IMPACT STATEMENT

1.0 PURPOSE

The purpose of this exhibit is to show the impact of certain material changes that have occurred since OPG submitted its pre-filed evidence in this Application on May 27, 2016, consistent with the requirements of paragraph 11.02 of the OEB's *Rules of Practice and Procedure*. These changes impact the revenue requirement for the nuclear facilities and result from (i) OPG's 2017-2019 business plan (the "2017-2019 Business Plan"), which includes an updated forecast of pension and other post-employment benefit ("OPEB") cash amounts, projected cost impacts of the 2017 to 2021 ONFA Reference Plan approved by the Province in December 2016 (the "2017 ONFA Reference Plan")[1], and new Canadian Nuclear Safety Commission ("CNSC") requirements; (ii) an updated forecast of used fuel and low and intermediate level ("L&ILW") revenues under the Bruce lease and associated agreements ("Bruce Lease") that was finalized subsequent to the approval of the 2017-2019 Business Plan; and (iii) the Return on Equity ("ROE") value of 8.78% published by the Ontario Energy Board ("OEB") on October 27, 2016 for use in 2017 custom IR applications (collectively, the "Drivers").[2]

The Application was filed based on OPG's 2016-2018 Business Plan, which also included a financial projection for the 2019-2021 period (Ex. A2-2-1). The 2017-2019 Business Plan was approved by OPG's Board of Directors ("OPG Board") on November 10, 2016 and includes a financial projection for the 2020-2021 period. The five-year planning information included in the 2017-2019 Business Plan was developed as part of the 2017-2019 business planning cycle, applying a consistent process for all years. A copy of the 2017-2019

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[1] See Attachment 4 for a copy of the letter from the Province approving the 2017-2021 ONFA Reference Plan.

[2] See Ontario Energy Board Web Posting, "*Cost of Capital Parameter Updates for 2017 Cost of Service and Custom Incentive Rate-setting Applications*", dated October 27, 2016 at http://www.ontarioenergyboard.ca/oeb/_Documents/2017EDR/OEB_Ltr_Cost_of_Capital_Update_20161027.pdf

Business Plan is provided in Attachment 1[3]. Attachment 1 is being filed in accordance with the requirements of the OEB's practice directions on confidential filings.

2.0 SUMMARY

This update to the Application reflects material changes in costs for the nuclear facilities in the 2017 to 2021 IR period resulting from the Drivers. In determining items to be included as part of this update, OPG evaluated changes with reference to a materiality threshold of an average $10M per year over the IR period. As shown in Chart 2.0 below, the changes in this update result in an overall net increase in the nuclear revenue requirement of approximately $7M in total for the IR period. The updated cost forecasts were determined using the same rigour and, unless otherwise noted in this Impact Statement, using the same methodologies as the original pre-filed evidence. OPG is not updating its nuclear production forecast, as there is no material change to that forecast in the 2017-2019 Business Plan. An updated Revenue Requirement Work Form reflecting the changes identified in this Impact Statement is attached as Attachment 2.

The update to the revenue requirement does not impact OPG's smoothing proposal of a constant 11 percent per year nuclear base rate increase. There are also no changes to the proposed deferral and variance account amortization amounts. As a result, OPG is not updating its request for smoothed nuclear payment amounts or riders, and there is no change to the annualized residential consumer impact of OPG's Application.

In addition to revenue requirement items, OPG is updating its forecast of pension and OPEB accrual costs attributed to the nuclear facilities for the IR period provided in the Application, to reflect the 2017-2019 Business Plan. As discussed in Ex. F4-3-2, OPG proposes to continue recording the difference between actual accrual costs and actual cash amounts for pension and OPEB in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, pending the outcome of the OEB's EB-2015-0040 consultation.

[3] A copy of OPG's 2017-2019 Business Planning Instructions can be found at Ex. L-1.2-1 Staff-003.

OPG is proposing to update the 2017 to 2021 nuclear revenue requirement in the following five areas, as discussed in greater detail in section 3.0:

- changes to forecast pension and OPEB cash amounts, including the impact of the latest filed pension funding valuation as of January 1, 2016 and an assumed subsequent valuation as of January 1, 2019 (see section 3.1);
- changes to forecast costs associated with OPG's liabilities for nuclear waste management and decommissioning ("nuclear liabilities"), including the projected impact of the 2017 ONFA Reference Plan effective January 1, 2017[4], as well as the income tax impacts of changes to forecast cash expenditures on nuclear waste management and decommissioning and corresponding disbursements from the nuclear segregated funds (see section 3.2);
- changes to Bruce Lease net revenues and related tax effects as a result of an updated forecast of used fuel and L&ILW revenues, under the amended Bruce Lease, for changes in revenue rates reflecting the 2017 ONFA Reference Plan cost estimates and new waste volume forecasts provided by Bruce Power LP (see section 3.3);
- an update to the forecast ROE amounts and related tax effects to reflect the most recent OEB-published Cost of Capital parameters (see section 3.4); and
- an increase in forecast Nuclear base OM&A costs resulting from new Fitness for Duty requirements from the CNSC (see section 3.5).

There are two consequential changes to the nuclear revenue requirements, also presented in Chart 2.0, as a result of the five changes identified above:

- an increase in nuclear stretch factor dollars as a result of the changes in Nuclear OM&A included in this Impact Statement; and
- the elimination of IR period regulatory tax loss carry forwards, as a result of the changes in regulatory taxable income arising from the items included in this Impact Statement (see section 3.6).

[4] Any difference between the projected impacts and the final impacts for the prescribed facilities arising from the approved 2017 ONFA Reference Plan will be recorded in the Nuclear Liability Deferral Account. Any such differences related to the Bruce facilities will be recorded in the Bruce Lease Net Revenues Variance Account.

Chart 2.0

Summary of Changes to Proposed Nuclear Revenue Requirement* ($M)

Line No.		2017	2018	2019	2020	2021	Total
1	Pension and OPEB Cash Amounts	19.1	18.3	53.8	81.0	79.3	251.5
2	Nuclear Liabilities	(40.3)	(57.2)	(21.0)	(121.2)	(156.0)	(395.6)
3	Used Fuel and Waste Services Bruce Lease Revenue	35.1	35.6	36.5	37.6	34.9	179.8
4	Return on Equity Value	(9.0)	(9.4)	(9.2)	(20.1)	(21.3)	(69.0)
5	New CNSC Requirements (Base OM&A)	0.5	0.5	16.7	11.7	11.7	41.0
6	Nuclear Stretch Dollars**	-	(0.0)	(0.1)	(0.1)	(0.2)	(0.5)
7	Tax Carryforwards	6.4	(15.2)	(52.0)	60.8	-	(0.0)
8	**Total Revenue Requirement Change**	11.9	(27.4)	24.6	49.6	(51.6)	7.1

*all amounts shown are inclusive of any income tax impacts; positive values are increases to revenue requirement and negative values are decreases
**reflects changes in Nuclear base OM&A due to new CNSC requirements and changes in nuclear liabilities costs

The updated nuclear requirement is provided in Ex. N1-1-1 Table 1. In order to minimize the impact on the proceeding schedule and to keep the Impact Statement to a manageable size, OPG is limiting the update to the changes described above.

The change in forecast pension and OPEB cash amounts for the nuclear facilities increases the nuclear revenue requirement by approximately $252M over the IR period. This is due to higher payments for pension deficit funding projected in the 2017-2019 Business Plan, primarily as a result of a decrease in discount rates relative to the pre-filed evidence. The forecast nuclear pension and OPEB accrual costs decrease by approximately $21M over the IR period. The 2017 to 2021 forecast excess of pension and OPEB accrual costs over cash amounts decreases to approximately $130M for the nuclear facilities, compared to approximately $403M in the pre-filed evidence.

Changes in forecasts related to nuclear liabilities decrease the IR period nuclear revenue requirement by approximately $396M, which consists of a decrease of approximately $551M related to the changes in nuclear liabilities costs for the Bruce facilities, an increase of approximately $280M associated with the changes in nuclear liabilities costs for the prescribed facilities, and a decrease of approximately $124M in income tax impacts related to changes in forecast cash expenditures on nuclear waste management and decommissioning and associated disbursements from the nuclear segregated funds.

The change in Bruce Lease net revenues as a result of updated used fuel and L&ILW revenue forecasts increases the nuclear revenue requirement by approximately $180M over the IR period, which consists of a $135M reduction in Bruce Lease net revenues and $45M in increased income tax impacts.

OPG is updating its ROE for all years of the IR period using the prevailing 2017 ROE as specified by the OEB[5]. The 2017 ROE value is 8.78%, which is 0.41% lower than the ROE value underpinning the pre-filed evidence. The change in ROE decreases the 2017 to 2021 nuclear revenue requirement by approximately $69M, inclusive of the related income taxes.

The new CNSC Fitness for Duty regulatory requirements will create an obligation for OPG to design and implement a Fitness for Duty program. OPG expects to incur Nuclear base OM&A costs of approximately $41M for implementation of this program during the IR period. Based on the regulatory significance of this new CNSC requirement, OPG has included this item as part of its update. These costs exceed $10M per year, for each year compliance is assumed to be required by the CNSC during the IR period (2019-2021).

As discussed in section 4.0, the above changes impact the nuclear revenue requirement and nuclear rate base approvals sought by OPG in Ex. A1-2-2, as well as the resulting portion of the annual nuclear revenue requirement OPG proposes to defer in the Rate Smoothing Deferral Account over the IR period.

3.0 ITEMS INCLUDED IN THE IMPACT STATEMENT

This section provides additional detail on each of the five changes reflected in the revised nuclear revenue requirement requested for the IR period. In addition, it presents the change in forecast pension and OPEB accrual costs for the period, to provide a forecast of the

[5] See footnote 1.

impact on the Pension & OPEB Cash Versus Accrual Differential Deferral Account. Each of the following sections covers the amount of the change and the reason(s) for the change.

3.1 Pension and OPEB

3.1.1 <u>Pension and OPEB Cash Amounts</u>

OPG is forecasting an overall increase of $251.5M in pension and OPEB cash amounts attributed to the nuclear facilities over the IR period, as detailed in Chart 3.1.1A below. This increase is primarily due to higher forecast pension contributions for 2019 to 2021, as a result of lower discount rates, partly offset by a decrease in forecast OPEB payments. The updated forecast of OPG's total pension and OPEB cash amounts was determined by its independent actuary, Aon Hewitt ("Aon"), using the same methodology as in the pre-filed evidence. Aon's report on the updated forecast of pension and OPEB cash amounts and accrual costs for 2017-2021 is provided in Attachment 2. As discussed in Ex. F4-3-2 and Ex. H1-1-1, OPG proposes to continue recording the difference between actual and forecast pension and OPEB cash amounts in the Pension & OPEB Cash Payment Variance Account.

Chart 3.1.1A

Revenue Requirement Changes – Nuclear Pension and OPEB Cash Amounts ($M)

Line No.		Reference	2017	2018	2019	2020	2021
	Pension:						
1	Original Submission	Ex. F4-3-2, Chart 1	171.1	175.5	180.3	157.2	162.1
2	N1 Update		200.0	202.9	243.5	247.9	250.6
3	Revenue Requirement Impact of Update	line 2 - line 1	28.9	27.4	63.2	90.7	88.5
	OPEB:						
4	Original Submission	Ex. F4-3-2, Chart 1	100.9	104.9	109.2	114.1	117.8
5	N1 Update		91.1	95.7	99.9	104.3	108.5
6	Revenue Requirement Impact of Update	line 5 - line 4	(9.8)	(9.2)	(9.3)	(9.8)	(9.3)
7	Total Revenue Req'ment Impact of Update	line 3 + line 6	19.1	18.3	53.8	81.0	79.3

In line with the 2017-2019 Business Plan, the updated forecast of cash amounts reflects the latest filed actuarial valuation of the OPG registered pension plan ("RPP") as of January 1, 2016, which sets out the minimum employer funding requirements for 2016 to 2018. The valuation was prepared and certified by Aon, and was filed with the Financial Services Commission of Ontario on September 30, 2016. As discussed in Ex. L-6.6-1 Staff-156, OPG made the decision to advance this valuation from January 1, 2017, in response to a decrease in long-term bond yields observed since the beginning of the year. The decrease in bond yields increased the likelihood of higher 2017 and 2018 contributions under a January 1, 2017 valuation, compared to a January 1, 2016 valuation. In addition, the January 1, 2016 valuation decreased OPG's 2016 pension contributions attributed to the nuclear facilities by approximately $80M. Further details and a copy of the January 1, 2016 funding valuation can be found at Ex. L-6.6-1 Staff-156.

The 2017-2019 Business Plan also reflects the projected results of the next funding valuation of the RPP as of the latest permitted date of January 1, 2019, which would set the minimum employer funding requirements for 2019 to 2021. Aon projected the results of this valuation by extrapolating information from, and using the same actuarial assumptions as, the January 1, 2016 filed valuation, updated for the decrease in solvency discount rates observed since the beginning of 2016.

As discussed in Ex. F4-3-2, minimum employer funding requirements pursuant to actuarial valuations of registered pension plans comprise current service cost (also known as normal cost), as well as going concern and solvency special payments towards the deficit, if required. The updated forecast reflects increased special payments over the IR period, as shown in Chart 3.1.1B below, mainly in the form of higher solvency special payments in 2019 to 2021 included in the 2017-2019 Business Plan based on the results of the January 1, 2019 projected valuation. In addition, the 2017-2019 Business Plan includes higher going concern special payments in 2017 and 2018, reflecting the results of the January 1, 2016 valuation.

Chart 3.1.1B

Components of Forecast Nuclear Pension Contributions ($M)

Line No.		Reference	2017	2018	2019	2020	2021
	Original Submission:						
1	Employer Normal Cost		157.2	161.6	166.3	157.2	162.1
2	Special Payments		13.9	13.9	14.0	-	-
3	Total Pension Contribution	Ex. F4-3-2, Chart 1	171.1	175.5	180.3	157.2	162.1
	N1 Update:						
4	Employer Normal Cost		155.8	158.6	161.7	166.1	170.9
5	Special Payments		44.3	44.3	81.8	81.8	79.8
6	Total Pension Contribution	Chart 3.1.1A, line 2	200.0	202.9	243.5	247.9	250.6
	Net Increase (Decrease):						
7	Employer Normal Cost	line 4 - line 1	(1.4)	(3.0)	(4.6)	8.9	8.8
8	Special Payments	line 5 - line 2	30.3	30.3	67.8	81.8	79.8
9	Total Pension Contribution	line 6 - line 3	28.9	27.4	63.2	90.7	88.5

The higher forecast special payments for 2019 to 2021 primarily result from a decrease in discount rates used to project solvency special payments. These rates are based on prescribed discount rates in effect at the time the projection is prepared. As noted in Ex. F4-3-2, p. 9, lines 18 to 21 and footnote 10, the discount rates for solvency valuations must be determined in accordance with specific standards of practice issued by the Canadian Institute of Actuaries, reflecting government of Canada bond yields and annuity purchase rates determined using information provided by insurance companies. The solvency discount rates reflected in the pre-filed evidence were based on end of 2015 information, as follows: 2.10% per annum for the first ten years and 3.70% per annum thereafter for commuted values and 3.20% per annum for annuity purchases. The updated forecast uses discount rates of 1.88% per annum for the first 10 years and 3.32% per annum thereafter for commuted values and 3.02% per annum for annuity purchases, determined as of mid-2016.[6] This decrease in the discount rates reflects the decline in long-term bond yields observed during the first half of 2016.

The updated forecast of OPEB payments for the IR period is lower than in the pre-filed evidence. As in the pre-filed evidence, cash amounts for OPEB represent forecast benefit payments to retirees and dependants in accordance with the provisions of the plans, and are based on estimated future cash flows used to project the corresponding benefit obligations. The lower forecast payments mainly result from lower per capita expected health care benefit costs and updated plan membership data as of January 1, 2016, both of which are included in the comprehensive accounting valuation discussed in section 3.1.2 below.

3.1.2 Pension and OPEB Accrual Costs

OPG is forecasting a net decrease of $21.2M in pension and OPEB accrual costs attributed to the nuclear facilities during the IR period, as detailed in Chart 3.1.2 below. OPG's total accrual costs for this period were determined by Aon in accordance with US GAAP, as detailed in Aon's report in Attachment 2. Other than the adoption of the Full Yield Curve

[6] The solvency discount rates used in the updated forecast reflect the assumed application of a smoothing (averaging) mechanism permitted under the *Pension Benefits Act* (Ontario). Smoothing has the effect of increasing discount rates used in the January 1, 2019 projected valuation and reducing the resulting projected solvency special payments for 2019 to 2021, relative to a solvency valuation without smoothing.

Approach to determining certain components of the pension and OPEB costs starting in 2017, discussed in section 3.1.2.1 below, the updated forecast was prepared using the same methodology as in the pre-filed evidence. The economic assumptions and pension plan asset values underpinning the updated forecast reflect market conditions as at June 30, 2016.

The updated forecast of the costs reflects an estimate of the impact of a new comprehensive accounting valuation to determine OPG's year-end 2016 plan obligations. As discussed in EB-2013-0321, comprehensive accounting valuations are conducted periodically to incorporate current demographics of plan membership, and update applicable assumptions to represent the current best estimate based on plan experience and current expectations.[7] The new comprehensive accounting valuation is triggered by the availability of more current information as a result of performing the January 1, 2016 funding valuation, and will ensure that OPG's accounting obligations continue to be fairly stated in accordance with US GAAP. The changes reflected as part of the new comprehensive accounting valuation are outlined in Aon's report in Attachment 2.

Chart 3.1.2

Updated Forecast of Nuclear Pension and OPEB Accrual Costs ($M)

Line No.		Reference	2017	2018	2019	2020	2021
	Pension:						
1	Original Submission	Ex. F4-3-2, Chart 1	222.8	167.5	153.0	140.0	131.4
2	N1 Update		214.4	174.0	166.2	163.5	163.8
3	Impact of Update	line 2 - line 1	(8.4)	6.5	13.2	23.5	32.4
	OPEB:						
4	Original Submission	Ex. F4-3-2, Chart 1	194.6	195.0	196.0	197.0	198.3
5	N1 Update		169.8	174.5	178.5	182.7	187.0
6	Impact of Update	line 5 - line 4	(24.8)	(20.5)	(17.5)	(14.3)	(11.3)
7	Total Impact of Update	line 3 + line 6	(33.2)	(13.9)	(4.3)	9.2	21.2

[7] For example, see EB-2013-0321 Ex. N1-1-1, section 2.2.1.

The overall decrease in the accrual costs compared to the pre-filed evidence reflects lower OPEB costs, partly offset by higher pension costs. The main factors contributing to the higher forecast pension costs include lower discount rates, the largely offsetting impact of adopting the Full Yield Curve Approach, actual asset performance during the first half of 2016, and updated membership data and other changes resulting from the new comprehensive accounting valuation. The decrease in projected OPEB costs is mainly driven by lower expected per capita health care benefit costs, reflecting lower costs of prescription drugs, as part of the comprehensive accounting valuation. This is partly offset by the impact of updated membership data and other changes in OPEB costs from the comprehensive accounting valuation. The effect of lower discount rates on OPEB costs is offset by the adoption of the Full Yield Curve Approach.

3.1.2.1 Discount Rates and Full Yield Curve Approach

To date, OPG has been determining the current service and interest cost components of pension and OPEB costs using the weighted-average discount rate reflected in the calculation of the plan benefit obligations, based on a AA corporate bond yield curve (the “Traditional Approach”).[8] In particular, the current service cost is calculated by discounting the underlying future cash flows at the weighted-average interest rate implicit in the entire benefit obligation, and the interest cost is calculated by multiplying the benefit obligation by that same rate. This has been the generally accepted approach to determining pension and OPEB costs in accordance with US GAAP.

The pension and OPEB cost forecast in the pre-filed evidence was determined using the Traditional Approach, based on the December 31, 2015 yield curve. The resulting weighted-average discount rates used to project the costs for the IR period were 4.10% per annum for pension, 4.20% per annum for other post-retirement benefits, and 3.40% per annum for long-term disability benefits (Ex. F4-3-2, p. 17, Chart 5). As of June 30, 2016, these discount rates, determined using the same approach, decreased to 3.60%, 3.70%

[8] The components of pension and OPEB costs are described in Ex. F4-3-2, section 5.0.

and 2.80%, respectively. Under the Traditional Approach, this would have caused an increase in the forecast pension and OPEB costs relative to the pre-filed evidence.

Recently, the Full Yield Curve Approach has emerged as an acceptable alternative to the Traditional Approach under US GAAP, with a view to more precisely measuring the current service and interest cost components.[8a] While the same yield curve is used under both approaches, the Full Yield Curve Approach determines current service cost by applying individual spot interest rates from the yield curve to each future year's underlying projected benefit payments, and interest cost by multiplying individual spot rates from the yield curve by each year's present values of future projected benefit payments.[9]

OPG believes that the Full Yield Curve Approach will result in a more precise measurement of pension and OPEB costs and is adopting it starting with the 2017 fiscal year costs and the 2017-2019 Business Plan. OPG's external auditors, Ernst & Young LLP, have indicated that the adoption of the Full Yield Curve Approach will be acceptable as a prospective change in accordance with US GAAP. With an upward sloping yield curve and the pattern of OPG's estimated future benefit cash flows, the adoption of the Full Yield Curve Approach is expected to lower OPG's current service and interest cost components, reducing the overall projected pension and OPEB costs in the initial years following adoption, including during the IR period.[10]

8a The U.S. Securities and Exchange Commission ("SEC") staff has indicated that they will not object to the use of the spot rate approach (i.e. the Full Yield Curve Approach) for setting accounting discount rate under US GAAP. The SEC staff also stated that they would not object if the change from the single weighted-average rate approach to the spot rate approach is treated as a change in accounting estimate, which would support prospective application of the change. See Remarks before the 2015 AICPA National Conference on Current SEC and PCAOB Developments dated December 9, 2015, found at the following link: https://www.sec.gov/news/speech/remarks-at-2015-aicpa-conference-wright.html

9 At page 7, Aon's report in Attachment 2 shows the single weighted average discount rates implicit in the current service cost and interest cost calculations under the Full Yield Curve Approach, which expectedly are different from the single weighted average discount rate shown for the overall obligation. Aon's report makes a further distinction under the Full Yield Curve Approach between the interest cost for the projected benefit obligation at the beginning of the period and the interest cost for the current service cost recorded during the period.

10 As the Full Yield Curve Approach does not change the calculation of the benefit obligation, the decrease in the current service and interest cost components will give rise to offsetting reductions in actuarial gains (or an increase in actuarial losses). These offsetting impacts will be recognized in OPG's pension and OPEB costs over time, through amortization of actuarial gains/losses under the corridor approach in accordance with US GAAP. As a result, the overall net effect of the Full Yield Curve Approach on pension and OPEB costs is expected to diminish in the longer term.

3.1.3 Pension and OPEB Cash to Accrual Differential

Compared to the pre-filed evidence, the forecast excess of pension and OPEB accrual costs over cash amounts for the nuclear facilities is reduced by $272.4M for the IR period, mainly due to the higher pension contributions discussed above. As detailed in Chart 3.1.3 below, total IR period forecast pension cash amounts for the nuclear facilities are now higher than accrual amounts by $262.9M, while total forecast OPEB cash amounts are $393.0M lower than the accrual costs.

Chart 3.1.3

Updated Forecast of Nuclear Pension and OPEB Accrual to Cash Differential* ($M)

Line No.		2017	2018	2019	2020	2021
1	Pension	14.4	(28.9)	(77.2)	(84.4)	(86.8)
2	OPEB	78.7	78.8	78.6	78.4	78.5
3	**Total**	**93.1**	**49.9**	**1.4**	**(6.0)**	**(8.3)**

*positive values represent excess of accrual costs over cash amounts

3.2 Nuclear Liabilities

3.2.1 Summary of Revenue Requirement Changes

OPG is now seeking to recover a total after-tax revenue requirement impact of $2,022.2M in respect of the nuclear liabilities costs for both prescribed and Bruce facilities over the IR period, which reflects the 2017 ONFA Reference Plan effective January 1, 2017. As detailed in Chart 3.2.1, line 8 below, this represents a decrease of $271.2M compared to the pre-filed evidence, consisting of an increase of $279.6M for the prescribed facilities and a decrease of $550.8M for the Bruce facilities. The increase for the prescribed facilities is primarily due to an increase in regulatory income taxes associated with the expected reduction in segregated fund contributions as a result of lower Used Fuel Disposal program[11] cost estimates, and the accounting impact of higher Decommissioning cost estimates. The decrease for the Bruce facilities is driven primarily by the accounting impact of the lower Used Fuel Disposal program cost estimates.

[11] The five nuclear waste management and decommissioning programs are described at Ex. C2-1-1, p. 3.

The lower Used Fuel Disposal program costs estimates reflect a proposed new, more cost effective container design and engineered barrier concept to house used nuclear fuel for disposal, as well as a later planned in-service date for Canada's proposed used fuel deep geologic repository. The increased cost estimates associated with Decommissioning primarily relate to a better definition of work required during the preparation for safe storage after station shutdown, including de-watering and de-fueling of reactors, and a higher volume of waste forecast to be generated during decommissioning.

In addition to the above, as detailed in Chart 3.2.1, line 17 below, OPG is reducing the amount of regulatory income taxes sought for recovery over the IR period by $124.4M, as a result of an increase in forecast cash expenditures on nuclear waste management and decommissioning attributed to the prescribed facilities and changes in associated segregated fund disbursements, in line with the 2017-2019 Business Plan.[12] As discussed in Ex. F4-2-1, sections 3.2.3 and 3.2.4, cash expenditures incurred and charged against the nuclear liabilities represent an income tax deduction for OPG, while disbursements from the segregated funds are taxable. The higher forecast expenditures attributed to the prescribed facilities are consistent with the projected cost flows underpinning the 2017 ONFA Reference Plan.

[12] There are no changes in the proposed revenue requirement on account of changes in nuclear liability expenditures and associated segregated fund disbursements attributed to the Bruce facilities because these changes result in equal and offsetting changes in the current and deferred income tax expense components of Bruce Lease net revenues, with no net effect.

Chart 3.2.1

Summary of Revenue Requirement Changes – Nuclear Liabilities ($M)

Line No.		Refererence	2017	2018	2019	2020	2021
	Nuclear Liabilities Costs						
	Original Submission:						
1	Prescribed Facilities	Ex. C2-1-1 Table 1, line 8	144.9	137.7	120.6	180.4	137.5
2	Bruce Facilities	Ex. C2-1-1 Table 1, line 17	309.4	312.4	318.5	325.6	306.5
3	Total Revenue Requirement Impact of Nuclear Liabilities Costs	line 1 + line 2	454.3	450.1	439.1	506.0	444.0
	N1 Update:						
5	Prescribed Facilities	Ex. N1-1-1 Table 2, line 8	222.8	216.8	231.3	211.0	118.8
6	Bruce Facilities	Ex. N1-1-1 Table 2, line 17	208.6	200.5	204.1	210.3	198.1
7	Total Revenue Requirement Impact of Nuclear Liabilities Costs	line 5 + line 6	431.4	417.3	435.4	421.2	316.9
8	Revenue Requirement Impact of Update	line 7 - line 3	(22.9)	(32.8)	(3.7)	(84.8)	(127.0)
	Expenditures on Nuclear Waste Management and Decommissioning and Segregated Fund Disbursements						
	Original Submission:						
9	Expenditures on Nuclear Waste Management and Decommissioning *(deduction for regulatory tax purposes)*	Ex. F4-2-1 Table 3a, line 13	166.0	177.4	200.6	230.7	228.0
10	Segregated Fund Disbursements *(addition for regulatory tax purposes)*	Ex. F4-2-1 Table 3a, line 4	85.0	108.3	140.0	208.4	191.6
11	Regulatory Taxable Income impact	line 10 - line 9	(80.9)	(69.0)	(60.6)	(22.3)	(36.5)
12	Income Tax Impact	line 11 x 25% / (1-25%)	(27.0)	(23.0)	(20.2)	(7.4)	(12.2)
	N1 Update:						
13	Expenditures on Nuclear Waste Management and Decommissioning *(deduction for regulatory tax purposes)*	Ex. N1-1-1 Table 3, line 8	217.5	227.9	232.8	283.6	317.0
14	Segregated Fund Disbursements *(addition for regulatory tax purposes)*	Ex. N1-1-1 Table 3, line 15	84.4	85.7	120.4	152.0	193.7
15	Regulatory Taxable Income impact	line 13 + line 14	(133.1)	(142.2)	(112.4)	(131.6)	(123.3)
16	Income Tax Impact	line 15 x 25% / (1-25%)	(44.4)	(47.4)	(37.5)	(43.9)	(41.1)
17	Revenue Requirement Impact of Update	line 16 - line 12	(17.4)	(24.4)	(17.3)	(36.4)	(29.0)
18	Total Revenue Requirement Impact of Updates Related to Nuclear Liabilities	line 8 + line 17	(40.3)	(57.2)	(21.0)	(121.2)	(156.0)

3.2.2 Accounting and Revenue Requirement Impacts of Changes in Nuclear Liabilities Costs

The revenue requirement impact of changes in forecast nuclear liabilities costs is shown in Ex. N1-1-1 Table 2. These changes reflect the accounting impacts of the 2017 ONFA Reference Plan in accordance with US GAAP. These include a year-end 2016 projected adjustment to reduce the carrying balance of OPG's asset retirement obligation ("ARO") and asset retirement costs ("ARC") by $1,529.7M, comprising $237.9M for the prescribed facilities and $1,291.8M for the Bruce facilities.[13] This adjustment is detailed, by station and program, in Ex. N1-1-1 Table 5.

