date of December 2013. The capital project expenditures for 2012 were $231 million and the life-to-date capital expenditures as at December 31, 2012 were $1.4 billion. The project is debt financed through the OEFC. Total costs of the project at completion are expected to be approximately $1.5 billion, compared to the approved budget of $1.6 billion.

Lower Mattagami

The Lower Mattagami River project will increase the capacity of the four generating stations on the Lower Mattagami River by 438 MW. The capital project expenditures for the year ended December 31, 2012 were $589 million and the life-to-date expenditures were $1.4 billion. The project budget of $2.6 billion includes the design-build contract, as well as contingencies, interest, and other OPG costs, including project management, contract management, impact agreements with First Nations, and transmission connection costs.

Atikokan Biomass Conversion

OPG is proceeding with its project to convert the Atikokan generating station from coal to biomass fuel. The converted station is expected to have a capacity of 200 MW. The conversion project has an approved cost estimate of $170 million and is expected to be completed in the first half of 2014.

Darlington Refurbishment

On March 1, 2012, OPG awarded a Retube and Feeder Replacement contract. The contract will be completed in two phases – a definition phase which includes the planning, design and testing of tooling, design and construction of a full scale reactor mock-up facility for testing and training, and an execution phase including the removal and replacement of major reactor components of the four reactors at the Darlington generating station. The contract value during the definition phase, for the period to 2015 is estimated at over $600 million. The execution phase work, which is still to be estimated and valued, includes removal and replacement of the 480 pressure tubes and calandria tubes, and 960 feeder pipes for each of the station's four reactors. Capital project expenditures for 2012 were $232 million and the life-to-date capital expenditures as at December 31, 2012 were $362 million. A detailed cost and schedule estimate for the refurbishment of the four units is expected to be completed in 2015.

Lease Commitments

The Company is party to various leases for real estate and equipment under operating lease arrangements. Real estate and transport equipment base rent expense for the year ended December 31, 2012 was $16 million (2011 – $17 million).

The Company leases Bruce A and B nuclear generating stations to Bruce Power L.P. until 2018, with Bruce Power L.P. having an option to renew for up to 25 years thereafter.

As per *Ontario Regulation 53/05* pursuant to the *Ontario Energy Board Act, 1998*, the difference between OPG's revenues, including lease revenues, and costs, including depreciation expense, associated with its ownership of the Bruce A and B nuclear generating stations is included in the determination of OPG's nuclear regulated prices established by the OEB. These revenues and costs are determined on the basis of the manner in which they are recognized in OPG's consolidated financial statements. As the Bruce assets are not Prescribed Facilities under *Ontario Regulation 53/05*, the net book value of the Bruce assets is not included in the rate base.

During 2012, OPG recorded lease revenue related to the Bruce generating stations of $164 million (2011 – $235 million), which included supplemental rent from Bruce Power L.P. of $113 million (2011 – $184 million), net of a required rebate of $78 million. The net book value of property, plant and equipment on lease to Bruce Power L.P. at December 31, 2012 was $1,963 million (2011 – $1,317 million).

Base rent payments as stipulated in the lease agreement due to the Company from Bruce Power L.P. are as follows:

(millions of dollars)	
2013	**81**
2014	**83**
2015	**85**
2016	**88**
2017	**90**
	427

Other Commitments

The Company maintains labour agreements with the Power Workers' Union ("PWU") and the Society of Energy Professionals ("The Society"). As at December 31, 2012, OPG had approximately 10,840 regular employees and about 89 percent of its regular labour force was covered by the collective bargaining agreements. The current collective agreement between OPG and the PWU has a three-year term, which expires on March 31, 2015. The collective agreement with The Society expired on December 31, 2012. OPG and The Society were unable to agree upon the terms for a renewal of the collective agreement and the dispute is currently before an arbitrator for resolution. The outcome of the arbitration will determine the terms and duration of a new collective agreement. The results of the arbitration are expected in the spring of 2013.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

Proxy Property Taxes

In November 2005, OPG received a letter from the Ministry of Finance ("MOF") indicating its intent to recommend to the Minister of Finance that an Ontario regulation covering proxy property taxes be updated retroactive to April 1, 1999, to reflect reassessments and appeal settlements of certain OPG properties since that date. OPG continues to monitor the resolution to this issue with the MOF, as updates to the regulation may not occur for several years. OPG has not recorded any amounts relating to this anticipated regulation change.

15. BUSINESS SEGMENTS

OPG has five reportable business segments. The business segments are: Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal.

