ONTARIO POWER GENERATION

EB-2016-0152

Payment Amounts Order

Response to Comments

Ontario Power Generation Inc.

February 5, 2018

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1.0 INTRODUCTION

OPG has received comments on the draft Payment Amounts Order ("PAO") from OEB staff, AMPCO, CME, SEC, Sustainability Journal and VECC. Below OPG addresses the specific additions and modifications proposed in these comments, but not all of the observations made. Where OPG proposes to revise the draft PAO in response to a comment, it states this explicitly[1], and provides a summary of the changes in Attachment 1 to this response. Beyond the revisions identified below, OPG does not believe that further changes to the draft PAO are warranted.

2.0 SEC'S SUBMISSION INCORRECTLY TREATS THE OEB'S DECISION ON EFFECTIVE DATE AS A REVENUE REQUIREMENT REDUCTION

This section responds to the submissions of SEC, supported by VECC, on the implications of the June 1, 2017 effective date for the calculation of payment amounts and rate riders (SEC Submission, paras. 2.1.1 through 2.2.23; VECC Submission, para. 3.3). As shown below, these submissions are incorrect in treating the reduction in the revenues that OPG will collect in 2017 as a result of the June 1, 2017 effective date as a revenue requirement reduction. SEC advocated for this approach in its final argument, but the OEB did not adopt it. It should be rejected again here. The SEC recommendations on tax losses that stem from this incorrect approach should be similarly rejected.

2.1 APPROVAL OF A JUNE 1, 2017 EFFECTIVE DATE IS NOT A REVENUE REQUIREMENT REDUCTION

SEC's fundamental point is that by delaying the effective date of OPG's payment amounts from January 1, 2017 to June 1, 2017, the OEB reduced OPG's revenue requirement.[2] This point is incorrect. Simply put, delaying the effective date did not change the 2017 revenue requirement that the OEB approved; the effective date was in fact determined independently of findings on

[1] OPG does not explicitly reference OEB staff's requested changes in Section 2.3 of its Submission, but has reflected those changes in the revised draft PAO. The changes are also captured in Attachment 1 to this response.

[2] SEC's submissions offer lengthy commentary without, in many instances, proposing changes to the draft PAO (See e.g., SEC Submission, paras. 2.2.8 through 2.2.17). In this response OPG focuses only on the proposed changes to the draft PAO, not SEC's commentary. OPG's decision not to respond to this commentary does not constitute agreement.

the revenue requirement. Rather, the June 1, 2017 effective date required OPG to forego collection of the approved 2017 payment amounts during the first five months of the year. While this certainly reduces OPG's revenues, it has no effect on its approved revenue requirement. Once this fundamental error is corrected, the remainder of SEC's observations and recommended adjustments in this area have no basis.

The OEB's decision (the "Decision") approved a nuclear revenue requirement for each year from 2017 through 2021 by making specific adjustments to OPG's requests. The OEB then determined that collection of the new payment amounts to recover this approved nuclear revenue requirement would not begin until June 1, 2017.[3] Nowhere does the OEB's Decision contain any suggestion that the OEB intended to reduce OPG's revenue requirement, beyond the specific disallowances made, based on the approved effective date or that the OEB's findings on the revenue requirement and the effective date were in fact linked.

SEC's final argument in this proceeding invited the OEB to adopt the view that moving the effective date beyond January 1, 2017 would constitute an additional revenue requirement reduction. Discussing how the OEB should proceed, SEC stated: "It should then determine that the revenue requirement for the period from the effective date until December 31, 2017 is the pro rata calculation of the calendar revenue requirement that otherwise would have been determined." (SEC Final Argument, para. 11.1.15). The OEB's Decision did not make the determination that SEC sought. SEC's submission on the draft payment amounts order reargues this point.

Where the OEB reduced OPG's revenue requirement request, the OEB made findings to identify the specific amount or percentage associated with each disallowance and the reasons for it.[4] In the context of its ruling on the effective date, the OEB stated: "The draft payment amounts order

[3] For the hydroelectric payment amounts, the OEB did not approve a revenue requirement. Rather it approved a rate-setting formula and the 2017 and 2018 values for the variables that are updated annually pursuant to that formula. It then found that the payment amounts, which result from the approved formula in 2017, would not go into effect until June 1 of that year.

[4] See e.g., EB-2016-0152, Decision, pp. 18 (in-service capital additions); 55 (base OM&A); 72 (corporate costs) and 79 (compensation).

will include the final revenue requirement and final production forecast for the nuclear facilities, and the final hydroelectric rate setting mechanism and 2017 and 2018 parameters, as reflected in the findings made by the OEB in this Decision." (Decision, p. 159 (emphasis added)). The OEB's decision made no finding to reduce the revenue requirement based on the effective date and made no disallowances that relate specifically to the period from January 2017 through June 2017.

This is not an issue of first impression for OPG's payment amounts. In OPG's last payment amounts proceeding (EB-2013-0321), the OEB approved an effective date that was later than OPG's request. The PAO in that proceeding did not reduce the revenue requirement to reflect the approved effective date. The only revenue requirement reductions shown in the approved PAO in EB-2013-0321 are those attributable to the specific disallowances in the OEB's decision (See EB-2013-0321, PAO, December 18, 2014, Tables 1-3). Here, OPG correctly followed the same approach in the draft PAO.

