ONTARIO POWER GENERATION

News
from Ontario Power Generation

700 University Avenue Toronto, ON M5G 1X6

Tel: 416-592-4008 or 1-800-592-4008 Fax: 416-592-2178
www.opg.com

Nov. 9, 2017

OPG REPORTS 2017 THIRD QUARTER FINANCIAL RESULTS

Darlington Refurbishment Project Remains on Time and on Budget at One-Year Mark

Toronto: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $131 million for the third quarter of 2017, compared to $194 million for the same period in 2016.

"The Company's focus continues to be on ensuring the success of the Darlington Refurbishment Project. After the one-year mark of work on Darlington's Unit 2, Canada's largest clean energy project remains on time and on budget," said Jeff Lyash, OPG President and CEO. "This is a ten-year project that will extend the life of the Darlington nuclear plant by 30 years, boosting Ontario's GDP by $90 billion and creating more than 14,000 jobs."

The 2017 Long-Term Energy Plan issued by Ontario's Ministry of Energy in October 2017 recognizes the refurbishment of Ontario's nuclear generating fleet as the most cost-effective option for producing emission-free baseload generation to meet Ontario's future needs and reaffirms the Province's commitment to the refurbishment of the four units at the Darlington Nuclear Generating Station (GS). OPG's Enterprise Total Generating Cost, which measures the overall productivity of the Company's nuclear, hydroelectric and thermal generating assets, was 4.8 cents per kilowatt hour for the first nine months of 2017.

Lyash continued, "I am also pleased with the strong performance of our Pickering Nuclear plant, which has so far generated 2.1 terawatt hours of electricity more than last year. We are applying for a licence to extend the operation of the station until 2024. This will ensure a reliable, clean source of low cost power during the Darlington Refurbishment Project and avoid 17 million tonnes of carbon emissions. The 2017 Long-Term Energy Plan confirms the value to customers of continuing Pickering operations to 2024."

"The successful performance of our assets is built around a strong safety culture. This quarter, the Canadian Nuclear Safety Commission has once again given our Pickering and Darlington stations the highest possible safety ratings," Lyash went on to say. "Darlington has now achieved this rating for eight consecutive years and Pickering has achieved the highest possible safety rating for the second year in a row."

“Additionally, OPG successfully completed its first public debt issuance in October, raising $500 million for our general corporate needs and to fund OPG's investment in Ontario’s Fair Hydro Plan,” added Lyash. “This will provide OPG with financial flexibility and further our ability to invest in projects to the benefit of customers and stakeholders.”

The earnings for the third quarter of 2017 were impacted by the expected year-over-year decline in generation revenue, reflecting lower nuclear electricity generation due to the refurbishment outage for Unit 2 at the Darlington GS without the resetting of base regulated prices, largely offset by higher generation from the strong performance of the Pickering GS. The lower earnings were mitigated by lower operations, maintenance and administration (OM&A) expenses across all business segments.

OPG provides electricity at a price that is 40 per cent less than other generators and is the only electricity generator in Ontario that has its prices set through a public hearing process by the Ontario Energy Board (OEB). Earlier in 2017, OPG completed the public hearing process for its current application with the OEB that will set prices for the Company’s nuclear and most of its hydroelectric generation for the next five years, with a proposed effective date of January 1, 2017. The OEB is expected to make a decision on the rate application prior to the end of the year. In the meantime, OPG is operating under base regulated prices that were set in 2014 and do not reflect this year’s reduced nuclear electricity generation, which is primarily due to the Darlington Refurbishment. As in the earlier quarters of this year, the continuation of these prices has negatively affected revenue and net income in the third quarter of 2017. The outcome of the current rate application and the effective date of the new regulated prices are expected to affect OPG’s revenue and net income for the fourth quarter of 2017.

Net income attributable to the Shareholder was $498 million for the nine months ended September 30, 2017, compared to $449 million for the same period in 2016. The gain of $283 million on the sale of OPG’s head office building and parking facility recorded in the second quarter of 2017 offset the year-to-date reduction in generation revenue and was the main driver of the increase in net income for the nine months ended September 30, 2017, compared to the same period in 2016.

Lower earnings on the nuclear fixed asset removal and nuclear waste management segregated funds of $52 million during the third quarter of 2017 and $41 million during the nine months ended September 30, 2017, compared to the corresponding periods in 2016, also contributed to the year-over-year change in net income.

Generation and Operating Performance

Electricity generated during the three months ended September 30, 2017 was 19.4 terawatt hours (TWh), compared to 19.5 TWh for the same quarter in 2016. Total electricity generated during the nine months ended September 30, 2017 decreased to 56.0 TWh from 59.9 TWh for the same period in 2016. The decrease in electricity generation reflected the expected lower generation from the Darlington GS and lower generation from the contracted plants. For the third quarter of 2017, the decrease was largely offset by higher generation from the Pickering GS, primarily due to fewer outage days, and higher generation from the regulated hydroelectric stations.

Regulated – Nuclear Generation Segment

Lower nuclear generation of 0.4 TWh and 4.0 TWh during the three and nine month periods ended September 30, 2017, respectively, was primarily due to the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment that began in October 2016 and is expected to continue until early 2020. Offsetting the reduction in generation from the Darlington GS was an increase in generation of 0.9 TWh and 2.1 TWh from the strong performance of the Pickering GS during the three and nine month periods ended September 30, 2017, respectively.

For the three months ended September 30, 2017, the unit capability factor for the operating units at the Darlington GS was 96.2 per cent, compared to 89.6 per cent for the same quarter in 2016. The increase was primarily due to a lower number of planned outage days during the third quarter of 2017. For the nine months ended September 30, 2017, the unit capability factor for the operating units at the Darlington GS was 82.1 per cent, compared to 87.6 per cent for the same period in 2016. The decrease was primarily a result of a higher number of planned outage days at the station in the first half of 2017, largely driven by constraints related to the transition of the station toward refurbishment.

At the Pickering GS, the unit capability factor increased to 88.7 per cent and 83.8 per cent for the three and nine month periods ended September 30, 2017, respectively, compared to 77.3 and 73.8 per cent for the same periods in 2016, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station in 2017.

Regulated – Hydroelectric Segment

Higher generation from the regulated hydroelectric stations of 0.4 TWh and 0.7 TWh during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows, primarily on the eastern Ontario river systems.

The availability of 87.6 per cent at these stations in the third quarter of 2017 was higher than 84.1 per cent for the same quarter in 2016, primarily due to a higher number of planned outage days in 2016 as a result of refurbishing the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. For the nine months ended September 30, 2017, the availability of the stations marginally decreased to 89.0 per cent, from 89.8 per cent for the same period in 2016. The marginal decrease in the availability was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

Lower generation from the Contracted Generation Portfolio of 0.1 TWh and 0.6 TWh during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was mainly due to lower generation from the segment's hydroelectric plants.

The availability of these hydroelectric stations for the three months ended September 30, 2017 was 66.1 per cent, compared to 68.2 per cent for the same quarter in 2016. The stations' availability for the nine months ended September 30, 2017 was 76.9 per cent, compared to 79.6 per cent for the same period in 2016. The decrease in the availability was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

Total Generating Cost

The Enterprise Total Generating Cost per megawatt hour (MWh) for the three months ended September 30, 2017 was $46.65, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory variance and deferral accounts and higher hydroelectric electricity generation adjusted for surplus baseload generation, partially offset by the expected reduction in nuclear electricity generation due to the Unit 2 refurbishment outage at the Darlington GS. The Enterprise Total Generating Cost per MWh for the nine months ended September 30, 2017 was $47.77, compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, which was largely offset by lower OM&A expenses before the impact of regulatory variance and deferral accounts and higher hydroelectric electricity generation adjusted for surplus baseload generation.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusted for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise Total Generating Cost would have been approximately $4 per MWh lower for the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Generation Development

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during the third quarter of 2017 were as follows:

Darlington Refurbishment

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. In October 2016, OPG commenced the refurbishment of the first unit, Unit 2. The de-fuelling and islanding of the reactor was completed in the first half of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components began in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies is in progress and expected to continue through the first quarter of 2018.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. The Re-tube Waste Processing Building is expected to be completed in November 2017. The completion of the Heavy Water Storage and Drum Handling Facility, which has been delayed due to challenges with construction, will resume following the substantial completion of the Re-tube Waste Processing Building. The Heavy Water Storage and Drum Handling Facility is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. OPG is in the process of finalizing the increased cost estimate for the Heavy Water Storage and Drum Handling Facility. The change in the cost estimate for the facility will not impact the overall Darlington Refurbishment project budget of $12.8 billion, as it will be accommodated within that budget. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities for Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit.