Regulated – Nuclear Generation Segment

OPG's Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement and related agreements with Bruce Power L.P. related to the Bruce nuclear generating stations. This revenue includes lease revenue and revenue from services such as heavy water sales and detritiation. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power and from isotope sales and ancillary services are included in the determination of the regulated prices for OPG's nuclear facilities by the OEB.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment engages in the management of used nuclear fuel and L&ILW, the decommissioning of OPG's nuclear generating stations (including the stations on lease to Bruce Power L.P.), the management of the Nuclear Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense on the Nuclear Liabilities and earnings from the Nuclear Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs variable costs related to nuclear used fuel and L&ILW generated. These costs increase the Nuclear Liabilities through the generation of additional used nuclear fuel bundles and other waste. These variable costs are charged to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy and earning revenue under the Bruce Lease and related agreements. Since variable costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated on OPG's Consolidated Statements of Income and Balance Sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because the costs associated with the Nuclear Liabilities are included in the determination of regulated prices for production from OPG's regulated nuclear facilities by the OEB.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Ancillary revenues and other revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services. These ancillary revenues and other revenues are included in the determination of the regulated prices for these facilities by the OEB.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from the Company's hydroelectric generating stations, which are not subject to rate regulation. Ancillary revenues and other revenues are earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services.

Unregulated – Thermal Segment

The Unregulated – Thermal business segment operates in Ontario, generating and selling electricity from the Company's thermal generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, automatic generation control, and other services.

Other

The Other category includes revenue that OPG earns from its 50 percent joint venture share of Brighton Beach related to an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc. This category also includes revenue that OPG earns from its 50 percent joint venture share of the PEC gas-fired generating station, which is operated under the terms of an Accelerated Clean Energy Supply contract with the OPA. The revenue and expenses related to OPG's trading and other non-hedging activities are also reported in the Other category. As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in the Other category. In addition, the Other category includes revenue from real estate rentals.

OM&A expenses of the generation segments include an inter-segment service fee for the use of certain property, plant and equipment, and intangible assets held within the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses.

The service fee included in OM&A expenses by segment for the years ended December 31 is as follows:

(millions of dollars)	**2012**	**2011**
Regulated – Nuclear Generation	**23**	22
Regulated – Hydroelectric	**2**	2
Unregulated – Hydroelectric	**3**	4
Unregulated – Thermal	**6**	7
Other	**(34)**	(35)

Segment Income (Loss) for the Year Ended December 31, 2012 *(millions of dollars)*	**Regulated**			**Unregulated**				
	Nuclear Generation	**Nuclear Waste Management**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Elimination**	**Total**
Revenue	**3,060**	**107**	**724**	**373**	**511**	**60**	**(103)**	**4,732**
Fuel expense	**261**	**-**	**261**	**71**	**162**	**-**	**-**	**755**
Gross margin	**2,799**	**107**	**463**	**302**	**349**	**60**	**(103)**	**3,977**
Operations, maintenance and administration	**1,930**	**114**	**103**	**236**	**361**	**7**	**(103)**	**2,648**
Depreciation and amortization	**480**	**-**	**33**	**73**	**59**	**19**	**-**	**664**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**712**	**-**	**-**	**13**	**-**	**-**	**725**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(651)**	**-**	**-**	**-**	**-**	**-**	**(651)**
Property and capital taxes	**26**	**-**	**(1)**	**(1)**	**16**	**7**	**-**	**47**
Restructuring	**-**	**-**	**-**	**-**	**3**	**-**	**-**	**3**
Other (income) loss	**(1)**	**-**	**4**	**4**	**9**	**(26)**	**-**	**(10)**
Income (loss) before interest and income taxes	**364**	**(68)**	**324**	**(10)**	**(112)**	**53**	**-**	**551**

Segment Income (Loss) for the Year Ended December 31, 2011 *(millions of dollars)* *(as adjusted – Note 22)*	**Regulated**		**Unregulated**					
	Nuclear Generation	**Nuclear Waste Management**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Elimination**	**Total**
Revenue	3,061	57	729	492	608	72	(55)	4,964
Fuel expense	243	-	261	75	175	-	-	754
Gross margin	2,818	57	468	417	433	72	(55)	4,210
Operations, maintenance and administration	2,001	65	108	239	419	4	(55)	2,781
Depreciation and amortization	473	-	38	75	88	20	-	694
Accretion on fixed asset removal and nuclear waste management liabilities	-	695	-	-	9	-	-	704
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(509)	-	-	-	-	-	(509)
Property and capital taxes	26	-	-	(2)	15	11	-	50
Restructuring	-	-	-	-	21	-	-	21
Other (income) loss	(3)	-	(19)	(2)	83	(55)	-	4
Income (loss) before interest and income taxes	321	(194)	341	107	(202)	92	-	465