SEC suggests that Appendix A, Table 1 be modified by adding a line following line 26 to show an additional revenue requirement reduction attributable to the approved effective date (SEC Submission, para. 2.2.5). As demonstrated above, including this modification would be an error because the OEB made no disallowance of revenue requirement based on the effective date. Applying the same logic, SEC's suggested changes to Tables 6 and 8 should also be rejected (SEC Submission, paras. 2.2.6 and 2.2.7).[5]

2.2 THERE ARE NO CHANGES TO REGULATORY TAX LOSSES AS A RESULT OF THE APPROVED EFFECTIVE DATE

SEC's submission speculates on the possible implications of the approved effective date on regulatory tax losses. As SEC's submission is rooted in several factually inaccurate statements, SEC's conclusions and recommendations should be disregarded.

[5] SEC's commentary, which questions whether the OEB's disallowances apply to all of 2017 or just to the last seven months, is equally incorrect. The OEB's disallowances are to the annual revenue requirement. Since SEC eventually agrees with this, OPG does not elaborate further on this issue (SEC Submission, paras. 2.2.8 and 2.2.17).

SEC begins by stating: "On the one hand, it is clear that a reduction in approved 2017 revenues of $266.1 million means, ultimately, a reduction in net income for that year and a resulting reduction in taxable income for that year." (SEC Submission, para. 2.2.19). As demonstrated above, the OEB did not reduce OPG's approved revenue requirement by any amount, including $266.1M, owing to the selection of a June 1, 2017 effective date. Since there was no disallowance, no adjustment to forecast income tax expense is required. Where the OEB has made disallowances that actually impact forecast income tax expense in 2017, OPG has made the appropriate adjustments (See draft PAO, Appendix A, Table 16).

SEC hypothesizes about how the reduced revenues caused by the June 1, 2017 effective date might impact OPG's actual regulatory income and actual regulatory income tax position in 2017 based on speculation as to how OPG might have adjusted its actual 2017 spending to reflect the OEB's Decision (SEC Submission, para. 2.2.21).[6] This discussion is of no moment. The basis for the revenue requirement being approved by the OEB is forecast information for the 2017-2021 period (the "IR Term"); no element of revenue requirement is based on actual results for 2017, including income taxes. Differences between actual revenues and forecast revenues over the 2017 through 2021 period and the resulting income tax implications going forward, if any, will be addressed in a future application, not here. This is true whether any such differences arise from the approved effective date or from some other source.

In conclusion, because there was no revenue requirement reduction associated with the approved effective date, there is no impact on forecast regulatory taxes or tax losses. SEC's use of this non-existent impact to support its argument on the proper calculation of the appropriate reference amounts for the deferral and variance accounts should also be rejected, for the reasons discussed in Section 3.0 below.

[6] Given that the OEB's Decision was issued on December 28, 2017, it is clear that the OEB's decision to adopt June 1, 2017 as the effective date could not have impacted OPG's actual spending during 2017.

3.0 DEFERRAL AND VARIANCE ACCOUNT TREATMENT

3.1 DISPOSITION

OEB staff agrees with the debit amounts noted in Appendix G of the draft PAO. OEB staff and SEC propose different timeframes and methodologies for recovery. The impacts of both proposals are addressed in Section 6.0 below.

3.2 CONTINUING DEFERRAL AND VARIANCE ACCOUNTS

3.2.1 New Reference Amounts for All Continuing Accounts Begin as of the Effective Date

OEB staff notes in its submission that deferral and variance accounts are currently described by the decisions in EB-2014-0369 and EB-2015-0374, and the PAO in EB-2014-0370 (OEB staff Submission, p.8).

OEB staff submits that OPG should explicitly note in Appendix G of the revised draft PAO that the continuing deferral and variance accounts are effective as of the effective date of June 1, 2017 (OEB staff Submission, p.8). SEC submits that the OEB's order should deal with the impact of effective date in each of the descriptions of the accounts and their entries (SEC Submission, para. 2.3.6). SEC further asserts that OPG should be required to provide all entries to deferral and variance accounts for the period of January 1, 2017 to May 31, 2017, with certain supporting information.

The final PAO resulting from this proceeding will govern the operation of deferral and variance accounts commencing on the effective date as determined by the OEB. As such, the descriptions of all deferral and variance accounts should similarly reflect the operation of these accounts as of the effective date. OPG has made changes in the revised draft PAO to clarify this point, as summarized in Attachment 1 to this response. Until the effective date, the deferral and variance account descriptions resulting from EB-2014-0370, EB-2014-0369 and EB-2015-0374 prevail.

OPG has provided evidence supporting the operation of its approved deferral and variance accounts prior to the effective date of this PAO.[7]

To be clear, while the monthly reference amounts are derived from approved annual amounts, the reference amounts are only applicable on and after the effective date. SEC's assertion that the derivation of a monthly reference amount for 2017 implies that these amounts are effective as of January 1, 2017 is incorrect (SEC Submission, para. 2.2.23). SEC's request for specific information on the monthly 2017 reference amounts prior to the effective date is not an appropriate part of this PAO and is unnecessary, given that the new monthly reference amounts commence on the effective date.

