ONTARIO POWER GENERATION

News
from Ontario Power Generation

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Nov. 13, 2015

OPG REPORTS 2015 THIRD QUARTER FINANCIAL RESULTS

Quarterly earnings were $80 million as OPG successfully executes the vacuum building outage at Darlington

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder before extraordinary gain for the three months ended Sep. 30, 2015 of $80 million compared to $118 million for the same quarter in 2014. The decreased earnings were mainly a result of lower nuclear generation and higher operations, maintenance and administration (OM&A) expenses reflecting the planned Vacuum Building Outage (VBO) at the Darlington Nuclear Generating Station.

Net income attributable to the Shareholder before extraordinary gain for the nine months ended Sep. 30, 2015 was $503 million compared to $475 million for the same period in 2014. The increased earnings over this period were mainly attributable to higher sales prices for OPG's regulated facilities authorized by the Ontario Energy Board (OEB) beginning in Nov. 2014, and to income from the new hydroelectric units on the Lower Mattagami River and the converted Atikokan and Thunder Bay biomass generating stations.

Jeff Lyash, OPG's President and CEO said, "I am encouraged by our good financial results to date and especially pleased with the excellent reliability of the Pickering Nuclear Generating Station this year. I am also impressed with the consistently strong performance of our hydroelectric and thermal fleet. This provides the base that we need as OPG prepares to proceed with our major investment in refurbishing the Darlington Nuclear Generating Station.

"The Darlington station investment would create thousands of jobs over the coming decade and ensure a secure, clean, domestic supply of reliable, economically-priced electricity for several decades. The investment also means the people of Ontario would continue to derive significant benefits from the four units at Darlington, which are a major public asset," added Lyash.

"OPG has been preparing for the refurbishment project for six years. Our focus has been on getting the basics right. Successfully operating our assets and delivering other major projects demonstrate that the company is ready to undertake this investment."

Overall, OPG received an average of 7.1 cents per kilowatt hour for its power in the third quarter of 2015, which was significantly lower than the average non-OPG commodity cost of electricity in Ontario.

Business Segment, Generating, and Operating Performance

Net income attributable to the Shareholder after extraordinary gain for the third quarter of 2015 was $80 million compared to $361 million for the same quarter in 2014. Net income attributable to the Shareholder after extraordinary gain for the nine months ended Sep. 30, 2015 was $503 million, compared to $718 million for the same period in 2014. The decreases in income primarily reflected the recognition of an extraordinary gain of $243 million in the third quarter of 2014 related to the 48 previously unregulated hydroelectric facilities prescribed for rate regulation beginning in Jul. 2014. The gain represents regulatory assets related to deferred income taxes expected to be recovered from customers through future regulated prices.

OPG's income before interest, income taxes and extraordinary item from the electricity generation business segments for the third quarter of 2015 and 2014 was $232 million and $220 million, respectively. This increase in income reflected higher earnings from the Regulated – Hydroelectric and Contracted Generation Portfolio segments, partially offset by lower earnings from the Regulated – Nuclear Generation segment. Earnings increased from the Regulated – Hydroelectric segment due to the new regulated prices effective Nov. 2014, and from the Contracted Generation Portfolio segment due to the new hydroelectric units on the Lower Mattagami River and the conversion to biomass fuel of the Atikokan and Thunder Bay generating stations. Lower earnings from the Regulated – Nuclear Generation segment were mainly due to an increase in OM&A expenses and lower generation as a result of the Darlington VBO, which commenced on Sep. 14, 2015.

Earnings from the electricity generation business segments were $927 million for the nine months ended Sep. 30, 2015, compared to $666 million for the same period of 2014. The increase reflected higher earnings from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments primarily as a result of the new regulated prices. Improved earnings from the Contracted Generation Portfolio also contributed to the higher earnings from the electricity generation segments.

The nuclear waste management business segment recorded a loss before interest, income taxes and extraordinary item of $59 million in the third quarter of 2015, compared to a loss of $32 million in the same quarter of 2014. For the nine months ended Sep. 30, 2015, the segment recorded a loss of $131 million, compared to a loss of $42 million for the same period in 2014. The decreases in earnings for the three and nine month periods ended Sep. 30, 2015 were primarily a result of higher accretion expense related to fixed asset removal and nuclear waste management liabilities in 2015.

Total electricity generated during the three months ended Sep. 30, 2015 was 19.1 terawatt hours (TWh) compared to 21.0 TWh for the same quarter in 2014. The decrease was mainly due to lower nuclear production as a result of the VBO at the Darlington GS, which required the shutdown of all four units for the duration of the outage, and decreased hydroelectric generation as a result of lower water flows in eastern Ontario. The VBO was completed safely on Oct. 30, 2015.

Total electricity generated during the nine months ended Sep. 30, 2015 was 61.2 TWh, compared to 61.3 TWh for the same period in 2014. The marginal decrease was mainly due to lower water flows in eastern Ontario and higher generation losses as a result of surplus baseload generation conditions, largely offset by higher nuclear generation primarily due to improved operating performance at the Pickering GS.

For the three months ended Sep. 30, 2015, the capability factor at the Darlington GS was 75.9 per cent compared to 98.4 per cent for the same quarter in 2014. For the nine months ended Sep. 30, 2015, the Darlington GS capability factor was 88.3 per cent compared to 90.7 per cent for the same period in 2014. The decreases for the three and nine month periods ended Sep. 30, 2015 were primarily due to the VBO.

At the Pickering GS, the capability factor improved to 82.2 per cent for the three months ended Sep. 30, 2015, compared to 79.9 per cent in the same quarter of 2014. The Pickering GS capability factor of 78.4 per cent for the nine months ended Sep. 30, 2015 was an improvement from the 74.7 per cent for the same period in 2014. The improved capability factors were primarily due to a decrease in the number of unplanned outage days reflecting improvements associated with fuel handling equipment performance, partially offset by an increase in planned outage days.

The availability of OPG's regulated hydroelectric generating stations for the three and nine month periods ended Sep. 30, 2015 remained above 90 per cent, and was comparable to availability for the same periods in 2014. The availability of OPG's contracted hydroelectric generating stations for the three months ended Sep. 30, 2015 was 81.5 per cent compared to 95.9 per cent for the same period in 2014. The lower availability was due to a higher number of planned outage days at the Lower Mattagami stations. For the nine months ended Sep. 30, 2015, the availability of OPG's contracted hydroelectric generating stations remained above 90 per cent. The thermal Equivalent Forced Outage Rate increased for the three and nine month periods ended Sep. 30, 2015, compared to the same periods in 2014, primarily due to an outage to perform repair work at the Lennox GS.

Generation Development

OPG is undertaking a number of generation development and refurbishment projects to support Ontario's long-term electricity supply requirements and operate a generation portfolio that is essentially free of greenhouse gases and smog-causing emissions. Significant developments to Sep. 30, 2015 were as follows:

Darlington Refurbishment project

- The Darlington Refurbishment project is currently in the definition phase.
- In November 2015, OPG's Board of Directors approved the budget of $12.8 billion including capitalized interest and escalation, and the schedule for the four-unit refurbishment. The approved budget is consistent with the previous total project cost estimate of less than $10 billion in 2013 dollars excluding capitalized interest and escalation. The refurbishment of the last unit is scheduled to be completed by 2026.
- The budget and schedule will be submitted for Shareholder concurrence. Upon Shareholder concurrence, the project will transition to the execution phase, including commencement of the first unit's refurbishment in late 2016.

- Life-to-date capital expenditures were $1,980 million as at Sep. 30, 2015.

Peter Sutherland Sr. GS

- In March 2015, OPG's Board of Directors approved a project to construct a new 28 MW generating station, Peter Sutherland Sr. GS, on the New Post Creek near its outlet to the Abitibi River, with a planned in-service date in the first half of 2018 and an approved budget of $300 million. Life-to-date capital expenditures were $67 million as at Sep. 30, 2015.
- In the second quarter of 2015, a hydroelectric energy supply agreement was executed for the station with the Independent Electricity System Operator (IESO).
- Construction work commenced during the second quarter of 2015 and project financing was completed in Oct. 2015.
- The station will be completed through a partnership between OPG and Coral Rapids L.P., a wholly owned subsidiary of the Taykwa Tagamou Nation.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Revenue	**1,426**	1,160	**4,164**	3,645
Fuel expense	**175**	161	**512**	464
Gross margin	**1,251**	999	**3,652**	3,181
Operations, maintenance and administration	**680**	595	**1,995**	1,931
Depreciation and amortization	**350**	184	**746**	546
Accretion on fixed asset removal and nuclear waste management liabilities	**224**	195	**672**	586
Earnings on nuclear funds - (a reduction to expenses)	**(163)**	(161)	**(535)**	(538)
Income from investments subject to significant influence	**(8)**	(9)	**(30)**	(32)
Other net expenses	**11**	15	**37**	39
Income before interest, income taxes and extraordinary item	**157**	180	**767**	649
Net interest expense	**42**	15	**136**	38
Income tax expense	**30**	46	**114**	133
Income before extraordinary item	**85**	119	**517**	478
Extraordinary item	**-**	243	**-**	243
Net income	**85**	362	**517**	721
Net income attributable to the Shareholder	**80**	361	**503**	718
Net income attributable to non-controlling interest [1]	**5**	1	**14**	3
Income (loss) before interest, income taxes and extraordinary item				
Electricity generation business segments	**232**	220	**927**	666
Regulated – Nuclear Waste Management	**(59)**	(32)	**(131)**	(42)
Services, Trading, and Other Non-Generation	**(16)**	(8)	**(29)**	25
Total income before interest, income taxes and extraordinary item	**157**	180	**767**	649
Cash flow				
Cash flow provided by operating activities	**449**	361	**1,354**	994
Electricity generation (TWh)				
Regulated – Nuclear Generation	**11.2**	12.8	**35.7**	35.4
Regulated – Hydroelectric				
Existing regulated hydroelectric stations	**5.3**	5.1	**14.6**	14.6
Hydroelectric stations prescribed for rate regulation beginning in 2014	**2.0**	2.5	**8.5**	9.1
Contracted Generation Portfolio [2]	**0.6**	0.6	**2.4**	2.2
Total electricity generation	**19.1**	21.0	**61.2**	61.3
Average commodity cost of electricity (¢/kWh)				
Average revenue for OPG [3]	**7.1**	5.1	**6.5**	5.5
Average non-OPG commodity cost of electricity [4]	**11.0**	10.8	**10.9**	10.5
Nuclear unit capability factor (per cent)				
Darlington GS	**75.9**	98.4	**88.3**	90.7
Pickering GS	**82.2**	79.9	**78.4**	74.7
Availability (per cent)				
Regulated – Hydroelectric	**90.5**	90.7	**91.3**	91.4
Contracted Generation Portfolio – hydroelectric stations	**81.5**	95.9	**91.5**	93.0
Equivalent forced outage rate				
Contracted Generation Portfolio – thermal stations	**7.4**	2.1	**14.1**	2.9
Return on common equity for the twelve months ended September 30, 2015 and December 31, 2014 (per cent) [5]			**5.9**	8.5
Return on common equity, excluding extraordinary gain, for the twelve months ended September 30, 2015 and December 31, 2014 (per cent) [5]			**6.0**	6.0
Funds from operations interest coverage for the twelve months ended September 30, 2015 and December 31, 2014 (times) [5]			**4.9**	2.8

1 Relates to the 25 per cent interest of a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership.

2 Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre (PEC) and Brighton Beach GS.

3 Average revenue for OPG is the quotient of (i) OPG's revenues from regulated prices established by the OEB, plus OPG's market based revenues, plus OPG's revenues from Energy Supply Agreements, and (ii) OPG's generation. The calculation includes OPG's share of revenues and generation from PEC and Brighton Beach, and in 2014, excludes revenue from the cost recovery agreements related to the Nanticoke GS and the Lambton GS which were shut down in 2013. OPG's average revenue is the average commodity cost of electricity generated by OPG.

4 The average non-OPG commodity cost of electricity is determined as the quotient of (i) the sum of hourly Ontario demand multiplied by the Hourly Ontario Energy Price (HOEP), plus total global adjustment payments, plus the sum of hourly net exports multiplied by the HOEP, less OPG's revenue as described in Note 3 above, and (ii) non-OPG generation. Non-OPG generation is calculated as the Ontario demand as published by the IESO, plus net exports, minus OPG's electricity generation.

5 "Return on common equity" and "Funds from operations interest coverage" 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 period ended September 30, 2015, 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 that is 99.7 per cent free of greenhouse gas and smog-causing emissions. Our focus is on the efficient production and sale of electricity from our generation assets, while operating in a safe, open and environmentally responsible manner.

Ontario Power Generation Inc.'s unaudited consolidated financial statements and Management's Discussion and Analysis as at and for the three and nine month periods ended September 30, 2015, 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

2015 THIRD QUARTER REPORT

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ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine month periods ended September 30, 2015. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, related party transactions, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, and the MD&A as at and for the year ended December 31, 2014.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the heading, *Exemptive Relief for Reporting under US GAAP,* in the section *Changes in Accounting Policies and Estimates* in OPG's 2014 annual MD&A. This MD&A is dated November 13, 2015.

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 section, *Risk Management*. All forward-looking statements 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, generating station performance, cost of fixed asset removal and nuclear waste management, performance of investment funds, repurposing, closure, or decommissioning of 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 or the Shareholder).

As at September 30, 2015, OPG's electricity generation portfolio had an in-service capacity of 17,059 megawatts (MW). OPG operates two nuclear generating stations, three thermal generating stations, 65 hydroelectric generating stations, and two wind power turbines. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the Contracted Generation Portfolio segment statistics set out in this report. The income of the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented in income from investments subject to significant influence under the Contracted Generation Portfolio segment.

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. The leased stations are not included in the generation portfolio statistics set out in this report. A description of OPG's segments is provided in OPG's 2014 annual MD&A in the section, *Business Segments*.

The in-service generating capacity by business segment as at September 30, 2015 and December 31, 2014 was as follows:

(MW)	As at September 30 2015	 December 31 2014
Regulated – Nuclear Generation	**6,606**	6,606
Regulated – Hydroelectric	**6,426**	6,426
Contracted Generation Portfolio [1]	**4,027**	4,027
Total	**17,059**	17,059

[1] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2015, compared to the same periods in 2014, are discussed below.