The year-end 2016 adjustment will represent the seventh tranche of OPG's ARO balance. Each tranche is calculated using a discount rate determined at the time of the adjustment. Unlike previous ARO adjustments, the projected year-end 2016 adjustment represents an overall downward revision in the undiscounted estimated cash flows underlying the obligation. As such, the adjustment will be calculated using the weighted average discount rate of the existing tranches, rather than a credit-adjusted risk-free rate determined as of the date of the ARO revision. The weighted average accretion rate of the total ARO balance after the adjustment is projected at approximately 4.95%.

The projected revenue requirement impact of changes in nuclear liabilities costs also reflects a projected reduction in segregated fund contributions, effective in 2017, based on the 2017 ONFA Reference Plan lifecycle liabilities and a projection of year-end 2016 segregated fund balances. The expected reduction in the contributions is due to an overall decrease in Used Fuel Disposal lifecycle liability estimates. The new segregated fund contributions are subject to confirmation by the Province.

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[13] In addition, OPG expects to record an ARO increase of $4.4 million on December 31, 2016 (Ex. N1-1-1 Table 3, line 3 and Table 4, line 3) in relation to changes to cost estimates related to the implementation of 2012 CNSC requirements to include certain facilities with Waste Nuclear Substance Licenses. Although these facilities were not included in the 2012 ONFA Reference Plan (see Ex. C2-1-1 Table 2, Note 6), they are included in the 2017 ONFA Reference Plan. In accordance with GAAP, the ARO adjustment will be expensed in 2016 (i.e. not included in ARC), as it relates to a legacy facility not used to support OPG's current operations.

The changes in the 2017 to 2021 revenue requirement impacts of the nuclear liabilities costs are itemized in Ex. N1-1-1 Table 6. The methodologies applied in deriving these impacts are unchanged from those applied in the pre-filed evidence as well as previous proceedings. Updated continuity schedules showing the opening, closing and average balances of the segregated funds, ARO, unfunded nuclear liability and ARC are provided in Ex. N1-1-1 Table 3 (for the prescribed facilities) and Table 4 (for the Bruce facilities).

The changes in the revenue requirement impacts of the nuclear liabilities costs arise primarily as a result of the following:

- Higher ARC depreciation for the prescribed facilities reflecting an increase in the Pickering ARC depreciation, partly offset by a reduction in the Darlington ARC depreciation;
- Lower return on rate base for the prescribed facilities due to the net reduction in the projected ARC balance and a lower weighted average accretion rate;
- Lower ARC depreciation for the Bruce facilities due to the reduction in the projected ARC balance;
- Lower accretion expense for the Bruce facilities due to the decrease in the projected ARO balance;
- Higher L&ILW variable expenses for both prescribed and Bruce facilities, mainly due to higher per cubic metre cost rates reflecting an overall increase in L&ILW storage and disposal baseline cost estimates per the 2017 ONFA Reference Plan, and a lower accounting discount rate. The projected discount rate used to determine variable expenses in the 2017-2019 Business Plan is 2.63%, compared to 3.21% reflected in the pre-filed evidence based on December 31, 2015 information;[14]

[14] As incremental variable expenses represent increases in undiscounted cash flows underlying the ARO, they are calculated using a credit-adjusted risk-free rate as of the date of the latest ARO adjustment. This approach is followed irrespective of whether the latest ARO adjustment was calculated using a credit-adjusted risk-free rate or a weighted average discount rate of the existing tranches (i.e. depending on the direction of change in the underlying undiscounted cash flows). Therefore, the final L&ILW and used fuel variable cost rates will be calculated using the credit-adjusted risk-free discount rate determined as of December 31, 2016 (using the methodology described in Ex. L-8.2-1 Staff-207).

- Lower segregated fund earnings for the Bruce facilities due to lower forecast segregated fund contributions over the period;[15] and
- Higher income taxes for the prescribed facilities due to lower forecast segregated fund contributions and above noted increases in prescribed facilities' depreciation and L&ILW variable expenses.

3.3 Used Fuel and Waste Services Revenue under Bruce Lease

As discussed in Ex. G2-2-1, under the terms of the amended Bruce Lease, the used fuel revenue rate per fuel bundle (i.e. supplemental rent) and the L&ILW revenue rate per cubic metre of waste are based on prevailing ONFA cost estimates and are recalibrated in conjunction with each ONFA Reference Plan update. The updated used fuel and L&ILW rates effective January 1, 2017 were finalized by OPG subsequent to the OPG Board approval of the 2017-2019 Business Plan. Overall, the updated revenue rates are lower than those reflected in the pre-filed evidence, due to a reduction in the underlying cost estimates to manage these wastes based on the 2017 ONFA Reference Plan. Another key driver of the lower L&ILW revenues over the IR period is a reduction in forecast waste volumes provided by Bruce Power. The revenue requirement impact of the lower projected used fuel and L&ILW revenues during the IR period is shown in Chart 3.3 below.

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[15] Segregated fund earnings continue to be forecast at 5.15% per annum consistent with the growth rate in the 2017 ONFA Reference Plan submitted to the Province.

Chart 3.3

Revenue Requirement Changes – Used Fuel and L&ILW Bruce Lease Revenues ($M)

Line No.		Refererence	2017	2018	2019	2020	2021
	Original Submission:						
1	Supplemental Rent Revenue (Used Fuel Fees)	Ex. G2-2-1 Table 2, line 6	184.5	176.0	187.5	200.7	161.2
2	Low and Intermediate Level Waste Services Revenue	Ex. G2-2-1 Table 2, line 2	28.9	32.5	31.2	30.0	35.5
3	Bruce Facilities' Current Income Taxes	(line 1 + line 2) x 25%	(53.3)	(52.1)	(54.7)	(57.7)	(49.2)
4	Bruce Lease Net Revenues Impact	line 1 + line 2 + line 3	160.0	156.3	164.0	173.1	147.5
5	Income Tax Impact	line 4 x 25% / (1-25%)	53.3	52.1	54.7	57.7	49.2
6	Revenue Requirement Impact	line 4 + line 5	213.4	208.5	218.7	230.8	196.7
	N1 Update:						
7	Supplemental Rent Revenue (Used Fuel Fees)		160.4	153.0	163.0	174.5	140.1
8	Low and Intermediate Level Waste Services Revenue		17.8	19.8	19.2	18.6	21.6
9	Bruce Facilities' Current Income Taxes	(line 7 + line 8) x 25%	(44.6)	(43.2)	(45.5)	(48.3)	(40.4)
10	Bruce Lease Net Revenues Impact	line 7 + line 8 + line 9	133.7	129.6	136.6	144.9	121.3
11	Income Tax Impact	line 10 x 25% / (1-25%)	44.6	43.2	45.5	48.3	40.4
12	Revenue Requirement Impact	line 10 + line 11	178.3	172.8	182.2	193.1	161.8
13	Revenue Requirement Impact of Update	line 6 - line 12	35.1	35.6	36.5	37.6	34.9

For comparative purposes, in Ex. N1-1-1 Tables 7 and 7a, OPG provides an updated view of total forecast Bruce Lease net revenues for the IR period that incorporates the above changes in used fuel and L&ILW revenues, as well as the changes in forecast nuclear liabilities costs outlined in section 3.2. The updated forecast of Bruce Lease net revenues over the IR period (Ex. N1-1-1 Table 7, line 30) is an increase of approximately $278M over the pre-filed evidence (Ex. G2-2-1 Table 1, line 9), which results in a reduction in the nuclear revenue requirement.

3.4 Return on Equity

OPG's pre-filed evidence reflects ROE calculated using the OEB's Cost of Capital parameters issued on October 15, 2015. The Application also proposes to set the final ROE for 2017 using the prevailing ROE value established by the OEB, and to use that value to determine the revenue requirement for 2018-2021 (Ex. C1-1-1, p.2, lines 24-30). On October 27, 2016, the OEB issued an update to the allowable ROE for 2017, lowering the rate from 9.19% to 8.78%. OPG has updated for this change by way of this Impact Statement, which results in an after-tax reduction of $69M to the requested 2017-2021 nuclear revenue requirement. Chart 3.4 below provides the details of this impact, by year.

Chart 3.4

Revenue Requirement Changes – Return on Equity ($M)

Line No.		Refererence	2017	2018	2019	2020	2021
1	Component of Nuclear Rate Base Financed by Common Equity	Ex. I1-1-1 Table 1, line 7	1,638.7	1,721.8	1,690.4	3,672.1	3,899.9
	Original Submission:						
2	Return on Equity (%)	Ex. C1-1-1 Tables 1-5, line 5	9.19%	9.19%	9.19%	9.19%	9.19%
3	Return on Equity	Ex. I1-1-1 Table 1, line 12	150.6	158.2	155.3	337.5	358.4
4	Income Tax Impact	line 3 x 25% / (1-25%)	50.2	52.7	51.8	112.5	119.5
5	Return on Equity Incl. Income Taxes	line 3 + line 4	200.8	211.0	207.1	450.0	477.9
					.		
	N1 Update:						
6	Return on Equity (%)		8.78%	8.78%	8.78%	8.78%	8.78%
7	Return on Equity	line 1 x line 6	143.9	151.2	148.4	322.4	342.4
8	Income Tax Impact	line 7 x 25% / (1-25%)	48.0	50.4	49.5	107.5	114.1
9	Return on Equity Incl. Income Taxes	line 7 + line 8	191.8	201.6	197.9	429.9	456.6
10	Revenue Requirement Impact of Update	line 9 - line 5	(9.0)	(9.4)	(9.2)	(20.1)	(21.3)

3.5 New CNSC Requirements

The 2017-2019 Business Plan includes Nuclear base OM&A costs for new regulatory requirements from the CNSC relating to Fitness for Duty. The CNSC will be publishing its formal Regulatory Document on Fitness for Duty related to employee drug, alcohol, psychological and physical testing (expected March 2017). The CNSC Regulatory Document has undergone a public comment period. This Regulatory Document will require OPG to design and implement a Fitness for Duty program with a scope that is anticipated to address testing for cause, pre-employment, post incident and random testing for workers in certain positions at OPG's nuclear plants. The 2017-2019 Business Plan assumes full compliance with the Regulatory Document to be required by 2019. These costs have been included in this update because they are driven by a regulatory requirement that is outside of OPG's control and exceed $10M per year for each year compliance is required (2019-2021).

The costs included in this update represent expected costs to implement the required Fitness for Duty initiative, including design, set up and implementation of a testing program, as well as for the ongoing operation of a testing program. The expected costs are $0.5M in 2017, $0.5M in 2018, $16.7M in 2019, $11.7M in 2020 and $11.7M in 2021.

3.6 Summary of Regulatory Income Tax Impacts

Changes in regulatory income taxes associated with each of the items included in this update are identified in the calculation of these items' impacts on the revenue requirement. For comparative purposes, in Ex. N1-1-1 Tables 8 and 8a, OPG provides an updated calculation of total nuclear regulatory income taxes for each year of the IR period, reflecting the changes associated with all of the updated items.

As shown at Ex. N1-1-1 Table 8, line 20, OPG projects nuclear regulatory taxable income for each year of the IR period, whereas the forecasts in the pre-filed evidence gave rise to nuclear regulatory tax losses in certain years (Ex. F4-2-1, Table 3a, line 20). These losses were carried back or forward, as appropriate, reducing regulatory income taxes in other IR period years, such that the losses were fully utilized by 2021 (Ex. F4-2-1, Table 3a, line 21). As a result of the elimination of the tax loss carry forwards in this update, the regulatory income taxes in individual IR period years change relative to the pre-filed evidence. These inter-period revenue requirement impacts are shown in Chart 2.0, line 7; they do not impact the total nuclear revenue requirement over the 2017-2021 period.

4.0 SUMMARY OF CHANGES IN APPROVALS SOUGHT

The items identified in this Impact Statement result in amendments to the following approvals sought by OPG in this Application for the IR period: (i) nuclear revenue requirements, (ii) nuclear rate base, and (iii) portion of the nuclear revenue requirements deferred under rate smoothing. The updated approvals are detailed below. Prior to the oral hearing, OPG will file with the OEB an amendment to Ex. A1-2-2 Approvals to reflect these changes and to Ex. A1-3-4 Drivers of Deficiency to reflect the changes in the drivers of revenue deficiency for the nuclear facilities over the IR period. As noted above, OPG is not updating its request for smoothed nuclear payment amounts or riders, and therefore there is no change to the annualized residential consumer impact of OPG's Application.

Nuclear Revenue Requirement

1. The approval of the following revised revenue requirements for the nuclear facilities, net of the nuclear stretch factor, for each year of the IR period:

Period	Revenue Requirement
January 1, 2017 through December 31, 2017	$3,201.8M
January 1, 2018 through December 31, 2018	$3,222.5M
January 1, 2019 through December 31, 2019	$3,309.6M
January 1, 2020 through December 31, 2020	$3,824.4M
January 1, 2021 through December 31, 2021	$3,437.8M

Nuclear Rate Base

2. The approval of the following revised rate base values for the nuclear facilities for each year of the IR period:[16]

Year	Rate Base
2017	$3,868.4M
2018	$3,960.6M
2019	$3,819.3M
2020	$7,786.2M
2021	$8,208.6M

[16] The changes to rate base values from the pre-filed evidence represent changes in forecast ARC balances, as a result of the projected year-end 2016 ARO/ARC adjustment to reflect changes in the nuclear liabilities related to the 2017 ONFA Reference Plan.

Deferred Nuclear Revenue Requirement

3. The approval of the deferred amounts resulting from the revised nuclear revenue requirements identified in item 1 above of $694M, $412M, $145M, $462M and $(97)M in 2017, 2018, 2019, 2020 and 2021, respectively, and as further illustrated below:

	2017	2018	2019	2020	2021
Proposed Revenue Requirement ($M)	$ 3,202	$ 3,223	$ 3,310	$ 3,824	$ 3,438
Forecast Production (TWh)	38.10	38.47	39.03	37.36	35.38
Smoothed Rate ($/MWh)	$ 65.81	$ 73.05	$ 81.09	$ 90.01	$ 99.91
Smoothed Revenue ($M)	$ 2,507	$ 2,810	$ 3,165	$ 3,362	$ 3,535
Deferred Revenue Requirement ($M)	$ 694	$ 412	$ 145	$ 462	$ (97)

LIST OF ATTACHMENTS

Attachment 1	OPG's 2017-2019 Business Plan
Attachment 2	Aon Hewitt Report on OPG's Estimated Pension and OPEB Costs for 2017-2021
Attachment 3	Updated Revenue Requirement Work Form
Attachment 4	Letter regarding Ontario Nuclear Funds Agreement Reference Plan

ONTARIO POWER GENERATION

FOR APPROVAL by the Board of Directors

November 10, 2016

OPG's 2017-2019 BUSINESS PLAN

DECISION REQUIRED

The purpose of this submission is to seek the Board's approval of OPG's 2017-2019 Business Plan, including a financial projection for the 2020-2021 period. Upon Board approval, the business plan will be submitted to the Shareholder for review and concurrence in accordance with the Memorandum of Agreement between the Shareholder and OPG.

ISSUE

OPG's 2017-2019 Business Plan implements the Company's strategic objectives by setting out performance targets and resource levels associated with meeting key business outcomes over the next several years. The business plan includes the budget for the 2017 year, which establishes the operational and financial control base against which actual results will be measured.

The business plan supports OPG's 5-year hydroelectric and nuclear rate application to the Ontario Energy Board (OEB) filed in May 2016. The rate application covers the 2017-2021 period and, for the nuclear operations, was based on the forecast of costs and production from the 2016-2018 Business Plan. The 2016-2018 Business Plan was approved by the Board in May 2016 and included a financial projection for 2019-2021. The 2017-2019 Business Plan will be used to update the rate application for material plan-over-plan changes and therefore includes a financial projection for 2020-2021. The OEB's decision on OPG's rate application is expected during the third quarter of 2017. The 2017-2019 Business Plan assumes that new regulated rates are made effective January 1, 2017.

ANALYSIS

Overview

OPG's business plan is focused on increasing value to the Shareholder, while continuing to act as a mitigator for customer price increases and supporting provincial policy objectives focused on the decarbonisation of the power sector and the broader economy. The plan meets the objectives of Ontario's 2013 Long-Term Energy Plan (LTEP). Future business plans will reflect any changes from the updated LTEP expected to be issued in 2017.

As OPG's operating and regulatory environment has not changed substantially during 2016, the objectives and results of the 2017-2019 Business Plan are consistent with the 2016-2018 Business Plan. In particular, the business plan continues to reflect resource and outage plans in support of achieving safe and reliable operations at Pickering to 2024 and successful execution of the Darlington refurbishment, in line with the approved budget and schedule including the Unit 2 cost estimate approved by the Board in August 2016. The plan also reflects OPG's efforts to close the staffing gap in key areas through resourcing strategies including selective hiring, while continuing to leverage attrition in other areas.

Consistent with the previous plan, the 2017-2019 Business Plan projects net income growing to [redacted] This reflects regulated rate increases consistent with OPG's May 2016 rate application, on the basis of a custom incentive regulation approach with rate smoothing for the nuclear operations and an incentive ratemaking formula for the hydroelectric operations. The rate application results in average increases of ~0.7% or ~$1.05 per month annually on a typical residential customer's monthly bill, with the overall customer cost of OPG's generation continuing to track considerably below that of other generators in Ontario. Management believes that the forecast credit metrics and operating cash flow levels in the plan that result from the proposed rate increases should continue to support OPG's current investment grade credit rating. The execution of the business plan will allow OPG to [redacted] over the 2017-2019 period.

The plan reflects the [redacted] The plan also reflects the estimated impact of the 2017 Ontario Nuclear Funds Agreement (ONFA) Reference Plan update, which is subject to approval by the Minister of Finance. The updated reference plan will reduce customer rate impacts, and improve operating cash flow by reducing segregated fund contributions. In addition, the plan assumes closing of the sale of OPG's head office property in the second quarter of 2017, [redacted], as directed.

Return on equity (ROE) is projected to [redacted] OPG's planned debt ratio [redacted]

The business plan is highly dependent on the outcome of OPG's OEB rate application and OEB decisions related to the recovery of pension and other post-employment benefit (OPEB) costs on an accrual basis. Different regulatory outcomes from those assumed in the plan could significantly lower net income, cash flow, and returns to the Shareholder, leading to higher borrowing requirements and increased risk to OPG's credit rating. This may in turn necessitate curtailment of project or other expenditures. In particular, the plan assumes that new regulated rates pursuant to the rate application are made effective as of January 1, 2017. A delay in this effective date could have significant adverse impacts on 2017 net income and future cash flow, largely due to the nuclear generation shortfall relative to existing rates, as a result of Darlington Unit 2 being offline for refurbishment. The plan also assumes that the OEB provides necessary assurance over future recovery of differences between pension and OPEB accrual and cash amounts, and associated income tax impacts.

Highlights of the 2017-2019 Business Plan, including the financial projection for the 2020-2021 period, are as follows:

	Forecast	**Business Plan**			**Projection**	
	2016	**2017**	**2018**	**2019**	**2020**	**2021**
Net Income Attributable to the Shareholder *($ millions)*	[redacted]					
Return on Equity *(%)*						
Enterprise Total Generating Cost per MWh *($/MWh)*						
Production (net of Surplus Baseload Generation) *(TWh)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OM&A Expenses from Ongoing Operations *($ millions)*	[redacted]					
Capital Expenditures *($ millions)*						
Headcount from Ongoing Operations						
Average Impact of 2017-2021 Rate Application on Residential Customer's Monthly Bill	N/A	Average increase of ~$1.05/month annually for 2017-2021				

[redacted]

Key Assumptions and Risks

- Planned activities carried out over the 2017-2020 period successfully enable Pickering continued operations beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operations beyond 2020 would result in a reduction to planned generation revenues and cash flow and the advancement of employee severance and station decommissioning expenditures. Extending Pickering operations has a moderating effect on OPG's nuclear rates.
- The Darlington refurbishment is executed consistent with the approved project budget and schedule. Failure to maintain cost and schedule commitments for the project could potentially result in significant write-offs against net income as well as reputational damage. In addition, inability to carry out the refurbishment of the first unit as planned may result in the Province of Ontario (Province) not proceeding with OPG's refurbishment of the remaining units.
- New regulated rates are effective January 1, 2017. An OEB decision that delays this effective date would result in a ~$50 million to $60 million reduction in net income per month. In addition, new rates established by the OEB that are lower than those requested by OPG may not provide for recovery of all costs of OPG's regulated operations or may not allow for an appropriate rate of return.
- Pension and OPEB costs allowed in the 2017-2021 nuclear rates are limited to cash amounts, with the difference between accrual and cash amounts (for nuclear and hydroelectric) continuing to be recorded in a deferral account. The OEB provides necessary assurance over future recovery of these amounts, including associated taxes, through the ongoing generic proceeding on this issue or otherwise. An OEB decision that leads to a write-off of the deferral account balance would result in material net income reductions of over ~$600 million over the planning period.
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations could adversely impact the successful execution of these projects and other strategic imperatives.
- OPG continues to report its financial results in accordance with United States generally accepted accounting principles (US GAAP) and the OEB continues to rate regulate OPG on that basis. Adoption of International Financial Reporting Standards (IFRS), either as a result of the expiry of the Ontario Securities Commission exemption allowing OPG to prepare its consolidated financial statements using US GAAP or the Shareholder's requirement to consolidate OPG's results under IFRS, is expected to cause significant volatility in OPG's net income compared to US GAAP. Currently, IFRS does not adequately address a rate regulated environment.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2017-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2. A discussion of the 2017-2019 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

Operational Excellence

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost. The business plan reflects funding and staffing levels aimed at achieving top performance at the Darlington nuclear station, maximizing the value of the Pickering nuclear station by continuing its safe and reliable operation to 2024, and maintaining strong cost-effective performance at OPG's hydroelectric and thermal facilities. Performance targets for safety and reliability over the planning period will continue to drive operational excellence.

Total Generating Cost* ($/MWh)	Forecast 2016	Business Plan 2017	2018	2019	Projection 2020	2021
Enterprise	[redacted]					
Nuclear	63.2	75.6	74.6	74.5	77.1	77.3
Hydroelectric	[redacted]					

* Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

The business plan builds on efficiencies achieved to date, with a focus on pursuing further opportunities for cost effectiveness improvement across the generating business units and support services. In 2016, OPG adopted Total Generating Cost (TGC) per MWh as an enterprise-wide measure of operational cost effectiveness, in addition to TGC per MWh metrics for each of the Nuclear and Hydroelectric operations. Enterprise-wide targets for TGC per MWh range from approximately [redacted] over the 2017-2021 period. The [redacted] in the TGC over the planning period reflects [redacted] the Darlington refurbishment outages, as well as [redacted] large hydroelectric project [redacted] the Sir Adam Beck I GS power canal liner rehabilitation. The TGC targets are adjusted for hydroelectric generation losses due to surplus baseload generation conditions.

A prominent feature of the OEB's incentive regulation framework is to encourage productivity savings. In particular, for the hydroelectric business, OPG's application requests regulated rates that reflect annual increases of less than inflation. For the nuclear business, OPG's application includes a stretch factor that reduces recoverable OM&A expenses below planned levels. This will challenge OPG to find additional cost savings within its operations, beyond those already reflected in planned cost levels. In order to improve profitability, OPG must identify and implement such additional efficiency improvements starting as early as 2017, with cost savings growing over time.

Benchmarking studies have indicated that OPG has reduced the gap to the average nuclear staffing benchmark from 17% in 2011 to 4% in 2014. With further sustained headcount reductions since 2014, OPG is confident that its current and planned nuclear staffing levels are at the benchmark level. OPG also benchmarks the costs of the Pickering and Darlington stations against other nuclear stations. On a per unit, basis, OPG's all-in operating and capital expenditures for the stations continue to be amongst the lowest in the industry. OPG's nuclear stations will continue to target strong reliability performance, including a top-quartile forced loss rate performance of 1.0% for the Darlington station and a 5.0% forced loss rate for the Pickering station consistent with planned investment levels, for the 2017-2019 period. The operational targets and associated initiatives for the Nuclear business unit are found in Appendix 4, with OPG's Nuclear strategic planning framework included in Appendix 5.

The hydroelectric stations continue to exhibit strong cost effectiveness performance, with regulated fleet operating costs, excluding Gross Revenue Charge (GRC) payable to the Province, benchmarking in the second quartile relative to peers. Operating targets for 2017-2019 include strong fleet-wide hydroelectric availability factors averaging [redacted] per year. The operational targets and associated initiatives for the Renewable Generation & Power Marketing (RG&PM) business unit are found in Appendix 6.

The operational targets and associated initiatives for OPG's centre-led Business and Administrative Services organization, which is focused on providing cost effective information technology, supply chain and real estate services in support of business priorities, are found in Appendix 7.

Production

Total planned OPG production ranges from [redacted] per year over the 2017-2019 period, [redacted] forecast in 2016 and [redacted] in 2021. This reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016, including a partial overlap starting in 2021 between the second and third unit refurbishments.

The following other main factors affect the variability in the planned nuclear production over the period:

- Incremental planned outage days at the Pickering station to enable continued operations in line with the business case approved by the Board in November 2015;
- Single Fuel Channel Replacement outage work at the Pickering station in 2019 and at the Darlington station in 2017 and 2020;

- Initial increase in the forced loss and planned outage days expected at the Darlington station as the first refurbished unit returns to service in early 2020; and
- Pickering VBO in 2021 requiring the shutdown of all units for the duration of the outage.

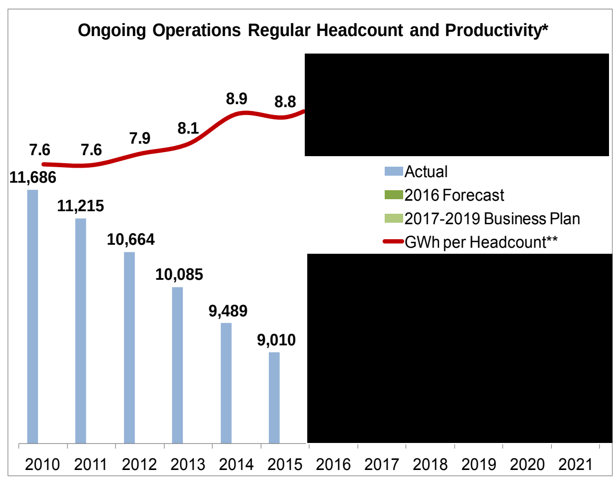
Production *(TWh)*	Forecast 2016	Business Plan 2017	2018	2019	Projection 2020	2021
Darlington	*25.8*	*19.1*	*19.3*	*19.7*	*17.8*	*16.6*
Pickering	*20.1*	*19.1*	*19.2*	*19.4*	*19.6*	*18.8*
Total Nuclear	45.9	38.1	38.5	39.0	37.4	35.4
Regulated Hydroelectric	30.5	31.2	32.2	32.0	31.2	30.8
Contracted Generation Portfolio	[redacted]					
Total Production (Net of SBG Losses)						
Regulated Hydroelectric SBG Losses	4.0	1.3	1.0	0.9	0.3	0.3
Contracted Plant SBG Losses	[redacted]					
Total SBG Losses						

The following are the main drivers of the forecast hydroelectric production for the period:

- Anticipated improvement in surplus baseload generation conditions during the planning period, largely driven by nuclear refurbishment outages;
- A major unit overhaul outage at the DeCew II GS in 2017;
- A series of outages at the Sir Adam Beck units to accommodate Hydro One's planned work in the Beck switchyard over 2017-2019;
- Outages at the Sir Adam Beck I GS to rehabilitate the forebay and crossover canal in 2020 and the power canal liner over 2020 and 2021; and
- [redacted]

Headcount

The downsizing efforts from OPG's Business Transformation initiative have been successful in achieving significant attrition-based headcount reductions across the organization since 2011, with cumulative savings from the reductions reaching $1 billion in 2016. However, continuing high levels of attrition reflecting employee demographics are necessitating increased hiring to fill key vacancies in certain areas (particularly in the Nuclear business unit). To address this gap and in light of the decision to pursue extended Pickering operations beyond 2020, OPG has modified resourcing plans and staffing models, taking into consideration the current need for qualified staff while seeking to minimize the financial impact of future downsizing programs associated with the planned Pickering end of life in 2024.