Selected Consolidated Balance Sheet Information as at December 31, 2012 *(millions of dollars)*	**Regulated**		**Unregulated**				
	Nuclear Generation	**Nuclear Waste Management**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Total**
Segment property, plant and equipment in-service, net	**4,921**	**-**	**3,695**	**3,310**	**256**	**176**	**12,358**
Segment construction in progress	**553**	**-**	**1,392**	**1,479**	**69**	**9**	**3,502**
Segment property, plant and equipment, net	**5,474**	**-**	**5,087**	**4,789**	**325**	**185**	**15,860**
Segment intangible assets in-service, net	**21**	**-**	**-**	**5**	**-**	**16**	**42**
Segment development in progress	**2**	**-**	**-**	**-**	**-**	**8**	**10**
Segment intangible assets, net	**23**	**-**	**-**	**5**	**-**	**24**	**52**
Segment materials and supplies inventory, net:							
Short-term	**83**	**-**	**-**	**-**	**7**	**-**	**90**
Long-term	**327**	**-**	**-**	**1**	**27**	**-**	**355**
Segment fuel inventory	**328**	**-**	**-**	**-**	**177**	**-**	**505**
Nuclear fixed asset removal and nuclear waste management funds	**-**	**12,717**	**-**	**-**	**-**	**-**	**12,717**
Fixed asset removal and nuclear waste management liabilities	**-**	**(15,177)**	**-**	**-**	**(313)**	**(32)**	**(15,522)**

Selected Consolidated Balance Sheet Information as at December 31, 2011 *(millions of dollars)* *(as adjusted – Note 22)*	**Regulated**			**Unregulated**			
	Nuclear Generation	**Nuclear Waste Management**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Total**
Segment property, plant and equipment in-service, net	4,745	-	3,749	3,333	307	182	12,316
Segment construction in progress	295	-	1,146	847	15	14	2,317
Segment property, plant and equipment, net	5,040	-	4,895	4,180	322	196	14,633
Segment intangible assets in-service, net	17	-	-	5	1	17	40
Segment development in progress	6	-	-	-	-	4	10
Segment intangible assets, net	23	-	-	5	1	21	50
Segment materials and supplies inventory, net:							
Short-term	68	-	-	-	14	-	82
Long-term	348	-	-	1	31	-	380
Segment fuel inventory	354	-	-	-	301	-	655
Nuclear fixed asset removal and nuclear waste management funds	-	11,898	-	-	-	-	11,898
Fixed asset removal and nuclear waste management liabilities	-	(14,060)	-	-	(300)	(32)	(14,392)

Selected Consolidated Cash Flow Information *(millions of dollars)*	**Regulated**			**Unregulated**			
	Nuclear Generation	**Nuclear Waste Management**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Total**
Year ended December 31, 2012							
Investment in property, plant and equipment, and intangible assets	**394**	**-**	**261**	**674**	**62**	**36**	**1,427**
Year ended December 31, 2011							
Investment in property, plant and equipment, and intangible assets	239	-	297	566	9	34	1,145

16. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Receivables from related parties	**(16)**	48
Other accounts receivable and prepaid expenses	**(22)**	(25)
Fuel inventory	**150**	79
Income taxes payable/recoverable	**(5)**	7
Materials and supplies	**(8)**	2
Accounts payable and accrued charges	**73**	55
	172	166

17. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province, Infrastructure Ontario, OPA, the other successor entities of Ontario Hydro, including Hydro One Inc. ("Hydro One"), the IESO, and the OEFC, and jointly controlled entities. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

These transactions for the years ended December 31 are summarized below:

(millions of dollars)	**Revenue** **2012**	**Expenses**	**Revenue** **2011** *(adjusted)*	**Expenses**
Hydro One				
Electricity sales	**10**	**-**	16	-
Services	**-**	**14**	-	13
Province of Ontario				
Gross revenue charge, water rentals and land tax	**-**	**118**	-	122
Guarantee fee	**-**	**8**	-	8
Used Fuel Fund rate of return guarantee	**-**	**282**	266	-
Decommissioning Fund excess funding	**-**	**64**	-	-
Pension benefits guarantee fund	**-**	**2**	-	-
OEFC				
Gross revenue charge and proxy property tax	**-**	**201**	-	217
Interest expense on long-term notes	**-**	**189**	-	196
Capital tax	**-**	**(3)**	-	(10)
Income taxes, net of investment tax credits	**-**	**77**	-	(12)
Contingency support agreement	**283**	**-**	367	-
Infrastructure Ontario				
Reimbursement of expenses incurred during the procurement process for new nuclear units	**-**	**(1)**	-	(2)
IESO				
Electricity sales	**3,823**	**34**	3,956	43
Ancillary services	**56**	**-**	55	-
OPA	**92**	**-**	98	-
	4,264	**985**	4,758	575

As at December 31, 2012, receivables from related parties included $3 million (2011 – $3 million) due from Hydro One, $337 million (2011 – $333 million) due from the IESO, $84 million (2011 – $74 million) due from the OEFC, $16 million (2011 – $16 million) due from the OPA, and $2 million (2011 – nil) due from PEC. Accounts payable and accrued charges as at December 31, 2012 included $2 million (2011 – $7 million) due to Hydro One, $51 million (2011 – $53 million) due to the OEFC, $3 million (2011 – $3 million) due to the Province, and nil (2011 – $1 million) due to Infrastructure Ontario.