Total life-to-date capital expenditures on the project were approximately $4.1 billion as at September 30, 2017.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended September 30 2017	Three Months Ended September 30 2016	Nine Months Ended September 30 2017	Nine Months Ended September 30 2016
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on Nuclear Segregated Funds - (a reduction to expenses)	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Other net expenses (gains)	**11**	13	**(350)**	12
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Income (loss) before interest and income taxes				
Electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
Total income before interest and income taxes	**180**	248	**699**	662
Cash flow				
Cash flow provided by operating activities	**485**	530	**698**	1,211
Electricity generation (TWh)				
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [2]	**0.8**	0.9	**1.9**	2.5
Total electricity generation	**19.4**	19.5	**56.0**	59.9
Nuclear unit capability factor (per cent) [3]				
Darlington Nuclear GS	**96.2**	89.6	**82.1**	87.6
Pickering Nuclear GS	**88.7**	77.3	**83.8**	73.8
Availability (per cent)				
Regulated – Hydroelectric	**87.6**	84.1	**89.0**	89.8
Contracted Generation Portfolio – hydroelectric stations	**66.1**	68.2	**76.9**	79.6
Equivalent forced outage rate				
Contracted Generation Portfolio – thermal stations	**2.6**	2.1	**6.0**	1.3
Enterprise Total Generating Cost per MWh ($/MWh) [4]	**46.65**	50.72	**47.77**	46.74
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended September 30, 2017 and December 31, 2016 (%) [4]			**4.4**	4.2
Funds from Operations (FFO) Adjusted Interest Coverage for the twelve months ended September 30, 2017 and December 31, 2016 (times) [4]			**4.2**	5.1

[1] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

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

[3] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[4] Enterprise Total Generating Cost per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the three and nine months ended September 30, 2017, in the sections *Highlights – FFO Adjusted Interest Coverage*, *Highlights – Return on Common Equity Excluding Accumulated Other Comprehensive Income*, and *Highlights – Enterprise Total Generating Cost per MWh*, as well as *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s unaudited interim consolidated financial statements and Management's Discussion and Analysis as at and for the three and nine month periods ended September 30, 2017 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

For further information, please contact: Investor Relations 416-592-6700
webmaster@opg.com

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

\- 30 -

ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2017 THIRD QUARTER REPORT

TABLE OF CONTENTS

ONTARIO POWER GENERATION

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 months ended September 30, 2017. 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, 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, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

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 section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

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 in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* 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 generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan) and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. 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 (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. 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 generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (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.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

(MW)	As at September 30 2017	December 31 2016
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,426**	6,421
Contracted Generation Portfolio [2]	**4,056**	4,028
Total	**16,210**	16,177

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

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

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

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, 2017, compared to the same periods in 2016, are discussed below.

(millions of dollars – except where noted) (unaudited)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2017	**2016**	**2017**	**2016**
Revenue	**1,217**	1,400	**3,539**	4,265
Fuel expense	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Property taxes	**8**	12	**30**	35
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains)	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest [1]	**9**	4	**17**	12
Electricity production (TWh) [2]	**19.4**	19.5	**56.0**	59.9
Cash flow provided by operating activities	**485**	530	**698**	1,211

[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, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[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 $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings of $54 million from the Regulated – Nuclear Waste Management segment, primarily due to a decrease in earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds).
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

Significant factor that increased income before interest and income taxes:

- Lower operations, maintenance and administration (OM&A) expenses of $31 million across all business segments.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest income.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of income tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

Significant factor that increased income before interest and income taxes:

- The gain on the sale of OPG's head office premises and associated parking facility recorded in the Services, Trading, and Other Non-Generation segment in the second quarter of 2017. The sale of these non-core real estate assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on the sale was $283 million, which is net of tax effects of $95 million.

Significant factors that reduced income before interest and income taxes:

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from the Pickering GS.
- Lower earnings of $53 million from the Regulated – Nuclear Waste Management segment, primarily due to a decrease in earnings on the Nuclear Segregated Funds.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.
- Lower rental revenue of $16 million from the Services, Trading, and Other Non-Generation segment, primarily as a result of the sale of the head office premises.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**20**	47	**(267)**	17
Regulated – Hydroelectric	**122**	117	**474**	500
Contracted Generation Portfolio	**75**	74	**229**	219
Total electricity generation business segments	**217**	238	**436**	736
Regulated – Nuclear Waste Management	**(36)**	18	**(123)**	(70)
Services, Trading, and Other Non-Generation	**(1)**	(8)	**386**	(4)
	180	248	**699**	662

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

(TWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Regulated – Nuclear Generation	**11.3**	11.7	**30.6**	34.6
Regulated – Hydroelectric	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio [1]	**0.8**	0.9	**1.9**	2.5
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Total electricity generation by all other generators in Ontario [2]	**16.6**	19.5	**51.7**	53.8

[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 electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. This was mainly due to lower electricity generation of 0.4 TWh and 4.0 TWh from the Regulated – Nuclear Generation segment for the three and nine month periods ended September 30, 2017, respectively. As expected, this was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, as well as higher electricity generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of forgone electricity generation as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric stations, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Baseload generation supply surplus in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the corresponding periods in 2016. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province under the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The decrease in cash flow for the nine months ended September 30, 2017 also was partially offset by lower pension plan contributions in 2017 reflecting an updated actuarial valuation of the OPG registered pension plan filed with the Financial Services Commission of Ontario, as well as the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on the sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB.

Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income, as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows, partly offset by the expected reduction in nuclear electricity generation due to the Unit 2 refurbishment outage at the Darlington GS.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh of $58.75 for the three months ended September 30, 2017 was comparable to $58.55 for the same quarter in 2016, as the higher electricity generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was largely offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows net of higher fuel expense, lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

Ontario's 2017 Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long-Term Energy Plan (2017 LTEP) that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous Long-Term Energy Plan issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 Long-Term Energy Plan. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business growth opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Ontario's Fair Hydro Plan

The *Ontario Fair Hydro Plan Act, 2017* (the Act) received Royal Assent on June 1, 2017 and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiative are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The aim of the Plan is to reduce electricity bills for residential, farm, small businesses and other eligible consumers by refinancing a portion of the Global Adjustment costs over a longer time period. The legislation appointed OPG as the Financial Services Manager of the Fair Hydro Plan and provides for a financing entity to be established by OPG. The regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

OPG's Board of Directors, which had established a Special Committee to provide oversight on behalf of the Board of Directors, has conditionally approved OPG's involvement with the Fair Hydro Plan on commercial terms. OPG is in the process of establishing the Fair Hydro Trust (the Trust) as the financing entity contemplated by the Act. The majority unitholder and beneficiary of the Trust will be a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations. Through this ownership and OPG's control over the key activities of the Trust, the Company expects to consolidate the financial results of the Trust in accordance with US GAAP, commencing in the fourth quarter of 2017.

In order for the Trust to finance the deferred portion of the Global Adjustment costs, it will incur senior debt from capital markets and subordinated debt from OPG, which it will use to periodically purchase an investment interest in the deferred Global Adjustment costs from the IESO. The Trust's investment will attract a financing amount and other related fees, which will be payable by the eligible consumers in the future.

Through an equity injection in OPG, the Province is expected to provide 44 percent of the total funding requirement related to the Trust's investment interest in the deferred Global Adjustment costs. OPG will invest the proceeds from the equity injection into subordinated debt issued to the Trust. A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province is in progress. OPG's Board of Directors' approval and a Shareholder Resolution are expected later in the year to authorize the amendment.

