DEPRECIATION AND AMORTIZATION

1.0 PURPOSE

This evidence describes OPG's depreciation and amortization policy and presents the depreciation and amortization expense for the nuclear facilities.

2.0 OVERVIEW

OPG is seeking approval of test period revenue requirements that include depreciation and amortization expense of $346.9M in 2017, $378.7M in 2018, $384.0M in 2019, $524.9M in 2020 and $338.1M in 2021 for the nuclear facilities, as shown in Ex. F4-1-1 Table 2. Exhibit F4-1-1 Table 2 also presents the depreciation and amortization expense for the historical and bridge years for the nuclear facilities.

Section 3.0 describes OPG's depreciation and amortization expense, summarizes OPG's depreciation and amortization policy and review process, and outlines nuclear station life changes effective December 31, 2015 based on the recommendations of OPG's Depreciation Review Committee ("DRC").

Section 4.0 discusses the trend in depreciation and amortization expense over the period 2013 to 2021.

The depreciation expense for the Bruce assets is presented in Ex. G2-2-1.

3.0 DEPRECIATION AND AMORTIZATION EXPENSE

OPG continues to determine depreciation and amortization expense in the same manner as presented in EB-2013-0321.

Allocation of depreciation expense is not required to attribute depreciation and amortization expense to the regulated facilities. Approximately 99 per cent of OPG's in-service fixed and intangible assets are associated with specific generation facilities or plant groups. The remaining in-service fixed and intangible assets, such as information technology assets, continue to be either directly associated with a business unit or to be held centrally for use by both regulated and unregulated generation business units. For the use of assets held centrally, generating business units (both regulated and unregulated) continue to be charged an asset service fee for the use of these assets. This charge continues to be reported as an OM&A cost. The asset service fees are described in Ex. F3-2-1**.**

3.1 Depreciation and Amortization Policy and Review Process

OPG's depreciation and amortization policy and treatment of asset retirements is unchanged from that presented in EB-2013-0321.

Depreciation and amortization rates for the various classes of OPG's in-service fixed and intangible assets continue to be based on their estimated service lives. The service life of an asset class is limited by the service life of the station(s) to which it relates. An average end-of-life ("EOL") date is established for depreciation purposes for all units at a particular station, which is typically based on estimated EOL dates for each operating unit of the station. The determination of the station EOL dates for depreciation purposes involves an assessment of the condition and expected remaining life of certain key components (referred to as life-limiting components), in conjunction with an estimate of the expected operation of the station, which includes economic viability considerations. For the nuclear stations, the life-limiting components are: fuel channels, steam generators, feeder pipes and reactor components.

The net book value of the prescribed nuclear facilities and the Bruce assets continues to include asset retirement costs ("ARC") relating to OPG's nuclear decommissioning and nuclear waste management liabilities (asset retirement obligation or "ARO"). Accordingly, the depreciation and amortization expense also includes the depreciation of ARC. The depreciation of ARC forms part of the revenue requirement impact for the recovery of the ARO as discussed and presented in Ex. C2-1-1**.**

The EOL dates for depreciation purposes for the prescribed nuclear facilities and the Bruce stations are provided below. As OPG anticipated in EB-2015-0374 and as further discussed in section 3.2, effective December 31, 2015, OPG changed the station EOL dates of Bruce

A, Bruce B, Pickering Units 5-8, and Darlington. These changes impact the 2016-2021 depreciation and amortization expense.

	Effective January 1, 2013[1]	Effective December 31, 2015
Darlington	December 31, 2051	December 31, 2052
Pickering Units 1 & 4	December 31, 2020	December 31, 2020
Pickering Units 5-8	April 30, 2020	December 31, 2020
Bruce A (Units 1-4)	December 31, 2048	December 31, 2052
Bruce B (Units 5-8)	December 31, 2019	December 31, 2061

In EB-2013-0321, the OEB accepted the results of the independent assessment of OPG's asset service life estimates and nuclear station EOL dates (the "EB-2013-0321 Depreciation Study") performed by Gannett Fleming Canada ULC ("Gannett Fleming"), predicated on OPG's continued application of the average life group method.[2] OPG continues to apply the average life group method for the purposes of calculating depreciation expense. With the exception of the changes in nuclear station EOL dates noted above, there have been no changes in the asset service lives for OPG's regulated business compared to those recommended by Gannett Fleming in the EB-2013-0321 Depreciation Study.

As part of its due diligence process, OPG continues to convene an internal DRC to examine the service lives of fixed and intangible assets and therefore the calculation of depreciation and amortization expense. The DRC is comprised of business unit representatives as well as staff from the Finance and Regulatory Affairs functions. The DRC considers available engineering, technical, operational and financial assessments/information as part of its regular review of the service lives of generating stations (including the Bruce stations) and a selection of asset classes with the general objective of reviewing all significant asset classes for the regulated assets over a five-year cycle. Periodic independent reviews of the service

[1] These EOL dates are as presented in EB-2013-0321 Ex. F4-1-1 and reflected in the approved revenue requirement in that proceeding.
[2] EB-2013-0321 Decision with Reasons, p. 98

live estimates of significant asset classes for the regulated assets are also performed over a five-year period, as recommended by Gannett Fleming.[3]

The DRC's scope and recommendations continue to be submitted for approval to OPG's senior executives, including the Chief Financial Officer and the business unit leader of the Nuclear operations. Approved DRC recommendations are used to calculate the depreciation and amortization expense that is reflected in OPG's financial statements and business plan. As part of the EB-2013-031 Depreciation Study, OPG's DRC review process was found by Gannett Fleming to be procedurally sound and meeting generally accepted regulatory objectives regarding depreciation.[4]

Since EB-2013-0321, the DRC was convened twice – in 2014 and in 2015. The 2014 DRC review did not recommend any changes to asset classes or station services lives. In 2015, the DRC recommended, and the Approvals Committee approved, changes to the nuclear station EOL dates effective December 31, 2015, as discussed in section 3.2. The 2015 DRC recommendations for the regulated business are found in Attachment 1.

Effective January 1, 2016, the revenue requirement impact on the prescribed facilities of the differences in depreciation and amortization expense arising from the December 31, 2015 nuclear station EOL date changes are being recorded in the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account established in EB-2015-0374, until the effective date of new nuclear payment amounts incorporating the impacts of the revised EOL dates. Any changes in the depreciation expense for the Bruce facilities are subject to the Bruce Lease Net Revenues Variance Account. OPG's deferral and variance accounts are discussed in Ex. H1-1-1.

As the EB-2013-0321 Depreciation Study, which was based on December 31, 2012 asset net book values, was conducted less than five years ago, OPG has not commissioned a new independent review of the service life estimates for the prescribed assets.

---

[3] EB-2013-0321 Ex. F4-1-1, Attachment 1, p I-7
[4] EB-2013-0321 Ex. F4-1-1, Attachment 1, pp. I-3 and I-4

3.2 Changes in Nuclear Station End-Of-Life Dates

As OPG anticipated in EB-2015-0374, OPG changed nuclear station EOL dates for depreciation and amortization purposes effective December 31, 2015 as described below. The previous and current nuclear station EOL dates can be found in the table provided in section 3.1.

<u>Bruce Nuclear Stations</u>

On December 3, 2015, the Province of Ontario announced that it will proceed with the refurbishment of the six not-yet-refurbished units operated by Bruce Power (i.e., Bruce A Units 3 and 4 and Bruce B Units 5 to 8) and that the previous refurbishment implementation agreement between the Independent Electricity System Operator and Bruce Power had been correspondingly updated. The resulting Amended and Restated Bruce Power Refurbishment Implementation Agreement ("ARBPRIA") was made public in December 2015 following the Province's announcement.[5]

The ARBRIPA sets out the target refurbishment schedule for the six not-yet-refurbished Bruce units and the corresponding estimated post-refurbishment EOL dates for each of the eight operating Bruce units. The Province's announcement and the execution of the ARBPRIA provided OPG with the necessary evidence to align the Bruce EOL dates for accounting purposes with the ARBPRIA, effective December 31, 2015. As a result, for OPG's accounting purposes, the average EOL date of the Bruce A station was extended from December 31, 2048 to December 31, 2052 and the average EOL date of the Bruce B station was extended from December 31, 2019 to December 31, 2061.

The estimated annual impact on depreciation and amortization expense for the Bruce assets from the above revision in station EOL dates is a reduction of approximately $59 million starting in 2016.[6] This comprises approximately $57 million related to the existing ARC balance and approximately $2 million related to the non-ARC asset balances.

[5] https://news.ontario.ca/mei/en/2015/12/ontario-commits-to-future-in-nuclear-energy.html
[6] Excluding the depreciation impact of the December 31, 2015 ARC adjustment discussed in Ex. C2-1-1

Pickering Nuclear Station

In 2015, OPG achieved high confidence that all four of Pickering Units 5 to 8 are expected to be technically fit to operate until at least the end of 2020. This confidence was achieved through work on the Fuel Channel Life Extension Project and execution of inspection and technical work programs.

As a result, OPG adopted an average EOL date, for accounting purposes, of December 31, 2020 for these units, effective December 31, 2015. This represents an extension from the previous average EOL date of April 30, 2020, which assumed that some of the units would be shut down prior to the end of 2020.

The estimated annual impact on depreciation and amortization expense for the prescribed assets from the above revision in the station EOL date is a reduction of approximately $8 million starting in 2016.[7] This comprises approximately $4 million related to the existing ARC balance and approximately $4 million related to the non-ARC asset balances.

As discussed in Ex. F2-2-3, OPG is undertaking a set of initiatives to extend Pickering operation beyond 2020, which will require the CNSC's approval. The December 31, 2020 accounting EOL date for the Pickering units is expected to be reassessed in the future when further technical work confirms that the units would be fit to operate beyond 2020. OPG will seek the OEB's approval of an accounting order related to any future changes to the Pickering EOL date based on the same requirements that underpinned OPG's EB-2015-0374 application.

Darlington Nuclear Station

In January 2016, the Province announced that Ontario is moving forward with OPG's refurbishment of the four-unit Darlington Generating Station, with the refurbishment of the last unit scheduled to be completed by 2026. The Province's announcement followed the approval of the project budget and schedule by OPG's Board of Directors in November 2015.

[7] Ibid.

Based on the refurbishment schedule and an assumed post-refurbishment operating life for the units, OPG extended the average station EOL date for Darlington to December 31, 2052, from the previous date of December 31, 2051, effective December 31, 2015. The DRP is discussed in Ex. D2-2-1 and related exhibits.

The estimated annual impact on depreciation and amortization expense for the prescribed assets from the above revision in the station EOL date is a reduction of approximately $1 million starting in 2016.[8] This reduction in expense predominantly relates to the ARC balance.

4.0 DEPRECIATION AND AMORTIZATION EXPENSE TRENDS

The depreciation and amortization expense for the prescribed nuclear facilities increases moderately from 2013 to 2019, with year-over-year increases largely due to the impact of in-service additions at the Pickering and Darlington stations and for the Darlington Refurbishment Project, which are discussed in Ex. D2-1-2 and Ex. D2-2-1. The projected increase in depreciation and amortization expense in 2016, compared to 2015, is a net of a reduction in prescribed facilities' ARC depreciation as a result of the changes in station EOL dates discussed in section 3.2 as well as the related year-end 2015 adjustments in the ARO and ARC balances. The year-end 2015 ARO and ARC adjustments and related revenue requirement impacts are discussed in Ex. C2-1-1, section 5.0.

Nuclear depreciation and amortization expense is forecast to increase notably in 2020 when rate base increases in 2020 as a result of Darlington Unit 2's return to service in February 2020. Nuclear depreciation and amortization expense declines significantly in 2021, compared to 2020, as the assumed Pickering EOL date of December 31, 2020 is reached.[9]

[8] Ibid.

[9] In line with the current EOL date, most of the forecast Pickering capital additions in 2021 are assumed, in OPG's business plan and this Application, to be fully depreciated in 2021

ATTACHMENTS

Attachment 1: 2015 Depreciation Review Committee Recommendations for Regulated Business

2015

DEPRECIATION REVIEW COMMITTEE RECOMMENDATIONS

FOR

REGULATED BUSINESS

DECEMBER 2015

2015 Depreciation Review Committee Recommendations – Regulated Business

PURPOSE AND SUMMARY

This memorandum is intended to obtain approval of recommendations resulting from the 2015 Depreciation Review Committee ("DRC") review of the average asset service lives for OPG's prescribed nuclear facilities and Bruce nuclear generating stations.

The 2015 DRC review recommends the following changes to OPG's nuclear station service lives for depreciation purposes, effective December 31, 2015:

- Pickering Units 5-8: extend end-of-life (EOL) date from April 30, 2020 to December 31, 2020
- Darlington: extend EOL date from December 31, 2051 to December 31, 2052
- Bruce A (units 1-4): extend EOL date from December 31, 2048 to December 31, 2052
- Bruce B (unit 5-8): extend EOL date from December 31, 2019 to December 31, 2061

The Pickering Units 1 and 4 EOL date is recommended to remain unchanged at December 31, 2020.

BACKGROUND

The DRC is convened annually to review the service lives for depreciation purposes of OPG's major facilities and a selection of asset classes in those facilities with the general objective of reviewing all significant asset classes over a five year period. Excluding asset retirement costs, the DRC reviews in 2013 and 2014 are estimated to have covered over half of the in-service net book value of the asset classes in OPG's regulated business.

In November 2014, the Ontario Energy Board ("OEB") issued its decision on OPG's application for 2014/15 regulated rates, in which it approved OPG's forecast depreciation expense for the regulated and Bruce assets as filed, based on asset service lives then in effect. The OEB also accepted the results of independent depreciation studies filed by OPG as part of the rate application. The latest of these studies was based on in-service balances of OPG's prescribed assets as at December 31, 2012 as well as the Niagara Tunnel. In its decision, the OEB also accepted OPG's continued use of the average life group method.

SCOPE OF 2015 DRC REVIEW

The focus of the work of the 2015 DRC was to review the service lives for OPG's nuclear stations based on the most recent information available including refurbishment plans and schedules, major components service lives, developments related to the Bruce stations and other relevant information available.

SUMMARY OF RECOMMENDATIONS

The DRC is recommending changes to the station service life assumptions for depreciation purposes for each of OPG's nuclear stations based on the evidence discussed below for each station.

Prescribed Nuclear Generating Stations

Pickering Station

The DRC is recommending an extension of the Pickering Units 5-8 average EOL date from April 30, 2020 to December 31, 2020. The DRC is not recommending changes to the average EOL date for Pickering Units 1 and 4 of December 31, 2020.

In 2012, the DRC received confirmation of high confidence that Pickering Units 5-8 could be operated until at least 247,000 effective full power hours ("EFPH") based primarily on the results of the Fuel Channel Life Management project. Pickering Units 5 and 6 in particular were expected to shut down before the end of 2020. The resulting average EOL date for all four Pickering Units 5-8 was established as April 30, 2020, effective December 31, 2012.

As noted in the 2014 DRC recommendations, OPG launched the Fuel Channel Life Extension ("FLCE") project with the aim of achieving high confidence in operating Pickering Units 5-8 to at least 261,000 EFPH, which would allow all four of the units to operate until at least the end of 2020. In the fourth quarter of 2015, the DRC received technical confirmation of high confidence that all four Pickering Units 5-8 are now expected to be technically fit to safely operate until at least December 31, 2020 based on the results of the FCLE project. This determination forms the basis for the DRC's recommendation to extend the average station EOL date for Pickering Units 5-8 to December 31, 2020, effective December 31, 2015.

The estimated annual impact on depreciation expense of the above service life change, before the impact of anticipated year-end 2015 adjustments to the asset retirement obligation ("ARO") estimate and asset retirement costs ("ARC") is a reduction of approximately $8M. Of this amount, approximately $4M relates to the existing ARC balances and approximately $4M to non-ARC assets.[1]

Darlington Station

The DRC recommends extending the Darlington station's EOL date from December 31, 2051 to December 31, 2052.

Darlington's current EOL date of December 31, 2051 was established effective January 1, 2010 following the decision to proceed with the definition phase of the Darlington refurbishment. This reflected a preliminary refurbishment outage schedule, which included an assumption of "over-lapped" refurbishment outages for the first two units being refurbished.

In November 2015, OPG's Board of Directors approved the budget and schedule for the four-unit Darlington refurbishment. The approved schedule includes substantial "un-lapping" of the refurbishment outages for the first two units. Based on the approved refurbishment outage schedule and target return-to-service dates for each unit and continuing to assume a 30-year post-refurbishment operating life, the DRC recommends extending the Darlington EOL date to December 31, 2052, effective December 31, 2015.

The estimated annual impact on depreciation expense of the above service life change, before the impact of anticipated year-end 2015 ARO / ARC adjustments, is a reduction of approximately $1M related to the

[1] The ARO / ARC change at year-end 2015 is expected to have a material impact on depreciation expense. These impacts will be finalized once all inputs into the calculation of the ARO / ARC change are determined early in 2016.

existing ARC balance. There is a minimal impact on non-ARC asset depreciation expense of less than $1M per year.[2]

Bruce Nuclear Generating Stations

The DRC is recommending an extension to the EOL date for the Bruce A station (Units 1-4) to December 31, 2052 from December 31, 2048 and an extension to the EOL date for the Bruce B station (Units 5-8) to December 31, 2061 from December 31, 2019.

In December 2015, the Province of Ontario (the "Province") publicly announced that it will proceed with the refurbishment of the six yet-to-be refurbished units (i.e. Bruce Units 3-8) operated by Bruce Power and that the previous refurbishment implementation agreement between the Independent Electricity System Operator ("IESO") and Bruce Power has been correspondingly updated. The resulting Amended and Restated Bruce Power Refurbishment Implementation Agreement ("ARBPRIA") made public in December 2015 formally outlines specific refurbishment plans with respect to Bruce Units 3-8 and creates a positive obligation on Bruce Power to refurbish these units. The ARBPRIA includes a target refurbishment schedule for Units 3-8, as well as the following corresponding EOL dates estimated for each of the eight Bruce units:

Bruce A	Bruce B
Unit 1: December 31, 2043	Unit 5: December 31, 2062
Unit 2: December 31, 2043	Unit 6: December 31, 2058
Unit 3: December 31, 2061	Unit 7: December 31, 2063
Unit 4: December 31, 2062	Unit 8: December 31, 2063

The Province's public announcement and the information contained in the ARBPRIA provide the evidence for the DRC's recommendation to revise the Bruce A and Bruce B station EOL dates to December 31, 2052 and December 31, 2061, respectively, effective December 31, 2015. The recommended new dates reflect the estimated EOL dates specified in the ARBPRIA.

The estimated annual impact on depreciation expense of the above service life changes, before the impact of anticipated year-end 2015 ARO / ARC adjustments, is a reduction of approximately $58M. Of this amount, approximately $57M relates to the existing ARC balances and approximately $1M to non-ARC assets.[3]

[2] See footnote 1
[3] See footnote 1

DRC MEMBERS AND APPROVALS COMMITTEE

The DRC includes representatives from the operating business units as well as representatives having experience in finance and accounting, investment planning, and rate regulation.

The Approvals Committee is responsible for approving the DRC recommendations and is comprised of:

- Glenn Jager, President, OPG Nuclear and Chief Nuclear Officer
- Mike Martelli, Senior Vice President, Hydro Thermal Operations
- Carlo Crozzoli, Senior Vice President and Interim Chief Financial Officer
- Bruce Boland, Senior Vice President, Commercial Operations and Environment

The DRC is comprised of the following members:

- Charanjit Singh (DRC Chair), Vice President, Shared Financial Services
- John Mauti, Vice President, Chief Controller and Accounting Officer
- Carla Carmichael, Vice President, Nuclear Finance
- Lubna Ladak, Vice President, HTO Finance
- Mario Mazza, Vice President, Strategic Operations, Hydro Thermal Operations
- Alex Kogan, Vice President, Business Planning and Reporting
- Randy Pugh, Director, Ontario Regulatory Affairs
- Stephen Rogers, Director, Asset Planning and Integration, Nuclear Finance
- Alec Cheng, Director, External Reporting and Accounting Policy
- Dave Bell, Senior Manager, Accounting and Reporting
- Dwight Zerkee, Senior Manager, Investment Management, Nuclear Finance

Numbers may not add due to rounding.

Table 1

Depreciation and Amortization - Regulated Hydroelectric ($M)

Intentionally left blank (See Ex. A1-3-1)

Numbers may not add due to rounding.

Table 2
Depreciation and Amortization - Nuclear ($M)

Line No.	Cost Item	2013 Actual[1]	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Darlington NGS**	32.3	34.0	31.5	36.8	44.2	51.3	56.9	62.7	69.1
2	**Darlington Refurbishment Project**	2.3	4.7	7.0	14.1	25.8	29.9	30.0	159.1	177.6
3	**Pickering NGS**	127.5	140.9	147.3	165.7	199.9	223.2	226.7	233.3	53.1
4	**Nuclear Support Divisions**	27.3	27.4	26.6	26.8	26.7	24.1	20.1	19.5	19.6
5	**Asset Retirement Costs**	80.7	80.7	80.7	50.3	50.3	50.3	50.3	50.3	18.7
6	**Other[2]**	(0.0)	(2.5)	4.9	0.0	0.0	0.0	0.0	0.0	0.0
7	**Total**	270.1	285.3	298.0	293.6	346.9	378.7	384.0	524.9	338.1

Notes:
1 2013 Actual from EB-2013-0321 Ex. L-1.0-1 Staff-002, Att. 1, Table 28, col. (d).
2 Includes losses on retirements, gains on disposal and other related charges.

TAXES

1.0 PURPOSE

This evidence presents taxes, including income tax, commodity tax, and property tax, for the regulated nuclear facilities for the 2017-2021 test period, and income taxes for total regulated facilities for the historical and bridge periods**.**

2.0 OVERVIEW

OPG is seeking approval of the 2017 to 2021 nuclear income tax expense of \$(18.4)M, \$(18.4)M, \$(18.4)M, \$51.2M and \$51.7M and property tax expense of \$14.6M, \$14.9M, \$15.3M, \$15.7M and \$17.0M, respectively, as presented in Ex. F4-2-1 Table 2.

For all tax matters for the prescribed facilities addressed in this exhibit OPG has applied the same principles and methodology as in EB-2013-0321. Taxes included in the determination of Bruce Lease net revenues are discussed in Ex. G2-2-1.

3.0 INCOME TAX EXPENSE

3.1 Calculation of Regulatory Income Tax Expense

Under the *Electricity Act, 1998,* OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation ("OEFC") and to file federal and provincial income tax returns with the Ontario Ministry of Finance. The tax payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under federal and Ontario tax legislation.

OPG continues to use the taxes payable method for determining regulatory income taxes for its prescribed assets. Under the taxes payable method, only the current income tax expense is reflected in the revenue requirement. Regulatory income taxes are determined by applying the statutory tax rates to the regulatory taxable income of the prescribed facilities and reducing the resulting amount by recognized investment tax credits ("ITCs") for qualifying Scientific Research and Experimental Development ("SR&ED") expenditures. There have been no changes in the statutory income tax rates in the historic period and none are forecast in the bridge or test periods. SR&ED ITCs are discussed in section 3.4.

Regulatory taxable income is computed by making additions and deductions to regulatory earnings before tax for items affected by differences in regulatory accounting treatment and tax treatment reflecting applicable requirements of the tax legislation. These additions and deductions are described in the next section, and are detailed in the calculation of regulatory income taxes in Ex. F4-2-1 Table 3 for 2013 to 2016 and Ex. F4-2-1 Table 3a for 2017 to 2021.

As in EB-2013-0321, regulatory income taxes for the historical and bridge periods continue to be determined by applying statutory tax rates to the regulatory taxable income of the combined prescribed nuclear and hydroelectric facilities, less SR&ED ITCs. Total regulatory income taxes are then allocated based on each business' regulatory taxable income, while SR&ED ITCs are predominantly directly attributed to each business unit based on the underlying expenditures giving rise to the ITCs.

For nuclear ratemaking purposes for 2017 to 2021, the forecast regulatory income tax is presented for the prescribed nuclear facilities only, and is determined by applying statutory tax rates to the forecast regulatory taxable income of these facilities, less corresponding forecast SR&ED ITCs. In a situation where a tax loss is forecast for the nuclear business unit in a given year of the test period, the loss is applied (carried back or carried forward) to reduce the nuclear business unit's taxable income in other years of the test period, with any remaining tax losses carried forward to future test periods. This approach is consistent with the cost allocation principle of direct assignment, whereby costs directly related to a business unit are directly assigned to that business unit.

As discussed in section 3.3, the income tax impacts associated with amounts recorded in variance and deferral accounts continue to be considered in the calculation of regulatory taxable income in the periods they are recovered from or refunded to ratepayers, rather than the periods in which these amounts arise. Therefore, additions or deductions that reverse amounts reflected in regulatory earnings before tax are presented net of any corresponding additions recorded in variance and deferral accounts in the period, and any return on rate base recorded in deferral or variance accounts in the period is also reversed.

In Attachment 1, OPG is providing, as confidential material, the most recent corporate income tax returns and the associated notices of assessment. The returns are for the 2014 taxation years, for the same companies included in EB-2013-0321. Ex. F4-2-1 Table 4 presents the reconciliation of OPG's consolidated taxable income based on its 2014 tax returns to the calculation of the regulatory taxable income for the prescribed facilities for that year.

3.2 Description of Additions and Deductions to Regulatory Earnings Before Tax

3.2.1 Depreciation and Amortization/Capital Cost Allowance

Accounting depreciation and amortization of fixed/intangible assets is not deductible for income tax purposes; however, capital cost allowance ("CCA") is deductible. Therefore, depreciation and amortization expense is an addition to earnings before tax, while CCA is deducted from earnings before tax. Accounting depreciation and amortization of fixed/intangible assets for the prescribed facilities is determined as described in Ex. F4-1-1.

The amount of depreciation/amortization expense added back in Ex. F4-2-1 Tables 3, for 2013 to 2016, is net of depreciation amounts for the prescribed facilities recorded (or forecasted to be recorded) in the year as additions to the Nuclear Liability Deferral Account, the Capacity Refurbishment Variance Account, the Pickering Life Extension Depreciation Variance Account, and, in 2016, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account and the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account.

OPG's 2014 income tax returns provided in Attachment 1 include the calculations of CCA deductions by applying, by asset class, a prescribed rate to the Undepreciated Capital Cost balance (i.e. Schedules 8 of Ex. F4-2-1 Attachment 1). These schedules contain consolidated information for both OPG's regulated and unregulated assets. Undepreciated Capital Costs ("UCC") and CCA schedules for combined prescribed nuclear and hydroelectric assets are provided for 2014 to 2016 in Ex. F4-2-1 Tables 5-7 and for the prescribed nuclear facilities for 2017 to 2021 in Ex. F4-2-1 Tables 8-12.

3.2.2 Nuclear Waste Management Variable Expenses

Consistent with the provisions of the *Income Tax Act* (Canada), accounting expenses accrued by OPG relating to its obligations for decommissioning its nuclear stations and managing nuclear used fuel and low and intermediate level waste produced by these facilities (collectively, the "nuclear liabilities") are not deductible for tax purposes. Therefore, used fuel storage and disposal and low and intermediate level waste management variable expenses incurred in the period in relation to the prescribed nuclear assets are added back to earnings before tax. These expenses are presented in Ex. C2-1-1 Table 2, lines 2 and 3. The amount added back to earnings before tax for these expenses in Ex. F4-2-1 Table 3, for 2013 and 2014, is net of amounts recorded as additions to the Nuclear Liability Deferral Account and, in 2016, net of amounts forecast to be recorded in the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account.

3.2.3 Cash Expenditures for Nuclear Waste Management and Decommissioning

Cash expenditures incurred and charged against the nuclear liabilities for waste management and decommissioning activities are generally deductible for tax purposes in accordance with the regulations under the *Electricity Act, 1998*. The expenditures for the prescribed nuclear facilities are presented in Ex. C2-1-1 Table 2, line 5.

The full amount of cash expenditures relating to the prescribed nuclear assets is presented at line 14 in Ex. F4-2-1 Table 3 and line 13 in Ex. F4-2-1 Table 3a as a deduction from earnings before tax. As part of Other additions presented at line 11 in Ex. F4-2-1 Table 3 and line 10 in Ex. F4-2-1 Table 3a and as noted in section 3.2.8 below, a portion of these expenditures deemed to be capital for tax purposes is added back to earnings before tax in order to adjust the amount of cash expenditures deducted in arriving at taxable income. The CCA deduction discussed in section 3.2.1 includes CCA related to these expenditures.

3.2.4 Segregated Fund Contributions and Receipts

The regulations under the *Electricity Act, 1998* allow OPG a tax deduction for contributions made to segregated funds pursuant to the Ontario Nuclear Funds Agreement ("ONFA"). The ONFA contribution schedule based on the current approved ONFA Reference Plan is used to determine OPG's contributions to the segregated funds. The contributions for the prescribed nuclear facilities are presented in Ex. C2-1-1 Table 2, line 14 and are deducted from earnings before tax.

When OPG receives disbursements from the funds for reimbursement of eligible expenditures, the amounts received are taxable as per the regulations under the *Electricity Act, 1998*. The amounts related to the prescribed nuclear facilities are presented in Ex. C2-1-1 Table 2 line 15 and are added to earnings before tax.

3.2.5 Pension and Other Post-Employment Benefits

Pension and other post-employment benefits ("OPEB") accrual costs recorded by OPG for accounting purposes (discussed in Ex. F4-3-2) are not deductible for tax purposes per the provisions of the *Income Tax Act* (Canada). Therefore, these costs are added back to earnings before tax. OPG's cash contributions to its registered pension plan as well as the payments for its OPEB and supplementary pension plans are deductible for tax purposes, and are reflected as deductions from earnings before tax.

The amount added back to earnings before tax for pension and OPEB accrual costs in Ex. F4-2-1 Table 3, prior to November 1, 2014, is net of amounts recorded in the period as additions to the Pension and OPEB Cost Variance Account. From November 1, 2014 to the end of 2016, the amount added back to earnings before tax is net of amounts recorded (or forecasted to be recorded) in the period in the Pension & OPEB Cash Versus Accrual Differential Deferral Account. For the test period, OPG proposes to limit pension and OPEB costs included in the nuclear revenue requirement to the forecast cash requirements, while continuing to record the difference between accrual costs and cash amounts in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, as further discussed in Ex. F4-3-2. As such, the amount OPG applies as an addition to earnings before tax for the test period is the same as the forecast cash amounts deducted from earnings before tax.

3.2.6 Adjustment Related to Financing Cost for Nuclear Liabilities

The calculation of regulatory earnings before tax adds back an adjustment in respect of the financing cost (i.e., return on rate base) for the prescribed facilities' portion of the nuclear liabilities. This adjustment is required as a result of the methodology for the recovery of the revenue requirement impact of the nuclear liabilities (approved in EB-2007-0905 and applied in EB-2010-0008 and EB-2013-0321) and the inclusion of tax deductions for nuclear segregated fund contributions and nuclear waste management and decommissioning cash expenditures. As part of the approved methodology discussed in Ex. C2-1-1, the revenue requirement treatment of the nuclear liabilities includes an amount derived by applying the weighted average accretion rate to the lesser of the average unfunded nuclear liabilities and the average unamortized asset retirement costs for the prescribed facilities. This amount is deducted in determining regulatory earnings before tax. For years 2013 to 2021, the derivation of this amount is presented in Ex. C1-1-1 Tables 1-9, line 7. The segregated fund contributions also include financing costs related to the nuclear liabilities, as discussed in section 3.2.4 above. Therefore, an adjustment is included as an addition to regulatory earnings before tax to remove an otherwise duplicate deduction between the return on rate base at the weighted average accretion rate and deductions for the nuclear segregated fund contributions and nuclear liability expenditures. The amount added to earnings before tax in Ex. F4-2-1 Table 3, for 2013 and 2014, is net of amounts recorded as additions to the Nuclear Liability Deferral Account and, for 2016, net of amounts forecast to be recorded in the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account.

3.2.7 Disallowance of Niagara Tunnel Project Expenditures

As a result of the OEB's EB-2013-0321 disallowance related to the Niagara Tunnel Project, in 2014, OPG wrote off the portion of the project expenditures that exceeded the amount approved for inclusion in rate base. The write off was not deductible for income tax purposes and was added back to 2014 regulatory earnings before tax. Based on the OEB's EB-2014-0369 Decision and Order that reduced the original disallowance, a portion of the above write-off was reversed in 2016. As the reversal is not subject to tax, the amount is deducted from regulatory earnings before tax in 2016.

3.2.8 Other

This category includes other required additions or deduction to earnings before tax such as:

- Nuclear materials and supplies obsolescence expenses recorded for accounting purposes as part of nuclear base OM&A (as noted in Ex. F2-2-1, section 3.3) that are not deductible for tax purposes as per the *Income Tax Act* (Canada).
- Computer equipment expenditures that are expensed for accounting purposes but must be capitalized and are eligible for CCA deductions for tax purposes.
- Fifty per cent of OPG's nuclear fuel expense incurred in a given year, which is not deductible for tax purposes until the following year. Therefore, OPG adds back 50 per cent of a given year's nuclear fuel expense and deducts 50 per cent of the prior year's nuclear fuel expense. The resulting net addition or net deduction adjusts earnings before tax.
- Meals and entertainment expenses that are subject to the 50 per cent tax deduction limitation.
- Adjustment to decrease the reduction for cash expenditures on nuclear waste management and decommissioning by the portion of the expenditures deemed to be capital for tax purposes, as discussed in section 3.2.3.

3.3 Regulatory Tax Treatment of Variance and Deferral Account Recovery

Amounts recorded by OPG in variance and deferral accounts in a given period, which are reported as regulatory assets or liabilities for accounting purposes, typically impact OPG's actual taxable income in a different period. As a result, amounts recognized for accounting purposes as regulatory assets or liabilities in the period are reversed from regulatory earnings before tax in determining OPG's actual taxable income (e.g. 21-23 of Ex. F4-2-1 Table 4, col. (a)).

