ONTARIO POWER GENERATION

News
from Ontario Power Generation

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OPG REPORTS 2019 THIRD QUARTER FINANCIAL RESULTS

Darlington Refurbishment Project Remains on Time and on Budget at Three-Year Mark; Company Continues to Build Business through Investment

Toronto: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $319 million for the third quarter of 2019, compared to $279 million for the same quarter of 2018.

"Our strong financial results for the quarter once again demonstrate the high quality performance across our fleet," said Ken Hartwick, OPG President and CEO. "Within our nuclear fleet, we have seen unprecedented levels of uninterrupted generation, continuing to provide the people of Ontario with clean, reliable energy every day."

The Darlington Refurbishment project reached its third anniversary in October 2019. "As we mark this important milestone on the 10-year Darlington Refurbishment project, we remain focused on delivering Canada's largest clean energy project on time, and on budget," said Hartwick. "The refurbishment of Unit 2 is 90 per cent complete, including the completion of lower feeders and the commencement of reloading fuel into the reactor in preparation for the return to service."

OPG also confirmed that it had completed the previously announced acquisitions of Cube Hydro, a hydropower platform in the United States, and the remaining 50 per cent interest in the combined-cycle natural gas-fired Brighton Beach generating station (GS) in Windsor, Ontario. "The acquisition of Cube Hydro provides additional high quality, clean generation assets to OPG's existing U.S. hydroelectric portfolio," commented Hartwick. "Natural gas is an enabler of renewable energy and the acquisition of the remaining interest in Brighton Beach will ensure that this facility continues to provide additional generation flexibility to Ontario. These acquisitions contribute to our strategic goals of building our business."

The Company's net income for the third quarter of 2019 was favourably impacted by a decrease in overall outage days at the Pickering and Darlington nuclear generating stations, compared to the same quarter in 2018. This resulted in higher electricity generation and higher revenue from the Regulated – Nuclear Generation segment compared to the same quarter in 2018.

OPG continues to provide electricity at a price that is approximately 40 per cent less than the average of other generators in Ontario. OPG is the only electricity generator in Ontario that has its prices set through a public hearing process by the Ontario Energy Board.

Generation and Operating Performance

Electricity generated during the third quarter of 2019 was 19.1 terawatt hours (TWh), compared to 18.3 TWh for the same quarter in 2018. Total electricity generated during the nine month period ended September 30, 2019 increased to 58.4 TWh from 54.3 TWh for the same period in 2018.

Regulated – Nuclear Generation Segment

Higher nuclear electricity generation of 1.0 TWh and 3.1 TWh during the three and nine month periods ended September 30, 2019, respectively, compared to the same periods in 2018, was primarily due to fewer outage days at the Pickering and Darlington generating stations.

For the third quarter of 2019, the unit capability factor for the operating units at the Darlington GS was 91.1 per cent, compared to 91.7 per cent for the same quarter in 2018. For the nine month period ended September 30, 2019, the unit capability factor for the operating units at the Darlington GS was 86.5 per cent, compared to 85.2 per cent for the same period in 2018. The factors were comparable in both the three and nine month periods, in line with the similar number of overall outage days at the station in both periods. For the third quarter of 2019, overall outage days for the units decreased to 28 days from 30 days for the same quarter in 2018. For the nine month period ended September 30, 2019, overall outage days decreased to 114 days from 129 days for the same period in 2018.

At the Pickering GS, the unit capability factor increased to 94.3 per cent and 89.1 per cent for the three and nine month periods ended September 30, 2019, respectively, compared to 87.9 per cent and 77.9 per cent for the same periods in 2018. The increase in both periods was due to fewer overall outage days at the station. For the third quarter of 2019, overall outage days for the six units decreased to 35 days from 98 days for the same quarter in 2018. For the nine month period ended September 30, 2019, overall outage days decreased to 182 days from 393 days for the same period in 2018.

Regulated – Hydroelectric Segment

Electricity generation from the regulated hydroelectric stations decreased by 0.2 TWh and increased by 0.8 TWh during the three and nine month periods ended September 30, 2019, respectively, compared to the same periods in 2018. The decrease in the third quarter of 2019 was primarily due to higher forgone hydroelectric generation as a result of lower demand for electricity in Ontario, partially offset by higher water flows in various regions of the province. The increase in the nine month period ended September 30, 2019 was primarily due to higher water flows across most of the province, particularly in the spring of 2019.

The availability of 82.0 per cent at these stations in the third quarter of 2019 was lower than 82.6 per cent for the same quarter in 2018. For the nine month period ended September 30, 2019, the availability of the stations increased to 87.7 per cent, from 86.1 per cent for the same period in 2018. The decrease in the availability in the third quarter of 2019 was primarily due to higher unplanned outages, mainly at the stations in the Niagara and eastern Ontario regions. The increase in the availability in the nine month period ended September 30, 2019 was primarily due to fewer planned outage days at the eastern Ontario and Niagara regions' stations.

Contracted and Other Generation Segment

Electricity generation from the Contracted and Other Generation segment in the third quarter of 2019 was comparable to the same quarter in 2018. The higher generation from the Contracted and Other Generation segment of 0.2 TWh during the nine month period ended September 30, 2019, compared to the same period in 2018, was primarily due to electricity generation from the Eagle Creek facilities in the United States, partially offset by higher electricity generation forgone as a result of lower demand for generation from contracted facilities in Ontario.

The availability of the Ontario-based hydroelectric stations of the Contracted and Other Generation segment for the third quarter of 2019 was 69.1 per cent, compared to 67.7 per cent for the same quarter in 2018. The stations' availability for the nine month period ended September 30, 2019 was 77.9 per cent, compared to 78.1 per cent for the same period in 2018. The increase in the third quarter was primarily due to fewer planned outage days at the Kipling GS. The availability in the nine month period ended September 30, 2019 was comparable to the same period in 2018.

Total Generating Cost

The Enterprise Total Generating Cost per megawatt hour (MWh) for the third quarter of 2019 was $50.41, compared to $53.64 for the same quarter in 2018. The Enterprise Total Generating Cost per MWh for the nine month period ended September 30, 2019 was $48.89, compared to $53.02 for the same period in 2018. The decrease in Enterprise TGC per MWh was primarily due to higher nuclear electricity generation and lower OM&A expenses before the impact of OEB-authorized regulatory variance and deferral accounts at the nuclear facilities, partially offset by higher sustaining capital expenditures.

Generation Development

OPG undertakes generation development and life extension projects in support of Ontario's electricity planning initiatives and expected to provide incremental value in the future. Significant developments during the third quarter of 2019 included the following:

Darlington Refurbishment

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by at least 30 years.

The Unit 2 refurbishment has substantially completed the third major segment, the installation and reassembly of reactor components, which included the installation of fuel channel assemblies and installation of new feeder tubes. During the third quarter, work progressed on the Lower Feeder installation series and was completed in October 2019. The Lower Body Tubing installation series is expected to commence in the fourth quarter of 2019, and its completion will represent the end of the third major segment of the Unit 2 refurbishment. The fourth major segment, the return to service of the unit, began in November 2019 with the commencement of fuel loading into the reactor.

Unit 2 is expected to return to service in the second quarter of 2020, following the safe completion of commissioning activities. The Darlington Refurbishment project, the execution of which began in 2016, continues to track on schedule overall and to the $12.8 billion budget.

In addition to the execution of refurbishment activities on Unit 2, OPG continues to progress with the planning and prerequisite activities for the refurbishment of Unit 3, incorporating the experience learned to date on Unit 2's execution. After considering the optimization of resources being engaged in returning Unit 2 to service, the Unit 3 refurbishment is now targeted to commence in the second quarter of 2020, reflecting a coordinated effort between the project and operations teams. As of September 30, 2019, $437 million has been invested in planning and prerequisite activities related to the refurbishment of Unit 3.

Total life-to-date expenditures on the project were approximately $6.4 billion as at September 30, 2019.

Ranney Falls Hydroelectric GS

OPG continues construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site. The new unit will replace an existing unit that reached its end of life in 2014. During the quarter, testing and commissioning of the turbine and generator of the new unit continued. The unit is housed in a new powerhouse and the total station capacity will double from 10 MW to 20 MW, generating clean, renewable power. 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. The Ranney Falls GS is included in the Regulated – Hydroelectric segment.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

(millions of dollars – except where noted)	Three Months Ended September 30 2019	Three Months Ended September 30 2018	Nine Months Ended September 30 2019	Nine Months Ended September 30 2018
Revenue	**1,508**	1,373	**4,500**	4,062
Fuel expense	**172**	175	**495**	496
Operations, maintenance and administration	**661**	638	**2,091**	2,103
Depreciation and amortization	**268**	200	**798**	584
Other net expenses (gains) [1]	**17**	27	**50**	(169)
Income before interest and income taxes	**390**	333	**1,066**	1,048
Net interest expense	**5**	19	**35**	56
Income tax expense	**62**	31	**135**	44
Net income	**323**	283	**896**	948
Net income attributable to the Shareholder	**319**	279	**883**	935
Net income attributable to non-controlling interest [2]	**4**	4	**13**	13
Income before interest and income taxes				
Electricity generating business segments	**419**	370	**1,134**	866
Regulated – Nuclear Waste Management	**(26)**	(26)	**(87)**	(91)
Other	**(3)**	(11)	**19**	273
Total income before interest and income taxes	**390**	333	**1,066**	1,048
Cash flow				
Cash flow provided by operating activities	**743**	524	**1,928**	1,163
Electricity generation (TWh)				
Regulated – Nuclear Generation	**11.6**	10.6	**32.7**	29.6
Regulated – Hydroelectric	**6.8**	7.0	**23.1**	22.3
Contracted and Other Generation [3]	**0.7**	0.7	**2.6**	2.4
Total electricity generation	**19.1**	18.3	**58.4**	54.3
Nuclear unit capability factor (per cent) [4]				
Darlington Nuclear GS	**91.1**	91.7	**86.5**	85.2
Pickering Nuclear GS	**94.3**	87.9	**89.1**	77.9
Availability (per cent)				
Regulated – Hydroelectric	**82.0**	82.6	**87.7**	86.1
Contracted and Other Generation – hydroelectric stations [5]	**69.1**	67.7	**77.9**	78.1
Equivalent forced outage rate [6]				
Contracted and Other Generation – thermal stations	**0.5**	6.4	**5.2**	2.8
Enterprise Total Generating Cost (TGC) per MWh ($/MWh) for the three and nine months ended September 30, 2019 and September 30, 2018 ($/MWh) [7]	**50.41**	53.64	**48.89**	53.02
Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended September 30, 2019 and December 31, 2018 (%) [7]			**8.4**	9.5

[1] For the nine month period ended September 30, 2018, includes the pre-tax gain on the sale of the former Lakeview GS site.

[2] 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 Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership, and the 15 per cent and 5 per cent interest of corporations wholly owned by the Six Nations of Grand River Development Corporation and by the Mississaugas of the Credit First Nation, respectively, in Nanticoke Solar LP.

[3] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities. For the three and nine month periods ended September 30, 2019, includes generation from the Eagle Creek facilities, including the proportionate share of electricity generation from co-owned and minority shareholdings.

[4] 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.

[5] Reflects the availability of contracted hydroelectric generating stations in Ontario.

[6] Reflects the reliability of wholly-owned thermal stations. For the three and nine month periods ended September 30, 2018, includes unplanned outage days at the Thunder Bay GS prior to cessation of operations in July 2018. Excludes the Brighton Beach GS, the remaining 50 per cent of which was acquired on August 30, 2019.

[7] Enterprise TGC per MWh and ROE Excluding AOCI 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 month periods ended September 30, 2019, in the sections *Highlights – Return on Equity Excluding Accumulated Other Comprehensive Income*, *Highlights – Enterprise Total Generating Cost per MWh*, and *Supplementary Non-GAAP Financial Measures.*

OPG is the largest electricity generator in the province, providing almost half the power Ontarians rely on every day. It is also one of the most diverse generators in North America with expertise in nuclear, hydro, biomass, solar and gas.

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, 2019 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2019 THIRD QUARTER REPORT

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine month periods ended September 30, 2019. 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, Annual Information Form, and MD&A as at and for the year ended December 31, 2018.

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. Since January 1, 2012, OPG has also received exemptive relief from the Ontario Securities Commission (OSC) that allows OPG to apply US GAAP instead of International Financial Reporting Standards. In April 2018, the OSC approved an exemption which allows the Company to continue to apply US GAAP up to January 1, 2024. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2024. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP* in OPG's 2018 annual MD&A. This MD&A is dated November 12, 2019.

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 (GS) 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, performance of newly acquired businesses, defined benefit pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of electricity industries in Ontario and the United States (US), the continued application and renewal of power purchase agreements for non-regulated facilities, foreign currency exchange rates, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC) and the Federal Energy Regulatory Commission (FERC), health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulated prices, the impact of regulatory decisions by the OEB, forecasts of earnings, cash flows, Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC), operations, maintenance and administration (OM&A) expenditures and project expenditures, retention of critical talent, and supplier and third party performance. 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.

Use of Non-GAAP Financial Measures

The Company uses the following non-GAAP financial performance measures in the MD&A:

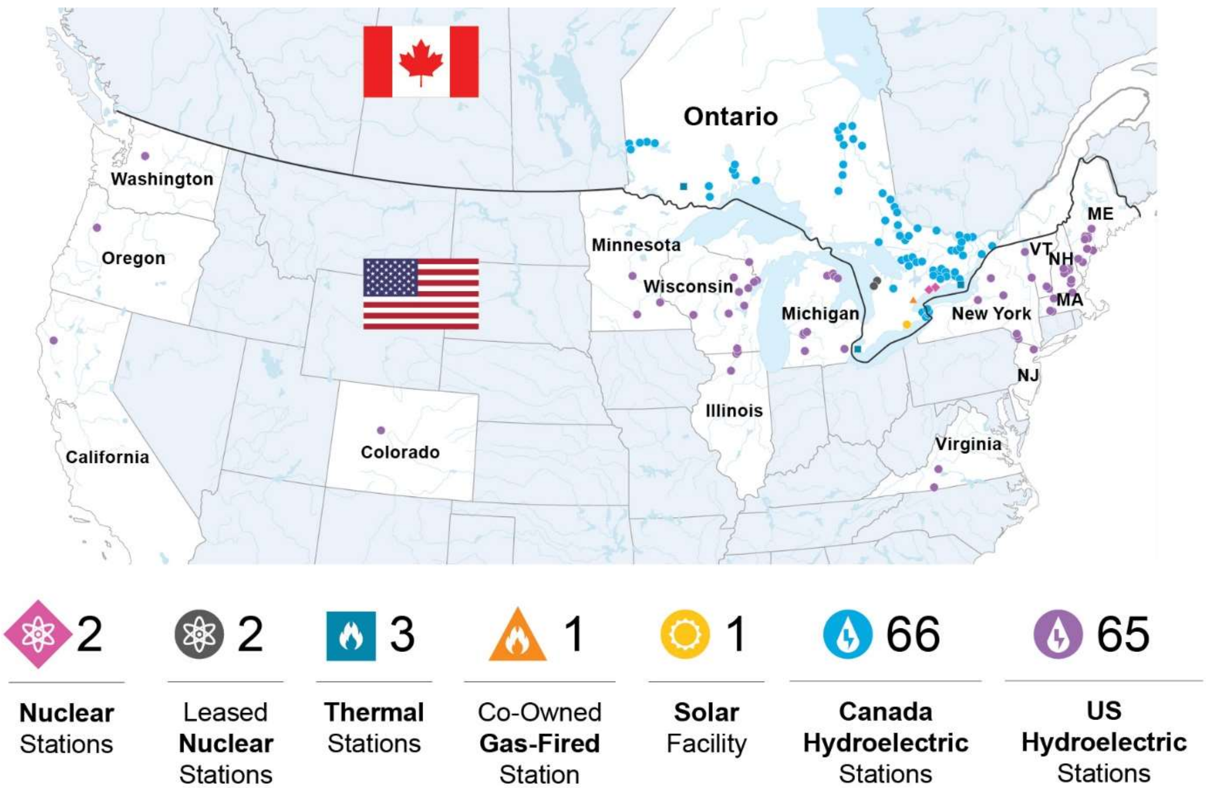
- “Return on Equity Excluding Accumulated Other Comprehensive Income”;
- “Enterprise Total Generating Cost per Megawatt-Hour”;
- “Nuclear Total Generating Cost per Megawatt-Hour”;
- “Hydroelectric Total Generating Cost per Megawatt-Hour”; and
- “Gross Margin”.

For a detailed description of each of the non-GAAP measures used in this MD&A and a detailed reconciliation to the most directly comparable measure under US GAAP, refer to the section, *Key Operating Performance Indicators and Non-GAAP Financial Measures*. The non-GAAP financial performance measures set out in this MD&A are intended to provide additional information to investors and do not have any standardized meaning under US GAAP, and therefore may not be comparable to other issuers, and should not be considered in isolation or as a substitute for measures of performance prepared under US GAAP.

THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder). OPG's electricity generation portfolio had an in-service generating capacity of 16,629 megawatts (MW) as at September 30, 2019.

As at September 30, 2019, OPG owned and operated two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations and one solar facility in Ontario, Canada. The Company also had interests in 79 hydroelectric generating stations in the United States[1], of which 65 are wholly owned and operated, and minority shareholdings in two solar facilities, through its Eagle Creek Renewable Energy, LLC (Eagle Creek) subsidiary. In addition, OPG and TC Energy Ltd. co-own the 550 MW Portlands Energy Centre gas-fired combined cycle GS (PEC), located in Ontario. OPG also owns two nuclear generating stations in Ontario, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power L.P. As at September 30, 2019, OPG did not operate PEC, the Bruce A GS, the Bruce B GS, and co-owned and minority-held facilities in the United States.



[1] On October 7, 2019, OPG acquired 100 percent of the equity in Cube Hydro Partners, LLC and affiliate Helix Partners, LLC, adding a further 19 hydroelectric generating stations in the United States. For additional discussion, refer to the details in the section, *Highlights* under the heading, *Recent Developments – Acquisition of Cube Hydro*.