* Excludes Darlington refurbishment headcount
** Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017 - 2021, the lower production due to the Darlington refurbishment outages

Through these efforts, OPG has hired ~500 regular (full-time) employees (excluding Darlington refurbishment) between January 2016 and the end of September 2016, and is actively continuing to ramp up recruitment and on-boarding efforts to attract the necessary talent. In addition, to date OPG has hired ~60 Term Employees, a new category of non-regular employees negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015, with a view to adding fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations. OPG is targeting to bridge the remaining staffing gap in 2017 by filling open positions, which will increase year-end 2017 regular headcount from ongoing operations by [redacted] compared to 2016. While planned positions are being filled, work programs are being managed through the selective use of temporary resources and overtime.

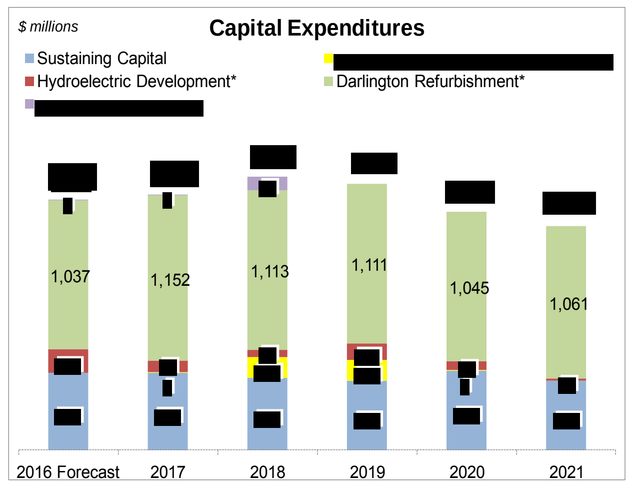
After 2017, planned staffing levels from ongoing operations begin to [redacted] By the end of 2021, headcount from ongoing operations is expected to be about [redacted] than at the end of 2016 and about [redacted] than at the end of 2017. These reductions reflect efficiency improvement initiatives and the impact on work programs from the approaching Pickering end of life. These reductions are expected to be realized by leveraging attrition. The decline in future staffing levels also reflects [redacted]. Employee productivity, as measured by GWh per headcount, remains relatively stable during the planning period.

The Darlington refurbishment headcount peaks at about 640 during the planning period, compared to about 460 at the end of 2016. This headcount is not considered part of ongoing operations.

Project Excellence

Asset base growth through development or acquisition is a key element to achieving increased profitability and ROE levels. OPG continues to focus on delivering projects safely, on time, on budget and with high quality. In line with the 2013 LTEP, OPG's capital program is focused on the continued efficient utilization of existing generation assets through sustaining expenditures, the refurbishment of the Darlington units, development of new and existing hydroelectric sites, and the pursuit of other renewable energy opportunities. The upcoming 2017 LTEP may or may not support OPG's pursuit of additional investment opportunities.

Total annual capital expenditures range between [redacted] per year over the 2017-2019 period and between [redacted] and [redacted] in 2020 and 2021. This includes Darlington refurbishment expenditures of between ~$1.0 billion and ~$1.2 billion per year in line with the Board-approved Unit 2 cost estimate, [redacted]



* Includes expenditures budgeted by Support Services

The first refurbished Darlington unit, Unit 2, is assumed to be returned to service in February 2020 per the high-confidence project schedule, with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming any necessary concurrence from the Province is obtained. The planned in-service amount associated with the return to service of Unit 2 is $4.8 billion in February 2020, including costs incurred during the planning phase of the project.

Total sustaining capital expenditures average [redacted] per year over the 2017-2021 period. This includes Nuclear expenditures in the order of ~$300 million per year to 2020, decreasing to ~$245 million by 2021 as regulatory programs are completed and non-refurbishment capital project work at Darlington is temporarily reduced while two units undergo refurbishment. Pickering expenditures decline over the period in line with the planned end of life in 2024.

Excluding the Sir Adam Beck I GS power canal liner rehabilitation project, regulated hydroelectric sustaining capital expenditures over the 2017-2021 period average ~$130 million per year. This includes a number of projects aimed at maintaining and enhancing availability and reliability of OPG's renewable fleet, including:

- The completion of the Sir Adam Beck Pump GS reservoir rehabilitation in 2017;
- The overhaul and upgrade of the DeCew II GS Unit 2 scheduled for completion in 2018;
- The overhaul and upgrade of Sir Adam Beck I GS Unit 5 in 2018-2019 and Unit 8 in 2020-2021;
- Electrical equipment, headgate and sluicegate replacements in Eastern Operations;
- Rehabilitation of the forebay and crossover canal at the Sir Adam Beck I GS in 2020;
- Flow control equipment replacements in Northwest Operations; and
- Unit overhauls at the Sir Adam Beck Pump GS.

The total expenditures for the power canal liner rehabilitation project at the Sir Adam Beck I GS are projected at ~$125 million over 2020 and 2021. The project will repair concrete deterioration and restore the original flow capacity, ensuring reliable operations for the next 50 years.

[redacted]

Other planned generation development projects include the conversion of the Sir Adam Beck Units 1 and 2 to 60 Hz to increase capacity, and the expansion/redevelopment of regulated hydroelectric stations that are approaching end of life by leveraging existing infrastructure (i.e. Ranney Falls, Coniston and Calabogie generating stations). [redacted]

Planned expenditures against previously established provision for nuclear station decommissioning and waste management are planned to increase over the planning period, from close to $300 million in 2016 to $525 million by 2021. The increase over the period reflects the following:

- The Nuclear Waste Management Organization's planned siting process activities for the Adaptive Phased Management used fuel disposal program;
- Expenditures on the Darlington refurbishment nuclear waste containers; and
- Expenditures for proceeding with OPG's proposed low and intermediate level waste deep geologic repository (L&ILW DGR), assuming receipt of a preparation and construction licence.

Eligible nuclear provision expenditures are funded from the nuclear segregated funds.

[redacted]

Financial Strength

In line with the Company's commercial mandate, OPG's business plan is focused on increasing net income and return on the Shareholder's investment, through higher revenues and a continued focus on efficiency improvements, while ensuring that the Company is able to cost effectively fund its major projects and obligations. In pursuing commercial objectives, OPG takes into account the impact on Ontario electricity customers by continuing to seek further efficiencies in the Company's cost structure.

Net Income and Return on Equity

Net income attributable to the Shareholder is forecast to [redacted] respectively. By 2021, net income attributable to the Shareholder is projected to [redacted] different regulatory outcomes from those assumed in the plan could result in significantly lower net income and returns to the Shareholder.

The planned 2017 net income attributable to the Shareholder [redacted] is primarily a result of:

[redacted]

- New regulated rates assumed to come into effect at the beginning of 2017;
- [redacted] new leaseback costs [redacted]
- Recognition of regulatory assets for the portion of the nuclear revenue requirement, including associated interest, deferred for future recovery under nuclear rate smoothing starting in 2017; and
- Higher capitalized interest for the Darlington refurbishment capital expenditures.
- These factors are partially offset by [redacted], planned outages at Sir Adam Beck I and DeCew II hydroelectric stations in 2017, and a gain recognized in 2016 from the OEB's decision to partially reverse a previous disallowance of Niagara Tunnel project expenditures.

Net income attributable to the Shareholder is planned to [redacted] primarily due to:
- Year-over-year higher capitalized interest for the Darlington refurbishment capital expenditures;
- Fewer outages at the regulated hydroelectric stations compared to 2017;
- [redacted]
- [redacted]
- [redacted]

Net income attributable to the Shareholder is projected to [redacted] as the first refurbished Darlington unit returns to service and enters rate base in February 2020. This is partially offset by the depreciation of the Pickering rate base, the impact of outages at the Sir Adam Beck I GS related to the rehabilitation work on the forebay and crossover canal as well as the power canal liner, and the [redacted]

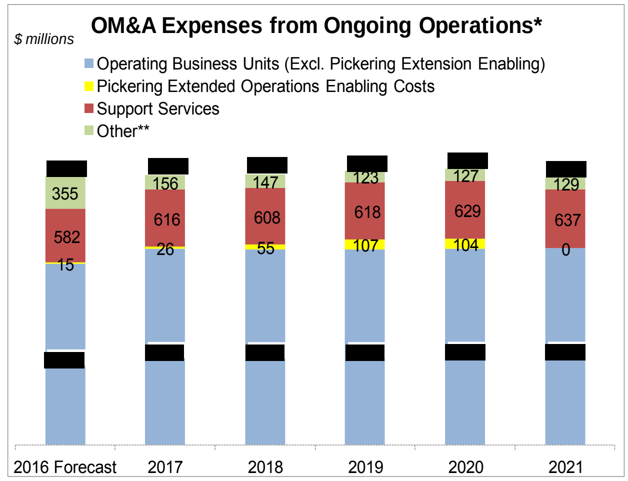
Assurance of recovery of pension and OPEB costs on an accrual basis (including associated taxes) through OEB regulated rates remains a material risk to the business plan. As the generic proceeding related to the treatment of pension and OPEB costs for regulated utilities in Ontario is ongoing, the plan continues to assume that the recovery of pension and OPEB costs for 2017-2021 is limited to cash amounts and that the difference between cash and accrual amounts continues to accumulate in an OEB authorized deferral account (for both nuclear and hydroelectric operations). This is in line with the proposal put forward in OPG's May 2016 rate application. The deferral account balance is projected to accumulate to ~$480 million by the end of 2016, with further additions of ~$150 million over the 2017-2021 period. The future outcome of the OEB generic proceeding or another related OEB decision are expected to determine the recoverability of the deferral account (and associated income taxes). An OEB decision leading to a write-off of the balance would result in a substantial reduction of up to $630 million in net income over the planning period. Write-offs would be recorded in the period the applicable OEB decision is issued.

The plan reflects an updated valuation of OPG's registered pension plan filed with the Financial Services Commission of Ontario in September 2016, as approved by the Board. The valuation was performed as of January 1, 2016 and determined OPG's required cash contributions for 2016 to 2018. Compared to the previous valuation, this reduced OPG's 2016 contributions by about $100 million, while increasing the cash-to-accrual differential recorded in the deferral account for 2016.

In its 2015-2017 Business Plan concurrence letter, the Shareholder recognized that OPG's existing accrual accounting methods for recovery of pension and OPEB costs are a fair representation of the long-term nature of these liabilities. OPG continues to believe that the accrual accounting basis aligned with OPG's financial accounting requirements is the most appropriate rate recovery basis for the Company's pension and OPEB costs, and has made submissions to this effect through the OEB's generic proceeding.

Operations, Maintenance & Administration Expenses

OM&A expenses from ongoing operations, which exclude the impact of regulatory variance and deferral account offsets as well as Darlington Refurbishment project expenses, average [redacted] per year during the 2017-2019 period, [redacted]. This reflects increases in business unit expenditures across the organization, partly offset by declining pension and OPEB costs. The increases in business unit expenditures are primarily driven by the following:
- Incremental outage and other work program costs to enable Pickering continued operations in line with the business case approved by the Board;



* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets
** Includes centrally held pension /OPEB costs

- Changes in nuclear outage scope, including maintenance work on Darlington Unit 2 to be performed during the refurbishment outage that would have otherwise occurred online or during regular outages, and Single Fuel Channel Replacement outage work at Darlington scheduled for 2017;
- Planned external hiring to fill critical staffing gaps and support effective succession planning across the Company;
- Sustaining projects to maintain asset reliability at regulated and contracted hydroelectric stations, including unit overhauls, repair work, and civil structure remediation;
- New drug testing program expected to take effect for the nuclear facilities during the planning period in accordance with CNSC Fitness for Duty regulatory requirements;
- Additional maintenance and other work programs at the nuclear stations to maintain asset reliability and address equipment aging issues;
- Labour cost escalation pursuant to collective agreements, and inflationary impacts; and
- Higher nuclear liability insurance requirements pursuant to federal legislation.
- These increases are partially offset by a gradual decline in regular staffing levels after the planned increase in 2017, as well as higher expenses in 2016 associated with inventory obsolescence costs.

OM&A expenses from ongoing operations begin to decrease in 2021, reflecting the following:
- Completion of work programs to enable Pickering continued operations;
- Further reductions in staffing levels, reflecting efficiency improvement initiatives and the impact on work programs from the approaching Pickering end of life;
- Decline in nuclear outage expenses in 2021 as no major outages are planned to occur at the Darlington station in that year, partly offset by the incremental costs of the assumed station-wide Pickering VBO in 2021.

Declining pension and OPEB costs over the period are due to a combination of factors, including: projected pension asset returns, the impact of increased employee contributions, and a recently emergent, more refined US GAAP method for applying discount rates to determine the interest components of pension and OPEB costs that OPG expects to adopt for financial reporting purposes starting in 2017. This approach determines interest costs by applying individual spot rates in the yield curve to each year of cash flows, rather than a single weighted average discount rate determined based on the yield curve. This has the effect of lowering OPG's pension and OPEB costs over the planning period, compared to 2016. The factors decreasing pension and OPEB costs relative to 2016 are partly offset by the reduction in discount rates, from 4.1% for pension and 4.2% for other post retirement benefits at the beginning of 2016 to 3.6% and 3.7%, respectively. The regulated portion of the decreases in pension and OPEB costs is assumed to be offset by the pension and OPEB cash-to-accrual deferral account, resulting in a relatively small overall impact on net income.

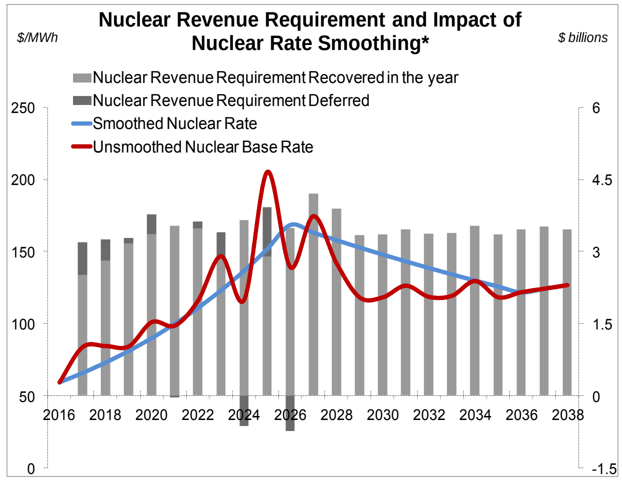
The regulatory variance and deferral account offsets to OM&A expenses decline over the planning period. This reflects a narrowing of the differential between pension and OPEB accrual costs and cash amounts that is being recorded in the cash-to-accrual deferral account. The Darlington Refurbishment project expenses vary over the planning period with the expected timing of pressure tube and feeder removal activities and other work programs not eligible for capitalization.

Regulated Rates

The plan reflects OPG's filed 2017-2021 nuclear and hydroelectric rate application, which results in an estimated average increase in a typical residential customer's monthly bill of ~0.7% or ~$1.05 each year to the end of 2021. Based on the application, the plan assumes annual hydroelectric base rate increases of ~1.5% beginning in 2017, off the existing base rates with some adjustments.

For the nuclear operations, consistent with *Ontario Regulation 53/05*, the rate application includes OPG's 11% per year rate smoothing proposal that avoids large price spikes arising during the Darlington refurbishment and at the end of Pickering operations. Under rate smoothing, the rate application seeks approval of annual nuclear revenue requirements as well as a smoothed rate trajectory for the 5-year period. The difference between the approved revenue requirements and the approved base rate trajectory will be recorded in a deferral account for recovery in the post-refurbishment period. The assumed nuclear rate trajectory from the rate application is below the 2013 LTEP assumptions for OPG's nuclear rates.

In accordance with the regulation, the portion of the approved nuclear revenue requirement deferred for future collection will be determined by the OEB and captured in a deferral account that will earn interest at a long-term debt rate reflecting OPG's long-term borrowing cost as authorized by the OEB, compounded annually. Pursuant to the regulation, the OEB must authorize the recovery of the account balance over a period of up to 10 years beginning at the end of the refurbishment project. The rate smoothing illustration shown assumes recovery of the deferred balance over the 10-year period following the completion of the Darlington refurbishment. Based on the assumed rate trajectory, the deferral account balance, including associated interest, is projected to grow to ~$1.3 billion by 2019 and ~$1.9 billion by 2021. In accordance with US GAAP, rate smoothing deferrals in a given period will be recorded by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Accordingly, the collection of the deferred amounts in future years will not result in additional net income.



* Information beyond 2021 is included for illustrative purposes

Although for planning purposes OPG assumes smoothed nuclear base rate increases of 11% per year for the full Darlington refurbishment period, the determination of the rate trajectory beyond 2021 is not part of OPG's current rate application and will be established by the OEB in the future. Leading up to that period, OPG will continue to focus on improving its cost structure and generation performance.

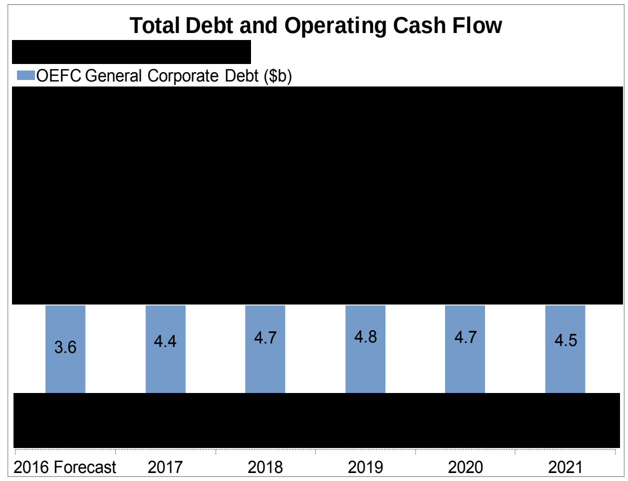
Ontario Nuclear Funds Agreement Reference Plan Update

The plan reflects estimated impacts from the 2017 ONFA Reference Plan, assumed to be approved by the Minister of Finance by the end of 2016. The impacts over the planning period include the elimination of ~$180 million per year in OPG's contributions to the ONFA segregated funds, due to lower funding obligations for nuclear decommissioning and waste management. The impacts also include a decrease of ~$1.5 billion in OPG's present value accounting liability for these obligations, at the end of 2016. The main driver of the reduced obligations is lower costs associated with the long-term management of used nuclear fuel as estimated by the Nuclear Waste Management Organization. The lower costs are primarily due to a combination of a more cost effective used fuel disposal container and a delay in the assumed construction of the used fuel deep geologic repository as part of the Adaptive Phase Management plan. OPG's decommissioning and waste management obligations include those for the stations leased to Bruce Power.

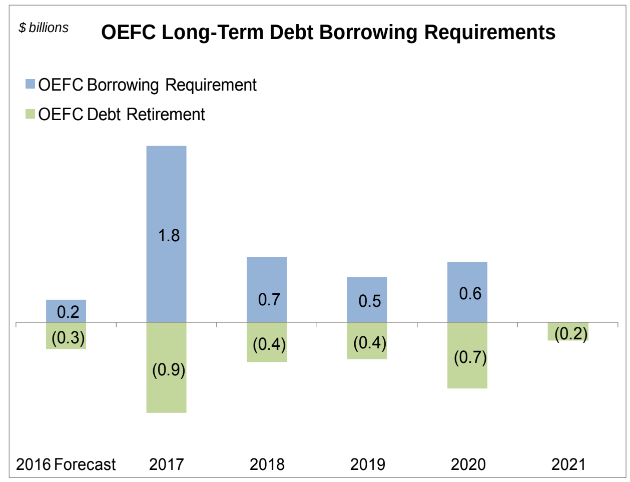
The reduction in segregated fund contributions reflects the expectation that both the Decommissioning Segregated Fund and the Used Fuel Segregated Fund will be fully funded when the new ONFA Reference Plan with lower obligations is approved by the Province. This change improves OPG's operating cash flow but will not impact earnings, as the contributions are not treated as operating expenses. The reduction in the accounting liability lowers future depreciation, accretion and other related expenses; however, the majority of this impact does not affect net income as it will reduce amounts recovered through regulated rates. Upon approval of the new ONFA Reference Plan, OPG expects to file an update to its May 2016 rate application to reflect the lower costs to the benefit of customers.

Financing and Liquidity

With the exception of 2017, OPG's operating cash flow outlook is forecast [redacted]. In 2017, operating cash flow is expected to [redacted] as nuclear production decreases by ~8 TWh, a nuclear rate rider of $10.84/MWh for collection of deferral and variance account balances expires at the end of 2016, and the collection of new regulated rates based on the anticipated timing of the OEB's decision on OPG's rate application does not begin until approximately the fourth quarter of 2017. Assuming that the OEB's decision is issued in the third quarter of 2017 and makes new rates effective January 1, 2017, the full revenue shortfall for the period between January 1, 2017 and the implementation date of the decision would be accrued in net income at the time of the decision, but would be collected over time. [redacted] operating cash flow starting in 2018 reflects 11% per year increases in nuclear base rates, partly offset by the impact of decreasing nuclear production in 2020 and 2021.



Total debt is forecast to [redacted], as nuclear rate smoothing defers collection of revenue and [redacted] The assumed effective interest rate for new debt is 4.5%, resulting in a weighted average interest rate on OPG's long-term debt of approximately 4.75% over the planning period. The debt ratio ranges from [redacted] level reflected in the OEB deemed capital structure used to set regulated rates.



The cash flow forecast for 2017 includes proceeds from the Shareholder-directed sale of OPG's head office property, an asset of OPG's unregulated business, [redacted]

[redacted] the plan assumes that Darlington refurbishment expenditures and other corporate borrowing needs continue to be financed through general-purpose long-term corporate debt sourced through the Ontario Electricity Financial Corporation (OEFC).

At the end of September 2016, OPG's average term to maturity of OEFC debt is less than 6 years. OPG intends to extend this average term to reflect the longer life cycle of its assets; however the OEFC restricts the amount of debt OPG can issue with a term longer than 10 years to 50% of the amount issued at any time. This restriction increases interest rate risk and refinancing risk, as debt will need to be refinanced in the future, at which time the interest rates may be significantly higher than the current historically low rates. OPG believes that, with interest rates at these low levels, it is prudent to take advantage of beneficial market conditions to issue longer term debt to fix future interest costs.

[redacted]

Credit Metrics

Maintaining an investment grade credit rating is critical to the Company's ability to access cost effective financing. To support this objective, OPG monitors the Funds from Operations (FFO)/Total Debt ratio and the Debt/EBITDA ratio, which are the core measures used in Standard & Poor's credit rating methodology. OPG also monitors the

FFO Adjusted Interest Coverage ratio, which is the Company's main liquidity metric.

[redacted]

[redacted]

Management believes that the forecast credit metrics and operating cash flow, combined with the support for future collection of rate smoothing deferrals under the regulation, should continue to support OPG's current investment grade credit rating. Different regulatory outcomes from those assumed in the plan could result in significantly lower cash flows, increased borrowing and weaker credit metrics, increasing the risk of a credit rating downgrade. In turn, this could increase costs, limit borrowing capacity, and/or necessitate curtailment of project or other expenditures.

Delivering Shareholder Value

[redacted]

OPG's Total Shareholder Return consists of net income, income taxes, hydroelectric GRC payments, and payments in lieu (PILs) of property taxes to the OEFC. OPG plans to [redacted]

The 2017 Total Shareholder Return on OPG's fiscal basis is projected at [redacted] Total Shareholder Return is projected to [redacted]

Social Licence

OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous Relations.

Environment and Climate Change

OPG's virtually carbon free generation has underpinned the decarbonisation of the power sector and can act as a catalyst for reducing carbon emissions from the broader economy. With a generating fleet that is 99% emission free, OPG avoids over 30 million tonnes of greenhouse gas emissions annually in comparison to a fleet of gas generators. OPG's business plan supports Ontario's climate change strategy and technology deployment and electrification objectives, including microgrids, energy storage technology and electric vehicles. In addition to continuing to drive a focus on environmental performance through business plan targets, the decisions to proceed with the Darlington refurbishment and to pursue continued operations at Pickering will contribute to achieving Ontario's climate change objectives by leveraging OPG's lower-priced, carbon-free baseload nuclear power. It is expected that the refurbished Darlington station will reduce greenhouse gas emissions by an estimated 297 million tonnes over its life, which is the equivalent of removing two million cars per year from Ontario's roads.

Climate change adaption and related safety considerations are a key aspect of OPG's plans for the hydroelectric facilities. These plans consider the impact of water availability, its utilization and the associated environmental and stewardship responsibilities. OPG is also taking steps to better understand the potential changes in water flow conditions that these facilities may experience, including consideration of extreme weather events. This includes development of flood forecasting models in an effort to better predict potential impacts of these changes and to put in place appropriate risk mitigation plans. OPG will continue to operate its hydroelectric facilities by balancing the economic, environmental, social, and legal requirements associated with the affected watersheds while optimizing electricity production.

OPG is in the process of obtaining approvals, establishing processes, and implementing systems for compliance with the requirements of Ontario's new climate change legislation including a cap-and-trade program effective January 1, 2017. Overall, compliance with these requirements is not expected to have a significant financial cost impact on the plan given OPG's virtually emission free generating fleet.

Public Safety

OPG is committed to high standards of workplace and public safety and will continue to operate all of its facilities in a safe, secure and reliable manner, while making investments to maintain and enhance the safety of its generating assets. In particular, OPG will continue to operate with nuclear safety as an overriding priority, by maintaining a strong focus on nuclear safety programs and continuing to invest in nuclear safety systems. In the past five years, as a result of lessons learned from the Fukushima accident, OPG has strengthened the nuclear safety program at its stations by installing multiple portable emergency mitigating equipment units, enhancing emergency preparedness and response capability, and improving protocols and procedures in response to potential adverse events. Probabilistic safety assessment results have confirmed that these initiatives have further strengthened the safety of OPG's nuclear plants. OPG also will continue to demonstrate strong industry leadership with its hydroelectric Dam Safety Program, which encompasses public safety and emergency management over the Company's 238 dams and 65 hydroelectric facilities. Many aspects of the program are considered to be international best practice.

Indigenous Relations

Throughout the planning period, OPG will remain committed to engaging proactively and building long-term, mutually beneficial working relationships with Indigenous communities, people, businesses and organizations through a number of diverse initiatives. This includes pursuing generation-related development partnerships, such as the Peter Sutherland Sr. GS and the Nanticoke solar facility, collaborating on capacity building initiatives and projects, such as the recently completed shoreline restoration projects, and conducting community outreach efforts.

Moderating Electricity Prices and Contributing to the Economy

[redacted]

Taking into account the assumed rate increases over the 2017-2021 period from OPG's current rate application, the cost to customers of electricity generated by OPG is expected to [redacted] below the average non-OPG cost of electricity in Ontario to 2019 and [redacted] by 2021. The expected average increase from OPG's nuclear and hydroelectric rate application on a typical residential customer's monthly bill over the period to 2021 is estimated to be ~0.7% each year.

OPG will continue to make a significant contribution to the Ontario economy and job creation, including through the refurbishment and continued operation of the Darlington station. According to The Conference Board of Canada, Ontario's Gross Domestic Product is estimated to increase by a total of ~$90 billion in the period spanning to the end of the post-refurbishment life of the station.

RECOMMENDATION / RESOLUTION

It is recommended that the Board of Directors approve OPG's 2017-2019 Business Plan including the financial projection for the 2020-2021 period.

Recommended by:

[original signed by]
Ken Hartwick
Senior Vice President,
Finance, Strategy, Risk and
Chief Financial Officer

Approved for submission to the Board of Directors by:

[original signed by]
Jeff Lyash
President and CEO

This Board memo was reviewed and approved for submission to the Board of Directors by the Audit and Risk Committee at their meeting on November 8, 2016.