For regulatory purposes, as in EB-2013-0321, the tax impact (i.e., tax benefits or costs) to be recovered from, or provided to, ratepayers of the amounts recorded in variance and deferral accounts is reflected in the calculation of regulatory taxable income over the same period as these amounts are recovered from, or refunded to, ratepayers. This approach is intended to result in the same total tax impact as the actual tax payable by OPG in respect of recovery or refund of the amounts, considering the entire period from when the variance or deferral account balance is initially recorded to when the balance is fully recovered or refunded. This regulatory treatment provides for a matching of costs and benefits in accordance with the principle that the party who bears a cost should be entitled to any related tax savings or benefits.

In calculating earnings, the balance of the variance and deferral accounts recovered or refunded through payment amounts in the period is reflected in both the regulated revenues and the amortization expense (or amortization credit) for that period. Amortization is not deductible for income tax purposes. Since the amounts of revenue and amortization typically would be equal and offsetting, there is no net impact on earnings before tax for the period. In calculating regulatory income taxes, no adjustment to regulatory earnings before tax is made for the amortization, subject to the discussion below, because the amount that would otherwise be added back to, or deducted from, earnings before tax as amortization expense/credit is the same as the amount that would be deducted from, or added back to, earnings before tax in order to attribute the associated benefit or cost to ratepayers.

To the extent that there is no tax benefit/cost to be matched to the variance or deferral account recovery or refund, there is a net income tax impact associated with the amounts recorded in these accounts. In instances where this impact is not otherwise reflected in the account balance itself, an adjustment to regulatory earnings before tax is required.

The Nuclear Liability Deferral Account, the Capacity Refurbishment Variance Account, the Pension and OPEB Cost Variance Account and, in 2016, the Impact Resulting from Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account are the principal accounts that record amounts for the prescribed facilities that do not have a matching tax benefit. These accounts reflect the associated income tax impacts as part of amounts recorded in the account, and therefore no adjustment to earnings before tax is required in respect of the recovery of these balances. With respect to the Pension & OPEB Cash Versus Accrual Differential Deferral Account, per the OEB's findings in the EB-2013-0321 Payment Amounts Order, the associated income tax impacts are not recorded in the account and, as the OEB noted in that order, can be addressed at the time that a determination is made regarding the account balance.[1]

An adjustment to regulatory earnings before tax continues to be required to address the impact of the regulatory treatment of the Bruce Lease net revenues on the disposition of the Bruce Lease Net Revenues Variance Account. The forecast net revenues from the Bruce Lease are applied against OPG's nuclear revenue requirement and therefore the earnings before tax for the prescribed facilities as shown in Ex. F4-2-1 Table 3b, note 1. To the extent that there is a difference between the forecast and actual net revenues from the Bruce Lease (i.e., an entry into the Bruce Lease Net Revenues Variance Account), there is a difference in the regulatory earnings before tax and therefore the taxes for the prescribed facilities. Hence, an adjustment to regulatory earnings before tax is required in the year of recovery/refund of the variance recorded in the Bruce Lease Net Revenues Variance Account to ensure that any over-collection of, or shortfall in, regulatory taxes is also refunded to or recovered from the ratepayers. Accordingly, the amortization of the Bruce Lease Net Revenues Variance Account is added back to regulatory earnings before tax, as shown in Ex. F4-2-1, Tables 3 and 3a, line 6. In addition to historical and bridge years, this adjustment is included in 2017

[1] On page 6 of the EB-2013-0321 Payment Amounts Order, the OEB stated: "The Decision's description of the Pension & OPEB Cash Versus Accrual Differential Deferral Account did not include taxes and the Board finds that this account will not record taxes. When a determination is made regarding the account balance, any tax matters can be addressed at that time."

and 2018 to reflect amortization amounts for the variance account proposed in this Application (see Ex. H1-1-1).

3.4 SR&ED Investment Tax Credits

OPG can claim a non-refundable federal ITC equal to 15 per cent (20 per cent prior to 2014) and an Ontario ITC of 3.5 per cent (4.5 per cent prior to June 1, 2016) of the qualifying SR&ED expenditures incurred in the year. OPG files annual ITC claims based on qualifying expenditures identified. The federal ITCs reduce the federal portion of corporate income taxes otherwise payable and are taxable in the subsequent year. The Ontario ITCs reduce the Ontario portion of corporate income taxes otherwise payable and are taxable in the year earned. Effective 2014, previously qualifying SR&ED expenditures of a capital nature (i.e. equipment) are no longer deductible for tax purposes in the year incurred, nor are eligible for SR&ED ITCs. These expenditures qualify for CCA deductions over time. Certain expenditures of a current nature that are capitalized for accounting purposes continue to be deductible for income tax purposes as SR&ED expenditures and remain eligible for SR&ED ITCs. These expenditures are deducted from earnings before tax in computing taxable income.

As in EB-2010-0008 and EB-2013-0321, the amount of ITCs recognized for accounting purposes is determined based on an assessment of the likelihood of their allowance, in accordance with generally accepted accounting principles. Under US GAAP, the amount of ITCs recognized in the period is recorded as a reduction to income tax expense for that period. The reduction to income tax expense for the prescribed facilities is presented at line 27 of Ex. F4-2-1 Table 3 and at line 25 of Ex. F4-2-1 Table 3a.

In determining actual and forecast income tax expense, OPG continues to recognize 75 percent of the estimated ITCs for taxation years that are subject to audit. For years the audit of which has been resolved, OPG adjusts, as needed, the previously recognized amount to reflect the audit resolution. To the extent the ultimate percentage of recognition for SR&ED ITCs differs from that applied in reducing regulatory income tax expense reflected in approved payment amounts, OPG records the difference in the Income and Other Taxes Variance Account.

4.0 INCOME TAX EXPENSE FOR 2013 to 2021

The actual (2013 to 2015) and forecast (2016) annual regulatory income tax expense for the combined nuclear and regulated hydroelectric prescribed facilities for the historical and bridge periods and for the nuclear prescribed facilities for 2017 to 2021 has been computed using the approach described in section 3. The 2013 to 2016 regulatory income tax expense calculations are shown in Ex. F4-2-1 Table 3. The 2017 to 2021 regulatory income tax expense calculations (for the nuclear facilities) are shown in Ex. F4-2-1 Table 3a. The resulting income taxes for the nuclear facilities for the 2013-2021 period are shown in Ex. F4-2-1 Table 2.

The forecast tax expense for the prescribed nuclear assets in the test period years of 2017 to 2021 is $(18.4)M, $(18.4)M, $(18.4)M, $51.2M and $51.7M respectively, including SR&ED ITCs. The negative tax expense shown for 2017 to 2019 represents the forecast amount of SR&ED ITCs attributed to the nuclear facilities in those years and reflects the carryover of projected regulatory tax losses arising in 2018 and 2019. The loss of $45.5M projected in 2018 is first carried back to reduce the regulatory taxable income for 2017 to nil and then, together with the 2019 loss, is carried forward and fully utilized to reduce the regulatory taxable income in 2020.

Regulatory earnings before tax increase from 2017 to 2019 as rate base increases through in-service capital for the Darlington Refurbishment Program and other nuclear projects; however regulatory taxable income (before the application of tax losses) decreases. The relatively small positive regulatory taxable income in 2017 (before the application of tax losses) and the losses in 2018 and 2019 are primarily driven by forecast CCA deductions, primarily on account of Darlington refurbishment expenditures, deductions for ONFA segregated fund contributions based on the current approved contribution schedule, and deductions for cash expenditures for nuclear waste management and decommissioning.

After the application of the losses carried forward from 2018 and 2019, the regulatory taxable income is projected at $278.4M in 2020. The forecast increase in the regulatory taxable income in 2020 is primarily driven by higher regulatory earnings before tax and higher depreciation expense, both due to a higher nuclear rate base as refurbished Darlington Unit 2 returns to service, and a lower contribution to the segregated funds based on the current approved contribution schedule. Although the projected 2021 regulatory taxable income of $280.2M (and resulting income tax expense) are similar to the 2020 forecast, it is lower than the 2020 taxable income before the application of the losses. This decrease in 2021 is largely attributable to lower depreciation and amortization expense related to the Pickering station, which is assumed to be close to fully depreciated by the end of 2020 based on the current accounting station end-of-life date. Station end-of-life dates and depreciation and amortization expense are discussed in Ex. F4-1-1. All forecast regulatory tax losses arising during the test period are utilized during the test period.

The negative regulatory income tax expense shown for the nuclear facilities for 2013 largely represents the regulatory tax loss of $211.6M in 2013, which was fully utilized by reducing the income tax expense in the 2014 nuclear revenue requirement approved in EB-2013-0321.[2] The negative regulatory income tax expense for the nuclear facilities over the 2014-2016 period primarily reflects directly assigned SR&ED ITCs related to those years.

5.0 COMMODITY TAX

Pursuant to the *Excise Tax Act* (Canada) OPG is subject to the 13 per cent Harmonized Sales Tax ("HST") on almost all of its purchases of goods and services. The recoverable portion of HST paid by OPG is claimed as input tax credits on returns filed monthly. The recoverable portion of HST forecast to be paid is therefore not included in the revenue requirement. The non-recoverable portion, which results from the restrictions pursuant to the *Excise Tax Act* (Canada) (i.e., restricted input tax credits), forms part of the cost of the

[2] EB-2013-0321 Payment Amounts Order, Table 7a, Note 5

underlying item (e.g., OM&A, capital, inventory, etc.) and continues to be included either in the test period forecasts for these items or Other centrally held costs presented in Ex. F4-4-1. OPG's purchases of energy (electricity, gas, steam, fuel) for non-production purposes are examples of items subject to restricted input tax credits. As in EB-2010-0008 and EB-2013-0321, the impact of HST is also incorporated into the computation of the cash working capital component of rate base presented in Ex. B1-1-2.

Since the introduction of HST in Ontario effective July 1, 2010 and prior to July 1, 2015, the restriction on input tax credits for the specified purchases was applied at the rate of 100% on the provincial component of the tax. Effective July 1, 2015 the restriction rate has been reduced to 75%. The restriction on full input tax credits will continue to be gradually phased out through further reductions in the restriction rates: 50% effective July 1, 2016, 25% effective July 1, 2017 and 0% effective July 1, 2018.

Where applicable, OPG continues to pay duty under the *Customs Act (*Canada) on goods imported into Canada; however, most of these imports continue to be either exempt or have duty free status through the North American Free Trade Agreement. For supply and installation contracts, the contractor's price includes duty, if applicable, on the goods imported to perform the work. Any duty paid forms part of the cost of the underlying item.

6.0 PROPERTY TAX EXPENSE

The nature, basis, and components of OPG's property tax expense are unchanged from the evidence presented in EB-2013-0321 and EB-2010-0008. OPG remains responsible for both the payment of municipal property taxes and a payment in lieu of property tax to the OEFC. The total of these two payments is intended to represent what a commercial generating company would pay as property tax, based on full Current Value Assessment ("CVA"), and represents OPG's property tax expense. OPG's property tax expense for the regulated nuclear facilities is presented in Ex. F4-2-1 Table 2, for the historical, bridge periods and test period years. The property tax expense for the regulated nuclear facilities increases relatively gradually over the bridge and test periods, reflecting differences in municipal property tax rates and changes in property assessment values.

Municipal property taxes paid by OPG for properties that are not directly associated with specific generation business units and are held centrally continue to form part of the asset service fees, as discussed in Ex. F3-2-1. Property taxes associated with the Bruce assets are presented separately in Ex. G2-2-1.

6.1 Municipal Property Taxes

Municipal property taxes are regulated under the *Assessment Act, R.S.O. 1990* (the "Act"). For prescribed nuclear and Bruce assets, property tax payments to municipalities continue to be paid based on a statutory assessment rate of $86.11 per square meter for most of the ground floor area of "generating" buildings (e.g., buildings that are used in, or auxiliary to, the generating process, such as a powerhouse, water treatment plant, pump houses, etc.) pursuant to the Act, and at CVA for "non-generating" buildings (e.g., administration/office buildings). For both "generating" and "non-generating" buildings, the Municipal Property Assessment Corporation issues notices of assessments annually. Additionally, for "generating" buildings, OPG continues to be subject to payment in lieu of property tax discussed below.

6.2 Payment in Lieu of Property Tax

Payment in lieu of property tax is regulated through O. Reg. 224/00 under the *Electricity Act, 1998* and is paid to the OEFC. The payment in lieu of property tax represents taxes based on the difference between CVA and the prescribed municipal assessment rate of $86.11 per square meter for most of the ground floor area of certain generating assets.

As previously noted in EB-2013-0321, EB-2010-0008 and EB-2007-0905, the assessment basis under O. Reg. 224/00 has not been updated since 1999. Consequently, the CVA used for payment in lieu of property tax calculations and the payments in lieu of tax amounts themselves remain subject to a possible update. Property tax expense forecasts for all years presented in this Application assume that O. Reg. 224/00 will not be updated in those years.

Changes in property taxes resulting from a change in O. Reg. 224/00 would be recorded in the Income and Other Taxes Variance Account, as per the OEB-approved scope of the account.

ATTACHMENTS

Attachment 1: Income Tax Returns and associated Notices of Assessment for 2014 (filed separately requesting treatment as confidential material)

Includes:

Part 1 – T2 Corporation Income Tax Return Ontario Power Generation Inc.
Part 2 – T2 Corporation Income Tax Return OPG – Huron A Inc.
Part 3 – T2 Corporation Income Tax Return OPG – Huron B Inc.
Part 4 – T2 Corporation Income Tax Return OPG – Huron Common Facilities Inc.
Part 5 – Notice of Assessment – Hydro Payment in Lieu

Numbers may not add due to rounding.

Table 1
Taxes - Regulated Hydroelectric ($M)

Intentionally left blank (See Ex. A1-3-1)

Numbers may not add due to rounding.

Table 2
Taxes - Nuclear ($M)

Line No.	Cost Item	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Income Tax[1,2]**	(76.4)	(61.5)	(31.8)	(18.7)	(18.4)	(18.4)	(18.4)	51.2	51.7
	Property Tax:									
2	**Darlington NGS**	8.7	8.3	8.3	8.5	9.2	9.4	9.6	9.9	10.7
3	**Pickering NGS**	4.9	4.9	4.9	5.0	5.4	5.5	5.7	5.8	6.3
4	**Sub-total**	13.6	13.2	13.2	13.5	14.6	14.9	15.3	15.7	17.0
5	**Total**	(62.8)	(48.3)	(18.6)	(5.2)	(3.8)	(3.5)	(3.1)	66.9	68.7

Notes:

1 The income tax expense is calculated on a combined basis for OPG's prescribed facilities for the years 2013 to 2016. As described in Ex. F4-2-1, the resulting expense is allocated between the regulated hydroelectric and nuclear businesses on the basis of each business's taxable income, and for SR&ED ITCs, on the basis of the underlying expenditures.

2 Amounts for 2017 to 2021 are from Ex. F4-2-1 Table 3a, line 26.

Table 3
Calculation of Regulatory Income Taxes for Prescribed Facilities ($M)
Years Ending December 31, 2013-2016

Line No.	Particulars	Note	2013 Actual	2014 Actual	2015 Actual	2016 Budget
			(a)	(b)	(c)	(d)
	Determination of Regulatory Taxable Income					
1	**Regulatory Earnings Before Tax**	1	(56.7)	271.6	162.2	162.2
	Additions for Regulatory Tax Purposes:					
2	**Depreciation and Amortization**		319.1	395.8	437.6	458.3
3	**Nuclear Waste Management Expenses**		25.1	31.3	57.7	60.0
4	**Receipts from Nuclear Segregated Funds**		44.7	42.3	41.1	66.1
5	**Pension and OPEB Accrual**		305.3	384.8	439.6	437.9
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**		62.9	41.9	49.5	165.3
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**		(18.7)	(12.4)	(4.5)	(8.9)
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**		76.8	75.2	70.3	65.8
9	**Disallowance of Niagara Tunnel Project Expenditures**		0.0	77.2	2.1	(21.6)
10	**Taxable SR&ED Investment Tax Credits**		28.4	19.2	62.3	18.7
11	**Other**		20.2	39.4	61.1	61.8
12	**Total Additions**		863.8	1,094.7	1,216.8	1,303.3
	Deductions for Regulatory Tax Purposes:					
13	**CCA**	2,3	307.7	404.3	425.7	513.8
14	**Cash Expenditures for Nuclear Waste Management & Decommissioning**		104.7	109.1	126.3	162.2
15	**Contributions to Nuclear Segregated Funds**		98.1	170.1	172.8	176.7
16	**Pension Plan Contributions**		242.9	322.5	331.3	326.6
17	**OPEB/SPP Payments**		81.9	97.0	108.3	111.3
18	**Reversal of Return on Rate Base Recorded in Deferral and Variance Accounts**		50.9	55.0	0.4	12.0
19	**Deductible SR&ED Qualifying Expenditures**		130.9	174.8	40.3	28.5
20	**Other**		1.6	11.0	6.7	24.2
21	**Total Deductions**		1,018.7	1,343.7	1,211.7	1,355.3
22	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 12 - line 21)	4	(211.6)	22.7	167.3	110.2
23	**Tax Loss Carry-Over**	5	0.0	0.0	0.0	0.0
24	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 22 + line 23)		(211.6)	22.7	167.3	110.2
25	**Regulatory Income Taxes - Federal** (line 24 x line 29)		(31.7)	3.4	25.1	16.5
26	**Regulatory Income Taxes - Provincial** (line 24 x line 30)		(21.2)	2.3	16.7	11.0
27	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(23.6)	(61.7)	(31.9)	(18.8)
28	**Total Regulatory Income Taxes** (line 25 + line 26 + line 27)		(76.5)	(56.0)	9.9	8.7
	Income Tax Rate:					
29	**Federal Tax**		15.00%	15.00%	15.00%	15.00%
30	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%
31	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%

For notes see Table 3b.

Table 3a
Calculation of Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)
Years Ending December 31, 2017-2021

Line No.	Particulars	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	Determination of Regulatory Taxable Income						
1	**Regulatory Earnings Before Tax**	1	198.3	214.2	222.8	470.8	503.2
	Additions for Regulatory Tax Purposes:						
2	**Depreciation and Amortization**		346.9	378.7	384.0	524.9	338.1
3	**Nuclear Waste Management Expenses**		57.8	59.8	72.1	61.9	63.1
4	**Receipts from Nuclear Segregated Funds**		85.0	108.3	140.0	208.4	191.6
5	**Pension and OPEB Accrual**	6	272.0	280.4	289.5	271.3	279.9
6	**Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct**		(24.0)	(24.0)	0.0	0.0	0.0
7	**Regulatory Liability Amortization - Income and Other Taxes Variance Acct**		(2.2)	(2.2)	0.0	0.0	0.0
8	**Adjustment Related to Financing Cost for Nuclear Liabilities**		39.6	37.1	34.5	31.9	30.2
9	**Taxable SR&ED Investment Tax Credits**		18.4	18.4	18.4	18.4	18.4
10	**Other**		63.7	49.2	38.4	38.6	40.2
11	**Total Additions**		857.2	905.7	976.8	1,155.4	961.4
	Deductions for Regulatory Tax Purposes:						
12	**CCA**	2,3	394.2	504.4	571.1	594.8	597.0
13	**Cash Expenditures for Nuclear Waste Management & Decommissioning**		166.0	177.4	200.6	230.7	228.0
14	**Contributions to Nuclear Segregated Funds**		156.1	175.3	265.7	35.2	35.2
15	**Pension Plan Contributions**		171.1	175.5	180.3	157.2	162.1
16	**OPEB/SPP Payments**		100.9	104.9	109.2	114.1	117.8
17	**Deductible SR&ED Qualifying Expenditures**		27.7	27.7	27.7	27.7	27.7
18	**Other**		20.3	0.1	1.1	5.7	16.5
19	**Total Deductions**		1,036.2	1,165.4	1,355.7	1,165.4	1,184.3
20	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 11 - line 19)		19.3	(45.5)	(156.1)	460.7	280.2
21	**Tax Loss Carry-Over**	5	(19.3)	45.5	156.1	(182.3)	0.0
22	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 20 + line 21)		0.0	0.0	0.0	278.4	280.2
23	**Regulatory Income Taxes - Federal** (line 22 x line 27)		0.0	0.0	0.0	41.8	42.0
24	**Regulatory Income Taxes - Provincial** (line 22 x line 28)		0.0	0.0	0.0	27.8	28.0
25	**Regulatory Income Taxes - SR&ED Investment Tax Credits**		(18.4)	(18.4)	(18.4)	(18.4)	(18.4)
26	**Total Regulatory Income Taxes** (line 23 + line 24 + line 25)		(18.4)	(18.4)	(18.4)	51.2	51.7
	Income Tax Rate:						
27	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
28	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
29	**Total Income Tax Rate**		25.00%	25.00%	25.00%	25.00%	25.00%

For notes see Table 3b.

Table 3b
Notes to Table 3 and 3a
Calculation of Regulatory Income Taxes
Years Ending December 31, 2017-2021

Notes:
1 Nuclear Regulatory Earnings Before Tax for 2016 are from Ex. I1-1-1, Table 4, line 20. Regulatory Earnings Before Tax for 2017-2021 are calculated as follows :

Line No.	Item	Reference	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(e)	(f)	(g)	(h)	(i)
1a	After Tax Return on Equity - Presecribed Nuclear Facilities	Ex. I1-1-1, Table 1, line 12	150.6	158.2	155.3	337.5	358.4
2a	Less: Bruce Lease Net Revenues		(66.1)	(74.3)	(85.9)	(82.1)	(93.1)
3a		line 1a - line 2a	216.7	232.6	241.2	419.5	451.5
4a	Additions for Regulatory Tax Purposes	line 11	857.2	905.7	976.8	1,155.4	961.4
5a	Deductions for Regulatory Tax Purposes	line 19	1,036.2	1,165.4	1,355.7	1,165.4	1,184.3
6a		line 3a + line 4a - line 5a	37.7	(27.1)	(137.7)	409.5	228.6
7a	Regulatory Income Taxes - Federal	(lines 6a + 13a + 25) x line 27 / (1 - line 29)	2.9	(6.8)	(23.4)	69.1	42.0
8a	Regulatory Income Taxes - Provincial	(lines 6a + 13a + 25) x line 28 / (1 - line 29)	1.9	(4.5)	(15.6)	46.1	28.0
9a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	(18.4)	(18.4)	(18.4)	(18.4)
10a	Total Regulatory Income Taxes Before Loss Carry-Over	line 7a + line 8a + line 9a	(13.6)	(29.8)	(57.4)	96.8	51.7
11a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal	line 21 x line 27	(2.9)	6.8	23.4	(27.3)	0.0
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial	line 21 x line 28	(1.9)	4.6	15.6	(18.2)	0.0
13a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 11a + line 12a	(4.8)	11.4	39.0	(45.6)	0.0
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 7a + line 11a	0.0	0.0	0.0	41.8	42.0
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 8a + line 12a	0.0	0.0	0.0	27.8	28.0
16a	Regulatory Income Taxes - SR&ED Investment Tax Credits	line 25	(18.4)	(18.4)	(18.4)	(18.4)	(18.4)
17a	Total Regulatory Income Taxes After Tax Loss Carry-Over	line 14a + line 15a + line 16a	(18.4)	(18.4)	(18.4)	51.2	51.7
18a	After Tax Return on Equity	line 1a	150.6	158.2	155.3	337.5	358.4
19a	Less: Bruce Lease Net Revenues		(66.1)	(74.3)	(85.9)	(82.1)	(93.1)
20a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	(18.4)	(18.4)	(18.4)	51.2	51.7
21a	Regulatory Earnings Before Tax	lines 18a - 19a + 20a	198.3	214.2	222.8	470.8	503.2

2 Amounts for 2014-2021 are from Ex. F4-2-1 Tables 5-12, line 20, col (j) - col. (i), respectively.
3 As noted in EB-2013-0321, OPG has elected to claim early CCA for the Darlington Refurbishment Project expenditures available under the Income Tax Act (Canada). Resulting total annual CCA for the Darlington Refurbishment Project expenditures is as follows: 2014 - $33.2M, 2015 - $66.7M, 2016 - $123.5M, 2017 - $183.1M, 2018 - $283.7M, 2019 - $354.4M, 2020 - $380.8M, 2021 - $383.2M
4 The tax loss for 2013 is as shown in EB-2013-0321 Ex J13.4, Att. 1, line 33, col. (8). The loss was utilized by being applied to reduce the 2014 revenue requirement in the EB-2013-0321 Payment Amounts Order.
5 As discussed in Ex. F4-2-1, section 3.1, in a situation where a tax loss is forecast in a given year(s) of the test period, the loss is applied (carried back or carried forward) to reduce the nuclear business unit's taxable income in other years of the test period, with any remaining tax losses carried forward to future test periods.
6 As discused in Ex. F4-2-1, section 3.2.5 and Ex. F4-3-2, OPG proposes to limit pension and OPEB costs included in the test period nuclear revenue requirement to the forecast cash requirements, while continuing to record the difference between accrual costs and cash amounts in the Pension & OPEB Cash Versus Accrual Differential Deferral Account. As such, the amount added back to earnings before tax for the test period in respect of pension and OPEB costs at line 5 is set equal to the forecast cash amounts deducted from earnings before tax at lines 15 and 16.

Table 4
Reconciliation of OPG's Tax Returns to Regulatory Income Tax Calculation for Prescribed Facilities ($M)
Year Ending December 31, 2014

		2014 Tax Returns					Adjustments		(e) - (f) - (g)
Line No.	Particulars	OPG Inc.	Subsidiaries	(a) + (b) Total[1]	Unregulated	(c) - (d) Regulated[2]	Bruce Lease[3]	Other Adjustments[4]	Regulatory Tax Calc'n[5]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Determination of Taxable Income								
1	**Earnings Before Tax**	793.3	(86.9)	706.4	92.6	613.8	135.6	206.6	271.6
	Additions for Tax Purposes:								
2	**Depreciation and Amortization**	454.5	103.3	557.8	29.4	528.4	104.0	28.6	395.8
3	**Nuclear Waste Management Expenses (incl Accretion Expense)**	967.1	0.0	967.1	0.0	967.1	449.4	486.4	31.3
4	**Receipts from Nuclear Segregated Funds**	76.3	0.0	76.3	0.0	76.3	34.0	0.0	42.3
5	**Pension and OPEB Accrual**	752.8	0.0	752.8	78.6	674.2	0.0	289.4	384.8
6	**Regulatory Asset Amortization - Nuclear Liability Deferral Account**	49.9	0.0	49.9	0.0	49.9	0.0	49.9	0.0
7	**Regulatory Asset Amortization - Bruce Lease Net Revenues**	41.9	0.0	41.9	0.0	41.9	0.0	0.0	41.9
8	**Regulatory Liability Amortization - Income and Other Taxes Variance Account**	(14.1)	0.0	(14.1)	0.0	(14.1)	0.0	(1.7)	(12.4)
9	**Regulatory Asset Amortization - Tax Loss Variance Account**	120.6	0.0	120.6	0.0	120.6	0.0	120.6	0.0
10	**Regulatory Asset and Liability Amortization - Other Variance and**	84.3	0.0	84.3	0.0	84.3	0.0	84.3	0.0
11	**Adjustment Related to Financing Cost for Nuclear Liabilities**	0.0	0.0	0.0	0.0	0.0	0.0	(75.2)	75.2
12	**Taxable SR&ED Investment Tax Credits**	20.2	0.0	20.2	1.0	19.2	0.0	0.0	19.2
13	**Disallowance of Niagara Tunnel Project Expenditures**	77.2	0.0	77.2	0.0	77.2	0.0	0.0	77.2
14	**Other**	117.6	0.0	117.6	16.6	101.1	49.2	12.4	39.4
15	**Total Additions**	2,748.3	103.3	2,851.6	125.6	2,726.1	636.6	994.7	1,094.7
	Deductions for Tax Purposes:								
16	**CCA**	495.6	5.1	500.7	88.3	412.4	5.3	2.9	404.3
17	**Cash Expenditures for Nuclear Waste Mngmt & Decommissioning and Facilities Removal**	209.1	0.0	209.1	0.0	209.1	100.1	0.0	109.1
18	**Contributions to and Earnings on Nuclear Segregated Funds**	959.6	0.0	959.6	0.0	959.6	380.5	409.0	170.1
19	**Pension Plan Contributions**	360.0	0.0	360.0	37.5	322.5	0.0	(0.0)	322.5
20	**OPEB/SPP Payments**	108.5	0.0	108.5	11.5	97.0	0.0	0.0	97.0
21	**Reversal of Nuclear Liability Deferral Account Additions**	66.9	0.0	66.9	0.0	66.9	0.0	66.9	0.0
22	**Reversal of Pension and OPEB Deferral and Variance Account Additions**	296.0	0.0	296.0	0.0	296.0	0.0	296.0	0.0
23	**Reversal of Regulatory Asset and Liability - Other Deferral and Variance Account Additions**	104.7	0.0	104.7	0.0	104.7	0.0	104.7	0.0
24	**Reversal of Return on Rate Base Recorded in Capacity Refurbishment Variance Account**	0.0	0.0		0.0	0.0	0.0	(55.0)	55.0
25	**Deductible SR&ED Qualifying Expenditures**	180.6	0.0	180.6	5.8	174.8	0.0	0.0	174.8
26	**Construction In Progress Interest Capitalized**	61.0	0.0	61.0	6.7	54.3	0.0	54.3	0.0
27	**Other**	307.2	0.0	307.2	239.1	68.1	58.9	(1.7)	11.0
28	**Total Deductions**	3,149.2	5.1	3,154.3	388.9	2,765.4	544.7	877.0	1,343.7
29	**Taxable Income** (line 1 + line 15 - line 28)	392.4	11.3	403.7	(170.7)	574.5	227.5	324.3	22.7

Notes:
1. Represents the consolidated OPG amounts. Earnings Before Tax at line 1 are as reported in OPG's 2014 audited consolidated financial statements and found at Ex. A2-1-1, Att. 2, p. 111.
2. Represents amounts for OPG's "regulated" segments as reported in accordance with generally accepted accounting principles in OPG's audited consolidated financial statements.
3. Represents Bruce Lease net revenues included in col. (e). Bruce Lease earnings before tax at line 1 are as per Ex. G2-2-1 Table 7, col. (b), line 1 and taxable income at line 34 as per Ex. G2-2-1 Table 7, col. (b), line 17
4. Represents items of income and expense reflected in OPG's income tax returns that do not form part of the regulatory income tax claculations as per OEB-approved methodology, and vice versa, as well as as line item presentation differenes bewteen the tax returns and the regulatory income tax calculation that do not impact taxable income
5. Amounts are as shown in Ex. F4-2-1 Table 3, col. (b).

Numbers may not add due to rounding.

Table 5
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations ($M)
Year Ending December 31, 2014

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,395.2	85.3	(77.3)	0.0	2,403.2	42.6	2,360.6	4%	0.0	94.4	2,308.8
2	**1-rolling start**	349.3	35.0	0.0	0.0	384.4	0.0	384.4	4%	0.0	15.4	369.0
3	**1.1**	176.8	7.6	2.3	0.0	186.6	3.8	182.8	6%	0.0	11.0	175.6
4	**1.1-rolling start**	73.0	0.0	0.0	0.0	73.0	0.0	73.0	6%	0.0	4.4	68.6
5	**2**	1,776.6	0.0	0.0	0.0	1,776.6	0.0	1,776.6	6%	0.0	106.6	1,670.0
6	**3**	0.4	0.0	0.0	0.0	0.4	0.0	0.4	5%	0.0	0.0	0.3
7	**6**	0.0	4.1	0.0	0.0	4.1	2.1	2.1	10%	0.0	0.2	3.9
8	**8**	300.4	50.1	2.3	0.9	351.9	24.6	327.3	20%	0.0	65.5	286.5
9	**8-rolling start**	2.4	0.0	0.0	0.0	2.4	0.0	2.4	20%	0.0	0.5	1.9
10	**10**	15.7	0.3	0.0	0.2	15.9	0.2	15.7	30%	0.0	4.7	11.2
11	**12**	6.3	8.1	0.0	0.0	14.4	4.1	10.3	100%	0.0	10.3	4.1
12	**13**	3.0	1.0	0.0	0.0	4.0	0.5	3.5	N/A	0.0	0.7	3.3
13	**17**	780.9	196.4	(2.0)	0.0	975.4	98.2	877.2	8%	0.0	70.2	905.2
14	**17-rolling start**	23.9	117.2	0.0	0.0	141.2	0.0	141.2	8%	0.0	11.3	129.9
15	**42**	4.5	0.0	0.0	0.0	4.5	0.0	4.5	12%	0.0	0.5	4.0
16	**43.1**	0.3	0.0	0.0	0.0	0.3	0.0	0.3	30%	0.0	0.1	0.2
17	**43.2**	9.6	2.7	0.0	0.0	12.3	1.3	10.9	50%	0.0	5.5	6.8
18	**45**	0.2	0.0	0.0	0.0	0.2	0.0	0.2	45%	0.0	0.1	0.1
19	**50**	4.6	1.5	0.0	0.0	6.1	0.8	5.4	55%	0.0	2.9	3.2
20	**Total**	5,923.1	509.4	(74.6)	1.1	6,356.8	178.1	6,178.7		0.0	404.3	5,952.6

Notes:
1 Net amount at line 20 represents capital expenditures on the Niagara Tunnel Project in excess of the amount allowed in rate base in EB-2013-0321.

Numbers may not add due to rounding.