18. OTHER (INCOME) LOSS

(millions of dollars)	**2012**	**2011**
Income from investments subject to significant influence	**(26)**	(35)
Thermal asset retirement obligation estimate change *(Note 3)*	**-**	66
Reduction to an environmental provision *(Note 14)*	**(1)**	(19)
Thunder Bay Generating Station conversion cost write off	**9**	-
Other loss (income)	**8**	(8)
Other (income) loss	**(10)**	4

19. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of PEC and Brighton Beach, which are accounted for using the equity method as described in Note 3. Details of the balance included in the Consolidated Balance Sheets as at December 31 are as follows:

(millions of dollars)	**2012**	**2011**
PEC		
Current assets	**8**	15
Long-term assets	**315**	330
Current liabilities	**(8)**	(6)
Long-term liabilities	**(3)**	(3)
Brighton Beach		
Current assets	**11**	11
Long-term assets	**209**	219
Current liabilities	**(11)**	(14)
Long-term liabilities	**(9)**	(9)
Long-term debt	**(139)**	(148)
Investments subject to significant influence	**373**	395

20. RESEARCH AND DEVELOPMENT

For the year ended December 31, 2012, research and development expenses of $113 million (2011 – $125 million) were charged to operations.

21. RESTRUCTURING

In 2009, OPG announced its decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations in 2010. Restructuring charges, primarily severance costs, related to these closures were $27 million. These costs were recognized in the consolidated financial statements in 2010 and 2011.

In 2011, OPG announced its decision to close two additional coal-fired units at the Nanticoke generating station, consistent with Ontario's Long-Term Energy Plan and Supply Mix Directive. Total restructuring costs, primarily severance costs, expected to be incurred related to these closures are $23 million. Restructuring costs of $21 million have been recognized to date in the consolidated financial statements and OPG expects to recognize $2 million in 2013. During the year ended December 31, 2012, restructuring charges of $3 million were recorded to expense due to the recognition of relocation costs of staff.

In January 2013, the Ministry of Energy announced the advanced shutdown of the remaining coal-fired units at the Lambton and Nanticoke generating stations by December 31, 2013, in advance of the previous December 31, 2014 deadline. OPG is estimating the restructuring costs, including severance and relocation to other OPG sites. The amount of restructuring costs cannot be reasonably estimated at this time, but OPG expects to accrue the severance costs in 2013. Relocation costs will be recorded as incurred, primarily in 2014.

OPG has ceased using coal at the Atikokan generating station, which has an impact on staff requirements. The total restructuring costs, primarily severance costs, are estimated to be $3 million and are expected to be recorded in 2013 and 2014 when they are finalized.

OPG conducted discussions with key stakeholders, including The Society and the PWU, in accordance with their respective collective bargaining agreements, at all plants impacted by the regulation requiring the cessation of burning coal for electricity generation. Given collective agreement provisions allowing deferral of severance payout to future periods, the restructuring liability is expected to be fully drawn down by 2015.

The change in the restructuring liability for severance costs during 2012 and 2011 is as follows:

(millions of dollars)	
Liability, January 1, 2011	15
Restructuring charges during the year	21
Payments during the year	(13)
Liability, December 31, 2011	23
Payments during the year	(20)
Liability, December 31, 2012	**3**

22. US GAAP TRANSITION

OPG is required to report under US GAAP beginning January 1, 2012. In January 2012, the Ontario Securities Commission approved the exemption for OPG to file its consolidated financial statements based on US GAAP. The exemption applies to the financial years that begin on or after January 1, 2012, but before January 1, 2015. Financial information derived from the consolidated financial statements for the 2011 comparative periods has been adjusted to be in accordance with US GAAP. In addition, certain of the 2011 comparative amounts have been reclassified to conform to the 2012 financial statement presentation. These adjustments are presented in this note.

US GAAP Reconciliation

OPG has previously filed its financial statements under Canadian GAAP. Material differences between US GAAP and Canadian GAAP impacting OPG's financial statements are discussed in this note. Refer to OPG's accounting policies under US GAAP as presented in Note 3.