The income from the co-owned and minority-held facilities is accounted for using the equity method of accounting, and OPG's share of income is included within income from investments subject to significant influence in the Contracted and Other Generation segment. OPG's proportionate share of the in-service generating capacity and generation volume from the co-owned facilities and minority shareholdings is included in the generation portfolio statistics set out in this report.

Income from the stations leased to Bruce Power L.P. is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the electricity generation and other operating statistics set out in this report.

In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of September 30, 2019 and December 31, 2018 was as follows:

(MW)	As at September 30 2019	 December 31 2018
Regulated – Nuclear Generation [1]	**5,728**	5,728
Regulated – Hydroelectric	**6,421**	6,426
Contracted and Other Generation [2]	**4,480**	4,141
Total	**16,629**	16,295

[1] Excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's proportionate share of in-service generating capacity from co-owned and minority shareholdings in electricity generating facilities.

During the nine months ended September 30, 2019, the total in-service generating capacity increased by 334 MW. The increase was primarily due to the acquisition of the remaining 50 percent interest in the Brighton Beach gas-fired combined cycle generating station (Brighton Beach GS) in August 2019, the completion of the Nanticoke solar facility which was placed in service in March 2019, and acquisitions of interests in hydroelectric facilities in the United States by Eagle Creek.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results and summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2019, compared to the same periods in 2018, are discussed below. 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 – except where noted)	**2019**	**2018**	**2019**	**2018**
Revenue	**1,508**	1,373	**4,500**	4,062
Fuel expense	**172**	175	**495**	496
Operations, maintenance and administration	**661**	638	**2,091**	2,103
Depreciation and amortization	**268**	200	**798**	584
Other net expenses (gains) [1]	**17**	27	**50**	(169)
Income before interest and income taxes	**390**	333	**1,066**	1,048
Net interest expense	**5**	19	**35**	56
Income tax expense	**62**	31	**135**	44
Net income	**323**	283	**896**	948
Net income attributable to the Shareholder	**319**	279	**883**	935
Net income attributable to non-controlling interest [2]	**4**	4	**13**	13
Electricity production (TWh) [3]	**19.1**	18.3	**58.4**	54.3
Cash flow				
Cash flow provided by operating activities	**743**	524	**1,928**	1,163
Segment Results				
Regulated – Nuclear Generation	**246**	179	**459**	170
Regulated – Hydroelectric	**117**	121	**476**	470
Contracted and Other Generation	**56**	70	**199**	226
Total electricity generating business segments	**419**	370	**1,134**	866
Regulated – Nuclear Waste Management	**(26)**	(26)	**(87)**	(91)
Other	**(3)**	(11)	**19**	273
Income before interest and income taxes	**390**	333	**1,066**	1,048

1 For the nine months ended September 30, 2018, includes the pre-tax gain on the sale of the former Lakeview GS site.

2 Relates to the 25 percent interest of Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in PSS Generating Station Limited Partnership, the 15 percent interest of a corporation wholly owned by Six Nations of Grand River Development Corporation in Nanticoke Solar LP and the 5 percent interest of a corporation wholly owned by Mississaugas of the Credit First Nation in Nanticoke Solar LP.

3 Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities.

Third Quarter

Net income attributable to the Shareholder was $319 million for the third quarter of 2019, representing an increase of $40 million compared to the same quarter in 2018. Income before interest and income taxes for the third quarter of 2019 was $390 million, an increase of $57 million compared to the same quarter in 2018.

The increase in income before interest and income taxes was primarily due to higher electricity generation from the Regulated – Nuclear Generation segment of 1.0 terawatt hour (TWh), resulting in higher revenue of $70 million.

Net interest expense decreased by $14 million during the third quarter of 2019, compared to the same quarter in 2018, largely due to higher interest income and a higher amount of interest costs capitalized related to the Darlington Refurbishment project, partially offset by a higher amount of interest costs on net debt issuances.

Income tax expense increased by $31 million for the three months ended September 30, 2019, compared to the same period in 2018. The increase was largely due to the impact of higher income before taxes.

Year-To-Date

Net income attributable to the Shareholder was $883 million for the first nine months of 2019, a decrease of $52 million compared to the same period in 2018. Income before interest and income taxes for the first nine months of 2019 was $1,066 million, an increase of $18 million compared to the same period in 2018.

The increase in income before interest and income taxes was primarily due to higher electricity generation from the Regulated – Nuclear Generation segment of 3.1 TWh, resulting in higher revenue of $242 million, and a decrease in nuclear OM&A expenses as a result of lower outage-related activity. The increase was largely offset by a one-time pre-tax gain on the sale of the former Lakeview GS site of $273 million recognized in net income upon completion of the transaction in the first quarter of 2018.

Net interest expense decreased by $21 million for the nine months ended September 30, 2019, compared to the same period in 2018, largely due to a higher amount of interest costs capitalized related to the Darlington Refurbishment project expenditures and higher interest income, partially offset by a higher amount of interest costs on net debt issuances.

Income tax expense increased by $91 million for the nine months ended September 30, 2019, compared to the same period in 2018. The increase was primarily due to a reduction in income taxes due to a refundable tax credit of $86 million recognized in 2018 and the impact of higher income before taxes.

Trends

OPG's quarterly electricity generation from the Regulated – Hydroelectric and Contracted and Other Generation segments is affected by changes in grid-supplied electricity demand. Changes in grid-supplied electricity demand are primarily caused by 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. Historically, there has been greater electricity demand in Ontario during the winter and summer months due to heating and air conditioning demands.

OPG's quarterly electricity generation from hydroelectric facilities is also impacted by weather conditions that affect water flows. Historically, there have been higher water flows in the springtime as a result of snow and ice melt entering the river systems. The financial impact of variability in water flows on the Regulated – Hydroelectric segment is mitigated by OEB-authorized regulatory variance accounts. The financial impact of variability in electricity generation from the Contracted and Other Generation segment is largely mitigated by the terms of the applicable Energy Supply Agreements for the contracted generating facilities in Ontario.

Electricity generation and financial results of the Regulated – Nuclear Generation segment are primarily impacted by outage activities at the nuclear generating stations. The frequency and timing of planned outages under a station's outage cycle may result in period-over-period variability in OPG's financial results, including the impact on revenue and OM&A expenses. The outage cycle at each of OPG's nuclear generating stations determines the number and frequency of planned outages in a particular year. The outage cycles are designed to ensure continued safe and reliable long-term operations of the plants and their compliance with the CNSC's regulatory requirements.

The Darlington nuclear GS (Darlington GS) and Pickering nuclear GS (Pickering GS) have been designed to operate at full power as baseload facilities and therefore electricity production is not adjusted in response to changes in grid-supplied electricity demand.

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2019 and 2018 was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(TWh)	**2019**	**2018**	**2019**	**2018**
Regulated – Nuclear Generation	**11.6**	10.6	**32.7**	29.6
Regulated – Hydroelectric	**6.8**	7.0	**23.1**	22.3
Contracted and Other Generation [1]	**0.7**	0.7	**2.6**	2.4
Total OPG electricity generation	**19.1**	18.3	**58.4**	54.3
Total electricity generation by other generators in Ontario [2]	**18.8**	19.3	**53.5**	55.8

[1] Includes OPG's proportionate share of electricity generation from co-owned and minority shareholdings in electricity generating facilities. For the three and nine month periods ended September 30, 2019, also includes generation from Eagle Creek's facilities of 0.2 TWh and 0.7 TWh, respectively.

[2] Calculated as Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation in Ontario.

Total OPG electricity generation increased by 0.8 TWh and 4.1 TWh for the three and nine month periods ended September 30, 2019, respectively, compared to the same periods in 2018. The increase for the three months ended September 30, 2019 was mainly due to higher electricity generation from the Regulated – Nuclear Generation segment, partially offset by lower electricity generation from the Regulated – Hydroelectric segment. The increase for the nine months ended September 30, 2019 was mainly due to higher electricity generation from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments.

The increase in electricity generation of 1.0 TWh from the Regulated – Nuclear Generation segment for the three months ended September 30, 2019, compared to the same period in 2018, was primarily due to fewer unplanned outage days at the Pickering GS. The increase of 3.1 TWh for the nine months ended September 30, 2019, compared to the same period in 2018, was primarily due to fewer planned and unplanned outage days at the Pickering GS and partially due to fewer planned outage days at the Darlington GS.

The decrease in electricity generation of 0.2 TWh from the Regulated – Hydroelectric segment for the three months ended September 30, 2019, compared to the same period in 2018, was primarily due to higher forgone hydroelectric generation as a result of lower demand for electricity in Ontario, partially offset by higher water flows in various regions of the province. The increase in electricity generation of 0.8 TWh for the nine months ended September 30, 2019, compared to the same period in 2018, was primarily due to higher water flows across most of the province, particularly in the spring of 2019.

The electricity generation from the Contracted and Other Generation segment for the three months ended September 30, 2019 was comparable to the same period in 2018, as electricity generation from the Eagle Creek facilities was offset by lower demand for electricity generation from some of the contracted facilities in Ontario. The increase of 0.2 TWh for the nine months ended September 30, 2019, compared to the same period in 2018, was primarily due to electricity generation from the Eagle Creek facilities, partially offset by higher electricity generation forgone at the contracted hydroelectric facilities as a result of lower demand for electricity in Ontario.

For the three and nine month periods ended September 30, 2019, Ontario's electricity demand as reported by the Independent Electricity System Operator (IESO) was 34.9 TWh and 101.5 TWh, respectively, compared to 36.5 TWh and 103.5 TWh for the same periods in 2018, 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 and certain nuclear stations, and other grid-connected renewable resources. Baseload generation supply surplus in Ontario was higher for the three and nine month periods ended September 30, 2019 compared to 2018, resulting in total OPG forgone hydroelectric electricity generation due to SBG conditions in Ontario of 0.7 TWh and 2.9 TWh, respectively, compared to 0.4 TWh and 2.4 TWh in the same periods in 2018. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions is offset by the impact of an OEB-authorized regulatory variance account. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

Regulated Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices approved by the OEB for electricity generated from these segments are discussed in the section, *Core Business, Strategy and Outlook* under the heading, *Financial Strength – Increasing Revenue, Reducing Costs and Achieving Appropriate Return.*

Average sales prices for the regulated generation business segments for the three and nine month periods ended September 30, 2019 and 2018 were as follows:

	Three Months Ended September 30		**Nine Months Ended September 30**	
cents per kilowatt hour (¢/kWh)	**2019**	**2018**	**2019**	**2018**
Regulated – Nuclear Generation [1]	**8.1**	7.9	**8.1**	7.7
Regulated – Hydroelectric	**4.5**	4.4	**4.5**	4.3

[1] Amounts deferred in the Rate Smoothing Deferral Account are not included in the calculation of the average sales price until the period they are settled with ratepayers. The OEB is required by *Ontario Regulation 53/05* to authorize recovery of the deferred amounts, together with interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, over a period not to exceed ten years following the end of the Darlington Refurbishment project.

For the Regulated – Nuclear Generation segment, the higher average sales price for the three and nine month periods ended September 30, 2019 was primarily due to higher rate riders in effect during 2019 related to the recovery of OEB-authorized regulatory variance and deferral account (regulatory account) balances. The higher average sales price for the nine months ended September 30, 2019 was also due to the partial reversal of a regulatory asset recorded for the June 1, 2017 to December 31, 2017 interim period revenue shortfall to reflect an estimate of the impact of the OEB's December 2017 decision on OPG's application for new regulated prices. The partial reversal was recorded in the first quarter of 2018 to reflect the issuance of the OEB's final payment amounts order in March 2018, which established the final regulated prices based on the findings in the December 2017 decision.

For the Regulated – Hydroelectric segment, the higher average sales price for the three and nine month periods ended September 30, 2019 was due to a higher hydroelectric base regulated price in effect during 2019 approved by the OEB in 2018 based on an annual formulaic adjustment, and higher rate riders in effect during 2019 related to the recovery of regulatory account balances.

Cash Flow from Operations

Cash flow provided by operating activities increased by $219 million and $765 million for the three and nine month periods ended September 30, 2019, compared to the same periods in 2018, respectively. The increase was primarily due to higher cash receipts from electricity generation revenue reflecting higher nuclear electricity production, the impact of higher rate riders in effect during 2019 related to the recovery of regulatory accounts, and the higher collection of the June 1, 2017 to February 28, 2018 interim period revenue shortfall pursuant to the collection mechanism directed in the OEB's March 2018 payment amounts order.

Return on 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 for the twelve months ended September 30, 2019 was 8.4 percent, compared to 9.5 percent for the twelve months ended December 31, 2018.

The decrease in ROE Excluding AOCI was primarily due to the one-time gain recognized on the sale of the former Lakeview GS site and the reduction in income tax due to a refundable tax credit, both recorded in the first quarter of 2018, partially offset by higher revenues due to greater electricity generation from the Regulated – Nuclear Generation segment in 2019. The impact of the gain on the sale of the former Lakeview GS site and the refundable tax credit contributed approximately 2.2 percent to ROE Excluding AOCI for the twelve months ended December 31, 2018.

Enterprise Total Generating Cost per Megawatt-Hour

The Enterprise TGC per megawatt-hour (MWh) was $50.41 and $48.89 for the three and nine month periods ended September 30, 2019, respectively, compared to $53.64 and $53.02 for the same periods in 2018. The decrease in Enterprise TGC per MWh was primarily due to higher nuclear electricity generation and lower OM&A expenses before the impact of regulatory accounts at the nuclear facilities, partially offset by higher sustaining capital expenditures.

Nuclear Total Generating Cost per Megawatt-Hour

The Nuclear TGC per MWh was $57.91 and $63.61 for the three and nine month periods ended September 30, 2019, respectively, compared to $64.72 and $73.05 for the same periods in 2018. The decrease in Nuclear TGC per MWh was primarily due to higher nuclear electricity generation and lower OM&A before the impact of regulatory accounts.

Hydroelectric Total Generating Cost per Megawatt-Hour

The Hydroelectric TGC per MWh was $32.66 and $26.17 for the three and nine month periods ended September 30, 2019, respectively, compared to $31.48 and $24.87 for the same periods in 2018. The increase in Hydroelectric TGC per MWh was primarily due to higher sustaining capital expenditures for the three and nine month periods ended September 30, 2019. For the nine months ended September 30, 2019, the increase was partially offset by higher SBG-adjusted electricity generation from the hydroelectric facilities.

Recent Developments

Acquisition of Brighton Beach GS

On August 30, 2019, OPG acquired the remaining 50 percent interest in the combined-cycle natural gas-fired Brighton Beach GS from ATCO Power Canada Ltd., an affiliate of Canadian Utilities Limited, for $200 million, inclusive of assumed debt and subject to customary working capital and other adjustments. The Brighton Beach GS, located in Windsor, Ontario, provides approximately 560 MW of in-service generating capacity and operates under an Energy Conversion Agreement expiring in 2024. The Brighton Beach GS will be operated by a wholly-owned subsidiary of OPG and is included in the Contracted and Other Generation segment.

Acquisition of Cube Hydro

On October 7, 2019, OPG acquired 100 percent of the equity in Cube Hydro Partners, LLC and affiliate Helix Partners, LLC (collectively, Cube Hydro) for US$1.12 billion, inclusive of assumed debt and subject to customary working capital and other adjustments. Cube Hydro is a hydropower platform with 385 MW of in-service generating capacity spread across 19 hydroelectric facilities throughout the northeastern and southeastern US, and provides additional scale to OPG's existing hydroelectric operations in the United States.

Agreement to Acquire Portfolio of Natural Gas-Fired Assets in Ontario

In July 2019, OPG, under a new subsidiary, entered into a purchase and sale agreement with affiliates of TC Energy Ltd. to acquire a portfolio of combined-cycle natural gas-fired plants in Ontario for $2.87 billion, subject to customary working capital and other adjustments. The acquired portfolio includes the 900 MW Napanee GS, the 683 MW Halton Hills GS, and the remaining 50 percent interest in the 550 MW Portlands Energy Centre. The acquisition is subject to a number of closing conditions, including the receipt of various regulatory approvals and the commencement of commercial operations at the Napanee GS. A pre-merger notification and a request for an Advance Ruling Certificate have been filed with the Commissioner of Competition, and the review is currently in process. Closing is expected to occur in the first quarter of 2020.

All of the assets being acquired from TC Energy Ltd. operate under Energy Supply Agreements with the IESO, with expiry dates ranging from 2029 to 2040. The natural gas electricity generation from these assets is an important component of maintaining Ontario's electricity system reliability, complementing the growth of variable sources of electricity generation in the province, such as wind and solar.

Medium Term Notes Issuance

On September 13, 2019, OPG issued $800 million of senior notes payable under the Company's Medium Term Note Program. The issuance consisted of $500 million of senior notes maturing in September 2029 with a coupon rate of 2.98 percent, and $300 million of senior notes maturing in September 2050 with a coupon rate of 3.65 percent. The net proceeds will be used for the repayment of existing indebtedness, financing the Company's acquisition and capital expenditure program, working capital requirements and general corporate purposes.

Society of United Professionals Collective Agreement

The Society of United Professionals (Society) represents approximately 3,100 regular employees at OPG or approximately 36 percent of OPG's regular workforce in Ontario as at September 30, 2019. In anticipation of the expiry of the one-year governing collective agreement between OPG and the Society on December 31, 2019, negotiations to renew the collective agreement took place in the second quarter of 2019. After the parties were unable to reach an agreement during negotiations, they proceeded to interest mediation/arbitration in November 2019. On November 5, 2019, the appointed arbitrator issued an arbitration award for a two-year collective agreement between the parties, covering the period from January 1, 2020 to December 31, 2021. The renewed collective agreement reduces OPG's labour relations risk for the term of the agreement, and provides increased flexibility to address the Company's evolving workforce requirements.

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 its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business expansion opportunities to the benefit of the Shareholder.