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	**2015**	**2014**	**2015**	**2014**
Revenue	**1,426**	1,160	**4,164**	3,645
Fuel expense	**175**	161	**512**	464
Gross margin	**1,251**	999	**3,652**	3,181
Operations, maintenance and administration	**680**	595	**1,995**	1,931
Depreciation and amortization	**350**	184	**746**	546
Accretion on fixed asset removal and nuclear waste management liabilities	**224**	195	**672**	586
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(163)**	(161)	**(535)**	(538)
Income from investments subject to significant influence	**(8)**	(9)	**(30)**	(32)
Property taxes	**9**	12	**34**	22
Restructuring	**-**	3	**1**	15
	1,092	819	**2,883**	2,530
Income before other loss, interest, income taxes and extraordinary item	**159**	180	**769**	651
Other loss	**2**	-	**2**	2
Income before interest, income taxes and extraordinary item	**157**	180	**767**	649
Net interest expense	**42**	15	**136**	38
Income before income taxes and extraordinary item	**115**	165	**631**	611
Income tax expense	**30**	46	**114**	133
Income before extraordinary item	**85**	119	**517**	478
Extraordinary item	**-**	243	**-**	243
Net income	**85**	362	**517**	721
Net income attributable to the Shareholder	**80**	361	**503**	718
Net income attributable to non-controlling interest [1]	**5**	1	**14**	3
Electricity production (TWh) [2]	**19.1**	21.0	**61.2**	61.3
Cash flow				
Cash flow provided by operating activities	**449**	361	**1,354**	994

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $80 million for the third quarter of 2015, a decrease of $281 million compared to the same quarter in 2014.

Income before interest, income taxes and extraordinary item was $157 million for the third quarter of 2015, a decrease of $23 million compared to the same quarter in 2014. The following summarizes the significant items which contributed to the variance:

Significant factors that reduced income before interest, income taxes and extraordinary item:

- Increase of $83 million in operations, maintenance and administration (OM&A) expenses primarily due to the commencement of the four-unit Darlington Vacuum Building Outage (VBO) in September 2015 and other outage activities during the quarter
- Lower nuclear gross margin of $83 million as a result of a 1.6 terawatt hour (TWh) decrease in nuclear generation primarily due to the commencement of the Darlington VBO in September 2015
- Fewer expenses deferred in regulatory accounts in 2015 resulting in higher depreciation, accretion, nuclear fuel and OM&A expenses of $70 million. The higher deferrals in 2014 were primarily due to costs not included in the regulated prices in effect prior to November 1, 2014.

Significant factors that increased income before interest, income taxes and extraordinary item:

- Increase in revenue of approximately $155 million as a result of higher average sales prices due to new base regulated prices authorized by the OEB effective November 1, 2014 for all of OPG's regulated facilities, including the 48 hydroelectric stations prescribed for rate regulation beginning in 2014
- Higher earnings of $64 million from the Contracted Generation Portfolio segment primarily due to the new units of the Lower Mattagami River hydroelectric generating stations that were placed in service throughout 2014, and the conversion to biomass fuel of the Atikokan and Thunder Bay generating stations.

Net interest expense increased by $27 million during the third quarter of 2015, compared to the same quarter in 2014, primarily due to costs related to the Niagara Tunnel no longer being deferred in 2015 in the Capacity Refurbishment Variance Account, as the new regulated prices effective November 1, 2014 reflect the impact of the Niagara Tunnel project.

Income tax expense for the three months ended September 30, 2015 was $30 million, compared to $46 million for the same quarter in 2014. The decrease in income tax expense was primarily due to lower income before income taxes and extraordinary item.

In the third quarter of 2014, OPG recognized an increase in regulatory assets related to deferred income taxes expected to be recovered from customers through future regulated prices in respect of the 48 hydroelectric facilities prescribed for rate regulation beginning in 2014, resulting in an extraordinary gain of $243 million in the consolidated statements of income in 2014.

Year-To-Date

Net income attributable to the Shareholder was $503 million for the first nine months of 2015, a decrease of $215 million compared to the same period in 2014.

Income before interest, income taxes and extraordinary item was $767 million, an increase of $118 million compared to the same period in 2014. The following summarizes the significant items which contributed to the variance:

Significant factors that increased income before interest, income taxes and extraordinary item:

- Increase in revenue of approximately $295 million as a result of higher average sales prices due to new base regulated prices for all of OPG's regulated facilities effective November 1, 2014
- Higher earnings of $157 million from the Contracted Generation Portfolio segment primarily due to the new units of the Lower Mattagami River hydroelectric generating stations that were placed in service throughout 2014, and the conversion to biomass fuel of the Atikokan and Thunder Bay generating stations.

Significant factors that reduced income before interest, income taxes and extraordinary item:

- Fewer expenses deferred in regulatory accounts in 2015 resulting in higher depreciation, accretion, nuclear fuel and OM&A expenses of $233 million. The higher deferrals in 2014 were primarily due to costs not included in the regulated prices in effect prior to November 1, 2014
- Increase in nuclear OM&A expenses of $75 million primarily due to the Darlington VBO and higher other expenditures, partly offset by savings in salary costs resulting from lower staff numbers
- Decrease in earnings from the Services, Trading, and Other Non-Generation segment of $54 million, primarily due to higher trading margins during the first quarter of 2014 as a result of the unseasonably cold winter.

Net interest expense increased by $98 million for the nine months ended September 30, 2015, compared to the same period in 2014, primarily due to costs that are no longer being deferred in 2015 in the Capacity Refurbishment Variance Account in respect of the Niagara Tunnel project, and the cessation of interest capitalization for the Lower Mattagami River project.

Income tax expense for the nine months ended September 30, 2015 was $114 million, compared to $133 million for the same period in 2014. The decrease in income tax expense was primarily due to a change in reserves from the resolution of uncertainties.

Segment Results

The following table summarizes OPG's income before interest, income taxes and extraordinary item by business segment:

(millions of dollars)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Income (loss) before interest, income taxes and extraordinary item				
Regulated – Nuclear Generation	**15**	143	**200**	132
Regulated – Hydroelectric	**139**	63	**508**	472
Contracted Generation Portfolio	**78**	14	**219**	62
Total electricity generation business segments	**232**	220	**927**	666
Regulated – Nuclear Waste Management	**(59)**	(32)	**(131)**	(42)
Services, Trading, and Other Non-Generation	**(16)**	(8)	**(29)**	25
	157	180	**767**	649

Income before interest, income taxes and extraordinary item from the electricity generation business segments for the third quarter of 2015 and 2014 was $232 million and $220 million, respectively, reflecting higher earnings from the Regulated – Hydroelectric and Contracted Generation Portfolio segments that were partially offset by lower earnings from the Regulated – Nuclear Generation Segment. The lower earnings from the Regulated – Nuclear Generation segment during the third quarter of 2015, compared to the same quarter in 2014, were primarily due to an increase in OM&A expenses and lower generation due to the Darlington VBO and other outage activities. The decrease in earnings in the segment was partially offset by the impact of higher base regulated prices effective November 1, 2014. The increase in earnings for the Regulated – Hydroelectric segment was also mainly due to the new base regulated prices effective November 1, 2014. The improvement in earnings in the Contracted Generation Portfolio segment was mainly due to an increase in income from the new units of the Lower Mattagami River hydroelectric generating stations and the conversion to biomass of the Atikokan and Thunder Bay generating stations.

Income before interest and income taxes from the electricity generation business segments increased by $261 million for the nine months ended September 30, 2015, compared to the same period in 2014, reflecting higher earnings from all three segments. The increase in income from the Regulated – Nuclear Generation and the Regulated Hydroelectric segments was primarily due to the new regulated prices. The improved earnings from the Contracted Generation Portfolio segment primarily reflected income from the new units of the Lower Mattagami River hydroelectric generating stations and the conversion to biomass of the Atikokan and Thunder Bay generating stations.

The decrease in earnings for the Regulated – Nuclear Waste Management business segment was $27 million during the third quarter of 2015 and $89 million for the nine months ended September 30, 2015, compared to the same periods in 2014. The decreases were primarily due to higher accretion expense in 2015 as a result of deferring costs in regulatory accounts in 2014 that were not included in regulated prices in effect prior to November 1, 2014.

For the nine months ended September 30, 2015, lower earnings from the Services, Trading, and Other Non-Generation segment, compared the same period in 2014, were primarily due to the decrease in trading margins for electricity sold to neighbouring energy markets, reflecting the higher margins in the first quarter of 2014 due to the unseasonably cold winter.

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2015 and 2014 was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(TWh)	**2015**	**2014**	**2015**	**2014**
Regulated – Nuclear Generation	**11.2**	12.8	**35.7**	35.4
Regulated – Hydroelectric				
Existing regulated hydroelectric generating stations	**5.3**	5.1	**14.6**	14.6
Hydroelectric generating stations prescribed for rate regulation beginning in 2014	**2.0**	2.5	**8.5**	9.1
Contracted Generation Portfolio [1]	**0.6**	0.6	**2.4**	2.2
Total OPG electricity generation	**19.1**	21.0	**61.2**	61.3
Total electricity generation by other generators in Ontario [2]	**19.1**	17.2	**56.5**	53.7

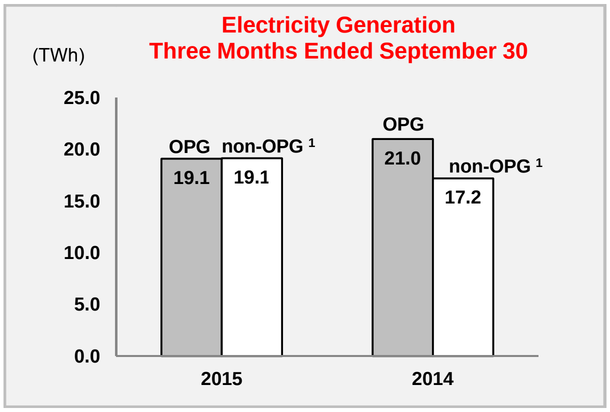
1 Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
2 Non-OPG generation is calculated as the Ontario demand as published by the Independent Electricity System Operator (IESO), plus net exports, minus OPG electricity generation.

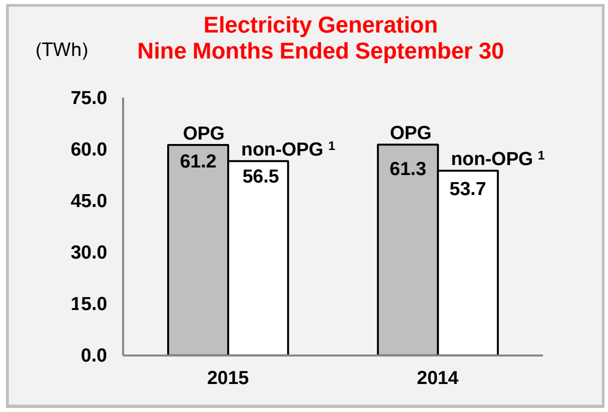
Lower nuclear generation of 1.6 TWh during the third quarter of 2015, compared to the same quarter in 2014, was primarily due to the VBO at the Darlington GS, which required the shutdown of all four units for the duration of the outage. The VBO started as planned on September 14, 2015 and was completed safely on October 30, 2015. This decrease in Darlington's generation was partially offset by an increase in generation from the Pickering GS. Lower generation of 0.3 TWh from the Regulated – Hydroelectric segment during the third quarter of 2015 was primarily due to decreased production as a result of lower water flows in eastern Ontario. This was partially offset by lower generation losses from surplus baseload generation (SBG) conditions described below and the impact of higher water flows in the Niagara region.

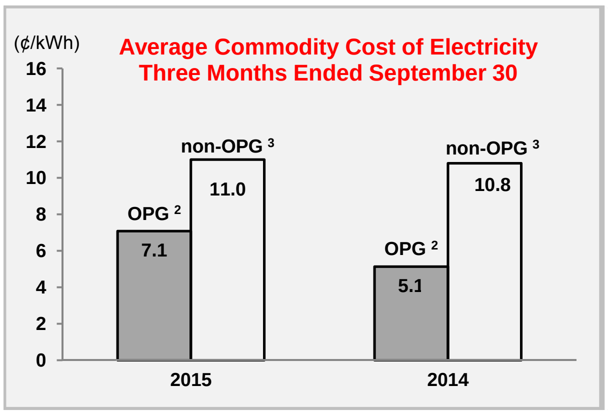
For the nine months ended September 30, 2015, higher generation losses from SBG conditions and lower water flows in eastern Ontario contributed to a marginal decrease in total OPG generation, compared to the same period in 2014. The decrease in generation was largely offset by higher nuclear generation of 0.3 TWh primarily due to improved operating performance at the Pickering GS. The new units of the Lower Mattagami River hydroelectric generating stations contributed additional generation of 0.6 TWh in the Contracted Generation Portfolio segment, partially offset by lower generation from other stations in the segment.

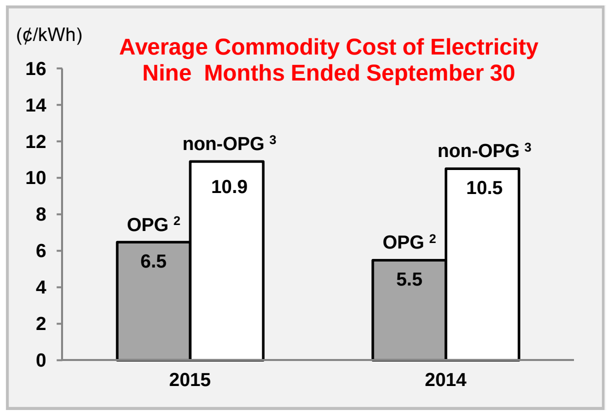
OPG's operating results are affected by changes in electricity demand resulting from variations in seasonal weather conditions and changes in economic conditions. Ontario demand was 35.3 TWh during the third quarter of 2015, an increase from 34.3 TWh during the same quarter of 2014. For the nine months ended September 30, 2015, Ontario demand was 104.3 TWh, compared to 105.3 TWh for the same period in 2014.

Baseload supply surplus to Ontario demand increased for the nine months ended September 30, 2015, compared to the same period in 2014, as a result of lower demand combined with increased baseload generation. The surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and nuclear stations and grid-connected renewable resources. Reducing hydroelectric production, which often results in spilling of water, is the first measure that the IESO uses to manage SBG conditions. During the third quarter of 2015, OPG lost 0.4 TWh of hydroelectric generation due to SBG conditions, compared to 0.7 TWh during the same quarter in 2014. During the nine months ended September 30, 2015, OPG lost 1.9 TWh of hydroelectric generation due to SBG conditions, compared to 1.2 TWh during the same period in 2014. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions is offset by a regulatory variance account authorized by the OEB.









[1] Non-OPG generation is calculated as the Ontario demand as published by the IESO, plus net exports, minus OPG's electricity generation.

[2] Average revenue for OPG is the quotient of (i) OPG's revenues from regulated prices established by the OEB, plus OPG's market based revenues, plus OPG's revenues from Energy Supply Agreements (ESAs), and (ii) OPG's generation. The calculation includes OPG's share of revenues and generation from PEC and Brighton Beach, and in 2014, excludes revenue from the cost recovery agreement related to the Nanticoke GS and the Lambton GS which were shut down in 2013. OPG's average revenue is the average commodity cost of electricity generated by OPG.