OPG expects to provide five percent of the total funding requirement related to the Trust's investment interest in the deferred Global Adjustment costs, through its subordinated debt investment in the Trust. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund its portion of the subordinated debt investment. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

The first set of transactions of the Trust is expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also finalizing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end-of-life assumptions for the Pickering GS are currently set at the end of 2020. These assumptions are expected to be reassessed in line with OPG's plans to extend the station's operation to 2024 when the work on the fuel channel analysis, other technical feasibility assessments and safety case consistent with submissions for the CNSC's approval, discussed below, provides the necessary technical confidence to support a change in the accounting end-of-life date. The technical work undertaken to date has yielded positive results, which will go toward supporting a change in the accounting end-of-life assumptions. OPG's current application with the OEB for new base regulated prices, presently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.

- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling, de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG is undertaking a Periodic Safety Review (PSR), which will confirm that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR) and the Integrated Implementation Plan (IIP). SFRs and GAR have been submitted to the CNSC, with the IIP on track for CNSC submission in November 2017.

- Work continues on the overhaul and upgrade of Unit 2 of the DeCew Falls hydroelectric GS, with completion of the power assembly, refurbishment of the turbine and final delivery of the major components, and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.

- During the third quarter, as part of a continued focus on operating performance and efficiency improvement, OPG opened an amalgamated control room located at the Saunders hydroelectric GS that will control all operational activities at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for the removal of the powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

Project *(millions of dollars)*	**Capital expenditures** **Year-to-date**	 **Life-to-date**	**Approved budget**	**Expected in-service date**	**Current status**
Darlington Refurbishment	924	4,109	12,800 [1]	First unit - 2020 Last unit - 2026	The setup of specialized tooling and equipment needed for the removal of Unit 2 reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the removal of fuel channel assemblies is in progress. Construction activities on the Heavy Water Storage and Drum Handling Facility will recommence following the substantial completion of the Re-tube Waste Processing Building in November 2017. Planning and procurement activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and on budget.
Peter Sutherland Sr. Hydroelectric GS	38	274	300	2017	The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress.
Ranney Falls Hydroelectric GS	17	20	77	2019	Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway. The project is tracking on schedule and on budget.
Nanticoke Solar Facility	1	2	107	2019	Project definition work is continuing, with construction planned to commence in the first quarter of 2018.
Deep Geologic Repository (DGR) for low and intermediate level radioactive waste (L&ILW)	7 [2]	202 [2]			On August 21, 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is assessing the new request.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS, including the costs of the pre-requisite projects in support of the execution phase of the refurbishment.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies is in progress and expected to continue through the first quarter of 2018. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved IIP for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. The Re-tube Waste Processing Building is expected to be completed in November 2017. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF will recommence following the substantial completion of the Re-tube Waste Processing Building. This sequencing ensures that the necessary resources are available for both projects and, through resource levelling, supports improved execution and cost efficiency of these projects.

The HWSF is expected to be completed by early 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. OPG is in the process of finalizing the increased cost estimate for the HWSF. The change in the cost estimate for the HWSF will not impact the overall Darlington Refurbishment budget of $12.8 billion, as it will be accommodated within that budget. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

OPG's current application with the OEB for new regulated prices seeks an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned placement in service of the $4.8 billion in capital expenditures upon return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the forecast Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*. OPG's application proposes that the recovery of the HWSF's costs through regulated prices be subject to a separate prudence review by the OEB, to be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work has been substantially completed and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act*. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is assessing the request. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year over year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

In addition to an increase in the nuclear rate base to reflect the planned placement in service of capital expenditures for the Darlington Refurbishment project, the application seeks an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices, effective in 2017. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The public hearing process for the application was completed in the second quarter of 2017. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. Following the decision, the OEB is expected to issue an order establishing and implementing the new regulated prices, including rate riders, based on the findings in the decision.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG continues to engage with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesasne (Akwesasne). As a result, the Akwesasne plan to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG is also developing recruitment plans targeting Indigenous peoples and, in October 2017, participated in several Indigenous-specific career fairs.

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, presently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period. The continuation of existing regulated prices during 2017 prior to the issuance of the OEB's decision has reduced income, particularly from the Regulated – Nuclear Generation segment, and lowered ROE Excluding AOCI.

In its application, OPG has requested January 1, 2017 as the effective date of the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. The issuance of the decision in the fourth quarter of 2017 would result in OPG's revenue for that quarter reflecting the impact of the new regulated prices, including the impact of any retrospective change in the regulated prices for the period between their effective date and their implementation date. As such, the OEB's decision on the effective date, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results for the fourth quarter of 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, the year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and work on the Ranney Falls GS expansion, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and the funded status of the two segregated funds, discussed below.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA Reference Plan. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

The Fair Hydro Plan is not expected to have a material impact on the Company's net income for the year ended December 31, 2017.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**739**	885	**2,000**	2,631
Fuel expense	**81**	79	**217**	239
Gross margin	**658**	806	**1,783**	2,392
Operations, maintenance and administration	**511**	521	**1,693**	1,665
Depreciation and amortization	**116**	230	**333**	691
Property taxes	**7**	6	**20**	19
Income (loss) before other losses, interest, and income taxes	**24**	49	**(263)**	17
Other losses	**4**	2	**4**	-
Income (loss) before interest and income taxes	**20**	47	**(267)**	17

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease for the nine months ended September 30, 2017 was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, mainly due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As the rate rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Unit Capability Factor *(%)* [1]				
Darlington GS	**96.2**	89.6	**82.1**	87.6
Pickering GS	**88.7**	77.3	**83.8**	73.8

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days in 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days in the first half of 2017, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in the Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

Regulated – Nuclear Waste Management Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**33**	36	**90**	102
Operations, maintenance and administration	**35**	38	**96**	108
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**230**	228	**696**	684
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
(Loss) Income before interest and income taxes	**(36)**	18	**(123)**	(70)

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine month periods ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account, reflecting earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (rate of return guarantee) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine month periods ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds recognized in net income during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and the rate of return guarantee. The higher earnings on both funds during the three and nine month periods ended September 30, 2016 reflected market returns and the rate of return guarantee, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded. Market returns and the rate of return guarantee in the third quarter of 2016 were higher than the funding liabilities' growth rate reflected in fund earnings during 2017, resulting in a year-over-year decrease in the amount of earnings recognized in net income. Further details on the accounting for the Nuclear Segregated Funds can be found in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the fourth quarter of 2017, as they are expected to continue to be offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's regulated prices, and thereafter by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*.

Regulated – Hydroelectric Segment

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue [1]	**327**	350	**1,069**	1,148
Fuel expense	**88**	88	**258**	259
Gross margin	**239**	262	**811**	889
Operations, maintenance and administration	**81**	87	**232**	238
Depreciation and amortization	**34**	56	**103**	169
Property tax	**1**	1	**1**	1
Income before other losses (gains), interest and income taxes	**123**	118	**475**	481
Other losses (gains)	**1**	1	**1**	(19)
Income before interest and income taxes	**122**	117	**474**	500

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 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 customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the deferral of outages and repairs and maintenance work during the high water period in 2017.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision reversing a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by lower OM&A expenses in the third quarter of 2017.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized hydroelectric rate rider on December 31, 2016. As the rate rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**87.6**	84.1	**89.0**	89.8

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outage days in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in the Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

Contracted Generation Portfolio Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**141**	149	**431**	431
Fuel expense	**15**	19	**42**	42
Gross margin	**126**	130	**389**	389
Operations, maintenance and administration	**39**	44	**118**	129
Depreciation and amortization	**20**	19	**59**	56
Accretion on fixed asset removal liabilities	**3**	2	**7**	6
Property taxes	**-**	1	**5**	6
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
Income before other loss, interest and income taxes	**75**	75	**229**	220
Other loss	**-**	1	**-**	1
Income before interest and income taxes	**75**	74	**229**	219

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	**2016**	**2017**	**2016**
Hydroelectric Availability *(%)*	**66.1**	68.2	**76.9**	79.6
Thermal EFOR *(%)*	**2.6**	2.1	**6.0**	1.3

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017.

Services, Trading, and Other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Revenue	**9**	15	**36**	52
Fuel expense	**1**	1	**1**	1
Gross margin	**8**	14	**35**	51
Operations, maintenance and administration	**1**	11	**2**	20
Depreciation and amortization	**8**	8	**22**	25
Accretion on fixed asset removal liabilities	**2**	2	**6**	6
Property taxes	**-**	4	**4**	9
(Loss) income before other gains, interest, and income taxes	**(3)**	(11)	**1**	(9)
Other gains	**(2)**	(3)	**(385)**	(5)
(Loss) income before interest and income taxes	**(1)**	(8)	**386**	(4)

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings reflected higher OM&A expenses in the third quarter of 2016 as a result of a write-off of project expenditures and the decision taken in the fourth quarter of 2016 to proceed with the decommissioning of the Lambton GS. Expenditures incurred in connection with the decommissioning activities at the Lambton GS are charged against a previously established decommissioning provision.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 as well as lower OM&A expenses, partially offset by a decrease in rental revenue due to the sale of the head office premises.