APPENDICES

1. Key Planning Assumptions
2. Key Risks
3. Financial and Headcount Plan Information
4. Nuclear Financial Plan, Operational Targets, and Initiatives
5. Nuclear Strategic Framework
6. Renewable Generation & Power Marketing Financial Plan, Operational Targets, and Initiatives
7. Business and Administrative Services (BAS) Financial Plan, Operational Targets, and Initiatives

APPENDIX 1: KEY PLANNING ASSUMPTIONS

- Darlington Unit 2 is refurbished from October 2016 to February 2020, with Unit 3 refurbishment starting immediately after Unit 2 is returned to service and Unit 1 refurbishment starting in July 2021.
- All six operating Pickering units operate until 2022, with four of these units operating until 2024. The plan includes additional costs and outage days to achieve Pickering operations beyond 2020, in line with the business case approved by the Board.
- A station-wide Vacuum Building Outage takes place at Pickering in 2021
- The plan reflects currently approved accounting station service lives for Pickering to December 2020, Darlington to 2052, Bruce Units 1-4 to 2052 and Bruce Units 5-8 to 2061. The Pickering service life will be reassessed upon technical work confirming ability to achieve operations beyond 2020.
- The first Bruce unit refurbishment starts in 2020, as per the Bruce Power refurbishment agreement
- The site preparation and construction licence is received for the proposed L&ILW DGR
- Incremental expenses are allocated in the plan for potential initial planning and preparation activities related to the study of new nuclear facilities starting in 2018
- The following major projects are carried out at the Sir Adam Beck plants:
    - Sir Adam Beck Pump GS reservoir rehabilitation is completed in the first half of 2017
    - Sir Adam Beck I GS Units 1 & 2 are converted to 60 Hz over the 2018-2020 period
    - Sir Adam Beck I GS power canal liner rehabilitation takes place over 2020 and 2021
- [redacted]
- [redacted]
- [redacted]
- Nuclear base rates increase by 11% per year under nuclear rate smoothing, effective January 1, 2017. Effective January 1, 2017, hydroelectric base rates increase by ~1.5% per year, off the existing base rates with some adjustments, under an incentive regulation approach.
- Recoveries for pension and OPEB are limited to cash requirements in the 2017-2021 rate application, pending the outcome of OEB's generic consultation and any other applicable OEB determinations, with the difference between cash and accrual amounts continuing to accumulate in the existing deferral account (for nuclear and hydroelectric operations)
- Carbon pricing in Ontario is based on the Province's cap-and-trade program effective January 1, 2017
- The sale of OPG's head office property, an asset of the unregulated business, is closed in the second quarter of 2017 [redacted] as directed by the Shareholder. [redacted]
- Nuclear Fund investments earn 5.15%/yr
- Pension fund investments earn 6%/yr. An accounting discount rate of 3.6% is used for valuing pension costs and 3.7% for other post retirement benefit costs.
- The plan reflects the January 1, 2016 actuarial funding valuation of OPG's registered pension plan as filed with the regulator and a subsequent valuation as of January 1, 2019
- Due to inherent uncertainties, inflationary impacts on salary costs are assumed for periods after the expiry of the current collective agreements
- The 2017 ONFA Reference Plan is assumed to be approved by the Province by the end of 2016
- Existing OEFC debt platform continues to be used for long-term corporate debt purposes, [redacted] The assumed effective interest rate for new debt is 4.5%.
- OPG continues to prepare its consolidated financial statements and report its financial results in accordance with US GAAP for the full planning period

APPENDIX 2: KEY RISKS

The key risks associated with the 2017-2019 Business Plan are outlined below.

Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule;
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance;
- Risk of the Province not concurring with the refurbishment of the subsequent Darlington units;
- Inability to retain and attract effective, knowledgeable and engaged leadership talent during the Darlington refurbishment and continued Pickering operations given an aging workforce and Management group compensation constraints;
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges;
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance;
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures; and
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions.

Rate Regulation Risks

OEB rulings impacting OPG's rate regulated operations may be unfavourable compared to assumptions in the plan, including the following:

- Inability to receive sufficient assurance from the OEB for future recovery of the pension and OPEB cash-to-accrual deferral account balance projected at ~$480 million by the end of 2016 with further additions totalling ~$150 million over the 2017-2021 period, and associated taxes, which would result in a write-off against net income;
- An OEB-set nuclear rate smoothing trajectory that does not provide sufficient cash flow to fund operations, projects and/or obligations, and/or to maintain the current investment grade credit rating. A credit rating downgrade would increase borrowing costs and could reduce borrowing capacity;
- OEB-approved revenue requirements that do not allow for recovery of the full costs of the regulated operations and/or do not allow the regulated business to earn an appropriate return; and
- An effective date for new regulated rates that is later than the assumed January 1, 2017 date, which would reduce 2017 planned net income by ~$50 to $60 million per month.

Financial Risks

- Risk of delay in the Province's approval of the 2017 ONFA Reference Plan to 2017, which could result in a reduction in 2017 planned nuclear segregated fund earnings, through a reduction limiting fund asset balance sheet values to the updated, lower ONFA funding obligations. The impact of this reduction is currently reflected in the 2016 forecast net income on the assumption that the new reference plan is approved by the end of 2016.
- Risk of lower than planned returns on segregated nuclear and pension fund assets as a result of various market factors, including equity prices, interest rates, inflation, and commodity prices, which would lower net income and potentially increase future funding requirements compared to the plan;
- Risk of lower discount rates and other differences in assumptions for future pension and OPEB accounting and funding valuations, compared to the plan, including those due to underlying financial market conditions; and
- Risk of adoption of IFRS for financial reporting purposes, either as a result of the expiry of the Ontario Securities Commission exemption allowing OPG to prepare its consolidated financial statements under US GAAP or the Shareholder's requirement to consolidate OPG's results using IFRS. Adoption of IFRS is expected to cause significant net income volatility compared to US GAAP.

APPENDIX 3: Financial and Headcount Plan Information

Key Financial Metrics *(in millions of dollars unless otherwise noted)*	**Forecast 2016**	**Business Plan 2017**	**Business Plan 2018**	**Business Plan 2019**	**Projection 2020**	**Projection 2021**
Net Income Attributable to the Shareholder	[redacted]					
Net Income	[redacted]					
Earnings Before Tax	[redacted]					
Return on Equity* *(%)*	[redacted]					
Nuclear Total Generating Cost per MWh** *($/MWh)*	63.2	75.6	74.6	74.5	77.1	77.3
Hydroelectric Total Generating Cost per MWh** *($/MWh)*	[redacted]					
Enterprise Total Generating Cost per MWh** *($/MWh)*	[redacted]					
FFO / Total Debt Ratio *(%)* *(Minimum threshold of 9%)*	[redacted]					
Debt / EBITDA Ratio (times) *(Maximum threshold of 5.5)*	[redacted]					
FFO Adjusted Interest Coverage Ratio* (times) *(Minimum threshold of 3)*	[redacted]					
Debt Ratio *(%)*	[redacted]					
Net Cash from Operations	[redacted]					
Cash Balance at Year-End	[redacted]					
Total Debt at Year-End	[redacted]					
Total Return to Shareholder***	[redacted]					
OM&A Expenses from Ongoing Operations	[redacted]					
Darlington Refurbishment Capital Expenditures	1,037	1,152	1,113	1,111	1,045	1,061
Darlington Refurbishment In-Service Additions	387	398	2	-	4,849	-
Capital Expenditures excluding Darlington Refurbishment	[redacted]					
In-Service Additions excluding Darlington Refurbishment	[redacted]					
Nuclear Waste and Thermal Decom. Provision Expenditures	[redacted]					

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Nuclear TGC/MWh adjusted for lower production due to the Darlington refurbishment outages is: $63.8/MWh in 2017, $63.2/MWh in 2018, $65.8/MWh in 2019, $62.8/MWh in 2020 and $60.4/MWh in 2021.

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

Total Shareholder Return *$ millions*	**Provincial Fiscal Year Basis ending March 31 — 2017**	**2018**	**2019**	**2020**
Net Income Attributable to Shareholder	[redacted]			
Non Income Tax PILs				
GRC: Payable to OEFC & Niagara Parks Commission	[redacted]			
Property Tax Payable to OEFC	[redacted]			
Total Non Income Tax PILs	[redacted]			
Income Tax PILs	[redacted]			
Total Shareholder Return	[redacted]			

Operating Statement - Years Ended December 31	**Forecast**	**Business Plan**		
(in millions of dollars)	**2016**	**2017**	**2018**	**2019**
Electricity Generation Revenues	[redacted]			
Fuel and Gross Revenue Charge				
Generation Sales Gross Margin				
Net Trading Margin				
Non-Electricity Generation Gross Margin				
Total Gross Margin				
OM&A Expenses [redacted]				
Accretion on Nuclear Waste and Other Liabilities				
Earnings on Nuclear Funds				
Depreciation and Amortization				
Property Taxes				
Restructuring				
Total Expenses				
Income before Interest and Other Income				
Net Interest Expense				
Other (Income)/Expense*				
Income before Tax				
Income Tax				
Net Income				
Net Income Attributable to the Shareholder				
Net Income Attributable to Non-Controlling Interests				

* Includes [redacted] representing OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre and the Brighton Beach GS, respectively. In 2017, also includes [redacted]

Balance Sheet - As at December 31	Forecast	Business Plan		
(in millions of dollars)	2016	2017	2018	2019
Assets	[redacted]			
Current assets				
Cash and cash equivalents				
Available-for-sale securities				
Short-term investments				
Accounts receivable*				
Fuel inventory				
Materials and supplies				
Other current assets				
Property, plant and equipment and intangible assets				
Fixed and intangible assets (net)**				
Other assets				
Nuclear fixed asset removal and nuclear waste management fund				
Long-term materials and supplies				
Regulatory assets (net)				
Investments subject to significant influence				
Other long-term assets				
Total Assets				
Liabilities				
Current liabilities				
Short-term notes payable				
Accounts payable and accrued charges				
Deferred revenue due within one year				
Current income taxes payable				
Long-term debt due within one year				
Long-term debt				
Other liabilities				
Fixed asset removal and nuclear waste management liabilities**				
Pension liabilities (non-current)				
Other post-employment benefit liabilities (non-current)				
Long-term accounts payable and accrued charges				
Deferred revenue				
Deferred income taxes				
Equity				
Common shares				
Retained earnings				
Accumulated other comprehensive loss				
Equity attributable to non-controlling interests				
Total Liabilities and Equity				

* As at December 31, 2017, includes accrued revenues for new regulated rates for the period from January 1, 2017 to the implementation date of the OEB's decision, which is assumed to be received in the third quarter of 2017. The accrued balance is assumed to be fully collected by the end of 2018.

** As at December 31, 2016, reflects an adjustment that reduces the nuclear decommissioning and waste management liabilities based on cost estimates from the 2017 ONFA Reference Plan update process.

OM&A Expenses by Business Unit *(in millions of dollars)*	**Forecast 2016**	**Business Plan 2017**	**2018**	**2019**	**Projection 2020**	**2021**
Nuclear Operations*	1,601	1,725	1,735	1,786	1,777	1,689
Renewable Generation & Power Marketing	[redacted]					
[redacted]						
Total Operations	[redacted]					
Business and Administrative Services (Chief Information Officer, Real Estate, Supply Chain)	298	299	295	300	305	309
Finance (excl. Insurance) (Finance, Risk & Assurance, Corp. Bus. Development)	82	84	81	80	80	81
Insurance	31	42	45	48	52	53
People/Culture & Communications	135	149	148	150	152	151
Legal/Ethics & Compliance (Law, Regulatory Affairs, Environment)	32	36	32	32	33	35
Corporate Office	5	7	7	8	8	8
Total Support Services	**582**	**616**	**608**	**618**	**629**	**637**
Total Business Unit Expenditures	[redacted]					
Centrally Held Pension and OPEB	277	89	60	42	37	37
Other (incl. Cost of Goods Sold)	77	67	88	81	90	92
Total Ongoing Operations	[redacted]					
OEB Variance and Deferral Account Offsets	(129)	(103)	(62)	(12)	(7)	(6)
Darlington Refurbishment Project	3	49	16	7	52	26
Nuclear New Build	1	2	7	10	11	11
Total OM&A Expenses	[redacted]					

* Total Pickering extended operations enabling costs are: $15M in 2016, $26M in 2017, $55M in 2018, $107M in 2019 and $104M in 2020.

Regular Headcount by Business Unit	Forecast	Business Plan			Projection	
	2016	2017	2018	2019	2020	2021
Nuclear Operations	5,552	5,760	5,755	5,678	5,571	5,496
Renewable Generation & Power Marketing	[redacted]					
[redacted]	[redacted]					
Total Operations	[redacted]					
Business and Administrative Services (Chief Information Officer, Real Estate, Supply Chain)	829	864	863	862	849	849
Finance (Finance, Risk & Assurance, Corp. Bus. Development)	350	351	343	337	332	332
People/Culture & Communications	647	681	674	678	673	665
Legal/Ethics & Compliance (Law, Regulatory Affairs, Environment)	96	99	98	98	98	98
Corporate Office	9	12	12	12	12	12
Total Support Services	**1,931**	**2,007**	**1,990**	**1,987**	**1,964**	**1,956**
Total Ongoing Operations	[redacted]					
Darlington Refurbishment Project	458	631	642	626	610	642
Total Regular Headcount	[redacted]					

Capital Expenditures *(in millions of dollars)*	**Forecast 2016**	**Business Plan 2017**	**2018**	**2019**	**Projection 2020**	**2021**
Sustaining						
Nuclear	291	322	319	299	289	244
Regulated Hydroelectric						
Sir Adam Beck 1 Canal Liner Rehabilitation	-	-	1	1	62	62
Sir Adam Beck Pump GS Reservoir Rehabilitation	40	7	-	-	-	-
Other Projects	109	125	111	120	153	133
Total Regulated Hydroelectric	149	132	112	122	215	195
Contracted Generation Portfolio						
[redacted]	[redacted]					
Other Projects						
Total Contracted Generation Portfolio						
Support Services	59	49	38	38	35	35
Total Sustaining Capital	[redacted]					
Generation Development Projects*						
Hydroelectric Development						
[redacted]	[redacted]					
Sir Adam Beck Units 1 & 2 Conversion	-	2	17	43	27	-
[redacted]	[redacted]					
Ranney Falls GS Expansion	2	35	18	8	-	-
Coniston GS Redevelopment	-	-	6	28	14	7
Calabogie GS Redevelopment	-	3	4	34	20	11
Other	[redacted]					
Total Hydroelectric Development						
Darlington Refurbishment Project***	1,037	1,152	1,113	1,111	1,045	1,061
[redacted]	[redacted]					
Total Generation Development Capital						
Total Capital Expenditures	[redacted]					

* While in definition phase, projects are budgeted by Corporate Business Development and, while in execution phase, projects are budgeted by RG&PM

[redacted]

*** Includes expenditures budgeted by the Nuclear organization and Support Services

Provision Expenditures *(in millions of dollars)*	**Forecast 2016**	**Business Plan 2017**	**2018**	**2019**	**Projection 2020**	**2021**
Nuclear Decommissioning and Nuclear Waste Management Expenditures						
Nuclear Operations*	272	358	377	418	471	511
Support Services	15	16	16	13	14	14
Total Nuclear Provision Expenditures	**287**	**375**	**392**	**431**	**485**	**525**
[redacted]	[redacted]					
Total Provision Expenditures	[redacted]					

* Includes expenditures for the Darlington Refurbishment Project nuclear waste containers

Financing and Liquidity Outlook - Years Ended Dec 31 *(in millions of dollars)*		**Forecast 2016**	**Business Plan 2017**	**2018**	**2019**	**Projection 2020**	**2021**
Opening Cash Balance		**464**	**275**	**259**	**264**	**246**	**224**
Net Operating Cash Inflows before the following:		[redacted]					
Interest Paid							
Nuclear Funds Contribution		(150)	-	-	-	-	-
Pension Fund Contribution		(253)	(248)	(251)	(299)	(305)	(308)
OPEB Payments		(120)	(113)	(118)	(123)	(128)	(133)
Internally Funded Nuclear Provision Expenditures		(196)	(220)	(236)	(217)	(213)	(195)
Net Cash from Operations		[redacted]					
Investing Activities							
Sustaining Capital Expenditures		[redacted]					
Darlington Refurbishment		(1,037)	(1,152)	(1,113)	(1,111)	(1,045)	(1,061)
[redacted]		[redacted]					
Other Generation Development							
Cash Outflow for Capital Investments							
[redacted]							
Pre-tax Proceeds from Sale of OPG Head Office							
[redacted]							
Investment in Hydro One Shares		(213)	-	-	-	-	-
Other		(4)	-	-	-	-	-
Net Cash Outflow for Investing Activities		[redacted]					
Financing Activities							
General Corporate (OEFC)	- *Debt Issuance/Refinancing*	220	1,750	650	450	600	-
	- *Debt Retirement*	(270)	(900)	(395)	(365)	(660)	(185)
Project Financing (Private Placement)	- *Debt Issuance/Refinancing*	[redacted]					
	- *Debt Retirement*						
Short-Term Notes	- *Net Issuance (Repayment)*						
Dividends Paid							
Distribution Paid to Non-Controlling Interests							
Net Cash from Financing Activities							
Net Cash (Outflow) Inflow for Period							
Ending Cash Balance							
Total Debt at Year-End							

APPENDIX 4: NUCLEAR FINANCIAL PLAN, OPERATIONAL TARGETS, AND INITIATIVES

Financial Plan

	Forecast	Business Plan			Projection	
(in millions of dollars)	2016	2017	2018	2019	2020	2021
OM&A						
Base*	1,172	1,196	1,215	1,254	1,263	1,281
Outage Incremental	319	392	373	343	328	322
Project Portfolio	94	111	91	82	82	87
Pickering Continued Operations Enabling Costs	15	26	55	107	104	-
Darlington Refurbishment Project	3	49	16	7	52	26
Nuclear New Build	1	2	7	10	11	11
Total Nuclear OM&A	**1,605**	**1,776**	**1,758**	**1,803**	**1,841**	**1,727**
Capital						
Project Portfolio (including Spares and Minor Fixed Assets)**	291	322	319	299	289	244
Darlington Refurbishment Project (excl. Support Services)	1,008	1,119	1,084	1,082	1,019	1,035
Total Nuclear Capital	**1,299**	**1,441**	**1,403**	**1,381**	**1,308**	**1,279**
Provision Expenditures						
ONFA Funded	85	150	147	206	264	325
Internally Funded - Base	101	115	115	122	125	127
Internally Funded - Projects	54	49	70	45	45	40
Internally Funded - Darlington Refurbishment Waste Containers	31	44	45	45	38	19
Total Nuclear Provision Expenditures	**272**	**358**	**377**	**418**	**471**	**511**
Fuel Expense (Pickering and Darlington)	**263**	**223**	**220**	**228**	**217**	**198**

* Includes an estimated $4M to $5M per year for work in support of the RG&PM business unit

** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

Operational Targets

The key 2017-2019 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station and continuing work on fuel channel inspections at the Pickering station.

			Pickering					Darlington[1]				
Metric	NPI Max	Industry Best Quartile	2016 Target	2016 Forecast	2017 Target	2018 Target	2019 Target	2016 Target	2016 Forecast	2017 Target	2018 Target	2019 Target
All Injury Rate[2] (#/200k hrs worked)	N/A	0.69	0.24	0.49	0.24	0.24	0.24	0.24	0.23	0.24	0.24	0.24
Collective Radiation Exposure (person-rem/unit)	80.00	38.17	111.50	104.50	126.90	137.30	153.30	65.00	80.90	111.90	82.70	78.40
Unit Capability Factor (%)	92.0	91.3	77.6	75.3	71.5	72.0	72.6	91.1	90.0	85.1	86.0	87.8
Forced Loss Rate (%)	1.00	0.38	5.00	4.37	5.00	5.00	5.00	1.00	1.93	1.00	1.00	1.00
On-line Corrective Maintenance Backlog (work orders/unit)	N/A	7	55	80	28	28	28	20	20	15	10	7
WANO NPI (Index)	N/A	93.5	72.3	75.6	69.7	67.2	65.9	87.3	85.5	83.1	90.7	91.0
Human Performance Error Rate	N/A	0.0010	0.0030	0.0030	0.0030	0.0030	0.0030	0.0030	0.0053	0.0020	0.0020	0.0020
Total Generating Cost per MWh[3]	N/A	$38.93	$71.09	$72.46	$78.83	$80.09	$81.49	$47.35	$46.46	$49.75	$49.54	$52.33

[1] Darlington targets reflect the impact of the Unit 2 Refurbishment starting in October of 2016, where applicable.

[2] Also applies to Darlington Refurbishment Project and Contractors.

[3] Metrics exclude centrally-held Pension and OPEB costs and asset service fees. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized after 2016 for generation forgone during the Unit 2 refurbishment.

Initiatives

The following initiatives represent the focus areas of the Nuclear business unit aimed at closing performance gaps in order to achieve targeted results:

- **Outage Execution:** This initiative focuses on delivering predictable outage performance through improved planning and execution of outage work to meet planned outage day targets. Areas for improvement include: outage schedule and resource planning quality; implementation of a long-term purchased services agreement to optimize contracted work and improve quality of supplemental staff execution; inspection and maintenance execution improvements; Life Cycle Management Plan development improvements; and studying the option of moving Pickering to a 30-month outage cycle.
- **Workforce Planning & Resourcing Initiative:** This initiative focuses on implementing the resourcing strategy to support the safe operation of the plants and successful completion of the Darlington refurbishment, while minimizing disruption and costs associated with the Pickering end of commercial operations. A dedicated team provides oversight on the resourcing strategies and resourcing approval process.
- **Equipment Reliability:** This initiative aims to improve equipment reliability, improve effectiveness of the maintenance program and reduce equipment failures to meet forced loss rate targets.
- **Project Excellence Initiative:** This initiative supports the corporate-wide initiative focused on implementing a standard scalable project delivery model throughout OPG via the established Project Management Centre of Excellence, in order to increase project predictability and successful project outcomes.
- **Parts Improvement Sustainment:** This initiative aims to sustain and continuously improve on the results of the 19 completed sub-initiatives of the overall Parts Improvement Project. The focus of the Parts Improvement Project has been on obtaining the right parts on time, reducing churn in the work management system, and ultimately improving equipment reliability through the completion of the 19 cross-functional sub-initiatives across the Engineering, Supply Chain, Fleet Operations & Maintenance, and Work Management functions.
- **Human Performance:** This initiative focuses on: 1) Behaviours associated with procedural use and adherence; 2) Leadership accountability whereby leaders understand and model the behaviours expected from all staff; and 3) Supervisor effectiveness whereby supervisors set and communicate clear expectations to positively influence behaviours.

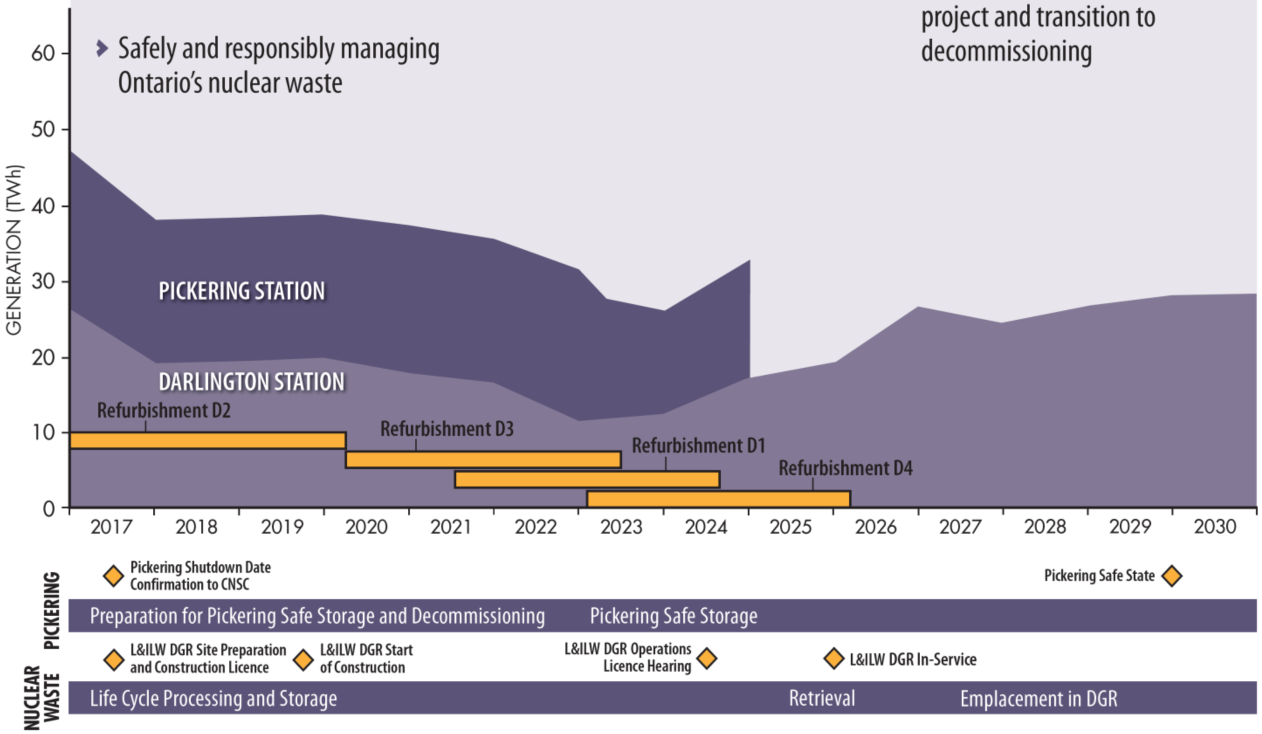
APPENDIX 5: NUCLEAR STRATEGIC FRAMEWORK

Nuclear Strategic Framework

Nuclear Cornerstones of Excellence

• Safety • Reliability • Value for Money • Human Performance

- Extending the life of Pickering station to 2024
- Achieving the cost and schedule commitments for the Darlington Refurbishment Project
- Safely and responsibly managing Ontario's nuclear waste
- Establish an organization that positions Darlington to achieve Top Quartile operational and financial performance
- Execute Pickering SAFSTOR project and transition to decommissioning



Key Strategic Goals

2017–2019

OPERATIONAL EXCELLENCE

- Protecting the health and safety of workers, public, environment, and plant.
- Establishing an Equipment Reliability Centre of Excellence to support sustainable reliability of our Nuclear stations.

PROJECT EXCELLENCE

- Integrating and executing the Darlington Unit 2 Refurbishment on schedule and budget.
- Improving project outcomes across the enterprise through the Project Management Centre of Excellence.

FINANCIAL STRENGTH

- Focusing on outage performance to meet our generation commitments.
- Optimizing inventory levels while ensuring availability of critical parts.
- Completing assessments to enable extending Pickering operations to 2024.

SOCIAL LICENCE

- Complying with all applicable laws, codes, and regulations.
- Ensuring safety of the public and environment and reducing tritium emissions as low as reasonably achievable.
- Strong community and stakeholder relations.

APPENDIX 6: RENEWABLE GENERATION & POWER MARKETING FINANCIAL PLAN, OPERATIONAL TARGETS, AND INITIATIVES

Financial Plan

	Forecast	Business Plan			Projection	
(in millions of dollars)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
OM&A						
Regulated Hydroelectric	192	199	193	194	205	206
Contracted Generation Portfolio	[redacted]					
Other* [redacted]	[redacted]					
Total Base OM&A	[redacted]					
Regulated Hydroelectric	44	71	95	96	107	98
Contracted Generation Portfolio	[redacted]					
Total Project OM&A	[redacted]					
Regulated Hydroelectric	236	270	287	290	312	303
Contracted Generation Portfolio	[redacted]					
Other* [redacted]	[redacted]					
Total RG&PM OM&A	[redacted]					
Capital						
Sustaining						
<u>Regulated Hydroelectric</u>						
Sir Adam Beck Pump GS Reservoir Rehabilitation	40	7	-	-	-	-
Sir Adam Beck I GS Canal Liner Rehabilitation	-		1	1	62	62
Other Sustaining Projects	109	125	111	120	153	133
Total Regulated Hydroelectric	**149**	**132**	**112**	**122**	**215**	**195**
<u>Contracted Generation Portfolio</u>						
[redacted]	[redacted]					
Other Sustaining Projects						
Total Contracted Generation Portfolio						
Total Sustaining Capital						
Development Capital						
[redacted]						
Sir Adam Beck Units 1 & 2 Conversion	0	2	17	43	27	-
[redacted]	[redacted]					
Ranney Falls GS Expansion	-	33	18	8	-	-
[redacted]	[redacted]					
Total Development Capital						
Total RG&PM Capital						
[redacted]						
Hydroelectric Gross Revenue Charge and Thermal Fuel						
Regulated Hydroelectric (net of SBG losses)**	322	331	344	338	327	321
Contracted Generation Portfolio	[redacted]					
Other						

* Includes $8M to $10M per year for work in support of the Nuclear Organization
** Regulated hydroelectric GRC expenses assuming no SBG losses are: $324M in 2016, $348M in 2017, $357M in 2018, $350M in 2019, $331M in 2020, and $324M in 2021.

Operational Targets

The key 2017-2019 RG&PM targets designed to drive continuous performance are set out below.