The following sections provide an update to OPG's disclosures in the 2018 annual MD&A related to its four business imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these imperatives is included in the 2018 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.

<u>Electricity Generation Production and Reliability</u>

In October 2019, OPG renewed the operating services agreement with Hydro-Québec that will facilitate continued safe and reliable operation of the jointly-owned Chats Falls GS, a partnership between the two companies since 1928. OPG is the operator and maintainer of this eight-unit, 192 MW hydroelectric station located on the Ottawa River near the Ontario-Québec border and sending power to both provinces. The operating agreement sets out a framework for how the facility is operated and maintained, and how costs are recovered, allowing both companies to share their respective expertise and experience.

Project Excellence

OPG is pursuing a number of generation development and other projects in line with Ontario's electricity planning initiatives and expected to provide incremental value in the future. The status update for OPG's major projects as at September 30, 2019 is outlined below.

Project *(millions of dollars)*	**Capital expenditures** **Year-to-date**	 **Life-to-date**	**Approved budget**	**Expected in-service date**	**Current status**
Darlington Refurbishment	901	6,414	12,800 [1]	First unit - 2020 Last unit - 2026	The reassembly of Unit 2 reactor components is substantially complete. In October 2019, the Lower Feeder installation series was completed. In November 2019, the project began loading fuel into the reactor. Planning activities for the refurbishment of Unit 3 are progressing as planned. The overall project is tracking on schedule and to the $12.8 billion budget.
Ranney Falls Hydroelectric GS	13	70	77	2019	In the third quarter of 2019, testing and commissioning of the turbine and generator of the unit continued. The project's expected in-service date is in the fourth quarter of 2019. The project is tracking on schedule and on budget.
Deep Geologic Repository for Low and Intermediate Level Radioactive Waste	5 [2]	218 [2]			In August 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. OPG continues its engagement with the SON, working towards securing support for the project and to formulate a response to the information request. A series of province-wide SON community engagement sessions have been conducted in 2019 with a goal to reach a resolution regarding support via a community-wide voting process.

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.

[2] Expenditures are charged against the 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 at least 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. The first refurbished unit is expected to be returned to service in the second quarter of 2020 and the last unit is scheduled to be completed in 2026.

The third major segment of the Unit 2 refurbishment, the installation and reassembly of reactor components, has been substantially completed. The segment included the installation of fuel channel assemblies, completed in April 2019, and the installation of new feeder tubes. During the quarter, work progressed on the Lower Feeder installation series and was completed in October 2019. The Lower Body Tubing installation series is expected to commence in the fourth quarter of 2019 and its completion will represent the end of the third major segment of the Unit 2 refurbishment. The fourth major segment began in November 2019 with the commencement of fuel loading into the reactor. This segment will focus on restoring the reactor vault and returning Unit 2 to service. Taking into account the challenges that were experienced in achieving the planned installation rates for the Lower Feeder installation series and the expected time required for the start-up schedule, it is expected that Unit 2 will return to service in the second quarter of 2020, following the safe completion of commissioning activities.

The remainder of the Unit 2 refurbishment program that is not on the critical path is progressing well and poses no risk to the schedule. The work committed to for 2019 to support the requirements set out in the CNSC-approved Integrated Implementation Plan for the station is also progressing as planned. In addition to refurbishment activities on Unit 2, OPG has also completed substantially all of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements. These pre-requisite projects are integral to the refurbishment of all the units and to the continued operation of the Darlington GS. The final pre-requisite project covering the refurbishment of all units, the Heavy Water Storage and Drum Handling Facility, is tracking to be completed by the end of 2019, ahead of the commencement of Unit 3 refurbishment activities.

Planning and pre-requisite activities related to the refurbishment of the second unit, Unit 3, continue to progress in accordance with the overall project schedule, incorporating experience learned to date from the Unit 2 refurbishment. Commissioning on the Full Scale Maintenance Simulator for the turbine generator has been completed. Procurement for major components that require long lead times and receipt of long lead materials for the Re-tube and Feeder Replacement of Unit 3 are continuing. After considering the optimization of resources being engaged in returning Unit 2 to service, the Unit 3 refurbishment is now targeted to commence in the second quarter of 2020, reflecting a coordinated effort between the project and operations teams. As of September 30, 2019, $437 million has been invested in planning and pre-requisite activities related to the Unit 3 refurbishment.

Upgrade and Rehabilitation of Hydroelectric Generating Stations

OPG continues to make investments in its existing hydroelectric generating fleet. During the third quarter of 2019, the Company completed the overhaul and upgrade of Unit 2 of the DeCew Falls GS and continued definition phase work on the overhaul and upgrade of the R.H. Saunders GS units.

Decommissioning of Thermal Generating Stations

In August 2019, OPG safely imploded the boilerhouse of the former Nanticoke GS. Demolition and site clean-up activities are expected to be completed in 2020. The demolition work continues to track on schedule and on budget.

The costs of decommissioning activities are charged to a previously established decommissioning provision.

Financial Strength

As a commercial enterprise, OPG's financial priority is to ensure a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and supports expansion of the business.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on electricity customers by seeking further efficiencies in the Company's cost structure.

For regulated operations, achievement of the above objectives is largely dependent on outcomes of applications for regulated prices to the OEB and growth of the asset base earning a return. OPG's revenues from regulated operations include recovery of amounts deferred in regulatory accounts.

The following table presents the OEB-authorized regulated prices in effect for electricity generated from regulated facilities for the period from January 1, 2018 to December 31, 2021:

($/MWh)	**2018**	**2019**	**2020**	**2021**
Regulated – Nuclear Generation				
Base regulated price [1]	78.64	**77.00**	85.00	89.70
Interim period shortfall rider [2]	2.88	**7.71**	5.64	-
Deferral and variance account rate riders [3]	1.05	**4.99**	4.32	6.13
	82.57	**89.70**	94.96	95.83
Regulated – Hydroelectric				
Base regulated price [4]	42.05	**42.51**	n/a	n/a
Interim period shortfall rider [2]	0.13	**0.35**	0.24	-
Deferral and variance account rate riders [3]	0.52	**2.60**	2.26	2.05
	42.70	**45.46**	n/a	n/a

1 Base regulated prices for nuclear facilities presented do not include amounts deferred in the Rate Smoothing Deferral Account. These prices were established by the payment amounts order issued by the OEB in March 2018 using a rate smoothing approach that defers a portion of each year's approved nuclear revenue requirement for future collection in the Rate Smoothing Deferral Account. Amounts deferred in the Rate Smoothing Deferral Account for future collection are recorded as revenue in the period to which the underlying approved revenue requirement relates. Pursuant to the payment amounts order issued in March 2018, no amounts were recorded in the Rate Smoothing Deferral Account for 2017 or 2018, with $102 million to be deferred for future collection in 2019 and $391 million in 2020. During the three and nine month periods ended September 30, 2019, $26 million and $77 million, respectively, was deferred for future collection in the Rate Smoothing Deferral Account and recorded as revenue in the Regulated – Nuclear Generation segment.

2 In its payment amounts order issued in March 2018, the OEB authorized separate rate riders to allow for the recovery of the revenue shortfall between the new base regulated prices approved with an effective date of June 1, 2017 and the previously approved base regulated prices that OPG continued to receive during the interim period between June 1, 2017 and February 28, 2018. The interim period revenue shortfall amount approved for recovery was recognized as a regulatory asset, and is being collected through rate riders approved by the OEB based on actual generation for the March 1, 2018 to December 31, 2020 period.

3 Beginning in 2018, deferral and variance account riders reflect the OEB's March 2018 payment amounts order that authorized recovery of balances recorded in deferral and variance accounts as at December 31, 2015. Beginning in 2019, these riders also reflect the OEB's February 21, 2019 decision and order that authorized recovery of balances recorded in deferral and variance accounts as at December 31, 2017.

4 Base regulated prices for regulated hydroelectric facilities for 2020 and 2021 will be determined annually through a formulaic adjustment using the OEB-approved incentive regulation formula and OEB-published inflation indices.

For the hydroelectric facilities, base regulated prices are determined by annually escalating the base regulated prices in effect prior to June 1, 2017, with some adjustments, using an approved formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB, less a stretch factor adjustment. In September 2019, OPG applied for the annual formulaic adjustment to set the 2020 base regulated price for the regulated hydroelectric facilities. The OEB's decision on OPG's application is expected to be received before the end of 2019.

<u>Ensuring Availability of Cost Effective Funding</u>

As discussed in the section, *Highlights* under the heading, *Recent Developments – Agreement to Acquire Portfolio of Natural Gas-Fired Assets in Ontario*, the Company has entered into an agreement to acquire a portfolio of natural gas-fired generating stations from TC Energy Ltd., with the acquisition expected to close in the first quarter of 2020. OPG has secured liquidity sources to ensure adequate financing is available to maintain ongoing liquidity and for its financing requirements, including its capital expenditure program and the closing of the announced acquisition agreements. These financing activities included:

- On July 17, 2019, OPG established a new $800 million general corporate credit facility agreement with the Ontario Electricity Financial Corporation (OEFC) expiring on December 31, 2021. The Company expects that the credit facility agreement will be amended in the fourth quarter of 2019, increasing the facility to $1.3 billion. In August 2019, OPG issued senior notes payable to the OEFC totalling $100 million, with a maturity date of August 2039 and a coupon rate of 3.49 percent.
- In October 2019, OPG received a binding commitment from a syndicate of banks for a $1 billion one-year term loan.
- In October 2019, OPG received a binding commitment for a 364-day revolving credit facility with a one year extension option of USD $750 million.

OPG continues to maintain a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches.

In April 2019, 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)'. In July 2019, subsequent to OPG's acquisition announcements, S&P Global Ratings (S&P) re-affirmed both OPG's long-term credit rating at 'BBB+', with a revised outlook from stable to negative, and commercial paper rating for OPG is 'A-1 (low)'. DBRS re-affirmed OPG's long-term credit rating at 'A (low)'. All ratings from DBRS have a stable outlook.

Social Licence

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's Social Licence initiatives and activities are discussed in the section, *Environmental, Social, Governance and Sustainability*.

Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of the Company's applications for regulated prices to the OEB and the generation performance of the nuclear and hydroelectric fleet.

Based on the OEB-approved regulated prices and anticipated generation performance and outage plans for the generation fleet for the remainder of the year, OPG expects its existing operations to continue to provide a strong level of net income and ROE Excluding AOCI in 2019. The increase in the regulated prices in 2019, as set out under the heading above, *Financial Strength – Increasing Revenue, Reducing Costs and Achieving Appropriate Return*, is expected to continue to contribute to an improvement in cash flow from operating activities during 2019, compared to 2018.

Several regulatory accounts will continue to reduce the relative variability of the regulated operations' contribution to the Company's net income, particularly for the Regulated – Hydroelectric Generation segment. Among others, these 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 such, earnings from the Regulated – Hydroelectric segment are expected to continue to be generally stable on a year-over-year basis.

There are no regulatory accounts in place related to the impact of variability in the nuclear stations' generation performance on revenue from base regulated prices. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, building on recent initiatives to improve the overall reliability and predictability of the fleet. Taking into account outage activity planned at the nuclear generating stations during the remainder of the year, OPG expects a year-over-year increase in earnings from the Regulated – Nuclear Generation segment.

Energy and capacity provided by most of OPG's non-regulated assets is subject to Energy Supply Agreements with the IESO or other long-term power purchase agreements. Based on these agreements, OPG expects existing operations of the Contracted and Other Generation segment to contribute a generally stable level of earnings and cash flow from operating activities in 2019.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC measures for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures, nuclear outage profile and water flows may also impact TGC measures in future periods.

OPG's total forecast capital expenditures for the 2019 year are approximately $2.1 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects, and sustaining capital investments across the generating fleet, and excludes the impact of acquisition-related activity. OPG's major projects are discussed in the section, *Core Business, Strategy and Outlook* under the heading, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by earnings on the nuclear fixed asset removal and nuclear waste management segregated funds (Nuclear Segregated Funds) established under the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, 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 specified in the ONFA, the rates of return earned in a given period can be subject to volatility due to financial market conditions, including changes in the Ontario consumer price index (CPI) that affect earnings on the portion of the Used Fuel Segregated Fund guaranteed by the Province, and can cause fluctuations in the Company's income in the short term. This volatility is partially reduced by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and during periods when the funds are in a fully funded or overfunded position.

As at September 30, 2019, the Decommissioning Segregated Fund was overfunded by approximately 30 percent and the Used Fuel Segregated Fund was overfunded by approximately 2 percent based on the current 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. No overall contributions to the Nuclear Segregated Funds are currently expected until the end of 2021 when the next update of the ONFA reference plan is scheduled. At that time, the value of the funds will be compared to the respective underlying funding liabilities to determine any required future contributions.

ENVIRONMENTAL, SOCIAL, GOVERNANCE AND SUSTAINABILITY

Consistent with OPG's business imperatives, the Company continues to seek opportunities to invest in the generation of clean and sustainable energy. The following is a summary of recent actions taken to advance this strategy.

Environmental and Sustainability

Under the federal *Greenhouse Gas Pollution Pricing Act* (GGPPA), an Output-Based Pricing System (OBPS) for industrial facilities took effect on January 1, 2019 and a fuel charge came into effect on April 1, 2019 in Ontario. On July 10, 2019, OBPS regulations were published, including fuel-specific performance standards for electricity generation that apply retroactively beginning January 1, 2019. OPG has implemented processes to comply with the federal requirements and recover associated carbon costs to the extent possible.

On July 4, 2019, the Government of Ontario published Greenhouse Gas Emissions Performance Standards (EPS) to provide Ontario with an alternative to the OBPS portion of the federal GGPPA. Only the registration provisions of the EPS currently apply. Other key provisions will not apply while Ontario is subject to the federal OBPS requirements. Neither the federal pricing system nor the provincial EPS are expected to have a material financial impact on the Company.

In September 2019, the Darlington GS was presented with the 2019 Sustainability Award by the Oshawa Chamber of Commerce for its commitment to environmental stewardship and sustainability initiatives. The Chamber considers a wide range of criteria for its sustainability award, and this recognition reflects OPG's commitment to clean, low-carbon energy, engagement with the local community, and initiatives to protect the environment and biodiversity.

Details of OPG's approach to operating in a sustainable manner, including recent initiatives and performance data related to OPG's most significant environmental, social and economic impacts, are available on the Company's website at www.opg.com.

Climate Change

The following developments related to OPG's actions to advance its strategy of investing in the generation of clean and sustainable energy took place during the nine months ended September 30, 2019:

- On July 15, 2019, the Canadian federal government issued the notice of commencement of an environmental assessment for a small modular reactor project proposed by Global First Power (GFP) with support from nuclear-technology-innovator Ultra Safe Nuclear Corporation™ (USNC) and OPG. GFP, USNC and OPG propose to construct and operate a 15 MW thermal (approximately 5 MW electrical) Micro Modular Reactor (MMR™) plant at the Chalk River Laboratories, owned by Atomic Energy of Canada Limited and operated by Canadian Nuclear Laboratories (CNL). In parallel, GFP will provide CNL with the required information as the proponent selection process continues, and provide the CNSC with information to support the licence application process.

- OPG maintains a site preparation licence granted by the CNSC in 2012 in relation to the potential construction of four new nuclear units at the Darlington site. The licence expires in 2022. OPG has informed the CNSC of the Company's intent to renew the licence and, in June 2019, submitted a relicensing plan to the CNSC. OPG intends to submit a licence renewal application in mid-2020. OPG is investigating potential technology partners for new nuclear reactor development at the Darlington site. No decision on technology has been made and no project has been commenced.

- On October 7, 2019, the Company acquired 100 percent of the equity of Cube Hydro, a hydropower platform with 19 hydroelectric facilities and 385 MW of in-service generating capacity operated in the US.

- In August 2019, OPG acquired the 4 MW Falls Creek GS, a hydroelectric generating station located in the Willamette National Forest in Oregon, through its wholly-owned subsidiary, Eagle Creek.

- OPG and a subsidiary of Hydro One Limited (Hydro One) have formed a partnership to own and operate electric vehicle fast charging stations across Ontario, under the Ivy Charging Network brand. This initiative is in line with OPG's strategy to invest in sustainable growth opportunities.

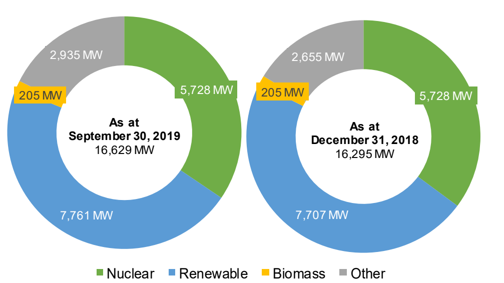
- OPG has constructed a vehicle to grid (V2G) pilot with electric vehicles and bidirectional chargers hosted at two commercial buildings in Toronto. This pilot implementation with Peak Power Inc., a global energy technology services provider, will explore feasibility of demand management using an aggregate resource.

Performance and Key Climate-Related Metrics

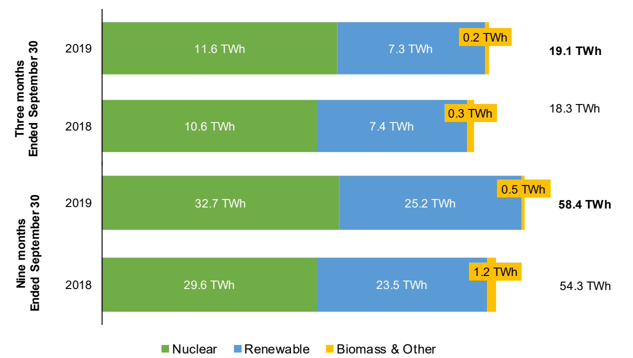
Pending development of longer-term metrics and targets for climate change adaptation, OPG has identified certain initial current metrics that it considers relevant to stakeholders. These are outlined below.