Table 6
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations ($M)
Year Ending December 31, 2015

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,308.8	60.9	(73.6)	0.0	2,296.1	30.4	2,265.7	4%	0.0	90.6	2,205.5
2	**1-rolling start**	369.0	0.0	(23.6)	0.0	345.4	0.0	345.4	4%	0.0	13.8	331.5
3	**1.1**	175.6	55.6	97.8	0.0	329.0	27.8	301.2	6%	0.0	18.1	310.9
4	**1.1-rolling start**	68.6	0.0	0.0	0.0	68.6	0.0	68.6	6%	0.0	4.1	64.5
5	**2**	1,670.0	0.0	0.0	0.0	1,670.0	0.0	1,670.0	6%	0.0	100.2	1,569.8
6	**3**	0.3	0.0	0.0	0.0	0.3	0.0	0.3	5%	0.0	0.0	0.3
7	**6**	3.9	0.0	0.0	0.0	3.9	0.0	3.9	10%	0.0	0.4	3.5
8	**8**	286.5	72.4	(0.3)	0.0	358.6	36.2	322.4	20%	0.0	64.5	294.1
9	**8-rolling start**	1.9	0.0	0.0	0.0	1.9	0.0	1.9	20%	0.0	0.4	1.6
10	**10**	11.2	0.2	0.0	0.0	11.4	0.1	11.3	30%	0.0	3.4	8.0
11	**12**	4.1	9.6	0.0	0.0	13.6	4.8	8.9	100%	0.0	8.9	4.8
12	**13**	3.3	0.0	0.0	0.0	3.3	0.0	3.3	N/A	0.0	0.8	2.5
13	**17**	905.2	337.0	(0.9)	0.0	1,241.3	168.5	1,072.8	8%	0.0	85.8	1,155.5
14	**17-rolling start**	129.9	222.0	0.0	0.0	351.9	0.0	351.9	8%	0.0	28.1	323.7
15	**42**	4.0	0.0	0.0	0.0	4.0	0.0	4.0	12%	0.0	0.5	3.5
16	**43.1**	0.2	0.0	0.0	0.0	0.2	0.0	0.2	30%	0.0	0.1	0.1
17	**43.2**	6.8	0.3	0.0	0.0	7.1	0.1	7.0	50%	0.0	3.5	3.6
18	**45**	0.1	0.0	0.0	0.0	0.1	0.0	0.1	45%	0.0	0.0	0.1
19	**50**	3.2	2.8	0.0	0.0	6.0	1.4	4.6	55%	0.0	2.5	3.5
20	**Total**	5,952.6	760.7	(0.6)	0.0	6,712.7	269.4	6,443.3		0.0	425.7	6,287.0

Notes:
1 Amounts are from Ex. F4-2-1 Table 5, col. (k).

Numbers may not add due to rounding.

Table 7

Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Operations ($M)

Year Ending December 31, 2016

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Net Adjustments[2]	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	2,205.5	145.8	17.8	0.0	2,369.1	72.9	2,296.2	4%	0.0	91.8	2,277.2
2	**1-rolling start**	331.5	0.0	(20.5)	0.0	311.1	0.0	311.1	4%	0.0	12.4	298.6
3	**1.1**	310.9	52.7	22.6	0.0	386.2	26.3	359.8	6%	0.0	21.6	364.6
4	**1.1-rolling start**	64.5	0.0	0.0	0.0	64.5	0.0	64.5	6%	0.0	3.9	60.6
5	**2**	1,569.8	0.0	0.0	0.0	1,569.8	0.0	1,569.8	6%	0.0	94.2	1,475.6
6	**3**	0.3	0.0	0.0	0.0	0.3	0.0	0.3	5%	0.0	0.0	0.3
7	**6**	3.5	0.0	0.0	0.0	3.5	0.0	3.5	10%	0.0	0.4	3.2
8	**8**	294.1	130.4	0.0	0.0	424.5	65.2	359.3	20%	0.0	71.9	352.6
9	**8-rolling start**	1.6	0.0	0.0	0.0	1.6	0.0	1.6	20%	0.0	0.3	1.2
10	**10**	8.0	20.6	0.0	0.0	28.6	10.3	18.3	30%	0.0	5.5	23.1
11	**12**	4.8	37.3	0.0	0.0	42.1	18.7	23.4	100%	0.0	23.4	18.7
12	**13**	2.5	0.0	0.0	0.0	2.5	0.0	2.5	N/A	0.0	0.8	1.7
13	**17**	1,155.5	674.4	0.0	0.0	1,829.9	337.2	1,492.7	8%	0.0	119.4	1,710.5
14	**17-rolling start**	323.7	426.8	0.0	0.0	750.5	0.0	750.5	8%	0.0	60.0	690.4
15	**42**	3.5	0.9	0.0	0.0	4.4	0.5	4.0	12%	0.0	0.5	3.9
16	**43.1**	0.1	0.0	0.0	0.0	0.1	0.0	0.1	30%	0.0	0.0	0.1
17	**43.2**	3.6	0.0	0.0	0.0	3.6	0.0	3.6	50%	0.0	1.8	1.8
18	**45**	0.1	0.0	0.0	0.0	0.1	0.0	0.1	45%	0.0	0.0	0.0
19	**50**	3.5	14.2	0.0	0.0	17.7	7.1	10.6	55%	0.0	5.8	11.8
20	**Total**	6,287.0	1,503.1	19.9	0.0	7,810.0	538.1	7,271.8		0.0	513.8	7,296.2

1 Amounts are from Ex. F4-2-1 Table 6, col. (k).

2 Net amount at line 20 represents the Undepreciated Capital Cost at January 1, 2016 for the portion of the EB-2031-0321 Niagara Tunnel Project disallowance that was reversed in EB-2014-0369. The difference between the EB-2014-0369 reversal amount of $21.6M and the net adjustment shown of $19.9M includes CCA for the November 1, 2014 to December 31, 2015 period, which is recorded in the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account as a ratepayer credit.

Numbers may not add due to rounding.

Table 8
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2017

Line No.	Class	Undepreciated Capital Cost at Beginning of Year	Cost of Acquisitions[2]	Net Adjustments[3]	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	729.0	216.2	0.0	0.0	945.2	108.1	837.1	4%	0.0	33.5	911.7
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	341.4	380.7	0.0	0.0	722.1	190.3	531.8	6%	0.0	31.9	690.2
4	**1.1-rolling start**	60.6	0.0	0.0	0.0	60.6	0.0	60.6	6%	0.0	3.6	57.0
5	**2**	(0.0)	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	303.0	98.0	0.0	0.0	401.0	49.0	352.0	20%	0.0	70.4	330.6
9	**8-rolling start**	1.2	0.0	0.0	0.0	1.2	0.0	1.2	20%	0.0	0.2	1.0
10	**10**	18.9	18.5	0.0	0.0	37.3	9.2	28.1	30%	0.0	8.4	28.9
11	**12**	15.2	31.1	0.0	0.0	46.3	15.5	30.7	100%	0.0	30.7	15.5
12	**13**	1.7	0.0	0.0	0.0	1.7	0.0	1.7	N/A	0.0	0.8	0.9
13	**17**	1,417.3	272.5	0.0	0.0	1,689.8	136.2	1,553.5	8%	0.0	124.3	1,565.5
14	**17-rolling start**	690.4	350.3	0.0	0.0	1,040.7	0.0	1,040.7	8%	0.0	83.3	957.4
15	**42**	0.6	0.7	0.0	0.0	1.3	0.3	1.0	12%	0.0	0.1	1.2
16	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
17	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
18	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
19	**50**	11.2	2.8	0.0	0.0	14.0	1.4	12.6	55%	0.0	6.9	7.1
20	**Total**	3,590.7	1,370.6	0.0	0.0	4,961.3	510.2	4,451.1		0.0	394.2	4,567.1

Numbers may not add due to rounding.

Table 9
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2018

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	911.7	144.9	0.0	0.0	1,056.6	72.5	984.2	4%	0.0	39.4	1,017.3
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	690.2	12.4	0.0	0.0	702.6	6.2	696.4	6%	0.0	41.8	660.8
4	**1.1-rolling start**	57.0	0.0	0.0	0.0	57.0	0.0	57.0	6%	0.0	3.4	53.6
5	**2**	(0.0)	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	330.6	79.0	0.0	0.0	409.6	39.5	370.1	20%	0.0	74.0	335.6
9	**8-rolling start**	1.0	0.0	0.0	0.0	1.0	0.0	1.0	20%	0.0	0.2	0.8
10	**10**	28.9	12.7	0.0	0.0	41.6	6.3	35.3	30%	0.0	10.6	31.0
11	**12**	15.5	27.6	0.0	0.0	43.1	13.8	29.3	100%	0.0	29.3	13.8
12	**13**	0.9	0.0	0.0	0.0	0.9	0.0	0.9	N/A	0.0	0.5	0.4
13	**17**	1,565.5	1,238.0	0.0	0.0	2,803.5	619.0	2,184.5	8%	0.0	174.8	2,628.7
14	**17-rolling start**	957.4	613.6	0.0	0.0	1,571.0	0.0	1,571.0	8%	0.0	125.7	1,445.3
15	**42**	1.2	0.6	0.0	0.0	1.8	0.3	1.5	12%	0.0	0.2	1.6
16	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
17	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
18	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
19	**50**	7.1	2.8	0.0	0.0	9.9	1.4	8.5	55%	0.0	4.7	5.2
20	**Total**	4,567.1	2,131.5	0.0	0.0	6,698.6	759.0	5,939.6		0.0	504.4	6,194.1

Notes:
1 Amounts are from Ex. F4-2-1 Table 8, col. (k).

Numbers may not add due to rounding.

Table 10
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2019

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,017.3	58.8	0.0	0.0	1,076.1	29.4	1,046.7	4%	0.0	41.9	1,034.2
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	660.8	7.9	0.0	0.0	668.7	3.9	664.8	6%	0.0	39.9	628.8
4	**1.1-rolling start**	53.6	0.0	0.0	0.0	53.6	0.0	53.6	6%	0.0	3.2	50.4
5	**2**	(0.0)	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	335.6	54.1	0.0	0.0	389.7	27.0	362.6	20%	0.0	72.5	317.1
9	**8-rolling start**	0.8	0.0	0.0	0.0	0.8	0.0	0.8	20%	0.0	0.2	0.6
10	**10**	31.0	9.8	0.0	0.0	40.8	4.9	35.9	30%	0.0	10.8	30.0
11	**12**	13.8	20.6	0.0	0.0	34.3	10.3	24.1	100%	0.0	24.1	10.3
12	**13**	0.4	0.0	0.0	0.0	0.4	0.0	0.4	N/A	0.0	0.1	0.3
13	**17**	2,628.7	591.5	0.0	0.0	3,220.2	295.7	2,924.4	8%	0.0	234.0	2,986.2
14	**17-rolling start**	1,445.3	313.3	0.0	0.0	1,758.6	0.0	1,758.6	8%	0.0	140.7	1,617.9
15	**42**	1.6	0.4	0.0	0.0	1.9	0.2	1.8	12%	0.0	0.2	1.7
16	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
17	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
18	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
19	**50**	5.2	2.8	0.0	0.0	8.1	1.4	6.6	55%	0.0	3.7	4.4
20	**Total**	6,194.1	1,059.1	0.0	0.0	7,253.2	372.9	6,880.3		0.0	571.1	6,682.1

Notes:
1 Amounts are from Ex. F4-2-1 Table 9, col. (k).

Numbers may not add due to rounding.

Table 11
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2020

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,034.2	80.3	0.0	0.0	1,114.5	40.1	1,074.3	4%	0.0	43.0	1,071.5
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	628.8	10.6	0.0	0.0	639.5	5.3	634.2	6%	0.0	38.0	601.4
4	**1.1-rolling start**	50.4	0.0	0.0	0.0	50.4	0.0	50.4	6%	0.0	3.0	47.3
5	**2**	(0.0)	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	317.1	69.2	0.0	0.0	386.3	34.6	351.7	20%	0.0	70.3	316.0
9	**8-rolling start**	0.6	0.0	0.0	0.0	0.6	0.0	0.6	20%	0.0	0.1	0.5
10	**10**	30.0	12.3	0.0	0.0	42.3	6.1	36.2	30%	0.0	10.9	31.5
11	**12**	10.3	24.8	0.0	0.0	35.1	12.4	22.7	100%	0.0	22.7	12.4
12	**13**	0.3	0.0	0.0	0.0	0.3	0.0	0.3	N/A	0.0	0.1	0.2
13	**17**	2,986.2	870.8	0.0	0.0	3,857.0	435.4	3,421.6	8%	0.0	273.7	3,583.3
14	**17-rolling start**	1,617.9	0.3	0.0	0.0	1,618.2	0.0	1,618.2	8%	0.0	129.5	1,488.7
15	**42**	1.7	0.5	0.0	0.0	2.2	0.2	2.0	12%	0.0	0.2	2.0
16	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
17	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
18	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
19	**50**	4.4	2.8	0.0	0.0	7.2	1.4	5.8	55%	0.0	3.2	4.0
20	**Total**	6,682.1	1,071.6	0.0	0.0	7,753.6	535.6	7,218.0		0.0	594.8	7,158.8

Notes:
1 Amounts are from Ex. F4-2-1 Table 10, col. (k).

Numbers may not add due to rounding.

Table 12
Undepreciated Capital Cost and Capital Cost Allowance Schedule for OPG's Regulated Nuclear Operations ($M)
Year Ending December 31, 2021

Line No.	Class	Undepreciated Capital Cost at Beginning of Year[1]	Cost of Acquisitions	Net Adjustments	Proceeds of Dispositions	(a)+(b)+(c)-(d) UCC1	50% Rule	(e)-(f) Reduced Undepreciated Capital Cost	CCA Rate	Recapture/ Terminal Loss	Capital Cost Allowance	(e)+(i)-(j) Undepreciated Capital Cost at End of Year
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**1**	1,071.5	61.4	0.0	0.0	1,132.9	30.7	1,102.2	4%	0.0	44.1	1,088.8
2	**1-rolling start**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	4%	0.0	0.0	0.0
3	**1.1**	601.4	8.4	0.0	0.0	609.8	4.2	605.6	6%	0.0	36.3	573.5
4	**1.1-rolling start**	47.3	0.0	0.0	0.0	47.3	0.0	47.3	6%	0.0	2.8	44.5
5	**2**	(0.0)	0.0	0.0	0.0	(0.0)	0.0	(0.0)	6%	0.0	(0.0)	(0.0)
6	**3**	(0.0)	0.0	0.0	0.0	(0.0)	0.0	(0.0)	5%	0.0	(0.0)	(0.0)
7	**6**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10%	0.0	0.0	0.0
8	**8**	316.0	56.8	0.0	0.0	372.8	28.4	344.4	20%	0.0	68.9	303.9
9	**8-rolling start**	0.5	0.0	0.0	0.0	0.5	0.0	0.5	20%	0.0	0.1	0.4
10	**10**	31.5	10.0	0.0	0.0	41.5	5.0	36.5	30%	0.0	10.9	30.5
11	**12**	12.4	21.3	0.0	0.0	33.7	10.7	23.1	100%	0.0	23.1	10.7
12	**13**	0.2	0.0	0.0	0.0	0.2	0.0	0.2	N/A	0.0	0.1	0.0
13	**17**	3,583.3	39.4	0.0	0.0	3,622.6	19.7	3,603.0	8%	0.0	288.2	3,334.4
14	**17-rolling start**	1,488.7	0.0	0.0	0.0	1,488.7	0.0	1,488.7	8%	0.0	119.1	1,369.6
15	**42**	2.0	0.4	0.0	0.0	2.4	0.2	2.2	12%	0.0	0.3	2.1
16	**43.1**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	30%	0.0	0.0	0.0
17	**43.2**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50%	0.0	0.0	0.0
18	**45**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45%	0.0	0.0	0.0
19	**50**	4.0	2.8	0.0	0.0	6.8	1.4	5.4	55%	0.0	3.0	3.9
20	**Total**	7,158.8	200.5	0.0	0.0	7,359.3	100.3	7,259.1		0.0	597.0	6,762.3

Notes:
1 Amounts are from Ex. F4-2-1 Table 11, col. (k).

COMPENSATION AND BENEFITS

1.0 PURPOSE

The purpose of this exhibit is to:

- Describe the work undertaken by OPG employees and where that work occurs,
- Provide 2013-2021 compensation information for Nuclear,
- Discuss OPG's use of overtime,
- Describe the compensation framework for OPG's regulated facilities, and
- Introduce the results of the independent compensation study prepared by Willis Towers Watson ("Towers").

2.0 OVERVIEW

The compensation costs presented in this exhibit are equivalent to approximately 50 per cent of OPG's forecast 2017 nuclear revenue requirement, reflecting the vital role OPG employees play in producing electricity for Ontario.

OPG has a wide variety of employees, from senior executives who lead the organization, professional staff who provide technical expertise related to OPG's prescribed generation facilities, and the skilled trades who operate and maintain generating facilities. These employees work in generating stations and facilities across the province, and are largely unionized. Additional details on OPG's workforce, including the extent of unionization, working conditions, and demographics are presented in section 3.0.

Given the extent of unionization, collective bargaining plays a dominant role in determining OPG's compensation costs. Collective bargaining directly affects the wages and incentives provided to unionized employees, as well as the pensions and benefits they earn. Collective bargaining also has an indirect impact on the compensation provided to non-unionized positions because internal equity, career development and attracting experienced employees into management positions are important factors in workforce planning and development.

An overview of OPG's compensation elements for both unionized and non-unionized positions is found in section 4.0, and includes discussion of the actions that OPG has taken to manage compensation costs. This section also includes a summary of compensation costs for OPG's nuclear business, with additional details available at Attachment 1 (Full Time Equivalents ["FTE"], Compensation and Benefit Information for OPG's Nuclear Facilities ["Appendix 2k"]).

To ensure compensation costs are competitive, affordable and aligned with OPG's business strategy and the environment in which OPG operates, compensation benchmarking is undertaken. This work demonstrates that overall, OPG's Total Direct Compensation provided is reasonable and is at market.[1] Section 5.0 provides an overview of the compensation study performed by Towers and Attachment 2 contains the full report. This study meets the requirement set out by the OEB in EB-2013-0321.[2]

The pensions and benefits earned by OPG employees continue to be similar to those provided by other Ontario electricity market participants with roots in the former Ontario Hydro, including Hydro One and Bruce Power.[3] While OPG is taking steps to reduce its pension and benefits costs, such costs currently remain above those in the broader labour market. This is captured in the compensation benchmarking study described in section 5.0 and presented in Attachment 2.

Comparison of OPG's wages to those provided by Bruce Power was also undertaken by Towers. Bruce Power is OPG's closest competitor, operating in the same energy market, with a workforce represented by the same unions as OPG. Bruce Power unionized wages are higher than those of OPG. See section 6.0 for additional details on OPG's compensation relative to Bruce Power.

[1] Total Direct Compensation reflects the cash compensation paid to employees, excluding overtime. It includes base salaries and pay at risk incentives (see Attachment 2, p. 8).
[2] EB-2013-0321, Decision with Reasons, p. 76
[3] Jim Leech, 2014, *Report on the Sustainability of Electricity Sector Pension Plans to the Minister of Finance.* Retrieved from http://www.fin.gov.on.ca/en/pension/electricity-sector.pdf

In recognition of the impact that unionization has on sector-wide compensation, a broader approach to collective bargaining has been taken, involving both Hydro One and the Government of Ontario ("Government"). The resulting agreement with the Power Workers' Union ("PWU") and Society of Energy Professionals ("Society") made progress toward reducing OPG's pension contributions and modified eligibility rules and pension benefits to be provided to OPG's represented employees in the future. A summary of these negotiated changes and the commensurate pension reforms implemented for Management employees are presented in section 4.0.

3.0 OPG's WORKFORCE

At the end of 2015, OPG had 9,247 regular employees. Of this total, approximately 7,294 employees worked directly in or supported OPG's Nuclear facilities.

Unionization: OPG's staff supporting regulated operations work in a predominantly unionized environment, with approximately 90 per cent of staff belonging to either the PWU or the Society. Nearly two thirds of OPG's unionized staff belong to the PWU and approximately one third belong to the Society. The extent of unionization and the mix of PWU, Society and non-unionized staff (Management Group) have generally remained stable over the past several years.

Work Locations and Employees: OPG's nuclear employees work in generating stations and other facilities across the province as shown in Figure 1.

OPG employs individuals from a variety of disciplines, many of which are specialized technical roles. This includes engineers and operations staff that operate and maintain OPG's nuclear facilities in a safe and responsible manner.

An overview of employee counts as of December 31, 2015 by type of position is shown in Figure 2. Note that this information includes staff supporting both OPG's regulated and unregulated facilities.

Figure 1 - OPG Nuclear Work Locations

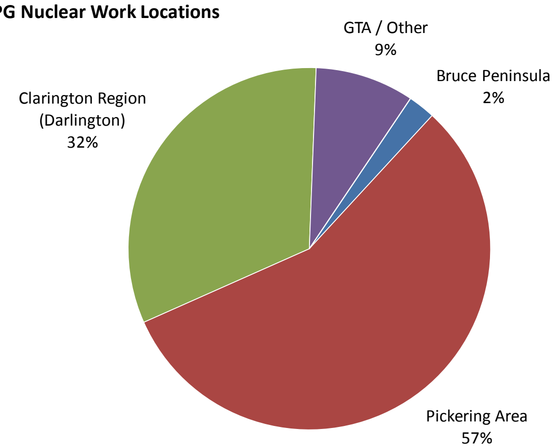
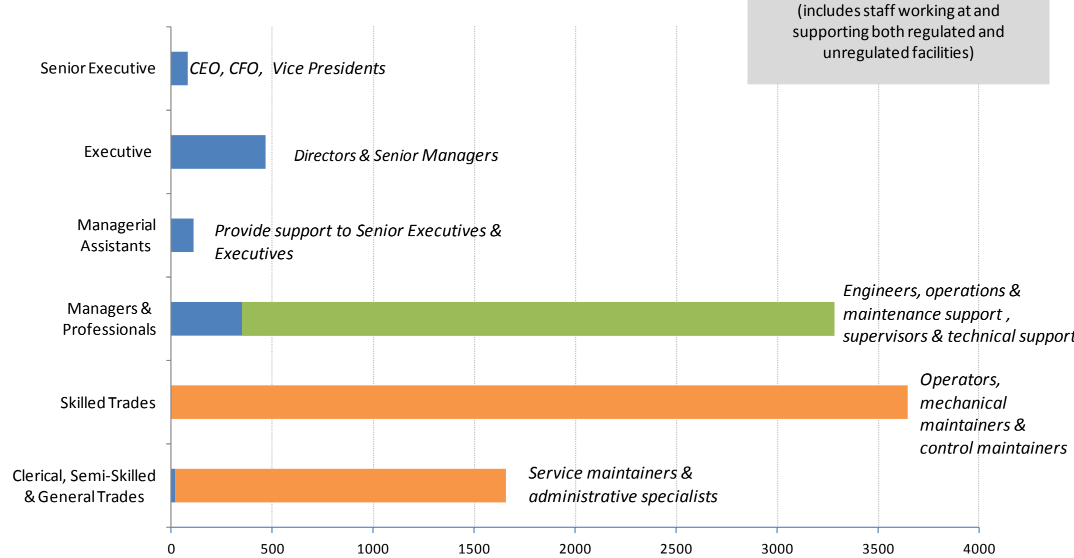


Figure 2 - OPG Regular Headcount by Type of Position (December 31, 2015)

Total Number of Regular Staff
9,247
(includes staff working at and supporting both regulated and unregulated facilities)



	Clerical, Semi-Skilled & General Trades	Skilled Trades	Managers & Professionals	Managerial Assistants	Executive	Senior Executive
Mgmt Group	15	0	353	112	467	80
Society	0	0	2933	0	0	0
PWU	1641	3646	0	0	0	0

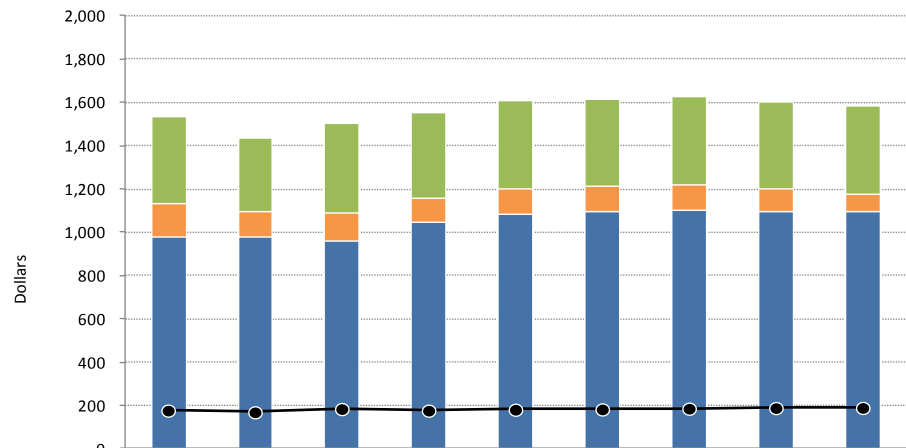
Demographics and OPG's Business Transformation: OPG has a mature and experienced workforce. By year-end 2016, approximately 20 per cent of active employees will be eligible to retire with an undiscounted pension, with an additional 4 per cent becoming eligible to retire each year thereafter.

OPG has been able to utilize this demographic profile to support its objectives of transforming the business to a more cost effective and sustainable model. As part of Business Transformation, OPG changed its structure to a centre-led matrix organization that required fewer staff to support the production of electricity. By managing staffing reductions through retirements and putting in place vacancy controls, OPG was able to reduce its regular headcount by nearly 2,700 positions between 2011 and 2015 while avoiding costly severance packages and minimizing disruptions associated with the redeployment of staff. While Business Transformation has ended as a discrete initiative, efforts to continually improve and manage OPG's resources are embedded in day-to-day operations and business plans.

4.0 COMPENSATION COSTS

Figure 3 summarizes the compensation costs for OPG's Nuclear facilities for 2013-2021 and reflects the impacts of wage escalation during the test period. The wage increases OPG negotiated in its collective agreements are moderate (i.e., increases below expected inflation), with increases arising as a result of the arbitrated progression catch up and items negotiated in exchange for pension reforms. As discussed further below, the number of FTEs grows between 2015 and 2017 before declining over the remainder of the rate period (2018-2021). This growth contributes significantly to the 2013 to 2021 trend in nuclear compensation costs.

Figure 3 - Compensation Costs for Nuclear Facilities



	2013	2014	2015	2016	2017	2018	2019	2020	2021
Pensions & Benefits (M$)*	399	342	417	397	407	400	405	404	405
Overtime (M$)	159	118	132	112	117	116	119	102	81
Base Salaries & Incentives (M$)	976	978	956	1,046	1,082	1,095	1,099	1,097	1,096
Total Compensation (M$)	1,534	1,438	1,506	1,554	1,606	1,611	1,623	1,603	1,582
Growth Rate (Total Compensation)	6%	-6%	5%	3%	3%	0%	1%	-1%	-1%
Total Compensation (K$ / FTE)	179	171	186	178	182	184	187	190	191
Full Time Equivalents**	8594	8432	8114	8721	8801	8761	8665	8430	8293

*Pension and benefits include current service costs and are shown on an accrual basis.
** FTE includes both regular and non-regular FTEs. The actual 2013 FTEs shown are adjusted from those provided in EB-2013-0321, J7.3, Attachment 1. The adjustment increases the number of FTEs by excluding the impact of banked overtime (overtime taken as time off rather than pay) and shows the 2013 Actual FTEs on a consistent basis with the remaining years in the table.

Each component of compensation is described in more detail below, beginning with staffing levels. Additional details can also be found in Attachment 1 (FTE, Compensation and Benefit Information for OPG's Nuclear Facilities ["Appendix 2k"]).

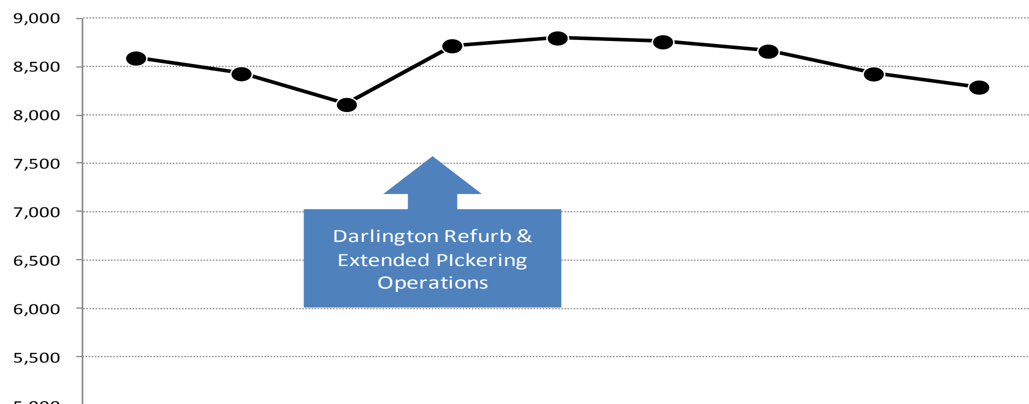
FTE Staffing levels

In 2016, staffing levels for OPG's Nuclear facilities are expected to increase by over 600 FTEs due largely to the Darlington Refurbishment Project ("DRP") and, to a lesser extent, the workforce renewal required to sustain Pickering operations. In 2015, Nuclear attrition was at its highest level in years, with over 300 retirements.[4] This represents a 20 per cent increase in the number of retirements in Nuclear compared to 2014. Over two thirds of the 2015

[4] These retirements include only those reporting to the Nuclear organization directly. Attrition associated with support staff attributed to the prescribed nuclear facilities is not reflected in this number.

retirements were in critical operations, maintenance, engineering and technical roles and will need to be replaced. As shown in Figure 4, staffing levels peak in 2017 and then decline by over 500 FTEs by 2021. Nuclear staffing levels are discussed further in Ex. F2-1-1.

Figure 4- Nuclear Full Time Equivalents (FTE)



	2013*	2014	2015	2016	2017	2018	2019	2020	2021
Temporary	634	734	843	808	833	853	816	731	694
Regular	7,960	7,698	7,271	7,912	7,968	7,909	7,848	7,699	7,599
Total	8,594	8,432	8,114	8,721	8,801	8,761	8,665	8,430	8,293

* The actual 2013 FTEs shown are adjusted from those provided in EB-2013-0321, J7.3, Attachment 1. The adjustment increases the number of FTEs by excluding the impact of banked overtime (overtime taken as time off rather than pay) and shows the 2013 Actual FTEs on a consistent basis with the remaining years in the table.

Workforce renewal leading up to the end of commercial operations at Pickering in 2022/2024 will be required to continue operating the station safely. To assist in mitigating the anticipated disruption and costs associated with deployment and involuntary terminations after Pickering is shut down, a new category of employees called “Term Employees” was negotiated with the PWU for the current collective agreement period. In general, term employees may be hired to avoid adding regular staff in circumstances where additional regular employees are likely to be laid off as a result of Pickering’s end of commercial operations. Term employees are hired with the understanding that they have no expectation of ongoing employment once Pickering’s operations cease.

Base Salaries and Incentives represent about 68 per cent of OPG’s total compensation costs related to the Nuclear facilities over the test period. These costs are largely a function of staffing levels and the collective bargaining agreements that cover approximately 90 per cent of OPG's employees.

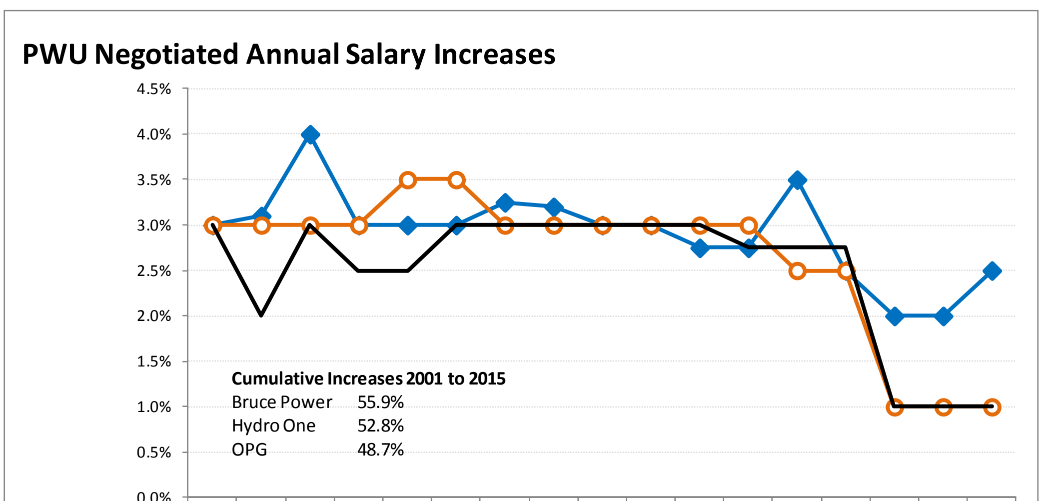
Unionized Salaries:

OPG is legally bound by its collective agreements. These agreements govern salary increases, cost of living adjustments, and progressions through established salary ranges.

OPG, with the direct involvement and support of the Government, negotiated agreements with both the PWU and Society in 2015 that will keep wage escalation below inflation. Both agreements provide for a one per cent escalation increase each year and cover a three year period, running from April 1, 2015 to March 31, 2018 for the PWU and from January 1, 2016 to December 31, 2018 for the Society.