OEB staff agrees with the majority of the deferral and variance account descriptions and provides comments on descriptions of the following accounts in the draft PAO Appendix G: Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Bruce Lease Net Revenues Variance Account, including the Derivative Sub-Account. OPG accepts OEB staff's comments on the above-noted account descriptions and has reflected the suggested changes in the revised draft PAO and as summarized in Attachment 1 to this response.

SEC states that, for the Pension and OPEB Cost Variance Account – Post-2012 Additions, the draft PAO "notes that this component of the account is due to be fully recovered as of June 30, 2021" (SEC Submission, para. 4.8.1). Based on OPG's proposal to recover the balances approved in this proceeding over the 2019-2021 period, a portion of the account balance will not be fully recovered by June 30, 2021.

OPG believes that this approach is not contrary to the OEB's previous orders. The OEB authorized recovery of the balance in this account "over 72 months, commencing July 1, 2015."

[7] See Ex. H1-1-1, p. 5, footnote 4 (Hydroelectric Water Conditions Variance Account); p. 8, lines 2-8 (Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear); p. 10, footnote 10 (Hydroelectric Surplus Baseload Generation Variance Account); p. 12, lines 2-7 (Income and Other Taxes Variance Account); p. 13, footnote 15 (Capacity Refurbishment Variance Account); p. 17 line 28 to p. 18, line 8 (Pension & OPEB Cash Payment Variance Account); p. 23, line 28 to p. 24, line 3 (Nuclear Development Variance Account); p. 26, lines 15 to 20 and footnote 25 (Bruce Lease Net Revenues Variance Account—Non-Derivative Sub-Account).

(See EB-2014-0370, PAO, Appendix B, p. 3). This meant that in the normal course the balance would have been recovered by June 30, 2021. However, under OPG's proposal no portion of the balance would be recovered during the 24-month period commencing January 1, 2017 until December 31, 2018. Therefore, while the total elapsed time period from July 1, 2015 may exceed 72 months, as a result of the 24-month "break" in recovery, the actual recovery can still occur over the OEB-authorized recovery period of 72 months. OPG has revised the description of the Pension & OPEB Cost Variance Account – Post-2012 Additions in the revised draft PAO to reflect the recovery over 72 months, rather than by June 30, 2021, consistent with the OEB's previous approvals. This change is reflected in Attachment 1 to this response.

3.2.2 Comments on the Capacity Refurbishment Variance Account ("CRVA")

SEC claims that the draft PAO incorrectly prorates the reference amount for the hydroelectric portion of the CRVA for 2017 to reflect the effective date (SEC Submission, para. 2.3.14). Consistent with the general approach discussed in Section 3.2.1 above, OPG disagrees.

OPG recognizes that this PAO reflects a new rate-making methodology for hydroelectric facilities, and that this has a specific implication for the operation of the hydroelectric portion of the CRVA. As of the effective date, there is no longer a direct linkage between specific projects reflected in an approved revenue requirement and the actual costs of projects that qualify for CVRA treatment in accordance with IRM principles that decouple costs from rates. The Decision approved $0.9M as the revenue requirement reflected in the base hydroelectric payment amounts in relation to CRVA-eligible projects, and required that this amount be escalated by the approved price cap index annually to determine the hydroelectric reference amount in each year of the IR Term. As explained in the draft PAO (Appendix G, pp. 8-9), OPG believes that the new reference amount for the CRVA begins with the effective date and has prorated the 2017 amounts accordingly.

Prior to the effective date, the approved reference amount has no relevance. Therefore, it is necessary to prorate the reference amount in 2017 as of the effective date. The same applies to the funding amount included in the account description as the threshold for determining the portion of the recorded amounts that are eligible for recovery under the incentive ratemaking methodology. The full annual funding amount is pro-rated in 2017 because the new methodology is not effective until that date.

For deferral and variance accounts, annual reference amounts are converted to monthly reference amounts on a straight-line basis.[8] The consistent application of this to the CRVA account for hydroelectric operation requires that the above amounts be applied monthly on and after the effective date. The account description in the revised draft PAO has been adjusted to clarify that this approach has been used.

For the nuclear portion of the CRVA, OPG's approach follows the same principle. The reference amounts based on the new revenue requirement begin to apply as of June 1, 2017. For January 2017 through May 2017, the reference amounts established in EB-2013-0321 and EB-2014-0370 continue. The account description in the revised draft PAO has been adjusted to clarify that this approach has been used (SEC Submission, para. 2.3.18).

3.2.3 Comments on Other Continuing Accounts

For all continuing accounts, the monthly reference amounts for January 2017 through May 2017 are those approved in EB-2013-0321 and EB-2014-0370 because no aspect of the OEB's Decision varied, amended or replaced the OEB's orders in EB-2013-0321 or EB-2014-0370. For June 2017 through December 2017 the monthly reference amounts are the annual amounts approved in this proceeding divided by 12 (*Ibid.*). Thus, the additional information that SEC requests Section 2.3 of its Submission is unnecessary.

As requested by SEC in its submission (SEC Submission, paras. 2.3.24), OPG confirms that there are no additions in the Nuclear Liability Deferral Account in 2017 after the effective date of June 1, 2017. OPG does not confirm that there are no additions in the Bruce Lease Net Revenues Variance Account – Non Derivative Sub-Account (SEC Submission, para. 2.3.27) in 2017 after the effective date of June 1, 2017. There would be normal course entries in this sub-account calculated in accordance with the account description provided in the draft PAO

[8] The Hydroelectric Water Conditions Variance Account uses a monthly profile of forecast energy production.