As reflected in this note, the adoption of US GAAP is on a retrospective basis, with a restatement of prior period financial statements. Reconciliations are provided for the Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholder's Equity as of January 1, 2011, the date of transition to US GAAP, and December 31, 2011. Reconciliations for Consolidated Statements of Income and Comprehensive Income, and Consolidated Statements of Cash Flows for the year ended December 31, 2011 are also provided. The effects of transition from Canadian GAAP to US GAAP are identified in the statements below, with references to descriptions of transition impacts provided in the *Notes to Transitional Adjustments* section.

Reconciliation of the Consolidated Balance Sheet from Canadian GAAP to US GAAP as at January 1, 2011, the date of transition to US GAAP

As at January 1, 2011 *(millions of dollars)*	**Notes**	**Canadian GAAP**	**Effect of Transition to US GAAP**	**US GAAP**
Assets				
Current assets				
Cash and cash equivalents	E	280	(11)	269
Accounts receivable	H	270	(270)	-
Prepaid expenses	H	42	(42)	-
Receivables from related parties	F,H	-	476	476
Other accounts receivable and prepaid expenses	E,H	-	72	72
Nuclear fixed asset removal and nuclear waste management funds	H	-	12	12
Fuel inventory		734	-	734
Materials and supplies	E	85	(1)	84
Regulatory assets	H	-	28	28
Income taxes recoverable		65	-	65
Deferred income taxes [1]	B	73	(10)	63
		1,549	254	1,803
Property, plant and equipment	C,E	19,654	(664)	18,990
Less: accumulated depreciation	C,E	6,099	(104)	5,995
		13,555	(560)	12,995
Intangible assets		345	-	345
Less: accumulated amortization		297	-	297
		48	-	48
Other assets				
Deferred pension asset	A	1,146	(1,146)	-
Nuclear fixed asset removal and nuclear waste management funds	H	11,246	(12)	11,234
Long-term investments	H	30	(30)	-
Long-term materials and supplies		400	-	400
Regulatory assets	A,B,H	1,559	2,242	3,801
Investments subject to significant influence	E	-	420	420
Other long-term assets [2]	E,G	44	28	72
		14,425	1,502	15,927
		29,577	1,196	30,773

[1] Presented as future income taxes under Canadian GAAP.

[2] Presented as long-term accounts receivable and other assets under Canadian GAAP.

As at January 1, 2011 *(millions of dollars)*	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Liabilities				
Current liabilities				
Accounts payable and accrued charges	E	762	(7)	755
Short-term debt	F	155	250	405
Deferred revenue due within one year		12	-	12
Long-term debt due within one year	E	385	(9)	376
		1,314	234	1,548
Long-term debt	E,G	3,843	(154)	3,689
Other liabilities				
Fixed asset removal and nuclear waste management liabilities	C,E	12,704	14	12,718
Pension liabilities	A	160	1,308	1,468
Other post-employment benefit liabilities	A	1,748	504	2,252
Long-term accounts payable and accrued charges	B,E,H	525	(12)	513
Deferred revenue	D	152	(59)	93
Deferred income taxes	B	798	(179)	619
Regulatory liabilities		248	-	248
		16,335	1,576	17,911
Shareholder's equity				
Common shares		5,126	-	5,126
Retained earnings	A,B,C,D	3,024	42	3,066
Accumulated other comprehensive loss	A,B	(69)	(498)	(567)
Attributable to the Shareholder of Ontario Power Generation Inc.		8,081	(456)	7,625
Non-controlling interest	H	4	(4)	-
		8,085	(460)	7,625
		29,577	1,196	30,773

Reconciliation of the Consolidated Balance Sheet from Canadian GAAP to US GAAP as at December 31, 2011

As at December 31, 2011 *(millions of dollars)*	**Notes**	**Canadian GAAP**	**Effect of Transition to US GAAP**	**US GAAP**
Assets				
Current assets				
Cash and cash equivalents	E	642	(12)	630
Accounts receivable	H	461	(461)	-
Prepaid expenses	H	27	(27)	-
Receivables from related parties	F,H	-	426	426
Other accounts receivable and prepaid expenses	E,H	-	100	100
Nuclear fixed asset removal and nuclear waste management funds	H	-	20	20
Fuel inventory		655	-	655
Materials and supplies	E	84	(2)	82
Regulatory assets	H	-	299	299
Income taxes recoverable		55	3	58
Deferred income taxes	B	89	(47)	42
		2,013	299	2,312
Property, plant and equipment	C,E	21,686	(576)	21,110
Less: accumulated depreciation	C,E	6,611	(134)	6,477
		15,075	(442)	14,633
Intangible assets		363	-	363
Less: accumulated amortization		313	-	313
		50	-	50
Other assets				
Deferred pension asset	A	1,188	(1,188)	-
Nuclear fixed asset removal and nuclear waste management funds	H	11,898	(20)	11,878
Long-term investments	H	32	(32)	-
Long-term materials and supplies		380	-	380
Regulatory assets	A,B,H	1,457	3,261	4,718
Investments subject to significant influence	E	-	395	395
Other long-term assets	E,G	43	34	77
		14,998	2,450	17,448
		32,136	2,307	34,443