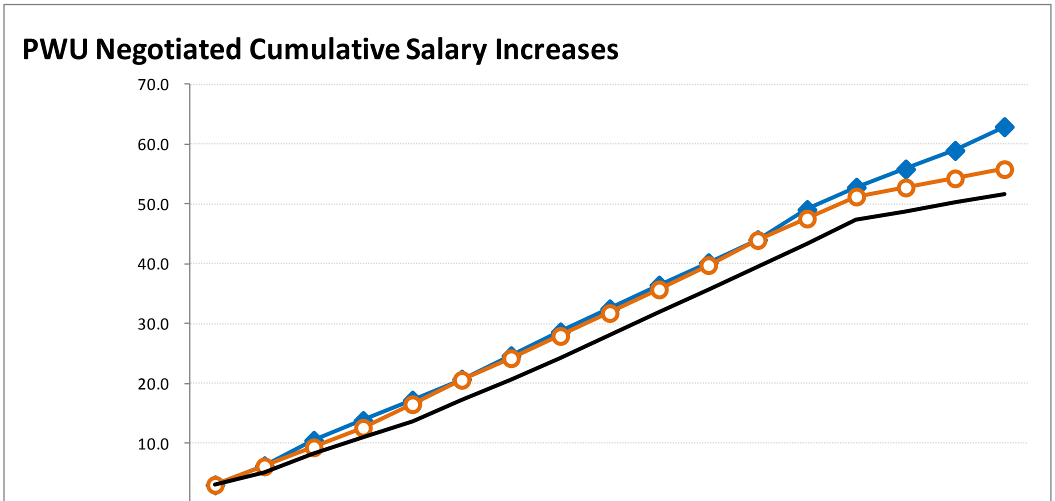
Until recently, typical union salary increases have tended to be between 2 per cent and 3 per cent per year for both OPG and other large companies within the electricity sector in Ontario, as shown in Figures 5 to 8.

Figure 5



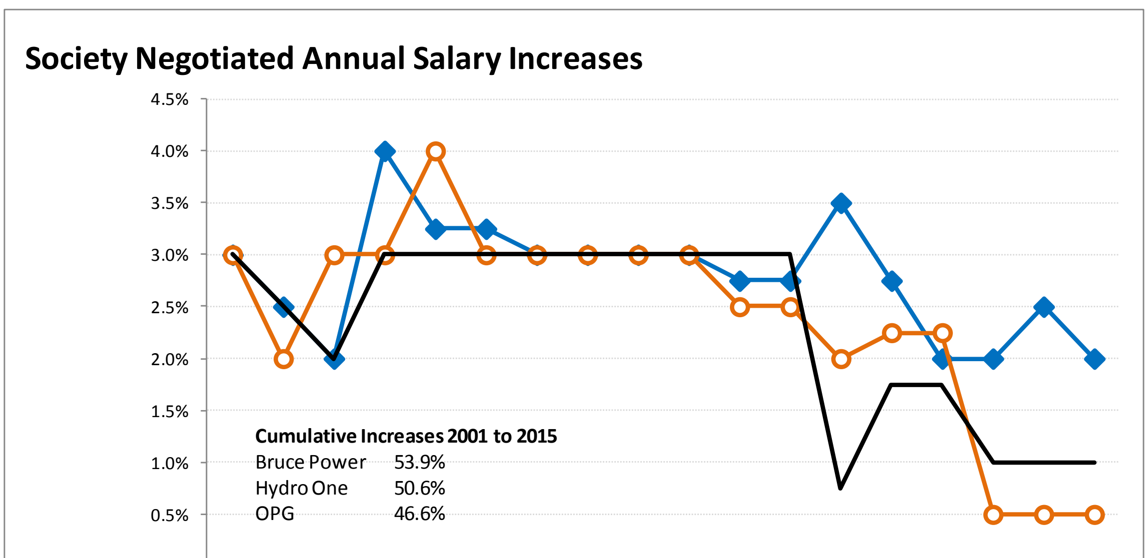
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Bruce Power	3.0%	3.1%	4.0%	3.0%	3.0%	3.0%	3.25%	3.2%	3.0%	3.0%	2.75%	2.75%	3.5%	2.5%	2.0%	2.0%	2.5%
Hydro One	3.0%	3.0%	3.0%	3.0%	3.5%	3.5%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.5%	2.5%	1.0%	1.0%	1.0%
OPG	3.0%	2.0%	3.0%	2.5%	2.5%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.75%	2.75%	2.75%	1.0%	1.0%	1.0%

Figure 6



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Bruce Power	3.0	6.2	10.4	13.8	17.2	20.7	24.6	28.6	32.4	36.4	40.2	44.0	49.1	52.8	55.9	59.0	62.9
Hydro One	3.0	6.1	9.3	12.6	16.5	20.6	24.2	27.9	31.7	35.7	39.8	44.0	47.6	51.3	52.8	54.3	55.8
OPG	3.0	5.1	8.2	10.9	13.7	17.1	20.6	24.2	28.0	31.8	35.8	39.5	43.3	47.3	48.7	50.2	51.7

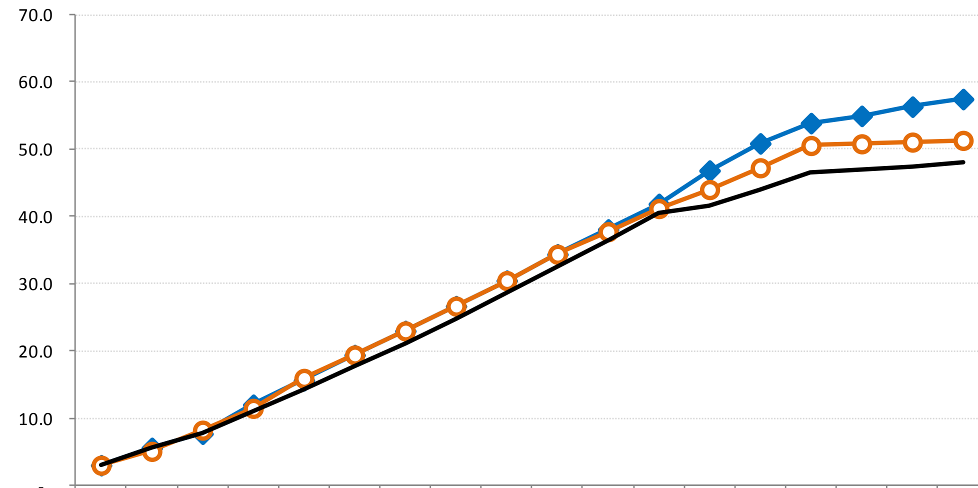
Figure 7



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Bruce Power	3.0%	2.5%	2.0%	4.0%	3.25%	3.25%	3.0%	3.0%	3.0%	3.0%	2.75%	2.75%	3.5%	2.75%	2.0%	2.0%	2.5%	2.0%
Hydro One	3.0%	2.0%	3.0%	3.0%	4.0%	3.0%	3.0%	3.0%	3.0%	3.0%	2.5%	2.5%	2.0%	2.25%	2.25%	0.5%	0.5%	0.5%
OPG	3.0%	2.5%	2.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	0.75%	1.75%	1.75%	1.0%	1.0%	1.0%

Figure 8

Society Negotiated Cumulative Salary Increases



	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Bruce Power	3.0	5.6	7.7	12.0	15.6	19.4	23.0	26.7	30.5	34.4	38.1	41.9	46.8	50.9	53.9	55.0	56.3	57.5
Hydro One	3.0	5.1	8.2	11.5	15.9	19.4	23.0	26.7	30.5	34.4	37.7	41.2	44.0	47.2	50.6	50.8	51.1	51.3
OPG	3.0	5.6	7.7	10.9	14.2	17.7	21.2	24.8	28.6	32.4	36.4	40.5	41.6	44.0	46.6	47.0	47.5	48.0

In addition to the one per cent annual escalation increase to wages, additional payments were negotiated in exchange for pension reforms that will be payable to a subset of employees for a limited time period. These are discussed in more detail below as part of the changes to pensions and benefits. Compensation costs presented in this application reflect escalation increases, pension reform savings and related payments negotiated with the PWU and the Society in 2015.

<u>Management Salaries:</u>

For the remaining ten per cent of employees who are not covered by collective agreements (Management Group or “Management”), base salary ranges and OPG’s pay for performance programs are approved by the Board of Directors and subject to legislative restraints.

To control compensation costs for Management employees, OPG has taken the following actions:

a) Between 2011 and 2015, OPG's Management employees received no annual base salary increase. This has resulted in OPG's Management compensation benchmarking at or below the broader labour market for most positions, as shown in section 5.0.

b) OPG continues to comply with compensation restraints outlined in the *Broader Public Sector Accountability Act*, *2010*, including amendments associated with Bill 55 (*The Strong Action for Ontario Act [Budget Measures], 2012*). These restraints prohibit compensation increases to Vice President level positions and above, and limit the amount of monies available for OPG's Stakeholder Return Program, a pay at risk program that compensates Management employees based on the achievement of corporate and individual performance objectives. These restraints are in place until such time as the Ontario Budget is balanced or a compensation framework is approved by the Lieutenant Governor of Ontario under the *Broader Public Sector Executive Compensation Act*, *2014*. This act was introduced as part of Bill 8 (*Public Sector and MPP Accountability and Transparency Act, 2014*). As in OPG's previous proceedings, the costs of the Stakeholder Return Program are shown separately as a centrally held cost in Ex. F4-4-1 Table 1 and Table 3, and are included in Attachment 1.

While the salary restraint measures have helped to reduce Management compensation costs, they have created the following issues regarding internal equity and the ability to attract talent.

a) Salary compression exists across OPG with approximately 250 managers currently earning less than the staff they supervise, making it difficult to attract qualified represented staff into Management positions.

b) The prospect of a long term salary freeze for Management is a concern for represented staff when recruiting qualified internal personnel into Management positions. This has led to the use of temporary and acting assignments to fill some of the Management roles. This situation was cited in a recent World Association of

Nuclear Operators review of OPG Nuclear facility operations and noted as an area for improvement.

c) OPG's ability to attract and retain senior Management staff can be negatively impacted by our compensation relative to market.

To address these issues, OPG has re-instated its annual base pay increase program for Management staff below the Vice President level and obtained OPG Board approval of funding for 2016.[5] Under this program, salary increases are performance based, linked to external labour markets in line with the benchmarking results discussed in section 5.0, and enable some compression issues to be addressed where appropriate. The cost of this program is being off-set through savings associated with Management headcount reductions and movement towards market compensation for some Management positions.

In determining this course of action, OPG gave consideration to the business environment it operates in and the expectations of the shareholder (i.e., the Government of Ontario) and other stakeholders. The Government, which was experiencing similar issues, recently lifted restraints in place and has also provided salary increases to its Management employees.

Overtime provisions are established through collective bargaining, with actual overtime hours worked approved by OPG Management. Over the test period, overtime costs typically account for about 7 per cent of the total compensation costs for OPG's nuclear facilities. Overtime rates are usually paid on a premium basis, at either time and a half or double time, consistent with many unionized environments. Only unionized employees receive overtime payments; Management employees do not receive overtime payments for work outside of normal working hours. OPG uses overtime to meet peak demands and as a cost effective alternative to other work resourcing options. Overtime requirements fluctuate with outage work programs.

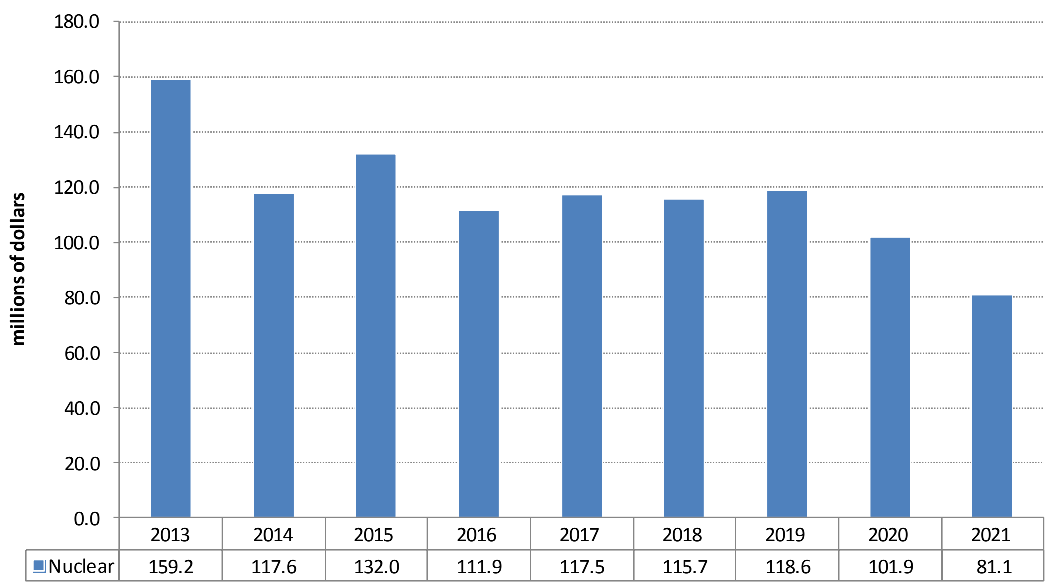
Overtime continues to be closely managed, with pre-approvals being required for non-emergency situations, and regular monitoring by executive staff and Finance. Periodic

[5] This pay for performance program excludes positions subject to Bill 55 compensation restraints (i.e., Vice President and above).

reviews are also conducted to assess overtime usage and alternative options to address work needs.

Overtime costs for OPG's Nuclear facilities are expected to decline significantly, by approximately 50 per cent, between 2013 and 2021, as shown in Figure 9 below. Over the test period, overtime costs range from 7 per cent to 5 per cent of the Total Compensation associated with OPG's Nuclear facilities. See Attachment 1 for additional details.

Fgure 9 - Overtime Costs for Nuclear



Pension and Benefits costs represent approximately 25 per cent of OPG's nuclear compensation costs over the test period and include current employee benefits and current service costs for pension and other post employment benefits ("OPEB"). In this Application, OPG is proposing to limit the recovery of pension and OPEB costs to cash amounts during the test period, subject to the outcome of the OEB's generic proceeding on pension and OPEB costs (EB-2015-0040). OPG is also proposing to record the difference between actual accrual and actual cash valuations for pension and OPEB costs in the Pension & OPEB Cash Versus Accrual Differential Deferral Account (see Ex. H1-1-1). In this exhibit and as in

EB-2013-0321, the current service pension and OPEB costs are presented on an accrual basis, consistent with OPG's labour costing for planning, accounting and reporting purposes. The amount and calculation of pension and OPEB costs are described in Ex. F4-3-2, which also shows the total cash amounts that OPG is seeking to recover in this Application. Although OPG's pension and OPEB proposal in this Application aligns with the OEB's EB-2013-0321 Decision, OPG continues to be of the view that it would be appropriate for OPG to recover its accrual pension and OPEB costs, as set out in OPG's July 31, 2015 submission in the EB-2015-0040 generic consultation and as summarized in Ex. F4-3-2.

i) Current Benefits includes the cost of OPG's Health, Dental and Group Life Insurance benefits for employees while on payroll, as well as statutory requirements such as the Employer Health Tax, Canada Pension Plan, Employment Insurance and Workers Compensation. Current employee benefit costs are expected to remain relatively stable on a per capita basis between 2013 and 2021. While the cost of health and dental services are expected to increase over this period, administrative savings and more stringent adjudication of claims are expected to offset these cost pressures. OPG outsources claims administration to Sun Life Financial and has a number of plan management and adjudication mechanisms in place to control benefit costs. These include the mandatory substitution of generic drugs, maximizing coordination of benefit opportunities, and a requirement for prior approval for certain drug and treatment therapies.

Health, dental and life insurance benefits for PWU and Society employees are negotiated with the unions whereas OPG's Board of Directors approves the Management benefit programs. To reduce costs and demonstrate leadership, Management benefits for new hires since 2001 reflect a lower cost health and dental benefit plan. With higher co-payments and different benefit coverage, this plan is nearly 20 per cent less costly than the plan provided to Management employees hired before July 1, 2001.

ii) Pension and Other Post Employment Benefits (OPEB) costs include the employer paid costs of providing a pension along with other post-employment benefits such as life insurance, and health and dental care for pensioners and their dependants, as well as long-term disability ("LTD") benefits for current employees.

As discussed in Ex. F4-3-2, pension and OPEB accrual costs are actuarially determined to reflect the benefits earned by today's employees for service they have rendered in support of the company's operations. These costs are sensitive to changing economic conditions (e.g., changes to interest rates that drive the discount rates used in the actuarial calculations) as well as demographic and other actuarial assumptions. Ex. F4-3-2 discusses the major drivers of year-over-year trends in pension and OPEB costs.

Pension and OPEB provided to Management employees are determined by OPG's Board of Directors. Collective agreements with the PWU and Society contain pension and benefits clauses that can only be changed through negotiations.

iii) Changes to Pension and Benefits were recently negotiated with the direct involvement of the Government and other electricity sector stakeholders. The Minister of Energy established the bargaining mandate for OPG, and appointed Ed Clark, the Chair of the Premier's Advisory Council on Government Assets to lead the main bargaining team. This mandate included obtaining a multi-year agreement, wage increases that were neutral to Ontario taxpayers and electricity ratepayers, and longer term solutions to help address pension sustainability. With the Government's support, negotiations succeeded in introducing a number of pension reform measures aimed at reducing pension benefit costs over the long term. The Government was satisfied that the mandate was met.

a) <u>Employee Contributions Increases</u>

Through negotiations, OPG was able to increase employee pension contributions beginning April 1, 2015 for PWU employees, and January 1, 2016 for Society employees. Comparable changes were made to contributions for Management employees starting January 1, 2016. Figure 10 provides an overview of the increase in employee contributions.

Figure 10[6]

Employee Pension Contributions	% of Pensionable Earnings Contributed by Employees (% below / above YMPE)			Contribution Ratio (Employee/Employer)
	MG	PWU	Society	
2014	7 / 7	5 / 7	7 / 7	24% / 76%
2015	7 / 7	6 / 8	7 / 7	
2016	7.3 / 8.25	7 / 9	8 / 8	
2017	7.6 / 9.5	7.5 / 10	9 / 9	35% / 65%

b) <u>Earnings Basis for Pension</u>

OPG negotiated changes to the basis for determining pension benefits. Previously, the calculation basis was an employee's highest three consecutive years. This was increased to the highest five consecutive years for future service beginning March 31, 2025 for both the PWU and Society. This change applies to both current employees and new hires.

c) <u>Retirement Eligibility for an Undiscounted Pension</u>

OPG successfully negotiated a change in the retirement eligibility formula. Currently, PWU and Society employees can retire with an undiscounted pension when their age plus service equals 82; this is referred to as the Rule of 82. For service after March 31, 2025, the eligibility for an undiscounted pension will be changed to the Rule of 85. The retirement eligibility formula of age plus service was also changed for Management employees from 84 to 90 years, effective July 1, 2014 for new Management employees, and effective for future service beginning January 1, 2025 for existing employees.

In exchange for these pension reforms that were negotiated with the assistance of the Government, existing PWU and Society employees contributing to the pension plan will receive the following:

[6] YMPE is defined as the year's maximum pensionable earnings.

a) <u>Lump Sum Payment</u>

Both the PWU and society represented employees are entitled to receive non-pensionable lump sum payments of 1 per cent of salary in the first year of the contract and 2 per cent of salary in the second year of the contract.

b) <u>Share Performance Plan</u>

PWU and Society represented employees who were contributing to the pension plan on April 1, 2015 (PWU) and January 1, 2016 (Society) and had less than 35 years of pensionable service as of those dates will be granted Hydro One Limited shares awards at the start of the third year of the current contract term (April 1, 2017 for PWU and January 1, 2018 for Society). Eligible employees will continue to receive shares annually for up to 15 years subject to the following conditions:

1. The number of shares to be awarded annually will be based on a set percentage of salary at the beginning of the contract term (2.75 per cent of salary as of April 1, 2015 for PWU and 2.0 per cent of salary as of January 1, 2016 for Society)

2. Shares will be granted annually to active employees with less than 35 years of pensionable service on April 1 of the corresponding year for the PWU and January 1 for the Society. The last share award will be granted on April 1, 2031 for eligible PWU employees and January 1, 2032 for eligible Society employees.

In 2016, OPG acquired nine million Hydro One shares at a price per share of $23.65, as a risk management strategy against future fluctuations in the price of the shares. OPG expects to be able to satisfy its share award obligations to eligible PWU and Society employees during the test period by using the shares it acquired in 2016. Forecast compensation costs included in the nuclear revenue requirement for the test period reflect the expense corresponding to the years in the test period associated with projected share award obligations, at the purchase price of the shares at the time of acquisition (i.e., $23.65 per share). As such, ratepayers are protected from fluctuations in the market price of the shares. In this Application, OPG is not seeking recovery of expenses of the post-2021 period associated with the share awards.

Over the test period, the costs associated with the lump sum payments and the share performance plan largely equal the cost savings from the pension reforms, but the pension savings will continue to grow over time.

5.0 COMPENSATION BENCHMARKING STUDY

Benchmarking conducted by Towers indicates that OPG's Total Direct Compensation is at market. A copy of the report prepared by Towers is attached as Attachment 2, and an overview of the approach taken, comparator groups used, and summarized results are provided below.

In assessing OPG's compensation relative to external labour markets, OPG's positions were categorized into three segments: Utility, Nuclear Authorized, and General Industry. OPG's compensation in each of these segments was compared to other companies who employ similar positions.

This assessment included reviewing OPG's Base Salaries, Total Direct Compensation, as well as Pensions and Benefits. Total Direct Compensation reflects the cash compensation paid to employees, excluding overtime. It includes Base Salaries and pay at risk incentives.

Compensation benchmarking results are considered to be at market if they are within +/- 10 per cent of the target market positioning. OPG's target market positioning is the 50th percentile for positions in the Utility and General Industry segments, and 75th percentile for the Nuclear Authorized segment.

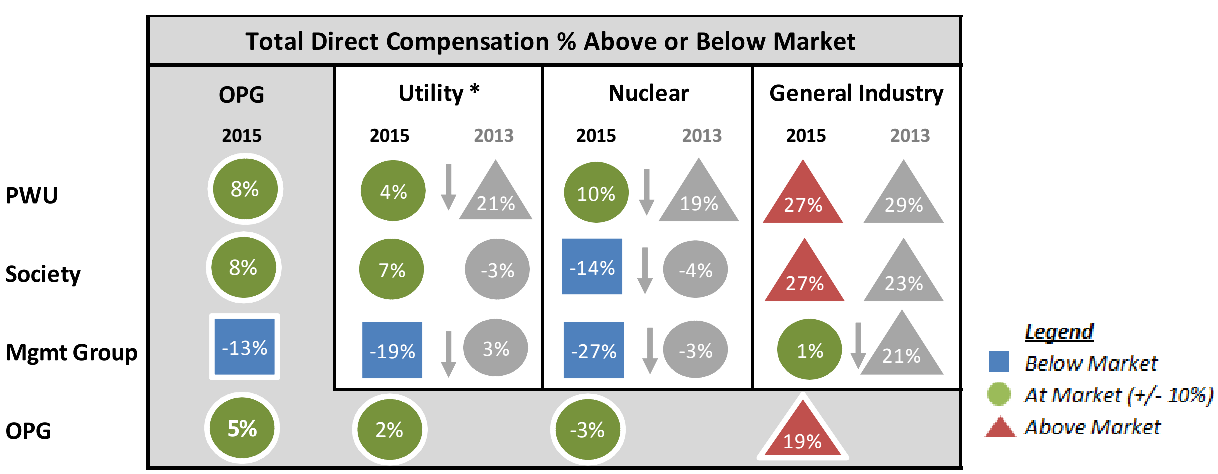
Most of OPG's positions (about 69 per cent) fall into the Utility segment, including many positions associated with the regulated facilities. The Nuclear Authorized segment captures only those positions that require the incumbent to be, or have been, licensed by federal regulators, and represents a very small portion of OPG's employee population (about 4 per cent). The General Industry segment positions (about 27 per cent) are those commonly found in many different types of industries, and that rely on expertise and knowledge from disciplines not specific to energy generation (i.e., administrative support staff, finance, law, human resources, etc.).

In determining the appropriate comparator group or companies, Towers focused on the following types of organizations:

a) organizations from which OPG recruits,
b) organizations to which OPG loses staff,
c) organizations which operate in the same or similar industry sectors, and
d) organizations that reflect the complexity and size of OPG.

Figure 11 depicts the results of the Towers study in 2015 compared to the compensation study conducted by AON Hewitt ("AON") that was filed with the OEB in EB-2013-0321. These results are shown by industry segment and union representation, capturing whether OPG's Total Direct Compensation is above, at, or under market. The downward arrows in this table indicate those areas where OPG's Total Direct Compensation dropped relative to the market since 2013.

Figure 11



** Largest portion of OPG employees are in the Utility segment (69%).*

Some variation in the benchmarking results has been noted between segments and by representation:

a) Within the Utility and Nuclear Authorized segments, PWU represented employee compensation is considered to be at market. Most PWU represented employees work in positions in the Utility segment, and receive compensation that is at market. PWU represented employee total direct compensation continues to be above market in the General Industry segment. A small percentage of PWU employees (about 5 per cent) work in the Nuclear Authorized segment and about a quarter of PWU employees work in general industry segment jobs.

b) Society represented employees in the Utility segment receive compensation that is considered to be at market, and is comparable to that provided in the comparator organizations. Society represented employees in the Nuclear Authorized segment receive compensation that is considered to be below market. 80 per cent of Society represented employees work in the Utility and Nuclear Authorized segments.

c) Management compensation, as measured by total direct compensation, has dropped significantly across all three segments since 2013 and is currently below market overall. This is partly due to on-going salary restraints, as well as the inclusion of long-term incentives in the market data. The incentives data were not included in the AON study because there was insufficient data available for a valid comparison. Long-term incentives are common in the market for Senior Management positions. OPG does not have a long-term incentive program.

Overall results by segment suggest that the compensation provided for positions in the Utility and Nuclear Authorized segments is appropriate. This is where the large majority of OPG's employees work.

Challenges continue to be faced for PWU and Society positions in the General Industry segment where OPG is above market, although the comparison would be closer to market if measured against similar positions at utility companies. Challenges are also faced in the Management Group in the Utility segment where compensation continues to be significantly below market.[7]

To address these challenges the following actions have been taken:

a) Benchmarking information was shared with the unions to inform and set context for the collective bargaining processes, along with a pension education session conducted by AON.

b) New Management salary ranges were established in 2015 to align the mid-point of the salary range with the target market position for each segment. OPG's target market for base salaries was set at the 50th percentile. Use of these new schedules will help to align Management salaries for all segments and levels with the market in the future.

Further changes to OPG's compensation program are anticipated as part of Bill 8. Bill 8 allows the Lieutenant Governor of Ontario to establish a compensation framework for senior leadership (e.g., Vice President and above) that OPG would be required to comply with.

6.0 WAGES AND THE GENERATION OF ELECTRICITY IN ONTARIO

Bruce Power is OPG's closest competitor for attracting and retaining talent. Both Bruce Power and OPG generate electricity in the same energy market, operate similar technology, have a workforce comprised of similar roles, and have staff represented by the same unions.

Towers undertook a comparison of OPG's wages to those provided by Bruce Power. The results of this comparison are captured in Attachment 3 and a summary is provided below in Figure 12. Bruce Power's unionized wages are 16 per cent higher for PWU positions and 2 per cent higher for Society positions.

[7] The Nuclear Authorized segment results are being affected by volatile exchange rates. Under more "typical" economic conditions, the gap to market presented above is expected to be smaller than that shown here. These results do however reflect the current situation in the US market.

Figure 12

Comparison of OPG and Bruce Power PWU and Society Base Salary

Annual Base Salary Comparison	OPG	Bruce Power	Difference (OPG - Bruce Power) k$	Difference (OPG - Bruce Power) %
PWU	104.0	119.6	(15.7)	(16%)
Society	127.6	130.6	(3.0)	(2%)

Note that OPG and Bruce Power both utilize a common job rating system and salary structure for Society represented positions. Accordingly, a higher percentage of OPG's Society population could be compared to Bruce Power, than that depicted for the PWU. OPG and Bruce Power no longer share a common salary structure for PWU represented positions, which requires that the comparison be done by matching of individual jobs.

7.0 CONCLUSION

OPG employs a highly skilled workforce across the Province. Its regulated facilities constitute critical infrastructure for the Province's electric supply. OPG's compensation and benefits are largely the product of its collective agreements, which have recently been renegotiated with the direct involvement of the Government of Ontario. Progress has been made in both the recent PWU and Society collective agreements to bring compensation levels closer to market, when compared to the levels in the EB-2013-0321 proceeding, as reflected in the updated compensation benchmarking study. This includes wage increases below expected CPI escalation and reductions to OPG's pension costs.

ATTACHMENTS

Attachment 1 - FTE, Compensation and Benefit Information for OPG's Nuclear Facilities ("Appendix 2k")

Attachment 2 - Total Compensation Benchmarking Study prepared by Willis Towers Watson

Attachment 3 - Comparison of Salary Schedules for Society and PWU Roles prepared by Willis Towers Watson

Note: Attachments 2 and 3 are marked "Confidential", however, OPG has determined them to be non-confidential in their entirety.

Numbers may not add due to rounding

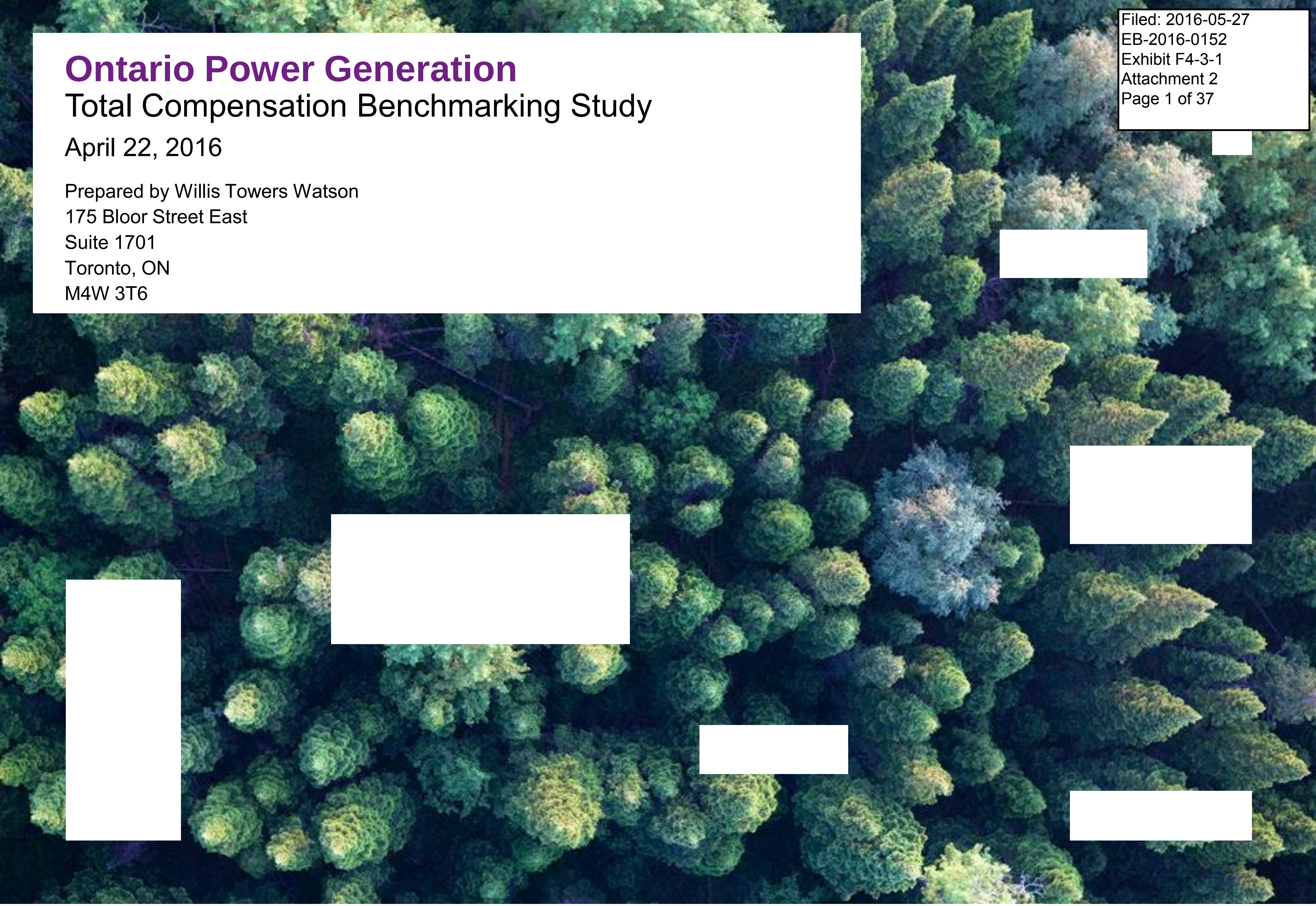
Line No.	NUCLEAR FACILITIES	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Staff** (Regular and Non-Regular)	FTEs	FTEs	FTEs	FTEs	FTEs	FTEs	FTEs	FTEs	FTEs
2										
3	**Nuclear - Direct**									
4	Management	578.6	553.1	521.7	573.3	605.8	602.9	606.2	596.0	583.2
5	Society	2,008.5	1,922.2	1,893.7	2,089.7	2,119.0	2,117.1	2,065.9	1,994.4	1,955.1
6	PWU	4,026.9	4,002.4	3,975.2	4,164.9	4,162.8	4,165.6	4,173.2	4,015.4	3,885.7
7	EPSCA	60.2	69.6	94.2	119.6	170.7	172.1	139.6	165.1	213.1
8	Subtotal	6,674.2	6,547.3	6,484.8	6,947.4	7,058.4	7,057.7	6,984.9	6,770.9	6,637.0
9										
10	**Nuclear - Allocated**									
11	Management	382.2	376.0	368.6	353.6	352.7	347.3	339.6	337.6	337.4
12	Society	607.1	625.6	590.3	664.2	665.5	652.8	642.2	638.9	636.9
13	PWU	930.2	882.8	658.0	739.5	708.7	687.6	682.0	666.6	665.9
14	EPSCA	0.0	0.0	12.0	16.0	16.0	16.0	16.0	16.0	16.0
15	Subtotal	1,919.5	1,884.4	1,628.9	1,773.3	1,742.8	1,703.7	1,679.8	1,659.0	1,656.2
16										
17	**NUCLEAR FACILITIES**									
18	Management	960.8	929.1	890.3	926.9	958.5	950.2	945.7	933.6	920.6
19	Society	2,615.5	2,547.8	2,484.0	2,753.9	2,784.5	2,769.9	2,708.1	2,633.3	2,592.0
20	PWU	4,957.1	4,885.2	4,633.2	4,904.3	4,871.4	4,853.2	4,855.3	4,681.9	4,551.5
21	EPSCA	60.2	69.6	106.2	135.6	186.7	188.1	155.6	181.1	229.1
22	Total	8,593.7	8,431.8	8,113.7	8,720.7	8,801.2	8,761.4	8,664.7	8,429.9	8,293.2
23										
24	**Salary & Incentive Pay** (including Fiscal Adjustment)	$M	$M	$M	$M	$M	$M	$M	$M	$M
25	Management	145.8	147.8	144.1	147.2	152.9	153.5	155.0	154.8	153.7
26	Society	318.9	312.9	310.8	348.9	361.0	367.3	363.0	362.1	363.5
27	PWU	502.1	507.0	487.3	535.8	549.1	555.2	565.2	560.4	553.9
28	EPSCA	8.9	10.6	14.3	13.6	19.1	19.3	16.3	19.3	25.0
29	Total	975.7	978.4	956.5	1,045.6	1,082.1	1,095.3	1,099.5	1,096.7	1,096.1
30	**Overtime**	$M	$M	$M	$M	$M	$M	$M	$M	$M
31	Management	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32	Society	46.8	32.2	36.8	33.1	36.0	35.7	36.8	30.4	24.0
33	PWU	110.5	83.4	89.4	77.5	79.6	78.4	80.3	69.9	54.6
34	EPSCA	1.8	1.9	5.7	1.3	1.8	1.7	1.5	1.6	2.5
35	Total	159.2	117.6	132.0	111.9	117.5	115.7	118.6	101.9	81.1
36	**Benefits** (Current Benefits and Pension & OPEB)	$M	$M	$M	$M	$M	$M	$M	$M	$M
37	Management	57.8	48.7	51.3	50.2	52.6	51.4	51.8	51.6	51.0
38	Society	147.1	117.7	136.3	141.0	145.0	141.7	142.8	142.5	143.1
39	PWU	194.0	174.8	228.6	200.2	201.8	200.0	204.6	203.1	201.4
40	EPSCA	0.5	0.6	1.0	5.1	7.2	7.2	6.1	7.2	9.4
41	Total	399.5	341.9	417.2	396.5	406.5	400.3	405.2	404.4	404.9
42										
43	Current Benefits (Statutory)	56.5	55.6	58.7	56.1	58.2	57.2	57.4	57.5	57.7
44	Current Benefits (Non-Statutory)	48.3	47.5	47.2	63.2	65.1	64.5	64.2	64.0	65.1
45	Pension & OPEB (Current Service)*	294.7	238.8	311.3	277.2	283.2	278.7	283.6	283.0	282.1
46	**TOTAL COMPENSATION**	$M	$M	$M	$M	$M	$M	$M	$M	$M
47	Management	203.6	196.6	195.4	197.5	205.5	204.8	206.8	206.4	204.8
48	Society	512.8	462.9	483.9	523.0	542.0	544.7	542.6	535.0	530.7
49	PWU	806.6	765.3	805.4	813.5	830.5	833.7	850.0	833.5	809.9
50	EPSCA	11.3	13.1	21.0	20.0	28.2	28.2	23.8	28.2	36.9
51	Total	1,534.4	1,437.8	1,505.7	1,554.0	1,606.1	1,611.4	1,623.3	1,603.0	1,582.2
52										
53	*presented on an accrual basis									

Ontario Power Generation

Total Compensation Benchmarking Study

April 22, 2016

Prepared by Willis Towers Watson
175 Bloor Street East
Suite 1701
Toronto, ON
M4W 3T6



Willis Towers Watson

Table of Contents

Introduction

- Willis Towers Watson has conducted a total compensation benchmarking study for roles across Ontario Power Generation's (OPG) Management, PWU and Society employee groups.
- This benchmark review has been conducted on a segmented basis. Roles are benchmarked against comparator organizations best representing the underlying skill sets required.
- The three segments are: Utility, Nuclear Authorized and General Industry.
- 78% of OPG incumbents are in roles covered by this benchmark review. In our experience, this is a strong representative sample.