	Forecast	Business Plan		
	2016	2017	2018	2019
All Injury Rate *(#/200k hrs worked)*	2.06	0.90	0.65	0.40
Environment				
Significant Environmental Events (incl. Category A and B Spills)	-	-	-	-
Category C Spills	7	9	9	9
Environmental Infractions	7	8	8	8
Capacity *(MW)*	[redacted]			
Regulated Hydroelectric	*6,421*	*6,433*	*6,433*	*6,509*
Contracted Generation Portfolio (Hydro, Thermal and Solar)	[redacted]			
Wind (No Contract)				
Hydroelectric Availability *(%)*	[redacted]			
Regulated Hydroelectric	*89.1*	*87.3*	*90.0*	*90.7*
Contracted Generation Portfolio Hydroelectric	[redacted]			
Hydroelectric Equivalent Forced Outage Rate *(%)*	[redacted]			
Regulated Hydroelectric	*1.9*	*1.7*	*1.7*	*1.7*
Contracted Generation Portfolio Hydroelectric	[redacted]			
Thermal Equivalent Forced Outage Rate (Operating) *(%)*				
Total Hydroelectric Generating Cost per MWh* *($/MWh)*	[redacted]			

* Calculated assuming no production is foregone due to SBG losses

Initiatives

The RG&PM business unit continues to focus on performance excellence, while continuing to drive for efficiency improvements through the following strategic initiatives:

- **Safety:** This initiative will focus on driving improvements in medical treatment injuries through stringent All Injury Rate targets.
- **Workforce Planning and Resourcing Efficiency:** This initiative will focus on resource planning with an emphasis on filling required positions. RG&PM will continue to review positions as they become vacant and challenge whether they are required. Attrition in engineering is being addressed through the re-introduction of the graduate engineer training program and the hiring of additional temporary senior engineers, to address shortfalls in the short term.
- **Environment:** This initiative aims to continue good environmental performance through programs such as the Management Self-Assessment on Drainage Surveys and support of the corporate environmental management system.
- **Project Excellence:** This initiative supports the corporate-wide initiative focused on implementing a standard scalable project delivery model throughout OPG via the established Project Management Centre of Excellence, in order to increase project predictability and successful project outcomes.
- **Operational Excellence:** This initiative focuses on sustaining hydroelectric availability and the thermal Equivalent Forced Outage Rate (operating) across the business plan period, as per targets and contractual limits, to ensure unit availability during the Darlington refurbishment.
- **Building Leadership Capability:** This initiative focuses on building strategic leadership capability, continuous improvement in succession planning, engagement in the company-wide leadership development program, mentoring of high potential individuals, and continuing to strengthen and develop partnerships with host communities and Indigenous communities.
- **Productivity Improvements:** This initiative focuses on continued review of opportunities for efficiency gains from strategic initiatives, optimizing the productivity of maintenance staff, and focusing on the Attendance Support Program.
- **Regionalization:** This initiative will continue to explore further efficiencies through regionalization.

APPENDIX 7: BUSINESS AND ADMINISTRATIVE SERVICES FINANCIAL PLAN, OPERATIONAL TARGETS, AND INITIATIVES

Financial Plan

	Forecast	Business Plan			Projection	
(in millions of dollars)	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
OM&A						
Chief Information Officer	118	120	119	121	122	121
Real Estate	96	99	99	101	102	107
Supply Chain	53	56	56	57	58	60
SVP Office	1	1	1	1	1	1
Base OM&A	**267**	**277**	**275**	**280**	**283**	**289**
Chief Information Officer	30	16	15	14	15	14
Real Estate	2	5	5	5	6	5
Project OM&A	**32**	**22**	**20**	**19**	**21**	**19**
Total BAS OM&A	**298**	**299**	**295**	**300**	**305**	**309**
Capital						
Chief Information Officer	41	30	26	26	26	26
Real Estate	18	18	11	12	8	8
Darlington Refurbishment Project	20	22	19	18	17	18
Total BAS Capital	**79**	**70**	**56**	**56**	**51**	**52**
Nuclear Waste Provision Expenditures	**3**	**5**	**5**	**5**	**6**	**6**
[redacted]	[redacted]					

Operational Targets

Business and Administrative Services (BAS) comprises the Company's centralized Supply Chain, Chief Information Office, and Real Estate Services functions. The key 2017-2019 targets for BAS include the following:

	Forecast	Business Plan		
	2016	2017	2018	2019
Employee Safety				
All Injury Rate *(#/200k hrs worked)*	< 0.38	< 0.35	< 0.35	< 0.35
Lost Time Injuries	0	0	0	0
Total Sick Days per Employee Annualized *(days)*	13.5	12.4	11.9	11.4
Environment				
Category C Spills	1	1	1	1
Environmental Infractions	3	3	2	2
Waste Diversion Target *(%)*	≥ 80	≥ 80	≥ 80	≥ 80
Supply Chain				
Unplanned Nuclear Generation Loss Due to Vendor Quality *(days)*	14.0	12.5	12.0	12.0
Scope Removal due to Unavailable Parts - Nuclear *(%)*	DN=3.0 PN=1.8	10% of outage scope variance target		
Stock-out Nuclear Materials (Critical 1 & 2 Parts) *(%)*	1.8	1.3	1.0	1.0
Strategic Sourcing (value improvement on addressable spend) *($m)*	[redacted]			
Supply Chain Achievement of Projects Business Unit Milestones *(%)*	100	100	100	100
Information Technology *(%)*				
Critical IT System Availability	99.98	99.98	99.98	99.98
Cyber Security Capability Health *(% Adherence to Plan)*	N/A	98	98	98
IT Projects Benefits Realization	98	98	98	98
IT Execution Phase Project Adherence (Portfolio)	95	95	95	95
Real Estate				
Cost Performance Index LTD Active Projects	≥ 0.95	≥ 0.95	≥ 0.95	≥ 0.95
Schedule Performance Index LTD Active Projects	≥ 0.95	≥ 0.95	≥ 0.95	≥ 0.95

Initiatives

Key initiatives of BAS focus on delivering cost effective, value added services in support of generation business unit operations and projects, while continuing to improve efficiency. The initiatives include:

- **Strategic Sourcing**: Supply Chain will maximize OPG spend leverage through a re-compete sourcing strategy and enhanced spend category management to achieve a targeted [redacted] value improvement over the business planning period.
- **Project and Contract Management Excellence**: Supply Chain, in collaboration with operating business units, will establish and execute an enterprise-wide model for project and contract management, leveraging industry best practices. This will include establishing a Centre of Excellence to provide leadership and oversight for governance, reporting, systems and tools, and training and development.
- **Supplier Quality and Counterfeit, Fraudulent and Sub-Standard Parts**: While Supply Chain has established effective programs for managing these risks, continuous improvement opportunities will continue to be identified through self-evaluation, benchmarking and third party review. In addition, Supply Chain will expand supplier quality programs to mitigate risk exposure from counterfeit, fraudulent and suspect items across second and third tier sub-suppliers by the fourth quarter of 2018.
- **IT Innovation Strategies and Technology Investments:** Chief Information Office will continue to leverage new IT technologies and automate business processes to deliver operational productivity and cost efficiency improvements.
- **Information Management Optimization Strategy:** Chief Information Office will advance the use of electronic records to transition to a common records and document management system to reduce costs and improve services to less than 5 days by November 2018.
- **Cyber Security:** Chief Information Office will continue to implement the 8-point cyber security program to better ensure OPG remains vigilant, secure and resilient against growing and emerging threats. This is in direct support of the OPG Board Policy on Cyber Security.
- **Strategic Long-Term Accommodation Plan:** Real Estate & Services will partner with business units across OPG to develop a long-term accommodation strategy to optimize owned and lease premises.
- **Infrastructure Life Cycle Planning:** Real Estate & Services will undertake an initiative to optimize infrastructure capital investment through life cycle planning to maintain aging assets and facilities.

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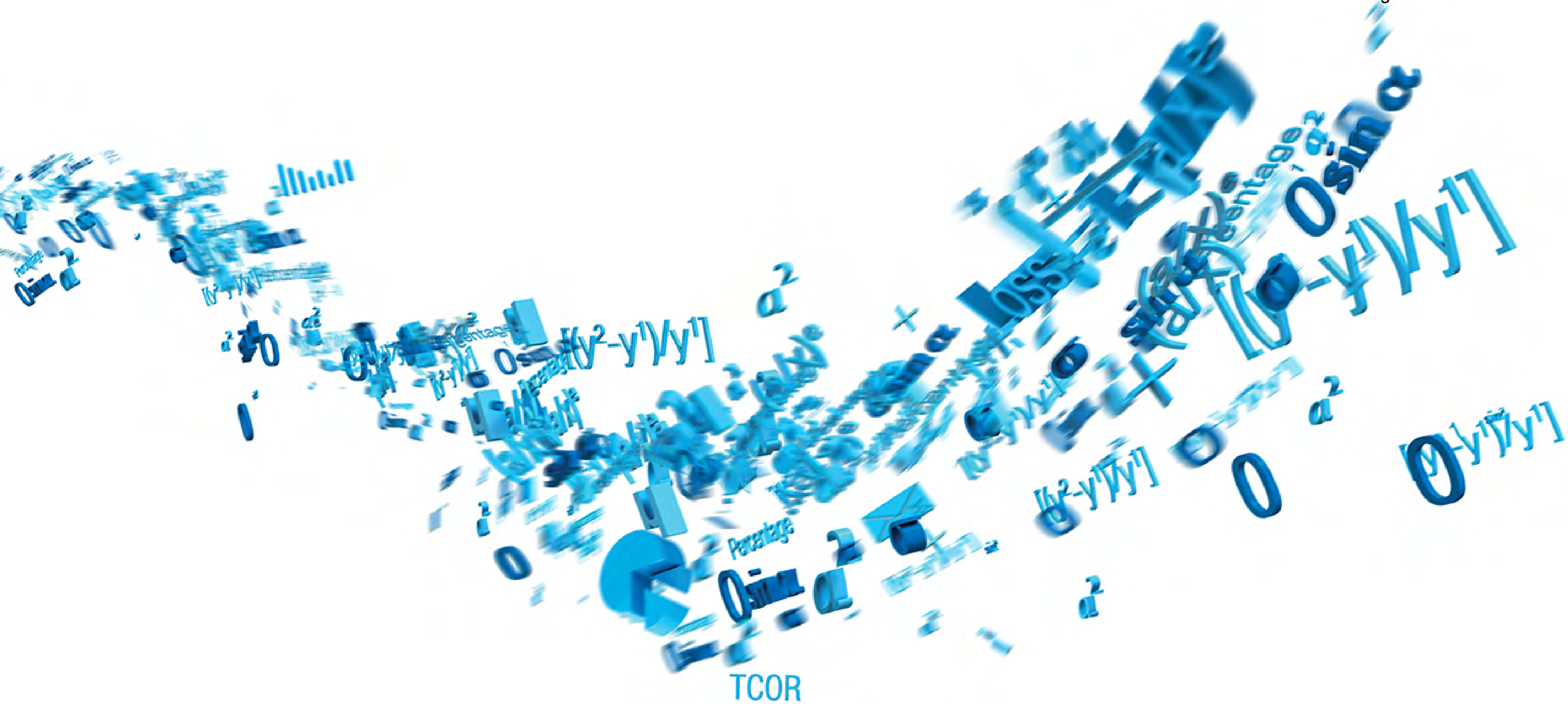

Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2017 to 2021

Ontario Power Generation Inc.
January 1, 2017 to December 31, 2021

December 2016

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Introduction

This report summarizes the estimated accounting costs for fiscal years 2017 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, 2017 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 Aon Hewitt's Report on the Estimated Accounting Cost for Post Employment Benefit Plans for Fiscal Years 2016 to 2021 dated May 2016 and 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.

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December 2016

Actuarial Report

Results for Fiscal Years 2017 to 2021

OPG's total estimated pension and OPEB costs for fiscal years 2017 through 2021 as determined in accordance with US GAAP are as follows:

(in Canadian $000s)	2017	2018	2019	2020	2021
RPP	$ 265,509	$ 214,903	$ 204,425	$ 201,066	$ 201,252
SPP	24,521	24,133	23,688	23,551	23,558
OPRB	167,728	173,243	177,518	182,711	187,586
LTD	18,054	18,158	18,287	18,442	18,627
Total	$ 475,812	$ 430,437	$ 423,918	$ 425,770	$ 431,023

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 3A through 3E to this report.

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.

We have conducted a new comprehensive accounting valuation of OPG's plans in 2016 using data as of December 31, 2015, including updated plan membership information, to reflect the most recent census data available as a result of the filed funding valuation as at January 1, 2016 for the RPP, and updated best estimate assumptions in accordance with US GAAP based on plan experience and current expectations. The results of the new comprehensive accounting valuation will be reflected in the pension and OPRB obligations as at December 31, 2016, and are reflected in the estimated 2017 to 2021 pension and OPRB obligations and costs contained in this report. Further details of the membership information as at December 31, 2015 are provided in Schedules 1A to 1C. We continue to update membership for the LTD plan annually.

Actuarial Methods and Assumptions

As part of the new comprehensive accounting valuation, we reviewed all assumptions and have recommended that updated assumptions be used in the calculation of OPG's pension and OPRB obligations as at December 31, 2016, and 2017 to 2021 estimated costs for these plans. The assumptions updated include termination rates for all plans, disability incidence rates for RPP, SPP and OPRB valuations, and health care benefit claims costs for the OPRB valuation. The updated assumptions reflect OPG's actual plan experience and current outlook, and, in our opinion, represent a better estimate of future events. The updated assumptions are detailed in the Actuarial Methods and Assumptions section of this report.

The actuarial methodology and accounting policies used in the development of the estimated costs for fiscal years 2017 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, with reference to those representative of AA corporate bond yields in Canada as at June 30, 2016 having duration similar to the liabilities of the plans;
- Prior to 2017, the current service cost and interest cost for OPG's pension and OPEB plans have been determined using the single equivalent discount rate approach. Under the single equivalent discount rate approach, a single weighted average discount rate is set by reference to a yield curve reflecting the projected cash flow stream of the plans, and this discount rate is used to determine the benefit obligation and cost components such as current service cost and interest cost. Effective January 1, 2017, OPG is adopting the recently-emerged full yield curve approach to measure pension and OPEB costs, on a prospective basis, in accordance with US GAAP as a change in accounting estimate. The full yield curve approach provides a more precise measurement of current service cost and interest cost components, which, in our opinion, improves the overall allocation of the net periodic pension/benefit costs to the appropriate reporting periods. Under the full yield curve approach, individual spot discount rates along the yield curve are applied to the present values of the projected cash flows at the relevant maturity to derive a more precise interest cost. The current service cost is more precisely determined under the full yield curve approach based on an application of duration-specific spot rates in discounting the service cost projected cash flows.

- The following effective discount rates (per annum) were used to estimate OPG's 2017 to 2021 pension and OPEB costs under the full yield curve approach[1]:

	RPP and SPP	OPRB	LTD
Current Service Cost	3.79%	3.84%	2.80%
Interest Cost[2]	3.02%	3.18%	2.18%

  The discount rates used to determine the projected benefit obligations are 3.60% per annum for RPP and SPP, 3.70% per annum for OPRB and 2.80% per annum for LTD.

  The full yield curve approach changes how the yield curve is applied to calculate period service and interest costs. It does not impact the determination of the projected benefit obligations or the yield curve itself. Therefore, the expected reduction in OPG's current service and interest costs under the full yield curve approach, relative to the single weighted average discount rate approach, will result in an offsetting change in the actuarial gains or losses upon re-measurement of the benefit obligation.

- 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 2017 through 2021 RPP costs;
- The projected asset value for the RPP as at December 31, 2016 is based on the actual asset value at June 30, 2016, projected to December 31, 2016 using the expected rate of return on assets of 6.0% per annum;
- The assumed termination rates have been updated for all plans and the RPP, SPP and OPRB disability incidence assumption has been removed, both to better reflect the actual experience of the plans. The updates to these assumptions are consistent with those reflected in the most recently filed funding actuarial valuation of the RPP as at January 1, 2016. Further details of the updated termination rates are provided in Schedule 2;

[1] A series of individual spot rates applied to projected cash flows under the full yield curve approach is expressed as a single effective discount rate for disclosure purposes.
[2] The rates shown apply to interest cost on the projected benefit obligations at the beginning of the year. Under the full yield curve approach, a separate rate is used to calculate the interest cost on the current service cost recognized during the year. This rate is 3.59% for RPP and SPP costs, 3.74% for OPRB costs and 2.18% for LTD costs.

- Health care benefit claims costs for the OPRB valuation have been updated to reflect actual OPRB plan experience in 2014 and 2015. Overall, the updated per capita claims cost basis is lower than expected, primarily due to the impact of reduced cost of prescription drugs as a result of the reduced pricing of generic drugs and the patent expiry of brand name drug therapies. Further details of the updated health care claims costs at age 65 are provided in Schedule 2. Age-based utilization rates (factors), as set out in the Reports, are applied to the per capita cost basis in determining the health care benefit claims costs by age;

- 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 2017 to 2021 costs, and the salary scale increase rates, 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 2017 for PWU-represented employees and for the 2017-2018 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	6,075	6,258	6,261	6,210	6,082	6,014
Hydro / Thermal	1,541	1,541	1,518	1,509	1,484	1,445
Support Services	2,064	2,048	2,032	2,028	2,005	1,995
Total	9,680	9,847	9,811	9,747	9,571	9,454

- 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 2017 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 2017 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 2017 to 2018 contributions to the RPP fund are based on the latest filed actuarial valuation for funding purposes as of January 1, 2016 of the RPP. The next actuarial valuation for funding purposes must have an effective date no later than January 1, 2019. We have assumed that based on a triennial filing, the next actuarial valuation for funding purposes would have an effective date of January 1, 2019.

In order to project contributions to the RPP for 2019 to 2021, an estimate of the going concern and solvency positions of the RPP is required. The estimated contributions for 2019 to 2021 are based on the projected going concern and solvency funded status as of January 1, 2019. The assumptions and methods used for the determination of the projected going concern funded status as of January 1, 2019 are the same as those used for the funding valuation as of January 1, 2016.

The assumptions and methods used for the determination of the projected solvency funded status as of January 1, 2019 are the same as those used for the funding valuation as of January 1, 2016, adjusted for the application of a five-year solvency smoothing approach permitted by legislation and updated to reflect the following prescribed solvency discount rates assumptions:

- The five-year smoothed non-indexed discount rates at January 1, 2019 are: 1.88% per annum for the first 10 years and 3.32% per annum thereafter for commuted values, and 3.02% per annum for annuity purchases; and
- The calculation of the five-year non-indexed discount rates at January 1, 2019 assumes the following unsmoothed non-indexed discount rates for the period from January 1, 2017 to January 1, 2019: 1.70% per annum for the first 10 years and 3.10% per annum thereafter for commuted values, and 2.91% per annum for annuity purchases. These rates are those in effect as of July 1, 2016.

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

Schedule 1A – Summary of Registered Pension Plan Membership at December 31, 2015

	December 31, 2015
Active Members	
Number	9,290
Average age (years)	46.8
Average credited service (years)	15.7
Average pensionable earnings for the following year	$ 109,297
Accumulated contributions with interest	$ 824,900,414
Members on Long-Term Disability	
Number	343
Average age (years)	55.2
Average credited service (years)	24.8
Average pensionable earnings for the following year	$ 85,007
Accumulated contributions with interest	$ 21,318,514
Deferred Vested Members	
Number	739[1]
Average age (years)	53.8
Average annual lifetime pension[2]	$ 10,043

[1] Excludes 30 in-transit commuted value transfers (commuted value reflected in liabilities)
[2] Includes increases for 2015 effective January 1, 2016 of 100% of the increase in the Consumer Price Index

Schedule 1A – Summary of Registered Pension Plan Membership at December 31, 2015 (continued)

		December 31, 2015
Retired Members		
Number		9,245[1]
Average age (years)		69.6
Average annual lifetime pension[2]	$	48,041
Average annual bridge pension[2,3]	$	15,592
Survivors (excluding children)		
Number		2,117
Average age (years)		77.7
Average annual pension[2]	$	24,494
Children		
Number		11
Average age (years)		21.6
Average annual temporary pension[2]	$	19,796

[1] As adjusted for one retiree death early in 2016
[2] Includes increases for 2015 effective January 1, 2016 of 100% of the increase in the Consumer Price Index
[3] As at December 31, 2015, there were 3,163 retired members with an average age of 60.1 receiving a bridge benefit

Schedule 1B – Summary of Supplementary Pension Plan Membership at December 31, 2015

	SPS	ESPS	DSPS Canadian Obligations	DSPS Other Obligations
Active Members[1]				
Number	289	259	-	-
Average age (years)	50.2	51.8	-	-
Average pensionable service (years)	22.1	12.6	-	-
Average pensionable earnings	$ 181,997	$ 174,665	-	-
Shift and Duty Managers				
Number	-	-	39	-
Average age (years)	-	-	50.3	-
Average pensionable service (years)	-	-	24.3	-
Average pensionable earnings	-	-	$ 204,838	-
Deferred Vested Members				
Number	5	56	-	1[2]
Average age (years)	53.3	51.2	-	*
Average annual lifetime pension	$ 7,149	$ 5,595	-	*
Pensioners and Survivors				
Number	555	105	56	1[2]
Average age (years)	65.7	65.9	64.0	*
Average annual lifetime pension	$ 9,805	$ 14,025	$ 49,140	*

[1] Includes only members whose accrued benefits under the RPP as at December 31, 2015 would be limited to the projected maximum pension under the *Income Tax Act* (Canada). Includes members on long-term disability.
[2] Data withheld for confidentiality.

Schedule 1C – Summary of Other Post Retirement Benefit Plan Membership at December 31, 2015

	PWU	Society	Management Heritage	Management Millennium	Total
Active Members					
Number	5,333	2,929	629	398	9,289
Average age (years)	46.6	46.4	51.1	45.3	46.8
Average eligibility service (years)	16.1	16.0	22.5	8.9	16.2
Average basic earnings	$ 100,018	$ 117,540	$ 141,974	$ 121,320	$ 109,297
Number with health and dental coverage	5,166	2,858	590	377	8,991
Members on Long-Term Disability					
Number	279	44	18	2	343
Average age (years)	55.2	55.6	56.4	46.7	55.3
Average eligibility service (years)	25.3	26.6	29.2	9.9	25.6
Average deemed basic earnings	$ 81,205	$ 108,499	$ 90,377	$ 62,307	$ 85,077
Number with health and dental coverage	264	41	16	2	323
RPP Retirees					
Number of retirees	4,153	2,941	1,602	17	8,713
Average age (years)	68.9	69.2	70.2	63.6	69.2
Number of covered spouses	3,501	2,652	1,430	15	7,598
Number with health and dental coverage	4,107	2,934	1,597	17	8,655
RPP Surviving Spouses and Dependent Children					
Number	1,100	535	388	1	2,024
Average age (years)	77.8	77.2	81.8	61.1	78.4
Number with health and dental coverage	1,100	535	388	1	2,024

Schedule 1C – Summary of Other Post Retirement Benefit Plan Membership at December 31, 2015 (continued)

	PWU	Society	Management Heritage	Management Millennium	Total
Non-RPP Members, Surviving Spouses and Dependent Children					
Number	108	223	128	6	465
Average age (years)	79.8	65.8	72.6	62.1	70.9
Number with health and dental coverage	108	223	128	6	465
Deferred Vested Members Entitled to Coverage					
Number	16	10	10	0	36
Average age (years)	56.1	55.5	55.2	N/A	55.7

Schedule 2 – Summary of Updated Actuarial Assumptions

Sample rates of termination[1]

Age	Male	Female
20	2.9%	3.3%
25	2.2%	2.5%
30	1.6%	2.4%
35	1.3%	2.0%
40	1.0%	1.6%
45	0.9%	1.4%
50	0.9%	1.4%
55	0.0%	0.0%

- For LTD valuation purposes, termination rates for disabled members (by death or recovery) are set in accordance with the Canadian Institute of Actuaries 2004 to 2008 Group Long-Term Disability Termination Study dated October 2011.

[1] The table shown applies to RPP, SPP and OPRB valuations, where termination refers to any withdrawal from the plan due to reasons other than retirement, disability or death.

Schedule 2 – Summary of Updated Actuarial Assumptions (continued)

Post-retirement Health Care Claims Costs[1] at Age 65 – December 31, 2015

	Society	PWU	Management (Heritage)	Management (Millennium)
Hospital	$ 74	$ 85	$ 67	$ 64
Prescription drugs[2]	516	720	475	415
Vision care	192	184	132	77
Other medical	511	382	382	85
Dental	980	867	919	637
Total	$2,273	$2,238	$1,975	$1,278

[1] Amounts shown include administration expenses and taxes.
[2] Reflect drug offset assumption at age 65 and thereafter due to provincial drug plans. Additional cost of $227 is included to reflect Ontario Drug Deductible for individuals aged 65 and older.

Schedule 3A – 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	$ (16,897,238)	$ (343,782)	$ (2,920,165)	$ (196,166)
Fair Value of Plan Assets	13,277,831	0	0	0
Net Asset (Liability) Recognized	$ (3,619,407)	$ (343,782)	$ (2,920,165)	$ (196,166)
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)	4,191,113	122,014	419,171	0
Total Accumulated Other Comprehensive Loss (Income)	$ 4,191,113	$ 122,014	$ 424,439	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2017 to December 31, 2017				
Employer Current Service Cost	$ 316,782	$ 7,150	$ 63,706	$ 12,574
Interest Cost	511,660	10,360	94,158	4,266
Expected Return on Plan Assets	(774,854)	0	0	0
Amortization of Past Service Cost	0	0	583	0
Amortization of Net (Gain) Loss	211,921	7,011	9,281	1,214
Total Cost	$ 265,509	$ 24,521	$ 167,728	$ 18,054
2017 Estimated Employer Pension Contributions / Benefit Payments	$ 247,710	$ 18,469	$ 68,315	$ 26,078

Schedule 3B – 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	$ (17,245,702)	$ (345,102)	$ (3,026,189)	$ (188,142)
Fair Value of Plan Assets	13,629,605	0	0	0
Net Asset (Liability) Recognized	$ (3,616,097)	$ (345,102)	$ (3,026,189)	$ (188,142)
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)	4,170,004	117,282	426,365	0
Total Accumulated Other Comprehensive Loss (Income)	$ 4,170,004	$ 117,282	$ 431,050	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2018 to December 31, 2018				
Employer Current Service Cost	$ 319,897	$ 7,267	$ 66,343	$ 12,888
Interest Cost	520,964	10,399	97,541	4,103
Expected Return on Plan Assets	(808,664)	0	0	0
Amortization of Past Service Cost	0	0	583	0
Amortization of Net (Gain) Loss	182,706	6,467	8,776	1,167
Total Cost	$ 214,903	$ 24,133	$ 173,243	$ 18,158
2018 Estimated Employer Pension Contributions / Benefit Payments	$ 250,584	$ 18,838	$ 73,728	$ 25,663

Schedule 3C – 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	$ (17,535,675)	$ (346,220)	$ (3,133,376)	$ (180,637)
Fair Value of Plan Assets	13,914,532	0	0	0
Net Asset (Liability) Recognized	$ (3,621,143)	$ (346,220)	$ (3,133,376)	$ (180,637)
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)	4,210,731	113,105	434,620	0
Total Accumulated Other Comprehensive Loss (Income)	$ 4,210,731	$ 113,105	$ 438,722	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2019 to December 31, 2019				
Employer Current Service Cost	$ 327,067	$ 7,400	$ 67,593	$ 13,210
Interest Cost	530,315	10,431	100,920	3,953
Expected Return on Plan Assets	(828,095)	0	0	0
Amortization of Past Service Cost	0	0	583	0
Amortization of Net (Gain) Loss	175,138	5,857	8,422	1,124
Total Cost	$ 204,425	$ 23,688	$ 177,518	$ 18,287
2019 Estimated Employer Pension Contributions / Benefit Payments	$ 299,422	$ 19,215	$ 78,569	$ 25,035

Schedule 3D – 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	$ (17,852,990)	$ (347,140)	$ (3,240,842)	$ (173,889)
Fair Value of Plan Assets	14,289,495	0	0	0
Net Asset (Liability) Recognized	$ (3,563,495)	$ (347,140)	$ (3,240,842)	$ (173,889)
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)	4,248,080	109,552	443,720	0
Total Accumulated Other Comprehensive Loss (Income)	$ 4,248,080	$ 109,552	$ 447,239	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2020 to December 31, 2020				
Employer Current Service Cost	$ 332,150	$ 7,548	$ 69,649	$ 13,540
Interest Cost	539,915	10,459	104,329	3,816
Expected Return on Plan Assets	(848,109)	0	0	0
Amortization of Past Service Cost	0	0	539	0
Amortization of Net (Gain) Loss	177,110	5,544	8,194	1,086
Total Cost	$ 201,066	$ 23,551	$ 182,711	$ 18,442
2020 Estimated Employer Pension Contributions / Benefit Payments	$ 304,891	$ 19,599	$ 83,972	$ 24,742

Schedule 3E – 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	$ (18,169,247)	$ (347,861)	$ (3,348,986)	$ (167,589)
Fair Value of Plan Assets	14,681,013	0	0	0
Net Asset (Liability) Recognized	$ (3,488,234)	$ (347,861)	$ (3,348,986)	$ (167,589)
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)	4,276,644	106,321	453,664	0
Total Accumulated Other Comprehensive Loss (Income)	$ 4,276,644	$ 106,321	$ 456,644	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2021 to December 31, 2021				
Employer Current Service Cost	$ 333,735	$ 7,699	$ 71,231	$ 13,879
Interest Cost	549,082	10,480	107,737	3,696
Expected Return on Plan Assets	(866,506)	0	0	0
Amortization of Past Service Cost	0	0	539	0
Amortization of Net (Gain) Loss	184,941	5,379	8,079	1,052
Total Cost	$ 201,252	$ 23,558	$ 187,586	$ 18,627
2021 Estimated Employer Pension Contributions / Benefit Payments	$ 307,918	$ 19,991	$ 89,538	$ 23,822