(Appendix G, p. 14).[9] These entries capture differences between forecast Bruce lease net revenues approved by the OEB in the Decision and the actual Bruce lease net revenues.

3.2.4 Comments on New Accounts

OEB staff raises no concerns with the accounting orders for new deferral and variance accounts set out in the draft PAO Appendix H, but opposes the two variance accounts relating to the recovery of foregone revenue amounts. OPG's response to OEB staff's submissions on these accounts can be found in Section 5.0 below.

SEC comments on the calculation of the variance in the actual tax credits in the SR&ED ITC Variance Account. Specifically, SEC notes that there is no description of the method by which the net tax impact is grossed up before being recovered from or paid to customers (SEC Submission, paras. 4.9.1).

OPG has revised Appendix H of the draft PAO to include the information requested by SEC.

4.0 REVENUE REQUIREMENT ISSUES

4.1 CONTINUITY OF APPROVED PROPERTY, PLANT AND EQUIPMENT

Depreciation Expense

OEB staff submits that OPG's calculation of the depreciation expense reduction associated with the 10% annual reduction in nuclear operations and support services capital in-service additions does not properly reflect the intent of the Decision. Rather than using the Darlington station service life as OPG proposes, OEB staff recommends using a "weighted average depreciation rate based on the proportional asset mix that underpins the total non-Darlington Refurbishment Program (DRP) in-service amount for each year." (OEB staff Submission, p. 2). OEB staff's position is based on the view that the Decision "did not single out the Darlington assets as the

[9] There are no additions in the Bruce Lease Net Revenues Variance Account – Derivative Sub-Account in 2017 after the June 1, 2017 effective date, as described in the draft PAO (Appendix G, p. 14).

only asset category to which the 10% in-service reduction would apply," and that the reduction was intended to be applied by using an "envelope approach." (*Ibid*.).

The substantive issue raised by OEB staff is effectively whether some of the in-service reduction ordered by the OEB should apply to Pickering in-service capital and be depreciated to December 31, 2020 for revenue requirement purposes.[10] While OPG agrees that the Decision did not specify that the 10% in-service reduction would apply solely to Darlington assets, OPG believes its approach is appropriate for two reasons.

First, OPG's approach is better aligned with the Decision's rationale for the in-service capital reduction, as OPG noted in the draft PAO at Appendix A, Table 10a, Note 3 and further explained below.

OPG's in-service capital reduction approach recognizes that OPG's historical performance with respect to Darlington operations' capital is the implicit driver of the OEB's findings. At pp. 17-18 of the Decision, the OEB questions "elevated capital expenditures and in-service additions," referencing increases in the 2017-2021 period compared to historical levels. The comparison of forecast amounts to historical actual amounts appears to be the main basis for the OEB's direction to reduce forecast in-service additions. Since Darlington operations' in-service capital drives the higher total nuclear in-service capital additions in 2017-2021 compared to the historical period as shown in Chart 1, OPG believes that applying the reductions to Darlington in-service capital using the December 31, 2052 average remaining service life is the appropriate approach.

[10] The revenue requirement OPG proposed in this proceeding, based on its 2016-2018 business plan as updated by Ex. N1 and Ex. N2, assumed depreciation of all forecast nuclear operations in-service capital additions over either the remaining average service life for accounting purposes of the Darlington station to December 31, 2052 or the remaining average service life for accounting purposes of the Pickering station to December 31, 2020.The same approach was followed for forecasts presented in Ex J21.1, Attachments 1 and 2. Consistent with the business plan, most forecast support services capital additions were reflected in the "Darlington NGS" line in Ex. B3-3-1, Ex. B3-4-1 and Ex. J21.1 continuity schedules and assumed to be depreciated to December 31, 2052. In reality, some of the nuclear operations and support services capital placed in service over the IR Term that is reflected in the "Darlington NGS" line will be depreciated over a shorter period than to December 31, 2052 and will be reflected on that basis in the opening rate base in the next application term. By assuming a longer depreciation period than OPG will actually use for some assets, OPG's approach lowers the amount requested for depreciation expense, thereby benefiting customers.

Chart 1: 2010-2021 In-service Capital Additions

	2010	2011	2012	2013	2014	2015	2016	2010 - 2016 Average
Darlington	31.2	32.3	52.9	83.4	52.6	117.4	228.1	85.4
Pickering	166.8	27.4	41.0	99.7	75.7	79.6	51.3	77.4
Nuclear Support	35.6	30.6	22.5	33.9	13.4	17.1	15.8	24.1

		2017	2018	2019	2020	2021	2017 - 2021 Average	2017-2021 vs. 2010-2016
Darlington		279.2	263.2	351.8	201.5	143.7	247.9	190.2%
Pickering		212.8	98.4	31.8	38.3	31.4	82.5	6.7%
Nuclear Support		16.8	10.5	9.5	9.6	9.7	11.2	-53.4%

Source: 2010-2012: EB-2013-0321 Ex. D2-1-3 Table 4; 2017-2021: EB-2016-0152 Ex. J21.1 Att. 2 Tables 4 & 5

Second, OPG notes that, as a practical matter, given the relatively short remaining life of the Pickering station and its already significantly reduced capital program as the station begins to approach its end of life, OPG expects that there will be less operational flexibility to adjust Pickering's capital plan in response to the OEB's reduction in capital funding. Additionally, Pickering's capital program is an essential element of restoration costs in support of extended station operation beyond 2020. In OPG's view, these factors make a reduction to the Pickering capital in-service additions less consistent with the intent of the Decision and less consistent with the operational realities faced by OPG.