OPG Group	Total # OPG Incumbents	Total # OPG Incumbents Benchmarked	% OPG Incumbents Benchmarked
PWU	**5,533**	**4,475**	**81%**
Utility	3,754	3,169	84%
Nuclear Authorized	255	255	100%
General Industry	1,524	1,051	69%
Society	**2,918**	**2,151**	**74%**
Utility	2,235	1,808	81%
Nuclear Authorized	111	53	48%
General Industry	572	290	51%
Management	**1,062**	**754**	**71%**
Utility	532	355	67%
Nuclear Authorized	39	37	95%
General Industry	491	362	74%
Total	**9,513**	**7,380**	**78%**

Note: OPG incumbent information as of April 2015

[redacted]

Compensation Methodology

[redacted]

[redacted]

[redacted]

Segment Definitions

- Roles are benchmarked against peer groups appropriately representing the underlying skills sets required. These are categorized as three unique segments for benchmarking purposes.

Segment	% Total Population	Definition
Utility	69%	▪ Requires specific education and knowledge in a unique discipline related to the theories, principles and methods associated with the generation, regulation or trading of nuclear or non-nuclear energy. The requirement to apply this professional body of knowledge represents a significant portion of the job.
Nuclear Authorized	4%	▪ Requires federal licensing, specific education and in-depth knowledge in a unique discipline related to the theories, principles and methods associated with the generation, regulation or training of nuclear energy. The requirement to apply this professional body of knowledge represents a significant portion of the job.
General Industry	27%	▪ Roles that do not meet the Utilities and Nuclear segment definition criteria. ▪ These roles may require formal education and/or in-depth knowledge of a professional body of knowledge; however, this body of knowledge is not specific to energy generation. ▪ Previous industry experience may support faster contextual understanding, however this can be learned “on the job”.

Filed: 2016-05-27
EB-2016-0152
Exhibit F4-3-1
Attachment 2
Page 6 of 37

Comparator Group Selection

- Comparator groups by segment were derived from the full list of organizations participating in the Willis Towers Watson 2015 Compensation databases, based on the criteria below. The full list of comparator organizations used by segment is provided in *Appendix I*.

1. **Utility**
   - Primarily consists of public and private sector utility companies.
2. **Nuclear Authorized**
   - These roles represent a small percentage of the total OPG population and are characterized by unique complexity requirements and pay practices (particularly licensing and certification allowances). Comparable roles are not readily found in Canada. Unlike the comparator organizations for the other segments which reflect data for Canadian employees only, this comparator group reflects a sample of 10 large nuclear organizations of a comparable size to OPG, including Bruce Power (Canada) and nine US nuclear organizations.
3. **General Industry**
   - Includes both public and private companies requiring a large range of skill sets and emphasis on large Ontario employers. The "total sample" data consists of data weighted "50/50" between the public and private companies within the peer group.

Filed: 2016-05-27
EB-2016-0152
Exhibit F4-3-1
Attachment 2
Page 7 of 37

Compensation Benchmark Role Selection

- Based on job content information from OPG, each OPG role was matched to benchmark role functional specialities and levels of accountability within the Willis Towers Watson's 2015 Compensation databases where a suitable match was available.
- In total, 78% of incumbents matched to over 250 survey roles are included in the analysis. This encompasses roles across all OPG job families, employee groups and pay bands.
- For non-authorized roles residing in nuclear plants, no direct matches were available, however it is recognized that comparable skill sets reside within energy and utilities organizations. As such, jobs were matched to non-nuclear comparators based on similar skills and level of accountability. Based on a supplemental US analysis (*details in Appendix II) a* 10% adjustment was made to market statistics for nuclear operations management roles reflecting the premium for these roles observed in the US market where a critical mass of these skills reside.

Filed: 2016-05-27
EB-2016-0152
Exhibit F4-3-1
Attachment 2
Page 8 of 37

Compensation Elements and Market Statistics

- Market statistics reported reflect the 50th percentile and 75th percentile of the benchmark samples for the data elements summarized below:
  - 50th percentile represents the mid-point of the sample, 50% of the data points are positioned below and above this level.
  - 75th percentile represents the level where 75% of the data points are positioned below and 25% are positioned above this level.
    - For survey confidentiality purposes, the 75th percentile can only be shown if there are a minimum of 5 data points in the sample.
- Market data for the US nuclear peer group used for the Nuclear Authorized segment were converted to CAD, consistent with Willis Towers Watson's practice, using an average annual exchange rate to February 2016 of $1 USD - $1.29676 CAD to moderate fluctuations.

Compensation Element	Market	OPG
Salary	2015 actual reported comparator organization salaries of incumbents in benchmark roles	Average salary (as of April 2015) of incumbents in benchmark roles
Total direct compensation (TDC)	2015 actual reported comparator organization salary + target bonus + nuclear allowances + perquisites (if applicable) + long-term incentives (if applicable) of incumbents in benchmark roles	Average salary (as of April 2015) + target bonus (if applicable) + nuclear and/or and other applicable allowances of incumbents in benchmark roles

Compensation Benchmark Results Presentation

- The benchmark results are separated by segment and OPG Group and are summarized by job family.
  - All OPG roles have been aligned to one of the following job families based on the underlying skill set and benchmarked function:
    - Administration
    - Corporate Services
    - Engineering
    - Environment, Health & Safety
    - Finance
    - Human Resources
    - Information Technology
    - Maintenance
    - Operations
    - Supply Chain
- OPG and market findings reflect the average pay and market statistics for all incumbents benchmarked.
  - The % above or below the market reflects the variance between the sum of OPG's compensation and the sum of market results (i.e. 50th percentile or 75th percentile) for all incumbents benchmarked within the respective job family, OPG Group and segment for the data element reported where market data is available.

[redacted]

Overview: Compensation Analysis Results

[redacted]

[redacted]

[redacted]

Filed: 2016-05-27
EB-2016-0152
Exhibit F4-3-1
Attachment 2
Page 11 of 37

Overview: Compensation Analysis Results

- Willis Towers Watson considers compensation for benchmark jobs to be aligned with the competitive market when it falls within +/- 10% of the target market position. OPG's compensation philosophy defines a target market position at the 50th percentile for Utility and General Industry segments and the 75th percentile for the Nuclear Authorized Segment (based on role complexity).
- Overall, OPG's Total Direct Compensation is positioned within 5% of the target market. The Utility segment, which includes approximately three quarters of the incumbents, is positioned within 2% of the target market.

OPG Group and Segment	# OPG Matched Incumbents	% +/- Target Market Base Salary	% +/- Target Market TDC
PWU	**4,475**	**13%**	**8%**
Utility	3,169	10%	4%
Nuclear Authorized	255	7%	10%
General Industry	1,051	31%	27%
Society	**2,151**	**18%**	**8%**
Utility	1,808	17%	7%
Nuclear Authorized	53	-7%	-14%
General Industry	290	38%	27%
Management Group	**754**	**-7%**	**-13%**
Utility	355	-12%	-19%
Nuclear Authorized	37	-18%	-27%
General Industry	362	3%	1%
Overall	**7,380**	**12%**	**5%**

OPG Segment	% +/- Target Market Base Salary	% +/- Target Market TDC
Utility	10%	2%
Nuclear Authorized	1%	-3%
General Industry	25%	19%

Note: Target positioning for roles in the Nuclear Authorized segment is the 75th percentile, except for Senior Executive roles which target the 50th percentile.

[redacted]

Compensation Analysis Results by Job Family

[redacted]

[redacted]

[redacted]

Results by Job Family
Utility Segment

Job Family Distribution

- The PWU Group consists primarily of the Maintenance (62%) and Operations (37%) job families.
- The majority of benchmarked incumbents in the Society Group are within the Engineering Job Family (64%). Low population job families are related to energy trading and plant front-line technology training.
- The majority of benchmarked incumbents within the Management Group are within the Engineering (35%) and Corporate Services (28%) job families. Corporate Services includes industry specific regulatory affairs, sustainability and strategic planning roles.

Market Positioning

- Overall, the PWU, Society and Management Groups are positioned within the market competitive range on a Total Direct Compensation basis although overall positioning varies between groups and job families, with the Management Group falling below the market competitive range.

Utility Segment Results by Job Family
PWU

Segment: Utility
OPG Group: PWU

		Base Salary					Total Direct Compensation				
Job Family	# OPG Matched Incumbents	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75
Administration											
Corporate Services											
Engineering											
Environment, Health & Safety	16	$119	$123	-3%	$128	-7%	$119	$138	-14%	$145	-18%
Finance											
Human Resources											
Information Technology											
Maintenance	1,966	$108	$93	17%	$109	-1%	$108	$99	9%	$116	-6%
Operations	1,187	$104	$102	1%	$116	-11%	$104	$107	-3%	$121	-14%
Supply Chain											
Average (weighted average)				*10%*		*-5%*			*4%*		*-9%*

Note: 75th percentile % above or below the market reflects the variance between the sum of OPG's compensation and the sum of market results for all incumbents benchmarked where 75th percentile market data is available.

Filed: 2016-05-27
EB-2016-0152
Exhibit F4-3-1
Attachment 2
Page 15 of 37

Utility Segment Results by Job Family

Society

Segment: Utility
OPG Group: Society

		Base Salary					Total Direct Compensation				
Job Family	# OPG Matched Incumbents	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75
Administration											
Corporate Services	143	$129	$108	19%	$118	9%	$129	$119	8%	$130	-1%
Engineering	1,157	$111	$94	19%	$106	5%	$111	$101	10%	$114	-2%
Environment, Health & Safety	138	$123	$107	15%	$117	5%	$123	$119	4%	$129	-4%
Finance											
Human Resources											
Information Technology											
Maintenance	215	$139	$123	13%	$139	0%	$139	$138	0%	$160	-13%
Operations	155	$129	$119	9%	$133	-2%	$129	$131	-1%	$143	-10%
Supply Chain											
Average (weighted average)				*17%*		*4%*			*7%*		*-5%*

Note: 75th percentile % above or below the market reflects the variance between the sum of OPG's compensation and the sum of market results for all incumbents benchmarked where 75th percentile market data is available.

Utility Segment Results by Job Family
Management

Segment: Utility
OPG Group: Management

		Base Salary					Total Direct Compensation				
Job Family	# OPG Matched Incumbents	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75
Administration											
Corporate Services	100	$139	$157	-12%	$186	-26%	$162	$198	-18%	$240	-32%
Engineering	126	$129	$154	-16%	$172	-25%	$150	$184	-18%	$230	-35%
Environment, Health & Safety	23	$136	$144	-6%	$158	-14%	$157	$172	-9%	$199	-21%
Finance											
Human Resources											
Information Technology											
Maintenance	75	$139	$146	-5%	$158	-12%	$161	$172	-7%	$202	-20%
Operations	30	$176	$202	-13%	$228	-23%	$237	$395	-40%	$624	-62%
Supply Chain	1	---	---	20%	---	-14%	---	---	1%	---	-29%
Average (weighted average)				*-12%*		*-22%*			*-19%*		*-37%*

Note: 75th percentile % above or below the market reflects the variance between the sum of OPG's compensation and the sum of market results for all incumbents benchmarked where 75th percentile market data is available.

Due to small sample size (less than 4 incumbents), average compensation results for the Supply Chain Job Family can not be disclosed.

Results by Job Family

Nuclear Authorized Segment

Job Family Distribution

- The Operations Job Family represents 100% of benchmarked roles within the PWU and Society Groups and 97% of the Management Group benchmarked roles.

Market Positioning

- Total Direct Compensation positioning within the Nuclear Authorized segment relative to the target market position (75th percentile) varies by OPG Group.
  - The PWU Group is positioned within the competitive range while the Society and Management Groups are positioned below the competitive range, respectively.

Nuclear Authorized Segment Results by Job Family
PWU

Segment: Nuclear Authorized
OPG Group: PWU

		Base Salary					Total Direct Compensation				
Job Family	# OPG Matched Incumbents	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75
Administration											
Corporate Services											
Engineering											
Environment, Health & Safety											
Finance											
Human Resources											
Information Technology											
Maintenance											
Operations	255	$148	$134	11%	$138	7%	$167	$137	22%	$152	10%
Supply Chain											
Average (weighted average)				*11%*		*7%*			*22%*		*10%*

Note: 75th percentile % above or below the market reflects the variance between the sum of OPG's compensation and the sum of market results for all incumbents benchmarked where 75th percentile market data is available.

Nuclear Authorized Segment Results by Job Family
Society

Segment: Nuclear Authorized
OPG Group: Society

		Base Salary					Total Direct Compensation				
Job Family	# OPG Matched Incumbents	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75
Administration											
Corporate Services											
Engineering											
Environment, Health & Safety											
Finance											
Human Resources											
Information Technology											
Maintenance											
Operations	53	$172	$178	-3%	$185	-7%	$213	$229	-7%	$249	-14%
Supply Chain											
Average (weighted average)				*-3%*		*-7%*			*-7%*		*-14%*

Note: 75th percentile % above or below the market reflects the variance between the sum of OPG's compensation and the sum of market results for all incumbents benchmarked where 75th percentile market data is available.

Nuclear Authorized Segment Results by Job Family

Management

Segment: Nuclear Authorized
OPG Group: Management

		Base Salary					Total Direct Compensation				
Job Family	**# OPG Matched Incumbents**	**Avg. OPG**	**Avg. P50**	**% +/- P50**	**Avg. P75**	**% +/- P75**	**Avg. OPG**	**Avg. P50**	**% +/- P50**	**Avg. P75**	**% +/- P75**
Administration											
Corporate Services											
Engineering	1	---	---	-11%	---	-28%	---	---	-38%	---	-55%
Environment, Health & Safety											
Finance											
Human Resources											
Information Technology											
Maintenance											
Operations	36	$183	$216	-15%	$234	-22%	$287	$365	-21%	$418	-31%
Supply Chain											
Average (weighted average)				*-15%*		*-22%*			*-22%*		*-33%*

Note: 75th percentile % above or below the market reflects the variance between the sum of OPG's compensation and the sum of market results for all incumbents benchmarked where 75th percentile market data is available.
Due to small sample size (less than 4 incumbents), average compensation results for the Engineering Job Family can not be disclosed.
Target positioning for roles in the Nuclear Authorized segment is the 75th percentile, except for Senior Executive roles which target the 50th percentile. The Total Direct Compensation positioning to target market for the Management Group is -27%.

Results by Job Family
General Industry

Job Family Distribution

- Benchmarked incumbents within PWU are primarily within Administration (39%) and Maintenance (52%).
- Benchmarked incumbents also span seven job families within the Society Group with the majority within Finance (49%) and Information Technology (27%).
- Benchmarked incumbents span seven job families within the Management Group, with the majority in Administration (37%) and Human Resources (25%).

Market Positioning

- Total Direct Compensation positioning within the General Industry segment varies by OPG Group and Job Family:
  - The PWU and Society Groups are generally aligned above the competitive market range.
  - The Management Group is aligned overall with the competitive market range.

Filed: 2016-05-27
EB-2016-0152
Exhibit F4-3-1
Attachment 2
Page 22 of 37

General Industry Segment Results by Job Family
PWU

Segment: General Industry
OPG Group: PWU

		Base Salary					Total Direct Compensation				
Job Family	# OPG Matched Incumbents	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75
Administration	408	$71	$49	45%	$54	33%	$71	$51	40%	$57	25%
Corporate Services											
Engineering											
Environment, Health & Safety											
Finance	78	$79	$53	48%	$60	32%	$79	$55	44%	$62	27%
Human Resources											
Information Technology											
Maintenance	551	$84	$69	21%	$78	9%	$84	$72	18%	$84	0%
Operations											
Supply Chain	14	$84	$52	62%	$60	40%	$84	$53	57%	$64	31%
Average (weighted average)				***31%***		***19%***			***27%***		***11%***

Note: 75th percentile % above or below the market reflects the variance between the sum of OPG's compensation and the sum of market results for all incumbents benchmarked where 75th percentile market data is available.

Filed: 2016-05-27
EB-2016-0152
Exhibit F4-3-1
Attachment 2
Page 23 of 37

General Industry Segment Results by Job Family

Society

Segment: General Industry
OPG Group: Society

		Base Salary					Total Direct Compensation				
Job Family	# OPG Matched Incumbents	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75	Avg. OPG	Avg. P50	% +/- P50	Avg. P75	% +/- P75
Administration	14	$105	$85	23%	$100	5%	$105	$93	13%	$114	-8%
Corporate Services	20	$114	$82	39%	$95	20%	$114	$90	27%	$106	8%
Engineering											
Environment, Health & Safety											
Finance	142	$123	$88	40%	$101	22%	$123	$96	29%	$112	10%
Human Resources	7	$104	$68	54%	$79	33%	$104	$72	46%	$87	20%
Information Technology	79	$124	$93	34%	$103	21%	$124	$100	24%	$114	10%
Maintenance											
Operations											
Supply Chain	28	$118	$85	39%	$96	23%	$118	$91	30%	$105	12%
Average (weighted average)				***38%***		***21%***			***27%***		***9%***

Note: 75th percentile % above or below the market reflects the variance between the sum of OPG's compensation and the sum of market results for all incumbents benchmarked where 75th percentile market data is available.

General Industry Segment Results by Job Family
Management

Segment: General Industry
OPG Group: Management

		Base Salary					Total Direct Compensation				
Job Family	**# OPG Matched Incumbents**	**Avg. OPG**	**Avg. P50**	**% +/- P50**	**Avg. P75**	**% +/- P75**	**Avg. OPG**	**Avg. P50**	**% +/- P50**	**Avg. P75**	**% +/- P75**
Administration	133	$56	$53	7%	$57	-2%	$61	$55	10%	$61	0%
Corporate Services	40	$151	$144	5%	$167	-9%	$184	$185	0%	$229	-19%
Engineering											
Environment, Health & Safety	11	$93	$79	18%	$126	-26%	$104	$90	16%	$155	-33%
Finance	68	$137	$131	5%	$143	-4%	$162	$164	-2%	$183	-12%
Human Resources	91	$108	$111	-3%	$126	-14%	$128	$131	-2%	$152	-16%
Information Technology	4	---	---	2%	---	-13%	---	---	-3%	---	-23%
Maintenance											
Operations											
Supply Chain	15	$139	$129	8%	$148	-6%	$162	$147	10%	$172	-6%
Average (weighted average)				***3%***		***-7%***			***1%***		***-12%***

Note: 75th percentile % above or below the market reflects the variance between the sum of OPG's compensation and the sum of market results for all incumbents benchmarked where 75th percentile market data is available.
Due to small sample size (less than 4 incumbents), average compensation results for the Information Technology Job Family can not be disclosed.

[redacted]

Pension and Benefits Analysis

[redacted]

[redacted]

[redacted]

Methodology – Pension and Benefit Analysis

- Pension and benefit information was obtained from the Willis Towers Watson's Benefit Data Source – Canada based on comparator organizations representing a 50%/50% mix of private and public sector organizations. Comparator organizations are not differentiated by segment as organizations typically offer common pension and benefit plans across all roles and skill sets. A list of comparator organizations are presented in *Appendix I.*
- Comparator organizations were established based on data availability where program information is available for comparator PWU, Society and Management populations. Plan provisions valued are those that apply to newly hired employees.
- Results are based on the benefits data and information provided to Willis Towers Watson by participating organizations. Benefit plans included in the analysis are: pension, savings (including stock purchase, group RRSP, DPSP), active and retiree health care and dental care, short-term disability, long term disability and active and retiree benefits. Benefits no longer available to new hires are not considered.
- We determined a value for these benefits by applying a standard methodology to develop employee profiles based on applicable PWU, Society and Management age, service, gender and salary demographics. Detailed methodology is presented in *Appendix III*.

Market Statistics

- For the market studied in this review, pension and benefits represent a small component of the overall total compensation package.
- The table below illustrates the weighted average of pension and benefit employer-provided values as a % of base salary at OPG and how it compares to the 50th percentile of the market, recognizing that values vary across demographic, tenure and age profiles.
- The employer-provided value of OPG's pension and benefits as a % of base salary is above the 50th percentile of the market for the PWU, Society and Management Groups.

Pension & Benefits % of Base Salary		
OPG Group	**OPG**	**Market P50**
PWU	29.7%	20.2%
Society	30.3%	20.3%
Management	31.3%	22.8%

[redacted]

Appendices

[redacted]

[redacted]

[redacted]

Compensation Comparator Organizations
Utility Segment

#	Company (n = 29)		
1	Alberta Electric System Operator	16	FortisAlberta Inc.
2	Alcoa Canada	17	GE Energy
3	Algonquin Power and Utilities Corp.	18	Hydro One Inc.
4	Altalink	19	Hydro Quebec
5	ArcelorMittal Montreal Inc.	20	Kinross Gold Corporation
6	ATCO Group	21	Newfoundland and Labrador Hydro Electric Corporation
7	Barrick Gold Corporation	22	Rio Tinto Alcan Canada
8	BC Hydro Power & Authority	23	Samuel, Son & Co., Ltd.
9	Bruce Power LP	24	SaskPower
10	Capital Power Corporation	25	Spectra Energy Transmission*
11	Chevron Canada Limited	26	Toronto Hydro Electric
12	Enbridge Inc.*	27	TransAlta Corporation
13	ENMAX Corporation	28	TransCanada Corp.
14	EPCOR Utilities Inc.	29	United States Steel Canada
15	ExxonMobil Canada		

** Data excludes Alberta incumbents*

Compensation Comparator Organizations
Nuclear Authorized Segment

#	Company (n = 10)
1	Bruce Power
2	Dominion Resources
3	Duke Energy
4	Entergy
5	Exelon
6	FirstEnergy
7	NextEra Energy
8	Public Service Enterprise Group
9	Southern Company Services
10	Tennessee Valley Authority

Compensation Comparator Organizations
General Industry Segment – Public Sector

#	Company (n = 23)
Public Sector - weighted 50% for benchmarking purposes	
1	Alberta Electric System Operator
2	Alberta Energy Regulator (previously Energy Resources Conservation Board)
3	Bank of Canada
4	BC Hydro Power & Authority
5	British Columbia Lottery Corporation
6	Canada Post
7	Canadian Broadcasting Corporation/Radio Canada
8	CPP Investment Board
9	ENMAX Corporation
10	EPCOR Utilities Inc.
11	Healthcare of Ontario Pension Plan
12	Hydro-Québec
13	Insurance Corporation of British Columbia (ICBC)
14	Loto-Québec
15	Newfoundland and Labrador Hydro Electric Corporation
16	SaskPower
17	SGI Canada
18	Toronto Hydro Electric
19	Treasury Board of Canada Secretariat
20	University Health Network
21	VIA Rail Canada Inc.
22	Workplace Safety & Insurance Board - Ontario
23	York University

Filed: 2016-05-27
EB-2016-0152
Exhibit F4-3-1
Attachment 2
Page 32 of 37

Compensation Comparator Organizations

General Industry Segment – Private Sector

#	Company (n = 58)		
Private Sector - weighted 50% for benchmarking purposes			
1	The Coca-Cola Company-Canada	30	Kinross Gold Corporation
2	Air Canada	31	Kruger Inc.
3	Alcoa Canada	32	Loblaw Companies Limited
4	Algonquin Power and Utilities Corp.	33	Magna International Inc.
5	AMEC Americas Limited	34	Manulife Financial Corporation
6	ATCO Group	35	Maple Leaf Foods Inc.
7	ATS Automation Tooling Systems Inc	36	McCain Foods Limited
8	Bank of Montreal	37	Molson Coors Canada
9	BCE Inc.	38	Nexen Energy ULC
10	Bruce Power LP	39	Nissan Canada, Inc.
11	Canada Colors and Chemicals Limited	40	Parmalat Canada
12	Canadian Imperial Bank of Commerce	41	Procter & Gamble Inc.
13	Canadian National Railway	42	Purolator Inc.
14	Canadian Pacific Railway Ltd.	43	RBC Financial
15	Canadian Tire Corporation	44	Rio Tinto Alcan Canada
16	Capital Power Corporation	45	RioCan Real Estate Investment Trust
17	Cargill Limited	46	Rogers Communications Inc.
18	Celestica Inc.	47	Rothmans Bensons & Hedges
19	Chevron Canada Limited	48	Samuel, Son & Co., Ltd
20	Enbridge Inc. *	49	Scotiabank
21	Encana Corporation	50	Spectra Energy *
22	Ernst & Young Canada	51	Sun Life Financial
23	FCA Canada Inc. (Formerly Chrysler Canada Inc.)	52	Talisman Energy Inc.
24	Federal Express Canada Ltd.	53	TD Bank Financial Group
25	Ford Motor Company of Canada, Limited	54	Toyota Motor Manufacturing Canada
26	General Electric Canada	55	TransAlta Corporation
27	Gerdau Long Steel North America	56	TransCanada Corp.
28	Hydro One Inc.	57	Unilever Canada
29	Johnson and Johnson Canada	58	Viterra Inc

** Data will exclude Alberta incumbents*

Compensation Comparator Organizations
Pension & Benefits Analysis

#	Public Sector (n=12)	#	Private Sector (n=12)
1	British Columbia Hydro and Power Authority*	13	Bruce Power
2	Canada Post Corporation	14	Canadian Imperial Bank of Commerce
3	Canadian Blood Services	15	Canadian Tire Corporation
4	ENMAX Corporation	16	Enbridge Gas Distribution
5	EPCOR Utilities	17	Honda Canada†
6	Hospital for Sick Children, The*	18	Kinross Gold Corporation
7	Hydro One*	19	Maple Leaf Foods*
8	Hydro-Québec	20	Rogers Communications
9	Ontario Public Service	21	Samuel, Son & Co*†
10	SaskPower	22	Sun Life Financial
11	Toronto Hydro-Electric System Limited	23	TransAlta Corporation
12	Workplace Safety & Insurance Board	24	TransCanada Corp.

** Excluded from Society/PWU positioning.*
† Excluded from Senior Executives positioning.

Filed: 2016-05-27
EB-2016-0152
Exhibit F4-3-1
Attachment 2
Page 34 of 37

Nuclear Utilities (Non Authorized) Market Analysis

- To assess whether base salaries within the Non-Authorized Nuclear segment are different relative to the Utility segment for similar skills sets and levels of accountability, the following analysis was performed:
  - Comparison of relative job rates between select US utilities and nuclear organizations to understand whether nuclear roles within the US are paid differently than utility roles in the US (for roles reflecting comparable skills and level of accountability).
  - Comparison of relative job rates between the Canadian Utility comparator group (used for the benchmark review) and the US nuclear comparator group to assess whether there is any differentiation between these two markets (for roles reflecting comparable skills and level of accountability).
- The analysis indicated that for many roles and levels of work, salaries are comparable between these sectors. However, for nuclear operations management roles, base salaries are observed to carry an average premium of 10% relative to their non-nuclear counterparts. As such, where comparisons for non-authorized roles in nuclear facilities have been made to the Canadian utility comparator group, market data is adjusted by 10% to reflect this identified premium for such roles.

Filed: 2016-05-27
EB-2016-0152
Exhibit F4-3-1
Attachment 2
Page 35 of 37

Pension and Benefits Valuation

Pension Plans

- The methodology used determines the value to employees of each organization's benefits program by plan. The purpose is to quantify the provisions offered by each organization. The pension and benefit plan values are determined by applying a common set of actuarial methods and assumptions to employee profiles (these values are not intended to represent actual plan/program costs).
- Defined Benefit (DB) Plans
  - These plans are valued in terms of anticipated prospective benefit payments being allocated over the employee's entire working history (Projected Unit Credit with service prorate method was used except for Executives where the Entry Age Normal cost method was used).
  - The following elements are considered in determining comparative values for defined benefit pension plans: normal and early retirement benefits, preretirement and postretirement death benefits, termination benefits, postretirement pension adjustments and employee contributions.
  - For Executives, bridge benefits were not considered since these benefits are relatively low in comparison with the total pension benefit of high earners and information available on these benefits is limited.
- Defined Contribution (DC) and Savings Plans
  - Plans are valued by determining employee and employer contributions made during the year of valuation (Term Cost method). Employees are deemed to contribute in such a way that reflects their savings opportunity and ability to contribute. Accordingly, they will contribute differently depending on available income, on the level of contributions permitted in the plan and on the level of employer match. Contribution levels to profit sharing plans are determined by averaging the last five years' actual contributions to the plan.

Pension and Benefits Valuation

Benefit Plans

- Death Benefit Plans
  - Death Benefit plan values for the following benefits are calculated: preretirement and postretirement group life insurance (using the projected unit credit with service prorate method), accidental death and dismemberment benefits and survivor income benefits.
- Disability Plans
  - Short-term disability benefits include salary continuance and sickness plans. Values are determined according to specific plan provisions including waiting periods, durations and benefit amounts.
  - Long-term Disability Plan values are determined according to specific plan provisions including waiting periods, definitions of disability, durations, benefit amounts, benefits coordination and indexation.
- Flexible Benefits (other than pension)
  - The value determined for these benefits is based on the highest enrolled option for each plan.
  - When not determined by the plan design, flexible benefit credits are allocated in the following order: health care benefits, dental care benefits, life insurance benefits and disability benefits. Remaining flexible credits, if any, are directed to a Health/Dental Care Spending Account if it exists and the value of such credits are included in the value of the health care plan.
  - The postretirement Health/Dental Care Spending Account is assumed to remain at the current level unless stated otherwise by participants, in which case the annual increase assumption provided by each participant is applied.