[3] The average non-OPG commodity cost of electricity is determined as the quotient of (i) the sum of hourly Ontario demand multiplied by the Hourly Ontario Energy Price (HOEP), plus total global adjustment payments, plus the sum of hourly net exports multiplied by the HOEP, less OPG's revenue as described in Note 2 above, and (ii) non-OPG generation described in Note 1.

Average Revenue for OPG

OPG's average revenue reflects the average sales prices for all of its electricity generation segments. The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices, including rate riders, authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed in OPG's annual MD&A under the heading, *Revenue Mechanisms for Regulated and Unregulated Generation*. Additional rate riders beginning in 2015 were authorized by the OEB's October 2015 order and are discussed under the heading, *Recent Developments,* in this MD&A.

The average sales price for the Regulated – Nuclear Generation segment during the three months ended September 30, 2015 was 7.1 cents per kilowatt hour (¢/kWh), compared to 5.5 ¢/kWh during the same period in 2014. The average sales price for the Regulated – Hydroelectric segment during the third quarter of 2015 was 5.0 ¢/kWh, compared to 3.3 ¢/kWh during the same quarter in 2014. These increases reflect higher base regulated prices effective November 1, 2014 and new rate riders authorized by the OEB in October 2015, with an effective date of July 1, 2015, for recovery of variance and deferral account balances. The income impact of the new rate riders during the three and nine month periods ended September 30, 2015 was largely offset by a corresponding increase in amortization expense related to regulatory balances.

During the nine months ended September 30, 2015, the average sales price for the Regulated – Nuclear Generation segment was 6.3 ¢/kWh, compared to 5.5 ¢/kWh during the same period in 2014. The average sales price for the Regulated – Hydroelectric segment was 4.7 ¢/kWh, compared to 4.1 ¢/kWh during the same period in 2014. The increases in the average sales price were a result of the new base regulated prices effective November 1, 2014 and new rate riders effective in 2015. The average price for the Regulated – Hydroelectric segment in 2014 reflected the impact of spot market prices received prior to November 1, 2014 for the generation from the 48 hydroelectric stations prescribed for rate regulation beginning in 2014.

Cash Flow from Operations

Cash flow provided by operating activities for the three months ended September 30, 2015 was $449 million, compared to $361 million for the same quarter in 2014. The increase in cash flow provided by operating activities in 2015 compared to 2014 was primarily due to new base regulated prices effective November 1, 2014, higher revenue from the Contracted Generation Portfolio segment, lower income tax payments and lower pension fund contributions. The increase was partially offset by higher OM&A expenditures in 2015.

Cash flow provided by operating activities for the nine months ended September 30, 2015 was $1,354 million, compared to $994 million for the same period in 2014. The increase in cash flow provided by operating activities was primarily due to the new base regulated prices and higher revenue from the Contracted Generation Portfolio segment, partially offset by higher OM&A expenditures.

Funds from Operations Interest Coverage

Funds from Operations (FFO) Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. FFO Interest Coverage is measured over a 12-month period. FFO Interest Coverage for the twelve months ended September 30, 2015 was 4.9 times compared to 2.8 times for the twelve months ended December 31, 2014. The FFO Interest Coverage increased primarily due to higher cash flows provided by operating activities and lower adjusted interest expense resulting from an increase in the expected return on pension plan assets in 2015. The increase in the expected return in 2015 was mainly due to higher pension plan assets at the end of 2014 compared to 2013, as a result of the strong performance of the pension plan assets during 2014.

Return on Common Equity

Return on Common Equity (ROE) is an indicator of OPG's performance consistent with its objectives to operate on a financially sustainable basis and to enhance value for the Shareholder. ROE is measured over a 12-month period. ROE for the twelve months ended September 30, 2015 was 5.9 percent compared to 8.5 percent for the twelve months ended December 31, 2014. The decrease is primarily due to the impact of the extraordinary gain of $243 million recognized in 2014 related to the 48 hydroelectric stations prescribed for rate regulation beginning in 2014. The ROE, excluding the extraordinary gain in 2014, was 6.0 percent for both the twelve months ended September 30, 2015 and December 31, 2014.

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

Recent Developments

<u>OEB Application to Recover Balances in Variance and Deferral Accounts</u>

In December 2014, OPG filed an application with the OEB to recover approximately $1.8 billion in December 31, 2014 balances in most of its authorized variance and deferral accounts. A partial settlement agreement between

OPG and intervenors providing for the recovery of approximately $1.5 billion of the total amount sought by OPG (the Partial Settlement Agreement) was approved by the OEB in June 2015. On September 10, 2015, the OEB issued its decision approving for recovery, without adjustments, the remaining balances of $263 million requested in OPG's application, which were not covered by the Partial Settlement Agreement.

On October 8, 2015, the OEB issued an order implementing its June 2015 and September 2015 decisions on OPG's application. The order authorized OPG to recover $933 million over the period from October 1, 2015 to December 31, 2016 through the following new rate riders for generation from its nuclear and regulated hydroelectric facilities during this period.

($/Megawatt hour (MWh))	**Nuclear**	**Hydroelectric** [1]
2015/2016 rate riders	10.84	3.19
2015/2016 interim period rate riders [2]	2.17	0.64
Rate riders for the period October 1, 2015 to December 31, 2016	13.01	3.83

1 The rate riders apply to production from both the existing regulated hydroelectric stations and the 48 regulated hydroelectric stations prescribed for rate regulation beginning in 2014.

2 The interim period rate riders were authorized by the OEB to allow for the recovery of the new riders effective July 1, 2015, resulting in a corresponding revenue accrual for the period from July 1, 2015 to September 30, 2015 during the third quarter of 2015. The income impact of the revenue accrual was largely offset by a corresponding increase in amortization expense related to regulatory balances.

The new rate riders are in addition to those authorized by the OEB in its December 2014 order for production from OPG's nuclear and existing regulated hydroelectric generating stations during the period from January 1, 2015 to December 31, 2015.

As the rate riders are established to collect balances previously recorded in the variance and deferral accounts, the resulting increase in revenue is expected to be largely offset by an increase in amortization expense. Therefore, while the recovery of the approved balances will positively impact cash flow, it is not expected to materially affect OPG's income.

A further discussion on the variance and deferral account balances is included under the heading, *Balance Sheet Highlights*.

Supreme Court of Canada's Decision on 2011 OEB Ruling

In its March 2011 decision on OPG's application for regulated prices effective March 1, 2011, the OEB disallowed recovery of $145 million of OPG's forecast nuclear compensation costs for the 2011 to 2012 period. The majority of these costs were based on previously negotiated collective bargaining agreements. OPG appealed this decision to the Divisional Court of Ontario in 2011 and, through subsequent appeals, the matter was heard by the Supreme Court of Canada (Supreme Court) in December 2014. In September 2015, the Supreme Court issued its decision upholding the disallowance.

As OPG's financial results have previously reflected the effect of the OEB's disallowance, this decision by the Supreme Court does not impact OPG's 2015 results.

The Society of Energy Professionals Collective Agreement

As at September 30, 2015, the Society of Energy Professionals (The Society) represented approximately 2,900 OPG employees or approximately 30 percent of OPG's regular workforce. The governing collective agreement between OPG and The Society will expire on December 31, 2015. On October 16, 2015, the parties reached a tentative agreement on the renewal terms of the collective agreement. The tentative agreement is subject to ratification by The Society membership. The ratification process is expected to conclude by the end of November 2015.

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. The following sections provide an update to OPG's disclosures related to operational excellence, project excellence, and financial sustainability. A detailed discussion of OPG's three corporate strategies is included in the 2014 annual MD&A under the headings *Operational Excellence, Project Excellence,* and *Financial Sustainability*.

Operational Excellence

OPG is committed to excellence in the areas of generation, safety and the environment. Operational excellence at OPG's nuclear, hydroelectric and thermal generating facilities is accomplished by generating electricity in a safe, reliable, and cost-effective manner.

<u>Nuclear Generating Assets</u>

The station-wide Darlington GS VBO requiring the shutdown of all four units for the duration of the outage commenced as planned on September 14, 2015. The work performed during the VBO was a significant investment into the Darlington site and is in line with OPG's ongoing commitment to safety and excellence across the fleet. The VBO included inspection and testing of common safety systems to ensure continued availability throughout and to the end of the project to refurbish the four Darlington units. Station containment structure testing was also performed during the outage with favourable results. This was the last VBO prior to the planned execution of the Darlington Refurbishment project and, therefore, the successful execution of the VBO was a critical step in ensuring the project's success. The outage was completed safely on October 30, 2015.

OPG continues to make investments to improve the performance of the Pickering GS through to at least 2020, with a focus on fuel handling reliability improvements, reducing equipment maintenance backlogs and completing critical and high priority work. OPG also continues to evaluate options related to the Pickering GS end of life date.

In December 2013, OPG submitted a licence renewal application to the Canadian Nuclear Safety Commission (CNSC) for the Darlington GS that would span the planned duration of the Darlington Refurbishment project period. The hearing for the licence renewal application took place in August 2015 and November 2015. OPG expects the CNSC's decision in December 2015. The existing licence for the Darlington GS, which was approved by the CNSC in July 2014, expires on December 31, 2015.

In mid-November 2015, OPG will be hosting a corporate World Association of Nuclear Operators peer evaluation for OPG's support functions, which will focus on how these functions support the nuclear stations in their day-to-day operations. The evaluation will be led by an international panel of industry experts.

Generation and reliability at the nuclear generating stations for the three and nine month periods ended September 30, 2015 are discussed under the heading *Regulated – Nuclear Generation Segment* in the section *Discussion of Operating Results by Business Segment*.

<u>Hydroelectric Generating Assets</u>

OPG's hydroelectric generating stations that are prescribed for rate regulation by the OEB are included in the Regulated – Hydroelectric segment. Hydroelectric generating stations that are not subject to rate regulation by the OEB are included in the Contracted Generation Portfolio segment. A description of these reportable business segments is included under the heading, *OPG's Reporting Structure* in OPG's 2014 annual MD&A.

OPG continues to evaluate and implement plans to increase capacity, maintain performance, and extend the operating life of its hydroelectric generating assets. This includes capital investment programs such as runner upgrades, which increase the capacity of existing assets. During the third quarter of 2015, OPG performed major equipment overhauls and rehabilitation work on the Chats Falls GS, Sir Adam Beck Pump GS Unit 5, Lower Notch GS Units 1 and 2, and Otto Holden GS. In August 2015, OPG's Board of Directors approved a $58 million capital project to refurbish the Sir Adam Beck Pump GS reservoir with planned execution starting in the first half of 2016 and a targeted completion date of April 2017. Project activities will include de-watering of the existing reservoir and performing reservoir floor repairs. The refurbishment will ensure that the station will continue to operate safely for approximately the next 50 years. Other major hydroelectric generation development projects are discussed under the heading, *Project Excellence*.

Thermal Generating Assets

OPG's biomass and oil/gas fuelled generating stations are included in the Contracted Generation Portfolio segment. These stations operate as peaking facilities, depending on electricity demand. Ontario is the first jurisdiction in North America to fully eliminate coal as a source of electricity generation.

Thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation segment once the stations are removed from service. This includes the Nanticoke GS and the Lambton GS sites, which ended coal-fired generation in 2013. Earlier in 2015, OPG announced that it would decommission the Nanticoke GS, as it could not commercially support further preservation costs without a corresponding recovery mechanism. OPG is currently developing a decommissioning plan for the Nanticoke GS. The costs of decommissioning the Nanticoke GS are charged to a previously established decommissioning provision.

OPG continues to preserve the option to convert the Lambton GS to natural gas and/or biomass in the future. The cost of activities required to preserve the station is reflected in the operating costs of the Services, Trading, and Other Non-Generation segment. The decision to continue to incur preservation costs for the Lambton GS will be revisited in conjunction with Ontario's next Long-Term Energy Plan, which is expected to be developed in 2016.

Environmental Performance

During the third quarter of 2015, OPG's facilities continued to demonstrate strong environmental performance against targets, and there were no significant environmental events.

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2015. Disclosures relating to environmental policies and procedures and environmental risks are provided in the 2014 annual MD&A.

Project Excellence

OPG is pursuing several generation development and other projects to support Ontario's long-term electricity supply requirements. OPG's major projects include the refurbishment of the Darlington GS, new hydroelectric generation developments and plant expansions, and a repository for the long-term management of low and intermediate level nuclear waste (L&ILW). The status updates for OPG's major projects as of September 30, 2015 are outlined below.

Project *(millions of dollars)*	Capital Expenditures Year-to-date	Capital Expenditures Life-to-date	Approved Budget	Approved Planned In-service Date	Status
Darlington Refurbishment	520	1,980			See update below.
Lower Mattagami	93	2,462	2,600	June 2015	All six units were placed in-service by December 2014 ahead of schedule and under budget. Project closure activities are continuing.
Deep Geologic Repository for L&ILW [1]	6 [1]	185 [1]			See update below.
Peter Sutherland Sr. GS	55	67	300	First half of 2018	The budget was approved by OPG's Board of Directors and the hydroelectric ESA with the IESO was executed in the first half of 2015. Construction continued during the third quarter of 2015. See update below.

[1] Expenditures are funded by the nuclear fixed asset removal and nuclear waste management liabilities.

Darlington Refurbishment

The Darlington Refurbishment project is a multi-phase program comprised of the following five major sub-projects:

- Retube and Feeder Replacement
- Turbines and Generators
- Defueling and Fuel Handling
- Steam Generators
- Balance of Plant.

The definition phase of the project is well underway and is on track to be completed in 2015. The definition phase involves project planning, engineering, design and construction of pre-requisite projects, development of reactor tooling, and construction of a reactor training facility including a full-scale reactor mock-up. The funding for 2015 deliverables as part of the definition phase was approved by OPG's Board of Directors in November 2014.

In November 2015, OPG's Board of Directors approved the budget of $12.8 billion including capitalized interest, escalation and the schedule for the four-unit refurbishment. The approved budget is consistent with the previous total project cost estimate of less than $10 billion in 2013 dollars excluding capitalized interest and escalation. The refurbishment of the last unit is scheduled to be completed by 2026. The budget and schedule will be submitted for Shareholder concurrence.

Upon Shareholder concurrence, the project will transition from the definition phase to the execution phase. A plan is in place to support this transition and to support the planned commencement of the first unit's refurbishment in late 2016.

There are a number of pre-requisite projects, including construction of facilities, infrastructure upgrades, and installation of safety enhancements, which are being completed in support of the execution phase of the project. A portion of these projects has been completed, with the remaining projects tracking to be completed in line with the execution plan for the first unit's refurbishment.