Climate change metrics

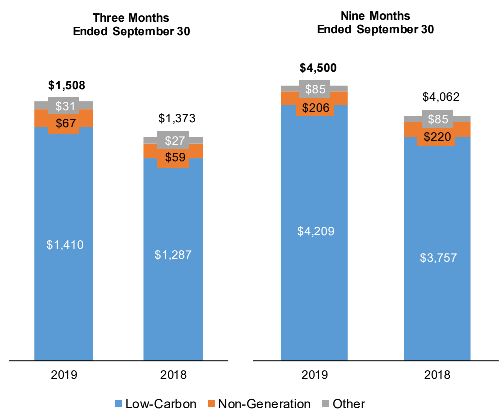
In-service generating capacity by generation type (MW)



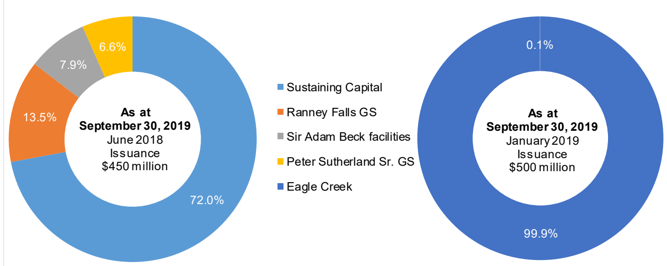
Electricity generation by generation type (TWh)



Revenue by facility category (millions of dollars)



Value and use of net proceeds from green bond offerings [1]



In-service generating capacity[2] by generation type	In-service generating capacity from renewable sources increased during the nine months ended September 30, 2019 due to the completion of the Nanticoke solar facility and the acquisition of interests in hydroelectric facilities in the United States by Eagle Creek.
Electricity generation by generation type	During the three and nine month periods ended September 30, 2019, approximately 99 percent of OPG's electricity generation was supplied by low-carbon sources, comprised of Nuclear, Renewable and Biomass generation.
Revenue by facility category	Approximately 98 percent of OPG's revenue from electricity generation operations continues to be derived from low-carbon facilities. Revenue from low-carbon generation increased during three and nine month periods ended September 30, 2019, compared to the same periods in 2018, primarily from the Regulated – Nuclear Generation segment.
Value and use of net proceeds from green bond offerings	As at September 30, 2019, OPG has allocated 100 percent of the net proceeds from green bond offerings to eligible projects, a group of selected projects that offer tangible environmental benefits as defined under OPG's Green Bond Framework.

[1] Sir Adam Beck facilities includes the frequency conversion of Unit 1 and Unit 2 of the Sir Adam Beck 1 GS, the Water Conveyance System rehabilitation of Sir Adam Beck 1 GS and the Sir Adam Beck Pump GS Reservoir Refurbishment project.

[2] Includes OPG's proportionate share of in-service generating capacity from co-owned and minority shareholdings in electricity generating facilities.

Indigenous Relations

OPG believes in 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 Indigenous communities. OPG seeks to establish these relationships based on a foundation of respect, transparency and mutual responsibility. OPG's commitment in this area includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements and other joint projects.

As at September 30, 2019, OPG's in-service generation capacity of facilities constructed in partnership with Indigenous communities was 522 MW (December 31, 2018 – 478 MW). For the three and nine month periods ended September 30, 2019, revenues earned from facilities in partnership with Indigenous communities were $61 million and $181 million, respectively (three and nine month periods ended September 30, 2018 – $59 million and $176 million, respectively).

In August 2019, OPG completed the commissioning of a renewable micro grid in partnership with the Kiashke Zaaging Anishinaabek (KZA), also known as the Gull Bay First Nation. The micro grid utilizes solar panels, lithium-ion storage batteries and automated control technology to help the community reduce its diesel use by approximately 30 percent of its current consumption, eliminating more than 400 tonnes of carbon emissions annually. Ownership of the micro grid will be transferred to KZA upon completion of a system monitoring period.

In August 2019, OPG and Lac Seul First Nation held a celebration marking the tenth anniversary of the commercial partnership in the Obishikokaang Waasiganikewigamig (Lac Seul GS). This partnership was formed in 2009, with the Lac Seul First Nation becoming a 25 percent equity holder in the Lac Seul hydroelectric GS. The equity partnership was the first of its kind and was subsequently used by OPG as a model for developing other renewable energy projects in partnership with Indigenous communities, including the Lower Mattagami River project, the Peter Sutherland Sr. hydroelectric GS and the Nanticoke solar facility.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars)	Three Months Ended September 30 2019	2018	Nine Months Ended September 30 2019	2018
Revenue	**1,011**	898	**2,879**	2,512
Fuel expense	**75**	73	**218**	208
Gross margin	**936**	825	**2,661**	2,304
Operations, maintenance and administration	**515**	507	**1,679**	1,731
Depreciation and amortization	**169**	131	**504**	382
Property taxes	**6**	8	**19**	21
Income before interest and income taxes	**246**	179	**459**	170

Income before interest and income taxes from the segment increased by $67 million and $289 million for the three and nine month periods ended September 30, 2019, respectively, compared to the same periods in 2018.

Higher electricity generation due to overall fewer outage days across the nuclear generating stations increased segment revenue by approximately $70 million and $242 million for the three and nine month periods ended September 30, 2019, respectively, compared to the same periods in 2018. The increase in revenue was partially offset by lower base regulated prices for nuclear facilities in 2019, compared to 2018, which resulted in lower revenue of approximately $19 million and $56 million for the three and nine month periods ended September 30, 2019, respectively, compared to the same periods in 2018.

Segment revenue also increased during the three and nine month periods ended September 30, 2019 due to amounts being deferred for future collection in the Rate Smoothing Deferral Account, pursuant to the payment amounts order issued by the OEB in March 2018. This resulted in an increase in segment revenue of $26 million and $77 million for the three and nine month periods ended September 30, 2019, respectively.

In the third quarter of 2019, OM&A expenses increased primarily due to higher amounts recorded as refundable to customers through regulatory accounts, partially offset by lower outage-related costs due to overall fewer outage days at the nuclear generating stations. The decrease in OM&A expenses for the nine months ended September 30, 2019 was primarily due to lower outage-related costs, partially offset by higher amounts recorded as refundable to customers through regulatory accounts.

Higher rate riders for the recovery of regulatory accounts in effect during the three and nine month periods ended September 30, 2019 also contributed to an increase in segment revenue, compared to the same periods in 2018. This increase in revenue was largely offset by a corresponding increase in the amortization expense related to these balances.

The planned and unplanned outage days at the Darlington GS and Pickering GS were as follows:

	Three Months Ended September 30 2019	2018	Nine Months Ended September 30 2019	2018
Planned Outage Days				
Darlington GS	**3.7**	17.1	**89.2**	110.8
Pickering GS	**28.3**	26.5	**151.1**	274.4
Unplanned Outage Days				
Darlington GS	**24.3**	13.0	**24.7**	18.2
Pickering GS	**6.9**	71.8	**30.9**	118.9

Changes in the number of planned outage days are primarily driven by each station's cyclical maintenance schedule. In the third quarter of 2019, an outage was taken at the Darlington GS to safely conduct a repair that was discovered during a routine check, resulting in an increase in unplanned outage days. In the third quarter of 2018, the Pickering GS experienced higher unplanned outage days after significant amounts of algae debris interfered with water intake screens following inclement weather.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	**2018**	**2019**	**2018**
Unit Capability Factor *(%)* [1]				
Darlington GS	**91.1**	91.7	**86.5**	85.2
Pickering GS	**94.3**	87.9	**89.1**	77.9

[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 Pickering GS increased during the three and nine month periods ended September 30, 2019, compared to the same periods in 2018, due to overall fewer outage days at the station in 2019.

The Unit Capability Factor at the Darlington GS during the three and nine month periods ended September 30, 2019 was comparable to the same periods in 2018, in line with the similar number of overall outage days at the station in both periods.

In 2019, several generating units at the Pickering and Darlington generation stations have set records for the longest consecutive online operating days without taking an outage. Several units have run for over 400 consecutive days without taking an outage, demonstrating strong operational excellence and unit reliability.

Regulated – Nuclear Waste Management Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2019**	**2018**	**2019**	**2018**
Revenue	**37**	33	**100**	98
Operations, maintenance and administration	**37**	33	**100**	98
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**251**	242	**755**	729
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(225)**	(216)	**(668)**	(638)
Loss before interest and income taxes	**(26)**	(26)	**(87)**	(91)

The segment earnings for the three and nine month periods ended September 30, 2019 were comparable to the same periods in 2018. Higher earnings from the Nuclear Segregated Funds were largely offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

The higher earnings from the Nuclear Segregated Funds was primarily due to the growth in the present value of the underlying funding liabilities per the current approved ONFA reference plan in effect since January 1, 2017. As both the Decommissioning Segregated Fund and the Used Fuel Segregated Fund were in an overfunded position during the three and nine month periods ended September 30, 2019, they were not impacted by market returns and the rate of return guaranteed by the Province for a portion of the Used Fuel Segregated Fund. When both funds are in an overfunded position, 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.

Further details on the accounting for the Nuclear Segregated Funds can be found in OPG's 2018 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The higher accretion expense on the Nuclear Liabilities was due to the increase in the present value of the underlying obligation to reflect the passage of time.

Regulated – Hydroelectric Segment

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2019	**2018**	**2019**	**2018**
Revenue [1]	**340**	331	**1,132**	1,077
Fuel expense	**84**	87	**242**	242
Gross margin	**256**	244	**890**	835
Operations, maintenance and administration	**82**	83	**244**	245
Depreciation and amortization	**55**	39	**167**	115
Property tax	**1**	1	**1**	1
Other losses	**1**	-	**2**	4
Income before interest and income taxes	**117**	121	**476**	470

[1] During the three and nine month periods ended September 30, 2019, the segment revenue included incentive payments of $2 million and $4 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2018 – incentive payments of $8 million in each period). 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.

Income before interest and income taxes from the segment decreased by $4 million for the three months ended September 30, 2019, compared to the same period in 2018. The decrease in earnings was mainly due to lower incentive payments, partially offset by increased revenue reflecting the impact of the new base regulated price approved by the OEB in December 2018 pursuant to an annual formulaic adjustment, effective from January 1, 2019 to December 31, 2019.

During the nine months ended September 30, 2019, income before interest and income taxes from the segment increased by $6 million, compared to the same period in 2018. The increase in earnings was primarily due to higher revenue reflecting the impact of the new base regulated price approved by the OEB in December 2018, partially offset by lower incentive payments and higher fixed asset depreciation expense.

Higher rate riders for the recovery of regulatory accounts in effect during the three and nine month periods ended September 30, 2019 contributed to an increase in segment revenue, compared to the same period in 2018. This increase in revenue was largely offset by a corresponding increase in amortization expense related to these balances.

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	
	2019	**2018**	**2019**	**2018**
Hydroelectric Availability *(%)*	**82.0**	82.6	**87.7**	86.1

The Hydroelectric Availability decreased for the three months ended September 30, 2019, compared to the same period in 2018, primarily due to higher unplanned outages at regulated hydroelectric stations, mainly in the Niagara and eastern Ontario regions.

For the nine months ended September 30, 2019, the Hydroelectric Availability increased compared to the same period in 2018, primarily due to fewer planned outage days at regulated hydroelectric stations, mainly in the eastern Ontario and Niagara regions.

Contracted and Other Generation Segment

(millions of dollars)	Three Months Ended September 30 2019	2018	Nine Months Ended September 30 2019	2018
Revenue	**146**	142	**456**	440
Fuel expense	**13**	15	**35**	46
Gross margin	**133**	127	**421**	394
Operations, maintenance and administration	**51**	43	**150**	127
Depreciation and amortization	**32**	21	**92**	60
Accretion on fixed asset removal liabilities	**1**	2	**5**	6
Property taxes	**4**	1	**10**	5
Income from investments subject to significant influence	**(10)**	(12)	**(33)**	(32)
Other (gains) losses	**(1)**	2	**(2)**	2
Income before interest and income taxes	**56**	70	**199**	226

Income before interest and income taxes from the segment decreased by $14 million for the third quarter of 2019, compared to the same period in 2018. The decrease was largely due to the impact of seasonally low water flows on electricity generation from the Eagle Creek facilities and partially due to the timing of planned outages at the Atikokan GS.

Income before interest and income taxes from the segment decreased by $27 million for the nine months ended September 30, 2019, compared to the same period in 2018. The decrease in earnings was primarily due to the impact of seasonally low water flows on electricity generation from the Eagle Creek facilities in the third quarter, higher OM&A expenses at the Lower Mattagami and Lennox generating stations, and the closure of the Thunder Bay GS in July 2018.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the assets operated by OPG within the Contracted and Other Generation segment in Ontario were as follows:

	Three Months Ended September 30 2019	2018	Nine Months Ended September 30 2019	2018
Hydroelectric Availability *(%)* [1]	**69.1**	67.7	**77.9**	78.1
Thermal EFOR *(%)* [2]	**0.5**	6.4	**5.2**	2.8

[1] The Hydroelectric Availability reflects hydroelectric generating stations in Ontario. Eagle Creek operated generating stations which were acquired on November 27, 2018 are not reflected in these results.

[2] The Thermal EFOR reflects the reliability of a generating unit at OPG's wholly owned thermal stations. The Brighton Beach GS, the remaining 50 percent of which was acquired on August 30, 2019, is not reflected in these results.

The Hydroelectric Availability increased during the third quarter, compared to the same period in 2018, primarily due to fewer planned outage days at the Kipling GS. The Hydroelectric Availability was comparable for the nine months ended September 30, 2019 and the same period in 2018.

The Thermal EFOR decreased during the third quarter, compared to the same period in 2018, primarily due to fewer unplanned outage days at the Lennox GS and the unplanned outage days at the Thunder Bay GS prior to its closure in July 2018. The Thermal EFOR increased during the nine months ended September 30, 2019, primarily due to a higher number of unplanned outage days at the Lennox GS for maintenance and repair activities, partially offset by the unplanned outage days at the Thunder Bay GS prior to its closure.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the OEFC, long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuances. These sources are used for multiple purposes including: to invest in plants and technologies, undertake major projects and business acquisitions, fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, make payments under the OPEB plans, fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, service and repay long-term debt, and provide general working capital.

Changes in cash and cash equivalents for the three and nine month periods ended September 30, 2019 and 2018 as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2019**	**2018**	**2019**	**2018**
Cash, cash equivalents and restricted cash, beginning of period	**563**	585	**313**	234
Cash flow provided by operating activities	**743**	524	**1,928**	1,163
Cash flow used in investing activities	**(646)**	(489)	**(1,675)**	(1,632)
Cash flow provided by (used in) financing activities	**810**	(99)	**905**	756
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**3**	-	**2**	-
Net increase (decrease) in cash, cash equivalents and restricted cash	**910**	(64)	**1,160**	287
Cash, cash equivalents and restricted cash, end of period	**1,473**	521	**1,473**	521

For a discussion of cash flow provided by operating activities, refer to the details in the section, *Highlights* under the heading, *Cash Flow from Operations*.

Investing Activities

Cash flow used in investing activities during the three months ended September 30, 2019 increased by $157 million compared to the same period in 2018, primarily due to the acquisition of the remaining 50 percent of the Brighton Beach GS on August 30, 2019.

Cash flow used in investing activities during the nine months ended September 30, 2019 increased by $43 million, compared to the same period in 2018. The increase was primarily due to higher investment in fixed assets in 2019, the acquisition of the remaining 50 percent of Brighton Beach GS on August 30, 2019 and the one-time receipt of proceeds from the sale of the former Lakeview GS site in March 2018, partially offset by the purchases of Investment Interests from the IESO by the Fair Hydro Trust (the Trust) in 2018.

Financing Activities

Cash flow provided by financing activities for the three months ended September 30, 2019 increased by $909 million compared to the same period in 2018. The increase is primarily due to the issuance of $800 million of Medium Term Notes in September 2019 and the issuance of $100 million of senior notes payable to the OEFC in August 2019.

Cash flow provided by financing activities for the nine months ended September 30, 2019 increased by $149 million, compared to the same period in 2018. The increase was primarily due to higher net issuances of OPG long-term debt in 2019 and the special dividend paid to the Shareholder in March 2018, partially offset by the net issuance of the Fair Hydro Trust long-term debt and proceeds received from the issuances of Class A shares to the Province in 2018.

Share Capital

As at September 30, 2019 and December 31, 2018, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder, the Province.

As at September 30, 2019 and December 31, 2018, OPG had 18,343,815 Class A shares issued and outstanding at a stated value of $787 million.

Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Regulatory Authority of Ontario in September 2019, with an effective date of January 1, 2019. The annual funding requirements in accordance with the new actuarial valuation are $178 million for 2019, $181 million for 2020, and $183 million for 2021. The next actuarial valuation must have an effective date no later than January 1, 2022.

BALANCE SHEET HIGHLIGHTS

Highlights of OPG's interim consolidated financial position are noted below:

(millions of dollars)	As At September 30 2019	 December 31 2018
Property, plant and equipment – net	**24,374**	22,987
The increase was primarily due to capital expenditures on the Darlington Refurbishment, the recognition of the Brighton Beach GS within property, plant and equipment following the acquisition of the remaining 50 percent interest in August 2019, and investments in other capital projects, partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**18,087**	17,483
The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities.		
Long-term debt *(current and non-current portions)*	**7,911**	7,556
The increase was primarily due to the issuance of senior notes payable under the Company's Medium Term Note Program, partially offset by the derecognition of long-term debt issued by the Fair Hydro Trust upon deconsolidation of the Trust effective May 9, 2019.		
Fixed asset removal and nuclear waste management liabilities	**21,876**	21,225
The increase was primarily a result of accretion expense, partially offset by expenditures on nuclear fixed asset removal and nuclear 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 consolidated financial statements or are recorded in the Company's consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities 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 OPG's audited consolidated financial statements as at and for the year ended December 31, 2018. A discussion of recent accounting pronouncements and changes in accounting estimate is 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, 2019. OPG's critical accounting policies are consistent with those noted in OPG's 2018 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 2018 annual MD&A.