As at December 31, 2011 *(millions of dollars)*	**Notes**	**Canadian GAAP**	**Effect of Transition to US GAAP**	**US GAAP**
Liabilities				
Current liabilities				
Accounts payable and accrued charges	E	836	(11)	825
Short-term debt	F	10	50	60
Deferred revenue due within one year		12	-	12
Long-term debt due within one year	E	413	(10)	403
Regulatory liabilities	H	-	130	130
		1,271	159	1,430
Long-term debt	E,G	4,484	(143)	4,341
Other liabilities				
Fixed asset removal and nuclear waste management liabilities	C,E	14,219	173	14,392
Pension liabilities	A	177	2,670	2,847
Other post-employment benefit liabilities	A	1,900	716	2,616
Long-term accounts payable and accrued charges	B,E,H	542	4	546
Deferred revenue	D	177	(57)	120
Deferred income taxes	B	819	(318)	501
Regulatory liabilities	H	154	(130)	24
		17,988	3,058	21,046
Shareholder's equity				
Common shares		5,126	-	5,126
Retained earnings	A,B,C,D	3,426	(36)	3,390
Accumulated other comprehensive loss	A,B	(163)	(727)	(890)
Attributable to the Shareholder of Ontario Power Generation Inc.		8,389	(763)	7,626
Non-controlling interest	H	4	(4)	-
		8,393	(767)	7,626
		32,136	2,307	34,443

Reconciliation of the Consolidated Statement of Income from Canadian GAAP to US GAAP for the year ended December 31, 2011

(millions of dollars except where noted)	**Notes**	**Canadian GAAP**	**Effect of Transition to US GAAP**	**US GAAP**
Revenue	D,E	5,061	(97)	4,964
Fuel expense		754	-	754
Gross margin		4,307	(97)	4,210
Expenses				
Operations, maintenance and administration	A,B,E	2,756	25	2,781
Depreciation and amortization	E,H	723	(29)	694
Accretion on fixed asset removal and nuclear waste management liabilities	C,E	702	2	704
Earnings on nuclear fixed asset removal and nuclear waste management liabilities		(509)	-	(509)
Property and capital taxes	E	51	(1)	50
Restructuring		21	-	21
		3,744	(3)	3,741
Income before other income, interest and income taxes		563	(94)	469
Other (income) loss	C,E	(29)	33	4
Income before interest and income taxes		592	(127)	465
Net interest expense	E	165	(11)	154
Income before income taxes		427	(116)	311
Income tax expense (recovery)	B,H	11	(38)	(27)
Net income		416	(78)	338
Basic and diluted income per common share *(dollars)*	A,B,C,D	1.62	(0.30)	1.32
Common shares outstanding *(millions)*		256.3	-	256.3

Reconciliation of the Consolidated Statement of Cash Flows from Canadian GAAP to US GAAP for the year ended December 31, 2011

(millions of dollars)	**Notes**	**Canadian GAAP**	**Effect of Transition to US GAAP**	**US GAAP**
Cash flow provided by operating activities	A,B,C,D,E	990	189	1,179
Cash flow used in investing activities		(1,138)	-	(1,138)
Cash flow provided by financing activities	E,G,F	510	(190)	320
Net increase in cash and cash equivalents		362	(1)	361
Cash and cash equivalents, beginning of year	E	280	(11)	269
Cash and cash equivalents, end of year	E	642	(12)	630

Reconciliation of the Consolidated Statement of Comprehensive Income from Canadian GAAP to US GAAP for the year ended December 31, 2011

(millions of dollars)	**Notes**	**Canadian GAAP**	**Effect of Transition to US GAAP**	**US GAAP**
Net income		416	(78)	338
Other comprehensive loss, net of income taxes				
Net loss on derivatives designated as cash flow hedges [1]		(100)	-	(100)
Reclassification to income of losses on derivatives designated as cash flow hedges [2]		6	-	6
Reclassification to income of amounts related to pension and other post-employment benefits [3]	A,B	-	17	17
Current year actuarial loss and past service costs related to pension and other post-employment benefits [4]	A,B	-	(246)	(246)
Other comprehensive loss for the year		(94)	(229)	(323)
Comprehensive income		322	(307)	15

[1] Net of income tax recovery of $20 million for the year ended December 31, 2011.
[2] Net of income tax expense of $1 million for the year ended December 31, 2011.
[3] Net of income tax expense of $5 million for the year ended December 31, 2011.
[4] Net of income tax recovery of $82 million for the year ended December 31, 2011.