Deep Geologic Repository for L&ILW

In 2012, the CNSC and the Canadian Environmental Assessment Agency (CEAA) appointed a three-member Joint Review Panel (JRP) for OPG's Deep Geologic Repository (DGR) for L&ILW. The JRP examined the environmental effects of the proposed DGR to meet the requirements of the *Canadian Environmental Assessment Act*. On May 6, 2015, the JRP submitted its report and recommendations on the Environmental Assessment (EA) to the federal Minister of Environment. The report concluded that, given mitigation, there is unlikely to be significant environmental impact from the project and recommended that the Minister approve the EA. The report further suggested that the project should be implemented expeditiously.

In June 2015, the CEAA announced that the public had until September 1, 2015 to provide comments on the potential environmental conditions relating to the JRP report. OPG responded to the CEAA's list of potential conditions in August 2015. OPG accepted the majority of the conditions as stated but requested amendments to the proposed wording for a small number of conditions. Earlier in 2015, the CEAA stated that the Minister's decision on the EA was expected by December 2, 2015.

New Nuclear Units

Ontario's 2013 Long-Term Energy Plan indicated that the Ontario Ministry of Energy would work with OPG to maintain the site preparation licence granted by the CNSC in relation to the potential construction of two new nuclear reactors at the Darlington site. As such, OPG has been undertaking activities required to support the EA and existing licence.

In September 2015, the Federal Court of Appeal granted the appeal brought forward by OPG, the Attorney General of Canada, and the CNSC related to the May 2014 Federal Court (Canada) decision on the judicial review of the issuance of the CNSC Power Reactor Site Preparation Licence and the Darlington New Nuclear Project EA. The Federal Court of Appeal decision upheld the EA approval as well as the CNSC Power Reactor Site Preparation Licence and awarded OPG its costs of the appeal.

On November 6, 2015, an application for leave to appeal was filed with the Supreme Court by the parties that brought the judicial review. OPG and the other respondents have a right to respond and the applicants will have a further right of reply. The Supreme Court's decision on whether leave is granted is expected to be issued in the first half of 2016.

Peter Sutherland Sr. GS

The construction of the Peter Sutherland Sr. GS, a new 28 MW station on the New Post Creek near its outlet to the Abitibi River, commenced in the second quarter of 2015. The station has a planned in-service date in the first half of 2018 and an approved budget of $300 million. The station will be constructed through PSS Generating Station LP, a partnership between OPG and Coral Rapids L.P., a wholly owned subsidiary of the Taykwa Tagamou Nation. Under the partnership agreement, Coral Rapids L.P. may acquire up to a 33 percent interest in the partnership. During the second quarter of 2015, a hydroelectric ESA for the station was executed by the IESO and the partnership. The hydroelectric ESA formalized the long-term financial agreement with the IESO for the development of the station and the supply of electricity and related products to the Ontario market.

Construction work on the project continued during the third quarter of 2015, including construction of the project camp and setup of the batch concrete plant. Project financing was completed in October 2015, as discussed under the heading, *Financing Activities*, in the *Liquidity and Capital Resources* section.

Financial Sustainability

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of financial performance that will ensure its long-term financial sustainability and enhance 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 enables OPG to finance its operations and generation development projects.

Revenue Growth

Regulated Assets

Electricity produced from OPG's regulated facilities receives regulated prices determined by the OEB. OPG's objectives with respect to its regulated operations are to clearly demonstrate that the costs for these operations are prudently incurred and should be fully recovered, and to earn an appropriate return on its investment in these assets.

In December 2014, OPG filed an application with the OEB requesting approval to recover approximately $1.8 billion in December 31, 2014 balances in most of the authorized regulatory variance and deferral accounts, through new rate riders beginning in 2015. In June 2015, the OEB approved the Partial Settlement Agreement between OPG and intervenors that allowed for the recovery of approximately $1.5 billion of the total amount sought by OPG. In September 2015, the OEB issued a decision approving for recovery the remaining balances of $263 million requested in OPG's application which were not covered by the Partial Settlement Agreement. In October 2015, the OEB issued an order implementing its June 2015 and September 2015 decisions and authorized OPG to recover $933 million over the period from October 1, 2015 to December 31, 2016 through new rate riders for its nuclear and regulated hydroelectric production during this period. Refer to the *Recent Developments* and *Balance Sheet Highlights* sections for more details related to the OEB's decisions and order on OPG's variance and deferral account application.

OPG currently plans to apply to the OEB in 2016 for new regulated prices for production from its regulated hydroelectric and nuclear facilities, effective in 2017. The OEB has previously stated that its expectation is that these prices would be determined on the basis of an incentive regulation ratemaking methodology for the hydroelectric operations, and a longer term, multi-year forecast cost of service ratemaking approach with incentive regulation features for the nuclear operations.

Assets under Contracts

OPG has negotiated ESAs for most of its unregulated hydroelectric and thermal facilities. In June 2015, a hydroelectric ESA was executed with the IESO for the new 28 MW Peter Sutherland Sr. GS located on the New Post Creek.

In 2015, the IESO launched the first phase of its Large Renewable Procurement (LRP) program, which is a competitive bidding process for procuring large renewable energy projects in Ontario. In September 2015, OPG submitted bids for both ground mounted solar and hydroelectric projects under this program. The bids for ground mounted solar projects were submitted in partnership with a solar project developer, SunEdison. Contracts under the LRP are expected be awarded to successful bidders by the end of 2015.

OPG continues to explore and evaluate other energy projects and procurements including opportunities for redevelopment of existing assets, and energy storage.

<u>Improving Efficiency and Reducing Costs</u>

OPG remains focused on reducing costs by pursuing efficiency and productivity improvements across operating business units and support functions.

From January 1, 2011 to December 31, 2014, OPG reduced headcount from ongoing operations by approximately 2,200. During the first nine months of 2015, OPG further reduced headcount from ongoing operations by approximately 400. From January 1, 2011 to September 30, 2015, OPG has realized cumulative savings of approximately $840 million through headcount reductions.

In October 2015, following a competitive bid process, OPG awarded a five-year information technology services outsourcing contract to its incumbent provider, effective February 2016. The new contract is expected to generate ongoing cost savings for OPG. For further details, refer to the disclosure under the *Liquidity and Capital Resources* section.

<u>Strengthening Financial Position</u>

In addition to initiatives to increase revenue, pursue efficiencies, and reduce costs, OPG employs the following four strategies to strengthen its financial position. The following are updates to the strategies since the 2014 annual MD&A:

- **Ensuring sufficient liquidity:** During the first nine months of 2015, cash flow provided by operating activities increased to $1,354 million, compared to $994 million for the same period in 2014. In 2015, OPG renewed and extended its $1 billion bank credit facility to May 2020.
- **Maintaining an investment grade credit rating:** In March 2015, DBRS Ltd. re-affirmed the long-term credit rating on OPG’s debt at A (low), and the commercial paper rating at R-1 (low). All ratings from DBRS Ltd. have a stable outlook. On July 7, 2015, Standard & Poor’s lowered OPG’s long-term corporate credit rating from ‘A-’ to ‘BBB+’ with a stable outlook. Standard & Poor’s rating action followed its July 6, 2015 downgrade to the Province of Ontario’s rating from 'AA-' to 'A+'.
- **Ensuring that generation development projects are economic and provide for cost recovery and an appropriate return:** During the second quarter of 2015, OPG negotiated an ESA for the Peter Sutherland Sr. GS as discussed under the heading *Project Excellence* in the section, *Core Business and Strategy.* As discussed in that section under the heading, *Revenue Growth*, OPG submitted bids to the IESO in September 2015 as part of the LRP competitive bidding process for both ground-mounted solar and hydroelectric projects.

- **Evaluating financial performance:** OPG continuously evaluates its financial performance using key financial metrics. For further details, refer to the ROE and FFO Interest Coverage disclosure under the section, *Supplementary Non-GAAP Financial Measures*.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2015**	**2014**	**2015**	**2014**
Regulated generation sales	**791**	703	**2,260**	1,947
Variance accounts	**12**	77	**55**	(87)
Other	**77**	7	**188**	318
Total revenue	**880**	787	**2,503**	2,178
Fuel expense	**78**	81	**235**	230
Variance and deferral accounts	**(1)**	(16)	**(1)**	(49)
Total fuel expense	**77**	65	**234**	181
Gross margin	**803**	722	**2,269**	1,997
Operations, maintenance and administration	**536**	444	**1,577**	1,457
Depreciation and amortization	**245**	128	**472**	387
Property taxes	**7**	7	**20**	21
Income before interest, income taxes and extraordinary item	**15**	143	**200**	132

The decrease in segment earnings of $128 million during the third quarter of 2015, compared to the same quarter in 2014, was primarily a result of lower generation of 1.6 TWh and higher OM&A expenses. The commencement of the VBO and a higher number of planned outage days at the Darlington GS in the third quarter of 2015 were the primary drivers for the decrease in generation and higher OM&A expenses. Fewer fuel, depreciation and OM&A expenses totalling $53 million deferred in regulatory variance and deferral accounts during the third quarter of 2015, compared to the same period in 2014, also contributed to the decrease in earnings. The higher deferrals in 2014 primarily related to costs not included in the regulated prices in effect prior to November 1, 2014. Higher average sales prices as a result of higher base regulated price authorized by the OEB effective November 1, 2014 partially offset the decrease in segment earnings.

During the nine months ended September 30, 2015, compared to the same period in 2014, the increase in segment earnings of $68 million was primarily due to the higher OEB-approved base regulated price effective November 1, 2014. This was partially offset by OM&A expenses related to the VBO, and additional depreciation expense of $92 million, additional fuel expense of $48 million and additional OM&A expenses of $45 million during the first nine months of 2015 due to higher amounts deferred in regulatory accounts during the same period in 2014.

Generation revenue for the three and nine month periods ended September 30, 2015 also reflected a revenue accrual in the third quarter of 2015 for the new rate riders authorized by the OEB in October 2015 with an effective date of July 1, 2015. This increase in revenue was largely offset by higher amortization expense related to the regulatory balances. The impact of the new rate riders is discussed further under the section, *Balance Sheet Highlights.*

The change in other revenue for the three and nine month periods ended September 30, 2015, compared to the same periods in 2014, was primarily due to the change in the fair value of the derivative liability embedded in the terms of the Bruce Power lease agreement (Bruce Lease). Changes in the fair value of this derivative are recorded in other revenue, with corresponding changes in the regulatory asset related to the Bruce Lease Net Revenues

Variance Account. As such, there was no income impact related to the changes in the fair value of the derivative liability during the three and nine month periods ended September 30, 2015.

The Unit Capability Factors for the Darlington and Pickering generating stations and the Nuclear Total Generating Cost (TGC) per MWh were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2015	**2014**	**2015**	**2014**
Unit Capability Factor *(%)*				
Darlington GS	**75.9**	98.4	**88.3**	90.7
Pickering GS	**82.2**	79.9	**78.4**	74.7
Nuclear TGC per MWh *($/MWh)*	**57.77**	42.83	**53.79**	48.70

The decrease in the Unit Capability Factor at the Darlington GS for the three and nine month periods ended September 30, 2015, compared to the same periods in 2014, was primarily due to the four-unit VBO.

The marginal increase in the Unit Capability Factor at the Pickering GS for the three and nine month periods was primarily due to higher reliability as the number of unplanned outage days decreased, partially offset by an increase in planned outage days. Improvements in reliability at the Pickering GS were primarily associated with better fuel handling equipment performance.

The increase in Nuclear TGC per MWh during the quarter compared to the same quarter in 2014 primarily reflected decreased production and higher OM&A expenses as a result of the VBO and other outage activities in 2015. The increase during the nine month period in 2015 compared to the same period in 2014 primarily reflected higher expenses OM&A due to the VBO and other OM&A expenditures, partially offset by improved operating performance at the Pickering GS.

Regulated – Nuclear Waste Management Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2015**	**2014**	**2015**	**2014**
Revenue	**30**	31	**91**	89
Operations, maintenance and administration	**33**	32	**97**	94
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**219**	192	**660**	575
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(163)**	(161)	**(535)**	(538)
Loss before interest, income taxes and extraordinary item	**(59)**	(32)	**(131)**	(42)

Higher accretion expense contributed to increased losses for the segment for the third quarter of 2015 and the nine months ended September 30, 2015, compared to the same periods in 2014. The higher accretion expense was primarily due to higher amounts deferred in regulatory accounts during the three and nine month periods ended September 30, 2014.

Regulated – Hydroelectric Segment

(millions of dollars)	Three Months Ended September 30 2015	2014	Nine Months Ended September 30 2015	2014
Regulated generation sales [1]	**369**	196	**1,078**	569
Spot market sales	**-**	53	**-**	401
Variance accounts	**-**	6	**33**	15
Other	**24**	20	**85**	102
Total revenue	**393**	275	**1,196**	1,087
Fuel expense	**89**	89	**234**	239
Variance accounts	**(1)**	2	**14**	10
Total fuel expense	**88**	91	**248**	249
Gross margin	**305**	184	**948**	838
Operations, maintenance and administration	**82**	80	**236**	241
Depreciation and amortization	**81**	40	**201**	122
Property tax	**1**	1	**1**	1
Income before other loss, interest, income taxes and extraordinary item	**141**	63	**510**	474
Other loss	**2**	-	**2**	2
Income before interest, income taxes and extraordinary item	**139**	63	**508**	472

[1] During the three and nine month periods ended September 30, 2015, the Regulated – Hydroelectric segment generation sales included incentive payments of $7 million and $21 million, respectively, related to the OEB approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2014 – $3 million and $15 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to ratepayers.

Income before interest, income taxes and extraordinary item increased by $76 million during the third quarter of 2015, compared to the same period in 2014. The increase in income was largely due to new base regulated prices authorized by the OEB effective November 1, 2014. The revenue impact of higher rate riders in 2015 was largely offset by a corresponding increase in amortization expense related to regulatory balances.

The increase in income of $36 million for the nine months ended September 30, 2015, compared to the same period in 2014, was primarily due to higher base regulated prices effective November 1, 2014, partially offset by lower other station revenue.

The Regulated – Hydroelectric availability and OM&A expense per MWh were as follows:

	Three Months Ended September 30 2015	2014	Nine Months Ended September 30 2015	2014
Hydroelectric Availability *(%)*	**90.5**	90.7	**91.3**	91.4
Hydroelectric OM&A expense per MWh *($/MWh)*	**11.2**	10.5	**10.2**	9.9

Hydroelectric availability for the third quarter of 2015 and the nine months ended September 30, 2015 was comparable to the same periods in 2014.

The increase in hydroelectric OM&A expense per MWh for the three and nine month periods ended September 30, 2015, compared to the same periods in 2014, was primarily due to lower generation.