Risks to Maintaining Financial Strength

Acquisition and Growth Strategy

There are execution and integration risks associated with the Company's acquisition and growth strategy with the potential to cause realized value to differ from baseline projections. To mitigate these risks, OPG conducts detailed due diligence and has put in place a robust process for integrating acquisitions. Additionally, OPG is engaged in open and transparent communication with the acquired companies to build forward momentum and employee engagement throughout the process.

Government Legislation and Regulation Changes

In August 2019, legislation to amend the *Fisheries Act* to further protect fish and fish habitat and the *Impact Assessment Act* came into force. There is a risk that strengthened fish and fish habitat protection provisions under the *Fisheries Act* may affect OPG's hydroelectric operations. To mitigate this risk, OPG and its industry partners are working with Fisheries and Oceans Canada to develop the codes, policies and procedures that will determine how the regime is administered. OPG is also developing a compliance strategy. The *Impact Assessment Act* and its supporting regulations are not expected to impact OPG's current projects.

Commodity Markets

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

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

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

	2019 [1]	**2020**	**2021**
Estimated fuel requirements hedged [2]	73%	76%	75%

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2019 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected electricity generation (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 rate regulation. In the case of hydroelectric electricity generation in Ontario, 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 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 primarily denominated in or tied to US dollars. 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, 2019, OPG had no foreign exchange contracts outstanding. In addition, volatility in the Canadian/US foreign exchange rate also impacts OPG's financial results from its Eagle Creek subsidiary, whose operations are based exclusively in the US.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, and treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit exposure relating to energy markets transactions as at September 30, 2019 was $480 million, including $465 million with the IESO. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market in Ontario. 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.

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

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. 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.

Related party transactions are summarized below:

	Three Months Ended September 30			
	2019		**2018**	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**-**	**-**	2	-
Services	**-**	**6**	-	2
Dividends	**2**	**-**	1	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**44**	-	(39)
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**51**	-	(48)
Hydroelectric gross revenue charge	**-**	**24**	-	24
OEFC				
Hydroelectric gross revenue charge	**-**	**59**	-	61
Interest expense on long-term notes	**-**	**33**	-	38
Income taxes	**-**	**91**	-	58
IESO				
Electricity-related revenue	**1,387**	**-**	1,300	-
Earnings from Fair Hydro Trust [2]	**-**	**-**	19	-
Fair Hydro Trust				
Interest income [2]	**8**	**-**	-	-
	1,397	**308**	1,322	96

[1] The Nuclear Segregated Funds are reported on OPG's consolidated balance sheets net of amounts recognized as due to the Province in respect of any excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2019 and December 31, 2018, the Nuclear Segregated Funds were reported net of amounts due to the Province of $5,079 million and $3,496 million, respectively.

[2] The Fair Hydro Trust was deconsolidated from OPG's consolidated financial results effective May 9, 2019. As a result, certain transactions that were previously eliminated on consolidation, including interest income earned by OPG from its investment in the Trust's subordinated debt, are now treated as transactions with entities outside of OPG, and are disclosed as related party transactions. Earnings from the Trust are for the period prior to the deconsolidation of the Trust and primarily comprise net interest income earned by the Trust from the IESO on financing receivables, which were consolidated within OPG's financial results up to May 9, 2019.

	Nine Months Ended September 30			
	2019		**2018**	
(millions of dollars)	**Income**	**Expense**	**Income**	**Expense**
Hydro One				
Electricity sales	**5**	**-**	8	-
Services	**-**	**12**	-	9
Dividends	**5**	**-**	5	-
Province of Ontario				
Change in Decommissioning Segregated Fund amount due to Province [1]	**-**	**712**	-	63
Change in Used Fuel Segregated Fund amount due to Province [1]	**-**	**871**	-	72
Hydroelectric gross revenue charge	**-**	**82**	-	80
OEFC				
Hydroelectric gross revenue charge	**-**	**157**	-	156
Interest expense on long-term notes	**-**	**103**	-	112
Income taxes	**-**	**256**	-	152
IESO				
Electricity-related revenue	**4,148**	**-**	3,694	-
Earnings from Fair Hydro Trust [2]	**24**	**-**	47	-
Fair Hydro Trust				
Interest income [2]	**12**	**-**	-	-
	4,194	**2,193**	3,754	644

[1] The Nuclear Segregated Funds are reported on OPG's consolidated balance sheets net of amounts recognized as due to the Province in respect of any excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2019 and December 31, 2018, the Nuclear Segregated Funds were reported net of amounts due to the Province of $5,079 million and $3,496 million, respectively.

[2] The Fair Hydro Trust was deconsolidated from OPG's consolidated financial results effective May 9, 2019. As a result, certain transactions that were previously eliminated on consolidation, including interest income earned by OPG from its investment in the Trust's subordinated debt, are now treated as transactions with entities outside of OPG, and are disclosed as related party transactions. Earnings from the Trust are for the period prior to the deconsolidation of the Trust and primarily comprise net interest income earned by the Trust from the IESO on financing receivables, which were consolidated within OPG's financial results up to May 9, 2019.

Balances between OPG and its related parties are summarized below:

(millions of dollars)	September 30 2019	December 31 2018
Receivables from related parties		
Hydro One	**8**	1
IESO - Electricity-related receivables	**460**	478
Fair Hydro Trust [1]	**12**	-
IESO - Fair Hydro Trust [2]	**-**	2
OEFC	**3**	-
PEC	**-**	2
Province of Ontario	**2**	-
Loan receivable		
Fair Hydro Trust [2]	**928**	-
Financing receivables		
IESO - Fair Hydro Trust [2]	**-**	1,788
Equity securities		
Hydro One shares	**165**	153
Accounts payable and accrued charges		
Hydro One	**3**	4
OEFC	**35**	50
Province of Ontario	**6**	8
IESO - Electricity-related payables	**4**	8
IESO - Fair Hydro Trust [2]	**-**	13
Long-term debt (including current portion)		
Notes payable to OEFC	**3,220**	3,400

[1] Represents the receivable balance from interest income earned by OPG from its investment in the Trust's subordinated debt.

[2] The Fair Hydro Trust was deconsolidated from OPG's consolidated results effective May 9, 2019. As a result, certain balances are no longer recognized in OPG's consolidated balance sheet. The loan receivable represents OPG's investment in the subordinated debt issued by the Fair Hydro Trust with a face value of $876 million, and is reported on OPG's consolidated balance sheet subsequent to the deconsolidation date.

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2019, the Nuclear Segregated Funds held $1,512 million of Province of Ontario bonds (December 31, 2018 – $1,399 million) and $18 million of Province of Ontario treasury bills (December 31, 2018 – $2 million). As of September 30, 2019, the registered pension fund held $69 million of Province of Ontario bonds (December 31, 2018 − $41 million) and $2 million of Province of Ontario treasury bills (December 31, 2018 – nil). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

INTERNAL CONTROL OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal control 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 financial statements.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected operational and 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)	**September 30 2019**	**June 30 2019**	**March 31 2019**	**December 31 2018**
Electricity generation (*TWh*)	**19.1**	20.2	19.1	19.7
Revenue	**1,508**	1,566	1,426	1,475
Net income	**323**	356	217	265
Less: Net income attributable to non-controlling interest	**4**	5	4	5
Net income attributable to the Shareholder	**319**	351	213	260
Earnings per share, attributable to the Shareholder *(dollars)*	**$1.16**	$1.28	$0.78	$0.95

(millions of dollars – except where noted)	**September 30 2018**	**June 30 2018**	**March 31 2018**	**December 31 2017**
Electricity generation (*TWh*)	18.3	17.2	18.8	18.1
Revenue	1,373	1,282	1,407	1,619
Net income	283	126	539	366
Less: Net income attribute to the non-controlling interest	4	5	4	4
Net income attributable to the Shareholder	279	121	535	362
Earnings per share, attributable to the Shareholder *(dollars)*	$1.02	$0.44	$1.99	$1.41

KEY OPERATING PERFORMANCE INDICATORS AND NON-GAAP FINANCIAL MEASURES

Key Operating Performance Measures

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate imperatives include measures of production reliability, cost effectiveness, environmental performance and safety performance. Certain of the measures used vary depending on the generating technology.

Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities that are not designed for fluctuating production levels to meet peaking demand. The nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. An outage day represents a single unit being offline or derated for an amount of time equivalent to one day. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS has been excluded from the measure since October 2016, when the unit was taken offline as part of the Darlington Refurbishment project. As at September 30, 2019, the Darlington GS had three units in service and the Pickering GS had six units in service.

Hydroelectric Availability

OPG's hydroelectric stations operate as baseload, intermediate or peaking stations. Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period, weighted by unit capacity.

Thermal Equivalent Forced Outage Rate

EFOR is an index of the reliability of a generating unit at OPG's wholly owned thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

Other Key Indicators

In addition to production reliability, cost effectiveness and financial performance indicators, OPG has identified certain environmental and safety performance measures. As applicable, these measures are discussed in the section, *Environmental, Social, Governance and Sustainability*.

Non-GAAP Financial Performance 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 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 an indicator of OPG's financial performance consistent with its objective to deliver value to the Shareholder. It 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)	**September 30 2019**	**December 31 2018**
ROE Excluding AOCI		
Net income attributable to the Shareholder	**1,143**	1,195
Divided by: Average equity attributable to the Shareholder, excluding AOCI	**13,536**	12,623
ROE Excluding AOCI *(percent)*	**8.4**	9.5

(2) **Enterprise Total Generating Cost per MWh** is used to measure the overall cost performance of OPG's generating operations in Ontario. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project, other generation development project and business development costs, Eagle Creek, the impact of regulatory accounts, the Fair Hydro Trust, 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 accounts) and capital expenditures (excluding the Darlington Refurbishment project, other generation development projects and Eagle Creek) incurred during the period, divided by total electricity generation from OPG-operated generating stations in Ontario plus electricity generation forgone due to SBG conditions in Ontario during the period.

Enterprise TGC per MWh is calculated as follows for the three and nine month periods ended September 30, 2019 and September 30, 2018:

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted)	**2019**	**2018**	**2019**	**2018**
Enterprise TGC				
Total OM&A expenses	**661**	638	**2,091**	2,103
Total fuel expense	**172**	175	**495**	496
Total capital expenditures	**501**	527	**1,485**	1,282
Less: Darlington Refurbishment capital and OM&A costs	**(289)**	(290)	**(902)**	(807)
Less: Other generation development project and business development capital and OM&A costs	**(28)**	(59)	**(75)**	(104)
(Less) Add: OM&A and fuel expenses (refundable through) deferred in regulatory accounts	**(14)**	10	**(53)**	38
Less: Nuclear fuel expense for non OPG-operated stations	**(19)**	(16)	**(48)**	(48)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**10**	8	**31**	29
Less: OM&A expenses ancillary to electricity generation business	**(4)**	(5)	**(16)**	(12)
Less: OM&A expenses and capital expenditures related to Eagle Creek	**(16)**	-	**(62)**	-
Other adjustments	**(2)**	(2)	**(13)**	(3)
	972	986	**2,933**	2,974
Adjusted electricity generation *(TWh)*				
Total OPG electricity generation	**19.1**	18.3	**58.4**	54.3
Adjust for electricity generation forgone due to SBG conditions, OPG's share of electricity generation from co-owned facilities and Eagle Creek's electricity generation	**0.3**	0.1	**1.7**	1.8
	19.4	18.4	**60.1**	56.1
Enterprise TGC per MWh *($/MWh)* [1]	**50.41**	53.64	**48.89**	53.02

[1] Amounts may not calculate due to rounding.

(3) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets in Ontario. 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 accounts and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory 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.

Nuclear TGC per MWh is calculated as follows for the three and nine month periods ended September 30, 2019 and September 30, 2018:

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars – except where noted)	**2019**	**2018**	**2019**	**2018**
Nuclear TGC				
Regulated – Nuclear Generation OM&A expenses	**515**	507	**1,679**	1,731
Regulated – Nuclear Generation fuel expense	**75**	73	**218**	208
Regulated – Nuclear Generation capital expenditures	**399**	409	**1,188**	1,041
Less: Darlington Refurbishment capital and OM&A costs	**(289)**	(290)	**(902)**	(807)
(Less) Add: Regulated – Nuclear Generation OM&A and fuel expenses (refundable through) deferred in regulatory accounts	**(13)**	11	**(48)**	46
Less: Nuclear fuel expense for non OPG-operated stations	**(19)**	(16)	**(48)**	(48)
Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business	**(1)**	(1)	**(4)**	(4)
Other adjustments	**1**	(2)	**(5)**	(4)
	668	691	**2,078**	2,163
Nuclear electricity generation (TWh)	**11.6**	10.6	**32.7**	29.6
Nuclear TGC per MWh (*$/MWh*) [1]	**57.91**	64.72	**63.61**	73.05

[1] Amounts may not calculate due to rounding.

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

Hydroelectric TGC per MWh is calculated as follows for the three and nine month periods ended September 30, 2019 and September 30, 2018:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	**2019**	**2018**	**2019**	**2018**
Hydroelectric TGC				
Regulated – Hydroelectric OM&A expenses	**82**	83	**244**	245
Regulated – Hydroelectric fuel expense	**84**	87	**242**	242
Contracted and Other Generation OM&A expenses	**51**	43	**150**	127
Contracted and Other Generation fuel expense	**13**	15	**35**	46
Regulated – Hydroelectric and Contracted and Other Generation capital expenditures	**78**	104	**236**	204
Less: Regulated – Hydroelectric and Contracted and Other Generation development project capital and OM&A costs (excluding Eagle Creek)	**(13)**	(53)	**(54)**	(99)
Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted and Other Generation segment	**(35)**	(44)	**(103)**	(130)
Less: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory accounts	**(1)**	(1)	**(5)**	(8)
Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions	**10**	8	**31**	29
Less: OM&A expenses and capital expenditures related to Eagle Creek	**(16)**	-	**(62)**	-
Other adjustments	**(1)**	-	**(2)**	-
	252	242	**712**	656
Adjusted hydroelectric electricity generation *(TWh)*				
Regulated – Hydroelectric electricity generation	**6.8**	7.0	**23.1**	22.3
Contracted and Other Generation electricity generation	**0.7**	0.7	**2.6**	2.4
Adjust for hydroelectric electricity generation forgone due to SBG conditions, Eagle Creek's electricity generation, and non-hydroelectric electricity generation of the Contracted and Other Generation segment, including OPG's share of generation from co-owned facilities	**0.2**	-	**1.6**	1.7
	7.7	7.7	**27.3**	26.4
Hydroelectric TGC per MWh ***($/MWh)*** [1]	**32.66**	31.48	**26.17**	24.87

[1] Amounts may not calculate due to rounding.

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

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ONTARIO POWER GENERATION INC.

INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)

SEPTEMBER 30, 2019

ONTARIO POWER GENERATION

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2019	**2018**	**2019**	**2018**
Revenue	**1,508**	1,373	**4,500**	4,062
Fuel expense	**172**	175	**495**	496
Gross margin	**1,336**	1,198	**4,005**	3,566
Operations, maintenance and administration	**661**	638	**2,091**	2,103
Depreciation and amortization	**268**	200	**798**	584
Accretion on fixed asset removal and nuclear waste management liabilities	**254**	245	**764**	739
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(225)**	(216)	**(668)**	(638)
Property taxes	**11**	10	**32**	28
Income from investments subject to significant influence	**(10)**	(12)	**(33)**	(32)
	959	865	**2,984**	2,784
Income before other gains, interest and income taxes	**377**	333	**1,021**	782
Other gains *(Note 20)*	**(13)**	-	**(45)**	(266)
Income before interest and income taxes	**390**	333	**1,066**	1,048
Net interest expense *(Note 8)*	**5**	19	**35**	56
Income before income taxes	**385**	314	**1,031**	992
Income tax expense	**62**	31	**135**	44
Net income	**323**	283	**896**	948
Net income attributable to the Shareholder	**319**	279	**883**	935
Net income attributable to non-controlling interest	**4**	4	**13**	13
Basic and diluted earnings per share *(dollars) (Note 16)*	**1.16**	1.02	**3.22**	3.43

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

(millions of dollars)	Three Months Ended September 30 2019	2018	Nine Months Ended September 30 2019	2018
Net income	**323**	283	**896**	948
Other comprehensive income (loss), net of income taxes *(Note 11)*				
Reclassification to income of amounts related to pension and other post-employment benefits [1]	**2**	2	**7**	7
Reclassification to income of losses on derivatives designated as cash flow hedges [2]	**4**	4	**11**	13
Currency translation adjustment [3]	**9**	-	**(11)**	-
Other comprehensive income for the period	**15**	6	**7**	20
Comprehensive income	**338**	289	**903**	968
Comprehensive income attributable to the Shareholder	**334**	285	**890**	955
Comprehensive income attributable to non-controlling interest	**4**	4	**13**	13

1 Net of income tax expenses of nil and $1 million for the three months ended September 30, 2019 and 2018, respectively. Net of income tax expenses of $2 million and $3 million for the nine months ended September 30, 2019 and 2018, respectively.

2 Net of income tax expense of $1 million for the three months ended September 30, 2019 and 2018, respectively. Net of income tax expenses of $2 million for the nine months ended September 30, 2019 and 2018, respectively.