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Filed December 19 2016

EB-2016-0152
Revenue Requirement Work Form

Ontario Power Generation

Ontario Power Generation

EB-2016-0152 Revenue Requirement Work Form

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Ontario Power Generation

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Legend / Colour Scheme

	OPG Proposed Amounts
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	Automatically Generated Calculations

OEB Adjustment Input Sheet

		Total Generating Facilities																			
		2017				2018				2019				2020				2021			
Line No.	Description	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Capital Structure																				
1	Common Equity	49.0%	49.0%		49.0%	49.0%	49.0%		49.0%	49.0%	49.0%		49.0%	49.0%	49.0%		49.0%	49.0%	49.0%		49.0%
2	Debt	51.0%	51.0%	0.0%	51.0%	51.0%	51.0%	0.0%	51.0%	51.0%	51.0%	0.0%	51.0%	51.0%	51.0%	0.0%	51.0%	51.0%	51.0%	0.0%	51.0%
	Cost of Capital																				
3	Short-Term Debt Facility Cost ($M)	2.6	2.6		2.6	2.6	2.6		2.6	2.6	2.6		2.6	2.6	2.6		2.6	2.6	2.6		2.6
4	Short-Term Debt Interest Cost ($M)	0.6	0.6		0.6	1.1	1.1		1.1	1.5	1.5		1.5	1.5	1.5		1.5	1.5	1.5		1.5
5	Short-Term Debt Cost ($M)	2.9	2.9		2.9	3.4	3.4		3.4	3.8	3.8		3.8	3.8	3.8		3.8	3.8	3.8		3.8
6	Regulated Portion of Short-Term Debt Cost Rate	92.67%	92.67%		92.67%	92.67%	92.67%		92.67%	92.67%	92.67%		92.67%	92.67%	92.67%		92.67%	92.67%	92.67%		92.67%
7	Existing and Planned Long-Term Debt Cost Rate	4.89%	4.89%		4.89%	4.60%	4.60%		4.60%	4.52%	4.52%		4.52%	4.49%	4.49%		4.49%	4.48%	4.48%		4.48%
8	Other Long-Term Debt Provision Cost Rate	4.89%	4.89%		4.89%	4.60%	4.60%		4.60%	4.52%	4.52%		4.52%	4.49%	4.49%		4.49%	4.48%	4.48%		4.48%
9	Common Equity Cost Rate ROE	9.19%	8.78%		8.78%	9.19%	8.78%		8.78%	9.19%	8.78%		8.78%	9.19%	8.78%		8.78%	9.19%	8.78%		8.78%
10	Adjustment for Lesser of UNL/ARC Cost Rate	5.11%	4.95%		4.95%	5.11%	4.95%		4.95%	5.11%	4.95%		4.95%	5.11%	4.95%		4.95%	5.11%	4.95%		4.95%
	Capitalization ($M)																				
11	Short-Term Debt Principal	37.1	37.1		37.1	37.1	37.1		37.1	37.1	37.1		37.1	37.1	37.1		37.1	37.1	37.1		37.1
12	Existing and Planned Long-Term Debt Principal	2,878.4	2,878.4		2,878.4	3,168.1	3,168.1		3,168.1	3,489.7	3,489.7		3,489.7	3,527.6	3,527.6		3,527.6	3,406.0	3,406.0		3,406.0
13	Adjustment for Lesser of UNL/ARC	775.4	524.0		524.0	725.1	446.7		446.7	674.9	369.5		369.5	624.6	292.2		292.2	590.1	249.6		249.6

		Nuclear Facilities																			
Line No.	Description	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Rate Base ($M)																				
14	Gross Plant at Cost	7,627.1	7,389.1		7,389.1	8,122.9	7,885.0		7,885.0	8,416.1	8,178.2		8,178.2	12,887.2	12,649.3		12,649.3	13,763.5	13,525.6		13,525.6
15	Accumulated Depreciation/Amortization	4,218.8	4,232.3		4,232.3	4,581.6	4,622.1		4,622.1	4,962.9	5,030.4		5,030.4	5,417.3	5,511.8		5,511.8	5,848.8	5,951.4		5,951.4
16	Cash Working Capital	11.0	11.0		11.0	11.0	11.0		11.0	11.0	11.0		11.0	11.0	11.0		11.0	11.0	11.0		11.0
17	Materials and Supplies	448.7	448.7		448.7	444.5	444.5		444.5	436.3	436.3		436.3	427.0	427.0		427.0	415.0	415.0		415.0
18	Nuclear Fuel Inventory	251.9	251.9		251.9	242.2	242.2		242.2	224.2	224.2		224.2	210.7	210.7		210.7	208.6	208.6		208.6
19	**Total**	**4,119.8**	**3,868.4**	**-**	**3,868.4**	**4,239.0**	**3,960.6**	**-**	**3,960.6**	**4,124.7**	**3,819.3**	**-**	**3,819.3**	**8,118.6**	**7,786.2**	**-**	**7,786.2**	**8,549.2**	**8,208.6**	**-**	**8,208.6**
	Expenses ($M)																				
20	OM&A	2,318.6	2,346.0		2,346.0	2,327.1	2,351.4		2,351.4	2,347.9	2,425.1		2,425.1	2,368.0	2,469.0		2,469.0	2,248.7	2,349.1		2,349.1
21	Fuel	219.9	218.2		218.2	222.0	219.9		219.9	233.1	232.1		232.1	228.2	224.4		224.4	212.7	209.1		209.1
22	Depreciation/Amortization	346.9	373.9		373.9	378.7	405.7		405.7	384.0	411.0		411.0	524.9	551.9		551.9	338.1	327.3		327.3
23	Property Taxes	14.6	14.6		14.6	14.9	14.9		14.9	15.3	15.3		15.3	15.7	15.7		15.7	17.0	17.0		17.0
24	**Total**	**2,900.0**	**2,952.6**	**-**	**2,952.6**	**2,942.8**	**2,991.9**	**-**	**2,991.9**	**2,980.3**	**3,083.5**	**-**	**3,083.5**	**3,136.7**	**3,261.0**	**-**	**3,261.0**	**2,816.5**	**2,902.5**	**-**	**2,902.5**
	Other Revenues ($M)																				
25	Bruce Lease Revenues Net of Direct Costs	(66.1)	(16.9)		(16.9)	(74.3)	(17.1)		(17.1)	(85.9)	(27.4)		(27.4)	(82.1)	(23.8)		(23.8)	(93.1)	(38.1)		(38.1)
26	Ancillary and Other Revenue	31.7	31.7		31.7	22.0	22.0		22.0	22.7	22.7		22.7	22.2	22.2		22.2	22.9	22.9		22.9
27	**Total**	**(34.5)**	**14.8**	**-**	**14.8**	**(52.4)**	**4.9**	**-**	**4.9**	**(63.2)**	**(4.7)**	**-**	**(4.7)**	**(59.9)**	**(1.6)**	**-**	**(1.6)**	**(70.2)**	**(15.1)**	**-**	**(15.1)**
28	**Forecast Production** (TWh)	**38.1**	**38.1**		**38.1**	**38.5**	**38.5**		**38.5**	**39.0**	**39.0**		**39.0**	**37.4**	**37.4**		**37.4**	**35.4**	**35.4**		**35.4**

OEB Adjustment Input Sheet

Line No.	Description	Nuclear Facilities																			
		2017				2018				2019				2020				2021			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Applicable Tax Rates																				
29	Federal Rate	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%	15.00%	15.00%		15.00%
30	Provincial Rate	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%	10.00%	10.00%		10.00%
31	**Total Tax Rate**	**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**	**25.00%**	**25.00%**	**-**	**25.00%**
	Tax Credits and Payment Adjustments ($M)																				
32	SR&ED Investment	(18.4)	(18.4)		(18.4)	(18.4)	(18.4)		(18.4)	(18.4)	(18.4)		(18.4)	(18.4)	(18.4)		(18.4)	(18.4)	(18.4)		(18.4)
	Taxable Income Adjustments ($M)																				
	Additions																				
33	Depreciation and Amortization	346.9	373.9		373.9	378.7	405.7		405.7	384.0	411.0		411.0	524.9	551.9		551.9	338.1	327.3		327.3
34	Pension and OPEB Accrual	272.0	291.2		291.2	280.4	298.7		298.7	289.5	343.3		343.3	271.3	352.3		352.3	279.9	359.2		359.2
35	Regulatory Liability Amortization - Income and Other Taxes Variance Acct	(2.2)	(2.2)		(2.2)	(2.2)	(2.2)		(2.2)	-	-		-	-	-		-	-	-		-
36	Regulatory Asset Amortization - Bruce Lease Net Revenues Variance Acct	(24.0)	(24.0)		(24.0)	(24.0)	(24.0)		(24.0)	-	-		-	-	-		-	-	-		-
37	Taxable SR&ED Investment Tax Credits	18.4	18.4		18.4	18.4	18.4		18.4	18.4	18.4		18.4	18.4	18.4		18.4	18.4	18.4		18.4
38	Adjustment Related to Financing Cost for Nuclear Liabilities	39.6	25.9		25.9	37.1	22.1		22.1	34.5	18.3		18.3	31.9	14.5		14.5	30.2	12.4		12.4
39	Nuclear Waste Management Expenses	57.8	63.9		63.9	59.8	63.2		63.2	72.1	77.9		77.9	61.9	66.5		66.5	63.1	68.8		68.8
40	Receipts from Nuclear Segregated Funds	85.0	84.4		84.4	108.3	85.7		85.7	140.0	120.4		120.4	208.4	152.0		152.0	191.6	193.7		193.7
41	Other	63.7	63.7		63.7	49.2	49.2		49.2	38.4	38.4		38.4	38.6	38.6		38.6	40.2	40.2		40.2
42	**Total Additions**	**857.2**	**895.2**	**-**	**895.2**	**905.7**	**916.9**	**-**	**916.9**	**976.8**	**1,027.6**	**-**	**1,027.6**	**1,155.4**	**1,194.1**	**-**	**1,194.1**	**961.4**	**1,019.9**	**-**	**1,019.9**
	Deductions																				
43	CCA	394.2	394.2		394.2	504.4	504.4		504.4	571.1	571.1		571.1	594.8	594.8		594.8	597.0	597.0		597.0
44	Cash Expenditures for Nuclear Waste & Decomissioning	166.0	217.5		217.5	177.4	227.9		227.9	200.6	232.8		232.8	230.7	283.6		283.6	228.0	317.0		317.0
45	Contributions to Nuclear Segregated Funds	156.1	-		-	175.3	-		-	265.7	-		-	35.2	-		-	35.2	-		-
46	Pension Plan Contributions	171.1	200.0		200.0	175.5	202.9		202.9	180.3	243.5		243.5	157.2	247.9		247.9	162.1	250.6		250.6
47	OPEB/SPP Payments	100.9	91.1		91.1	104.9	95.7		95.7	109.2	99.9		99.9	114.1	104.3		104.3	117.8	108.5		108.5
48	Deductible SR&ED Qualifying Expenditures	27.7	27.7		27.7	27.7	27.7		27.7	27.7	27.7		27.7	27.7	27.7		27.7	27.7	27.7		27.7
49	Other	20.3	20.3		20.3	0.1	0.1		0.1	1.1	1.1		1.1	5.7	5.7		5.7	16.5	16.5		16.5
50	**Total Deductions**	**1,036.2**	**950.9**	**-**	**950.9**	**1,165.4**	**1,058.8**	**-**	**1,058.8**	**1,355.7**	**1,176.0**	**-**	**1,176.0**	**1,165.4**	**1,264.1**	**-**	**1,264.1**	**1,184.3**	**1,317.4**	**-**	**1,317.4**

Line No.	Description	Deferral Accounts							
		2017				2018			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Hydroelectric Facilities ($M)								
51	Hydroelectric Water Conditions Variance	(8.7)	(8.7)		(8.7)	(8.7)	(8.7)		(8.7)
52	Ancillary Services Net Revenue Variance - Hydroelectric	(6.6)	(6.6)		(6.6)	(6.6)	(6.6)		(6.6)
53	Hydroelectric Incentive Mechanism Variance	(0.0)	(0.0)		(0.0)	(0.0)	(0.0)		(0.0)
54	Hydroelectric Surplus Baseload Generation Variance	41.2	41.2		41.2	41.2	41.2		41.2
55	Income and Other Taxes Variance - Hydroelectric	(0.0)	(0.0)		(0.0)	(0.0)	(0.0)		(0.0)
56	Capacity Refurbishment Variance - Hydroelectric	1.6	1.6		1.6	1.6	1.6		1.6
57	Pension and OPEB Cost Variance - Hydroelectric - Future	1.1	1.1		1.1	1.1	1.1		1.1
58	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions	5.9	5.9		5.9	5.9	5.9		5.9
59	Pension & OPEB Cash Payment Variance - Hydroelectric	2.1	2.1		2.1	2.1	2.1		2.1
60	Hydroelectric Deferral and Variance Over/Under Recovery Variance	6.7	6.7		6.7	6.7	6.7		6.7
61	**Total**	**43.4**	**43.4**	**-**	**43.4**	**43.4**	**43.4**	**-**	**43.4**
	Nuclear Facilities ($M)								
62	Nuclear Development Variance	0.9	0.9		0.9	0.9	0.9		0.9
63	Ancillary Services Net Revenue Variance - Nuclear	0.5	0.5		0.5	0.5	0.5		0.5
64	Capacity Refurbishment Variance - Nuclear - Capital Portion	(18.8)	(18.8)		(18.8)	(18.8)	(18.8)		(18.8)
65	Capacity Refurbishment Variance - Nuclear - Non-Capital Portion	(15.8)	(15.8)		(15.8)	(15.8)	(15.8)		(15.8)
66	Bruce Lease Net Revenues Variance - Derivative Sub-Account	(34.3)	(34.3)		(34.3)	(34.3)	(34.3)		(34.3)
67	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions	10.3	10.3		10.3	10.3	10.3		10.3
68	Income and Other Taxes Variance - Nuclear	(2.2)	(2.2)		(2.2)	(2.2)	(2.2)		(2.2)
69	Pension and OPEB Cost Variance - Nuclear - Future	21.5	21.5		21.5	21.5	21.5		21.5
70	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	113.1	113.1		113.1	113.1	113.1		113.1
71	Pension & OPEB Cash Payment Variance - Nuclear	11.7	11.7		11.7	11.7	11.7		11.7
72	Nuclear Deferral and Variance Over/Under Recovery Variance	22.1	22.1		22.1	22.1	22.1		22.1
73	**Total**	**108.9**	**108.9**	**-**	**108.9**	**108.9**	**108.9**	**-**	**108.9**

OPG Rate Base and Cost of Capital

Line No.	Description	Total Generating Facilities 2017 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	Nuclear Facilities 2018 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	2019 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	2020 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	2021 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
1	Nuclear Rate Base Financed by Capital Structure ($M)	3,344.4	3,344.4	-	3,344.4	3,513.9	3,513.9	-	3,513.9	3,449.8	3,449.8	-	3,449.8	7,494.0	7,494.0	-	7,494.0	7,959.1	7,959.1	-	7,959.1
2	Nuclear Allocation Factor	30.90%	30.90%	0.00%	30.90%	31.96%	31.96%	0.00%	31.96%	31.58%	31.58%	0.00%	31.58%	49.70%	49.70%	0.00%	49.70%	50.88%	50.88%	0.00%	50.88%

Line No.	Description	Nuclear Facilities 2017 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	2018 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	2019 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	2020 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	2021 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
Capitalization ($M)																					
3	Total Rate Base	4,119.8	3,868.4	-	3,868.4	4,239.0	3,960.6	-	3,960.6	4,124.7	3,819.3	-	3,819.3	8,118.6	7,786.2	-	7,786.2	8,549.2	8,208.6	-	8,208.6
4	Adjustment for Lesser of UNL/ARC	775.4	524.0	-	524.0	725.1	446.7	-	446.7	674.9	369.5	-	369.5	624.6	292.2	-	292.2	590.1	249.6	-	249.6
5	**Rate Base Financed by Capital Structure**	**3,344.4**	**3,344.4**	**-**	**3,344.4**	**3,513.9**	**3,513.9**	**-**	**3,513.9**	**3,449.8**	**3,449.8**	**-**	**3,449.8**	**7,494.0**	**7,494.0**	**-**	**7,494.0**	**7,959.1**	**7,959.1**	**-**	**7,959.1**
6	**Common Equity**	**1,638.7**	**1,638.7**	**-**	**1,638.7**	**1,721.8**	**1,721.8**	**-**	**1,721.8**	**1,690.4**	**1,690.4**	**-**	**1,690.4**	**3,672.1**	**3,672.1**	**-**	**3,672.1**	**3,899.9**	**3,899.9**	**-**	**3,899.9**
7	Total Debt	1,705.6	1,705.6	-	1,705.6	1,792.1	1,792.1	-	1,792.1	1,759.4	1,759.4	-	1,759.4	3,821.9	3,821.9	-	3,821.9	4,059.1	4,059.1	-	4,059.1
8	Short-Term Debt	11.5	11.5	-	11.5	11.8	11.8	-	11.8	11.7	11.7	-	11.7	18.4	18.4	-	18.4	18.9	18.9	-	18.9
9	Existing and Planned Long-Term Debt	889.5	889.5	-	889.5	1,012.6	1,012.6	-	1,012.6	1,102.1	1,102.1	-	1,102.1	1,753.1	1,753.1	-	1,753.1	1,733.0	1,733.0	-	1,733.0
10	**Other Long-Term Debt Provision**	**804.6**	**804.6**	**-**	**804.6**	**767.7**	**767.7**	**-**	**767.7**	**645.6**	**645.6**	**-**	**645.6**	**2,050.4**	**2,050.4**	**-**	**2,050.4**	**2,307.3**	**2,307.3**	**-**	**2,307.3**
Cost of Capital ($M)																					
11	Adjustment for Lesser of UNL/ARC	39.6	25.9	-	25.9	37.1	22.1	-	22.1	34.5	18.3	-	18.3	31.9	14.5	-	14.5	30.2	12.4	-	12.4
12	**Common Equity**	**150.6**	**143.9**	**-**	**143.9**	**158.2**	**151.2**	**-**	**151.2**	**155.3**	**148.4**	**-**	**148.4**	**337.5**	**322.4**	**-**	**322.4**	**358.4**	**342.4**	**-**	**342.4**
13	Existing and Planned Long-Term Debt	43.5	43.5	-	43.5	46.6	46.6	-	46.6	49.8	49.8	-	49.8	78.8	78.8	-	78.8	77.6	77.6	-	77.6
14	Other Long-Term Debt Provision	39.3	39.3	-	39.3	35.3	35.3	-	35.3	29.2	29.2	-	29.2	92.1	92.1	-	92.1	103.4	103.4	-	103.4

Numbers may not add due to rounding

OPG Regulatory Income Taxes

		Nuclear Generating Facilities																			
		2017				2018				2019				2020				2021			
Line No.	Description	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Applicable Tax Rates																				
1	Federal Rate	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%	15.00%	15.00%	0.00%	15.00%
2	Provincial Rate	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%	10.00%	10.00%	0.00%	10.00%
3	**Total Tax Rate**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**	**25.00%**	**25.00%**	0.00%	**25.00%**
	Taxable Income ($M)																				
4	Earnings Before Tax	198.3	171.2	-	171.2	214.2	152.5	-	152.5	222.8	160.5	-	160.5	470.8	413.7	-	413.7	503.2	383.6	-	383.6
5	Adjustments: Additions	857.2	895.2	-	895.2	905.7	916.9	-	916.9	976.8	1,027.6	-	1,027.6	1,155.4	1,194.1	-	1,194.1	961.4	1,019.9	-	1,019.9
6	Adjustments: Deductions	1,036.2	950.9	-	950.9	1,165.4	1,058.8	-	1,058.8	1,355.7	1,176.0	-	1,176.0	1,165.4	1,264.1	-	1,264.1	1,184.3	1,317.4	-	1,317.4
7	Tax Loss Carry Over	(19.3)	-		-	45.5	-		-	156.1	-		-	(182.3)	-		-	-	-		-
8	**Total Taxable Income**	**0.0**	**115.5**	-	**115.5**	**0.0**	**10.6**	-	**10.6**	**0.0**	**12.0**	-	**12.0**	**278.4**	**343.7**	-	**343.7**	**280.2**	**86.2**	-	**86.2**
	Income Taxes ($M)																				
9	Federal Income Taxes	0.0	17.3	-	17.3	0.0	1.6	-	1.6	0.0	1.8	-	1.8	41.8	51.6	-	51.6	42.0	12.9	-	12.9
10	Provincial Income Taxes	0.0	11.6	-	11.6	0.0	1.1	-	1.1	0.0	1.2	-	1.2	27.8	34.4	-	34.4	28.0	8.6	-	8.6
11	Tax Credits (SR&ED Investment)	(18.4)	(18.4)	-	(18.4)	(18.4)	(18.4)	-	(18.4)	(18.4)	(18.4)	-	(18.4)	(18.4)	(18.4)	-	(18.4)	(18.4)	(18.4)	-	(18.4)
12	**Total Income Taxes**	**(18.4)**	**10.5**	-	**10.5**	**(18.4)**	**(15.8)**	-	**(15.8)**	**(18.4)**	**(15.4)**	-	**(15.4)**	**51.2**	**67.5**	-	**67.5**	**51.7**	**3.2**	-	**3.2**
	Earnings Before Tax ($M)																				
13	**Requested After Tax ROE**	**150.6**	**143.9**	-	**143.9**	**158.2**	**151.2**	-	**151.2**	**155.3**	**148.4**	-	**148.4**	**337.5**	**322.4**	-	**322.4**	**358.4**	**342.4**	-	**342.4**
14	Bruce Lease Net Revenues	(66.1)	(16.9)	-	(16.9)	(74.3)	(17.1)	-	(17.1)	(85.9)	(27.4)	-	(27.4)	(82.1)	(23.8)	-	(23.8)	(93.1)	(38.1)	-	(38.1)
15	Total Regulatory Income Taxes After Tax Loss Carry-Over	(18.4)	10.5		10.5	(18.4)	(15.8)		(15.8)	(18.4)	(15.4)		(15.4)	51.2	67.5		67.5	51.7	3.2		3.2
16	**Total Earnings Before Tax**	**198.3**	**171.2**	-	**171.2**	**214.2**	**152.5**	-	**152.5**	**222.8**	**160.5**	-	**160.5**	**470.8**	**413.7**	-	**413.7**	**503.2**	**383.6**	-	**383.6**
	Adjustments ($M)																				
	Additions																				
16	Depreciation and Amortization	346.9	373.9	-	373.9	378.7	405.7	-	405.7	384.0	411.0	-	411.0	524.9	551.9	-	551.9	338.1	327.3	-	327.3
17	Pension and OPEB Accrual	272.0	291.2	-	291.2	280.4	298.7	-	298.7	289.5	343.3	-	343.3	271.3	352.3	-	352.3	279.9	359.2	-	359.2
18	Regulatory Liability Amortization - Income and Other Taxes Variance Account	(2.2)	(2.2)	-	(2.2)	(2.2)	(2.2)	-	(2.2)	-	-	-	-	-	-	-	-	-	-	-	-
19	Regulatory Asset Amortization - Bruce Regulatory Asset	(24.0)	(24.0)	-	(24.0)	(24.0)	(24.0)	-	(24.0)	-	-	-	-	-	-	-	-	-	-	-	-
20	Taxable SR&ED Investment Tax Credits	18.4	18.4	-	18.4	18.4	18.4	-	18.4	18.4	18.4	-	18.4	18.4	18.4	-	18.4	18.4	18.4	-	18.4
21	Adjustment Related to Financing Cost for Nuclear Liabilities	39.6	25.9	-	25.9	37.1	22.1	-	22.1	34.5	18.3	-	18.3	31.9	14.5	-	14.5	30.2	12.4	-	12.4
22	Nuclear Waste Management Expenses	57.8	63.9	-	63.9	59.8	63.2	-	63.2	72.1	77.9	-	77.9	61.9	66.5	-	66.5	63.1	68.8	-	68.8
23	Receipts from Nuclear Segregated Funds	85.0	84.4	-	84.4	108.3	85.7	-	85.7	140.0	120.4	-	120.4	208.4	152.0	-	152.0	191.6	193.7	-	193.7
24	Other	63.7	63.7	-	63.7	49.2	49.2	-	49.2	38.4	38.4	-	38.4	38.6	38.6	-	38.6	40.2	40.2	-	40.2
25	**Total Additions**	**857.2**	**895.2**	-	**895.2**	**905.7**	**916.9**	-	**916.9**	**976.8**	**1,027.6**	-	**1,027.6**	**1,155.4**	**1,194.1**	-	**1,194.1**	**961.4**	**1,019.9**	-	**1,019.9**
	Deductions																				
26	CCA	394.2	394.2	-	394.2	504.4	504.4	-	504.4	571.1	571.1	-	571.1	594.8	594.8	-	594.8	597.0	597.0	-	597.0
27	Cash Expenditures for Nuclear Waste & Decomissioning	166.0	217.5	-	217.5	177.4	227.9	-	227.9	200.6	232.8	-	232.8	230.7	283.6	-	283.6	228.0	317.0	-	317.0
28	Contributions to Nuclear Segregated Funds and Earnings	156.1	-	-	-	175.3	-	-	-	265.7	-	-	-	35.2	-	-	-	35.2	-	-	-
29	Pension Plan Contributions	171.1	200.0	-	200.0	175.5	202.9	-	202.9	180.3	243.5	-	243.5	157.2	247.9	-	247.9	162.1	250.6	-	250.6
30	OPEB Payments	100.9	91.1	-	91.1	104.9	95.7	-	95.7	109.2	99.9	-	99.9	114.1	104.3	-	104.3	117.8	108.5	-	108.5
31	SR&ED Costs Capitalized for Accounting	27.7	27.7	-	27.7	27.7	27.7	-	27.7	27.7	27.7	-	27.7	27.7	27.7	-	27.7	27.7	27.7	-	27.7
32	Other	20.3	20.3	-	20.3	0.1	0.1	-	0.1	1.1	1.1	-	1.1	5.7	5.7	-	5.7	16.5	16.5	-	16.5
33	**Total Deductions**	**1,036.2**	**950.9**	-	**950.9**	**1,165.4**	**1,058.8**	-	**1,058.8**	**1,355.7**	**1,176.0**	-	**1,176.0**	**1,165.4**	**1,264.1**	-	**1,264.1**	**1,184.3**	**1,317.4**	-	**1,317.4**

Numbers may not add due to rounding

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OPG Revenue Requirement

Line No.	Description	Nuclear Facilities																			
		2017				2018				2019				2020				2021			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Cost of Capital ($M)																				
1	Short-term Debt	0.9	0.9	0.0	0.9	1.1	1.1	0.0	1.1	1.2	1.2	0.0	1.2	1.9	1.9	0.0	1.9	1.9	1.9	0.0	1.9
2	Long-Term Debt	82.8	82.8	0.0	82.8	81.9	81.9	0.0	81.9	79.0	79.0	0.0	79.0	170.9	170.9	0.0	170.9	181.0	181.0	0.0	181.0
3	ROE	150.6	143.9	0.0	143.9	158.2	151.2	0.0	151.2	155.3	148.4	0.0	148.4	337.5	322.4	0.0	322.4	358.4	342.4	0.0	342.4
4	Adjustment for Lesser of UNL/ARC	39.6	25.9		25.9	37.1	22.1		22.1	34.5	18.3		18.3	31.9	14.5		14.5	30.2	12.4		12.4
5	**Total**	**273.9**	**253.5**	0.0	253.5	**278.2**	**256.2**	0.0	256.2	**270.1**	**246.9**	0.0	246.9	**542.1**	**509.6**	0.0	509.6	**571.5**	**537.7**	0.0	537.7
	Expenses ($M)																				
6	OM&A	2,318.6	2,346.0	0.0	2,346.0	2,327.1	2,351.4	0.0	2,351.4	2,347.9	2,425.1	0.0	2,425.1	2,368.0	2,469.0	0.0	2,469.0	2,248.7	2,349.1	0.0	2,349.1
7	Fuel	219.9	218.2	0.0	218.2	222.0	219.9	0.0	219.9	233.1	232.1	0.0	232.1	228.2	224.4	0.0	224.4	212.7	209.1	0.0	209.1
8	Depreciation/Amortization	346.9	373.9	0.0	373.9	378.7	405.7	0.0	405.7	384.0	411.0	0.0	411.0	524.9	551.9	0.0	551.9	338.1	327.3	0.0	327.3
9	Property Taxes	14.6	14.6	0.0	14.6	14.9	14.9	0.0	14.9	15.3	15.3	0.0	15.3	15.7	15.7	0.0	15.7	17.0	17.0	0.0	17.0
10	**Total**	**2,900.0**	**2,952.6**	0.0	2,952.6	**2,942.8**	**2,991.9**	0.0	2,991.9	**2,980.3**	**3,083.5**	0.0	3,083.5	**3,136.7**	**3,261.0**	0.0	3,261.0	**2,816.5**	**2,902.5**	0.0	2,902.5
	Other Revenues ($M)																				
11	Bruce Lease Net Revenues	(66.1)	(16.9)		(16.9)	(74.3)	(17.1)		(17.1)	(85.9)	(27.4)		(27.4)	(82.1)	(23.8)		(23.8)	(93.1)	(38.1)		(38.1)
12	Ancillary and Other Revenue	31.7	31.7	0.0	31.7	22.0	22.0	0.0	22.0	22.7	22.7	0.0	22.7	22.2	22.2	0.0	22.2	22.9	22.9	0.0	22.9
13	**Total**	**(34.5)**	**14.8**	0.0	14.8	**(52.4)**	**4.9**	0.0	4.9	**(63.2)**	**(4.7)**	0.0	(4.7)	**(59.9)**	**(1.6)**	0.0	(1.6)	**(70.2)**	**(15.1)**	0.0	(15.1)
14	**Regulatory Income Tax** ($M)	**(18.4)**	**10.5**	0.0	10.5	**(18.4)**	**(15.8)**	26.2	10.5	**(18.4)**	**(15.4)**	25.9	10.5	**51.2**	**67.5**	0.0	67.5	**51.7**	**3.2**	0.0	3.2
15	**Revenue Requirement** ($M)	**3,189.9**	**3,201.8**	0.0	3,201.8	**3,255.0**	**3,227.5**	26.2	3,253.8	**3,295.1**	**3,319.8**	25.9	3,345.7	**3,790.0**	**3,839.8**	0.0	3,839.8	**3,509.8**	**3,458.4**	0.0	3,458.4