Contracted Generation Portfolio Segment

(millions of dollars)	Three Months Ended September 30 2015	2014	Nine Months Ended September 30 2015	2014
Revenue	**147**	67	**414**	224
Fuel expense	**11**	5	**29**	32
Gross margin	**136**	62	**385**	192
Operations, maintenance and administration	**46**	43	**133**	129
Depreciation and amortization	**17**	11	**52**	22
Accretion on fixed asset removal liabilities	**2**	1	**6**	5
Property taxes	**1**	1	**5**	(2)
Income from investments subject to significant influence	**(8)**	(9)	**(30)**	(32)
Restructuring	**-**	1	**-**	8
Income before interest, income taxes and extraordinary item	**78**	14	**219**	62

Income before interest, income taxes and extraordinary item increased by $64 million during the third quarter of 2015 and $157 million for the nine months ended September 30, compared to the same periods in 2014. The increases primarily resulted from higher revenue from the stations of the Lower Mattagami River project, due to all new units being in service since the end of 2014. Also contributing to the higher income in 2015 was higher revenue from the Atikokan GS and the Thunder Bay GS, which have been converted to biomass fuel.

The increase in income for the three and nine month periods ended September 30, 2015 was partially offset by higher depreciation expense, which was primarily due to the new assets placed in service as part of the Lower Mattagami River and biomass conversion projects. The higher income for the nine months ended September 30, 2015 was also partially offset by lower revenue from the Lennox GS, primarily as a result of higher average sales prices during the first half of 2014, and higher restructuring expenses in the second quarter of 2014 related to staffing requirement changes at the Thunder Bay GS prior to its conversion to biomass.

The hydroelectric availability, hydroelectric OM&A expense per MWh, and the thermal Equivalent Forced Outage Rate (EFOR) for the segment were as follows:

	Three Months Ended September 30 2015	2014	Nine Months Ended September 30 2015	2014
Hydroelectric Availability *(%)*	**81.5**	95.9	**91.5**	93.0
Hydroelectric OM&A expense per MWh *($/MWh)*	**28.0**	24.0	**22.6**	24.0
Thermal EFOR *(%)*	**7.4**	2.1	**14.1**	2.9

Lower hydroelectric availability during the third quarter of 2015 and for the nine months ended September 30, 2015, compared to the same periods in 2014, was primarily due to a higher number of planned outage days at the Lower Mattagami stations.

The increase in hydroelectric OM&A expense per MWh during the third quarter of 2015, compared to the same quarter in 2014, was due to a marginal increase in OM&A expenses related to the Lower Mattagami stations**.** The improvement in the hydroelectric OM&A expense per MWh for the nine month period ended September 30, 2015, compared to the same period in 2014, was due to higher generation from the Lower Mattagami stations that were placed in service throughout 2014.

The thermal EFOR increased for the three and nine month periods ended September 30, 2015, compared to the same periods in 2014, primarily due to an outage to perform repair work at the Lennox GS in 2015. The extended duration of the outage reflected market conditions that made it more cost effective to carry out the repair work over a longer period.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2015**	**2014**	**2015**	**2014**
Revenue	**5**	30	**48**	153
Fuel (recovery) expense	**(1)**	-	**1**	2
Gross margin	**6**	30	**47**	151
Operations, maintenance and administration	**12**	26	**40**	96
Depreciation and amortization	**7**	5	**21**	15
Accretion on fixed asset removal liabilities	**3**	2	**6**	6
Property taxes	**-**	3	**8**	2
Restructuring	**-**	2	**1**	7
(Loss) income before interest, income taxes and extraordinary item	**(16)**	(8)	**(29)**	25

Segment earnings decreased by $8 million during the third quarter of 2015, compared to the same quarter in 2014. The decrease in earnings was largely due to the expiry of the cost recovery agreement for the Nanticoke GS and the Lambton GS, and recoveries recognized during 2014 related to property tax reassessments. The decrease in earnings was largely offset by lower OM&A expenses for the Nanticoke GS and the Lambton GS.

Segment earnings decreased by $54 million for the nine months ended September 30, 2015, compared to the same period in 2014. The decrease in earnings was primarily due to a decrease in trading margins for electricity sold to neighbouring energy markets and the expiry of the cost recovery agreement for the Nanticoke GS and the Lambton GS. The unseasonably cold winter in 2014 contributed to higher trading margins in the first quarter of 2014.

Earlier in 2015, OPG announced that it would no longer preserve the option to convert the Nanticoke GS to natural gas and/or biomass but will continue to preserve this option for the Lambton GS. The Nanticoke GS will be closed safely, securely and in an environmentally responsible manner.

Income Taxes

Income tax expense for the three months ended September 30, 2015 was $30 million compared to $46 million for the same quarter in 2014. The decrease in income tax expense was primarily due to lower income before taxes in 2015.

Income tax expense for the nine months ended September 30, 2015 was $114 million compared to $133 million for the same period in 2014. The decrease in income tax expense was primarily due to a change in reserves from the resolution of uncertainties.

LIQUIDITY AND CAPITAL RESOURCES

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

Changes in cash and cash equivalents for the three and nine month periods ended September 30, 2015 are as follows:

(millions of dollars)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Cash and cash equivalents, beginning of period	**575**	625	**610**	562
Cash flow provided by operating activities	**449**	361	**1,354**	994
Cash flow used in investing activities	**(354)**	(347)	**(982)**	(1,082)
Cash flow (used in) provided by financing activities	**(102)**	(2)	**(414)**	163
Net (decrease) increase	**(7)**	12	**(42)**	75
Cash and cash equivalents, end of period	**568**	637	**568**	637

For a discussion regarding cash flow provided by operating activities and FFO Interest Coverage, refer to the *Highlights* section.

Investing Activities

Cash flow used in investing activities during the third quarter of 2015 was comparable with the same period in 2014.

Cash flow used in investing activities during the nine months ended September 30, 2015 decreased by $100 million compared to the same period in 2014. The decrease was primarily due to lower capital expenditures for the Lower Mattagami River and Atikokan biomass conversion projects, which were placed in-service in 2014. The decrease was partially offset by higher expenditures on nuclear sustaining capital programs and construction of the Peter Sutherland Sr. GS in 2015.

OPG's forecasted capital expenditures for 2015 are approximately $1.4 billion, which includes amounts for the Darlington Refurbishment project, hydroelectric development, and sustaining capital investments.

Financing Activities

Cash flow used in financing activities during the three months ended September 30, 2015 was $102 million, compared to $2 million for the same period in 2014, primarily due to the repayment of long-term debt of $200 million during the third quarter of 2015, partially offset by a net issuance of short-term notes of $100 million during the third quarter of 2015.

Cash flow used in financing activities during the nine months ended September 30, 2015 was $414 million, mainly due to the repayment of $502 million of long-term debt during the first nine months of 2015. In the comparative period of 2014, cash flow provided by financing activities of $164 million was largely due to the issuance of long-term debt of $200 million, partially offset by a net repayment of short-term notes of $32 million, in the first nine months of 2014.

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2015, OPG renewed and extended both tranches to May 2020. As at September 30, 2015, there were no outstanding borrowings under the bank credit facility.

As at September 30, 2015, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $460 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 general corporate purposes. As at September 30, 2015, a total of $386 million of Letters of Credit had been issued. This included $349 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. The agreement expires on November 30, 2016. As at September 30, 2015 and December 31, 2014, there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plan.

The Lower Mattagami Energy Limited Partnership maintains a $500 million bank credit facility to support funding requirements, including the commercial paper program of the Lower Mattagami River project. The facility originally consisted of two $300 million multi-year term tranches. The first and second tranche were to mature in August 2019 and August 2015, respectively. In the third quarter of 2015, OPG extended the maturity of the first tranche to August 2020. During the same period, the second tranche was reduced to $200 million and extended to August 2016. As at September 30, 2015, there was $100 million in external commercial paper 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 September 30, 2015, there were no outstanding borrowings under this credit facility. This credit facility expires in June 2016.

In 2014, OPG entered into an $800 million general corporate credit facility agreement with the OEFC in support of its financing requirements for 2015 and 2016. As at September 30, 2015, there were no outstanding borrowings under this credit facility. This credit facility expires on December 31, 2016.

In October 2015, PSS Generating Station LP, a subsidiary of OPG, issued long-term debt totalling $245 million maturing in October 2067 to support the construction of the Peter Sutherland Sr. GS. The effective interest rate for the debt was 4.9 percent and the coupon interest rate was 4.8 percent. The debt is secured by the assets of the project.

Contractual and Commercial Commitments

OPG's commitments and contingencies are outlined in Note 15 to the audited consolidated financial statements as at and for the year ended December 31, 2014. A discussion of changes in commitments and contingencies since December 31, 2014 is included in Note 11 to OPG's interim consolidated financial statements for the third quarter of 2015. Disclosure regarding OPG's contractual and commercial commitments is also included in OPG's 2014 MD&A.

<u>Information Technology Services Contract</u>

OPG conducted a competitive bid process for outsourced information technology services over the 2014 and 2015 period, issuing a Request For Proposal to a number of qualified suppliers. In October 2015, following the competitive bid process, a five-year agreement was awarded to the incumbent effective February 2016. The estimated value of the new outsourcing contract is approximately $300 million over the five-year period.

BALANCE SHEET HIGHLIGHTS

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

	As At	
(millions of dollars)	**September 30 2015**	**December 31 2014**
Property, plant and equipment - net	**18,071**	17,593
The increase was primarily due to capital expenditures on the Darlington Refurbishment project and sustaining capital programs. The increase was partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**14,957**	14,379
The increase was primarily due to earnings on the Nuclear Funds and contributions to the Used Fuel Segregated Fund, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Fixed asset removal and nuclear waste management liabilities	**17,640**	17,028
The increase was primarily a result of accretion expense, partially offset by expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Regulatory assets *(current and non-current portions)*	**7,018**	7,191
The decrease was primarily due to a reduction in the regulatory asset related to pension and OPEB for amounts reclassified from accumulated other comprehensive income to net income, and the amortization of balances related to variance and deferral accounts approved for recovery by the OEB. See below for further discussion of the account balances approved by the OEB in 2015.		

Impact of New Rate Riders for Recovery of OEB-authorized Variance and Deferral Account Balances

The OEB's decisions in June 2015 and September 2015 approved for recovery OPG's December 31, 2014 deferral and variance balances of approximately $1.8 billion. The approval includes recovery of $714 million recorded in the Pension and OPEB Cost Variance Account during 2013 and 2014 over six years starting on July 1, 2015 and $225 million recorded in this variance account prior to 2013 that will continue to be recovered until December 31, 2024 as previously authorized by the OEB. The majority of the approved balances of $809 million in other accounts were approved for recovery over a period of 18 months starting on July 1, 2015.

The OEB's October 2015 order implementing its June 2015 and September 2015 decisions established new rate riders with an effective date of July 1, 2015, as discussed under the heading *OEB Application to Recover Balances in Variance and Deferral Accounts* in the *Highlights* section. As a result of the OEB's decisions and order, during the third quarter of 2015, OPG recorded $150 million in amortization expense for regulatory balances related to the period from July 1, 2015 to September 30, 2015, which was offset by a corresponding revenue accrual. As at September 30, 2015, net regulatory assets of $602 million were classified as current on OPG's balance sheet in respect of the expected recovery of regulatory balances over the next 12 months based on the OEB's October 2015 order.

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 interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities that OPG undertakes include guarantees, which provide financial or performance assurance to third-parties on behalf of certain subsidiaries, and long-term fixed price contracts.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2014. A discussion of changes in accounting policies is included in OPG's interim consolidated financial statements for the third quarter of 2015 under the heading, *Changes in Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2014 annual MD&A.

Asset Retirement Obligation

As at September 30, 2015, OPG's asset retirement obligation (ARO) was $17,640 million (December 31, 2014 − $17,028 million). The ARO comprises of expected costs to be incurred up to and the beyond termination of operations and the closure of nuclear and thermal generating plant facilities and other facilities, including station decommissioning and the management of nuclear used fuel and L&ILW. The significant assumptions underlying operational and technical factors used in measuring the ARO are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of programs and station end-of-life dates, may result in significant changes to the value of the ARO.

Following the release of Ontario's Long-Term Energy Plan in 2013, Bruce Power and the IESO entered into negotiations for the refurbishment of units at the Bruce generating stations, which Bruce Power leases from OPG on a long-term basis. Under the terms of the lease agreement and as required by the CNSC, OPG is primarily responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations. OPG's average estimated service life, for accounting purposes, of the Bruce A station is to the end of 2048 and of the Bruce B station to the end of 2019. OPG expects to reassess its accounting assumptions for the useful lives of the Bruce stations following the finalization of a refurbishment agreement between Bruce Power and the IESO. This is expected to result in a corresponding impact to OPG's ARO and related asset retirement costs capitalized to fixed assets.

RISK MANAGEMENT

The following discussion provides an update of OPG's risk management activities since the date of OPG's 2014 annual MD&A. As such, this risk management disclosure should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Operational Risks

Risks Associated with Major Development Projects

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

Darlington Refurbishment

A large proportion of the costs of the Darlington Refurbishment project will be paid to contractors and suppliers, including vendors that will engineer, procure, and construct components of the project. There is a risk that, as the volume of work increases significantly, vendor performance shortfalls may impact project objectives and deliverables. There is also an increased risk of contractor initiated safety events, which may impact OPG's reputation. Mitigating actions include collaborative front end planning, active risk management, increased field presence by supervisory staff, and assisting vendors in removing barriers to work.

Financial Risks

Commodity Markets

Changes in the market price of 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.

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

	2015 [1]	2016	2017
Estimated fuel requirements hedged [2]	69%	75%	67%

1 Includes forecast for the remainder of the year.

2 Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of facility (nuclear and thermal) for which OPG has entered into contractual arrangements or obligations in order to secure the price of fuel. Excess fuel inventories in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Trading

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

OPG's trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of this trading activity is Value at Risk (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. For the third quarter of 2015, the VaR utilization ranged between $0.5 million and $1.0 million (third quarter of 2014 – between $0.3 million and $0.7 million).

Credit

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

OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2015 was $342 million, including $312 million to the IESO. Over 95 percent of the remaining $30 million exposure is related to investment grade counterparties.

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.

Nuclear Regulatory Requirements

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

The units of the Darlington GS, based on original design assumptions, are currently forecast to reach their end-of-life between 2019 and 2020. In July 2014, the CNSC approved the renewal of the Darlington GS operating license until December 31, 2015. OPG is currently seeking a longer term licence renewal that would span the planned duration of the Darlington Refurbishment project. The CNSC hearings in support of a relicensing decision took place in August 2015 and November 2015. The CNSC's decision on OPG's application is expected by the end of 2015.

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 from OPG's regulated facilities are determined by the OEB using forecast information. There is an inherent risk that the prices established by an economic regulator may not provide for recovery of all actual costs incurred by the regulated operations, or may not allow the regulated operations to earn an appropriate rate of return.

In September 2015, the Supreme Court upheld the OEB's March 2011 decision disallowing $145 million of OPG's forecast nuclear compensation costs for the 2011-2012 period that were based on previously negotiated collective agreements.