Pension and Benefits Valuation

Benefit Plans

- Health Care and Dental Care Plans
  - Values are generated for preretirement and postretirement coverage (using the projected unit credit with service prorate method). Postretirement values and retiree contributions are increased to reflect future inflation. However, deductibles under postretirement health care plans are assumed to remain at the current level in the future. Values are determined using recent claims experience for large organizations taking into account plan deductibles, coinsurance and maximums as well as eligibility requirements.
  - In line with general market practice, health care plans (including drug plans) are generally assumed to be second payer to any provincial health care plans when applicable. It is also assumed that the current practice with respect to government programs having an impact on our calculations would remain unchanged. Amounts allocated to the Health/Dental Care Spending Account are included in the health care plan value.

Ontario Power Generation (OPG)

Comparison of Salary Schedules for Society and PWU roles (OPG vs Bruce Power)

25 April, 2016

Willis Towers Watson

Base Salary Comparison

Society of Energy Professional Roles

			2015							
			Weekly				Yearly			
OPG Band	**Sample Job Titles**	**April 2015 Headcount**	**OPG**	**Bruce Power**	**Difference (OPG - Bruce Power)**		**OPG**	**Bruce Power**	**Difference (OPG - Bruce Power)**	
					$ Per Week	**% Per Week**			**$ Per Year**	**% Per Year**
Authorized	Shift Supervisor In Training	53	$3,008.08	$3,107.00	-$98.92	*-3%*	$156,850	$162,008	-$5,158	*-3%*
	Control Room Shift Supervisor, Training Supervisor	58	$3,363.23	$3,793.00	-$429.77	*-13%*	$175,368	$197,778	-$22,409	*-13%*
MP6 - 40 Hr	Section Manager Outage, Real Time Markets Supv (Shift)	23	$3,043.52	$3,104.00	-$60.48	*-2%*	$158,806	$161,962	-$3,156	*-2%*
MP5 - 40 Hr	Project Site Supervisor, Real Time Markets Specialist (Shift)	22	$2,854.88	$2,912.00	-$57.12	*-2%*	$148,964	$151,944	-$2,980	*-2%*
MP4 - 40 Hr	FLM, Control/Mechanical / Trades Mgmt Supv, Hydroelectric	518	$2,677.83	$2,730.00	-$52.17	*-2%*	$139,725	$142,447	-$2,722	*-2%*
MP3 - 40 Hr	FLM, Civil Maintenance	32	$2,511.01	$2,560.00	-$48.99	*-2%*	$131,021	$133,577	-$2,556	*-2%*
MP6 - 35 Hr	Section Head Information Systems, Senior Performance Improvement Officer	347	$2,598.28	$2,650.00	-$51.72	*-2%*	$135,575	$138,273	-$2,699	*-2%*
MP5 - 35 Hr	Sr Engineer/Scientist - Specialist	226	$2,436.59	$2,486.00	-$49.41	*-2%*	$127,138	$129,716	-$2,578	*-2%*
MP4 - 35 Hr	Senior Technical Engineer/Officer , Eng/Applied Science Trainee	1513	$2,285.19	$2,331.00	-$45.81	*-2%*	$119,238	$121,628	-$2,390	*-2%*
MP3 - 35 Hr	Assistant Procurement Specialist, Financial Analyst	80	$2,144.04	$2,186.00	-$41.96	*-2%*	$111,873	$114,062	-$2,189	*-2%*
MP2 - 35 Hr	Materials Co-Ordinator, Support Specialist	24	$2,010.61	$2,051.00	-$40.39	*-2%*	$104,911	$107,018	-$2,107	*-2%*
Totals & Weighted Average		***2,896***	***$2,446.24***	***$2,502.93***	***-$56.69***	***-2%***	***$127,637***	***$130,594***	***-$2,957***	***-2%***
% of OPG Society population		**100%**								

Notes:

- *Employee headcount is based on incumbent file dated April 2015*
- *Sample job titles are those roles with the highest employee populations*
- *Hours worked are the same for both OPG and Bruce Power*
- *Where annualized salary is calculated it is based on a 365.25 day year recognizing the effect of the 2016 leap year*

Sources:

- *Collective Agreement between Bruce Power and the Society of Energy Professionals (Jan 1, '15 – Dec 31, '18) attained from the Ministry of Labour*
- *OPG Society of Energy Professionals salary schedules obtained from OPG as they were not filed with the Ministry of Labour at the date of the analysis*

Base Salary Comparison

Power Workers' Union Roles

			2015							
			Hourly				Yearly			
OPG Band	Job Titles	April 2015 Headcount	OPG	Bruce Power	Difference (OPG - Bruce Power)		OPG	Bruce Power	Difference (OPG - Bruce Power)	
					$ Per Hour	% Per Hour			$ Per Year	% Per Year
Authorized	Authorized Nuclear Operator (including Trainees, excluding supervisors)	227	$73.14	$71.75	$1.39	*2%*	$152,654	$149,752	$2,901	*2%*
	Certified Unit 0 Control Room Operator (including Trainees)	22	$65.81	$64.58	$1.23	*2%*	$137,355	$134,788	$2,567	*2%*
Band 3	Nuclear Operator (including Trainees)	649	$51.97	$60.96	-$8.99	*-17%*	$108,469	$127,232	-$18,763	*-17%*
	Electrical & Control Techn & Technologists / Shift Control Technician	729	$51.97	$59.87	-$7.90	*-15%*	$108,469	$124,957	-$16,488	*-15%*
	Mechanical Technician & Technologist / Mechanical Maintainer	714	$51.97	$59.70	-$7.73	*-15%*	$108,469	$124,602	-$16,134	*-15%*
	Chemical Technician / Chemical Technologist†	72	$51.97	$62.12	-$10.15	*-20%*	$108,469	$113,447	-$4,978	*-5%*
	Planning & Cost Control Technician / Cost & Scheduling Technician†	45	$51.97	$55.02	-$3.05	*-6%*	$108,469	$100,480	$7,989	*7%*
	Project Technician - E&C / Project Tech II - E&C	28	$51.97	$53.69	-$1.72	*-3%*	$101,690	$105,047	-$3,358	*-3%*
Band 2	Civil & Service Trades Maintainers / Civil Maintainer I	435	$40.42	$54.74	-$14.32	*-35%*	$84,362	$114,250	-$29,888	*-35%*
	Civil & Service Trades Maintainers / Civil Maintainer II		$40.42	$51.27	-$10.85	*-27%*	$84,362	$107,008	-$22,645	*-27%*
	Nuclear Security Officer	n/a	$40.42	$42.73	-$2.31	*-6%*	$84,362	$89,184	-$4,821	*-6%*
	Emergency Response Maintainer / Emergency Services Maintainer	84	$40.42	$49.33	-$8.91	*-22%*	$84,362	$102,959	-$18,596	*-22%*
	Office Support Representative II / Administrative Assistant - Clerk I (Admin)	194	$40.42	$48.12	-$7.70	*-19%*	$73,817	$87,879	-$14,062	*-19%*
	Finance Clerk / Payroll & Accounting Services Specialist	42	$40.42	$50.96	-$10.54	*-26%*	$73,817	$93,066	-$19,249	*-26%*
Band 1	Office Support Representative I / Clerk II	101	$33.20	$37.21	-$4.01	*-12%*	$60,631	$67,955	-$7,323	*-12%*
Totals & Weighted Average		***3,342***	***$50.32***	***$58.18***	***-$7.85***	***-17%***	***$103,967***	***$119,634***	***-$15,667***	***-16%***
% of PWU population		**60%**								

Notes:

- *Employee headcount is based on incumbent file dated April 2015*
- *OPG collective agreement provides salary schedules by band, whereas the Bruce Power agreement is on a role basis. Prior to the introduction of skill broadening, OPG utilized a salary schedule that was structured similar to Bruce Power. Therefore comparisons are on a best effort basis by matching jobs at Bruce Power to those previously used by OPG and which continue to be utilized today in a broader capacity*
- *As there are differences in hours worked between OPG and Bruce Power (cases where † is indicated), annualized salary has been provided which takes into account the different working hours*
- *Where annualized salary is calculated it is based on a 365.25 day year recognizing the effect of the 2016 leap year*

Sources:

- *Collective Agreement between Bruce Power and the Power Workers' Union (Jan 1,'14 – Dec 31, '17) attained from the Ministry of Labour*
- *Collective Agreement between OPG and the Power Workers Union (Apr 1, '15 – Mar 31, '18) attained from the Ministry of Labour and OPG*

PENSION AND OTHER POST EMPLOYMENT BENEFIT COSTS

1.0 PURPOSE

The purpose of this exhibit is to:

- Describe OPG's proposal to maintain the same treatment for pension and other post-employment benefit ("OPEB") costs as that resulting from the OEB's EB-2013-0321 Decision With Reasons ("EB-2013-0321 Decision"), pending the outcome of the OEB's generic consultation on pension and OPEB costs (EB-2015-0040);
- Detail the forecast test period pension contributions and OPEB benefit payments ("cash amounts") included in the proposed nuclear revenue requirements; and
- Present the pension and OPEB amounts for the nuclear facilities determined in accordance with US GAAP ("accrual costs") as well as the differential between pension and OPEB accrual costs and cash amounts.

2.0 OVERVIEW

OPG's pension and OPEB programs consist of a registered pension plan ("RPP"), a supplementary pension plan, other post-retirement benefits such as group life insurance and health and dental care for pensioners and their dependants, as well as long-term disability ("LTD") benefits for current employees.[1]

OPG proposes to maintain the same treatment for recovering pension and OPEB costs during the test period as that resulting from the EB-2013-0321 Decision (pp. 87-89), pending the outcome of the OEB's EB-2015-0040 consultation on pension and OPEB costs. In particular, OPG proposes to include pension and OPEB cash amounts in the test period nuclear revenue requirements, and, for both regulated hydroelectric and nuclear facilities, to record differences between actual and forecast cash amounts in the Pension & OPEB Cash Payment Variance Account, and the difference between actual accrual costs and actual cash amounts in the Pension & OPEB Cash Versus Accrual Differential Deferral Account.

[1] The term "other post-retirement benefits" is used to refer to post employment benefit plans other than the RPP and LTD benefits. Unless otherwise noted, OPEB is used to refer to all post-employment benefits other than the RPP benefits.

Consistent with the OEB's findings in EB-2013-0321, OPG is proposing that the future consideration of recovery of the difference between accrual costs and cash amounts for the test period be limited to the outcome of the generic consultation and not be subject to a future prudence review beyond the proceeding for this Application. OPG is providing evidence in this exhibit, Ex. F4-3-1 and elsewhere in the Application to support a review of the forecast accrual costs.

Forecast pension and OPEB cash amounts attributed to the nuclear facilities for the test period are \$272.0M in 2017, \$280.4M in 2018, \$289.5M in 2019, \$271.3M in 2020 and \$279.9M in 2021. The total difference between pension and OPEB accrual costs and cash amounts is forecast to decease significantly over the period, from an average of \$230.8M in 2014-2015 to \$49.8M by 2021. Pension cash amounts are forecast to exceed accrual costs starting in 2018. Total forecast pension cash amounts for the nuclear facilities are higher than accrual amounts by \$31.5M over the test period, while total forecast OPEB cash amounts are \$434.0M lower than the accrual costs over the test period. On an annual basis, test period pension and OPEB accrual costs and cash amounts are significantly lower than in 2014 and 2015.

As discussed in Ex. H1-1-1, given that the EB-2015-0040 generic consultation is ongoing, OPG is not proposing to clear amounts accumulated in the Pension & OPEB Cash Versus Accrual Differential Deferral Account since November 1, 2014. OPG is proposing to clear the December 31, 2015 balance in the Pension & OPEB Cash Payment Variance Account.

Although OPG has aligned its test period proposal for pension and OPEB costs with the OEB's EB-2013-0321 Decision, OPG continues to be of the view that it would be appropriate for OPG to recover its accrual pension and OPEB costs for the following reasons, as set out in detail in OPG's July 31, 2015 submission in the EB-2015-0040 consultation:

- Using accrual accounting for rate setting ensures that rates reflect the true cost of providing the service during the periods to which the rates relate, which minimizes intergenerational inequity and supports efficient consumption through appropriate price signals;

- The use of accrual pension and OPEB costs for rate recovery purposes is consistent with financial accounting requirements, which are developed through a transparent and rigorous process with an objective of appropriately attributing costs across periods. The use of financial reporting requirements provides a reliable and verifiable basis to set just and reasonable rates, and minimizes the financial burden of keeping two sets of records;
- The accrual basis of recovery would provide OPG with revenues on the same basis and in a similar timeframe as the accounting requirement to recognize post-retirement obligations on the company's balance sheet. As such, using the accrual accounting basis for rate-setting would avoid significant adverse financial consequences to OPG (including reductions in net income, write-offs of regulatory asset balances and erosion of shareholder's equity) and corresponding increases in the risks to the shareholder, which are likely to arise if a different basis of recovery is adopted; and
- Maintaining the recovery of costs on an accrual basis promotes consistency and simplicity and supports period-over-period comparability of results, particularly when that basis was previously applied to set the utility's rates, as is the case for OPG.

As OPG is proposing that the EB-2013-0321 regulated hydroelectric payment amounts form the starting point for determining the regulated hydroelectric payment amounts for 2017 to 2021, pension and OPEB cash amounts and accrual costs for the regulated hydroelectric business are not presented in this exhibit.

Section 3 presents the cash amounts, accrual costs and the difference between the two for the nuclear facilities for the historical, bridge and test periods. It also further details OPG's proposed treatment of pension and OPEB costs in this Application. Sections 4 and 5, respectively, set out how the cash amounts and accrual costs presented in section 3 were developed and discuss related trends and variances.

Cash and accrual amounts presented in this Application reflect changes to RPP provisions from the 2015 round of collective bargaining with the Power Workers' Union ("PWU") and

The Society of Energy Professionals ("The Society") and from changes applicable to Management employees (i.e., pension reform), all of which are discussed in Ex. F4-3-1.

The nature of accrual costs and cash amounts presented in this exhibit and the methodologies used to derive them are unchanged from those reflected in EB-2012-0002, EB-2013-0321 and EB-2014-0370.

3.0 PROPOSED TEST PERIOD TREATMENT OF PENSION AND OPEB COSTS

In the EB-2013-0321 Decision, the OEB required OPG to recover cash amounts for pension and OPEB for 2014 and 2015 and established the Pension & OPEB Cash Versus Accrual Differential Deferral Account to record the differential between actual accrual costs and actual cash amounts. The OEB also indicated that it was "not necessarily moving from an accrual to a cash basis for setting OPG's payment amounts" and that "transition to a different accounting treatment of pensions and OPEBs for OPG, if required, would be addressed by the Board in OPG's next cost of service proceeding, having been informed by the outcomes of the generic proceeding" (p. 88). The EB-2013-0321 Decision also clarified that "the Board is not setting aside the difference between the cash and accrual amounts .... for purposes of another future prudence review of these costs", noting that "any future treatment regarding the deferral account would be limited to the outcomes of the generic proceeding" and that "[b]ased on the policy outcome of the generic proceeding, a future panel will decide on the appropriate disposition (if any) of the deferral account balance." (pp. 88-89)

As the EB-2015-0040 generic consultation has not concluded at the time of this Application, consistent with the OEB's EB-2013-0321 Decision, OPG is seeking to include forecast pension and OPEB cash amounts in the nuclear revenue requirements for the test period. With respect to the regulated hydroelectric facilities, the 2017-2021 hydroelectric payment amounts proposed under a price cap incentive regulation approach would continue to reflect the EB-2013-0321 approved forecast cash amounts.

Chart 1 below sets out pension and OPEB cash amounts attributed to the nuclear facilities in the historical, bridge and test years. The cash amounts consist of contributions to the RPP and benefit payments to retirees and dependants under the OPEB plans. OPG's total projected cash amounts for pension and OPEB for 2016-2021 were calculated by an independent actuary, Aon Hewitt, as shown in Attachment 1. Pension contributions, which are typically set by triennial actuarial valuations, are projected to decrease after each such assumed valuation during the test period, effective January 1, 2017 and January 1, 2020, as discussed in section 4.2. Forecast amounts for pension contributions represent estimated minimum required company contributions for current service cost and going concern special payments.[2] Increasing OPEB benefit payments over the period reflect the growing retiree population and expected increases in per capita medical and other costs.

Chart 1

Pension and OPEB Cash Amounts – Nuclear[3] ($M)									
	2013 Actual	**2014 Actual**	**2015 Actual**	**2016 Projection**	**2017 Plan**	**2018 Plan**	**2019 Plan**	**2020 Plan**	**2021 Plan**
Pension	231.6	280.9	284.5	283.3	171.1	175.5	180.3	157.2	162.1
OPEB	78.1	84.5	93.1	96.6	100.9	104.9	109.2	114.1	117.8
Total	**309.7**	**365.4**	**377.6**	**379.9**	**272.0**	**280.4**	**289.5**	**271.3**	**279.9**

Chart 2 sets out pension and OPEB accrual costs attributed to the nuclear facilities in the historical, bridge and test years. OPG's total accrual costs for these periods were determined by Aon Hewitt in accordance with US GAAP, as set out in Attachment 1 for the 2016-2021 projection and Attachment 2 for the 2014-2015 actual amounts.

[2] No solvency special payments are projected for 2016-2021 and none were made in 2013-2015.
[3] Nuclear pension and OPEB amounts presented in this exhibit exclude amounts related to the Nuclear Waste Management Organization ("NWMO"), which is consolidated into OPG's financial statements.

Chart 2

Total Pension and OPEB Accrual Costs – Nuclear[4] ($M)									
	2013 Actual	**2014 Actual**	**2015 Actual**	**2016 Projection**	**2017 Plan**	**2018 Plan**	**2019 Plan**	**2020 Plan**	**2021 Plan**
Pension	365.4	411.2	414.4	294.6	222.8	167.5	153.0	140.0	131.4
OPEB	223.0	176.1	202.8	192.6	194.6	195.0	196.0	197.0	198.3
Total	**588.4**	**587.3**	**617.2**	**487.2**	**417.4**	**362.5**	**349.0**	**337.0**	**329.7**

As set out in section 2.0 and Ex. H1-1-1, OPG proposes to record the difference between actual accrual costs and actual cash amounts during the test period in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, and the difference between actual and forecast cash amounts in the Pension & OPEB Cash Payment Variance Account. Notwithstanding this proposal in light of the OEB's ongoing generic consultation on pension and OPEB, OPG continues to be of the view that it would be appropriate for it to recover accrual costs for pension and OPEB for the regulated business for reasons summarized in section 2.0.

Chart 3 below sets out the difference between pension and OPEB accrual costs and cash amounts attributed to the nuclear facilities for the historical, bridge and test periods (i.e., the difference between the amounts in Chart 2 and the amounts in Chart 1). The difference is expected to decline significantly by the end of the test period. Cash amounts for pension are expected to exceed accrual costs starting in 2018. This trend reflects lower pension accrual costs discussed in section 5.3. The OPEB cash-to-accrual difference is projected to decline gradually over the test period as cash amounts increase.

[4] Ibid.

Chart 3

Pension and OPEB Accrual-Cash Differential Amounts – Nuclear[5] ($M)									
	2013 Actual	2014 Actual	2015 Actual	2016 Projection	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
Pension	133.8	130.3	129.9	11.3	51.7	(8.0)	(27.3)	(17.2)	(30.7)
OPEB	144.9	91.6	109.7	96.0	93.7	90.1	86.8	82.9	80.5
Total	**278.7**	**221.9**	**239.6**	**107.3**	**145.4**	**82.1**	**59.5**	**65.7**	**49.8**

3.1 Presentation of Pension and OPEB Costs in the Application

In costing labour for planning, target setting and financial reporting purposes, OPG includes accrual costs for pension and OPEB in line with US GAAP requirements. Accordingly, OPG's corporate and business unit business plans, which present financial information in accordance with US GAAP, reflect accrual costs for pension and OPEB. This Application is based on OPG's approved 2016-2018 Business Plan and therefore presents business unit and compensation related cost information on the same basis as the business plan.[6] In order to reconcile this presentation with OPG's proposed treatment of pension and OPEB costs in the test period, a negative adjustment in the amount of the forecast differential between pension and OPEB accrual costs and cash amounts (shown in Chart 3) is included as a separate entry in centrally-held costs for the nuclear facilities in each of the test years (Ex. F4-4-1 Table 3, line 2).

4.0 CASH AMOUNTS FOR PENSION AND OPEB

OPG's pension plans are defined benefit pension plans that provide members with a pension amount based on years of service and salary at retirement. The RPP is funded by member (i.e., employee) and OPG (i.e., employer) contributions.[7] The *Pension Benefits Act* (Ontario) ("PBA") sets the minimum funding requirements for registered pension plans to ensure that

[5] Although the accrual-to-cash differential is presented starting in 2013 for illustrative purposes, 2014 is the first year for which the OEB set payment amounts on the basis of cash amounts for pension and OPEB. Positive amounts represent excess of accrual costs over cash amounts.
[6] As in previous proceedings and as discussed in section 5.2, the current service component of accrual costs is largely reflected in costs charged to the business units, while the other components of accrual costs are held centrally and are assigned and allocated to the business units.
[7] The supplementary pension plan is not funded but is secured by letters of credit.

plans have sufficient assets in place to meet existing and future obligations. Contributions must be made to fund the plan's current service cost (also known as normal cost), as well as deficiencies (i.e., deficits), if any, through defined special payments over a period of time.

The PBA requires actuarial valuations on both going concern and solvency bases to be performed at least once every three years to determine the funded status of a registered pension plan (i.e., the difference between the value of pension fund assets and the actuarial present value of the accrued liability[8] as of the valuation date) and required future contributions. The going concern valuation measures the financial position of the pension plan assuming that the plan continues indefinitely into the future. The solvency valuation measures the financial position of the pension plan, as defined pursuant to the PBA, assuming that the plan is wound-up on the valuation date and all benefits are settled by either lump sum payments or annuity purchases. To the extent that going concern special payments will not eliminate the solvency deficit over a 5-year period, additional payments towards the solvency deficit (i.e., solvency special payments) are required over the 5-year period. Going concern special payments are made over a 15-year period. Valuations are prepared and certified by an independent actuary and must be filed with the Financial Services Commission of Ontario ("FSCO") and the Canada Revenue Agency ("CRA").

In determining the going concern accrued liability and current service cost, an actuary attributes the present value of future expected benefits over each plan member's projected service. The obligation at a particular date is the actuarial present value of the benefits attributed to each member's service rendered up to that date. Employer's current service cost represents the actuarial present value of benefits earned in respect of each additional year of employee service, less any required employee contributions to the pension plan.

In order to establish funding requirements, economic and demographic assumptions are required to determine the plan's accrued liability as of the valuation date and to project current service cost for future years. Examples of economic assumptions include discount rates, inflation rate, and salary escalation rate. Examples of demographic assumptions

[8] The term "accrued liability" and "benefit obligation" may be used interchangeably in this exhibit.

include mortality rates and improvement scale, termination rates, and retirement rates. As discussed below, certain assumptions differ between going concern valuations and solvency valuations. Many of the assumptions used in the going concern funding valuations are also applied in accounting valuations for determining the pension obligation and accrual costs.

Going concern valuation assumptions and methods are determined by the actuary preparing the valuation, in accordance with accepted actuarial practice and taking into account regulatory and legislative constraints and guidance issued by the Canadian Institute of Actuaries ("CIA"), with input from plan sponsors. As prescribed by the PBA, key assumptions used in the solvency valuation are required to be set in accordance with specific CIA standards of practice.

The going concern benefit obligation and funding requirements are determined using a discount rate based on the expected long-term rate of return on pension plan assets, taking into account a margin for adverse deviation for some potential barriers to achieving this return. This long-term rate of return is based on the pension fund asset mix and capital market expectations of future risk and return for each asset class within the fund portfolio, net of passive investment management fees.[9] For the solvency valuation, the discount rates used to determine the benefit obligation are required to be determined in accordance with specific standards of practice issued by the CIA and with reference to government of Canada bonds.[10]

The most recently filed actuarial valuation of OPG's RPP is as at January 1, 2014. That valuation showed that the pension fund was in a deficit position. Specifically, the RPP was 90.5 per cent funded on a going concern basis and 99 per cent funded on a solvency basis. Funding requirements pursuant to the valuation included going concern special payments

[9] The long-term expected rate of return used for US GAAP accrual accounting purposes is determined in a similar way to the going concern discount rate, with the main differences being that the accounting rate does not take into account either a margin for adverse deviation or an allowance for passive investment management fees.
[10] The solvency discount rates are typically lower than the going concern discount rates, as the solvency rates reflect current government bond yields and annuity purchase rates determined using information provided by insurance companies rather than the rate of return expected to be earned on pension fund assets.

(over 15 years), but no solvency special payments.[11] In 2014 and 2015, OPG made approximately the minimum required contributions pursuant to the January 1, 2014 valuation and, subject to employee contribution increases discussed in Ex. F4-3-1, is forecasting contributions on the same basis for 2016. The January 1, 2014 valuation was previously filed with the OEB in EB-2013-0321.[12]

The next actuarial valuation of the OPG RPP is expected to be completed in 2017 using data and assumptions as of January 1, 2017, and must be filed with FSCO and CRA by September 30, 2017. A subsequent valuation would need to be completed as of January 1, 2020 at the latest. The test period nuclear revenue requirements reflect projected RPP contributions for the 2017-2021 period as determined by Aon Hewitt. As discussed further in section 4.1, Aon Hewitt prepared this projection based on information available as of December 31, 2015, extrapolating to the assumed January 1, 2017 and January 1, 2020 future valuation dates.

Cash amounts for OPEB reflect OPG's benefit payments to retirees and dependants in accordance with the provisions of the plans. Forecast OPEB payments for the 2016-2021 period represent the nuclear portion of total estimated future cash flows used by Aon Hewitt to project OPEB benefit obligations over this period.

4.1 Forecasting Pension and OPEB Cash Amounts

Forecasting RPP contributions requires estimating the funded status of the plan as of the date of each assumed future funding valuation. Developing these estimates requires expectations of assumptions that will be used to determine the accrued liability as of these dates, and projections of the actual pension fund performance to those dates. OPG's total projected required RPP contributions for 2017-2021 were calculated by Aon Hewitt, as set out in Attachment 1, by projecting the going concern and solvency funded status of the plan

[11] Although the pension plan was less than 100 per cent funded on a solvency basis, there was no requirement for additional solvency funding since the going concern special payments were determined by the valuation to be sufficient to fund the solvency deficit within 5 years.
[12] EB-2013-0321 Ex. J9.6, Attachment 1.

as at January 1, 2017 and January 1, 2020 based on year-end 2015 information. These projections are reflected in OPG's approved 2016-2018 Business Plan.

In order to project the January 1, 2017 and January 1, 2020 benefit obligations, Aon Hewitt applied the January 1, 2014 funding valuation assumptions, subject to certain updates as at year-end 2015.[13] For the going concern valuation, the main update was a decrease in the discount rate from 5.60 per cent per annum to 5.50 per cent per annum to reflect lower expected long-term returns from pension fund assets based on the pension fund asset allocation and capital market return expectations. For the solvency valuation, the changes were to update the prescribed assumptions, including discount rates as at December 31, 2015 and the mortality assumption, which the CIA has now aligned with the recommendations in their February 2014 CIA Final Report: Canadian Pensioners' Mortality. The January 1, 2017 and January 1, 2020 pension asset values were projected by Aon Hewitt based on the actual December 31, 2015 value, at the expected long-term rate of return of 6.0 per cent per annum discussed in section 5.1.[14]

Aon Hewitt's projections of the funded status of the RPP based on year-end 2015 information indicate that the plan will have a minimal going concern deficit as at January 1, 2017, and will be fully funded on both going concern and solvency bases as at January 1, 2020. As such, the projected minimum required pension plan contributions for 2017 to 2019 based on the projected January 1, 2017 valuation comprise employer current service costs and small going concern special payments. The total minimum required contributions for 2020 and 2021 based on the projected January 1, 2020 valuation represent the employer's current service cost only. For all years of the projection, the employer's current service cost has been reduced to reflect increases in employee contribution levels discussed in Ex. F4-3-1.

Projected benefit payments for OPEB plans reflect the cash flows of the underlying accounting benefit obligations discussed in section 5.0.

[13] Attachment 1, pp. 7-8.
[14] This is the same assumption that was used to project accrual pension costs discussed in section 5.0. The difference between the going concern discount rate of 5.5 per cent and the expected long-term rate of return of 6.0 per cent relates to the factors described in footnote 9.

As in previous proceedings, total OPG projected RPP contributions and OPEB payments for 2016-2021 were attributed to the nuclear facilities in proportion to the respective benefit costs, which are allocated using the methodology discussed in section 5.2. The resulting cash amounts for the nuclear facilities are presented in Chart 1 above.

4.2 Comparison of Pension and OPEB Cash Amounts

Pension contributions for the nuclear facilities were lower in 2013 relative to the 2014-2016 period primarily due to the higher going concern special payments required pursuant to the January 1, 2014 valuation. Pension contributions are forecasted to decrease in 2017 relative to the 2014-2016 period as the projected January 1, 2017 funding valuation indicates a lower going concern deficit and therefore lower going concern special payments for the 2017-2019 period. As noted above, the going concern special payments are forecasted to be eliminated in the January 1, 2020 valuation. There are no actual or projected solvency special payments during the 2013-2021 period.

OPEB benefit payments increased gradually during the historical period and are expected to continue to increase during the bridge and test periods. This trend reflects a growing retiree population and expected increases in per capita medical and other costs.

Charts 4 below presents the EB-2013-0321 projected (2013) and OEB-approved (2014 and 2015) pension and OPEB cash amounts for the nuclear facilities.

Chart 4

EB-2013-0321 Projected Pension and OPEB Cash Amounts – Nuclear ($M)			
	2013	**2014**[15]	**2015**[16]
Pension	290.0	277.9	283.4
OPEB	80.9	77.3	82.4
Total	**370.9**	**355.2**	**365.8**

Actual pension contributions for 2013 were lower than projected primarily because OPG did not make an additional, voluntary contribution to the pension plan assumed in the budget. The actual pension contributions for 2014 and 2015 were largely in line with the OEB-approved forecast amounts. Actual OPEB payments for 2013 were close to projected amounts, while the 2014 and 2015 amounts were higher than the OEB-approved forecast, mainly as a result of retirements.

5.0 ACCRUAL COSTS FOR PENSION AND OPEB

As in EB-2013-0321, OPG's accrual costs for pension and OPEB continue to be determined in accordance with US GAAP and comprise several components. These components are: current service cost (net of required employee contributions for funded plans), interest cost on the benefit obligations at the appropriate discount rate, the expected return on RPP fund assets using an assumed long-term rate of return, amounts for past service costs arising from plan amendments, and amounts for actuarial gains or losses. Actuarial gains and losses consist of experience gains and losses, which arise because actual experience differs from that assumed (e.g., investment experience different than expected or higher or lower inflation

[15] The total of EB-2013-0321 OEB-approved pension and OPEB cash amounts for the nuclear facilities for each of 2014 and 2015 can be re-calculated as follows (subject to rounding): EB-2013-0321 Ex. N2-1-1, Chart 1, "December 31, 2013 Update" lines for Nuclear for each of 2014 and 2015 less EB-2013-0321 Payment Amounts Order, App. A, Table 3a, Note 4, line 1a, col. (a) for 2014 and col. (b) for 2015. The total of 2014 and 2015 OEB-approved nuclear cash amounts for each of pension and OPEB can be re-calculated as follows (subject to rounding): EB-2013-0321 Payment Amounts Order, App G., p. 15, $23.38M x 24 mos. for pension and $6.66M x 24 mos. for OPEB.

than assumed), and adjustments for changes in assumptions (e.g., discount rates or mortality assumptions[16]).

In accordance with US GAAP, OPG's pension and other post-retirement benefit accrual costs for a given year are based on the measurement of benefit obligations and RPP fund assets at the end of the previous year. As discussed below, the full impact of certain events arising during a year is not charged to pension and OPEB costs for that year; rather, certain amounts are accumulated and amortized over future periods. OPG's LTD costs for the current year are based on the measurement of the benefit obligation at the end of both the current and the previous year, in accordance with US GAAP. The full impact of events arising during a year related to LTD benefits is charged to OPEB costs for that year.

Similar to the going concern pension funding benefit obligation, the accounting obligations for pension and other post-retirement benefits continue to be determined using the projected benefit method pro-rated on service. Under this method, an equal portion of the total estimated benefit liability is attributed to each year of service until the date the plan participant would be entitled to the full benefit. The obligation at a particular date is the actuarial present value of the benefits attributed to the service rendered up to that date. The LTD obligation continues to be determined using the projected benefit method on a terminal basis. Under this method, the total estimated future benefit is attributed to the year of service in which a disability occurs.

OPG's pension and OPEB costs and obligations continue to be determined annually by an independent actuary using management's best estimate assumptions, both economic (e.g., inflation, salary escalation and health care cost trends) and demographic (e.g., mortality rates and improvement scale, termination rates and retirement rates).[17] The long-term inflation assumption is based on the most recent long-term outlook view of the consumer price index, informed by economic forecasts and the Bank of Canada's target range of

[16] There have been no changes to mortality assumptions used to develop OPG's US GAAP based pension and OPEB benefit obligations, from those outlined in EB-2013-0321 Ex. N2-1-1, section 2.2 and EB-2013-0321 Ex. L-6.8-1 Staff-112.
[17] Many of the pension assumptions used for accounting purposes are the same as those used in the actuarial valuations for funding purposes discussed in section 4.0.

inflation. The salary escalation rate builds on the long-term inflation assumption, subject to adjustments in the near term for known short-term salary expectations based on collective agreement provisions and other expectations of salary growth. As in EB-2013-0321, the longer term salary escalation rate continues to be equal to the long-term inflation rate plus 0.5 per cent.