Numbers may not add due to rounding

OPG Revenue Requirement Deficiency / (Sufficiency)

		Nuclear Facilities																			
		2017				2018				2019				2020				2021			
Line No.	Description	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Production & Revenue																				
1	Forecast Production (TWh)	38.1	38.1	0.0	38.1	38.5	38.5	0.0	38.5	39.0	39.0	0.0	39.0	37.4	37.4	0.0	37.4	35.4	35.4	0.0	35.4
2	Current Payment Rate ($/MWh)	59.29	59.29	0.00	59.29	59.29	59.29	0.00	59.29	59.29	59.29	0.00	59.29	59.29	59.29	0.00	59.29	59.29	59.29	0.00	59.29
3	**Revenue From Current Payment Rate ($M)**	**2,258.9**	**2,258.9**	**0.0**	**2,258.9**	**2,280.9**	**2,280.9**	**0.0**	**2,280.9**	**2,313.9**	**2,313.9**	**0.0**	**2,313.9**	**2,214.8**	**2,214.8**	**0.0**	**2,214.8**	**2,097.9**	**2,097.9**	**0.0**	**2,097.9**
	Revenue Requirement																				
4	Revenue Requirement ($M)	3,189.9	3,201.8	0.0	3,201.8	3,255.0	3,227.5	26.2	3,253.8	3,295.1	3,319.8	25.9	3,345.7	3,790.0	3,839.8	0.0	3,839.8	3,509.8	3,458.4	0.0	3,458.4
5	**Revenue Requirement Deficiency (Sufficiency)** ($M)	**931.1**	**943.0**	0.0	**943.0**	**974.0**	**946.6**	26.2	**972.8**	**981.2**	**1,005.9**	25.9	**1,031.8**	**1,575.2**	**1,625.0**	0.0	**1,625.0**	**1,411.9**	**1,360.6**	0.0	**1,360.6**

Numbers may not add due to rounding

OPG Requested Payment Amounts

		Hydroelectric Facilities																			
		2017				2018				2019				2020				2021			
Line No.	Description	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
1	**Requested Payment Amount ($/MWh)**	41.71	41.71		41.71	42.33	42.33		42.33	42.97	42.97		42.97	43.61	43.61		43.61	44.27	44.27		44.27

		Nuclear Facilities																			
		2017				2018				2019				2020				2021			
Line No.	Description	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
2	Revenue Requirement ($M)	3,189.9	3,201.8	0.0	3,201.8	3,255.0	3,227.5	26.2	3,253.8	3,295.1	3,319.8	25.9	3,345.7	3,790.0	3,839.8	0.0	3,839.8	3,509.8	3,458.4	0.0	3,458.4
3	Stretch Adjustment ($M)	N/A	N/A	N/A	N/A	5.0	5.0	0.0	5.0	10.2	10.2	0.0	10.2	15.3	15.3	0.0	15.3	20.6	20.6	0.0	20.6
4	Forecast Production (TWh)	38.1	38.1	0.0	38.1	38.5	38.5	0.0	38.5	39.0	39.0	0.0	39.0	37.4	37.4	0.0	37.4	35.4	35.4	0.0	35.4
5	**Unsmoothed Payment Amount ($/MWh)**	83.73	84.04	-	84.04	84.48	83.77	-	84.45	84.17	84.81	-	85.47	101.05	102.38	-	102.38	98.61	97.16	-	97.16
6	**Smoothed Payment Amount (11%)**	65.81	65.81	-	65.81	73.05	73.05	-	73.05	81.09	81.09	-	81.09	90.01	90.01	-	90.01	99.91	99.91	-	99.91

Numbers may not add due to rounding

OPG Recovery of Deferral and Variance Accounts and Riders

Line No.	Description	Previously Regulated Hydroelectric Facilities Amortization 2017/2018 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	Variance Accounts ($M)				
1	Hydroelectric Water Conditions Variance	(17.3)	(17.3)	0.0	(17.3)
2	Ancillary Services Net Revenue Variance - Hydroelectric	(13.2)	(13.2)	0.0	(13.2)
3	Hydroelectric Incentive Mechanism Variance	(0.1)	(0.1)	0.0	(0.1)
4	Hydroelectric Surplus Baseload Generation Variance	82.5	82.5	0.0	82.5
5	Income and Other Taxes Variance - Hydroelectric	(0.0)	(0.0)	0.0	(0.0)
6	Capacity Refurbishment Variance - Hydroelectric	3.3	3.3	0.0	3.3
7	Pension and OPEB Cost Variance - Hydroelectric - Future	2.1	2.1	0.0	2.1
8	Pension and OPEB Cost Variance - Hydroelectric - Post 2012 Additions	11.8	11.8	0.0	11.8
9	Pension & OPEB Cash Payment Variance - Hydroelectric	4.3	4.3	0.0	4.3
10	Hydroelectric Deferral and Variance Over/Under Recovery Variance	13.5	13.5	0.0	13.5
11	**Total**	**86.8**	**86.8**	0.0	**86.8**
12	**2015 Actual Production (divided by 12, multiplied by 24)** (TWh)	**60.5**	**60.5**	0.0	**60.5**
13	**Rider** ($/MWh) (Line 12 / Line 13)	**1.44**	**1.44**	0.0	**1.44**

Line No.	Description	Nuclear Facilities Amortization 2017/2018 OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	Variance Accounts ($M)				
14	Nuclear Development Variance	1.7	1.7	0.0	1.7
15	Ancillary Services Net Revenue Variance - Nuclear	1.0	1.0	0.0	1.0
16	Capacity Refurbishment Variance - Nuclear - Capital Portion	(37.6)	(37.6)	0.0	(37.6)
17	Capacity Refurbishment Variance - Nuclear - Non-Capital Portion	(31.6)	(31.6)	0.0	(31.6)
18	Bruce Lease Net Revenues Variance - Derivative Sub-Account	(68.6)	(68.6)	0.0	(68.6)
19	Bruce Lease Net Revenues Variance - Non-Derivative Sub-Account - Post 2012 Additions	20.6	20.6	0.0	20.6
20	Income and Other Taxes Variance - Nuclear	(4.3)	(4.3)	0.0	(4.3)
21	Pension and OPEB Cost Variance - Nuclear - Future	42.9	42.9	0.0	42.9
22	Pension and OPEB Cost Variance - Nuclear - Post 2012 Additions	226.2	226.2	0.0	226.2
23	Pension & OPEB Cash Payment Variance - Nuclear	23.4	23.4	0.0	23.4
24	Nuclear Deferral and Variance Over/Under Recovery Variance	44.1	44.1	0.0	44.1
25	**Total**	**217.9**	**217.9**	0.0	**217.9**
26	**Forecast Production** (TWh)	**76.6**	**76.6**	0.0	**76.6**
27	**Rider** ($/MWh) (Line 28 / Line 29)	**2.85**	**2.85**	0.0	**2.85**

Numbers may not add due to rounding

OPG Customer Bill Impacts

Line No.	Description	Residential Consumers																			
		2013-0321/2014-0370 >> EB-2016-0152				EB-2016-0152				EB-2016-0152				EB-2016-0152				EB-2016-0152			
		2017				2018				2019				2020				2021			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Production and Demand																				
1	Typical Usage, including Line Losses[1] (kWh/Month)	789.4	789.4	n/a	789.4	789.4	789.4	n/a	789.4	789.4	789.4	n/a	789.4	789.4	789.4	n/a	789.4	789.4	789.4	n/a	789.4
2	Forecast Production (TWh)	68.3	68.3	-	68.3	68.7	68.7	-	68.7	69.3	69.3	-	69.3	67.6	67.6	-	67.6	65.6	65.6	-	65.6
3	IESO Forecast Provincial Demand[2] (TWh)	137.6	137.6	n/a	137.6	137.6	137.6	n/a	137.6	137.6	137.6	n/a	137.6	137.6	137.6	n/a	137.6	137.6	137.6	n/a	137.6
4	OPG Proportion of Consumer Usage (line 2 / line 3)	49.7%	49.7%	0.0%	49.7%	49.9%	49.9%	0.0%	49.9%	50.3%	50.3%	0.0%	50.3%	49.1%	49.1%	0.0%	49.1%	47.7%	47.7%	0.0%	47.7%
5	Typical Usage of OPG Generation (kWh/Month) (line 1 x line 4)	392	392	-	392	394	394	-	394	397	397	-	397	388	388	-	388	376	376	-	376
6	**Typical Bill[1] ($/Month)**	**150.58**	**150.58**	n/a	**150.58**	**150.58**	**150.58**	n/a	**150.58**	**150.58**	**150.58**	n/a	**150.58**	**150.58**	**150.58**	n/a	**150.58**	**150.58**	**150.58**	n/a	**150.58**
	Production-Weighted Average Rates																				
7	Prior Year weighted average rate with proposed payment amounts and riders ($/MWh)	60.66	60.66	-	60.66	57.37	57.37	-	57.37	61.76	61.76	-	61.76	64.45	64.45	-	64.45	69.26	69.26	-	69.26
8	Current Year weighted average rate with proposed payment amounts and riders ($/MWh)	57.37	57.37	-	57.37	61.76	61.76	-	61.76	64.45	64.45	-	64.45	69.26	69.26	-	69.26	74.27	74.27	-	74.27
	Impact																				
9	**Typical Bill Impact** ($/Month)	**(1.29)**	**(1.29)**	**-**	**(1.29)**	**1.73**	**1.73**	**-**	**1.73**	**1.07**	**1.07**	**-**	**1.07**	**1.86**	**1.86**	**-**	**1.86**	**1.89**	**1.89**	**-**	**1.89**
10	**Percentage Change of Typical Bill** (line 9 / line 6)	**-0.9%**	**-0.9%**	**0.0%**	**-0.9%**	**1.1%**	**1.1%**	**0.0%**	**1.1%**	**0.7%**	**0.7%**	**0.0%**	**0.7%**	**1.2%**	**1.2%**	**0.0%**	**1.2%**	**1.3%**	**1.3%**	**0.0%**	**1.3%**

Line No.	Description	2013-0321/2014-0370			
		Current Rates			
		OPG Proposed 5/27/2016	Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)
	Payment Amounts ($MWh)				
11	Regulated Hydroelectric	40.72	40.72	n/a	40.72
12	Nuclear	59.29	59.29	n/a	59.29
	Riders ($MWh)				
13	Regulated Hydroelectric	3.83	3.83	n/a	3.83
14	Nuclear	13.01	13.01	n/a	13.01
	Total Annual Rates ($MWh)				
15	Regulated Hydroelectric	44.55	44.55	n/a	44.55
16	Nuclear	72.30	72.30	n/a	72.30
	Forecast Production EB-2016-0152 (TWh)				
17	Regulated Hydroelectric	33.8	33.8	n/a	33.83
18	Nuclear	46.8	46.8	-	46.8
19	**Total**	**80.6**	**80.6**	**-**	**80.6**
	Production-Weighted Average Rates ($MWh)				
20	Regulated Hydroelectric	18.69	18.69	n/a	18.69
21	Nuclear	41.97	41.97	-	41.97
22	**Total** (line 20 + line 21)	**60.66**	**60.66**	**-**	**60.66**
23	**Total Production-Weighted Average Rate** ($MWh)	**60.66**	**60.66**	**-**	**60.66**

Line No.	Description	EB-2016-0152				EB-2016-0152				EB-2016-0152				EB-2016-0152				EB-2016-0152			
		Proposed Rates				Proposed Rates				Proposed Rates				Proposed Rates				Proposed Rates			
		2017				2018				2019				2020				2021			
		OPG Proposed 5/27/2016	N1 Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 7/9/1905	N1 Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 7/9/1905	N1 Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 7/9/1905	N1 Update 12/19/2016	OEB Adjustment	OEB Approved	OPG Proposed 7/9/1905	N1 Update 12/19/2016	OEB Adjustment	OEB Approved
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)
	Payment Amounts ($MWh)																				
24	Regulated Hydroelectric	41.71	41.71	-	41.71	42.33	42.33	-	42.33	42.97	42.97	-	42.97	43.61	43.61	-	43.61	44.27	44.27	-	44.27
25	Nuclear	65.81	65.81	-	65.81	73.05	73.05	-	73.05	81.09	81.09	-	81.09	90.01	90.01	-	90.01	99.91	99.91	-	99.91
	Riders ($MWh)																				
26	Regulated Hydroelectric	1.44	1.44	-	1.44	1.44	1.44	-	1.44												
27	Nuclear	2.85	2.85	-	2.85	2.85	2.85	-	2.85												
	Total Annual Rates ($MWh)																				
28	Regulated Hydroelectric	43.14	43.14	-	43.14	43.77	43.77	-	43.77	42.97	42.97	-	42.97	43.61	43.61	-	43.61	44.27	44.27	-	44.27
29	Nuclear	68.66	68.66	-	68.66	75.90	75.90	-	75.90	81.09	81.09	-	81.09	90.01	90.01	-	90.01	99.91	99.91	-	99.91
	Forecast Production EB-2016-0152 (TWh)																				
30	Regulated Hydroelectric	30.2	30.2	n/a	30.23	30.2	30.2	n/a	30.23	30.2	30.2	n/a	30.23	30.2	30.2	n/a	30.23	30.2	30.2	n/a	30.23
31	Nuclear	38.1	38.1	-	38.1	38.5	38.5	-	38.5	39.0	39.0	-	39.0	37.4	37.4	-	37.4	35.4	35.4	-	35.4
32	**Total**	**68.3**	**68.3**	**-**	**68.3**	**68.7**	**68.7**	**-**	**68.7**	**69.3**	**69.3**	**-**	**69.3**	**67.6**	**67.6**	**-**	**67.6**	**65.6**	**65.6**	**-**	**65.6**
	Production-Weighted Average Rates ($MWh)																				
33	Regulated Hydroelectric	19.09	19.09	n/a	19.09	19.26	19.26	n/a	19.26	18.75	18.75	n/a	18.75	19.51	19.51	n/a	19.51	20.39	20.39	n/a	20.39
34	Nuclear	38.28	38.28	-	38.28	42.50	42.50	-	42.50	45.70	45.70	-	45.70	49.75	49.75	-	49.75	53.88	53.88	-	53.88
35	**Total** (line 20 + line 21)	**57.37**	**57.37**	**-**	**57.37**	**61.76**	**61.76**	**-**	**61.76**	**64.45**	**64.45**	**-**	**64.45**	**69.26**	**69.26**	**-**	**69.26**	**74.27**	**74.27**	**-**	**74.27**
36	**Total Production-Weighted Average Rate** ($MWh)	**57.37**	**57.37**	**-**	**57.37**	**61.76**	**61.76**	**-**	**61.76**	**64.45**	**64.45**	**-**	**64.45**	**69.26**	**69.26**	**-**	**69.26**	**74.27**	**74.27**	**-**	**74.27**

Numbers may not add due to rounding

Notes:

1 Typical monthly consumption (750 kWh) and typical monthly bill are based on the OEB "Bill Calculator" for estimating monthly electricity bills (using Time of Use pricing), available at: http://www.ontarioenergyboard.ca/OEB/Consumers/Electricity/Your+Electricity+UtilityTypical Consumption includes line losses (Assumed loss factor of 1.0525)

2 Based on forecast demand for 2017 (137.6 TWh) from Table 3.1 of IESO 18-Month Outlook Update for April 2016 to September 2017, published March 22, 2016.

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Corporate and Electricity Finance Division
Assistant Deputy Minister's Office

Ontario

December 20, 2016

MEMORANDUM TO: John Mauti
Vice President, Chief Controller and Accounting Officer
Ontario Power Generation Inc.

FROM: Ronald Kwan
Assistant Deputy Minister

SUBJECT: **Ontario Nuclear Funds Agreement Reference Plan**

With a covering memo dated November 10, 2016, Ontario Power Generation Inc. (OPG) submitted its proposed 2017 Ontario Nuclear Funds Agreement (ONFA) reference plan update to the Province.

Based on our review and in accordance with section 5.4.1 of ONFA, the Province approves, effective January 1, 2017, the reference plan submitted by OPG dated as of November 10, 2016.

Provincial approval of a new reference plan constitutes a "Triggering Event" under ONFA, and ONFA prescribes a number of tasks that must be carried out by OPG following a Triggering Event.

Staff and I are prepared to work with OPG and provide feedback on OPG's proposed implementation of the calculations mandated by ONFA sections 3.6, 3.7, 3.8 and 4.6.

I look forward to continuing to work with you and other OPG officials and staff in the implementation and administration of ONFA.

Sincerely,

Ronald Kwan

cc: Marianne Nguyen
Gadi Mayman
Ken Hartwick
Christopher Ginther

Table 1
Updated Summary of Revenue Requirement - Nuclear ($M)
(Updated Ex.I1-1-1 Table 1)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note	2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
	Rate Base						
1	**Net Fixed Assets**	1,2	3,156.9	3,262.9	3,147.8	7,137.5	7,574.1
2	**Working Capital**		700.5	686.7	660.5	637.7	623.5
3	**Cash Working Capital**		11.0	11.0	11.0	11.0	11.0
4	**Total Rate Base**		3,868.4	3,960.6	3,819.3	7,786.2	8,208.6
	Capitalization						
5	**Short-term Debt**		11.5	11.8	11.7	18.4	18.9
6	**Long-Term Debt**		1,694.2	1,780.2	1,747.7	3,803.5	4,040.3
7	**Common Equity**		1,638.7	1,721.8	1,690.4	3,672.1	3,899.9
8	**Adjustment for Lesser of UNL or ARC**	1,3	524.0	446.7	369.5	292.2	249.6
9	**Total Capital**		3,868.4	3,960.6	3,819.3	7,786.2	8,208.6
	Cost of Capital						
10	**Short-term Debt**		0.9	1.1	1.2	1.9	1.9
11	**Long-Term Debt**		82.8	81.9	79.0	170.9	181.0
12	**Return on Equity**	4	143.9	151.2	148.4	322.4	342.4
13	**Adjustment for Lesser of UNL or ARC**	1,5	25.9	22.1	18.3	14.5	12.4
14	**Total Cost of Capital**		253.5	256.2	246.9	509.6	537.7
	Expenses:						
15	**OM&A**	6	2,346.0	2,351.4	2,425.1	2,469.0	2,349.1
16	**Fuel**	1,7	218.2	219.9	232.1	224.4	209.1
17	**Depreciation & Amortization**	1,8	373.9	405.7	411.0	551.9	327.3
18	**Property Tax**		14.6	14.9	15.3	15.7	17.0
19	**Total Expenses**		2,952.6	2,991.9	3,083.5	3,261.0	2,902.5
	Less:						
	Other Revenues						
20	**Bruce Lease Revenues Net of Direct Costs**	9	(16.9)	(17.1)	(27.4)	(23.8)	(38.1)
21	**Ancillary and Other Revenue**		31.7	22.0	22.7	22.2	22.9
22	**Total Other Revenues**		14.8	4.9	(4.7)	(1.6)	(15.1)
23	**Income Tax**	10	10.5	(15.8)	(15.4)	67.5	3.2
24	**Revenue Requirement Before Stretch Factor**		3,201.8	3,227.5	3,319.8	3,839.8	3,458.4
	(line 14 + line 19 - line 22 + line 23)						
25	**Previously Filed Requirement Before Stretch Factor**		3,189.9	3,255.0	3,295.1	3,790.0	3,509.8
26	**Variance Between Revised and Prefiled Revenue Requirement Before Stretch Factor**		11.9	(27.4)	24.7	49.8	(51.4)
27	**Cumulative Nuclear Stretch Dollars**		0.0	5.0	10.2	15.3	20.6
28	**Revenue Requirement Net of Stretch Factor**		3,201.8	3,222.5	3,309.6	3,824.4	3,437.8
	(line 24 - line 27)						
29	**Amortization of Variance & Deferral Account Amounts**		108.9	108.9	-	-	-
30	**Revenue Requirement Net of Stretch Factor Plus Variance & Deferral Account Amounts** (line 28 + line 29)		3,310.7	3,331.5	3,309.63	3,824.44	3,437.85
31	**Prefiled Revenue Requirement Net of Stretch Factor Plus Variance & Deferral Account Amounts**		3,298.9	3,358.9	3,285.01	3,774.80	3,489.42
32	**Variance Between Revised and Prefiled Revenue Requirement Net of Stretch Factor Plus Variance & Deferral Account Amounts**		11.9	(27.4)	24.6	49.6	(51.6)

Notes:
1 Change from pre-filed evidence is due to changes in nuclear liabilities.
2 Calculated as Ex. I1-1-1 Table 1, line 1, plus Ex. N1-1-1 Table 3, line 26, less Ex. C2-1-1, Table 2, line 26.
3 Calculated as Ex. I1-1-1 Table 1, line 8, plus Ex. N1-1-1 Table 3, line 27, less Ex. C2-1-1, Table 2, line 27.
4 Change from pre-filed evidence is due to updated OEB-published ROE value. Calculated as Ex. I1-1-1 Table 1, line 13, plus Ex. N1-1-1, Chart 3.4, line 7, less Ex. N1-1-1, Chart 3.4, line 3.
5 Calculated as Ex. I1-1-1 Table 1, line 13, plus Ex. N1-1-1 Table 2, line 4, less Ex. C2-1-1 Table 1, line 4.
6 Change from pre-filed evidence is due to changes in pension and OPEB cash amounts, nuclear liabilities, and Nuclear base OM&A expenses related to new CNSC requirements. Calculated as Ex. I1-1-1 Table 1, line 15, plus Ex. N1-1-1, Chart 3.1.2A, line 7, plus Ex. N1-1-1 Table 2, line 3, less Ex. C2-1-1 Table 1, line 3, plus incremental Nuclear base OM&A expenses related to new CNSC requirements outlined in Ex. N1-1-1 section 3.5.
7 Calculated as Ex. I1-1-1 Table 1, line 16, plus Ex. N1-1-1 Table 2, line 2, less Ex. C2-1-1, Table 1, line 2.
8 Calculated as Ex. I1-1-1 Table 1, line 17, plus Ex. N1-1-1 Table 2, line 1, less Ex. C2-1-1, Table 1, line 1.
9 Change from pre-filed evidence is due to changes in nuclear liabilities and used fuel and low and intermediate level waste revenues. Calculated as Ex. I1-1-1 Table 1, line 20, plus Ex. C2-1-1 Table 1, line 17, less Ex. N1-1-1 Table 2, line 17, plus Ex. N1-1-1, Chart 3.3, line 10, less Ex. N1-1-1, Chart 3.3, line 4.

10 Change from pre-filed evidence is due to changes in nuclear liabilities, updated OEB-published ROE value, Bruce Lease net revenues, and regualtory tax loss carry forwards during IR period. Calculated as Ex. I1-1-1 Table 1, line 23, plus Ex. N1-1-1 Table 2, lines 7 and 16, less Ex. C2-1-1 Table 1, lines 7 and 16, plus Ex. N1-1-1, Chart 3.4, line 8, plus Ex. N1-1-1, Chart 3.3, line 5, less Ex. N1-1-1, Chart 3.3, line 11, plus Ex. N1-1-1, Chart 3.2.1, line 17, plus Ex. N1-1-1, Chart 2, line 7.

Numbers may not add due to rounding.

Table 2
Updated Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
(Updated Ex. C2-1-1 Table 1)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note or Reference	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	PRESCRIBED FACILITIES						
1	**Depreciation of Asset Retirement Costs**	Ex. N1-1-1 Table 3	77.3	77.3	77.3	77.3	7.9
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. N1-1-1 Table 3	51.4	53.1	65.7	52.5	52.9
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. N1-1-1 Table 3	12.5	10.1	12.2	14.0	15.9
	Return on ARC in Rate Base:						
4	**Return on Rate Base at Weighted Average Accretion Rate**	Note 1	25.9	22.1	18.3	14.5	12.4
5	**Return on Rate Base at Weighted Average Cost of Capital**	Note 1	0.0	0.0	0.0	0.0	0.0
6	**Pre-Tax Revenue Requirement Impact**		167.1	162.6	173.4	158.2	89.1
7	**Income Tax Impact**	Note 2	55.7	54.2	57.8	52.7	29.7
8	**Total Revenue Requirement Impact - Prescribed Facilities** (line 6 + line 7)		222.8	216.8	231.2	211.0	118.8
	BRUCE FACILITIES						
9	**Depreciation of Asset Retirement Costs**	Ex. N1-1-1 Table 4	68.6	68.6	68.6	68.6	68.6
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. N1-1-1 Table 4	71.0	68.1	73.0	78.6	63.5
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. N1-1-1 Table 4	2.7	3.2	3.0	3.6	5.0
12	**Accretion Expense**	Ex. N1-1-1 Table 4	462.1	473.2	489.1	505.6	523.4
13	**Less: Segregated Fund Earnings (Losses)**	Ex. N1-1-1 Table 4	395.8	412.5	429.5	446.1	462.3
14	**Impact on Bruce Facilities' Income Taxes**	Note 3	(52.1)	(50.1)	(51.0)	(52.6)	(49.5)
15	**Pre-Tax Revenue Requirement Impact (Impact on Bruce Lease Net Revenues)**		156.4	150.4	153.1	157.7	148.6
16	**Income Tax Impact** (line 15 x tax rate / (1-tax rate))	Note 4	52.1	50.1	51.0	52.6	49.5
17	**Total Revenue Requirement Impact - Bruce Facilities** (line 15 + line 16)		208.6	200.5	204.1	210.3	198.1
18	**Total Revenue Requirement Impact - Prescribed and Bruce Facilities**		431.4	417.3	435.4	421.2	316.9
	(line 8 + line 17)						

See Ex. N1-1-1 Table 2a for notes

Table 2a
Updated Revenue Requirement Impact of OPG's Nuclear Liabilities ($M)
Years Ending December 31, 2017 to 2021
(Updated Ex. C2-1-1 Table 1a)
Notes to Ex. N1-1-1, Table 2

Notes:
1 The lesser of average Unfunded Nuclear Liabilities (UNL) and average Asset Retirement Costs (ARC) for the prescribed facilities earns the weighted average accretion rate. The amount, if any, by which average ARC exceeds average UNL earns the weighted average cost of capital (WACC).