Reconciliation of Shareholder's Equity as Previously Reported under Canadian GAAP to US GAAP

As at January 1, 2011 *(millions of dollars)*	**Retained Earnings**	**AOCI**	**Non-controlling Interest**	**Common Shares**	**Total Equity**
Shareholder's equity as reported under **Canadian GAAP**	3,024	(69)	4	5,126	8,085
US GAAP adjustments (decrease) increase:					
Note A – Pension and OPEB	(40)	(664)	-	-	(704)
Note B – Income taxes	31	166	-	-	197
Note C – Thermal ARO	(8)	-	-	-	(8)
Note D – Deferred revenue	59	-	-	-	59
Reclassification of non-controlling interest	-	-	(4)	-	(4)
Shareholder's equity as reported under **US GAAP**	3,066	(567)	-	5,126	7,625

As at December 31, 2011 *(millions of dollars)*	**Retained Earnings**	**AOCI**	**Non-controlling Interest**	**Common Shares**	**Total Equity**
Shareholder's equity as reported under **Canadian GAAP**	3,426	(163)	4	5,126	8,393
US GAAP adjustments (decrease) increase:					
Note A – Pension and OPEB	(51)	(970)	-	-	(1,021)
Note B – Income taxes	37	243	-	-	280
Note C – Thermal ARO	(79)	-	-	-	(79)
Note D – Deferred revenue	57	-	-	-	57
Reclassification of non-controlling interest	-	-	(4)	-	(4)
Shareholder's equity as reported under **US GAAP**	3,390	(890)	-	5,126	7,626

Notes to Transitional Adjustments

Adjustments Which Affect Equity

(A) Pension and OPEB

Under Canadian GAAP, OPG presented defined benefit pension and OPEB assets or liabilities in the Consolidated Balance Sheet as the cumulative difference between the recognized benefit costs and OPG's pension contributions and benefit payments. The unamortized actuarial gains or losses and unamortized past service costs were presented in the notes to the consolidated financial statements.

Upon transition to US GAAP, OPG recognized on its January 1, 2011 balance sheet the funded status of its defined benefit plans. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation on a plan-by-plan basis.

Previously unamortized actuarial losses and past service costs in respect of pension and OPRB were recognized at the date of transition in equity as part of AOCI, net of taxes. After transition, gains or losses and past service costs or credits that arise during the period and are not recognized immediately as components of benefit costs are recognized as increases or decreases in OCI in the period incurred. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of benefit costs. OPG recorded an offsetting regulatory asset for the portion of the transition adjustments to AOCI attributable to the regulated operations, in order to reflect the expected recovery of these amounts through future regulated prices charged to customers. After transition, OPG records a corresponding change in this regulatory asset for the amount of the increases or decreases in OCI and for the reclassification of the AOCI into benefit costs during the period.

As a result, OPG reduced its deferred pension asset by $1,146 million, increased its pension and OPEB liabilities by $1,772 million, increased regulatory assets by $2,254 million, and decreased pre-tax AOCI by $664 million at transition. At December 31, 2011, OPG reduced its deferred pension asset by $1,188 million, increased its pension and OPEB liabilities by $3,335 million, increased regulatory assets by $3,553 million, and decreased pre-tax AOCI by $970 million.

Under Canadian GAAP, the net cumulative unamortized actuarial gain or loss for the LTD benefits in excess of 10 percent of the benefit obligation was amortized over the expected average remaining service life of the employees. Past service costs for the LTD benefits were recognized over the expected average remaining service life of the affected employee groups. Under US GAAP, all actuarial gains and losses and past service costs related to the LTD benefits must be recognized immediately. As a result, on January 1, 2011, OPG increased OPEB liabilities and decreased retained earnings by $40 million, of which $31 million relates to regulated operations. As at

December 31, 2011, OPG increased OPEB liabilities and decreased retained earnings by $51 million, of which $40 million relates to regulated operations. For the year ended December 31, 2011, the increase to OM&A expenses was $11 million, of which $9 million relates to regulated operations.

The portion of these increases in OPEB liabilities related to regulated operations on transition and for the year ended December 31, 2011 was recorded in the first quarter of 2012 as a regulatory asset for the Impact for USGAAP Deferral Account authorized by the OEB, as discussed in Note 5. Refer to Note 10 for additional disclosures regarding pension and OPEB plans.