Auxiliary Heating System ("AHS") and Operations Support Building ("OSB")

OEB staff submits that the disallowance to in-service capital for the AHS and OSB projects should be allocated on a pro-rated basis relative to the amounts of capital that went into service prior to and in 2017. While OEB staff does not dispute the calculation of the total disallowance for each project, it believes that OPG's proposed approach over-allocates disallowances to 2017 as opposed to earlier years and that OPG's approach reflects the notion "that amounts that came into service later are somehow more impacted by the poor management and performance issues." (OEB staff Submission, p. 3).

OPG disagrees with this characterization. OPG's approach is simply to calculate the disallowance by taking 50% of the difference between the actual or forecast in-service amount in a given year and the in-service amount identified in the First Execution BCS for that year. It is not intended to be reflective of any notional allocation of "performance issues" across different time periods. For example, for AHS, the total disallowance was $27.6M. The portion of that disallowance that was applied to 2016 was $24.8M, calculated as the actual 2016 in-service amount of $93.1M less the 2016 in-service amount identified in the First Execution BCS of $43.6M, multiplied by 50% (draft PAO, Appendix A, Table 9a, footnote 2). Similarly, the portion of the total AHS disallowance applied to 2017 was $2.8M, calculated as the 2017 forecast in-service amount of $5.6M less the 2017 in-service amount identified in the First Execution BCS of $0, multiplied by 50%. OPG applies the same approach to allocate the OSB-related disallowance.

OPG believes that its approach is aligned with the disallowance that the OEB directed as stated in its Decision (Decision, pp. 21-22). However, OPG does agree with OEB staff's submission that, should the OEB adopt OEB staff's position on this issue, the resulting revenue requirement reduction would be immaterial (OEB staff Submission, p. 4).

4.2 CAPITALIZATION AND COST OF CAPITAL ADJUSTED TO REFLECT FINAL RATE BASE AND CAPITAL STRUCTURE FINDINGS

OEB staff submits that OPG's "calculation of its cost of debt for nuclear payment amounts is not consistent with the evidence and Decision" (OEB staff Submission, p.4). OEB staff's primary concern relates to the principal amounts shown for short-term debt in Appendix A, Tables 11-15 of the draft PAO. OEB staff notes that these amounts are all different from, and lower than, the amount shown in OPG's evidence at Ex. C1-1-1 Tables 1 to 5, line 1, col (a). OPG disagrees with OEB staff's submission and offers the following clarification.

In its Decision, the OEB noted OPG's proposal is to maintain a constant amount of short-term debt through 2021 ($37.1M) (Decision, p. 112). The OEB agreed with OPG that there is no reason to adjust the level of short-term debt, and that the final approved debt costs will be adjusted by the final rate base and capital structure findings in the Decision (Decision, p. 112).

As discussed in Ex. I1-1-1 Table 1, note 2, capitalization is allocated to regulated hydroelectric and nuclear operations using rate base financed by capital structure. The $37.1M is the allocation of short-term debt to the total regulated operations; however, in determining the cost of capital for nuclear payment amounts, the short-term debt allocated to the regulated hydroelectric business must be deducted from the overall short-term debt of the regulated operations as shown at Ex. I1-1-1 Table 1, line 5 (as updated by Ex. N2-1-1 Table 1, line 5) and explained in Ex. I1-1-1 Table 1, Note 2. Furthermore, as stated in the Decision, the amount of short-term debt allocated to the nuclear business changes as a result of the OEB's adjustments to rate base and capital structure findings. The impact of the Decision on short term debt amounts as compared to OPG's proposal, on a nuclear-only basis, is shown in column (b), line 5, of the draft PAO Appendix A, Tables 1-5. For these reasons, the amount of short-term debt in the draft PAO appropriately differs from the $37.1M amount.

4.3 IMPLEMENTATION OF FINDINGS ON NUCLEAR LIABILITIES REVENUE REQUIREMENT FOR PRESCRIBED FACILITIES

OEB staff states that it was not able to confirm the impact of implementing the OEB's findings on nuclear liabilities revenue requirement (OEB staff Submission, p. 5). As such, OEB staff requests that OPG provide a summary of how the findings on the nuclear liabilities revenue requirement have been implemented.

Chart 2 provides the details of adjustments to the proposed revenue requirement to reflect the impact of the final 2017 Ontario Nuclear Funds Agreement ("ONFA") contribution schedule and actual year-end 2016 asset retirement obligation adjustment and discount rate.