In accordance with US GAAP, the discount rates used in determining benefit obligations and accrual costs for pension and OPEB continue to be based on AA corporate bond yields in Canada for the appropriate duration of the benefit obligation. The discount rates used to establish the accrual costs for the historical, bridge and test years were determined using the same approach as in EB-2013-0321.[18]

For purposes of determining pension costs, RPP fund assets continue to be valued using a market-related value of assets. The market-related value used in determining OPG's pension costs recognizes gains and losses on equity assets relative to a six per cent assumed real return over a five-year period. This contributes to the smoothing of impacts from equity market volatility over time. Gains and losses on other than equity assets continue to be recognized in the market-related value of assets immediately.

The expected long-term rate of return on the RPP fund assets continues to be calculated by Aon Hewitt based on the pension fund asset mix and capital market expectations of future risk and return for each asset class within the fund portfolio.[19]

Actuarial gains and losses for pension and other post-retirement benefits are generally amortized over future periods. In accordance with US GAAP, OPG amortizes the net cumulative unamortized gain or loss for each of these plans in excess of 10 per cent of the greater of the benefit obligation and the market-related value of the plan assets over the expected average remaining service life of the employees (i.e., the "corridor approach.") Past service costs or credits for pension and other post-retirement benefits continue to be

[18] EB-2013-0321 Ex. F4-3-1, section 6.3.3.
[19] See footnote 9.

amortized over the expected average remaining service period to full eligibility of the affected employee groups. All actuarial gains and losses and past service costs related to LTD benefits continue to be recognized in the year they arise, in accordance with US GAAP.

5.1 Forecasting Pension and OPEB Accrual Costs

Forecasting pension and OPEB accrual costs requires estimating the values of the benefit obligations and pension fund asset value at the end of the year preceding the forecast year. Developing these estimates requires making projections of the actual pension fund performance as well as projections of assumptions that will be used to determine the actual obligations. Forecasting LTD costs also requires estimating the value of the benefit obligation at the end of the last year in the forecast period.

OPG's total projected pension and OPEB accrual costs for 2016-2021 underpinning this Application were determined by Aon Hewitt using the actual December 31, 2015 values of the benefit obligations and pension fund assets, and the final assumptions as at December 31, 2015. The forecast 2017-2021 costs reflect projections of benefit obligations and pension fund assets at the end of each year in the 2016-2020 period using the December 31, 2015 final assumptions.[20]

Chart 5 below presents the assumptions used to determine OPG's 2013-2015 actual and 2016-2021 projected pension and OPEB accrual costs in accordance with US GAAP.[21]

[20] As the final December 31, 2015 assumptions were used in the projection, the 2016 pension and OPEB costs are expected to be close to the actual costs for the year with the exception of LTD costs, absent any significant unexpected changes in legislation or OPG's operations. The 2016 LTD cost projections are less definitive because the actual costs will be calculated using information as of year-end 2016.

[21] Assumptions for 2013 and 2014 were previously presented in EB-2014-0370 Ex. H1-1-1, Chart 1, in accordance with Canadian GAAP. The only assumption difference between US GAAP and Canadian GAAP applicable to OPG's pension and OPEB costs in those years is the use of the year-end discount rate to determine LTD costs under US GAAP rather than the beginning of year discount rate under Canadian GAAP. As such, the LTD discount rate assumptions shown in Chart 5 for 2013 and 2014 differ from those presented in EB-2014-0370.

Chart 5

Pension and OPEB Accrual Cost Assumptions (rate per annum)					
	2013 Actual[22]	**2014 Actual**[23]	**2015 Actual**	**2016 Projection**[23]	**2017-2021 Plan**[24]
Discount rate for pension	4.30%	4.90%	4.00%	4.10%	4.10%
Discount rate for other post-retirement benefits	4.40%	5.00%	4.10%	4.20%	4.20%
Discount rate for long-term disability	4.10%	3.30%	3.40%	3.40%	3.40%
Expected long-term rate of return on pension fund assets	6.25%	6.25%	6.25%	6.0%	6.0%
Inflation rate	2.0%	2.0%	2.0%	2.0%	2.0%
Weighted average salary schedule escalation rate[24]	2.5%	2.5%	2.0% from Jan 1, 2015 to Dec 31, 2020 and 2.5% thereafter	1.6% from Jan 1, 2016 to Dec 31, 2021 and 2.5% thereafter	1.6% from Jan1, 2016 to Dec 31, 2021 and 2.5% thereafter
Rate of return used to project year-end pension fund asset values[25]	N/A	N/A	N/A	N/A	6.0% in 2016 to 2020

The actual returns on pension fund assets were 9.2 per cent in 2013, 16.2 per cent in 2014, and 9.7 per cent in 2015.

[22] Except for the LTD discount rate determined at year end, these are the same assumptions used to develop the 2013 and the final 2014 pension and OPEB cost projections presented in EB-2013-0321 (see EB-2013-0321: Ex. F4-3-1, Chart 1 for 2013 and OPG's Argument-in-Chief, p. 97 for 2014).
[23] The assumptions for 2016-2021 can also be found at pp. 6-7 of Aon Hewitt's report in Attachment 1.
[24] The weighted average salary schedule escalation rate of 1.6 per cent per year to the end of 2021 reflects assumptions (1.0 per cent per year to the end of 2017 for PWU-represented employees and 1.0 per cent to the end of 2018 for employees represented by The Society) based on current collective agreement provisions discussed in Ex. F4-3-1, and 2.0 per cent per year (i.e., inflation rate) thereafter. The longer term salary schedule escalation (after 2021) is set at the assumed inflation rate plus 0.5 per cent, as in EB-2013-0321.
[25] Projections of rates of return to determine year-end pension fund asset values are not required for the calculation of the 2013-2016 costs because the actual prior year-end asset values are known.

5.2 Pension and OPEB Accrual Cost Distribution

A portion of OPG's total pension and OPEB accrual costs continues to be charged to the business units as part of standard labour rates and other direct charges. The portion of the costs that is charged to the business units[26] is based on an estimate of the accrual current service cost for pension and OPEB. The remainder of pension and OPEB accrual costs, which includes interest costs on the obligations, the expected return on pension plan assets, amounts for past service costs and actuarial gains and losses, and any current service cost variance from the estimate reflected in standard labour rates and related direct charges to the business units,[26] continues to be recorded as a centrally-held cost (line 1 of Ex. F4-4-1 Table 1 and Table 3).

The centrally-held portion of pension and OPEB costs continues to be directly assigned and allocated to the nuclear business unit, in proportion to amounts of pension and OPEB costs charged to the business unit (including amounts assigned and allocated as part of corporate Support Services costs). This methodology was used in EB-2010-0008, EB-2012-0002, EB-2013-0321 and EB-2014-0370. It was reviewed by HSG Group, Inc. in the cost allocation study filed in EB-2013-0321, as well as by Black & Veatch Corporation Inc. in the cost allocation study filed in EB-2010-0008.

5.3 Comparison of Pension and OPEB Accrual Costs

Chart 6 below provides a breakdown of the 2013-2021 pension and OPEB costs shown in Chart 2 for the nuclear facilities between amounts charged to the business units and those recorded in centrally held costs. As noted above, OPG is providing in Attachments 1 and 2 independent actuarial reports in support of the total OPG forecast 2016-2021 costs and the actual 2014 an 2015 costs, respectively. An actuarial report in support of 2013 actual costs was filed in EB-2014-0370.[27]

---

[26] Includes pension and OPEB costs assigned and allocated as part of corporate Support Services costs.
[27] Refer to EB-2014-0370 Ex. H1-1-2, Attachment 2. Although that report was prepared on a Canadian GAAP basis, the differences from US GAAP accrual costs are limited to LTD costs. These differences were described in EB-2013-0321 Ex. A2-1-1 and EB-2012-0002 Ex. A3-1-2.

Chart 6[28]

Total Pension and OPEB Accrual Costs – Nuclear[29] ($M)									
	2013 Actual	**2014 Actual**	**2015 Actual**	**2016 Projec-tion**	**2017 Plan**	**2018 Plan**	**2019 Plan**	**2020 Plan**	**2021 Plan**
Pension – Business Unit Charge	222.2	214.6	218.6	228.6	243.0	230.4	239.0	242.4	244.3
Pension – Centrally Held	143.2	196.6	195.8	66.0	(20.2)	(62.9)	(86.0)	(102.4)	(112.9)
Total Pension Cost	**365.4**	**411.2**	**414.4**	**294.6**	**222.8**	**167.5**	**153.0**	**140.0**	**131.4**
OPEB – Business Unit Charge	77.2	74.2	55.6	58.5	67.8	66.2	67.1	68.1	68.6
OPEB – Centrally Held	145.8	101.9	147.2	134.1	126.8	128.8	128.9	128.9	129.7
Total OPEB Cost	**223.0**	**176.1**	**202.8**	**192.6**	**194.6**	**195.0**	**196.0**	**197.0**	**198.3**
Total Pension and OPEB Costs	**588.4**	**587.3**	**617.2**	**487.2**	**417.4**	**362.5**	**349.0**	**337.0**	**329.7**

Total pension accrual costs for the nuclear facilities increased from 2013 to 2014 primarily due to the updated mortality assumptions arising from a comprehensive accounting valuation of pension plan obligations as at December 31, 2013, as discussed in EB-2013-0321[30], and the impact of a lower than expected year-end 2013 pension fund asset value for fixed income investments. The increase was partially offset by the impact of the higher discount rate as at December 31, 2013. The pension accrual costs were largely stable in 2015 compared to 2014, primarily as the impact of the lower discount rate as at December 31, 2014 was largely offset by the impact of a higher than expected year-end 2014 pension fund asset value and negative expected net growth in cost components during 2015.[31] Pension costs for the

[28] "Business Unit Charge" amounts presented in Chart 6 and Chart 7 are equivalent to amounts labelled "Standard Labour Rate Component" in EB-2013-0321 evidence.
[29] See footnote 3.
[30] EB-2013-0321: Ex. N-1-1, Ex. N2-1-1 and Ex. L-6.8-1 Staff-112.
[31] As in previous proceedings, expected net growth (i.e. change) in cost components refers to the impact of changes in current service costs in the normal course, higher interest costs on a higher benefit obligation due to the passage of time, expected changes in the pension asset value, and related changes in amortization of historical actuarial gains or losses.

nuclear facilities are projected to decrease significantly over the 2016-2021 period reflecting negative expected net growth in cost components, primarily due to projected increases in the pension asset value and lower amortization of historical net actuarial losses under the corridor approach. The year-over-year decreases in forecast pension costs in 2016 and 2017 also reflect increases in employee contributions discussed in Ex. F4-3-1. Additionally, the impact of the slightly higher discount rate at December 31, 2015 and the impact of lower staffing levels contribute to the decrease in the costs in 2016 compared to 2015.

Total OPEB accrual costs for the nuclear facilities decreased from 2013 to 2014, mainly due to the lower expected per capita health care benefit costs reflected as part of the comprehensive accounting valuation as at December 31, 2013 and the impact of the higher discount rate as at December 31, 2013. The increase in OPEB costs from 2014 to 2015 was primarily due to the decrease in discount rates at December 31, 2014. OPEB costs are forecast to decrease from 2015 to 2016, mainly as a result of the slightly higher discount rate as at December 31, 2015 and lower staffing levels. In the projection for 2017 to 2021, OPEB costs for the nuclear facilities are expected to remain largely stable.

Chart 7 presents the current service cost component of the total pension and OPEB accrual costs shown in Chart 6. As discussed in section 5.2, total current service cost is comprised of estimated amounts charged to the business units through standard labour rates and other direct charges as well as variances from these estimated amounts, which are included in centrally-held costs. The sum of pension and OPEB current service cost shown in Chart 7 is presented as part of total compensation details at Ex. F4-3-1, Attachment 1, line 45.

Chart 7[32]

Pension and OPEB Accrual Current Service Cost – Nuclear[33] ($M)									
	2013 Actual	**2014 Actual**	**2015 Actual**	**2016 Projection**	**2017 Plan**	**2018 Plan**	**2019 Plan**	**2020 Plan**	**2021 Plan**
Pension – Business Unit Charge[34]	222.2	214.6	218.6	228.6	243.0	230.4	239.0	242.4	244.3
Pension – Centrally Held	(0.2)	(30.9)	32.0	(9.4)	(18.6)	(9.2)	(12.2)	(15.8)	(18.3)
Total Pension Current Service Cost	**222.0**	**183.7**	**250.6**	**219.2**	**224.4**	**221.2**	**226.8**	**226.6**	**226.0**
OPEB – Business Unit Charge[34]	77.2	74.2	55.6	58.5	67.8	66.2	67.1	68.1	68.6
OPEB – Centrally Held	(4.5)	(19.1)	5.1	(0.5)	(9.0)	(8.7)	(10.3)	(11.7)	(12.5)
Total OPEB Current Service Cost	**72.7**	**55.1**	**60.7**	**58.0**	**58.8**	**57.5**	**56.8**	**56.4**	**56.1**
Total Pension and OPEB Current Service Cost	**294.7**	**238.8**	**311.3**	**277.2**	**283.2**	**278.7**	**283.6**	**283.0**	**282.1**

Pension accrual current service cost for the nuclear facilities was lower in 2014 than in 2013 mainly on account of the higher discount rate as at December 31, 2013, partly offset by the impact of updated mortality assumptions from the comprehensive accounting valuation of plan obligations as at December 31, 2013. OPEB accrual current service cost was also lower in 2014 than in 2013, primarily as a result of the higher discount rate as at December 31, 2013 and lower expected per capita health care benefit costs reflected as part of the comprehensive accounting valuation. The higher pension and OPEB current service cost in 2015, compared to 2014, reflected a lower discount rate as at December 31, 2014. The lower pension and OPEB current service cost in 2016 compared to 2015 is mainly due to lower staffing levels and slightly higher discount rates, and, for pension, increased employee

32 See footnote 28.
33 See footnote 3.
34 As shown in Chart 6.

pension plan contributions. The current service cost for both pension and OPEB is largely stable over the test period.

The split of each year's accrual current service cost between business unit charges[35] and centrally-held costs primarily varies with differences between actual and budgeted current service cost amounts, and differences between total estimated payroll for regular employees used to develop standard labour rates and the company's actual payroll.

6.0 CONCLUSION

Although OPG continues to be of the view that it is appropriate for it to recover its pension and OPEB costs on an accrual basis, OPG proposes to continue the treatment for pension and OPEB costs adopted by the OEB in the EB-2013-0321 Decision pending the outcome of the OEB's generic consultation on pension and OPEB.

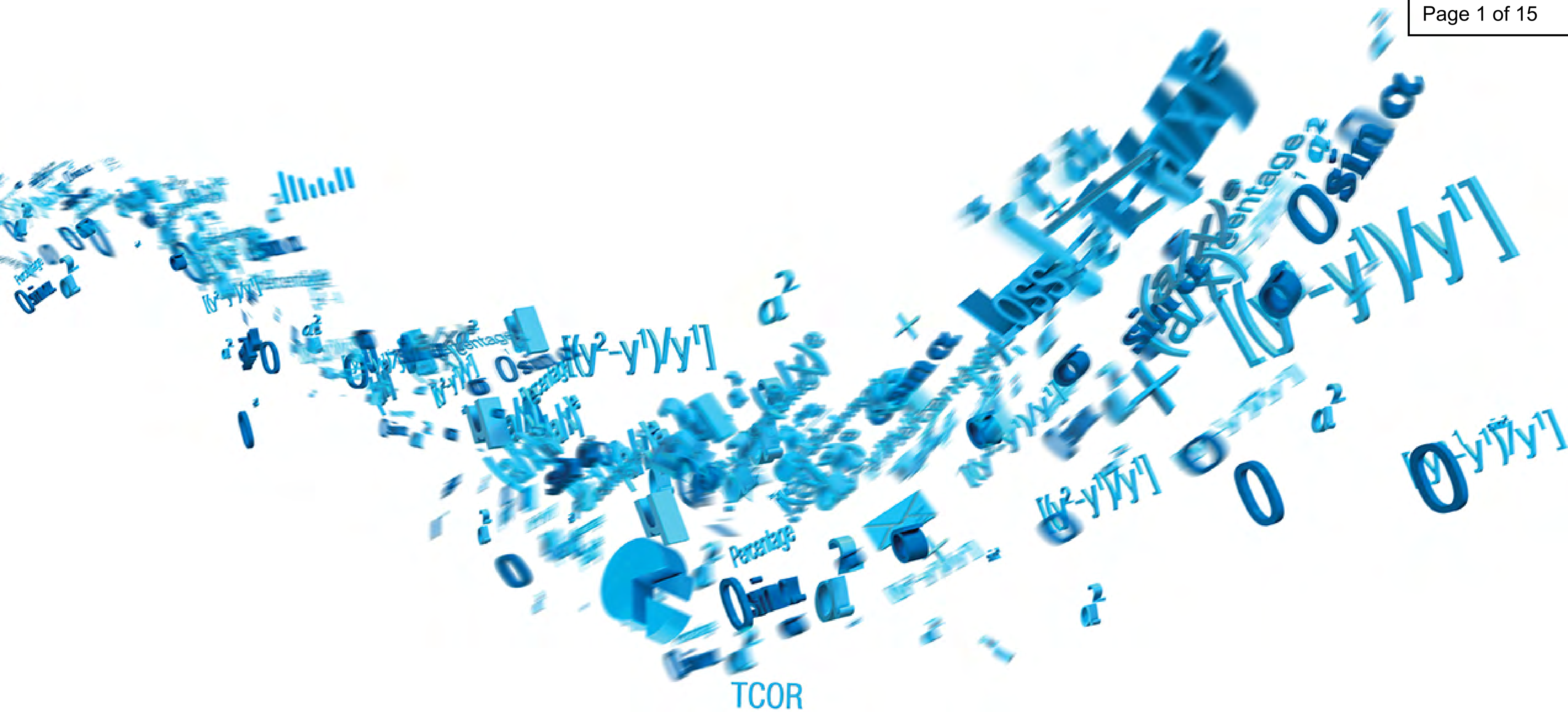
Both accrual costs and cash amounts for OPG's pension and OPEB plans are projected to decline during the test period. As accrual costs are decreasing at a faster pace, the annual difference between accrual costs and cash amounts is expected to narrow significantly from an average of about $230M per year in 2014-2015 to just under $50M by 2021 (for the nuclear facilities). These decreases reflect, among other factors, pension reforms for represented employees achieved through the 2015 round of collective bargaining with direct involvement and support of the Government of Ontario, as well as similar reforms introduced for the Management group. Cash amounts for pension are expected to exceed accrual costs starting in 2018.

[35] Includes pension and OPEB costs assigned and allocated as part of corporate support services costs.

ATTACHMENTS

Attachment 1:	Aon Hewitt Report on OPG's Estimated Pension and OPEB Costs for 2016-2021
Attachment 2:	Aon Hewitt Report on OPG's Pension and OPEB Costs for 2014 and 2015

Aon Hewitt



Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2016 to 2021

Ontario Power Generation Inc.

January 1, 2016 to December 31, 2021

Risk. Reinsurance. Human Resources.

Aon
Empower Results®

Table of Contents

Introduction

This report summarizes the estimated accounting costs for fiscal years 2016 through 2021 for the post employment benefit plans sponsored by Ontario Power Generation Inc. (“OPG”).

This report covers the following plans sponsored by OPG:

- Ontario Power Generation Inc. Pension Plan (“RPP”);
- Ontario Power Generation Inc. Supplementary Pension Plan (“SPP”) ;
- Non-pension Post Retirement Plan which provides other post retirement benefits (“OPRB”) including retiree medical, dental, life insurance, and retirement bonus benefits; and
- Post Employment Plan which provides long-term disability benefits (“LTD”) including sick leave benefits before LTD begins and the continuation of medical, dental and life insurance while on LTD.

Collectively SPP, OPRB and LTD are known as Other Post Employment Benefits (“OPEB”).

The results cover the fiscal years from January 1, 2016 to December 31, 2021. The results have been developed in accordance with US generally accepted accounting principles (“US GAAP”) under ASC 715, 712 and 710.

The results in this report do not include amounts related to the benefit plans of the Nuclear Waste Management Organization, which are included in OPG’s consolidated financial statements.

Unless otherwise stated all assumptions, data elements, methodologies, plan provisions, and information about assets reflected in this report are the same as those underlying and/or contained in the December 31, 2015 disclosure reports (“the Reports”) prepared by Aon Hewitt in accordance with US GAAP for the post employment benefit plans sponsored by OPG. These disclosure reports were dated March 2016 and are titled as follows:

- US GAAP Accounting Information Non-pension Post-retirement and Post-employment Benefits Plans; and
- US GAAP Accounting Information – Pension Plans.

Sincerely,

Aon Hewitt Inc.

[Original signed by]

Linda M. Byron
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Aon Hewitt Inc.

[Original signed by]

Gregory W. Durant
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

May 2016

Actuarial Report

Results for Fiscal Years 2016 to 2021

OPG's total estimated pension and OPEB costs for fiscal years 2016 through 2021 as determined in accordance with US GAAP are as follows:

All figures are shown in Canadian $000's.

US GAAP

	2016	**2017**	**2018**	**2019**	**2020**	**2021**
RPP	$ 367,277	$ 276,001	$ 206,870	$ 188,085	$ 172,093	$ 161,479
SPP	22,112	21,750	21,560	21,257	21,151	21,033
OPRB	199,546	201,470	202,065	203,238	205,056	207,160
LTD	18,348	17,715	17,095	16,510	15,965	15,466
Total	$ 607,283	$ 516,936	$ 447,590	$ 429,090	$ 414,265	$ 405,138

The estimated 2016 costs for the RPP, SPP and OPRB plans are not expected to change, unless a significant event, such as a curtailment or settlement or other unexpected changes to OPG's operations were to take place prior to December 31, 2016. The final 2016 cost under US GAAP for the LTD plan will be determined at December 31, 2016 based on applicable information and assumptions at that date.

The final 2017 to 2021 costs for all plans under US GAAP will be determined based on applicable information, experience and assumptions in the future.

Further details of the above OPG-wide estimated costs, by plan, as well as OPG's estimated contributions to the RPP fund and benefit payments for OPEB are provided in Schedules 1 through 6 to this report.

Actuarial Methods and Assumptions

The actuarial methodology and accounting policies used in the development of the estimated costs for fiscal years 2016 through 2021 under US GAAP are summarized below.

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;
- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs;
- The discount rates have been determined in accordance with US GAAP. The discount rates have been set with reference to those representative of AA corporate bond yields in Canada having duration similar to the liabilities of the plans. The December 31, 2015 discount rates were 4.10% per annum for determining the estimated 2016 through 2021 RPP and SPP costs, 4.20% per annum for determining the estimated 2016 through 2021 OPRB costs, and 3.40% per annum for determining the estimated 2016 through 2021 LTD costs. The actual discount rate as at December 31, 2016 will be used to determine the final 2016 LTD cost under US GAAP;
- A building block approach is used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using the fund's asset allocations, via a building block approach with proper consideration of diversification and rebalancing. Aon Hewitt calculated the expected return based on this methodology. An expected rate of return on assets of 6.00% per annum determined using the above approach was used for determining the estimated 2016 through 2021 RPP costs;
- Other actuarial assumptions are management's best estimate of future events, as determined in consultation with us and as set out in the Reports. These assumptions include the inflation rate, which was established at 2.00% for determining 2016 to 2021 costs, and the salary scale increase rate, which was established at 1.00% per annum to end of 2017 for Power Workers' Union ("PWU") represented employees and to the end of 2018 for employees represented by The Society of Energy Professionals ("The Society"), 2.00% per annum to the end of 2021, and 2.50% per annum thereafter (plus Promotion, Progression, Merit for all years). These salary scale increase assumptions for the 2016-2017 period for PWU-represented employees and for the 2016-2018 period for employees represented by The Society are consistent with the provisions of the corresponding collective agreements;
- The active membership headcount is first calculated for each business unit based on the assumed decrements, and then compared to the estimated active December 31, 2016 to December 31, 2021 headcounts for each business unit. If the calculated headcounts exceed the estimated headcounts at year-end, additional employees are assumed to retire or terminate to reduce the headcounts. Conversely, new

entrants are assumed to be added to the plan in order to achieve anticipated headcounts, if the calculated headcounts are lower than the estimated headcounts at year-end. The estimated December 31, 2016 to December 31, 2021 active headcounts used are as follows:

	2016	2017	2018	2019	2020	2021
Nuclear	6,185	6,237	6,229	6,179	6,048	5,978
Hydro / Thermal	1,517	1,469	1,447	1,406	1,389	1,358
Support Services	2,101	2,068	2,043	2,026	2,001	1,994
Total	9,803	9,774	9,719	9,611	9,438	9,330

- Actuarial gains or losses for RPP, SPP and OPRB have been amortized using the 10% corridor method, except where immediate recognition is required under US GAAP for non-routine events during the year (none expected during 2016 through 2021);
- Past service costs for RPP, SPP and OPRB have been amortized on a straight-line basis over the expected average remaining service lifetime at the amendment date, except where immediate recognition is required under US GAAP during the year (none expected during 2016 through 2021);
- For LTD, all actuarial gains and losses and past service costs are required to be recognized immediately in the cost. Therefore, under US GAAP, the cost is equal to the change in the benefit obligation plus benefit payments; and
- Expected return on assets and amortization of actuarial gains/losses are based on a market-related value of assets where investment gains and losses on equity assets in excess of an expected return of 6.0% per annum plus the increase in Consumer Price Index are smoothed over five years.

The 2016 contributions to the RPP fund are based on the latest actuarial valuation as of January 1, 2014 for funding purposes of the RPP, updated to reflect increases in required member contributions coming into effect for represented and non-represented members during 2016. The next actuarial valuation for funding purposes must have an effective date no later than January 1, 2017. We have assumed that based on a triennial filing, the subsequent actuarial valuation for funding purposes would have an effective date of January 1, 2020.

In order to project contributions to the RPP for 2017 to 2021, an estimate of the going concern and solvency positions of the RPP is required. The contributions for 2017 to 2019 are estimated based on the projected going concern and solvency funded status as of January 1, 2017. The estimated contributions for 2020 to 2021 are based on the projected going concern and solvency funded status as of January 1, 2020, Contributions during the period 2017 to 2021 reflect increases in required member contributions coming into effect during that period for represented and non-represented members. All assumptions used for the determination of the projected going concern funded status are the same as those used for the funding valuation as of January 1, 2014[1], updated to reflect a discount rate of 5.50% per annum which reflects lower expected returns from pension fund assets determined using our capital market expectation model based on the pension fund's asset allocation.

All assumptions used for the determination of the projected solvency funded status are the same as those used for the funding valuation as at January 1, 2014, updated to reflect the following prescribed assumptions:

- The non-indexed discount rates are 2.10% per annum for the first 10 years and 3.70% per annum thereafter for commuted values, and 3.20% per annum for annuity purchases. The indexed discount rates for commuted values are 1.30% per annum for the first 10 years and 1.80% per annum thereafter; and
- The mortality assumption is per the 2014 Canadian Pensioners' Mortality Table combined with the Canadian Pensioners Mortality Improvement Scale B (CPM-B), both as published in the February 2014 CIA Final Report: Canadian Pensioners' Mortality.

The projected benefit payments for the OPEB plans reflect the estimated cashflows of the underlying benefit obligations.

---

[1] Includes application of the January 1, 2014 valuation 3-year salary scale assumption as at January 1, 2017.

Schedule 1—Summary of Estimated 2016 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2016 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2016 to December 31, 2016 is determined based on the balance sheet items at January 1, 2016.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2016				
Projected Benefit Obligation	$ (15,404,062)	$ (295,295)	$ (2,914,927)	$ (259,900)
Fair Value of Plan Assets	13,072,299	0	0	0
Net Asset (Liability) Recognized	$ (2,331,763)	$ (295,295)	$ (2,914,927)	$ (259,900)
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2016				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 5,851	$ 0
Unrecognized Net Actuarial Loss (Gain)	3,017,663	77,532	537,802	0
Total Accumulated Other Comprehensive Loss (Income)	$ 3,017,663	$ 77,532	$ 543,653	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2016 to December 31, 2016				
Employer Current Service Cost	$ 273,247	$ 6,092	$ 56,497	$ 9,647
Interest Cost	630,810	11,986	123,223	8,701
Expected Return on Plan Assets	(728,898)	0	0	0
Amortization of Past Service Cost	0	0	583	0
Amortization of Net (Gain) Loss	192,118	4,034	19,243	0
Total Cost	$ 367,277	$ 22,112	$ 199,546	$ 18,348
2016 Estimated Employer Pension Contributions / Benefit Payments	$ 353,316	$ 18,107	$ 75,094	$ 27,280

Schedule 2—Summary of Estimated 2017 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2017 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2017 to December 31, 2017 is determined based on the projected balance sheet items at January 1, 2017.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2017				
Projected Benefit Obligation	$ (15,724,926)	$ (295,266)	$ (3,019,658)	$ (250,968)
Fair Value of Plan Assets	13,619,630	0	0	0
Net Asset (Liability) Recognized	$ (2,105,296)	$ (295,266)	$ (3,019,658)	$ (250,968)
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2017				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 5,268	$ 0
Unrecognized Net Actuarial Loss (Gain)	2,777,235	73,498	518,664	0
Total Accumulated Other Comprehensive Loss (Income)	$ 2,777,235	$ 73,498	$ 523,932	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2017 to December 31, 2017				
Employer Current Service Cost	$ 277,972	$ 6,194	$ 57,285	$ 9,316
Interest Cost	643,048	11,981	127,550	8,399
Expected Return on Plan Assets	(778,316)	0	0	0
Amortization of Past Service Cost	0	0	583	0
Amortization of Net (Gain) Loss	133,297	3,575	16,052	0
Total Cost	$ 276,001	$ 21,750	$ 201,470	$ 17,715
2017 Estimated Employer Pension Contributions / Benefit Payments	$ 211,838	$ 18,469	$ 80,053	$ 26,514

Schedule 3—Summary of Estimated 2018 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2018 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2018 to December 31, 2018 is determined based on the projected balance sheet items at January 1, 2018.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2018				
Projected Benefit Obligation	$ (16,072,677)	$ (294,972)	$ (3,123,933)	$ (242,169)
Fair Value of Plan Assets	13,998,249	0	0	0
Net Asset (Liability) Recognized	$ (2,074,428)	$ (294,972)	$ (3,123,933)	$ (242,169)
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2018				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 4,685	$ 0
Unrecognized Net Actuarial Loss (Gain)	2,682,204	69,923	502,105	0
Total Accumulated Other Comprehensive Loss (Income)	$ 2,682,204	$ 69,923	$ 506,790	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2018 to December 31, 2018				
Employer Current Service Cost	$ 273,168	$ 6,307	$ 55,676	$ 8,989
Interest Cost	654,686	11,966	131,753	8,106
Expected Return on Plan Assets	(817,206)	0	0	0
Amortization of Past Service Cost	0	0	583	0
Amortization of Net (Gain) Loss	96,222	3,287	14,053	0
Total Cost	$ 206,870	$ 21,560	$ 202,065	$ 17,095
2018 Estimated Employer Pension Contributions / Benefit Payments	$ 216,704	$ 18,838	$ 85,255	$ 25,470

Schedule 4—Summary of Estimated 2019 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2019 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2019 to December 31, 2019 is determined based on the balance sheet items at January 1, 2019.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2019				
Projected Benefit Obligation	$ (16,335,705)	$ (294,407)	$ (3,225,414)	$ (233,794)
Fair Value of Plan Assets	14,282,869	0	0	0
Net Asset (Liability) Recognized	$ (2,052,836)	$ (294,407)	$ (3,225,414)	$ (233,794)
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2019				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 4,102	$ 0
Unrecognized Net Actuarial Loss (Gain)	2,670,446	66,636	487,359	0
Total Accumulated Other Comprehensive Loss (Income)	$ 2,670,446	$ 66,636	$ 491,461	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2019 to December 31, 2019				
Employer Current Service Cost	$ 278,903	$ 6,433	$ 54,681	$ 8,678
Interest Cost	666,847	11,941	135,855	7,832
Expected Return on Plan Assets	(840,623)	0	0	0
Amortization of Past Service Cost	0	0	583	0
Amortization of Net (Gain) Loss	82,958	2,883	12,119	0
Total Cost	$ 188,085	$ 21,257	$ 203,238	$ 16,510
2019 Estimated Employer Pension Contributions / Benefit Payments	$ 221,692	$ 19,215	$ 90,910	$ 24,257

Schedule 5—Summary of Estimated 2020 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2020 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2020 to December 31, 2020 is determined based on the balance sheet items at January 1, 2020.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2020				
Projected Benefit Obligation	$ (16,646,750)	$ (293,566)	$ (3,323,905)	$ (226,047)
Fair Value of Plan Assets	14,647,094	0	0	0
Net Asset (Liability) Recognized	$ (1,999,656)	$ (293,566)	$ (3,323,905)	$ (226,047)
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2020				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 3,519	$ 0
Unrecognized Net Actuarial Loss (Gain)	2,650,873	63,753	474,105	0
Total Accumulated Other Comprehensive Loss (Income)	$ 2,650,873	$ 63,753	$ 477,624	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2020 to December 31, 2020				
Employer Current Service Cost	$ 278,643	$ 6,561	$ 54,332	$ 8,391
Interest Cost	678,648	11,903	139,841	7,574
Expected Return on Plan Assets	(862,245)	0	0	0
Amortization of Past Service Cost	0	0	539	0
Amortization of Net (Gain) Loss	77,047	2,687	10,344	0
Total Cost	$ 172,093	$ 21,151	$ 205,056	$ 15,965
2020 Estimated Employer Pension Contributions / Benefit Payments	$ 193,346	$ 19,599	$ 97,362	$ 23,326

Schedule 6—Summary of Estimated 2021 US GAAP Results

The following table provides a summary of the estimated US GAAP results for 2021 for the post employment benefit plans sponsored by OPG. The estimated net periodic pension/benefit cost for the period January 1, 2021 to December 31, 2021 is determined based on the balance sheet items at January 1, 2021.