3 Net of income tax expense of nil for the three months and nine months ended September 30, 2019 and 2018, 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)*	**2019**	**2018**
Operating activities		
Net income	**896**	948
Adjust for non-cash items:		
Depreciation and amortization	**798**	584
Accretion on fixed asset removal and nuclear waste management liabilities	**764**	739
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(668)**	(638)
Pension and other post-employment benefit costs *(Note 12)*	**328**	297
Deferred income taxes	**(75)**	(29)
Regulatory assets and regulatory liabilities	**268**	(96)
Other gains	**(25)**	(241)
Other	**(30)**	(27)
Expenditures on fixed asset removal and nuclear waste management	**(240)**	(218)
Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management	**65**	73
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(239)**	(243)
Distributions received from investments subject to significant influence	**44**	37
Net changes to other long-term assets and long-term liabilities	**24**	102
Net changes to non-cash working capital balances *(Note 19)*	**18**	(125)
Cash flow provided by operating activities	**1,928**	1,163
Investing activities		
Investment in property, plant and equipment and intangible assets	**(1,547)**	(1,296)
Acquisition of Brighton Beach generating station, net of cash acquired *(Note 3)*	**(128)**	-
Net proceeds from sale of property, plant and equipment	**-**	273
Acquisition of Fair Hydro Trust financing receivables	**-**	(609)
Cash flow used in investing activities	**(1,675)**	(1,632)
Financing activities		
Issuance of short-term debt	**3,088**	2,799
Repayment of short-term debt	**(3,278)**	(2,991)
Net proceeds from issuance of OPG long-term debt *(Note 8)*	**1,393**	1,047
Repayment of OPG long-term debt	**(290)**	(377)
Net proceeds from issuance of Fair Hydro Trust long-term debt	**-**	1,206
Repayment of Fair Hydro Trust revolving warehouse debt	**-**	(900)
Issuance of Class A shares	**-**	268
Distribution to non-controlling interest	**(13)**	(13)
Contribution from non-controlling interest	**5**	-
Dividend to the Province's Consolidated Revenue Fund	**-**	(283)
Cash flow provided by financing activities	**905**	756
Effect of exchange rate changes on cash, cash equivalents and restricted cash	**2**	-
Net increase in cash, cash equivalents and restricted cash	**1,160**	287
Cash, cash equivalents and restricted cash, beginning of period	**313**	234
Cash, cash equivalents and restricted cash, end of period	**1,473**	521

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2019**	**December 31 2018**
Assets		
Current assets		
Cash, cash equivalents and restricted cash *(Note 5)*	**1,473**	313
Equity securities	**165**	153
Receivables from related parties	**485**	483
Nuclear fixed asset removal and nuclear waste management funds	**32**	19
Inventory	**378**	397
Regulatory assets *(Note 7)*	**532**	490
Prepaid expenses	**122**	116
Other current assets	**120**	167
	3,307	2,138
Property, plant and equipment	**34,057**	32,209
Less: accumulated depreciation	**9,683**	9,222
	24,374	22,987
Intangible assets	**495**	467
Less: accumulated amortization	**245**	211
	250	256
Goodwill	**104**	107
Other non-current assets		
Nuclear fixed asset removal and nuclear waste management funds	**18,055**	17,464
Loan receivable *(Note 4)*	**928**	-
Financing receivables *(Note 4)*	**-**	1,788
Inventory	**384**	347
Regulatory assets *(Note 7)*	**6,475**	6,769
Investments subject to significant influence	**259**	339
Other long-term assets	**62**	57
	26,163	26,764
	54,198	52,252

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2019**	**December 31 2018**
Liabilities		
Current liabilities		
Accounts payable, accrued charges and other payables	**1,067**	1,207
Short-term debt *(Note 9)*	**120**	322
Long-term debt due within one year *(Note 8)*	**733**	368
Regulatory liabilities *(Note 7)*	**105**	36
	2,025	1,933
Long-term debt *(Note 8)*	**7,178**	7,188
Other non-current liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 10)*	**21,876**	21,225
Pension liabilities	**3,561**	3,642
Other post-employment benefit liabilities	**2,760**	2,697
Long-term accounts payable and accrued charges	**279**	250
Deferred revenue	**403**	410
Deferred income taxes	**1,130**	1,018
Regulatory liabilities *(Note 7)*	**925**	762
	30,934	30,004
Equity		
Common shares *(Note 15)*	**5,126**	5,126
Class A shares *(Note 15)*	**787**	787
Contributed surplus *(Note 4)*	**39**	-
Retained earnings	**8,175**	7,292
Accumulated other comprehensive loss *(Note 11)*	**(236)**	(243)
Equity attributable to the Shareholder	**13,891**	12,962
Equity attributable to non-controlling interest	**170**	165
Total equity	**14,061**	13,127
	54,198	52,252

Commitments and Contingencies *(Notes 8 and 17)*

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	**2019**	**2018**
Common shares *(Note 15)*	**5,126**	5,126
Class A shares *(Note 15)*		
Balance at beginning of period	**787**	519
Issuance of Class A shares	**-**	268
Balance at end of period	**787**	787
Contributed Surplus		
Balance at beginning of period	**-**	-
Gain on deconsolidation of Fair Hydro Trust *(Note 4)*	**39**	-
Balance at end of period	**39**	-
Retained earnings		
Balance at beginning of period	**7,292**	6,396
Reclassification of cumulative unrealized losses on equity securities to opening retained earnings	**-**	(9)
Adjustment to recognize income tax effects of intercompany transfer of assets to opening retained earnings	**-**	(7)
	7,292	6,380
Net income attributable to the Shareholder	**883**	935
Dividend to the Province's Consolidated Revenue Fund	**-**	(283)
Balance at end of period	**8,175**	7,032
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of period	**(243)**	(295)
Reclassification of cumulative unrealized losses on equity securities to opening retained earnings	**-**	9
	(243)	(286)
Other comprehensive income	**7**	20
Balance at end of period	**(236)**	(266)
Equity attributable to the Shareholder	**13,891**	12,679
Equity attributable to non-controlling interest		
Balance at beginning of period	**165**	165
Income attributable to non-controlling interest	**13**	13
Distribution to non-controlling interest	**(13)**	(13)
Equity contribution from non-controlling interest	**5**	-
Balance at end of period	**170**	165
Total equity	**14,061**	12,844

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, 2019 and 2018

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and nine months ended September 30, 2019 and 2018 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 (the Province or the Shareholder). 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, 2018.

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant.

In April 2018, OPG received an extension to its previous exemptive relief from the OSC. The exemptive relief will now terminate on the earliest of the following:

- January 1, 2024;
- The financial year that commences after OPG ceases to have activities subject to rate regulation; or
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

All dollar amounts are presented in Canadian dollars, unless otherwise noted. Certain 2018 comparative amounts have been reclassified from financial statements previously presented to conform to the 2019 interim consolidated financial statement presentation.

Seasonal Variations

OPG's quarterly electricity generation from the Regulated – Hydroelectric and Contracted and Other Generation segments is affected by changes in grid-supplied electricity demand. Changes in grid-supplied electricity demand are primarily caused by 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. OPG's quarterly electricity generation from hydroelectric facilities is also impacted by weather conditions that affect water flows. The financial impact of variability in water flows on the Regulated – Hydroelectric segment is mitigated by Ontario Energy Board (OEB)-authorized regulatory variance and deferral accounts (regulatory accounts). The financial impact of variability in electricity generation from the Contracted and Other Generation segment is largely mitigated by the terms of the applicable Energy Supply Agreements for the contracted generating facilities in Ontario.

Electricity generation and financial results of the Regulated – Nuclear Generation segment are primarily impacted by outage activities at the nuclear generating stations. The frequency and timing of planned outages under a station's outage cycle may result in period-over-period variability in OPG's financial results, including the impact on revenue and operating, maintenance and administration expenses.

2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

The accounting policies followed in the presentation of these interim consolidated financial statements are consistent with those of the previous financial year, with the exception of the adoption of the new lease accounting standard, a new policy for loan receivables, changes in OPG's variable interest entities and future accounting pronouncements noted below:

New Accounting Standards Effective in 2019

Lease Accounting

In February 2016, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2016-02, *Leases* (Topic 842) to replace existing lease accounting guidance under *Leases* (Topic 840). The update included comprehensive changes to existing guidance, particularly for lessees, with the aim of increasing transparency and comparability among organizations by requiring the recognition of right-of-use assets and lease liabilities on the balance sheet.

Effective January 1, 2019, OPG adopted Topic 842, utilizing the optional transition method wherein any cumulative impact from adopting the new standard is recognized as an adjustment to opening balances in the initial period of adoption, with comparative periods continuing to be presented in accordance with Topic 840, including disclosures. In transitioning to Topic 842, the Company elected to adopt the package of practical expedients, which permitted OPG to continue the established classification of leases under Topic 840, and did not require a reassessment of the existence of leases within existing or expired contracts nor the treatment of related indirect costs for previously established leases. OPG also adopted the practical expedient within ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842*, permitting the Company to not undertake an evaluation of existing or expired land easements under this accounting standard prior to its adoption. Any new land easements entered into following adoption of the new standard, along with modification of existing land easements, will be assessed under Topic 842.

A contract is determined to contain a lease if it consists of an identified asset, and the customer in the arrangement has the right to control the use of the asset for a period of time in exchange for consideration. Property, plant or equipment that is physically distinct or whose capacity is substantially received by the customer is representative of an identified asset. The customer's right to control the use of an identified asset is signified by its rights to obtain substantially all of the economic benefits from the use of the asset and to direct the use of the asset, throughout the period of use. A customer is able to direct the use of the asset if they have the decision-making rights that will most impact the economic benefits derived. Unless explicitly stated, it is presumed an arrangement does not contain substantive substitution rights, wherein it is impractical for the supplier to substitute alternative assets throughout the period of use or obtain any economic benefits from substituting.

As a practical expedient for leasing arrangements in which OPG is the lessee, the lease and non-lease components, if any, are combined and accounted for as a single lease cost. Similarly, as a practical expedient for leasing arrangements in which OPG is the lessor, the Company combines the lease and any non-lease components, and accounts for it as a single lease component. OPG does not account for any non-lease components separately from the combined component.

For arrangements in which OPG is the lessor, the Company has excluded all taxes assessed by a governmental authority on the lease revenue producing transaction, from the consideration in the contract and from variable payments not included in the consideration in the contract.

As permitted by the short-term lease exemption in the standard, OPG has elected not to apply the recognition requirements prescribed by Topic 842 for its short-term leases. Such arrangements include leases that have a term of 12 months or less at the commencement date and do not contain an option to purchase the underlying asset that the entity is reasonably certain to exercise.

When determinable, the rate implicit in the lease is used as the discount rate to calculate the present value of the lease payments related to arrangements in which the Company is the lessee. Otherwise, the incremental borrowing rate is used, which represents the rate of interest OPG would have to pay to borrow on a collateralized basis over a similar term an amount equal to the lease payments in a similar economic environment. The incremental borrowing rate for each lease is determined on inception of the leasing arrangement by obtaining an appropriate reference rate, to which any financing spread and lease specific adjustments are applied. The discount rate is reassessed if the respective lease liability is required to be re-measured because of changes in key assumptions or modifications in the underlying contract.

As at January 1, 2019, on implementation of Topic 842, the Company recognized:

(millions of dollars)	**January 1, 2019**	**Balance Sheet Line Item**
Right-of-use asset		
Current	**15**	Other current assets
Non-current	**59**	Property, plant and equipment
	74	
Operating lease liabilities		
Current	**15**	Accounts payable, accrued charges and other payables
Non-current	**63**	Long-term accounts payable and accrued charges
	78	

New Accounting Policy

Loan Receivables

Loan receivables are financial assets with fixed or determined payments that are not quoted in an active market. Loan receivables are initially recorded at fair value, and subsequently recorded at amortized cost using the effective interest method. The loan receivable relates to subordinated notes issued by the Fair Hydro Trust (the Trust) to OPG.

Variable Interest Entities

In March 2019, the Government of Ontario tabled Bill 87, *Fixing the Hydro Mess Act, 2019* (Fixing the Hydro Mess Act), proposed legislation to amend various statutes related to energy, including the *Ontario Fair Hydro Plan Act, 2017* (Fair Hydro Act). The Fixing the Hydro Mess Act received Royal Assent on May 9, 2019, resulting in OPG no longer having a variable interest in the Trust as defined in ASC 810 *Consolidation*, resulting in the deconsolidation of the Trust effective May 9, 2019. Refer to Note 4 for further discussion.

OPG continues to consolidate one variable interest entity, the Nuclear Waste Management Organization.

Use of Management Estimates

The preparation of interim 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 estimate 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 (PP&E), income taxes (including deferred income taxes), contingencies, regulatory assets and regulatory liabilities, goodwill and intangible assets, valuation of investments in segregated funds, depreciation and amortization expenses and inventories. Actual results may differ significantly from these estimates.

Recent Accounting Pronouncements Not Yet Adopted

i) Changes to Disclosure Requirements for Defined Benefit Plans

In August 2018, the FASB issued ASU No. 2018-14, *Compensation – Retirement Benefits – Defined Benefit Plans – General* (Subtopic 715-20): *Disclosure Framework – Changes to the Disclosure Requirements for Defined Benefit Plans* as part of its ongoing efforts to improve the effectiveness of disclosures in notes to financial statements for stakeholders. As part of this update, entities will be required to include additional disclosures such as narrative descriptions of the reasons for significant gains and losses related to changes in the benefit obligations for the period. The update also removed guidance that currently requires disclosures on the amounts in accumulated other comprehensive loss (AOCL) expected to be recognized as components of net periodic benefit cost over the next fiscal year, and for public entities, the effects of a one percent change in assumed health care trend rates on the net periodic benefit costs and benefit obligation for OPEB. Changes instituted by this update are effective retrospectively for all periods presented for fiscal years ending after December 15, 2020 with early adoption permitted. OPG is in the process of evaluating the impact from this update on the Company's disclosures for its post-employment benefit programs.

ii) Changes to Disclosure Requirements for Fair Value Measurement

In August 2018, the FASB issued ASU No. 2018-13, *Fair Value Measurement* (Topic 820): *Disclosure Framework – Changes to Disclosure Requirements for Fair Value Measurement* to continue to improve the effectiveness of disclosures in financial statements for users. Under the new guidance prescribed in this update, entities must disclose additional information regarding Level 3 fair value measurements held at the end of the reporting period. This amendment also clarified existing guidance around measurement uncertainty and investments in entities that calculate net asset value (NAV). This update is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019 with early adoption permitted. Additional disclosures stemming from this update will be applied prospectively. OPG is assessing its current fair value measurements to determine the impact from the changes in this update.

3. ACQUISITIONS

Acquisition of Eagle Creek Renewable Energy, LLC

On November 27, 2018, OPG acquired 100 percent ownership interest of Eagle Creek Renewable Energy, LLC (Eagle Creek) for a total cash purchase price of approximately US$298 million (C$386 million), subject to customary working capital and other adjustments. Transaction costs related to the acquisition were expensed in the consolidated statement of income in 2018.

Eagle Creek is a hydropower platform with interests in 76 hydroelectric facilities and two solar facilities throughout the United States (US) on the date of acquisition. The majority of facilities within Eagle Creek's fleet operate in the New England, Midwest and New York power market areas. Eagle Creek generates revenue from supplying electricity under long-term energy and capacity supply contracts and by offering energy and capacity into wholesale spot electricity markets.

The preliminary purchase price allocation of the Eagle Creek acquisition is estimated as follows, using the exchange rate on the acquisition date of $1.00 USD = $1.3289 CAD:

(millions of Canadian dollars)	
Current assets	**39**
Property, plant and equipment	**500**
Intangible assets	**109**
Goodwill	**104**
Other long-term assets	**36**
Total assets	**788**
Current liabilities	**92**
Long-term debt	**284**
Deferred income tax liability	**23**
Other long-term liabilities	**3**
Total liabilities	**402**
Total purchase price	**386**
Cash acquired	**(28)**
Total purchase price, net of cash acquired	**358**

The determination of the fair value of assets acquired and liabilities assumed is based upon management's preliminary estimates and assumptions and reflects the fair value of consideration paid, including customary working capital and other adjustments. The Company continues to review information and perform further analysis prior to finalizing the fair value of the assets acquired and the liabilities assumed within the permitted period of 12 months from the date of acquisition in accordance with US GAAP, including finalizing the componentization of fair value measurements to the individual assets acquired within PP&E.

Goodwill represents the excess of the purchase price over the aggregate fair value of net assets acquired. Contributing factors to the amount recorded as goodwill include synergies to be realized from a complementary hydroelectric generation fleet, the potential of using Eagle Creek as a vehicle for future growth of the business in the US, geographic diversification of operations and access to an experienced senior management team. Goodwill recognized as a result of the acquisition is reported within the Contracted and Other Generation segment.

Acquisition of Brighton Beach Generating Station

On August 30, 2019, OPG acquired the remaining 50 percent interest in the combined-cycle natural gas-fired 560 MW Brighton Beach generating station (GS) located in Windsor, Ontario from ATCO Power Canada Ltd. for $200 million, inclusive of assumed debt, and subject to customary working capital and other adjustments.
The acquisition of the Brighton Beach GS has been treated as an asset acquisition, as substantially all of the fair value of the gross assets acquired is concentrated within the Brighton Beach GS.

The 50 percent interest OPG previously held in the Brighton Beach GS and reported as an investment subject to significant influence was derecognized upon the acquisition, forming a component of the cost of the asset acquisition when recognizing the 100 percent ownership of the facility. No gain or loss was recognized upon derecognition of the investment subject to significant influence. Liabilities assumed in connection with the acquisition were recognized at fair value on the date of acquisition.

The assets acquired and liabilities assumed were recognized at the following values within OPG's consolidated balance sheet on the date of acquisition:

(millions of Canadian dollars)	
Current assets	**17**
Property, plant and equipment	**412**
Total assets	**429**
Current liabilities	**3**
Long-term debt	**153**
Deferred income tax liability	**37**
Fixed asset removal liability	**14**
Other long-term liabilities	**8**
Total liabilities	**215**
Net assets	**214**
Derecognition of carrying value of previously held interest as an investment subject to significant influence	**(76)**
Cash acquired	**(10)**
Total purchase price of remaining 50% acquired, net of cash acquired	**128**

Acquisition of Cube Hydro

Subsequent to the third quarter, on October 7, 2019, OPG completed the acquisition of 100 percent of the equity in Cube Hydro Partners, LLC and affiliate Helix Partners, LLC (collectively, Cube Hydro). Cube Hydro is a hydropower platform with 385 MW of in-service generating capacity spread across 19 hydroelectric facilities throughout the northeastern and southeastern US.