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), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on the Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

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

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars) (unaudited)	**2017**	**2016**	**2017**	**2016**
Cash and cash equivalents, beginning of period	**242**	295	**186**	464
Cash flow provided by operating activities	**485**	530	**698**	1,211
Cash flow used in investing activities	**(463)**	(390)	**(720)**	(1,253)
Cash flow provided by (used in) financing activities	**16**	(9)	**116**	4
Net increase (decrease)	**38**	131	**94**	(38)
Cash and cash equivalents, end of period	**280**	426	**280**	426

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the current collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to a Shareholder Declaration and a Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place as early as in the fourth quarter of 2017.

Financing Activities

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 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 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, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 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, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of LME's credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, with an expiry date of December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018. As at September 30, 2017, there were long-term borrowings of $800 million outstanding under this credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes and the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017, with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

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) (unaudited)	**September 30 2017**	**December 31 2016**
Property, plant and equipment - net	**20,801**	19,998
The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**16,534**	15,984
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Short-term debt	**160**	2
The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017.		
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484
The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

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 for OPG include guarantees and long-term 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, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the L&ILW DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON; however, the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

Risks to Maintaining Financial Strength

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 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.

	2017 [1]	**2018**	**2019**
Estimated fuel requirements hedged [2]	73%	73%	69%

1 Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and 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 OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

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

OPG's electricity 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 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 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

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

OPG manages its exposure to 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, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Ontario's Fair Hydro Plan

OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and the associated general regulation came into force in June 2017. As the Financial Services Manager of the Fair Hydro Plan, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The final report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at a prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, which is recognized as a regulatory asset on the Company's consolidated balance sheet. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

	Three Months Ended September 30			
	2017		**2016**	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**2**	**-**	1	-
Services	**-**	**3**	-	3
Dividends	**2**	**-**	2	-
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**(44)**	-	201
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**(39)**	-	295
Gross revenue charges	**-**	**27**	-	28
ONFA guarantee fee	**-**	**2**	-	2
Other	**-**	**2**	-	-
OEFC				
Gross revenue charges	**-**	**62**	-	57
Interest expense on long-term notes	**-**	**40**	-	42
Income taxes, net of investment tax credits	**-**	**23**	-	28
IESO				
Electricity related revenue	**1,126**	**4**	1,293	7
	1,130	**80**	1,296	663

	Nine Months Ended September 30			
	2017		2016	
(millions of dollars) (unaudited)	**Revenue**	**Expense**	**Revenue**	**Expense**
Hydro One				
Electricity sales	**7**	**-**	4	-
Services	**1**	**8**	1	12
Dividends	**6**	**-**	4	-
Province of Ontario				
Decommissioning Fund excess funding [1]	**-**	**164**	-	137
Used Fuel Fund rate of return guarantee and excess funding [1]	**-**	**217**	-	190
Gross revenue charges	**-**	**84**	-	91
ONFA guarantee fee	**-**	**6**	-	6
Other	**-**	**3**	-	-
OEFC				
Gross revenue charges	**-**	**156**	-	147
Interest expense on long-term notes	**-**	**122**	-	127
Income taxes, net of investment tax credits	**-**	**132**	-	112
IESO				
Electricity related revenue	**3,228**	**11**	3,894	22
	3,242	**903**	3,903	844

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

(millions of dollars) (unaudited)	**September 30 2017**	**December 31 2016**
Receivables from related parties		
Hydro One	**1**	1
IESO	**346**	421
OEFC	**3**	1
PEC	**2**	4
Province of Ontario	**5**	2
Available-for-sale securities		
Hydro One shares	**190**	212
Accounts payable and accrued charges		
OEFC	**37**	61
Province of Ontario	**6**	2
IESO	**2**	2
Long-term debt (including current portion)		
Notes payable to OEFC	**3,245**	3,295

OPG may hold interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected in the fourth quarter of 2017.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the 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 2017**	**June 30 2017**	**March 31 2017**	**December 31 2016**
Revenue	**1,217**	1,146	1,176	1,388
Net income (loss)	**140**	307	68	(8)
Less: Net income attributable to non-controlling interest	**9**	4	4	5
Net income (loss) attributable to the Shareholder	**131**	303	64	(13)
Per common share, attributable to the Shareholder *(dollars)*	**$0.51**	$1.18	$0.25	($0.05)

(millions of dollars - except where noted) *(unaudited)*	**September 30 2016**	**June 30 2016**	**March 31 2016**	**December 31 2015**
Revenue	1,400	1,387	1,478	1,312
Net income (loss)	198	135	128	(100)
Less: Net income attribute to the non-controlling interest	4	3	5	1
Net income (loss) attributable to the Shareholder	194	132	123	(101)
Per common share, attributable to the Shareholder *(dollars)*	$0.76	$0.51	$0.48	($0.39)

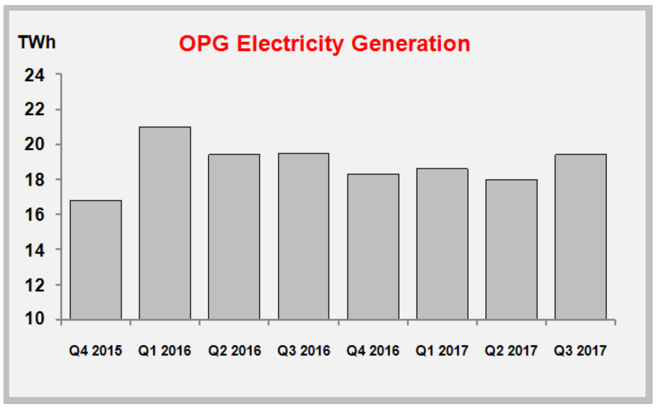
Trends

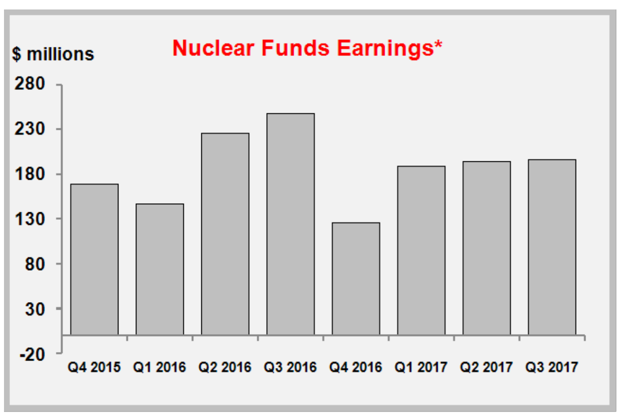
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand and prevalence of SBG 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. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation has been reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is scheduled to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of the earnings on the Nuclear Segregated Funds is mitigated by their funded status.