(B) Income Taxes

The transitional tax adjustments include the tax impacts related to other transitional adjustments, a reclassification of investment tax credits from OM&A expenses to income tax expense, and an adjustment for unrecognized tax benefits.

Under Canadian GAAP, future income tax assets were evaluated and if realization was not considered more likely than not, a valuation allowance was established. Under US GAAP, tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more likely than not recognition threshold is satisfied and are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Refer to Note 9 to these consolidated financial statements for disclosures related to income taxes under US GAAP, including required disclosures for unrecognized tax benefits.

(C) Thermal ARO

The liability for non-nuclear fixed asset removal under Canadian GAAP included a salvage value for scrap metal related to OPG's thermal stations. US GAAP requires that any gains from the expected disposal of assets not be taken into account when measuring a provision. Upon transition from Canadian GAAP to US GAAP, the scrap metal salvage value was removed from the non-nuclear fixed asset removal liability and became a residual value in the property, plant and equipment of the thermal segment. Upon transition on January 1, 2011, this change increased the non-nuclear liability for fixed asset removal by $21 million, increased net property, plant and equipment by $13 million, and decreased retained earnings by $8 million. The December 31, 2011 balance sheet was also adjusted as the liability increased by $180 million, net property, plant and equipment increased by $101 million, and retained earnings decreased by $79 million.

This GAAP difference increased the accretion on fixed asset removal liabilities by $1 million and $2 million the year ended December 31, 2011 as reflected in the income statement reconciliation.

(D) Deferred Revenue

Under Canadian GAAP, the lease revenue for certain historical years was recognized into income based on amounts as stipulated in the lease agreement. US GAAP requires deferred lease revenue to be retrospectively adjusted to a straight-line basis from lease inception. Upon transition to US GAAP, deferred revenue related to leases decreased by $59 million and retained earnings increased by $59 million as at January 1, 2011. At December 31, 2011, deferred revenue decreased by $57 million and retained earnings increased by $57 million. The pre-tax income statement impact of this GAAP difference was a decrease in revenue of $2 million for the year ended December 31, 2011.

Other Adjustments

Upon transition to US GAAP, OPG made the following adjustments that resulted in reclassification changes on the Consolidated Balance Sheets and Statements of Income.

(E) Accounting for Joint Ventures

Under Canadian GAAP, OPG proportionately consolidated its interests in joint ventures. Under US GAAP, OPG is required to account for its interests using the equity method.

This difference has resulted in the derecognition of OPG's 50 percent interest in the assets, liabilities, revenues and expenses of its joint ventures, PEC and Brighton Beach. The investment balances are presented under the heading *Investments subject to significant influence* on OPG's Consolidated Balance Sheets under US GAAP.

The adjustments to the balance sheet items as a result of the use of the equity method are as follows:

(millions of dollars)	**January 1 2011**	**December 31 2011**
Current assets	(25)	(26)
Property, plant and equipment, net	(573)	(545)
Investments subject to significant influence	420	395
Other assets	(4)	(4)
Current liabilities	(15)	(20)
Long-term debt	(157)	(148)
Other liabilities	(10)	(12)

The pre-tax adjustments of significant items on the Consolidated Statement of Income as a result of the use of the equity method are as follows:

(millions of dollars)	**2011**
Revenue	(94)
Operations, maintenance and administration	(19)
Net interest expense	(11)
Depreciation and amortization	(26)
Property and capital taxes	(1)
Other income	(37)

(F) Accounts Receivable and Short-term Debt

Under Canadian GAAP, OPG derecognized accounts receivable on the sale of securitized receivables to an independent trust. Under US GAAP, OPG no longer derecognizes the securitized receivables and presents the arrangement as a securitized borrowing. Upon transition on January 1, 2011, OPG increased receivables from related parties by $250 million and increased short-term debt by $250 million. In December 2011, OPG reduced the securitized receivables balance to $50 million, resulting in increases of $50 million to receivables from related parties and short-term debt as at December 31, 2011.

(G) Debt Issue Costs

US GAAP requires that transaction costs be treated as a separate asset on the balance sheet and not recorded as part of the underlying financial instruments to which they relate. As a result, OPG increased long-term debt and other long-term assets by $3 million as at January 1, 2011 and by $6 million as at December 31, 2011.

(H) Other

To conform with the financial statement presentation under US GAAP and the 2012 financial statement presentation, certain comparative figures were reclassified in 2011. Significant changes include a change in the presentation of nuclear fixed asset removal and nuclear waste management funds, and regulatory assets and liabilities to disclose the current and long-term portions separately. In addition, OPG has separately presented on the Consolidated Balance Sheets receivables due from related parties, which were previously included with other accounts receivable.