(in Canadian $000's)	RPP	SPP	OPRB	LTD
Projected Net Asset (Liability) Recognized as at January 1, 2021				
Projected Benefit Obligation	$ (16,929,550)	$ (292,431)	$ (3,419,351)	$ (218,686)
Fair Value of Plan Assets	14,956,659	0	0	0
Net Asset (Liability) Recognized	$ (1,972,891)	$ (292,431)	$ (3,419,351)	$ (218,686)
Estimated Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2021				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 2,980	$ 0
Unrecognized Net Actuarial Loss (Gain)	2,645,361	61,066	462,396	0
Total Accumulated Other Comprehensive Loss (Income)	$ 2,645,361	$ 61,066	$ 465,376	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2021 to December 31, 2021				
Employer Current Service Cost	$ 277,673	$ 6,693	$ 54,112	$ 8,118
Interest Cost	689,795	11,854	143,716	7,348
Expected Return on Plan Assets	(880,396)	0	0	0
Amortization of Past Service Cost	0	0	539	0
Amortization of Net (Gain) Loss	74,407	2,486	8,793	0
Total Cost	$ 161,479	$ 21,033	$ 207,160	$ 15,466
2021 Estimated Employer Pension Contributions / Benefit Payments	$ 199,146	$ 19,991	$ 103,326	$ 21,400

About Aon Hewitt

Aon Hewitt is the global leader in human capital consulting and outsourcing solutions. The company partners with organizations to solve their most complex benefits, talent and related financial challenges, and improve business performance. Aon Hewitt designs, implements, communicates and administers a wide range of human capital, retirement, investment management, health care, compensation and talent management strategies. With more than 30,000 professionals in 90 countries, Aon Hewitt makes the world a better place to work for clients and their employees.

For more information on Aon Hewitt, please visit aonhewitt.com.

About Aon

Aon plc (NYSE:AON) is the leading global provider of risk management, insurance and reinsurance brokerage, and human resources solutions and outsourcing services. Through its more than 66,000 colleagues worldwide, Aon unites to empower results for clients in over 120 countries via innovative and effective risk and people solutions and through industry-leading global resources and technical expertise. Aon has been named repeatedly as the world's best broker, best insurance intermediary, best reinsurance intermediary, best captives manager, and best employee benefits consulting firm by multiple industry sources. Visit aon.com for more information on Aon and aon.com/manchesterunited to learn about Aon's global partnership with Manchester United.

Aon Hewitt

Report on the Accounting Cost for Post Employment Benefit Plans For Fiscal Years 2014 and 2015

Ontario Power Generation Inc.
January 1, 2014 to December 31, 2015

AON
Empower Results®

Risk. Reinsurance. Human Resources.

Table of Contents

Introduction

This report summarizes the accounting costs for fiscal years 2014 and 2015 for the post employment benefit plans sponsored by Ontario Power Generation Inc. (“OPG”). In addition, Aon Hewitt prepared this report to provide an independent actuary’s confirmation of information for the post employment benefit plans sponsored by OPG in relation to the December 31, 2015 balances in OPG’s Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account established by the Ontario Energy Board (“OEB”). We understand that this report is expected to be filed with the OEB.

This report covers the following plans sponsored by OPG:

- Ontario Power Generation Inc. Pension Plan (“RPP”);
- Ontario Power Generation Inc. Supplementary Pension Plan (“SPP”);
- Non-pension Post Retirement Plan which provides other post retirement benefits (“OPRB”) including retiree medical, dental, life insurance, and retirement bonus benefits, and
- Post Employment Plan which provides long-term disability benefits (“LTD”) including sick leave benefits before LTD begins and the continuation of medical, dental and life insurance while on LTD.

Collectively SPP, OPRB and LTD are known as Other Post Employment Benefits (“OPEB”).

The results cover the fiscal years from January 1, 2014 to December 31, 2014 and from January 1, 2015 to December 31, 2015. The results have been developed in accordance with US generally accepted accounting principles (“US GAAP”) under ASC 715, 712 and 710.

The results in this report do not include amounts related to the benefit plans of the Nuclear Waste Management Organization, which are included in OPG’s consolidated financial statements.

Unless otherwise stated, all assumptions, data elements, methodologies, plan provisions, and information about assets reflected in this report are the same as those underlying and/or contained in the December 31, 2014 or the December 31, 2015 disclosure reports (“the Reports”) prepared by Aon Hewitt in accordance with US GAAP for the post employment benefit plans sponsored by OPG. These disclosure reports were dated February 2015 and March 2016, respectively, and are titled as follows:

- US GAAP Accounting Information Non-pension Post-retirement and Post-employment Benefits Plans; and
- US GAAP Accounting Information – Pension Plans.

Sincerely,

Aon Hewitt Inc.

[Original signed by]

Linda M. Byron
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Aon Hewitt Inc.

[Original signed by]

Gregory W. Durant
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

May 2016

Actuarial Report

Results for 2014 and 2015

This report confirms OPG's total actual pension and OPEB costs for the period from January 1, 2014 to December 31, 2015, as determined in accordance with US GAAP, are as follows:

(in Canadian $ 000's)	January 1 to October 31, 2014	November 1 to December 31, 2014	Total for January 1 to December 31, 2014	January 1 to December 31, 2015
RPP	$ 439,303	$ 87,861	$ 527,164	$ 523,447
SPP	21,532	4,306	25,838	25,332
OPRB	150,546	30,109	180,655	206,799
LTD	18,670	444	19,114	24,096
Total	$ 630,051	$ 122,720	$ 752,771	$ 779,674

Further details of the OPG-wide costs provided above, by plan, as well as OPG's actual contributions to the RPP fund and benefit payments for OPEB for the periods from January 1, 2014 to December 31, 2015 are provided in Schedules 1 and 2 to this report.

The above pension and OPRB costs for the period January 1 to October 31, 2014 are the same as those previously reported by us in the following report in support of the balance in OPG's Pension and OPEB Cost Variance Account established by the OEB, which was filed by OPG with the OEB under case number EB-2014-0370:

- "Report on the Accounting Cost for Post Employment Benefit Plans in Support of Pension and OPEB Cost Variance Account Calculations – Fiscal Year 2013 and the Period from January 1 to October 31, 2014" dated February 2015.

Up to October 31, 2014, the Pension and OPEB Cost Variance Account recorded the difference between actual pension and OPEB costs under Canadian GAAP for OPG's regulated operations and related tax impacts, and those reflected in the regulated prices established by the OEB under case number EB-2010-0008.

In its November 2014 decision under case number EB-2013-0321, the OEB established the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account for OPG's nuclear and regulated hydroelectric businesses, effective November 1, 2014. Additions to the Pension & OPEB Cash Versus Accrual Differential Deferral Account for the period from November 1, 2014 to December 31, 2015 were calculated by OPG by comparing the portion of the above November 1, 2014 to December 31, 2015 OPG-wide US GAAP costs attributed to OPG's nuclear and regulated hydroelectric businesses to the regulated businesses' portion of OPG's total actual contribution to the RPP fund and actual benefit payments under OPEB plans for the corresponding periods, (which are found in Schedules 1 and 2 to this report). Additions to the Pension & OPEB Cash Payment Variance Account for the period from November 1, 2014 to December 31, 2015 were calculated by OPG by comparing the regulated businesses' portion of the actual contribution to the RPP fund and actual benefit payments under OPEB plans to such forecast amounts included in the regulated prices established by the OEB under case number EB-2013-0321.

The balances of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account calculated and recorded by OPG as at December 31, 2015 are $315 million and $28 million to be recovered from ratepayers, respectively, as reported in the audited schedule of regulatory balances as at December 31, 2015, prepared by OPG for filing with the OEB, and dated April 7, 2016.

Actuarial Methods and Assumptions

Aon Hewitt confirms that the OPG-wide costs for the years ended December 31, 2014 (including specifically the period from November 1, 2014 to December 31, 2014) and December 31, 2015 were determined using the actuarial methodology and accounting standards described below. We furthermore confirm that the methodology under US GAAP is consistent with the methodology outlined in OPG's application to the OEB under case number EB-2013-0321 and used to determine the forecast of OPG-wide pension and OPEB costs for the 2014-2015 period, which were presented by OPG in that proceeding through the filing of our report on these costs dated March 2014 and titled "Update to Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2014 to 2015".

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;
- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs;
- The discount rates have been determined in accordance with US GAAP. The discount rates have been set with reference to those representative of AA corporate bond yields in Canada having a duration similar to the liabilities of the plans. The discount rates for determining the 2014 costs (including the period from November 1, 2014 to December 31, 2014) were 4.90% per annum for RPP and SPP, 5.00% per annum for OPRB, and 3.30% per annum for LTD. The discount rates for determining the 2015 costs were 4.00% per annum for RPP and SPP, 4.10% per annum for OPRB, and 3.40% per annum for LTD.
- A building block approach is used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using the fund's asset allocations, via a building block approach with proper consideration of diversification and rebalancing. Aon Hewitt calculated the expected return based on this methodology. An expected rate of return on assets of 6.25% per annum determined using the above approach was used for determining the 2014 and 2015 RPP costs;
- The best estimate assumptions for base mortality rates reflect OPG's actual experience derived from OPG's historical pensioner data. Starting with 2014 costs, the assumed mortality improvement rates were updated to reflect the improvement scale (CPM-B) developed by the Canadian Institute of Actuaries ("CIA") and published in the February 2014 CIA Final Report: Canadian Pensioners' Mortality;

- Other actuarial assumptions are management's best estimate of future events, as determined in consultation with us and as set out in the Reports. These assumptions include the inflation rate and the salary scale increase rate, which were established at 2.00% per annum and 2.50% per annum (plus Promotion, Progression, Merit), respectively, in determining the 2014 costs. For 2015 costs, the inflation rate was set at 2.00%, and the salary scale increase rate was set at 2.00% per annum for the first six years and 2.50% per annum thereafter (plus Promotion, Progression, Merit in all years);
- Actuarial gains or losses for RPP, SPP and OPRB have been amortized using the 10% corridor method, except where immediate recognition is required under US GAAP for non-routine events during the year (none during 2014 and 2015);
- Past service costs for RPP, SPP and OPRB have been amortized on a straight-line basis over the expected average remaining service lifetime at the amendment date, except where immediate recognition is required under US GAAP for non-routine events during the year (none during 2014 and 2015);
- For LTD, all actuarial gains and losses and past service costs are required to be recognized immediately in the cost. Therefore, under US GAAP, the cost is equal to the change in the benefit obligation plus benefit payments; and
- Expected return on assets and amortization of actuarial gains/losses are based on a market-related value of assets where investment gains and losses on equity assets in excess of an expected return of 6.0% per annum plus the increase in Consumer Price Index are smoothed over five years.

Schedule 1—Summary of 2014 US GAAP Results

The following table provides a summary of US GAAP results for 2014 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2014.

(in Canadian $ 000s)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2014				
Projected Benefit Obligation	$ (13,368,826)	$ (285,169)	$ (2,439,305)	$ (267,830)
Fair Value of Plan Assets	10,893,428	0	0	0
Net Asset (Liability) Recognized	$ (2,475,398)	$ (285,169)	$ (2,439,305)	$ (267,830)
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2014				
Unrecognized Past Service Costs (Credits)	0	0	950	0
Unrecognized Net Actuarial Loss (Gain)	3,492,617	78,721	319,518	0
Total Accumulated Other Comprehensive Loss (Income)	$ 3,492,617	$ 78,721	$ 320,468	$ 0
Components of Net Periodic Pension/Benefit Cost, January 1, 2014 to December 31, 2014				
Employer Current Service Cost	$ 235,496	$ 7,437	$ 51,620	$ 11.517
Interest Cost	655,696	14,110	122,963	10,887
Expected Return on Plan Assets	(624,026)	0	0	0
Recognition of LTD Actuarial (Gain) Loss	0	0	0	(3,290)
Amortization of Past Service Cost (Credit)	0	0	120	0
Amortization of Net (Gain) Loss	259,998	4,291	5,952	0
Total Cost (Annual)	$ 527,164	$ 25,838	$ 180,655	$ 19,114
Total Cost (January to October)	$ 439,303	$ 21,532	$ 150,546	$ 18,670
Total Cost (November to December)	$ 87,861	$ 4,306	$ 30,109	$ 444
2014 Estimated Employer Pension Contributions / Benefit Payments				
Annual amounts used for developing net periodic pension/benefit costs	$ 400,000	$ 9,278	$ 63,336	$ 27,644
2014 Actual Employer Pension Contributions / Benefit Payments				
Annual	$ 360,000	$ 15,690	$ 66,456	$ 26,317
January to October	300,000	12,804	53,788	18,355
November to December	60,000	2,886	12,668	7,962

Schedule 2—Summary of 2015 US GAAP Results

The following table provides a summary of US GAAP results for 2015 for the post employment benefit plans sponsored by OPG. The net periodic pension/benefit cost for this period was determined based on the balance sheet items at January 1, 2015.

(in Canadian $ 000s)	RPP	SPP	OPRB	LTD
Net Asset (Liability) Recognized as at January 1, 2015				
Projected Benefit Obligation	$ (15,601,615)	$ (313,377)	$ (2,866,895)	$ (260,627)
Fair Value of Plan Assets	12,328,171	0	0	0
Net Asset (Liability) Recognized	$ (3,273,444)	$ (313,377)	$ (2,866,895)	$ (260,627)
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2015				
Unrecognized Past Service Costs (Credits)	0	0	830	0
Unrecognized Net Actuarial Loss (Gain)	4,123,499	96,781	633,029	0
Total Accumulated Other Comprehensive Loss (Income)	$ 4,123,499	$ 96,781	$ 633,859	$ 0
Components of Net Periodic Pension/Benefit Cost, January 1, 2015 to December 31, 2015				
Employer Current Service Cost	$ 316,533	$ 7,158	$ 60,943	$ 8,601
Interest Cost	626,909	12,628	118,678	8,450
Expected Return on Plan Assets	(711,656)	0	0	0
Recognition of LTD Actuarial (Gain) Loss	0	0	0	7,045
Amortization of Past Service Cost (Credit)	0	0	120	0
Amortization of Net (Gain) Loss	291,661	5,546	27,058	0
Total Cost	$ 523,447	$ 25,332	$ 206,799	$ 24,096
2015 Estimated Employer Pension Contributions / Benefit Payments	$ 364,000	$ 9,678	$ 66,521	$ 26,334
Amounts used for developing net periodic pension/benefit cost				
2015 Actual Employer Pension Contributions / Benefit Payments	$ 359,292	$ 24,165	$ 68,561	$ 24,823

About Aon Hewitt

Aon Hewitt is the global leader in human capital consulting and outsourcing solutions. The company partners with organizations to solve their most complex benefits, talent and related financial challenges, and improve business performance. Aon Hewitt designs, implements, communicates and administers a wide range of human capital, retirement, investment management, health care, compensation and talent management strategies. With more than 30,000 professionals in 90 countries, Aon Hewitt makes the world a better place to work for clients and their employees.

For more information on Aon Hewitt, please visit aonhewitt.com/canada.

About Aon

Aon plc (NYSE:AON) is the leading global provider of risk management, insurance and reinsurance brokerage, and human resources solutions and outsourcing services. Through its more than 66,000 colleagues worldwide, Aon unites to empower results for clients in over 120 countries via innovative and effective risk and people solutions and through industry-leading global resources and technical expertise. Aon has been named repeatedly as the world's best broker, best insurance intermediary, best reinsurance intermediary, best captives manager, and best employee benefits consulting firm by multiple industry sources. Visit aon.com for more information on Aon and aon.com/manchesterunited to learn about Aon's global partnership with Manchester United.

CENTRALLY-HELD COSTS

1.0 PURPOSE

This evidence presents OPG's centrally-held costs and the period-over-period comparisons of centrally-held costs that are directly assigned and allocated to OPG's nuclear facilities.

2.0 OVERVIEW

This evidence supports the approval sought for the centrally-held costs included in the 2017 to 2021 nuclear revenue requirements proposed in this Application. The amounts included in the nuclear revenue requirements are $74.9M in 2017, $112.9M in 2018, $102.9M in 2019, $85.7M in 2020 and $75.7M in 2021.

Centrally-held costs are an integral part of the costs of operating OPG's generation facilities. They are company-wide costs that are recorded centrally for a variety of reasons, such as achieving record-keeping efficiency and maintaining proper oversight. They are not Support Services costs.

Categories of centrally-held costs are separately identified for those exceeding $10M per year on average over the test period. The category of "Other" reflects the remaining centrally-held costs, with a description of some of the more significant items provided in section 7.0. The centrally-held cost items described below were identified in EB-2013-0321 and EB-2010-0008 and the nature of these costs is unchanged.

Centrally-held costs continue to be directly assigned or allocated to OPG's regulated operations using the same methodology as in EB-2013-0321 and EB-2010-0008. The methodology was previously reviewed and found to be appropriate by Black & Veatch Corporation in EB-2010-0008. The methodology was similarly found to be appropriate as part of the independent review of OPG's cost allocation methodology by HSG Group Inc. in EB-2013-0321. The methodology is applied to total OPG-wide centrally-held costs presented in Ex. F4-4-1 Table 1, which results in costs attributed to the nuclear facilities presented in Ex. F4-4-1 Table 3. Ex. F4-4-2 Table 2 provides the period-over-period comparisons for the historical, bridge and test periods for the nuclear facilities and a comparison to the budgeted or OEB-approved amounts.

This evidence provides a description of the categories of centrally-held costs and discusses trends and variances for each category. The key drivers of these costs are identified within the discussions of trends and variances. Where these drivers do not adequately explain a year-over-year variance, a specific explanation is provided to the extent the variance is equal to or greater than 10 per cent.

Centrally-held costs increase from 2013 to 2015 primarily as a result of higher pension and OPEB-related accrual costs. The costs are forecast to decrease markedly during 2016-2021 as pension and OPEB-related amounts decline significantly. OPG's Application includes a proposed pension and OPEB adjustment to centrally-held costs for the nuclear facilities such that the 2017-2021 nuclear revenue requirements reflect forecast cash amounts for pension and OPEB pending the outcome of the EB-2015-0040 generic consultation. This negative adjustment is applied to test period centrally-held costs for the nuclear facilities (line 2 in Ex. F4-4-1 Table 3). The negative adjustment declines from $145.4M in 2017 to $49.8M in 2021 as the forecast differential between accrual costs and cash amounts declines significantly. OPG's proposed test period treatment of pension and OPEB costs and the difference between accrual costs and cash amounts are discussed in Ex. F4-3-2.

3.0 PENSION AND OPEB-RELATED ACCRUAL COSTS

3.1 Description

Certain components of pension and OPEB accrual costs for all of OPG's employees and retirees continue to be included in centrally-held costs. These cost components include interest costs on the obligations, the expected return on pension plan assets, amounts in respect of past service costs, amounts in respect of actuarial gains and losses, and variances from the estimated current service cost amounts charged to business units through standard labour rates and related charges. As in EB-2013-0321 and EB-2010-0008, the pension and OPEB-related accrual costs are directly assigned and allocated to business units in proportion to the pension and OPEB costs charged to the business units including amounts assigned and allocated as part of corporate Support Services costs.

3.2 Trends and Variances

Specific trends and variances in pension and OPEB accrual costs are discussed in section 5.3 of Ex. F4-3-2. In summary, variability in the pension and OPEB accrual costs in the historical period is primarily related to the December 31, 2013 comprehensive accounting valuation of pension and OPEB obligations[1], fluctuations in discount rates, and differences in pension fund asset values. Over the 2016-2021 period, the declining trend in these costs is mainly due to negative expected net growth in cost components from projected increases in pension asset values and lower amortization of historical net actuarial losses.[2]

4.0 OPG-WIDE AND NUCLEAR INSURANCE

4.1 Description

These are the costs of OPG's company-wide insurance program and the additional nuclear-specific insurance program. The company-wide program covers commercial general liability, directors and officers and fiduciary liability, all risk property, boiler and machinery breakdown, including statutory boiler and pressure vessel inspections, and business interruption.

As in EB-2013-0321 and EB-2010-0008, the costs of the company-wide insurance program are primarily directly assigned to the business units based on the applicability of each type of insurance coverage and the asset replacement cost of the generation facilities. The nuclear-specific insurance program relates to liability insurance associated with nuclear operations and additional property insurance for damage to the nuclear portions of OPG's nuclear generating stations, which complements the conventional property insurance program. This portion of insurance costs continues to be directly assigned to the nuclear facilities.

---

[1] See EB-2013-0321: Ex. N1-1-1, Ex. N2-1-1 and Ex. L-6.8-1 Staff-112

[2] Expected net growth (i.e., change) in pension cost components includes the impact of changes in current service costs in the normal course, higher interest costs on a higher benefit obligation due to the passage of time, expected changes in the pension asset value, and related changes in amortization of historical actuarial gains and losses.

4.2 Trends and Variances

OPG-wide insurance costs for the nuclear facilities are generally stable over the test period, with period-over-period fluctuations and budget-to-actual variances in historical and bridge periods attributable mainly to actual and assumed insurance premium increases and changes related to appraised asset replacement cost values.

The main trend in the planned increases in nuclear insurance costs over the bridge and test periods are increased premiums starting in 2016, due to higher statutory nuclear liability insurance limits that will be phased in over four years in accordance with the provisions of the new federal legislation. As noted in Ex. A1-6-1, the higher limits will result once the *Nuclear Liability and Compensation Act*, which received Royal Assent in February 2015, is in force and replaces the 1976 *Nuclear Liability Act*.

5.0 PERFORMANCE INCENTIVES

5.1 Description

These costs are for the pay-at-risk program that compensates OPG's Management (i.e. non-unionized) employees based on the achievement of corporate and individual performance objectives. The costs continue to be attributed to the business units based on the distribution of past performance incentive payments.

5.2 Trends and Variances

Performance incentive costs are projected assuming target performance is achieved and are generally stable over the 2016-2021 period. The costs fluctuate in the historical period, reflecting variations in actual corporate performance. The 2014 costs were close to the OEB-approved amount as the impact of exceeding target corporate performance was largely offset by lower staff levels. The 2015 costs were below the OEB-approved amount chiefly due to lower staff levels. OPG's Management compensation, including the pay-at-risk program, is discussed in Ex. F4-3-1.

6.0 IESO NON-ENERGY CHARGES

6.1 Description

IESO non-energy costs are charges that are applied to withdrawals of energy from the IESO-controlled grid. The charges include transmission charges, the debt retirement charge, the rural or remote electricity rate protection charge, charges associated with IESO administration fees uplift charges and the Global Adjustment. These charges are not discretionary and apply to all energy withdrawals from the IESO-controlled grid. These charges are directly assigned to the specific regulated facilities.

6.2 Trends and Variances

The fluctuations in the costs for the nuclear facilities over the 2013 to 2021 period are primarily due to the variability in Global Adjustment rates. Differences in Global Adjustment rates also represent the principle cause of the variances between actual and OEB-approved amounts for the nuclear facilities for 2014 and 2015.

7.0 OTHER

7.1 Description

As in EB-2013-0321, other centrally-held costs (“Other costs”) consist of a number of relatively smaller items. In the test period, these are comprised primarily of labour-related costs and the annual Ontario Nuclear Funds Agreement (“ONFA”) guarantee fee. The labour-related costs include the fiscal calendar and labour balancing adjustments, as well as the vacation accrual.

The fiscal calendar adjustment is a wage adjustment covering all business units that reflects the difference in the number of days between the 52 or 53 week fiscal calendar used for payroll accounting and OPG’s financial year ending on December 31. The adjustment is temporary and fluctuates from year to year, as the starting and ending days of the fiscal calendar vary from year to year. A negative adjustment (i.e., a reduction to costs) can occur in years when the fiscal calendar has 53 weeks. The costs (or a reduction to costs) are directly assigned to business units on the basis of each unit’s payroll.

The labour balancing adjustments relate to non-pension and OPEB components of the standard labour rates. These adjustments capture variances (positive or negative) between the amount of such costs charged or planned to be charged to the business units and Support Services groups through standard labour rates and the final actual or planned amount of these costs.

The vacation accrual represents the cost to OPG of the estimated outstanding vacation entitlement for all of its employees and is directly assigned to business units on the basis of each unit's payroll.

The annual ONFA guarantee fee is the amount payable by OPG to the Province of Ontario pursuant to the ONFA. In exchange for the fee, the Province of Ontario supports financial guarantees to the Canadian Nuclear Safety Commission by providing a guarantee relating to OPG's nuclear decommissioning and waste management liabilities and nuclear segregated funds pursuant to the ONFA. The fee is calculated as 0.5 per cent of the amount currently guaranteed of $1,551M, and is directly assigned to the nuclear facilities. OPG's nuclear decommissioning and waste management liabilities are discussed in Ex. C2-1-1.

7.2 Trends and Variances

Variances in Other costs over the 2013 - 2015 period are mainly caused by the variability in labour balancing and fiscal calendar adjustments.

The variability in the labour balancing adjustments primarily accounts for the decreasing trend in the actual Other costs for the nuclear facilities over the 2013-2015 period and the lower Other costs in 2015 relative to the 2016 projection. Actual amounts of the labour balancing adjustments are a function of each year's payroll related transactions processed by OPG on account of thousands of individual employees.

The negative fiscal calendar adjustment in 2017 is the main driver of the lower forecast Other costs for the nuclear facilities, compared to 2016. The negative fiscal calendar adjustment anticipated in 2017 is due to OPG's 2017 fiscal year being four days longer than the 2017 calendar year (the other fiscal years in the 2013-2021 period are shorter than the respective calendar years). Differences in the forecast Other costs over the 2019-2021 period are also chiefly due to the variability in the number of days covered by the fiscal calendar adjustment.

The forecast Other costs for the nuclear facilities are higher in 2018 than in 2017 and 2019. This is mainly due to labour balancing adjustments related to differences between amounts included in planning standard labour rates for payments to a subset of employees for a limited time period negotiated as part of the 2015 round of collective bargaining in exchange for pension reforms, and the final planned amounts of these costs. The 2015 collective bargaining and related outcomes are discussed in Ex. F4-3-1.

Numbers may not add due to rounding.

Table 1
Centrally Held Costs ($M)
OPG

Line No.	Corporate Costs	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Pension/OPEB Related Accrual Costs**	374.6	382.6	433.4	249.4	132.1	81.4	52.7	32.5	20.7
2	**OPG-Wide Insurance**	16.3	16.6	21.0	23.4	24.0	25.3	27.4	27.7	27.4
3	**Nuclear Insurance**	7.6	8.0	8.2	19.0	21.1	23.1	26.0	26.5	27.1
4	**Performance Incentives**	20.4	27.0	23.6	24.2	24.2	24.4	24.5	24.3	24.3
5	**IESO Non-Energy Charges**	92.6	77.0	108.0	94.4	93.7	85.1	78.7	82.6	62.1
6	**Other**	41.1	32.6	8.7	29.7	11.5	33.7	23.1	26.1	21.0
7	**Total**	552.6	543.8	602.9	440.1	306.7	273.0	232.5	219.7	182.6

Table 2

Allocation of Centrally Held Costs - Regulated Hydroelectric ($M)

Intentionally left blank (See Ex. A1-3-1)

Numbers may not add due to rounding.

Table 3
Allocation of Centrally Held Costs - Nuclear ($M)

Line No.	Costs	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Pension/OPEB Related Accrual Costs**	289.0	298.5	343.0	200.1	106.6	65.9	42.9	26.5	16.8
2	**Pension/OPEB Adjustment for Test Period Cash to Accrual Differences**[1]	0.0	0.0	0.0	0.0	(145.4)	(82.1)	(59.5)	(65.7)	(49.8)
3	**OPG-Wide Insurance**	3.3	3.4	4.6	6.2	6.4	6.5	7.0	7.0	6.8
4	**Nuclear Insurance**	7.6	8.0	8.2	19.1	21.1	23.1	26.1	26.5	27.1
5	**Performance Incentives**	14.5	20.2	17.1	18.4	18.4	18.5	18.6	18.5	18.5
6	**IESO Non-Energy Charges**	57.4	51.2	77.7	62.1	61.1	56.5	51.8	54.5	42.0
7	**Other**	38.1	29.7	9.4	21.0	6.7	24.5	16.0	18.3	14.3
8	**Total**	409.9	411.0	459.9	326.9	74.9	112.9	102.9	85.7	75.7

Notes:

1 As discussed in Ex. F4-4-1 and Ex. F4-3-2, the test period adjustment is included to reflect OPG's proposal to include cash amounts for pension and OPEB in the nuclear revenue requirement and defer the difference between accrual costs and cash amounts in the Pension & OPEB Cash to Accrual Differential Deferral Account pending the outcome of the EB-2015-0040 generic consultation, consistent with the EB-2013-0321 treatment.
The difference between accrual costs and cash amounts is found in Ex. F4-3-2 Chart 3.

Numbers may not add due to rounding.

Table 1
Comparison of Allocation of Centrally Held Costs ($M)
Regulated Hydroelectric

Intentionally left blank (See Ex. A1-3-1)

Numbers may not add due to rounding.

Table 2
Comparison of Allocation of Centrally Held Costs ($M)
Nuclear

Line No.	Business Unit	2013 Budget	(c)-(a) Change	2013 Actual	(g)-(c) Change	2014 OEB Approved	(g)-(e) Change	2014 Actual	(k)-(g) Change	2015 OEB Approved	(k)-(i) Change	2015 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	**Pension/OPEB Related Accrual Costs**	296.6	(7.6)	289.0	9.5	284.3	14.2	298.5	44.5	234.8	108.2	343.0
2	**Pension/OPEB Adjustment for Test Period Cash to Accrual Differences[1]**	0.0	0.0	0.0	0.0	(228.3)	228.3	0.0	0.0	(165.6)	165.6	0.0
3	**OPG-Wide Insurance**	3.8	(0.5)	3.3	0.1	3.9	(0.5)	3.4	1.2	4.0	0.6	4.6
4	**Nuclear Insurance**	9.7	(2.1)	7.6	0.4	12.9	(4.9)	8.0	0.2	14.7	(6.5)	8.2
5	**Performance Incentives**	20.8	(6.3)	14.5	5.7	20.8	(0.6)	20.2	(3.1)	20.8	(3.7)	17.1
6	**IESO Non-Energy Charges**	54.3	3.1	57.4	(6.2)	60.2	(9.0)	51.2	26.5	59.6	18.1	77.7
7	**Other**	21.9	16.2	38.1	(8.4)	27.8	1.9	29.7	(20.4)	32.3	(23.0)	9.4
8	**Total**	407.1	2.8	409.9	1.1	181.6	229.4	411.0	48.9	200.6	259.3	459.9

Line No.	Business Unit	2015 Actual	(c)-(a) Change	2016 Budget	(e)-(c) Change	2017 Plan	(g)-(e) Change	2018 Plan	(i)-(g) Change	2019 Plan	(k)-(i) Change	2020 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**Pension/OPEB Related Accrual Costs**	343.0	(142.9)	200.1	(93.5)	106.6	(40.7)	65.9	(23.0)	42.9	(16.4)	26.5
10	**Pension/OPEB Adjustment for Test Period Cash to Accrual Differences[1]**	0.0	0.0	0.0	(145.4)	(145.4)	63.3	(82.1)	22.6	(59.5)	(6.2)	(65.7)
11	**OPG-Wide Insurance**	4.6	1.6	6.2	0.2	6.4	0.1	6.5	0.5	7.0	0.1	7.0
12	**Nuclear Insurance**	8.2	10.9	19.1	2.0	21.1	2.0	23.1	3.0	26.1	0.4	26.5
13	**Performance Incentives**	17.1	1.3	18.4	0.0	18.4	0.1	18.5	0.1	18.6	(0.1)	18.5
14	**IESO Non-Energy Charges**	77.7	(15.6)	62.1	(1.0)	61.1	(4.6)	56.5	(4.7)	51.8	2.7	54.5
15	**Other**	9.4	11.7	21.0	(14.3)	6.7	17.7	24.5	(8.5)	16.0	2.4	18.3
16	**Total**	459.9	(133.0)	326.9	(251.9)	74.9	38.0	112.9	(10.0)	102.9	(17.3)	85.7

Line No.	Business Unit	2020 Plan	(c)-(a) Change	2021 Plan
		(a)	(b)	(c)
17	**Pension/OPEB Related Accrual Costs**	26.5	(9.7)	16.8
18	**Pension/OPEB Adjustment for Test Period Cash to Accrual Differences[1]**	(65.7)	15.9	(49.8)
19	**OPG-Wide Insurance**	7.0	(0.2)	6.8
20	**Nuclear Insurance**	26.5	0.6	27.1
21	**Performance Incentives**	18.5	0.0	18.5
22	**IESO Non-Energy Charges**	54.5	(12.6)	42.0
23	**Other**	18.3	(4.0)	14.3
24	**Total**	85.7	(9.9)	75.7

Notes:

1 The adjustment for 2014 and 2015 reflects the EB-2013-0321 Decision and Payment Amounts Order that limited the amount of pension and OPEB costs reflected in the approved revenue requirement to cash amounts and established the Pension & OPEB Cash versus Accrual Differential Deferral Account to record differences between accrual costs and cash amounts, pending the outcome of an OEB generic proceeding related to pension and OPEB costs. As discussed in Ex. F4-4-1 and Ex. F4-3-2, the adjustment for 2017-2021 is included to reflect OPG's proposal to apply the same treatment in this Application. The difference betwen accrual costs and cash amounts for the test period is found in Ex. F4-3-2 Chart 3.