The purchase price of US$1.12 billion is inclusive of assumed debt and subject to customary working capital and other adjustments. The costs related to the acquisition have been expensed in the consolidated statement of income.

Due to the timing of the acquisition closing, the Company is in the process of completing the fair value measurements. The Company will continue to review information and perform further analysis prior to finalizing the allocation of the consideration paid to the fair value of assets acquired and liabilities assumed and preparing the related pro forma information.

Agreement to Acquire Portfolio of Natural Gas-Fired Assets in Ontario

In July 2019, OPG, under a new subsidiary, entered into a purchase agreement with affiliates of TC Energy (formerly TransCanada Corporation) to acquire a portfolio of combined-cycle natural gas-fired plants in Ontario for $2.87 billion, subject to customary working capital and other adjustments. The acquired portfolio includes the 900 MW Napanee GS, the 683 MW Halton Hills GS, and the remaining 50 percent interest in the 550 MW Portlands Energy Centre. The acquisition is subject to a number of closing conditions, including the receipt of various regulatory approvals and the commencement of commercial operations at the Napanee GS. In October 2019, both a pre-merger notification and a request for an Advance Ruling Certificate were filed with the Commissioner of Competition, and the review is currently in process. Closing is expected to occur in the first quarter of 2020.

4. DECONSOLIDATION OF THE FAIR HYDRO TRUST

The Government of Ontario's Fixing the Hydro Mess Act received Royal Assent on May 9, 2019 and came into force in November 2019. Under the legislation, the Province is responsible for paying existing funding obligations administered by the Trust, while OPG is responsible for paying the operating costs of the Trust. As there will be no new Global Adjustment refinancing, and the Province is responsible for the existing funding obligations, including principal payments, administered by the Trust, the Trust is prohibited from issuing any new funding obligations.

The new legislation removes certain elements of control of the Trust from the Company. As a result, OPG determined that it no longer has a variable interest in the Trust, and deconsolidated the Trust as of the date Royal Assent was received for the new legislation. As of May 9, 2019, OPG accounts for its continuing equity investment in the Trust as an equity security held at fair value.

Following the deconsolidation, the carrying value of assets and liabilities of the Trust was derecognized from OPG's consolidated balance sheet, and OPG's continuing investment in the Trust was recorded at fair value at the date of deconsolidation. The amounts deconsolidated from OPG's balance sheet were as follows:

	As of May 9, 2019
Assets	
Financing receivables	**1,788**
Restricted cash	**39**
Total assets derecognized	**1,827**
Liabilities	
Long-term debt	**912**
Other net liabilities	**39**
Total liabilities derecognized	**951**
Net assets derecognized	**876**
Recognition of OPG's investment in subordinated debt issued by the Trust at fair value on May 9, 2019	**928**
Gain on deconsolidation	**52**
Deferred tax expense	**(13)**
After tax gain on deconsolidation	**39**

The fair value of OPG's continuing investment in the subordinated debt issued by the Trust of $928 million is reflective of the fair value of its retained creditor interest in the Trust. The fair value of this receivable is based on indicative pricing from the market and is considered a Level 2 input. As the deconsolidation of the Trust was triggered by legislation introduced by the Province, the after-tax fair value gain of $39 million has been recognized directly within equity, representing a transaction involving entities under common control.

OPG's continuing involvement with the Trust as Financial Services Manager is limited to paying the operating costs incurred by the Trust. Up to the date Royal Assent was received for the new legislation, these transactions were eliminated on consolidation and had no impact on OPG's consolidated statement of income. Following the deconsolidation of the Trust, these transactions represent expenses in OPG's consolidated financial statements.

5. CASH, CASH EQUIVALENTS AND RESTRICTED CASH

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. Restricted cash primarily includes amounts set aside pursuant to requirements of various debt and financing agreements. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market value.

Cash, cash equivalents and restricted cash consist of the following:

As at *(millions of dollars)*	**September 30 2019**	**December 31 2018**
Cash and cash equivalents	**1,453**	196
Restricted cash	**20**	117
Total cash, cash equivalents and restricted cash	**1,473**	313

Proceeds from OPG's green bond issuances are restricted in purpose and are to be used solely to finance eligible investments that offer tangible environmental benefits, as defined in OPG's Green Bond Framework. The net proceeds of $447 million from the first green bond issuance of $450 million in June 2018 were used to finance eligible hydroelectric projects and were held in a segregated account. As at September 30, 2019, there was no restricted cash balance related to the June 2018 green bond issuance (December 31, 2018 − $84 million).

The net proceeds of $498 million from the second green bond issuance of $500 million in January 2019 were used to finance eligible projects as defined in OPG's Green Bond Framework, including the acquisition of Eagle Creek, and were held in a segregated account. As at September 30, 2019, there was no restricted cash balance related to the January 2019 green bond issuance.

Certain cash accounts held within Eagle Creek are restricted for prescribed purposes, including debt service, insurance and general collateral purposes in accordance with applicable contractual arrangements. As at September 30, 2019, the restricted cash balance held within Eagle Creek is $20 million (December 31, 2018 − $17 million).

Prior to deconsolidation of the Fair Hydro Trust in the second quarter of 2019, cash on deposit held by the Trust was subject to contractual restrictions of the Trust's Master Trust Indenture. As a result of the deconsolidation of the Trust, there are no cash or restricted cash amounts related to the Trust as of September 30, 2019 (December 31, 2018 − $16 million).

6. RIGHT-OF-USE ASSETS AND LEASE LIABILITIES

The Company has entered into operating lease arrangements for office space to house key operational activities and personnel. OPG is also party to water power leases and Parks Canada licences that provide the Company with a right-of-use to the underlying lands on which most of its hydroelectric generating stations in Ontario are constructed. In addition, the Company leases vehicles and rail cars for use at its generating stations. OPG does not have any sales-type or direct financing lease arrangements.

While the Company's office leases are subject to fixed base rental charges, the arrangements also contain variable payments to reimburse lessors for provision of common area maintenance services during each year of the lease term. Payments in connection with OPG's water power leases and Parks Canada licences are entirely variable, based on the amount of electricity produced by its hydroelectric generating stations during each year of the lease term. These variable amounts are not included in the measurement of OPG's lease liabilities, but are recognized as a variable lease expense when incurred. Lease payments related to the Company's leased vehicles qualify for the short-term lease recognition exemption given the nature of the arrangement and therefore no right-of-use asset or liability has been recognized.

In leasing arrangements where OPG has the option to extend the lease term, payments associated with renewing the leases are not included in the measurement of their associated lease liabilities or right-of-use assets as they are not reasonably certain of being exercised. Similarly, in leasing arrangements where OPG has the option to terminate the lease prior to the end of the term, payments associated with terminating these leases are not included in the measurement of the lease liabilities or right-of-use assets as they are not reasonably certain of being exercised. OPG has not provided residual value guarantees within its leases, nor is the Company subject to any restrictions or covenants as a result of entering into these leasing arrangements.

During the three and nine months ended September 30, 2019 the Company incurred the following:

(millions of dollars)	**Three Months Ended September 30, 2019**	**Nine Months Ended September 30, 2019**
Variable lease costs	**15**	**55**
Fixed lease costs	**4**	**13**
Short-term lease costs	**1**	**4**
Total operating lease expenses	**20**	**72**
Cash outflows related to operating lease liabilities	**4**	**12**

OPG did not enter into any new operating lease arrangements during the three months ended September 30, 2019. During the three months ended March 31, 2019, OPG entered into new operating lease arrangements resulting in the recognition of $5 million of right-of-use assets and related operating lease liabilities. The Company had a weighted-average remaining lease term of 6.8 years and a weighted-average discount rate in its leasing arrangements of 3.15 percent as at September 30, 2019.

A maturity analysis of the leasing arrangements in which the Company is the lessee has been summarized below, along with a reconciliation to OPG's operating lease liabilities:

(millions of dollars)	**1 Year**	**2 Years**	**3 Years**	**4 Years**	**5 Years**	**Thereafter**	**Total**
Operating lease payments	14	12	11	8	13	8	66
Impact of discounting							(2)
Present value							64

OPG held corresponding current and long-term operating lease liabilities of $14 million and $50 million, respectively, as at September 30, 2019. In addition, the Company held corresponding current and long-term right-of-use assets under operating lease arrangements of $13 million and $47 million, respectively, as at September 30, 2019.

In addition to its lease arrangement with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations, OPG leases various real estate assets to various third-party customers under operating lease arrangements in which the Company is the lessor, providing customers with the right-of-use to assets including land and office space. The Company receives mostly fixed rental payments in connection with these agreements. However, some arrangements contain variable lease payments that are indexed to the applicable Consumer Price Index, with rents being subject to changes in the index over the course of the lease term. The arrangements do not contain any options to purchase the underlying asset from the Company that the lessee is reasonably certain to exercise. As the underlying asset in many of these arrangements is land, the Company expects to derive, at a minimum, the current fair value from these assets at the end of the lease term. OPG undertakes preventative and ongoing maintenance programs, combined with periodic major upgrades, to maintain the residual values of the underlying assets at the end of the lease term. Given the durability of such assets and their ability to hold or even appreciate their value, OPG considers the residual value risk from these leasing arrangements to be nominal.

An analysis of the leasing arrangements in which the Company is the lessor has been summarized below:

(millions of dollars)	**1 Year**	**2 Years**	**3 Years**	**4 Years**	**5 Years**	**Thereafter**	**Total**
Undiscounted operating lease receipts	41	9	38	5	35	655	783

7. REGULATORY ASSETS AND REGULATORY LIABILITIES

The regulatory assets and regulatory liabilities recorded as at September 30, 2019 and December 31, 2018 are as follows:

(millions of dollars)	**September 30 2019**	**December 31 2018**
Regulatory assets		
Variance and deferral accounts authorized by the OEB		
Pension & OPEB Cash Versus Accrual Differential Deferral Account	**834**	783
Pension and OPEB Cost Variance Account	**536**	673
Hydroelectric Surplus Baseload Generation Variance Account	**450**	449
Bruce Lease Net Revenue Variance Account	**161**	141
Rate Smoothing Deferral Account	**78**	-
Other variance and deferral accounts [1]	**72**	118
	2,131	2,164
Interim Period Revenue Shortfall	**254**	519
Pension and OPEB Regulatory Asset *(Note 12)*	**3,402**	3,514
Deferred Income Taxes	**1,220**	1,062
Total regulatory assets	**7,007**	7,259
Less: current portion	**532**	490
Non-current regulatory assets	**6,475**	6,769
Regulatory liabilities		
Variance and deferral accounts authorized by the OEB		
Pension & OPEB Cash Payment Variance Account	**299**	220
Hydroelectric Water Conditions Variance Account	**220**	191
Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account	**219**	124
Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account	**95**	103
Other variance and deferral accounts [2]	**197**	160
Total regulatory liabilities	**1,030**	798
Less: current portion	**105**	36
Non-current regulatory liabilities	**925**	762

[1] Represents amounts for the Nuclear Liability Deferral Account, the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Development Variance Account, the Fitness for Duty Deferral Account and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

[2] Represents amounts for the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account, the Hydroelectric Incentive Mechanism Variance Account, the SR&ED ITC Variance Account and the Capacity Refurbishment Variance Account.

On February 21, 2019, the OEB issued a decision and order that approved a full settlement agreement reached by OPG and intervenors on OPG's requested disposition of regulatory accounts, which resulted in the approval to recover a total of $1,322 million recorded in the Pension & OPEB Cash to Accrual Differential Deferral Account and other balances accumulated in regulatory accounts between January 1, 2016 and December 31, 2017 and $204 million in associated income tax impacts, without adjustments. These income tax impacts were previously recorded as part of the regulatory asset for deferred income taxes. The OEB's decision and order authorized OPG to collect $535 million of the approved balances through incremental nuclear and regulated hydroelectric rate riders for the period from January 1, 2019 to December 31, 2021. The remaining approved balances will be collected after 2021.

Any shortfall or over-recovery of the approved balances in the variance and deferral accounts due to differences between actual and forecast electricity production is recorded in the Nuclear Deferral and Variance Over/Under Recovery Variance Account and the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account authorized by the OEB.

8. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following:

(millions of dollars)	**September 30 2019**	**December 31 2018**
Senior notes payable to the Ontario Electricity Financial Corporation	**3,220**	3,400
Medium Term Notes	**2,250**	950
Lower Mattagami Energy Limited Partnership project debt	**1,595**	1,595
PSS Generating Station Limited Partnership project debt	**245**	245
UMH Energy Partnership project debt	**177**	178
Eagle Creek senior notes	**313**	323
Brighton Beach Power Limited Partnership notes	**124**	-
Fair Hydro Trust senior debt [1]	**-**	900
Other	**21**	21
	7,945	7,612
Less: net fair value discount	**(7)**	(31)
Less: unamortized bond issuance fees	**(27)**	(25)
Less: amounts due within one year	**(733)**	(368)
Long-term debt	**7,178**	7,188

[1] Senior debt owed by the Fair Hydro Trust to external third parties ceased to be recognized in OPG's consolidated financial statements following deconsolidation of the Trust in May 2019.

The following table summarizes the net interest expense:

(millions of dollars)	**Three Months Ended September 30**		**Nine Months Ended September 30**	
	2019	**2018**	**2019**	**2018**
Interest on long-term debt [1]	**83**	75	**242**	215
Interest on short-term debt	**3**	1	**7**	5
Interest income	**(14)**	(2)	**(24)**	(5)
Interest capitalized to property, plant and equipment and intangible assets	**(60)**	(48)	**(172)**	(139)
Interest related to regulatory assets and liabilities [2]	**(7)**	(7)	**(18)**	(20)
Net interest expense	**5**	19	**35**	56

1 Excludes interest on Fair Hydro Trust senior debt. As of May 9, 2019, OPG deconsolidated the Fair Hydro Trust. For additional discussion, refer to Note 4.

2 Includes interest to recognize the cost of financing related to regulatory accounts, as authorized by the OEB, and interest costs deferred in certain regulatory accounts.

In the first quarter of 2019, OPG issued a green bond offering of $500 million under its existing Medium Term Note Program, maturing in 2049. The coupon interest rate on this bond is 4.25 percent.

On September 13, 2019, OPG issued $800 million of senior notes payable under its existing Medium Term Note Program. The issuance consisted of $500 million of senior notes maturing in September 2029 with a coupon interest rate of 2.98 percent and $300 million of senior notes maturing in September 2050 with a coupon rate of 3.65 percent.

On July 17, 2019, OPG established a new $800 million general corporate credit facility agreement with the Ontario Electricity Financial Corporation (OEFC) expiring on December 31, 2021. The coupon rate will be set at the time OPG draws funds from the credit facility, based on the prevailing market rate at that time.

In August 2019, OPG issued senior notes payable to the OEFC totalling $100 million against this facility, maturing in August 2039 with a coupon rate of 3.49 percent.

OPG repaid long-term debt of $140 million, $75 million and $65 million to the OEFC during the first, second and third quarter of 2019, respectively.

In August 2019, OPG recognized long-term debt of $133 million owing by Brighton Beach Power Limited Partnership following the acquisition of the remaining 50 percent in the Brighton Beach GS from ATCO Power Canada Ltd. The debt was recognized at fair value on the date of acquisition of $153 million, with the corresponding fair value premium recognized within long-term debt. The senior bond is payable in quarterly instalments, has a coupon rate of 6.92 percent and expires in March 2024.

9. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches expiring in May 2023. In the second quarter of 2019, OPG renewed and extended $950 million of the credit facility to May 2024. There were no amounts outstanding under the bank credit facility as at September 30, 2019 (December 31, 2018 – nil). There was no commercial paper outstanding under OPG’s commercial paper program as at September 30, 2019 (December 31, 2018 − $170 million).

As at September 30, 2019, 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. The facility consists of a $300 million tranche maturing in August 2024 and a $100 million tranche maturing in August 2020. As at September 30, 2019, there was $120 million of external commercial paper outstanding under LME's commercial paper program (December 31, 2018 − $140 million). A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2019, under the $300 million tranche of LME's credit facility (December 31, 2018 − $55 million).

As at September 30, 2019, OPG maintained $25 million of short-term, uncommitted overdraft facilities (December 31, 2018 − $25 million) and $473 million of short-term, uncommitted credit facilities (December 31, 2018 − $476 million), 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, 2019, a total of $396 million of Letters of Credit had been issued under these facilities (December 31, 2018 − $404 million). This included $364 million for the supplementary pension plans, $31 million for general corporate purposes and $1 million related to the operation of the Portlands Energy Centre.

The Company's short-term, uncommitted credit facilities include 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, 2020. As at September 30, 2019, there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans (December 31, 2018 − $150 million).

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, 2019, total Letters of Credit of $15 million had been issued under these facilities (December 31, 2018 − $15 million).

10. 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, 2019 and December 31, 2018 consist of the following:

As at *(millions of dollars)*	**September 30 2019**	**December 31 2018**
Liability for nuclear used fuel management	**12,935**	12,523
Liability for nuclear decommissioning and nuclear low and intermediate level waste management	**8,640**	8,399
Liability for non-nuclear fixed asset removal	**301**	303
Fixed asset removal and nuclear waste management liabilities	**21,876**	21,225

11. ACCUMULATED OTHER COMPREHENSIVE LOSS

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

	Nine Months Ended September 30, 2019			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Currency Translation Adjustment**	**Total**
AOCL, beginning of period	**(48)**	**(208)**	**13**	**(243)**
Amounts reclassified from AOCL	**11**	**7**	**-**	**18**
Translation of foreign operations	**-**	**-**	**(11)**	**(11)**
Other comprehensive income (loss) for the period	**11**	**7**	**(11)**	**7**
AOCL, end of period	**(37)**	**(201)**	**2**	**(236)**

	Nine Months Ended September 30, 2018			
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and OPEB**	**Equity Securities**	**Total**
AOCL, beginning of period	(66)	(220)	(9)	(295)
Reclassification of cumulative unrealized losses on equity securities to opening retained earnings	-	-	9	9
	(66)	(220)	-	(286)
Amounts reclassified from AOCL	13	7	-	20
Other comprehensive income for the period	13	7	-	20
AOCL, end of period	(53)	(213)	-	(266)

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine months ended September 30, 2019 are as follows:

	Amount Reclassified from AOCL		
(millions of dollars)	**Three Months Ended September 30, 2019**	**Nine Months Ended September 30, 2019**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**5**	**13**	Net interest expense
Income tax recovery	**(1)**	**(2)**	Income tax expense
	4	**11**	
Amortization of amounts related to pension and OPEB			
Actuarial losses	**2**	**9**	See (1) below
Income tax recovery	**-**	**(2)**	Income tax expense
	2	**7**	
Total reclassifications for the period	**6**	**18**	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 12 for additional details).