Enterprise-Wide Risks

People and Culture

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

As of September 30, 2015, approximately 88 percent of OPG's regular labour force was represented by a union. In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights on OPG facilities. Thirteen of the collective agreements with the craft unions expired on April 30, 2015 and, as at September 30, 2015, renewal terms were reached for seven of these agreements. Negotiations to renew the remaining agreements are ongoing. In the event of a labour disruption by any of the craft unions, OPG could face financial and reputational impacts. OPG has contingency plans in place which are designed to minimize these impacts.

In October 2015, The Society and OPG reached a tentative agreement on the renewal terms of the collective agreement, which expires on December 31, 2015. The tentative agreement is subject to ratification by The Society membership, which is expected to conclude by the end of November 2015.

The Power Workers' Union (PWU) represents approximately 60 percent of OPG's regular workforce. During the second quarter of 2015, the PWU and OPG agreed to the terms of a renewed three-year collective agreement expiring on March 31, 2018. The agreement includes increases to employee pension plan contributions in each year of the agreement. The agreement also provides existing employees with lump sum payments for each of the first two years of the contract and eligibility to annually receive shares in Hydro One Inc. for up to 15 years, as long as these employees continue to make contributions to the OPG pension plan. The contract term was conditional on the initial public offering of Hydro One Inc. shares, which occurred in November 2015.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

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

QUARTERLY FINANCIAL HIGHLIGHTS

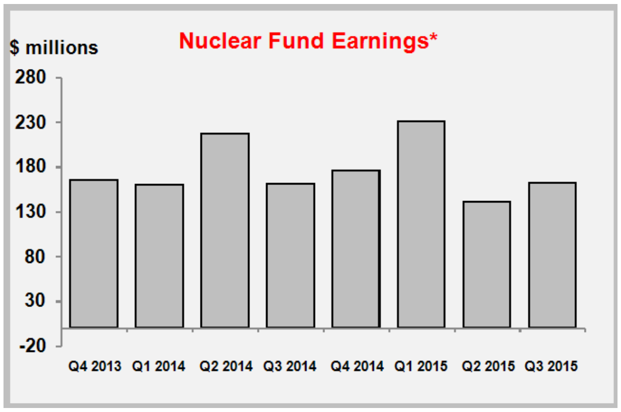
The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

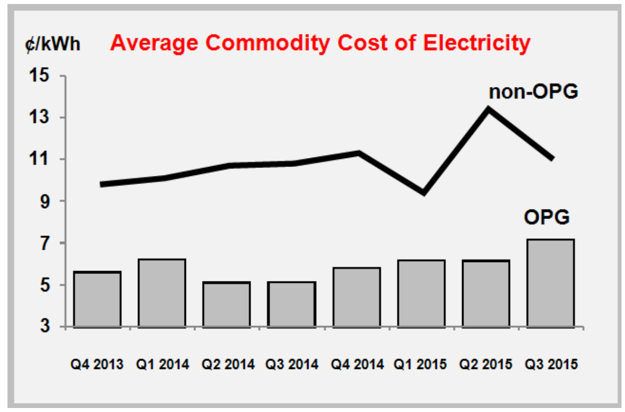
(millions of dollars - except where noted) (unaudited)	**September 30 2015**	**June 30 2015**	**March 31 2015**	**December 31 2014**
Revenue	**1,426**	1,383	1,355	1,318
Net income attributable to the Shareholder	**80**	189	234	86
Net income attributable to non-controlling interest	**5**	4	5	4
Net income	**85**	193	239	90
Per share, attributable to the Shareholder *(dollars)*				
Net income	**$0.31**	$0.74	$0.91	$0.34

(millions of dollars - except where noted) (unaudited)	**September 30 2014**	**June 30 2014**	**March 31 2014**	**December 31 2013**
Revenue	1,160	1,098	1,387	1,174
Income before extraordinary item attributable to the Shareholder	118	115	242	4
Income before extraordinary item attributable to non-controlling interest	1	1	1	-
Income before extraordinary item	119	116	243	4
Net income attributable to the Shareholder	361	115	242	4
Net income attributable to non-controlling interest	1	1	1	-
Net income	362	116	243	4
Per share, attributable to the Shareholder *(dollars)*				
Income before extraordinary item	$0.46	$0.45	$0.94	$0.02
Net income	$1.41	$0.45	$0.94	$0.02

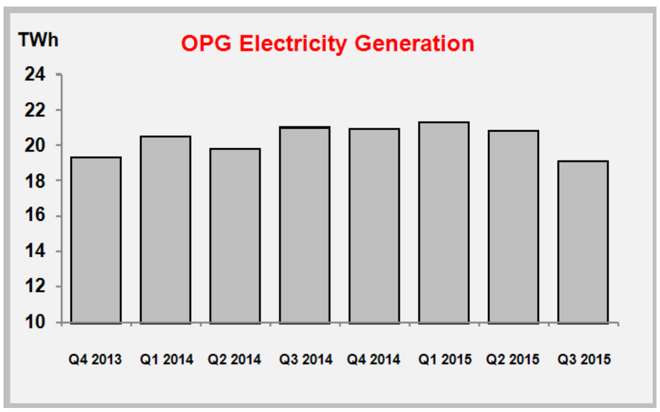
Trends

OPG's quarterly results are affected by changes in demand primarily resulting from variations in seasonal weather conditions. Historically, OPG's revenues have been 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. In addition to average revenue and generation volume, OPG's income is affected by earnings from the Nuclear Funds.





*net of regulatory variance account



Additional items which affected net income during the first six months of 2015, compared to the same period in 2014, are described below:

- Higher revenue of approximately $140 million as a result of higher average sales prices due to new base regulated prices for all of OPG's regulated facilities effective November 1, 2014
- Higher earnings of $93 million from the Contracted Generation Portfolio segment primarily due to all new units of the Lower Mattagami River hydroelectric generating stations being in service since the end of 2014, and the conversion to biomass of the Atikokan and Thunder Bay generating stations.

Additional items which affected net income prior to 2015 are described in OPG's 2014 annual MD&A.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A and unaudited interim consolidated financial statements. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A, unaudited interim consolidated financial statements and the notes thereto may 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, cash flows from operating activities or other measures 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 attributable to the Shareholder for the period divided by average equity attributable to the Shareholder excluding accumulated other comprehensive income for the same period. ROE is measured over a 12-month period.

(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 related to regulatory assets and liabilities, and interest on pension and OPEB projected benefit obligations less expected return on pension plan assets for the period.

FFO Interest Coverage is measured over a period of 12 months and is calculated as follows:

(millions of dollars – except where noted)	**For the twelve months ended September 30 2015**	**December 31 2014**
FFO before interest		
Cash flow provided by operating activities	**1,794**	1,433
Add: Interest paid	**269**	273
Less: Interest capitalized to fixed and intangible assets	**(102)**	(135)
Add: Decrease to non-cash working capital balances	**(109)**	(212)
FFO before interest	**1,852**	1,359
Adjusted interest expense		
Net interest expense	**178**	80
Add: Interest income	**9**	10
Add: Interest capitalized to fixed and intangible assets	**102**	135
Add: Interest related to regulatory assets and liabilities	**4**	75
Add: Interest on pension and OPEB projected benefit obligation less expected return on pension plan assets	**83**	179
Adjusted Interest Expense	**376**	479
FFO Interest Coverage *(times)*	**4.9**	2.8

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

Additional information about OPG, including its annual MD&A, and audited annual consolidated financial statements as at and for the year ended December 31, 2014 and notes thereto can be found on SEDAR at www.sedar.com.

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www.sedar.com

ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

SEPTEMBER 30, 2015

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)	Three Months Ended September 30 2015	Three Months Ended September 30 2014	Nine Months Ended September 30 2015	Nine Months Ended September 30 2014
Revenue *(Note 12)*	**1,426**	1,160	**4,164**	3,645
Fuel expense *(Note 12)*	**175**	161	**512**	464
Gross margin *(Note 12)*	**1,251**	999	**3,652**	3,181
Expenses *(Note 12)*				
Operations, maintenance and administration	**680**	595	**1,995**	1,931
Depreciation and amortization	**350**	184	**746**	546
Accretion on fixed asset removal and nuclear waste management liabilities	**224**	195	**672**	586
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(163)**	(161)	**(535)**	(538)
Property taxes	**9**	12	**34**	22
Income from investments subject to significant influence	**(8)**	(9)	**(30)**	(32)
Restructuring	**-**	3	**1**	15
	1,092	819	**2,883**	2,530
Income before other loss, interest, income taxes and extraordinary item	**159**	180	**769**	651
Other loss	**2**	-	**2**	2
Income before interest, income taxes and extraordinary item	**157**	180	**767**	649
Net interest expense *(Note 5)*	**42**	15	**136**	38
Income before income taxes and extraordinary item	**115**	165	**631**	611
Income tax expense	**30**	46	**114**	133
Income before extraordinary item	**85**	119	**517**	478
Extraordinary item [1]	**-**	243	**-**	243
Net income	**85**	362	**517**	721
Net income attributable to the Shareholder	**80**	361	**503**	718
Net income attributable to non-controlling interest	**5**	1	**14**	3
Basic and diluted net income per common share before extraordinary item *(dollars)*	**0.31**	0.46	**1.96**	1.87
Extraordinary item per common share *(dollars)*	**-**	0.95	**-**	0.95
Basic and diluted net income per common share *(dollars)*	**0.31**	1.41	**1.96**	2.80
Common shares outstanding *(millions)*	**256.3**	256.3	**256.3**	256.3

[1] Wholly attributable to the Shareholder

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

(millions of dollars)	Three Months Ended September 30 2015	2014	Nine Months Ended September 30 2015	2014
Net income	**85**	362	**517**	721
Other comprehensive income, net of income taxes *(Note 7)*				
Net loss on derivatives designated as cash flow hedges [1]	**(7)**	-	**(6)**	(3)
Reclassification to income of losses from cash flow hedges [2]	**4**	5	**11**	10
Reclassification to income of amounts related to pension and other post-employment benefits [3]	**6**	5	**15**	24
Recognition of pension and other post-employment benefits regulatory asset related to facilities prescribed for rate regulation as of July 1, 2014 [4]	**-**	184	**-**	184
Other comprehensive income for the period	**3**	194	**20**	215
Comprehensive income	**88**	556	**537**	936
Comprehensive income attributable to the Shareholder	**83**	555	**523**	933
Comprehensive income attributable to non-controlling interest	**5**	1	**14**	3

1 Net of income tax recovery of $2 million and income tax expense of $1 million for the three months ended September 30, 2015 and 2014, respectively. Net of income tax recovery of $2 million and $1 million for the nine months ended September 30, 2015 and 2014, respectively.

2 Net of income tax expense of $1 million and nil for the three months ended September 30, 2015 and 2014, respectively. Net of income tax expense of $2 million and $1 million for the nine months ended September 30, 2015 and 2014, respectively.

3 Net of income tax expense of $1 million and $2 million for the three months ended September 30, 2015 and 2014, respectively. Net of income tax expense of $4 million and $8 million for the nine months ended September 30, 2015 and 2014, respectively.

4 Net of income tax expense of nil for the three and nine months ended September 30, 2015. Net of income tax expense of $61 million for the three and nine months ended September 30, 2014.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	**2015**	**2014**
Operating activities		
Net income	**517**	721
Adjust for non-cash items:		
Depreciation and amortization	**746**	546
Accretion on fixed asset removal and nuclear waste management liabilities	**672**	586
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(535)**	(538)
Pension and other post-employment benefit costs *(Note 8)*	**363**	342
Deferred income taxes and other accrued charges	**31**	(186)
Mark-to-market on derivative instruments	**56**	(95)
Provision for used nuclear fuel and low and intermediate level waste	**88**	85
Regulatory assets and liabilities	**(76)**	(47)
Provision for materials and supplies	**21**	16
Provision for restructuring	**(2)**	10
Other	**(8)**	(12)
	1,873	1,428
Contributions to nuclear fixed asset removal and nuclear waste management funds	**(107)**	(104)
Expenditures on fixed asset removal and nuclear waste management	**(157)**	(147)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**62**	55
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(360)**	(352)
Expenditures on restructuring	**(11)**	(23)
Distribution received from investments subject to significant influence	**40**	52
Net changes to other long-term assets and liabilities	**1**	(31)
Net changes in non-cash working capital balances *(Note 13)*	**13**	116
Cash flow provided by operating activities	**1,354**	994
Investing activities		
Investment in property, plant and equipment and intangible assets	**(982)**	(1,082)
Cash flow used in investing activities	**(982)**	(1,082)
Financing activities		
Issuance of long-term debt	**-**	200
Repayment of long-term debt	**(502)**	(2)
Distribution paid to non-controlling interest	**(12)**	(3)
Issuance of short-term notes	**1,600**	1,517
Repayment of short-term notes	**(1,500)**	(1,549)
Cash flow (used in) provided by financing activities	**(414)**	163
Net (decrease) increase in cash and cash equivalents	**(42)**	75
Cash and cash equivalents, beginning of period	**610**	562
Cash and cash equivalents, end of period	**568**	637

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2015**	**December 31 2014**
Assets		
Current assets		
Cash and cash equivalents	**568**	610
Receivables from related parties	**479**	482
Other accounts receivable and prepaid expenses	**165**	136
Nuclear fixed asset removal and nuclear waste management funds	**13**	25
Fuel inventory	**325**	334
Materials and supplies	**100**	94
Regulatory assets *(Note 3)*	**671**	167
Deferred income taxes	**-**	8
	2,321	1,856
Property, plant and equipment	**26,792**	25,859
Less: accumulated depreciation	**8,721**	8,266
	18,071	17,593
Intangible assets	**460**	432
Less: accumulated amortization	**372**	356
	88	76
Other assets		
Nuclear fixed asset removal and nuclear waste management funds	**14,944**	14,354
Long-term materials and supplies	**328**	338
Regulatory assets *(Note 3)*	**6,347**	7,024
Investments subject to significant influence *(Note 14)*	**337**	348
Other long-term assets	**64**	64
	22,020	22,128
	42,500	41,653

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2015**	**December 31 2014**
Liabilities		
Current liabilities		
Accounts payable and accrued charges	**1,094**	1,151
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(Note 4)*	**3**	503
Short-term debt *(Note 5)*	**100**	-
Regulatory liabilities *(Note 3)*	**28**	5
Deferred income taxes	**105**	-
Income taxes payable	**110**	24
	1,452	1,695
Long-term debt *(Note 4)*	**5,225**	5,227
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 6)*	**17,640**	17,028
Pension liabilities	**3,470**	3,570
Other post-retirement benefit liabilities	**3,128**	3,050
Long-term accounts payable and accrued charges	**571**	529
Deferred revenue	**238**	212
Deferred income taxes	**742**	836
Regulatory liabilities *(Note 3)*	**42**	39
	25,831	25,264
Equity		
Common shares [1]	**5,126**	5,126
Retained earnings	**5,199**	4,696
Accumulated other comprehensive loss *(Note 7)*	**(476)**	(496)
Equity attributable to the Shareholder	**9,849**	9,326
Equity attributable to non-controlling interest	**143**	141
Total equity	**9,992**	9,467
	42,500	41,653

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at September 30, 2015 and December 31, 2014.