Chart 2: Total Nuclear Liability Revenue Requirement (Most Recent ONFA)

Line No.	Description	Note	2017	2018	2019	2020	2021
			(a)	(b)	(c)	(d)	(e)
1	**Depreciation Expense**	1	-3.1	-3.1	-3.1	-3.1	-0.2
2	**Used Fuel Storage and Disposal Variable Costs**	2	-9.8	-9.9	-12.0	-9.2	-9.1
3	**Low & Intermediate Level Waste Management Variable Expenses**	3	-1.2	-0.9	-1.0	-1.1	-1.2
4	**Return on Rate Based at Weighted Avg Accretion**	4	-0.9	-0.8	-0.6	-0.5	-2.3
5	**Return on Rate Base at WACC**	5	0.0	0.0	0.0	0.0	2.5
6	**Pre-Tax Revenue Requirement** (line 1 + line 2 + line 3 + line 4 + line 5)		-15.0	-14.7	-16.7	-13.9	-10.3
7	**Tax Impact**	6	-39.2	-39.1	-39.8	-38.8	-37.6
8	**Sum of Pre-Tax Revenue Requirement and Tax Impact**		-54.2	-53.8	-56.5	-52.7	-47.9
	Total Nuclear Liability Revenue Requirement for Prescribed Facilities						
9	**Per Exhibit N1-1-1**	7	178.4	169.4	193.7	167.0	77.7
10	**Per Undertaking J21-2, Chart 1**	8	124.2	115.6	137.1	114.3	29.8
11	**Revenue Requirement Impact of J21-2** (line 10 - line 11)		-54.2	-53.8	-56.6	-52.7	-47.9

Numbers may not add or completely reconcile due to rounding.

Notes:

1 Per PAO App. A, Table 1 - 5, Footnote 7(g).
2 Per PAO App. A, Table 1 - 5, line 16, col. (b).
3 Per PAO App. A, Table 1 - 5, Footnote 5(b).
4 Per PAO App. A, Table 1 - 5, line 13, col. (b).
5 The Weighted Average Cost of Capital applies when Asset Retirement Costs are greater than Unfunded Nuclear Liabilities. This occurs in 2021 only, calculated as: ARC of $241.8M (Ex. J21.1, Att. 2, Table 3, line 20, col. (i)) less UNL of $202.9M (PAO App. A, Table 15, line 7, col. (a)) times 2021 WACC rate of 6.43% (PAO App. A, Table 15, line 6, col. (c)). ($241.8M - $202.9M) * 6.43% = $2.5M.
6

	Description	2017	2018	2019	2020	2021
(a)	Adjustments to Pre-Tax Revenue Requirement (line 6 above)	-15.0	-14.7	-16.7	-13.9	-10.3
(b)	Contributions to Seg Funds (PAO App. A, Table 16 - 21, line 14, col. (c))	102.5	102.5	102.5	102.5	102.5
(c)	Taxable Income Pre-tax Revenue requirement less contributions (line (a) - line (b))	-117.5	-117.2	-119.2	-116.4	-112.8
(d)	Tax Impact (line (c) x 25%/(1-25%))	-39.2	-39.1	-39.8	-38.8	-37.6

7 Per OEB Staff Submission on Draft Payment Amounts Order, P. 5, Table 1.3, line (B)
8 Per OEB Staff Submission on Draft Payment Amounts Order, P. 5, Table 1.3, line (A)

4.4 NO CHANGE TO WORKING CAPITAL IS REQUIRED

In its submissions, SEC states that it is unclear why OPG's working capital is unchanged in the draft PAO given the changes in the components of revenue requirement resulting from the Decision (SEC Submission, para. 4.3.2).

The composition of OPG's nuclear working capital is described at Ex. B1-1-1, pp. 4-8 and presented at Ex. B1-1-1 Table 2. It has three components: (1) materials and supplies, (2) fuel inventory, and (3) cash working capital. In its Decision, the OEB did not adjust values for the first two components (for the second component, nuclear production was approved as proposed, which means that the fuel inventory amounts are unchanged). Cash working capital is the third component of OPG's working capital. The $11M forecast amount for 2017-2021 inclusive represents between 1% and 2% of OPG's total nuclear working capital and between 0.2% and 0.3% of OPG's total nuclear rate base. As described in Ex. B1-1-2, consistent with past applications, the cash working capital forecast is based on relevant 2015 expenses and costs and therefore is not affected by adjustments made in the OEB's Decision.

4.5 REGULATORY INCOME TAXES

As part of its submission, SEC requests further clarifications on regulatory income tax calculations, specifically: 1) the relationship between impacts of adjustments to depreciation expense and CCA in Appendix A, Tables 16-20 of the draft PAO; and 2) a non-capital loss continuity schedule to clarify the loss carryforward amounts.

The details of adjustments to depreciation expense are explained in the draft PAO Appendix A, Tables 1 to 5, footnote 7. OPG provides Tables 1-5 in Attachment 2 to this response, which reiterate the explanation of depreciation reflected in the above referenced footnote 7 for each year in the IR Term with an added column to reflect the CCA impact associated with each depreciation adjustment, where applicable. The difference between the depreciation and CCA amounts primarily relates to two factors: 1) some depreciated items do not qualify for CCA (i.e., asset retirement costs); and 2) CCA amounts are typically larger than depreciation amounts, which reflects tax incentives to encourage investment. Due to the latter, as shown in Attachment

2 to this response, the CCA decrease associated with the OEB Decision adjustments tends to be greater than the decrease in non-asset retirement costs depreciation expense.[11]

With respect to SEC's second requested clarification, non-capital loss continuity schedules are included in the revised draft PAO at Appendix A, Table 22**.**

4.6 OTHER REVENUE REQUIREMENT RECONCILIATIONS

VECC submits that there are differences in revenue requirement as between Table 4 in the OEB's Decision (Decision, p. 8) and draft PAO, Appendix A, Table 1. VECC acknowledges that the differences are relatively small, but requests that OPG provides a table reconciling them (VECC Submission, para. 2.2).