*net of regulatory variance account

Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under the section, *Quarterly Financial Highlights*.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. 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 would 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 measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

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

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**485**	436
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**11,055**	10,442
ROE Excluding AOCI *(percent)*	**4.4**	4.2

(2) **FFO Adjusted 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 is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

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

	Twelve Months Ended	
(millions of dollars – except where noted) (unaudited)	**September 30 2017**	**December 31 2016**
FFO before interest		
Cash flow provided by operating activities	**1,082**	1,595
Add: Interest paid	**270**	269
Less: Interest capitalized to fixed and intangible assets	**(161)**	(141)
Less: Changes to non-cash working capital balances	**38**	42
FFO before interest	**1,229**	1,765
Adjusted interest expense		
Net interest expense	**84**	120
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**161**	141
Add: Interest related to regulatory assets and liabilities	**43**	30
Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1]	**-**	45
Adjusted interest expense	**296**	343
FFO Adjusted Interest Coverage *(times)*	**4.2**	5.1

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted) (unaudited)	**2017**	**2016**	**2017**	**2016**
Enterprise TGC				
Total OM&A expenses	**635**	666	**2,054**	2,061
Total fuel expense	**185**	187	**518**	541
Total capital expenditures	**476**	444	**1,335**	1,162
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Less: Other generation development project capital and OM&A costs	**(17)**	(42)	**(53)**	(121)
Add (Less): OM&A and fuel expenses deferred in (refundable through) regulatory variance and deferral accounts	**4**	35	**(19)**	76
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(13)**	(17)
Other adjustments	**(3)**	(12)	**(7)**	(15)
	948	991	**2,877**	2,958
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.4**	19.5	**56.0**	59.9
Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities	**0.9**	0.1	**4.2**	3.4
	20.3	19.6	**60.2**	63.3
Enterprise TGC per MWh *($/MWh)* [1]	**46.65**	50.72	**47.77**	46.74

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted) (unaudited)	**2017**	**2016**	**2017**	**2016**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**511**	521	**1,693**	1,665
Regulated – Nuclear Generation fuel expense	**81**	79	**217**	239
Regulated – Nuclear Generation capital expenditures	**409**	339	**1,150**	896
Less: Darlington Refurbishment capital and OM&A costs	**(328)**	(269)	**(943)**	(717)
Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts	**5**	31	**6**	84
Less: Nuclear fuel expense for non OPG-operated stations	**(13)**	(18)	**(42)**	(50)
Less: Regulated - Nuclear Generation OM&A expenses ancillary to electricity generation business	**(1)**	(1)	**(3)**	(4)
Other adjustments	**1**	3	**(1)**	(1)
	665	685	**2,077**	2,112
Nuclear electricity generation (TWh)	**11.3**	11.7	**30.6**	34.6
Nuclear TGC per MWh (*$/MWh*) [1]	**58.75**	58.55	**67.87**	61.07

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted) (unaudited)	**2017**	**2016**	**2017**	**2016**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**81**	87	**232**	238
Regulated – Hydroelectric fuel expense	**88**	88	**258**	259
Contracted Generation Portfolio OM&A expenses	**39**	44	**118**	129
Contracted Generation Portfolio fuel expense	**15**	19	**42**	42
Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures	**56**	92	**141**	231
Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs	**(17)**	(41)	**(52)**	(117)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio	**(39)**	(51)	**(119)**	(126)
(Less) Add: Regulated – Hydroelectric OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts	**(1)**	4	**(25)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**13**	5	**47**	38
Other adjustments	**(1)**	(1)	**-**	(1)
	234	246	**642**	685
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**7.3**	6.9	**23.5**	22.8
Contracted Generation Portfolio electricity generation	**0.8**	0.9	**1.9**	2.5
Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities	**0.8**	0.1	**4.1**	3.4
	8.9	7.9	**29.5**	28.7
Hydroelectric TGC per MWh *($/MWh)* [1]	**26.20**	31.01	**21.74**	23.99

[1] Amounts may not calculate due to rounding.

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

For further information, please contact:	Investor Relations	416-592-6700
		webmaster@opg.com
	Media Relations	416-592-4008
		1-877-592-4008

www.opg.com
www.sedar.com

ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

SEPTEMBER 30, 2017

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)	Three Months Ended September 30 **2017**	**2016**	Nine Months Ended September 30 **2017**	**2016**
Revenue *(Note 12)*	**1,217**	1,400	**3,539**	4,265
Fuel expense *(Note 12)*	**185**	187	**518**	541
Gross margin	**1,032**	1,213	**3,021**	3,724
Expenses *(Note 12)*				
Operations, maintenance and administration	**635**	666	**2,054**	2,061
Depreciation and amortization	**178**	313	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**235**	232	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(196)**	(248)	**(579)**	(620)
Property taxes	**8**	12	**30**	35
Income from investments subject to significant influence	**(11)**	(11)	**(29)**	(28)
	849	964	**2,702**	3,085
Income before other losses (gains), interest and income taxes	**183**	249	**319**	639
Other losses (gains) *(Note 12)*	**3**	1	**(380)**	(23)
Income before interest and income taxes	**180**	248	**699**	662
Net interest expense *(Note 5)*	**21**	28	**56**	92
Income before income taxes	**159**	220	**643**	570
Income tax expense	**19**	22	**128**	109
Net income	**140**	198	**515**	461
Net income attributable to the Shareholder	**131**	194	**498**	449
Net income attributable to non-controlling interest	**9**	4	**17**	12
Basic and diluted net income per common share *(dollars)*	**0.51**	0.76	**1.94**	1.75
Common shares outstanding *(millions)*	**256.3**	256.3	**256.3**	256.3

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

(millions of dollars)	Three Months Ended September 30 2017	2016	Nine Months Ended September 30 2017	2016
Net income	**140**	198	**515**	461
Other comprehensive income, net of income taxes *(Note 7)*				
Reclassification to income of amounts related to pension and other post-employment benefits [1]	**3**	3	**8**	9
Reclassification to income of losses on derivatives designated as cash flow hedges [2]	**4**	4	**13**	14
Unrealized (loss) gain on available-for-sale securities [3]	**(4)**	-	**(6)**	15
Other comprehensive income for the period	**3**	7	**15**	38
Comprehensive income	**143**	205	**530**	499
Comprehensive income attributable to the Shareholder	**134**	201	**513**	487
Comprehensive income attributable to non-controlling interest	**9**	4	**17**	12

[1] Net of income tax expenses of nil and $1 million for the three months ended September 30, 2017 and 2016, respectively. Net of income tax expenses of $2 million and $3 million for the nine months ended September 30, 2017 and 2016, respectively.

[2] Net of income tax expenses of $1 million for the three months ended September 30, 2017 and 2016. Net of income tax expense of $2 million for the nine months ended September 30, 2017 and 2016.

[3] Net of income tax expense of nil for the three months ended September 30, 2017 and 2016. Net of income tax recovery of $1 million and income tax expenses of $5 million for the nine months ended September 30, 2017 and 2016, respectively.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	2017	2016
Operating activities		
Net income	**515**	461
Adjust for non-cash items:		
Depreciation and amortization	**517**	941
Accretion on fixed asset removal and nuclear waste management liabilities	**709**	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(579)**	(620)
Pension and other post-employment benefit costs *(Note 8)*	**339**	351
Deferred income taxes	**50**	(41)
Mark-to-market on derivative instruments	**(4)**	1
Provision for used nuclear fuel and low and intermediate level nuclear waste	**84**	91
Regulatory assets and liabilities	**(97)**	(82)
Provision for materials and supplies	**13**	38
Other gains	**(374)**	(23)
Other	**(35)**	(14)
	1,138	1,799
Contributions to nuclear fixed asset removal and nuclear waste management funds	**-**	(112)
Expenditures on fixed asset removal and nuclear waste management	**(231)**	(189)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**59**	49
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(270)**	(331)
Expenditures on restructuring	**(3)**	(3)
Distributions received from investments subject to significant influence	**37**	40
Net changes to other long-term assets and liabilities	**23**	17
Net changes in non-cash working capital balances *(Note 13)*	**(55)**	(59)
Cash flow provided by operating activities	**698**	1,211
Investing activities		
Proceeds from sale of property, plant and equipment	**484**	-
Purchase of available-for-sale securities	**-**	(213)
Proceeds from deposit note *(Note 4)*	**70**	65
Investment in property, plant and equipment and intangible assets	**(1,274)**	(1,105)
Cash flow used in investing activities	**(720)**	(1,253)
Financing activities		
Issuance of long-term debt *(Note 4)*	**800**	-
Repayment of long-term debt	**(852)**	(2)
Contribution from non-controlling interest	**19**	-
Distribution to non-controlling interest	**(11)**	(11)
Issuance of short-term notes	**1,458**	2,916
Repayment of short-term notes	**(1,298)**	(2,899)
Cash flow provided by financing activities	**116**	4
Net increase (decrease) in cash and cash equivalents	**94**	(38)
Cash and cash equivalents, beginning of period	**186**	464
Cash and cash equivalents, end of period	**280**	426