Commitments and Contingencies *(Notes 4, 10 and 11)*

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	**2015**	**2014**
Common shares	**5,126**	5,126
Retained earnings		
Balance at beginning of period	**4,696**	3,892
Net income attributable to the Shareholder	**503**	718
Balance at end of period	**5,199**	4,610
Accumulated other comprehensive loss, net of income taxes *(Note 7)*		
Balance at beginning of period	**(496)**	(684)
Other comprehensive income	**20**	215
Balance at end of period	**(476)**	(469)
Equity attributable to the Shareholder	**9,849**	9,267
Equity attributable to non-controlling interest		
Balance at beginning of period	**141**	-
Capital contribution from non-controlling interest	**-**	53
Distribution to non-controlling interests	**(12)**	(3)
Net income attributable to non-controlling interest	**14**	3
Balance at end of period	**143**	53
Total equity	**9,992**	9,320

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the three and nine months ended September 30, 2015 and 2014

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and nine month periods ended September 30, 2015 and 2014 include the accounts of Ontario Power Generation Inc. (OPG or Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (Province). Interests owned by other parties are reflected as non-controlling interest. These interim 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 interim financial statements. These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2014. All dollar amounts are presented in Canadian dollars.

Certain of the 2014 comparative amounts have been reclassified from financial statements previously presented to conform to the 2015 interim consolidated financial statement presentation.

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 interim 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 on historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefits (OPEB) liabilities, asset retirement obligations, income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments, depreciation and amortization, and inventories. Actual results may differ significantly from these estimates.

Seasonal Operations

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. Regulated prices for most of OPG's hydroelectric facilities and all of the nuclear facilities that OPG operates, and energy supply agreements for OPG's unregulated facilities reduce the impact of seasonal price fluctuations on the results of operations.

2. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

Recent Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers* (ASU 2014-09), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of ASU 2014-09 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. In July 2015, the FASB approved the deferral of the effective date of the new revenue standard by one year for public entities reporting under US GAAP from 2017 to 2018. As such, the standard is expected to be applicable to OPG for its 2018 fiscal year, including interim periods. OPG is currently assessing the impact of this new standard on its consolidated financial statements.

3. REGULATORY ASSETS AND LIABILITIES

In December 2014, OPG filed an application with the OEB to recover approximately $1.8 billion in December 31, 2014 balances in most of its authorized regulatory variance and deferral accounts. A partial settlement agreement between OPG and intervenors providing for the recovery of approximately $1.5 billion of the total amount sought by OPG was approved by the OEB in June 2015 (the Partial Settlement Agreement). On September 10, 2015, the OEB issued its decision approving for recovery, without adjustments, the remaining balances totalling $263 million requested in OPG's application, which were not covered by the Partial Settlement Agreement.

These approvals include recovery of $714 million in the Pension and OPEB Cost Variance Account recorded during 2013 and 2014 over six years starting on July 1, 2015 and $225 million recorded in this variance account prior to 2013 that will continue to be recovered until December 31, 2024 as previously authorized by the OEB. The remaining approved balances of $809 million include the $154 million portion of the Bruce Lease Net Revenues Variance Account related to the impact of the derivative liability embedded in the Bruce Power lease agreement (Bruce Lease), which will continue to be recovered on the basis of OPG's expected payments to Bruce Power L.P. and associated income tax impacts, and other account balances, the majority of which were approved for recovery over a period of 18 months from July 1, 2015 to December 31, 2016. The OEB's October 2015 order also approved the continuation of previously authorized variance and deferral accounts.

On October 8, 2015, the OEB issued an order implementing its June 2015 and September 2015 decisions on OPG's application. The order authorized OPG to recover $933 million over the period from October 1, 2015 to December 31, 2016 through the following new rate riders for generation from its nuclear and regulated hydroelectric facilities during this period:

($/Megawatt hour)	**Nuclear**	**Hydroelectric** [1]
2015/2016 rate riders	10.84	3.19
2015/2016 interim period rate riders [2]	2.17	0.64
Rate riders for the period October 1, 2015 to December 31, 2016	13.01	3.83

[1] The rate riders apply to production from both the existing regulated hydroelectric stations and the 48 regulated hydroelectric stations prescribed for rate regulation beginning in 2014.

[2] The interim period rate riders were authorized by the OEB to allow for the recovery of the new riders effective July 1, 2015, resulting in a corresponding revenue accrual for the period from July 1, 2015 to September 30, 2015 during the third quarter of 2015. The income impact of the revenue accrual was largely offset by a corresponding increase in amortization expense related to regulatory assets and liabilities for deferral and variance accounts.

The new rate riders are in addition to those authorized by the OEB in its December 2014 order for production from OPG's nuclear and existing regulated hydroelectric generating stations during the period from January 1, 2015 to December 31, 2015.

Any shortfall or over-recovery of the approved balances due to differences between actual and forecast production are recorded in the authorized Nuclear Deferral and Variance Over/Under Recovery Variance Account and Hydroelectric Deferral and Variance Over/Under Recovery Variance Account to be collected from, or refunded to, ratepayers in the future.

During the third quarter of 2015, OPG recorded amortization of the regulatory assets and liabilities for the deferral and variance accounts over the recovery periods authorized by the OEB's December 2014 and October 2015 orders.

The regulatory assets and liabilities recorded as at September 30, 2015 and December 31, 2014 are as follows:

(millions of dollars)	**September 30 2015**	**December 31 2014**
Regulatory assets		
Variance and deferral accounts as authorized by the OEB		
Pension and OPEB Cost Variance Account *(Note 8)*	**902**	939
Bruce Lease Net Revenues Variance Account	**329**	315
Nuclear Liability Deferral Account	**238**	286
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 8)*	**240**	36
Capacity Refurbishment Variance Account	**87**	190
Hydroelectric Surplus Baseload Generation Variance Account	**94**	67
Other variance and deferral accounts	**101**	134
	1,991	1,967
Pension and OPEB Regulatory Asset *(Note 8)*	**4,138**	4,363
Deferred Income Taxes	**889**	861
Total regulatory assets	**7,018**	7,191
Less: current portion	**671**	167
Non-current regulatory assets	**6,347**	7,024
Regulatory liabilities		
Variance and deferral accounts as authorized by the OEB		
Other variance and deferral accounts	**70**	44
Total regulatory liabilities	**70**	44
Less: current portion	**28**	5
Non-current regulatory liabilities	**42**	39

As at September 30, 2015 and December 31, 2014, regulatory assets for other variance and deferral accounts included the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Development Variance Account, the Pension & OPEB Cash Payment Variance Account, and other variance accounts authorized by the OEB. As at September 30, 2015 and December 31, 2014, regulatory liabilities for other variance and deferral accounts included the Ancillary Services Net Revenue Variance Account, the Hydroelectric Water Conditions Variance Account, the Income and Other Taxes Variance Account and other variance accounts authorized by the OEB.

4. LONG-TERM DEBT

Long-term debt consists of the following:

(millions of dollars)	September 30 2015	December 31 2014
Notes payable to the Ontario Electricity Financial Corporation	**3,465**	3,965
UMH Energy Partnership debt	**188**	190
Lower Mattagami Energy Limited Partnership debt	**1,575**	1,575
	5,228	5,730
Less: due within one year	**3**	503
Long-term debt	**5,225**	5,227

In October 2015, PSS Generating Station LP, a subsidiary of OPG, issued long-term debt totalling $245 million maturing in October 2067 to support the construction of the Peter Sutherland Sr. GS. The effective interest rate for the debt was 4.9 percent and the coupon interest rate was 4.8 percent. The debt is secured by the assets of the project.

5. 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 the second quarter of 2015, OPG renewed and extended both tranches to May 2020. As at September 30, 2015, there were no outstanding borrowings under the bank credit facility.

Lower Mattagami Energy Limited Partnership maintains a $500 million bank credit facility to support the funding requirements of the Lower Mattagami River project, including the commercial paper program. The facility originally consisted of two $300 million multi-year term tranches. The first tranche was to mature in August 2019 while the second tranche was to mature in August 2015. In the third quarter of 2015, OPG extended the maturity of the first tranche to August 2020 and extended the maturity of the second tranche, which was reduced to $200 million, to August 2016. As at September 30, 2015, there was $100 million of commercial paper outstanding under this facility (December 31, 2014 − nil).

The following table summarizes net interest expense:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	2015	2014	2015	2014
Interest on long-term debt	**71**	75	**213**	219
Interest on short-term debt	**-**	2	**2**	3
Interest income	**(2)**	(3)	**(7)**	(8)
Interest capitalized to property, plant and equipment and intangible assets	**(26)**	(35)	**(73)**	(106)
Interest related to regulatory assets and liabilities [1]	**(1)**	(24)	**1**	(70)
Net interest expense	**42**	15	**136**	38

[1] Includes interest to recognize the cost of financing related to regulatory assets and liabilities, as authorized by the OEB, and interest deferred in the regulatory assets for the Capacity Refurbishment Variance Account and the Bruce Lease Net Revenues Variance Account.

6. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at September 30, 2015 and December 31, 2014 consist of the following:

(millions of dollars)	**September 30 2015**	**December 31 2014**
Liability for nuclear used fuel management	**10,858**	10,459
Liability for nuclear decommissioning and low and intermediate level waste management	**6,406**	6,204
Liability for non-nuclear fixed asset removal	**376**	365
Fixed asset removal and nuclear waste management liabilities	**17,640**	17,028

7. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

	Nine Months Ended September 30, 2015		
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Total [1]**
AOCL, beginning of period	**(117)**	**(379)**	**(496)**
Net loss on cash flow hedges	**(6)**	**-**	**(6)**
Amounts reclassified from AOCL	**11**	**15**	**26**
Other comprehensive income for the period	**5**	**15**	**20**
AOCL, end of period	**(112)**	**(364)**	**(476)**

[1] All amounts are net of income taxes.

	Nine Months Ended September 30, 2014		
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges [1]**	**Pension and OPEB [1]**	**Total [1]**
AOCL, beginning of period	(129)	(555)	(684)
Net loss on cash flow hedges	(3)	-	(3)
Amounts reclassified from AOCL	10	24	34
Recognition of pension and OPEB regulatory assets related to facilities prescribed for rate regulation as of July 1, 2014	-	184	184
Other comprehensive income for the period	7	208	215
AOCL, end of period	(122)	(347)	(469)

[1] All amounts are net of income taxes.

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine month periods ended September 30, 2015 and 2014 are as follows:

(millions of dollars)	**Amount Reclassified from AOCL** **Three Months Ended**	**Nine Months Ended**	**Statement of Income Line Item**
	September 30, 2015		
Amortization of losses from cash flow hedges			
Losses	**4**	**11**	Net interest expense
Amortization of amounts related to pension and OPEB			
Net actuarial loss	**6**	**15**	See (1) below
Total reclassifications for the period	**10**	**26**	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

(millions of dollars)	**Amount Reclassified from AOCL** **Three Months Ended**	**Nine Months Ended**	**Statement of Income Line Item**
	September 30, 2014		
Amortization of losses from cash flow hedges			
Losses	5	10	Net interest expense
Amortization of amounts related to pension and OPEB			
Net actuarial loss	5	24	See (1) below
Total reclassifications for the period	10	34	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

8. PENSION AND OPEB

OPG's total post-employment benefit costs for the three months ended September 30, 2015 and 2014 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		OPEB	
(millions of dollars)	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Components of Cost Recognized						
Current service costs	**80**	59	**1**	2	**18**	16
Interest on projected benefit obligation	**157**	165	**4**	4	**31**	34
Expected return on plan assets, net of expenses	**(179)**	(157)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**73**	65	**1**	1	**8**	2
Cost recognized [2]	**131**	132	**6**	7	**57**	52

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the three months ended September 30, 2015 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $75 million (three months ended September 30, 2014 – $61 million).

[2] These pension and OPEB costs for the three months ended September 30, 2015 exclude the reduction of costs resulting from the recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account, Pension & OPEB Cash Versus Accrual Differential Deferral Account and Pension & OPEB Cash Payment Variance Account of nil, $71 million and $2 million, respectively (three months ended September 30, 2014 – $77 million, nil and nil, respectively).

OPG's total post-employment benefit costs for the nine months ended September 30, 2015 and 2014 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		OPEB	
(millions of dollars)	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Components of Cost Recognized						
Current service costs	**240**	178	**5**	6	**54**	48
Interest on projected benefit obligation	**472**	494	**10**	11	**95**	101
Expected return on plan assets, net of expenses	**(538)**	(471)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**219**	195	**4**	3	**21**	5
Cost recognized [2]	**393**	396	**19**	20	**170**	154

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the nine months ended September 30, 2015 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $225 million (nine months ended September 30, 2014 – $171 million).

[2] These pension and OPEB costs for the nine months ended September 30, 2015 exclude the reduction of costs resulting from the recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account, Pension & OPEB Cash Versus Accrual Differential Deferral Account and Pension & OPEB Cash Payment Variance Account of nil, $204 million and $15 million, respectively (nine months ended September 30, 2014 – $228 million, nil and nil, respectively).

An actuarial valuation of the OPG registered pension plan was completed as of January 1, 2014 and was filed with the Financial Services Commission of Ontario in June 2014.

9. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to 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 refinance existing debt and/or undertake new financing. 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.

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 primarily attributable to United States (US) dollar denominated transactions such as the purchase of fuels. 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 Independent Electricity System Operator (IESO) administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the 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 and the requirement for market participants to provide collateral. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at September 30, 2015 was less than $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 September 30, 2015				
Derivative embedded in the Bruce Lease	**n/a**	**5 years**	**(356)**	Long-term accounts payable and accrued charges
Other derivative instruments	**various**	**various**	**11**	Various
Total derivatives			**(345)**	

(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Balance Sheet Line Item**
As at December 31, 2014				
Derivative embedded in the Bruce Lease	n/a	5 years	(302)	Long-term accounts payable and accrued charges
Other derivative instruments	various	various	11	Various
Total derivatives			(291)	

Existing net losses of $21 million deferred in AOCL as at September 30, 2015 are expected to be reclassified to net income within the next 12 months.

10. FAIR VALUE MEASUREMENTS

The fair value of financial instruments traded in active markets is based on quoted market prices at the interim consolidated balance sheets 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 that do not have quoted market prices directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimate 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 dates of the interim consolidated balance sheets. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. 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 measure an instrument at fair value 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 were 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.