Table to Note 1

Line No.	Year	*(from Ex. N1-1-1 Table 3, line 26)* Average ARC ($M)	*(from Ex. N1-1-1 Table 3, line 20)* Average UNL ($M)	*(a) - (b)* ARC-UNL ($M)	Weighted Average Accretion Rate#	WACC Rate+	*col. (d) x Ex. N1-1-1 Table 3, line 27* Return on Rate Base at Accretion Rate ($M)	*(c) x (e) if >0* Return on Rate Base at WACC ($M)
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1a	2017	524.0	770.1	(246.1)	4.95%	6.80%	25.9	0.0
2a	2018	446.7	757.8	(311.1)	4.95%	6.66%	22.1	0.0
3a	2019	369.5	755.7	(386.3)	4.95%	6.63%	18.3	0.0
4a	2020	292.2	759.2	(467.0)	4.95%	6.61%	14.5	0.0
5a	2021	249.6	752.1	(502.5)	4.95%	6.60%	12.4	0.0

From Ex. N1-1-1, section 3.3.2
+ Reflects the 2017 ROE value published by the OEB on October 27, 2016 (see Ex. N1-1-1, section 3.4)

2 The income tax impact for prescribed facilities is calculated as follows:

Table to Note 2 ($M)

Line No.	Item	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)
1b	Regulatory Taxable Income Before Impact of Segregated Fund Contributions (Ex. N1-1-1, Table 2, line 6)	167.1	162.6	173.4	158.2	89.1
2b	Contributions to Nuclear Segregated Funds for Prescribed Facilities (Ex. N1-1-1 Table 3, line 14)	0.0	0.0	0.0	0.0	0.0
3b	Net Increase in Regulatory Taxable Income (line 1b - line 2b)	167.1	162.6	173.4	158.2	89.1
4b	Income Tax Rate (Note 4)	25.00%	25.00%	25.00%	25.00%	25.00%
5b	Income Tax Impact (line 3b x line 4b / (1 - line 4b))	55.7	54.2	57.8	52.7	29.7

3 The impact on Bruce facilities' income taxes relates to higher deductible temporary differences associated with expenses not deductible for tax purposes, as follows:

Table to Note 3 ($M)

Line No.	Item	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
		(a)	(b)	(c)	(d)	(e)
1c	Increase in Temporary Differences (Ex. N1-1-1 Table 2, lines 9 through 13)	208.6	200.5	204.1	210.3	198.1
2c	Income Tax Rate (Note 4)	25.00%	25.00%	25.00%	25.00%	25.00%
3c	Impact on Bruce Facilities' Income Taxes (line 1c x line 2c)	(52.1)	(50.1)	(51.0)	(52.6)	(49.5)

4 Income tax rates are from Ex. F4-2-1 Table 3a, line 29.

Table 3
Prescribed Facilities - Updated Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
(Updated Ex. C2-1-1 Table 2)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	ASSET RETIREMENT OBLIGATION						
1	**2016 Projected Closing Balance Before Year-End Adjustments**		9,246.3				
2	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(237.9)				
3	**Projected 2012 CNSC Requirements Adjustment at Year-End 2016**	2	2.2				
4	**Opening Balance** (col. (a): line 1 + line 2 + line 3)		9,010.6	9,347.5	9,677.7	10,033.6	10,342.6
5	**Used Fuel Storage and Disposal Variable Expenses**	3	51.4	53.1	65.7	52.5	52.9
6	**Low & Intermediate Level Waste Management Variable Expenses**	4	12.5	10.1	12.2	14.0	15.9
7	**Accretion Expense**		490.5	495.0	510.8	526.1	541.6
8	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(217.5)	(227.9)	(232.8)	(283.6)	(317.0)
9	**Consolidation and Other Adjustments**		0.0	0.0	0.0	0.0	0.0
10	**Closing Balance** (lines 4 through 9)		9,347.5	9,677.7	10,033.6	10,342.6	10,636.0
11	**Average Asset Retirement Obligation** ((line 4 + line 10)/2)		9,179.0	9,512.6	9,855.7	10,188.1	10,489.3
	NUCLEAR SEGREGATED FUNDS BALANCE						
12	**Opening Balance**		8,240.1	8,577.8	8,931.7	9,268.2	9,589.6
13	**Earnings (Losses)**		422.2	439.6	456.9	473.4	488.9
14	**Contributions**		0.0	0.0	0.0	0.0	0.0
15	**Disbursements**		(84.4)	(85.7)	(120.4)	(152.0)	(193.7)
16	**Closing Balance** (lines 12 through 15)		8,577.8	8,931.7	9,268.2	9,589.6	9,884.9
17	**Average Nuclear Segregated Funds Balance** ((line 12 + line 16)/2)		8,409.0	8,754.8	9,099.9	9,428.9	9,737.2
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)						
18	**Opening Balance** (line 4 - line 12)		770.5	769.6	746.0	765.4	752.9
19	**Closing Balance** (line 10 - line 16)		769.6	746.0	765.4	752.9	751.2
20	**Average Unfunded Nuclear Liability Balance** ((line 18 + line 19)/2)		770.1	757.8	755.7	759.2	752.1
	ASSET RETIREMENT COSTS (ARC)						
21	**2016 Projected Closing Balance Before Year-End Adjustments**		800.5				
22	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(237.9)				
23	**Opening Balance** (col. (a): line 21 + line 22)		562.6	485.4	408.1	330.8	253.5
24	**Depreciation Expense**		(77.3)	(77.3)	(77.3)	(77.3)	(7.9)
25	**Closing Balance Before Year-End Adjustments** (line 23 + line 24)		485.4	408.1	330.8	253.5	245.6
26	**Average Asset Retirement Costs** ((line 23 + line 25)/2)		524.0	446.7	369.5	292.2	249.6
27	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 20 or line 26)		524.0	446.7	369.5	292.2	249.6

Notes:
1 Adjustment expected to be recorded on December 31, 2016 per Ex. N1-1-1 Table 5, associated with the 2017 Approved ONFA Reference Plan.
2 Adjustment expected to be recorded on December 31, 2016 associated with the change to the previous cost estimates related to the implementation of new CNSC requirements in 2012 to include certain facilities with Waste Nuclear Substance Licences. Although these facilities were not included in the 2012 ONFA Reference Plan (see Ex. C2-1-1 Table 2, Note 6), they are included in the 2017 ONFA Reference Plan. As a result, the ARO is projected to increase by $4.4M at December 31, 2016, of which $2.2M is attributed to the prescribed facilities and $2.2M to the Bruce facilities. In accordance with GAAP, this amount will be expensed in 2016 (i.e. not included in ARC), as it relates to a legacy facility that is not used to support OPG's current operations.
3 See Ex. C2-1-1 Table 2, Note 3.
4 See Ex. C2-1-1 Table 2, Note 4.

Table 4
Bruce Facilities - Updated Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
(Updated Ex. C2-1-1 Table 3)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	ASSET RETIREMENT OBLIGATION						
1	**2016 Projected Closing Balance Before Year-End Adjustments**		11,373.1				
2	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(1,291.8)				
3	**Projected 2012 CNSC Requirements Adjustment at Year-End 2016**	2	2.2				
4	**Opening Balance** (col. (a): line 1 + line 2 + line 3)		10,083.5	10,462.3	10,842.5	11,209.0	11,595.8
5	**Used Fuel Storage and Disposal Variable Expenses**		71.0	68.1	73.0	78.6	63.5
6	**Low & Intermediate Level Waste Management Variable Expenses**		2.7	3.2	3.0	3.6	5.0
7	**Accretion Expense**		462.1	473.2	489.1	505.6	523.4
8	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(157.0)	(164.2)	(198.6)	(201.0)	(215.7)
9	**Consolidation and Other Adjustments**		0.0	0.0	0.0	0.0	0.0
10	**Closing Balance** (lines 4 through 9)		10,462.3	10,842.5	11,209.0	11,595.8	11,972.0
11	**Average Asset Retirement Obligation** ((line 4 + line 10)/2)		10,272.9	10,652.4	11,025.8	11,402.4	11,783.9
	NUCLEAR SEGREGATED FUNDS BALANCE						
12	**Opening Balance**		7,720.1	8,045.3	8,386.9	8,722.7	9,049.2
13	**Earnings (Losses)**		395.8	412.5	429.5	446.1	462.3
14	**Contributions**		0.0	0.0	0.0	0.0	0.0
15	**Disbursements**		(70.5)	(70.9)	(93.7)	(119.7)	(144.3)
16	**Closing Balance** (line 12 through 15)		8,045.3	8,386.9	8,722.7	9,049.2	9,367.1
17	**Average Nuclear Segregated Funds Balance** ((line 12 + line 16)/2)		7,882.7	8,216.1	8,554.8	8,885.9	9,208.1
	ASSET RETIREMENT COSTS (ARC)						
18	**2016 Projected Closing Balance Before Year-End Adjustments**		4,290.7				
19	**Projected 2017 ONFA Reference Plan Adjustment at Year-End 2016**	1	(1,291.8)				
20	**Opening Balance** (col. (a): line 18 + line 19)		2,999.0	2,930.4	2,861.9	2,793.3	2,724.8
21	**Depreciation Expense**		(68.6)	(68.6)	(68.6)	(68.6)	(68.6)
22	**Closing Balance** (line 20 + line 21)		2,930.4	2,861.9	2,793.3	2,724.8	2,656.2
23	**Average Asset Retirement Costs** ((line 20 + line 22)/2))		2,964.7	2,896.1	2,827.6	2,759.0	2,690.5

Notes
1 Adjustment expected to be recorded on December 31, 2016 per Ex. N1-1-1 Table 5, associated with the Approved 2017 ONFA Reference Plan
2 See Ex. N1-1-1 Table 3, Note 2.

Numbers may not add due to rounding.

Table 5
Projected Impact of 2017 ONFA Reference Plan Adjustment - Assignment of ARO Adjustment and Allocation of ARC to Nuclear Stations ($M)
(Updated Ex. C2-1-1 Table 4)

Line No.	Description	Pickering A (Units 1-4)	Pickering B (Units 5-8)	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	OPG Total[1]
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	December 31, 2016 Projected:								
1	**Decommissioning Program**	229.3	277.7	71.2	578.2	(52.6)	(40.5)	(93.1)	485.1
2	**Low and Intermediate Level Waste Storage Program**	15.0	43.5	35.5	94.0	26.7	(2.6)	24.2	118.2
3	**Low and Intermediate Level Waste Disposal Program**	(1.2)	33.1	26.5	58.4	(29.4)	(46.4)	(75.8)	(17.4)
4	**Used Fuel Disposal Program**	(193.7)	(245.4)	(431.8)	(871.0)	(440.3)	(617.0)	(1,057.2)	(1,928.2)
5	**Used Fuel Storage Program**	(9.7)	2.5	(90.4)	(97.6)	(42.3)	(47.5)	(89.8)	(187.4)
6	**ARO Adjustment Assignment to Station Level**	39.7	111.5	(389.1)	(237.9)	(537.7)	(754.0)	(1,291.8)	(1,529.7)
7	**Asset Retirement Cost Adjustment**	39.7	111.5	(389.1)	(237.9)	(537.7)	(754.0)	(1,291.8)	(1,529.7)

Notes:
1 Excludes ARO adjustment of $4.4M expected to be recorded on December 31, 2016 associated with the change to the previous cost estimates related to the implementation of new CNSC requirements in 2012 to include certain facilities with Waste Nuclear Substance Licences. These facilities were not included in the 2012 ONFA Reference Plan but are included in the 2017 ONFA Reference Plan. See Ex. N1-1-1 Table 3, Note 2 for further details.

Numbers may not add due to rounding.

Table 6
Revenue Requirement Impact of Changes in Projected Nuclear Liabilities Costs from Pre-Filed Evidence ($M)
Years Ending December 31, 2017 to 2021

Line No.	Description	Note or Reference (for cols. (a) to (e))	Updated Projection Reflecting 2017 ONFA Reference Plan 2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Note or Reference (for cols. (f) to (j))	As Reflected in Pre-filed Evidence 2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan	Sum (a) to (e) less Sum (f) to (j) Change in Nuclear Liabilities Costs
			(a)	(b)	(c)	(d)	(e)		(f)	(g)	(h)	(i)	(j)	(k)
	PRESCRIBED FACILITIES													
1	**Depreciation of Asset Retirement Costs**	Ex. N1-1-1 Table 2	77.3	77.3	77.3	77.3	7.9	Ex. C2-1-1 Table 1	50.3	50.3	50.3	50.3	18.7	97.2
2	**Used Fuel Storage and Disposal Variable Expenses**	Ex. N1-1-1 Table 2	51.4	53.1	65.7	52.5	52.9	Ex. C2-1-1 Table 1	53.0	55.2	66.7	56.3	56.5	(12.2)
3	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. N1-1-1 Table 2	12.5	10.1	12.2	14.0	15.9	Ex. C2-1-1 Table 1	4.8	4.5	5.4	5.6	6.5	37.9
	Return on ARC in Rate Base		0.0	0.0	0.0	0.0	0.0							
4	**Return on Rate Base at Weighted Average Accretion Rate**	Ex. N1-1-1 Table 2	25.9	22.1	18.3	14.5	12.4	Ex. C2-1-1 Table 1	39.6	37.1	34.5	31.9	30.2	(80.1)
5	**Return on Rate Base at Weighted Average Cost of Capital**	Ex. N1-1-1 Table 2	0.0	0.0	0.0	0.0	0.0	Ex. C2-1-1 Table 1	0.0	0.0	0.0	0.0	0.0	0.0
6	**Pre-Tax Revenue Requirement Impact**		167.1	162.6	173.4	158.2	89.1		147.7	147.1	156.9	144.1	111.9	42.8
7	**Income Tax Impact**	Ex. N1-1-1 Table 2	55.7	54.2	57.8	52.7	29.7	Ex. C2-1-1 Table 1	(2.8)	(9.4)	(36.3)	36.3	25.6	236.8
8	**Total Revenue Requirement Impact - Prescribed Facilities** (line 6 + line 7)		222.8	216.8	231.2	211.0	118.8		144.9	137.7	120.6	180.4	137.5	279.6
	BRUCE FACILITIES													
9	**Depreciation of Asset Retirement Costs**	Ex. N1-1-1 Table 2	68.6	68.6	68.6	68.6	68.6	Ex. C2-1-1 Table 1	100.2	100.2	100.2	100.2	100.2	(158.3)
10	**Used Fuel Storage and Disposal Variable Expenses**	Ex. N1-1-1 Table 2	71.0	68.1	73.0	78.6	63.5	Ex. C2-1-1 Table 1	71.4	70.8	74.9	81.7	64.2	(8.7)
11	**Low & Intermediate Level Waste Management Variable Expenses**	Ex. N1-1-1 Table 2	2.7	3.2	3.0	3.6	5.0	Ex. C2-1-1 Table 1	2.1	2.6	2.4	2.9	4.1	3.2
12	**Accretion**	Ex. N1-1-1 Table 2	462.1	473.2	489.1	505.6	523.4	Ex. C2-1-1 Table 1	531.4	552.4	573.9	595.6	617.8	(417.7)
13	**Less: Segregated Fund Earnings (Losses)**	Ex. N1-1-1 Table 2	395.8	412.5	429.5	446.1	462.3	Ex. C2-1-1 Table 1	395.7	413.7	432.8	454.8	479.8	(30.7)
14	**Impact on Bruce Facilities' Income Taxes**	Ex. N1-1-1 Table 2	(52.1)	(50.1)	(51.0)	(52.6)	(49.5)	Ex. C2-1-1 Table 1	(77.3)	(78.1)	(79.6)	(81.4)	(76.6)	137.7
15	**Pre-Tax Revenue Requirement Impact (Impact on Bruce Lease Net Revenues)**		156.4	150.4	153.1	157.7	148.6		232.0	234.3	238.9	244.2	229.8	(413.1)
16	**Income Tax Impact**	Ex. N1-1-1 Table 2	52.1	50.1	51.0	52.6	49.5	Ex. C2-1-1 Table 1	77.3	78.1	79.6	81.4	76.6	(137.7)
17	**Total Revenue Requirement Impact - Bruce Facilities** (line 15 + line 16)		208.6	200.5	204.1	210.3	198.1		309.4	312.4	318.5	325.6	306.5	(550.8)
18	**Total Revenue Requirement Impact - Prescribed and Bruce Facilities**		431.4	417.3	435.4	421.2	316.9		454.3	450.1	439.1	506.0	444.0	(271.2)
	(line 8 + line 17)													

Numbers may not add due to rounding.

Table 7
Updated Bruce Lease Net Revenues
(Updated Ex. G2-2-1 Table 2 and Table 5)
Years Ending December 31, 2017 to 2021 ($M)

Line No.	Particulars	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	Revenues:						
1	**Site Services (OPG to Bruce Power)**		0.7	0.7	0.7	0.7	0.7
2	**Low & Intermediate Level Waste Services**		17.8	19.8	19.2	18.6	21.6
3	**Cobalt-60**		0.5	0.5	0.5	0.5	0.5
4	**Total Services Revenue**		19.1	21.0	20.4	19.8	22.8
5	**Fixed (Base) Rent**		24.5	24.8	25.1	25.4	25.7
6	**Supplemental Rent - Non-Derivative Portion**		160.4	153.0	163.0	174.5	140.1
7	**Amortization of Initial Deferred Rent**		12.1	12.1	0.0	0.0	0.0
8	**Total Non-Derivative Rent Revenue**		197.0	189.9	188.1	200.0	165.9
9	**Total Non-Derivative Revenue** (line 4 + line 8)		216.0	210.9	208.5	219.8	188.7
10	**Supplemental Rent - Derivative Portion**		0.0	0.0	0.0	0.0	0.0
11	**Total Revenue** (line 9 + line 10)		216.0	210.9	208.5	219.8	188.7
	Costs:						
12	**Depreciation**	1	69.1	69.1	69.1	69.0	69.0
13	**Property Tax**		13.0	13.3	13.6	14.0	15.1
14	**Accretion**	2	462.1	473.2	489.1	505.6	523.4
15	**(Earnings) Losses on Segregated Funds**	3	(395.8)	(412.5)	(429.5)	(446.1)	(462.3)
16	**Used Fuel Storage and Disposal**	4	71.0	68.1	73.0	78.6	63.5
17	**Waste Management Variable Expenses and Facilities Removal Costs**	5	2.7	3.2	3.0	3.6	5.0
18	**Interest**		21.1	24.1	26.7	26.8	25.8
19	**Total Costs Before Income Tax**		243.2	238.5	245.1	251.5	239.5
20	**Income Tax - Current - Non-Derivative Portion**	6	36.0	32.3	12.8	21.3	16.0
21	**Income Tax - Deferred - Non-Derivative Portion**	7	(46.3)	(42.8)	(22.0)	(29.3)	(28.7)
22	**Total Income Tax - Non-Derivative Portion**		(10.4)	(10.4)	(9.1)	(7.9)	(12.7)
23	**Total Non-Derivative Costs** (line 19 + line 22)		232.9	228.0	235.9	243.5	226.8
24	**Income Tax - Current - Derivative Portion**		0.0	0.0	0.0	0.0	0.0
25	**Income Tax - Deferred - Derivative Portion**		0.0	0.0	0.0	0.0	0.0
26	**Total Income Tax - Derivative Portion**		0.0	0.0	0.0	0.0	0.0
27	**Total Costs** (line 23 + line 26)		232.9	228.0	235.9	243.5	226.8
28	**Bruce Lease Net Revenues - Non-Derivative Portion** (line 9 - line 23)		(16.9)	(17.1)	(27.4)	(23.8)	(38.1)
29	**Bruce Lease Net Revenues - Derivative Portion** (line 10 - line 26)		0.0	0.0	0.0	0.0	0.0
30	**Total Bruce Lease Net Revenues** (line 28 + line 29)		(16.9)	(17.1)	(27.4)	(23.8)	(38.1)

Notes:
1 Calculated as Ex. G2-2-1 Table 5, line 1, cols. (e) to (i), plus Ex. N1-1-1 Table 6, line 9, cols. (a) to (e), less Ex. N1-1-1 Table 6, line 9, cols. (f) to (j).
2 From Ex. N1-1-1 Table 4, line 7.
3 From Ex. N1-1-1 Table 4, line 13.
4 From Ex. N1-1-1 Table 4, line 5.
5 From Ex. N1-1-1 Table 4, line 6.
6 From Ex. N1-1-1 Table 7a, line 20.
7 From Ex. N1-1-1 Table 7a, line 27.

Numbers may not add due to rounding.

Table 7a
Updated Calculation of Bruce Income Taxes ($M)
(Updated Ex. G2-2-1 Table 8)
Years Ending December 31, 2017 to 2021

Line No.	Particulars	Note	2017 Plan	2018 Plan	2019 Plan	2020 Plan	2021 Plan
			(a)	(b)	(c)	(d)	(e)
	Determination of Taxable Income						
1	**Earnings (Loss) Before Tax**	1	(27.2)	(27.6)	(36.6)	(31.7)	(50.8)
	Additions for Tax Purposes - Temporary Differences:						
2	**Base Rent Accrual**		65.5	67.2	(9.1)	(9.1)	(9.1)
3	**Depreciation**	2	69.1	69.1	69.1	69.0	69.0
4	**Accretion**	3	462.1	473.2	489.1	505.6	523.4
5	**Used Fuel and Waste Management Expenses and Facilities Removal Costs**	4	73.7	71.3	76.0	82.3	68.5
6	**Receipts from Nuclear Segregated Funds**	5	70.5	70.9	93.7	119.7	144.3
7	**Other**		3.4	2.2	2.8	2.3	2.3
8	**Total Additions - Temporary Differences**		744.4	753.9	721.7	769.7	798.4
	Deductions for Tax Purposes - Permanent Differences:						
9	**Deferred Rent Revenue**		14.2	14.2	0.0	0.0	0.0
	Deductions for Tax Purposes - Temporary Differences:						
10	**CCA**		6.3	6.0	5.7	5.6	5.5
11	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**	6	157.0	164.2	198.6	201.0	215.7
12	**Contributions to Nuclear Segregated Funds**	7	0.0	0.0	0.0	0.0	0.0
13	**Earnings (Losses) on Nuclear Segregated Funds**	8	395.8	412.5	429.5	446.1	462.3
14	**Total Deductions - Temporary Differences**		559.1	582.8	633.8	652.7	683.5
15	**Taxable Income/(Loss) Before Loss Carry-Over**		143.9	129.4	51.3	85.3	64.2
16	**Tax Loss Carry-Over to Future Years / (from Prior Years)**		0.0	0.0	0.0	0.0	0.0
17	**Taxable Income After Loss Carry-Over**		143.9	129.4	51.3	85.3	64.2
	Determination of Current Income Taxes						
18	**Taxable Income After Loss Carry-Over**		143.9	129.4	51.3	85.3	64.2
19	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%
20	**Income Taxes - Current**		36.0	32.3	12.8	21.3	16.0
	Determination of Deferred Income Taxes						
21	**Total Net Temporary Differences (line 8 - line 14)**		185.3	171.1	87.9	117.0	114.9
22	**Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%	25.00%
23	**Deferred Income Taxes**		(46.3)	(42.8)	(22.0)	(29.3)	(28.7)
24	**Tax Loss / Tax Loss Carry-Over (line 16)**		0.0	0.0	0.0	0.0	0.0
25	**Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%
26	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over**		0.0	0.0	0.0	0.0	0.0
27	**Deferred Income Tax - Total (line 23 + line 26)**		(46.3)	(42.8)	(22.0)	(29.3)	(28.7)
	Income Tax Rate - Current						
28	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
29	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
30	**Total Income Tax Rate - Current**		25.00%	25.00%	25.00%	25.00%	25.00%
	Income Tax Rate - Deferred						
31	**Federal Tax**		15.00%	15.00%	15.00%	15.00%	15.00%
32	**Provincial Tax net of Manufacturing & Processing Profits Deduction**		10.00%	10.00%	10.00%	10.00%	10.00%
33	**Total Income Tax Rate - Deferred**		25.00%	25.00%	25.00%	25.00%	25.00%

Notes:

1. Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. N1-1-1 Table 7, line 11 and Total Costs Before Income Tax in Ex. N1-1-1, Table 7, line 19 for each corresponding year.
2. From Ex. N1-1-1 Table 7, line 12.
3. From Ex. N1-1-1 Table 7, line 14.
4. From Ex. N1-1-1 Table 7, line 16 plus line 17
5. From Ex. N1-1-1 Table 4, line 15.
6. From Ex. N1-1-1 Table 4, line 8.
7. From Ex. N1-1-1 Table 4, line 14.
8. From Ex. N1-1-1 Table 7, line 15.

Table 8
Updated Calculation of Regulatory Income Taxes for Prescribed Nuclear Facilities ($M)
(Updated Ex. F4-2-1 Table 3a)
Years Ending December 31, 2017 to 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	171.2	152.5	160.5	413.7	383.6
	Additions for Regulatory Tax Purposes:						
2	**Depreciation and Amortization**	2	373.9	405.7	411.0	551.9	327.3
3	**Nuclear Waste Management Expenses**	3	63.9	63.2	77.9	66.5	68.8
4	**Receipts from Nuclear Segregated Funds**	4	84.4	85.7	120.4	152.0	193.7
5	**Pension and OPEB Accrual**	5	291.2	298.7	343.3	352.3	359.2
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**	6	25.9	22.1	18.3	14.5	12.4
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**		895.2	916.9	1,027.6	1,194.1	1,019.9
	Deductions for Regulatory Tax Purposes:						
12	**CCA**	7	394.2	504.4	571.1	594.8	597.0
13	**Cash Expenditures for Nuclear Waste Management & Decommissioning**	8	217.5	227.9	232.8	283.6	317.0
14	**Contributions to Nuclear Segregated Funds**	9	0.0	0.0	0.0	0.0	0.0
15	**Pension Plan Contributions**	10	200.0	202.9	243.5	247.9	250.6
16	**OPEB/SPP Payments**	10	91.1	95.7	99.9	104.3	108.5
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**		950.9	1,058.8	1,176.0	1,264.1	1,317.4
20	**Regulatory Taxable Income Before Tax Loss Carry-Over** (line 1 + line 11 - line 19)		115.5	10.6	12.0	343.7	86.2
21	**Tax Loss Carry-Over**		0.0	0.0	0.0	0.0	0.0
22	**Regulatory Taxable Income After Tax Loss Carry-Over** (line 20 + line 21)		115.5	10.6	12.0	343.7	86.2
23	**Regulatory Income Taxes - Federal** (line 22 x line 27)		17.3	1.6	1.8	51.6	12.9
24	**Regulatory Income Taxes - Provincial** (line 22 x line 28)		11.6	1.1	1.2	34.4	8.6
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)		10.5	(15.8)	(15.4)	67.5	3.2
	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%

See Ex. N1-1-1 Table 8a for notes

Table 8a
Notes to Table 8
Updated Calculation of Regulatory Income Taxes
(Updated Ex. F4-2-1 Table 3b)
Years Ending December 31, 2017 to 2021

Notes:
1 Nuclear 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
			(a)	(b)	(c)	(d)	(e)
1a	After Tax Return on Equity - Prescribed Nuclear Facilities	Ex. N1-1-1, Table 1, line 12	143.9	151.2	148.4	322.4	342.4
2a	Less: Bruce Lease Net Revenues	Ex. N1-1-1, Table 7, line 30	(16.9)	(17.1)	(27.4)	(23.8)	(38.1)
3a		line 1a - line 2a	160.7	168.3	175.9	346.2	380.5
4a	Additions for Regulatory Tax Purposes	line 11	895.2	916.9	1,027.6	1,194.1	1,019.9
5a	Deductions for Regulatory Tax Purposes	line 19	950.9	1,058.8	1,176.0	1,264.1	1,317.4
6a		line 3a + line 4a - line 5a	105.0	26.3	27.4	276.2	83.1
7a	Regulatory Income Taxes - Federal	(lines 6a + line 27) x line 27 / line 29	17.3	1.6	1.8	51.6	12.9
8a	Regulatory Income Taxes - Provincial	(line 25) x line 28 / (line 29)	11.6	1.1	1.2	34.4	8.6
9a	Regulatory Income Taxes - SR&ED Investment Tax Credits	Ex. N1-1-1, Table 8, 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	10.5	(15.8)	(15.4)	67.5	3.2
11a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Federal		0.0	0.0	0.0	0.0	0.0
12a	Decrease in Regulatory Income Taxes Due to Tax Loss Carry-Over - Provincial		0.0	0.0	0.0	0.0	0.0
13a	Reduction in Total Regulatory Income Taxes Due to Loss Carry-Over	line 11a + line 12a	0.0	0.0	0.0	0.0	0.0
14a	Regulatory Income Taxes After Tax Loss Carry-Over - Federal	line 7a + line 11a	17.3	1.6	1.8	51.6	12.9
15a	Regulatory Income Taxes After Tax Loss Carry-Over - Provincial	line 8a + line 12a	11.6	1.1	1.2	34.4	8.6
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	10.5	(15.8)	(15.4)	67.5	3.2
18a	After Tax Return on Equity - Prescribed Nuclear Facilities	line 1a	143.9	151.2	148.4	322.4	342.4
19a	Less: Bruce Lease Net Revenues	line 2a	(16.9)	(17.1)	(27.4)	(23.8)	(38.1)
20a	Add: Total Regulatory Income Taxes After Tax Loss Carry-Over	line 17a	10.5	(15.8)	(15.4)	67.5	3.2
21a	Regulatory Earnings Before Tax	lines 18a - 19a + 20a	171.2	152.5	160.5	413.7	383.6

2 Calculated as Ex. F4-2-1 Table 3a, line 2, cols. (a) to (e), plus Ex. N1-1-1 Table 6, line 1, cols. (a) to (e), less Ex. N1-1-1 Table 6, line 1, cols. (f) to (j).
3 From Ex. N1-1-1 Table 3, line 5 plus line 6.
4 From Ex. N1-1-1 Table 3, line 15.
5 As discussed 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.
6 From Ex. N1-1-1 Table 2, line 4.
7 See Ex. F4-2-1, Table 3b, Notes 2 and 3.
8 From Ex. N1-1-1 Table 3, line 8.
9 From Ex. N1-1-1 Table 3, line 14.
10 As shown in Ex. N1-1-1, Chart 3.1.1A.