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2017**	**December 31 2016**
Assets		
Current assets		
Cash and cash equivalents	**280**	186
Available-for-sale securities	**190**	212
Receivables from related parties	**357**	429
Nuclear fixed asset removal and nuclear waste management funds	**19**	24
Fuel inventory	**290**	310
Materials and supplies	**96**	100
Income taxes recoverable	**11**	-
Prepaid expenses	**212**	198
Other current assets	**108**	298
	1,563	1,757
Property, plant and equipment	**30,491**	29,315
Less: accumulated depreciation	**9,690**	9,317
	20,801	19,998
Intangible assets	**546**	503
Less: accumulated amortization	**425**	404
	121	99
Other non-current assets		
Nuclear fixed asset removal and nuclear waste management funds	**16,515**	15,960
Long-term materials and supplies	**364**	345
Regulatory assets *(Note 3)*	**6,002**	5,855
Investments subject to significant influence *(Note 14)*	**313**	321
Other long-term assets	**27**	37
	23,221	22,518
	45,706	44,372

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2017**	**December 31 2016**
Liabilities		
Current liabilities		
Accounts payable and accrued charges	**1,144**	1,164
Deferred revenue	**12**	12
Short-term debt	**160**	2
Long-term debt due within one year *(Note 4)*	**628**	1,103
Income taxes payable	**-**	123
	1,944	2,404
Long-term debt *(Note 4)*	**4,840**	4,417
Other non-current liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 6)*	**20,075**	19,484
Pension liabilities	**2,867**	3,012
Other post-employment benefit liabilities	**2,959**	2,897
Long-term accounts payable and accrued charges	**235**	213
Deferred revenue	**338**	298
Deferred income taxes	**890**	829
Regulatory liabilities *(Note 3)*	**510**	310
	27,874	27,043
Equity		
Common shares [1]	**5,126**	5,126
Retained earnings	**6,034**	5,534
Accumulated other comprehensive loss *(Note 7)*	**(277)**	(295)
Equity attributable to the Shareholder	**10,883**	10,365
Equity attributable to non-controlling interest	**165**	143
Total equity	**11,048**	10,508
	45,706	44,372

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at September 30, 2017 and December 31, 2016.

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)*	**2017**	**2016**
Common shares	**5,126**	5,126
Retained earnings		
Balance at beginning of period	**5,534**	5,098
Net income attributable to the Shareholder	**498**	449
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**2**	-
Balance at end of period	**6,034**	5,547
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of period	**(295)**	(319)
Other comprehensive income	**15**	38
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**3**	-
Balance at end of period	**(277)**	(281)
Equity attributable to the Shareholder	**10,883**	10,392
Equity attributable to non-controlling interest		
Balance at beginning of period	**143**	140
Equity contribution from non-controlling interest *(Note 15)*	**21**	-
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**(5)**	-
Distribution to non-controlling interest	**(11)**	(11)
Income attributable to non-controlling interest	**17**	12
Balance at end of period	**165**	141
Total equity	**11,048**	10,533

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, 2017 and 2016

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and nine months ended September 30, 2017 and 2016 include the accounts of Ontario Power Generation Inc. (OPG or the 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). 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, 2016. All dollar amounts are presented in Canadian dollars.

Certain of the 2016 comparative amounts have been reclassified from financial statements previously presented to conform to the 2017 interim consolidated financial statement presentation.

Use of Management Estimates

The preparation of consolidated 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 for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations and associated asset retirement costs capitalized as part of property, plant and equipment, income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments and investments in segregated funds, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

Change in Accounting Estimate

<u>Pension and Other Post-Employment Benefits</u>

Effective January 1, 2017, OPG changed the method used to estimate the service and interest cost components of pension and OPEB costs. OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $35 million and $105 million for the three and nine months ended September 30, 2017, respectively. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company’s regulated business segments and therefore was offset by the impact of regulatory variance and deferral accounts authorized by the Ontario Energy Board (OEB).

Recent Accounting Pronouncements Not Yet Adopted

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 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. Either a full retrospective application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

As part of the project to implement the new revenue standard, OPG is continuing to assess the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the Independent Electricity System Operator (IESO). In March 2017, the American Institute of Certified Public Accountants (AICPA) issued Revenue Recognition Implementation Issue #13-1, *Scope Clarification Regarding Tariff Sales to Regulated Customers*. The draft implementation guidance was developed by the AICPA Power & Utilities task force. This draft guidance concludes that tariff-based revenue from the provision of regulated utility service to a utility's customers is within the scope of Topic 606. OPG has completed its analysis of the impact of Topic 606 on its accounting for generation revenue from base regulated prices and long-term contractual arrangements with the IESO, and has not identified any material differences in the timing or amount of revenue recognition for these streams. The Company continues to assess the impact of Topic 606 on its other revenue streams.

The Company currently expects to apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of concluding on the method of adoption.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the operations, maintenance and administration expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

3. REGULATORY ASSETS AND LIABILITIES

The regulatory assets and liabilities recorded as at September 30, 2017 and December 31, 2016 are as follows:

(millions of dollars)	**September 30 2017**	**December 31 2016**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension and OPEB Cost Variance Account	**716**	716
Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 8)*	**552**	497
Hydroelectric Surplus Baseload Generation Variance Account	**327**	210
Bruce Lease Net Revenues Variance Account	**131**	95
Other variance and deferral accounts	**137**	107
	1,863	1,625
Pension and OPEB Regulatory Asset *(Note 8)*	**3,260**	3,392
Deferred Income Taxes	**879**	838
Total regulatory assets	**6,002**	5,855
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Hydroelectric Water Conditions Variance Account	**143**	51
Impact Resulting from Changes in Station End-of-Life Dates Deferral Account	**124**	71
Other variance and deferral accounts	**243**	188
Total regulatory liabilities	**510**	310

OPG's May 2016 application with the OEB for new regulated prices included a request for new rate riders to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders in effect during 2016. The application also requested the continuation of all applicable existing variance and deferral accounts. In March 2017, the OEB approved a settlement agreement reached by OPG and intervenors on a limited set of issues in the application (Settlement Agreement). Among the settled issues, the agreement provided for the continuation of all applicable existing variance and deferral accounts and accepted a number of variance and deferral account balances for recovery, as requested in OPG's application. The periods of recovery or repayment for the accepted variance and deferral account balances are excluded from the scope of the Settlement Agreement. The Settlement Agreement did not impact OPG's financial results for the three and nine months ended September 30, 2017. The OEB's decision on OPG's application is pending.

As at September 30, 2017 and December 31, 2016, regulatory assets for other variance and deferral accounts included amounts for the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Liability Deferral Account, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, and the Nuclear Development Variance Account. As at September 30, 2017 and December 31, 2016, regulatory liabilities for other variance and deferral accounts included the amounts for the Pension & OPEB Cash Payment Variance Account, the Capacity Refurbishment Variance Account, the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account, and the Hydroelectric Incentive Mechanism Variance Account.

4. LONG-TERM DEBT

Long-term debt consists of the following:

(millions of dollars)	**September 30 2017**	**December 31 2016**
Notes payable to the Ontario Electricity Financial Corporation	**3,245**	3,295
UMH Energy Partnership	**182**	184
PSS Generating Station Limited Partnership	**245**	245
Lower Mattagami Energy Limited Partnership	**1,795**	1,795
Other	**15**	15
	5,482	5,534
Less: bond issuance fees	**(14)**	(14)
Less: due within one year	**(628)**	(1,103)
Long-term debt	**4,840**	4,417

In the fourth quarter of 2015, PSS Generating Station Limited Partnership (PSS), a subsidiary of OPG, issued long-term debt totalling $245 million in support of the Peter Sutherland Sr. Generating Station (GS) project. The majority of the debt proceeds, totalling $180 million, were invested in a structured deposit note with staggered maturity dates ranging from January 2016 to April 2017. As at September 30, 2017, the deposit note had matured.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the Ontario Electricity Financial Corporation (OEFC), which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended, with the credit facility increased to $2,350 million and the expiry date extended to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totaling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017.

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 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. As at September 30, 2017, there were no amounts outstanding under the bank credit facility. There was $160 million commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, the Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program, and the issuance of the Letters of Credit. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the first tranche of LME's credit facility.

As at September 30, 2017, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $463 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, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the Portlands Energy Centre (PEC), a jointly controlled entity in which OPG holds a 50 percent interest.

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, expiring on November 30, 2018. As at September 30, 2017, there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at September 30, 2017, total Letters of Credit of $14 million had been issued under these facilities.