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 September 30, 2015 and December 31, 2014.

	Fair Value		Carrying Value [1]		
(millions of dollars)	**2015**	**2014**	**2015**	**2014**	**Balance Sheet Line Item**
Nuclear Funds (includes current portion) [2]	**14,957**	14,379	**14,957**	14,379	Nuclear fixed asset removal and nuclear waste management funds
Payable related to cash flow hedges	**(58)**	(63)	**(58)**	(63)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	**(356)**	(302)	**(356)**	(302)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(5,720)**	(6,326)	**(5,228)**	(5,730)	Long-term debt
Other financial instruments	**19**	19	**19**	19	Various

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other accounts receivable, accounts payable and accrued charges, and short-term debt approximate their fair value due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Funds are comprised of the Decommissioning Segregated Fund (Decommissioning Fund) and the Used Fuel Segregated Fund (Used Fuel Fund). The fund values are net of amounts due to the Province of $1,117 million (December 31, 2014 − $1,100 million) for the Decommissioning Fund and $1,450 million (December 31, 2014 − $1,429 million) for the Used Fuel Fund.

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 as at September 30, 2015 and December 31, 2014:

	September 30, 2015			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	**3,108**	**2,811**	**550**	**6,469**
Used Fuel Fund	**645**	**7,739**	**104**	**8,488**
Other financial instruments	**4**	**4**	**19**	**27**
Total	**3,757**	**10,554**	**673**	**14,984**
Liabilities				
Derivative embedded in the Bruce Lease	**-**	**-**	**(356)**	**(356)**
Other financial instruments	**(5)**	**(3)**	**-**	**(8)**
Total	**(5)**	**(3)**	**(356)**	**(364)**
Net assets	**3,752**	**10,551**	**317**	**14,620**

	December 31, 2014			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	3,069	2,787	390	6,246
Used Fuel Fund	617	7,444	72	8,133
Other financial instruments	4	5	16	25
Total	3,690	10,236	478	14,404
Liabilities				
Derivative embedded in the Bruce Lease	-	-	(302)	(302)
Other financial instruments	(3)	(3)	-	(6)
Total	(3)	(3)	(302)	(308)
Net assets	3,687	10,233	176	14,096

During the nine months ended September 30, 2015, there were no transfers between Level 1, Level 2 and Level 3.

The following tables present the changes in OPG's assets and liabilities measured at fair value based on Level 3:

	For the three months ended September 30, 2015			
(millions of dollars)	Decom-missioning Fund	Used Fuel Fund	Derivative Embedded in the Bruce Lease [1]	Other Financial Instruments
Opening balance, July 1, 2015	478	92	(348)	19
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds [1]	28	5	-	-
Unrealized losses included in revenue	-	-	(8)	-
Realized losses included in revenue	(2)	-	-	(4)
Purchases	40	8	-	4
Sales	(7)	(2)	-	-
Settlements	13	1	-	-
Closing balance, September 30, 2015	550	104	(356)	19

[1] Excludes the impact of regulatory assets and liabilities.

	For the nine months ended September 30, 2015			
(millions of dollars)	Decom-missioning Fund	Used Fuel Fund	Derivative Embedded in the Bruce Lease [1]	Other Financial Instruments
Opening balance, January 1, 2015	390	72	(302)	16
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds [1]	50	9	-	-
Unrealized losses included in revenue	-	-	(54)	(2)
Realized losses included in revenue	(1)	-	-	(12)
Purchases	117	23	-	16
Sales	(10)	(3)	-	-
Settlements	4	3	-	-
Closing balance, September 30, 2015	550	104	(356)	18

[1] Excludes the impact of regulatory assets and liabilities.

Derivative Embedded in the Bruce Lease

Due to a significant 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 September 30, 2015:

(millions of dollars except where noted)	Fair Value	Valuation Technique	Unobservable Input	Range
Derivative embedded in the Bruce Lease	(356)	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, of certain units of the Bruce generating stations. 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 generating stations to the Bruce Power L.P. is included in the determination of regulated prices and is subject to the Bruce Lease Net Revenues Variance Account. As such, the income statement impact of changes in the fair value of the derivative liability is offset by the income statement impact of the Bruce Lease Net Revenues Variance Account.

Nuclear Funds

Nuclear Funds investments classified as Level 3 consist of infrastructure, real estate and agriculture and timberland 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 September 30, 2015:

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Infrastructure	817	463	n/a	n/a
Real Estate	577	232	n/a	n/a
Agriculture and Timberland	21	171	n/a	n/a
Pooled Funds				
Short-term Investments	9	n/a	Daily	1 - 5 Days
Fixed Income	601	n/a	Daily	1 - 5 Days
Equity	663	n/a	Daily	1 - 5 Days
Total	2,688	866		

The fair value of the above investments is classified as either Level 2 or Level 3.

<u>Infrastructure</u>

This class includes investments in funds whose investment objective is to generate a combination of long-term capital appreciation and current income, generally through investments such as 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 in the respective infrastructure funds are not redeemable. 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 2025.

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 are not redeemable. However, the Nuclear Funds may transfer any of their 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.

Agriculture and Timberland

This class includes a diversified portfolio of global farmland and timberland investments. The investment objective is to provide a differentiated return source, income yield and inflation protection.

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 investments are not redeemable. However, the Nuclear Funds may transfer any of their interests to another party, as stipulated in the shareholders' agreement, with prior written consent of the other shareholders.

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 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 values of the investments in this class have 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.

11. COMMITMENTS AND CONTINGENCIES

Litigation

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 against OPG and Bruce Power L.P. by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the 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). Both the action and the Arbitration relate to corrosion of a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power L.P.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power L.P. did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with “Good Utility Practices”. OPG has initiated the inspection of various documents referenced in the amended Statement of Claim prior to preparing its Statement of Defence.

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. 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.

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 September 30, 2015, the total amount of guarantees OPG provided to these entities was $81 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 2029. As at September 30, 2015, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and 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 September 30, 2015 are follows:

(millions of dollars)	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**	**Total**
Contractual obligations:							
Fuel supply agreements	46	177	169	153	71	131	747
Contributions under the Ontario Nuclear Funds Agreement (ONFA) [1]	36	150	163	193	288	2,418	3,248
Pension contributions to the OPG registered pension plan [2]	90	370	-	-	-	-	460
Long-term debt repayment	1	273	1,103	398	368	3,085	5,228
Interest on long-term debt	53	249	230	174	155	1,986	2,847
Unconditional purchase obligations	24	8	-	-	-	-	32
Operating lease obligations	4	15	15	13	12	60	119
Commitments related to Darlington Refurbishment [3]	249	-	-	-	-	-	249
Operating licence	11	23	22	22	1	-	79
Accounts payable	274	-	-	-	-	-	274
Other	120	25	15	4	1	72	237
	908	1,290	1,717	957	896	7,752	13,520
Significant commercial commitments:							
Lower Mattagami	21	12	-	-	-	-	33
Peter Sutherland Sr. GS	25	125	38	-	-	-	188
Total	954	1,427	1,755	957	896	7,752	13,741

[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 valuation of the OPG registered pension plan as at January 1, 2014. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2017. OPG’s 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 2017 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG’s additional voluntary contribution, if any, is revisited from time to time.

[3] Represents estimated currently committed costs to close the project, including demobilization of project staff and cancellation of existing contracts and material orders.

Peter Sutherland Sr. GS

In March 2015, OPG's Board of Directors approved the project to construct Peter Sutherland Sr. GS, a new 28 MW station on the New Post Creek near its outlet to the Abitibi River, with a planned in-service date in the first half of 2018 and an approved budget of $300 million. The station will be constructed through PSS Generating Station LP, a partnership between OPG and Coral Rapids L.P., a wholly owned subsidiary of the Taykwa Tagamou Nation. Under the partnership agreement, Coral Rapids L.P. may acquire up to a 33 percent interest in the partnership. During the second quarter of 2015, a hydroelectric ESA for the station was executed by the IESO and the partnership. The hydroelectric ESA formalizes the long-term financial agreement with the IESO for the development of the station and the supply of electricity and related products from the station to the Ontario market.

Power Workers' Union Collective Agreement

The Power Workers' Union (PWU) represents approximately 5,500 OPG regular employees or approximately 60 percent of OPG's regular workforce. The previous collective agreement between OPG and the PWU expired on March 31, 2015. During the second quarter of 2015, the parties agreed to renew the collective agreement for a three-year term, expiring on March 31, 2018.

The agreement includes increases to employee pension plan contributions in each year of the agreement. The agreement will also provide existing employees with lump sum payments for each of the first two years of the contract and eligibility to annually receive shares in Hydro One Inc. for up to 15 years, as long as these employees continue to make contributions to the OPG pension plan. The contract term was conditional on the initial public offering of Hydro One Inc. shares, which occurred in November 2015.

Information Technology Services Contract

OPG conducted a competitive bid process for outsourced information technology services over the 2014 and 2015 period, issuing a Request For Proposal to a number of qualified suppliers. In October 2015, following the competitive bid process, a five-year agreement was awarded effective February 2016. The estimated value of the new contract is approximately $300 million over the five-year period.

12. BUSINESS SEGMENTS

Segment Income (Loss) for the Three Months Ended September 30, 2015 *(millions of dollars)*	**Nuclear Generation**	**Regulated Nuclear Waste Manage-ment**	**Hydro-electric**	**Unregulated Contracted Generation Portfolio**	**Services, Trading, and Other Non-Generation**	**Elimination**	**Total**
Revenue	**880**	**30**	**393**	**147**	**5**	**(29)**	**1,426**
Fuel expense	**77**	**-**	**88**	**11**	**(1)**	**-**	**175**
Gross margin	**803**	**30**	**305**	**136**	**6**	**(29)**	**1,251**
Operations, maintenance and administration	**536**	**33**	**82**	**46**	**12**	**(29)**	**680**
Depreciation and amortization	**245**	**-**	**81**	**17**	**7**	**-**	**350**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**219**	**-**	**2**	**3**	**-**	**224**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(163)**	**-**	**-**	**-**	**-**	**(163)**
Property taxes	**7**	**-**	**1**	**1**	**-**	**-**	**9**
Income from investments subject to significant influence	**-**	**-**	**-**	**(8)**	**-**	**-**	**(8)**
Other loss	**-**	**-**	**2**	**-**	**-**	**-**	**2**
Income (loss) before interest, income taxes and extraordinary item	**15**	**(59)**	**139**	**78**	**(16)**	**-**	**157**

Segment Income (Loss) for the Three Months Ended September 30, 2014 *(millions of dollars)*	Nuclear Generation	Regulated Nuclear Waste Manage-ment	Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	787	31	275	67	30	(30)	1,160
Fuel expense	65	-	91	5	-	-	161
Gross margin	722	31	184	62	30	(30)	999
Operations, maintenance and administration	444	32	80	43	26	(30)	595
Depreciation and amortization	128	-	40	11	5	-	184
Accretion on fixed asset removal and nuclear waste management liabilities	-	192	-	1	2	-	195
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(161)	-	-	-	-	(161)
Property taxes	7	-	1	1	3	-	12
Income from investments subject to significant influence	-	-	-	(9)	-	-	(9)
Restructuring	-	-	-	1	2	-	3
Income (loss) before interest, income taxes and extraordinary item	143	(32)	63	14	(8)	-	180

Segment Income (Loss) for the Nine Months Ended September 30, 2015 *(millions of dollars)*	**Nuclear Generation**	**Regulated Nuclear Waste Manage-ment**	**Hydro-electric**	**Unregulated Contracted Generation Portfolio**	**Unregulated Services, Trading, and Other Non-Generation**	**Elimination**	**Total**
Revenue	**2,503**	**91**	**1,196**	**414**	**48**	**(88)**	**4,164**
Fuel expense	**234**	**-**	**248**	**29**	**1**	**-**	**512**
Gross margin	**2,269**	**91**	**948**	**385**	**47**	**(88)**	**3,652**
Operations, maintenance and administration	**1,577**	**97**	**236**	**133**	**40**	**(88)**	**1,995**
Depreciation and amortization	**472**	**-**	**201**	**52**	**21**	**-**	**746**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**660**	**-**	**6**	**6**	**-**	**672**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(535)**	**-**	**-**	**-**	**-**	**(535)**
Property taxes	**20**	**-**	**1**	**5**	**8**	**-**	**34**
Income from investments subject to significant influence	**-**	**-**	**-**	**(30)**	**-**	**-**	**(30)**
Restructuring	**-**	**-**	**-**	**-**	**1**	**-**	**1**
Other loss	**-**	**-**	**2**	**-**	**-**	**-**	**2**
Income (loss) before interest, income taxes and extraordinary item	**200**	**(131)**	**508**	**219**	**(29)**	**-**	**767**

Segment Income (Loss) for the Nine Months Ended September 30, 2014 *(millions of dollars)*	Regulated Nuclear Generation	Regulated Nuclear Waste Manage-ment	Regulated Hydro-electric	Unregulated Contracted Generation Portfolio	Unregulated Services, Trading, and Other Non-Generation	Elimination	Total
Revenue	2,178	89	1,087	224	153	(86)	3,645
Fuel expense	181	-	249	32	2	-	464
Gross margin	1,997	89	838	192	151	(86)	3,181
Operations, maintenance and administration	1,457	94	241	129	96	(86)	1,931
Depreciation and amortization	387	-	122	22	15	-	546
Accretion on fixed asset removal and nuclear waste management liabilities	-	575	-	5	6	-	586
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(538)	-	-	-	-	(538)
Property taxes	21	-	1	(2)	2	-	22
Income from investments subject to significant influence	-	-	-	(32)	-	-	(32)
Restructuring	-	-	-	8	7	-	15
Other loss	-	-	2	-	-	-	2
Income (loss) before interest, income taxes and extraordinary item	132	(42)	472	62	25	-	649

13. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	Nine Months Ended September 30 2015	2014
Receivables from related parties	**3**	57
Other accounts receivable and prepaid expenses	**(32)**	(12)
Fuel inventory	**9**	37
Income taxes payable/recoverable	**86**	60
Materials and supplies	**(6)**	(4)
Accounts payable and accrued charges	**(47)**	(22)
	13	116

14. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of Portlands Energy Centre and Brighton Beach, which are accounted for using the equity method. Details of the balances are as follows:

(millions of dollars)	**September 30 2015**	**December 31 2014**
Portlands Energy Centre		
Current assets	**16**	15
Long-term assets	**274**	287
Current liabilities	**(6)**	(5)
Long-term liabilities	**(5)**	(4)
Brighton Beach		
Current assets	**8**	6
Long-term assets	**179**	186
Current liabilities	**(15)**	(13)
Long-term debt	**(108)**	(118)
Other long-term liabilities	**(6)**	(6)
Investments subject to significant influence	**337**	348