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and months ended September 30, 2018 are as follows:

	Amount Reclassified from AOCL		
	Three Months Ended	Nine Months Ended	
(millions of dollars)	September 30, 2018		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	(1)	(3)	Income tax expense
	2	7	
Total reclassifications for the period	6	20	

1 These AOCL components are included in the computation of pension and OPEB costs (see Note 12 for additional details).

Existing pre-tax net losses for derivatives of $16 million deferred in AOCL as at September 30, 2019 are expected to be reclassified to net income within the next 12 months.

12. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and OPEB costs for the three months ended September 30, 2019 and 2018 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	2019	2018	2019	2018	2019	2018
Components of cost recognized for the period						
Current service costs	**78**	83	**2**	2	**18**	19
Interest on projected benefit obligation	**152**	142	**4**	3	**25**	27
Expected return on plan assets, net of expenses	**(207)**	(205)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**39**	49	**1**	2	**-**	2
Costs recognized [2]	**62**	69	**7**	7	**43**	48

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, 2019 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $38 million (three months ended September 30, 2018 – $50 million).

2 Pension and OPEB costs for the three months ended September 30, 2019 exclude the net reduction 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, 2018 − net reduction of costs of $25 million).

OPG's pension and OPEB costs for the nine months ended September 30, 2019 and 2018 are as follows:

(millions of dollars)	Registered Pension Plans 2019	Registered Pension Plans 2018	Supplementary Pension Plans 2019	Supplementary Pension Plans 2018	Other Post-Employment Benefits 2019	Other Post-Employment Benefits 2018
Components of cost recognized for the period						
Current service costs	**233**	248	**6**	6	**53**	59
Interest on projected benefit obligation	**457**	425	**10**	9	**76**	81
Expected return on plan assets, net of expenses	**(619)**	(615)	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**117**	148	**4**	5	**-**	5
Costs recognized [2]	**188**	206	**20**	20	**129**	145

[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, 2019 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $112 million (nine months ended September 30, 2018 – $148 million).

[2] Pension and OPEB costs for the nine months ended September 30, 2019 exclude the net reduction of costs of $9 million from the recognition of changes in the regulatory assets and regulatory liabilities for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (nine months ended September 30, 2018 − net reduction of costs of $74 million).

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Regulatory Authority of Ontario in September 2019, with an effective date of January 1, 2019. The annual funding requirements in accordance with the new actuarial valuation are $178 million for 2019, $181 million for 2020, and $183 million for 2021. The next actuarial valuation must have an effective date no later than January 1, 2022.

13. RISK MANAGEMENT AND DERIVATIVES

The management of interest rate, foreign exchange and commodity risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. The fair value of the derivatives totalled a net liability of $8 million as at September 30, 2019 (December 31, 2018 − net liability of $5 million).

Interest Rates

OPG is exposed to risks related to changes in market interest rates. 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. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

Foreign Exchange

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, US dollars. To manage this risk, the Company periodically employs various financial instruments such as forwards and other derivative contracts. In addition, volatility in the Canadian/US foreign exchange rate also impacts OPG's financial results from its Eagle Creek subsidiary, whose operations are based exclusively in the US.

Commodity Prices

OPG is also exposed to fluctuations in commodity prices. Changes in the market prices of nuclear fuels, oil, gas and biomass used to produce electricity can adversely impact OPG's earnings and cash flow from operations. To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

Credit

The majority of OPG's revenues are derived from sales through the Independent Electricity System Operator (IESO) administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at September 30, 2019 was less than $1 million (December 31, 2018 – less than $1 million).

14. FAIR VALUE MEASUREMENTS

The fair value of financial instruments traded in active markets is based on quoted market prices as 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 primarily consist of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as 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.

The fair value of the investments within the Used Fuel Segregated Fund and Decommissioning Segregated Fund's (together the Nuclear Segregated Funds) real assets portfolios are 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.

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 is a summary of OPG's financial instruments and their fair value:

	Fair Value		Carrying Value [1]		
(millions of dollars)	**September 30 2019**	**December 31 2018**	**September 30 2019**	**December 31 2018**	**Balance Sheet Line Item**
Nuclear Segregated Funds (includes current portion) [2]	**18,087**	17,483	**18,087**	17,483	Nuclear fixed asset removal and nuclear waste management funds
Loan receivable - from Fair Hydro Trust	**975**	-	**928**	-	Loan receivable
Financing receivables [3]	**-**	1,868	**-**	1,788	Financing receivables
Investment in Hydro One shares	**165**	153	**165**	153	Equity securities
Payable related to cash flow hedges	**(26)**	(32)	**(26)**	(32)	Long-term accounts payable and accrued charges
Long-term debt – OPG (includes current portion)	**(8,851)**	(6,924)	**(7,911)**	(6,656)	Long-term debt
Long-term debt – Fair Hydro Trust [3]	**-**	(913)	**-**	(900)	Long-term debt
Other financial instruments	**29**	28	**29**	28	Various

[1] The carrying values of other financial instruments included in cash, cash equivalents and restricted cash, receivables from related parties, other current assets, short-term debt and accounts payable, accrued charges and other payables 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. OPG's fair value of the Nuclear Segregated Funds is set not to exceed an amount equal to the funding liability pursuant to the Ontario Nuclear Funds Agreement when the Nuclear Segregated Funds are in a surplus position.

[3] Financing receivables owed to and long-term debt owed by the Fair Hydro Trust to external third parties ceased to be recognized in OPG's consolidated financial statements following deconsolidation of the Trust in May 2019. Refer to Note 4 for further discussion.

The fair value of OPG's long-term debt issued under the Medium Term Note Program is based on indicative pricing from the market. The fair value of these debt instruments is based on Level 2 inputs. The fair value of all other 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.

As a result of the deconsolidation of the Trust following receipt of Royal Assent for the Fixing the Hydro Mess Act, OPG has recognized its subordinated debt investment in the Trust as a loan receivable effective May 9, 2019. The loan receivable is valued using indicative pricing from the market for senior debt, adjusted for the incremental risks associated with the subordinated debt. 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, 2019 and December 31, 2018:

	September 30, 2019			
(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	**5,811**	**5,362**	**-**	**11,173**
Investments measured at NAV [1]				**1,991**
				13,164
Due to Province				**(2,853)**
Used Fuel Segregated Fund, net				**10,311**
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	**4,403**	**3,992**	**-**	**8,395**
Investments measured at NAV [1]				**1,607**
				10,002
Due to Province				**(2,226)**
Decommissioning Segregated Fund, net				**7,776**
Investment in equity securities	**165**	**-**	**-**	**165**
Other financial assets	**1**	**3**	**39**	**43**
Liabilities				
Other financial liabilities	**(13)**	**(1)**	**-**	**(14)**

	December 31, 2018			
(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	5,245	4,926	-	10,171
Investments measured at NAV [1]				1,775
				11,946
Due to Province				(1,982)
Used Fuel Segregated Fund, net				9,964
Decommissioning Segregated Fund				
Investments measured at fair value, excluding investments measured at NAV	3,962	3,635	-	7,597
Investments measured at NAV [1]				1,436
				9,033
Due to Province				(1,514)
Decommissioning Segregated Fund, net				7,519
Investment in equity securities	153	-	-	153
Other financial assets	5	3	43	51
Liabilities				
Other financial liabilities	(19)	(4)	-	(23)

[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 period ended September 30, 2019, there were no transfers between Level 1 and Level 2 and 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, 2019:

(millions of dollars)	**Other financial instruments**
Opening balance, July 1, 2019	**38**
Unrealized gains included in revenue	**1**
Realized losses included in revenue	**(4)**
Purchases	**4**
Closing balance, September 30, 2019	**39**

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, 2019:

(millions of dollars)	**Other financial instruments**
Opening balance, January 1, 2019	**43**
Unrealized losses included in revenue	**(1)**
Realized losses included in revenue	**(13)**
Purchases	**10**
Closing balance, September 30, 2019	**39**

Investments Measured at Net Asset Value

Decommissioning Segregated Fund and Used Fuel Segregated Fund

Nuclear Fund investments classified as Level 3 consist of real estate and infrastructure investments within its alternative investment portfolio. The fair value of the investments within the Nuclear Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's-length market transactions, 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.

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, 2019:

(millions of dollars except where noted)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Real Assets				
Infrastructure	**2,117**	**902**	**n/a**	**n/a**
Real Estate	**1,317**	**808**	**n/a**	**n/a**
Agriculture and Timberland	**164**	**31**	**n/a**	**n/a**
Pooled Funds				
Short-term Investments	**36**	**n/a**	**Daily**	**1-5 days**
Fixed Income	**1,983**	**n/a**	**Daily**	**1-5 days**
Equity	**873**	**n/a**	**Daily**	**1-5 days**
Total	**6,490**	**1,741**		

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture and timberland investment 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.

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 and Timberland

This class includes a diversified portfolio of global farmland and timberland investments. The investment objective is to provide a differentiated return source, income yield and inflation protection. The fair values of the investments in this class have been estimated using 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.

15. SHARE CAPITAL

Common Shares

As at September 30, 2019 and December 31, 2018, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder, the Province.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for equity injections in OPG. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to entitlement to dividends, and all dividends declared by OPG must be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new class of shares is subject to the consent of the Province. OPG is entitled to redeem outstanding Class A shares as may be approved by OPG's Board of Directors.

As at September 30, 2019 and December 31, 2018, OPG had 18,343,815 Class A shares issued and outstanding at a stated value of $787 million.

16. EARNINGS PER SHARE

Basic and diluted earnings per share are calculated by dividing net income attributable to the Shareholder by the weighted average number of shares outstanding during the period.

Class A shares are included in the weighted average number of shares outstanding. The weighted average number of shares outstanding for both the three month and nine month periods ended September 30, 2019 was 274.6 million (three months ended September 30, 2018 – 274.6 million; nine months ended September 30, 2018 – 272.7 million). There were no dilutive securities as at September 30, 2019 and September 30, 2018.

17. 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 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 from the Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter was to be set down for trial by December 31, 2018. OPG delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable. British Energy served a reply on November 14, 2018 and served its Affidavit of Documents on November 23, 2018. British Energy obtained an extension to the time required to set the matter down for trial. British Energy has set the matter down for trial, although no date for trial has been scheduled. The parties exchanged documentary productions in September 2019.

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 are 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 consolidated 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, 2019, the total amount of guarantees OPG provided to these entities was $79 million (December 31, 2018 − $81 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at September 30, 2019, 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 Obligations

OPG’s contractual obligations as at September 30, 2019 are as follows:

(millions of dollars)	**2019**[1]	**2020**	**2021**	**2022**	**2023**	**Thereafter**	**Total**
Fuel supply agreements	40	140	137	91	87	39	534
Contributions to the OPG registered pension plan [2]	25	181	183	-	-	-	389
Long-term debt repayment	96	692	440	203	74	6,440	7,945
Interest on long-term debt	68	315	286	270	263	4,893	6,095
Short-term debt repayment	120	-	-	-	-	-	120
Commitments related to Darlington Refurbishment project [3]	312	-	-	-	-	-	312
Operating licences	10	44	45	46	47	97	289
Operating lease obligations	4	13	12	10	7	20	66
Unconditional purchase obligations	15	59	5	-	-	-	79
Accounts payable and accrued charges	888	14	-	-	-	-	902
Other	36	29	11	11	8	90	185
Total	1,614	1,487	1,119	631	486	11,579	16,916

[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, 2019. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2022. 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 2021 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.

18. BUSINESS SEGMENTS

Segment Income (Loss) For the Three Months Ended September 30, 2019 (millions of dollars)	Regulated			Unregulated			
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Contracted and Other Generation	Other	Elimination	Total
Revenue from contracts with customers	1,005	-	340	146	-	-	1,491
Leasing revenue	6	-	-	-	5	-	11
Other revenue	-	37	-	-	19	(50)	6
Total revenue	1,011	37	340	146	24	(50)	1,508
Fuel expense	75	-	84	13	-	-	172
Gross margin	936	37	256	133	24	(50)	1,336
Operations, maintenance and administration	515	37	82	51	26	(50)	661
Depreciation and amortization	169	-	55	32	12	-	268
Accretion on fixed asset removal and nuclear waste management liabilities	-	251	-	1	2	-	254
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(225)	-	-	-	-	(225)
Income from investments subject to significant influence	-	-	-	(10)	-	-	(10)
Property taxes	6	-	1	4	-	-	11
Other losses (gains)	-	-	1	(1)	(13)	-	(13)
Income (loss) before interest and income taxes	246	(26)	117	56	(3)	-	390
Net interest expense							5
Income before income taxes							385
Income tax expense							62
Net income							323

Segment Income (Loss) For the Three Months Ended September 30, 2018 *(millions of dollars)*	Regulated			Unregulated			
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Contracted and Other Generation	Other	Elimination	Total
Revenue from contracts with customers	888	-	331	142	1	-	1,362
Leasing revenue	10	-	-	-	5	-	15
Other revenue	-	33	-	-	9	(46)	(4)
Total revenue	898	33	331	142	15	(46)	1,373
Fuel expense	73	-	87	15	-	-	175
Gross margin	825	33	244	127	15	(46)	1,198
Operations, maintenance and administration	507	33	83	43	18	(46)	638
Depreciation and amortization	131	-	39	21	9	-	200
Accretion on fixed asset removal and nuclear waste management liabilities	-	242	-	2	1	-	245
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(216)	-	-	-	-	(216)
Income from investments subject to significant influence	-	-	-	(12)	-	-	(12)
Property taxes	8	-	1	1	-	-	10
Other losses (gains)	-	-	-	2	(2)	-	-
Income (loss) before interest and income taxes	179	(26)	121	70	(11)	-	333
Net interest expense							19
Income before income taxes							314
Income tax expense							31
Net income							283

Segment Income (Loss) For the Nine Months Ended September 30, 2019 *(millions of dollars)*	Regulated			Unregulated			
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Contracted and Other Generation	Other	Elimination	Total
Revenue from contracts with customers	2,860	-	1,132	456	5	-	4,453
Leasing revenue	19	-	-	-	12	-	31
Other revenue	-	100	-	-	58	(142)	16
Total revenue	2,879	100	1,132	456	75	(142)	4,500
Fuel expense	218	-	242	35	-	-	495
Gross margin	2,661	100	890	421	75	(142)	4,005
Operations, maintenance and administration	1,679	100	244	150	60	(142)	2,091
Depreciation and amortization	504	-	167	92	35	-	798
Accretion on fixed asset removal and nuclear waste management liabilities	-	755	-	5	4	-	764
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(668)	-	-	-	-	(668)
Income from investments subject to significant influence	-	-	-	(33)	-	-	(33)
Property taxes	19	-	1	10	2	-	32
Other losses (gains)	-	-	2	(2)	(45)	-	(45)
Income (loss) before interest and income taxes	459	(87)	476	199	19	-	1,066
Net interest expense							35
Income before income taxes							1,031
Income tax expense							135
Net income							896

Segment Income (Loss) For the Nine Months Ended September 30, 2018 *(millions of dollars)*	Regulated			Unregulated			
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Contracted and Other Generation	Other	Elimination	Total
Revenue from contracts with customers	2,484	-	1,077	440	11	-	4,012
Leasing revenue	28	-	-	-	13	-	41
Other revenue	-	98	-	-	42	(131)	9
Total revenue	2,512	98	1,077	440	66	(131)	4,062
Fuel expense	208	-	242	46	-	-	496
Gross margin	2,304	98	835	394	66	(131)	3,566
Operations, maintenance and administration	1,731	98	245	127	33	(131)	2,103
Depreciation and amortization	382	-	115	60	27	-	584
Accretion on fixed asset removal and nuclear waste management liabilities	-	729	-	6	4	-	739
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(638)	-	-	-	-	(638)
Income from investments subject to significant influence	-	-	-	(32)	-	-	(32)
Property taxes	21	-	1	5	1	-	28
Other losses (gains)	-	-	4	2	(272)	-	(266)
Income (loss) before interest and income taxes	170	(91)	470	226	273	-	1,048
Net interest expense							56
Income before income taxes							992
Income tax expense							44
Net income							948

Change in Reportable Segments

Since the first quarter of 2019, OPG's financial results related to its role as the Financial Services Manager under the Fair Hydro Act, which primarily comprised the financial results of the Trust, ceased being reported as a separate business segment in the Company's consolidated financial statements as a result of the proposed and subsequently enacted legislative change by the Government of Ontario that resulted in the Trust's deconsolidation. The financial results related to the Company's continued involvement with the Trust are now reported within the Other category. The 2018 comparative amounts have been reclassified from consolidated financial statements previously presented to conform to the 2019 interim consolidated financial statement presentation. For further discussion regarding deconsolidation of the Trust, refer to Note 4.

19. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	**Nine Months Ended September 30 2019**	**2018**
Receivables from related parties	**(2)**	(66)
Inventory	**34**	12
Prepaid expenses	**1**	(4)
Other current assets	**73**	25
Accounts payable, accrued charges and other payables	**(88)**	(92)
	18	(125)

20. SALE OF NON-CORE ASSETS

Sale of Lakeview Site

In March 2018, OPG completed the sale of its former Lakeview generating station site property located in Mississauga, Ontario, with a gain on sale of $205 million, net of tax effects of $68 million, recognized in net income in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in June 2016.