The information VECC requests is provided in the draft PAO at Appendix A, Table 6 and the accompanying notes in Table 6A. This table provides a breakdown of OPG's proposed revenue requirement and deferral and variance account amortization amounts. It is provided to support Appendix A, Tables 1 to 5, which applies annual adjustments to OPG's proposed revenue requirement from Table 6 to determine the annual OEB approved revenue requirement.

SEC incorrectly submits that draft PAO, Appendix A Table 6 is a summary of the final approved revenue requirements. SEC further submits that it is unable to determine the purpose of this table, and that it should be replaced with one that, in SEC's view, more correctly summarizes Tables 1-5 (SEC Submission, paras. 4.5.1-4.5.2).

As stated above, Table 6 is a summary of OPG's proposed nuclear revenue requirement and deferral and variance account amortization amounts. This table is necessary to demonstrate OPG's proposal prior to making adjustments reflecting the OEB's findings in its Decision. The

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[11] Only in one instance, at line (a) for 2021, is the decrease in CCA smaller than the decrease in depreciation expense. This is due to the simplifying assumption made in OPG's application (and accepted by the OEB by virtue of the approval of the proposed depreciation expense) that most of the forecast Pickering capital additions in 2021 are fully depreciated in 2021 given the December 31, 2020 station end-of-life date for accounting purposes reflected in the application and consistent with OPG's business plan (Ex. L-6.9-1 Staff-177 c) (ii)).

same rationale applies to draft PAO, Appendix A Table 21, which shows OPG's proposed regulatory income tax amounts without any OEB adjustments. OPG disagrees with SEC's assertion that figures in these tables are incorrect and that the tables should be replaced.

SEC also questions the presentation of line 27 of Tables 1 to 5 in Appendix A of the draft PAO (SEC Submission, para. 4.4.1). The OEB directed OPG to include supporting schedules and a clear explanation of all the calculations and assumptions used in deriving the amounts used (Decision, pp. 159-60). As the amortization of deferral and variance accounts at draft PAO, Appendix A, Tables 1 to 5, line 27 is an integral part of OPG's current rate smoothing proposal, the information on line 27 is required. All line items in Tables 1 to 5 are subject to OEB review as part of the PAO approval process. Therefore, it is unnecessary to categorize any specific line item in Tables 1 to 5 differently than any other line item as proposed by SEC (SEC Submission, paras. 4.4.1-4.4.2).

4.7 THE REVENUE REQUIREMENT WORK FORM ("RRWF") IS UNCHANGED

OPG is not proposing to make any changes to either the revenue requirement or recovery of deferral and variance account balances reflected in the RRWF filed on January 17, 2018.

5.0 INTERIM PERIOD SHORTFALL RECOVERY

5.1 INTERIM PERIOD SHORTFALL OVER/UNDER RECOVERY VARIANCE ACCOUNT SHOULD BE APPROVED AS PROPOSED

5.1.1 Interim Period Revenue Shortfall and Its Recovery

OEB staff recognizes that the OEB has approved the proposed nuclear and hydroelectric Interim Period Shortfall Over/Under Recovery Variance accounts for OPG in the past. Nevertheless, OEB staff submits that these accounts should not be approved in this proceeding. OEB staff states that OPG should be at risk for the shortfall recovery and cite the treatment of other utilities to support this claim. Below OPG explains why the OEB's previously adopted approach continues to be appropriate for OPG and should be adopted here and responds to SEC's submissions on this issue.

The purpose of the shortfall riders is to allow OPG to recover the revenue it would have received if the approved changes to the nuclear and hydroelectric payment amounts had been implemented on the approved effective date. As explained in the cover letter to OPG's draft PAO, OPG proposes to calculate the amount of the interim period revenue shortfall by multiplying the difference between the approved and prior payment amounts by the actual production during the period between the effective date and the implementation date ultimately adopted by the OEB (i.e., the interim period) (draft PAO, Appendix H, pp. 5-6).[12] Under this approach, if actual interim period production exceeds the production forecast for the interim period, OPG's interim period shortfall revenues will be greater than forecast; if actual production is below forecast, revenues will be lower than forecast.

Given that OPG's revenues vary directly with production and contain no fixed payments, adoption of the proposed approach would put OPG at risk for 100% of any variance between forecast and actual production during the interim period. OPG and OEB staff agree that this is the correct approach to calculating the interim period shortfall amounts for nuclear and regulated hydroelectric facilities.

The interim period revenue shortfall will be collected through hydroelectric and nuclear riders. Differences between forecast and actual production during the recovery period could result in the approved riders over or under-recovering the interim period revenue shortfall. As discussed further below, given the size of the riders and the length of the recovery period proposed, these differences could be significant.