The following table summarizes the net interest expense:

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**
Interest on long-term debt	**74**	73	**215**	217
Interest on short-term debt	**-**	-	**2**	2
Interest income	**(4)**	(1)	**(6)**	(5)
Interest capitalized to property, plant and equipment and intangible assets	**(39)**	(36)	**(121)**	(101)
Interest related to regulatory assets and liabilities [1]	**(10)**	(8)	**(34)**	(21)
Net interest expense	**21**	28	**56**	92

[1] Includes interest to recognize the cost of financing related to regulatory variance and deferral accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance 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, 2017 and December 31, 2016 consist of the following:

(millions of dollars)	September 30 2017	December 31 2016
Liability for nuclear used fuel management	**11,690**	11,292
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,009**	7,811
Liability for non-nuclear fixed asset removal	**376**	381
Fixed asset removal and nuclear waste management liabilities	**20,075**	19,484

7. ACCUMULATED OTHER COMPREHENSIVE LOSS

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

	Nine Months Ended September 30, 2017			
(millions of dollars)	Unrealized Losses on Cash Flow Hedges [1]	Pension and OPEB [1]	Available-for-sale Securities [1]	Total [1]
AOCL, beginning of period	**(87)**	**(207)**	**(1)**	**(295)**
Unrealized loss on available-for-sale securities	**-**	**-**	**(6)**	**(6)**
Amounts reclassified from AOCL	**13**	**8**	**-**	**21**
Other comprehensive income (loss) for the period	**13**	**8**	**(6)**	**15**
Reclassification of non-controlling interest on change in ownership interest *(Note 15)*	**3**	**-**	**-**	**3**
AOCL, end of period	**(71)**	**(199)**	**(7)**	**(277)**

[1] All amounts are net of income taxes.

	Nine Months Ended September 30, 2016			
(millions of dollars)	Unrealized Losses on Cash Flow Hedges [1]	Pension and OPEB [1]	Available-for-sale Securities [1]	Total [1]
AOCL, beginning of period	(106)	(213)	-	(319)
Unrealized gain on available-for-sale securities	-	-	15	15
Amounts reclassified from AOCL	14	9	-	23
Other comprehensive income for the period	14	9	15	38
AOCL, end of period	(92)	(204)	15	(281)

[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 months ended September 30, 2017 are as follows:

	Amount Reclassified from AOCL		
	Three Months Ended	Nine Months Ended	
(millions of dollars)	September 30, 2017		Statement of Income Line Item
Amortization of losses from cash flow hedges			
Losses	**5**	**15**	Net interest expense
Income tax recovery	**(1)**	**(2)**	Income tax expense
	4	**13**	
Amortization of amounts related to pension and OPEB			
Actuarial losses	**3**	**10**	See (1) below
Income tax recovery	**-**	**(2)**	Income tax expense
	3	**8**	
Total reclassifications for the period	**7**	**21**	

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

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine months ended September 30, 2016 are as follows:

	Amount Reclassified from AOCL		
	Three Months Ended	Nine Months Ended	
(millions of dollars)	September 30, 2016		Statement of Income Line Item
Amortization of losses from cash flow hedges			
Losses	5	16	Net interest expense
Income tax recovery	(1)	(2)	Income tax expense
	4	14	
Amortization of amounts related to pension and OPEB			
Actuarial losses	4	12	See (1) below
Income tax recovery	(1)	(3)	Income tax expense
	3	9	
Total reclassifications for the period	7	23	

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

8. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and OPEB costs for the three months ended September 30, 2017 and 2016 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		OPEB	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Components of Cost Recognized for the period						
Current service costs	**68**	70	**2**	2	**17**	16
Interest on projected benefit obligation	**138**	158	**2**	3	**27**	34
Expected return on plan assets, net of expenses	**(191)**	(185)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**45**	49	**2**	1	**-**	5
Cost recognized [2]	**60**	92	**6**	6	**44**	55

[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, 2017 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $44 million (three months ended September 30, 2016 – $51 million).

[2] These pension and OPEB costs for the three months ended September 30, 2017 exclude the net addition of costs of $3 million from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended September 30, 2016 – net reduction of costs of $35 million).

OPG's pension and OPEB costs for the nine months ended September 30, 2017 and 2016 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		OPEB	
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Components of Cost Recognized for the period						
Current service costs	**205**	208	**5**	5	**51**	50
Interest on projected benefit obligation	**411**	475	**8**	9	**81**	100
Expected return on plan assets, net of expenses	**(574)**	(552)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**137**	145	**5**	3	**-**	15
Cost recognized [2]	**179**	276	**18**	17	**132**	165

[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, 2017 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $132 million (nine months ended September 30, 2016 – $151 million).

[2] These pension and OPEB costs for the nine months ended September 30, 2017 exclude the net addition of costs of $10 million from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (nine months ended September 30, 2016 − net reduction of costs of $107 million).

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018 and $219 million for 2019.

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 the Company's 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 includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/United States (US) foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. 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. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at September 30, 2017 was less than $1 million. OPG's fair value derivatives totalled a net liability of $16 million as at September 30, 2017 (December 31, 2016 – $24 million).

Existing pre-tax net losses of $20 million deferred in AOCL as at September 30, 2017 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 sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments. The fair value hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Certain alternative investments are measured at fair value by their investment managers using net asset value (NAV). Investments measured at NAV as a practical expedient for determining their fair value are excluded from the fair value hierarchy.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The following is a summary of OPG's financial instruments and their fair value as at September 30, 2017 and December 31, 2016:

	Fair Value		**Carrying Value** [1]		
(millions of dollars)	**2017**	**2016**	**2017**	**2016**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**16,534**	15,984	**16,534**	15,984	Nuclear fixed asset removal and nuclear waste management funds
Investment in Hydro One shares	**190**	212	**190**	212	Available-for-sale securities
Payable related to cash flow hedges	**(42)**	(48)	**(42)**	(48)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(5,859)**	(6,033)	**(5,482)**	(5,520)	Long-term debt
Other financial instruments	**(11)**	(18)	**(11)**	(18)	Various

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

2 The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated 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 financial liabilities measured at fair value in accordance with the fair value hierarchy as at September 30, 2017 and December 31, 2016:

	September 30, 2017			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**5,879**	**4,498**	**-**	**10,377**
Investments measured at NAV [1]				**1,231**
				11,608
Due to Province				**(2,155)**
Used Fuel Segregated Fund, net				**9,453**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,363**	**3,343**	**-**	**7,706**
Investments measured at NAV [1]				**1,016**
				8,722
Due to Province				**(1,641)**
Decommissioning Segregated Fund, net				**7,081**
Investment in available-for-sale securities [2]	**190**	**-**	**-**	**190**
Other financial assets	**4**	**3**	**7**	**14**
Liabilities				
Other financial liabilities	**(22)**	**(3)**	**-**	**(25)**

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

(millions of dollars)	December 31, 2016 Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	5,602	4,394	-	9,996
Investments measured at NAV [1]				1,086
				11,082
Due to Province				(1,938)
Used Fuel Segregated Fund, net				9,144
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	4,171	3,243	-	7,414
Investments measured at NAV [1]				903
				8,317
Due to Province				(1,477)
Decommissioning Segregated Fund, net				6,840
Investment in available-for-sale securities	212	-	-	212
Other financial assets	6	2	9	17
Liabilities				
Other financial liabilities	(29)	(6)	-	(35)

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the nine months ended September 30, 2017, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the three months ended September 30, 2017:

(millions of dollars)	Other financial instruments
Opening balance, July 1, 2017	**9**
Realized losses included in revenue	**(4)**
Purchases	**2**
Closing balance, September 30, 2017	**7**

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the nine months ended September 30, 2017:

(millions of dollars)	Other financial instruments
Opening balance, January 1, 2017	**9**
Unrealized losses included in revenue	**(2)**
Realized losses included in revenue	**(7)**
Purchases	**7**
Closing balance, September 30, 2017	**7**

Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references 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. Alternative investments are measured at fair value using NAV as a practical expedient.

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 these 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 Segregated Funds that are reported on the basis of NAV as at September 30, 2017:

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Alternative Investments				
Infrastructure	**1,276**	**835**	**n/a**	**n/a**
Real Estate	**892**	**465**	**n/a**	**n/a**
Agriculture	**78**	**106**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**12**	**n/a**	**Daily**	**1 - 5 Days**
Fixed Income	**643**	**n/a**	**Daily**	**1 - 5 Days**
Equity	**890**	**n/a**	**Daily**	**1 - 5 Days**
Total	**3,791**	**1,406**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

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 NAV of the Nuclear Segregated 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 Segregated Funds may transfer any of their 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 investments in institutional-grade real estate property. 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 NAV of the Nuclear Segregated Funds' ownership interest in these investments. The partnership investments are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreement. 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

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 NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements.

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. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the 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. (Bruce Power) 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 regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

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 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".

In November 2016, British Energy obtained consent to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set out in the timetable.

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of 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, 2017, the total amount of guarantees OPG provided to these entities was $82 million (December 31, 2016 − $83 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, 2017, 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

OPG's contractual obligations and commercial commitments as at September 30, 2017 are as follows:

(millions of dollars)	**2017** [1]	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
Fuel supply agreements	52	169	96	76	62	98	553
Contributions to the OPG registered pension plan [2]	23	215	219	-	-	-	457
Long-term debt repayment	251	398	368	663	413	3,389	5,482
Interest on long-term debt	54	244	225	203	175	3,167	4,068
Commitments related to Darlington Refurbishment [3]	530	-	-	-	-	-	530
Commitments related to Peter Sutherland Sr. GS project	7	1	-	-	-	-	8
Commitments related to Ranney Falls GS project	9	29	5	-	-	-	43
Operating licences	10	40	41	24	28	115	258
Operating lease obligations	8	27	25	25	23	93	201
Unconditional purchase obligations	15	59	58	56	5	-	193
Accounts payable and accrued charges	844	8	-	-	-	16	868
Other	35	43	30	2	1	65	176
Total	1,838	1,233	1,067	1,049	707	6,943	12,837

[1] Represents amounts for the remainder of the year.

[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, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 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 accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

12. BUSINESS SEGMENTS

Segment Income (Loss) for the Three Months Ended September 30, 2017 *(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	**739**	**33**	**327**	**141**	**9**	**(32)**	**1,217**
Fuel expense	**81**	**-**	**88**	**15**	**1**	**-**	**185**
Gross margin	**658**	**33**	**239**	**126**	**8**	**(32)**	**1,032**
Operations, maintenance and administration	**511**	**35**	**81**	**39**	**1**	**(32)**	**635**
Depreciation and amortization	**116**	**-**	**34**	**20**	**8**	**-**	**178**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**230**	**-**	**3**	**2**	**-**	**235**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(196)**	**-**	**-**	**-**	**-**	**(196)**
Property taxes	**7**	**-**	**1**	**-**	**-**	**-**	**8**
Income from investments subject to significant influence	**-**	**-**	**-**	**(11)**	**-**	**-**	**(11)**
Other losses (gains)	**4**	**-**	**1**	**-**	**(2)**	**-**	**3**
Income (Loss) before interest and income taxes	**20**	**(36)**	**122**	**75**	**(1)**	**-**	**180**

Segment Income (Loss) for the Three Months Ended September 30, 2016 *(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	885	36	350	149	15	(35)	1,400
Fuel expense	79	-	88	19	1	-	187
Gross margin	806	36	262	130	14	(35)	1,213
Operations, maintenance and administration	521	38	87	44	11	(35)	666
Depreciation and amortization	230	-	56	19	8	-	313
Accretion on fixed asset removal and nuclear waste management liabilities	-	228	-	2	2	-	232
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(248)	-	-	-	-	(248)
Property taxes	6	-	1	1	4	-	12
Income from investments subject to significant influence	-	-	-	(11)	-	-	(11)
Other losses (gains)	2	-	1	1	(3)	-	1
Income (Loss) before interest and income taxes	47	18	117	74	(8)	-	248

Segment Income (Loss) for the Nine Months Ended September 30, 2017 *(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	**2,000**	**90**	**1,069**	**431**	**36**	**(87)**	**3,539**
Fuel expense	**217**	**-**	**258**	**42**	**1**	**-**	**518**
Gross margin	**1,783**	**90**	**811**	**389**	**35**	**(87)**	**3,021**
Operations, maintenance and administration	**1,693**	**96**	**232**	**118**	**2**	**(87)**	**2,054**
Depreciation and amortization	**333**	**-**	**103**	**59**	**22**	**-**	**517**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**696**	**-**	**7**	**6**	**-**	**709**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(579)**	**-**	**-**	**-**	**-**	**(579)**
Property taxes	**20**	**-**	**1**	**5**	**4**	**-**	**30**
Income from investments subject to significant influence	**-**	**-**	**-**	**(29)**	**-**	**-**	**(29)**
Other losses (gains)	**4**	**-**	**1**	**-**	**(385)**	**-**	**(380)**
(Loss) Income before interest and income taxes	**(267)**	**(123)**	**474**	**229**	**386**	**-**	**699**

Segment Income (Loss) for the Nine Months Ended September 30, 2016 *(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	2,631	102	1,148	431	52	(99)	4,265
Fuel expense	239	-	259	42	1	-	541
Gross margin	2,392	102	889	389	51	(99)	3,724
Operations, maintenance and administration	1,665	108	238	129	20	(99)	2,061
Depreciation and amortization	691	-	169	56	25	-	941
Accretion on fixed asset removal and nuclear waste management liabilities	-	684	-	6	6	-	696
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(620)	-	-	-	-	(620)
Property taxes	19	-	1	6	9	-	35
Income from investments subject to significant influence	-	-	-	(28)	-	-	(28)
Other (gains) losses	-	-	(19)	1	(5)	-	(23)
Income (Loss) before interest and income taxes	17	(70)	500	219	(4)	-	662

Shareholder Declaration and Shareholder Resolution to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution that required the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. In December 2016, a purchase and sale agreement was executed, and the sale was completed in April 2017. A gain on sale of $283 million, which is net of tax effects of $95 million, was recognized in net income upon completion of the transaction for the nine months ended September 30, 2017. The pre-tax gain on sale was recorded as an item of Other gains in the interim consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG is working to finalize the amount of designated proceeds to be transferred into the Province's Consolidated Revenue Fund.

13. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	Nine Months Ended September 30 2017	2016
Receivables from related parties	**72**	107
Prepaid expenses	**(18)**	(52)
Other current assets	**10**	(7)
Fuel inventory	**20**	41
Income taxes (recoverable)/ payable	**(92)**	49
Materials and supplies	**4**	(2)
Accounts payable and accrued charges	**(51)**	(195)
	(55)	(59)

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 the PEC gas-fired combined cycle generating station and the Brighton Beach gas-fired combined cycle generating station (Brighton Beach), which are accounted for using the equity method. Details of the balances as at September 30, 2017 and December 31, 2016 are as follows:

(millions of dollars)	September 30 2017	December 31 2016
PEC		
Current assets	**19**	18
Long-term assets	**244**	256
Current liabilities	**(9)**	(8)
Long-term liabilities	**(5)**	(5)
Brighton Beach		
Current assets	**5**	5
Long-term assets	**162**	168
Current liabilities	**(17)**	(16)
Long-term liabilities	**(8)**	(7)
Long-term debt	**(78)**	(90)
Investments subject to significant influence	**313**	321

15. NON-CONTROLLING INTEREST

PSS Generating Station LP

PSS is a limited partnership between OPG, Coral Rapids Power Corporation (CRP) and PSS Generating Station Inc. (PSS GS Inc.). The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28 MW Peter Sutherland Sr. hydroelectric GS on the New Post Creek. OPG and PSS GS Inc. are general partners and CRP is a limited partner in the partnership. CRP is a wholly owned subsidiary of the Taykwa Tagamou Nation.

The Peter Sutherland Sr. GS was placed in-service in March 2017 and, in April 2017, CRP increased its interest in PSS to 33 percent under the partnership agreement, by making contributions of $21 million, reducing OPG's interest to 67 percent. As a result of the contributions made by OPG and CRP, PSS has met the criteria of having sufficient equity at risk to finance its activities, and ceased being classified as a variable interest entity during the second quarter of 2017. OPG continues to consolidate the results of PSS in its consolidated financial statements. CRP's 33 percent interest in PSS is reported as non-controlling interest. As a result of CRP increasing its interest in the partnership, PSS's AOCL and partner's deficit were proportionately allocated to CRP as a reduction to its non-controlling interest.