OPG and OEB staff differ over the treatment of this potential over or under-recovery. Following the method adopted in the OEB's EB-2007-0905 PAO, OPG has proposed that this amount be subject to true-up via the Interim Period Shortfall Over/Under Recovery Variance Accounts for nuclear and hydroelectric. OEB staff opposes the creation of these accounts stating that OPG

[12] Because OPG's proposal was submitted in mid-January 2018, it used actual production for the period June 2017 through December 2017 and the approved production forecast values for January 2018 and February 2018 on the assumption of a March 1, 2018 implementation date. As discussed elsewhere in this section this proposal follows the approach the OEB adopted in EB-2007-0905.

should be at risk for recovery of the shortfall amounts and arguing that the OEB has not established them for other utilities.

SEC has two issues with OPG's approach. It first suggests that forecast instead of actual production could be used to calculate the interim period revenue shortfall, but the use of forecast production would be inconsistent with holding OPG at risk for achieving its forecast production and counter to the OEB's past treatment of this issue (SEC Submission, paras. 4.7.1-4.7.4). Similarly, SEC claims that there is a mismatch in using forecast production to establish the payment amounts and actual production to determine the revenue shortfall. SEC is incorrect; there is no mismatch. This is exactly what would have happened if the payment amounts had been implemented on the effective date – the payment amounts would have been based on forecast production and OPG's revenues would have depended on actual production.

SEC next argues that the determination of the revenue shortfall should be based on the unsmoothed rates and that OPG's approach is incorrect, because smoothing is of the weighted average payment amounts ("WAPA") not the payment amounts (SEC Submission, paras. 4.7.5-4.7.12). Regardless of whether smoothing occurs based on WAPA or nuclear payment amounts, customers will pay the smoothed payment amounts approved by the OEB.[13] As discussed above, OPG's view is that the interim revenue shortfall, by definition, is the difference between the revenues OPG actually received during the interim period and the revenues that OPG would have received if the approved payment amounts had been collected starting on the effective date. Since OPG would have collected the approved smoothed payment amounts during the interim period, these are appropriately used in calculating the shortfall.

5.1.2 The Approach Adopted in EB-2007-0905 Should be Followed Here

Below OPG demonstrates that the approach to recovery of the interim period revenue shortfall proposed here:

[13] In arguing its point, SEC claims that using the unsmoothed rates to calculate the interim period shortfall would have "no ultimate impact on the amount OPG collects from customers." (SEC Submission, para. 4.7.11). This claim is incorrect because SEC's approach would increase the deferral amount, thereby increasing the amount of interest that customers will ultimately pay.

1) was adopted in EB-2007-0905 precisely to ensure that OPG was at risk for production;
2) is fairer to customers and to OPG; and
3) reflects the circumstances of OPG's payment amounts, which are substantially different than those of the utilities cited by OEB staff.

In the EB-2007-0905 PAO the OEB stated:

> Calculation and Recovery of Interim Period Shortfall
> The Decision, at pages 177-178, requires "that OPG remains at risk for its production forecast in the same way it would have been had the payments amounts been set on a prospective basis." To achieve the production risk exposure set out in its Decision, the Board directs that the new payment amounts be set using the forecast production for the test period and that the interim period shortfall be calculated using the actual production during the interim period (April 1, 2008 through November 30, 2008). The Board notes that it will be necessary to use forecast production for November 2008. Payment riders B and D to this Order have been calculated to reflect the Board's direction. To ensure that OPG is kept whole, the Board also directs that nuclear and hydroelectric variance accounts be established to record the difference between the calculated interim period shortfall and the amounts recovered through the interim period shortfall payment riders B and D. (EB-2007-0905, PAO, December 2, 2008, p. 3 (emphasis added)).

Following the approach adopted in EB-2007-0905, and advocated by OPG here, will ensure that OPG remains at risk for its production forecast during the interim period. With the proposed variance accounts, OPG would be at risk for 100% of the revenue variation associated with any differences in interim period production. Without the proposed accounts, not only would OPG be at risk for 100% of the revenue variation due to any difference between forecast and actual production during the interim period, it would also be at risk for an additional amount, based on the variation between forecast and actual production during the recovery period. The OEB recognized this in EB-2007-0905 when it implemented variance accounts to ensure that the entire interim period revenue shortfall was recovered, but not more or less (EB-2007-0905, PAO, December 2, 2008, p. 3).

The failure to approve the proposed accounts would introduce additional risk for both customers and OPG and would run counter to the fundamental purpose of collecting the interim period shortfall amounts - to put OPG in the position that it would have been if the new payment amounts had been implemented on the effective date. With this background, it is clear that adopting OEB staff's approach would make the recovery of the interim shortfall more risky than any other element of revenue requirement because this recovery is subject to production risk twice – once during the interim period and again during the recovery period.

Customers are put at additional risk under OEB staff's proposal because if OPG's actual production during the recovery period exceeds the forecast production used to establish the riders, OPG will collect more than the interim period revenue shortfall. In effect, customers would end up paying more than the approved payment amounts for production during the interim period. If actual production is less than forecast during the recovery period, the converse will be true; OPG will collect less than the interim period shortfall amounts and customers will pay less than the approved payment amounts for production during the interim period. These differences could be substantial in either direction given that the riders will be in effect for three years under OPG's proposal.

OEB staff asserts that, "Without the true up accounts, OPG would be at risk for recovery of the forgone revenue in the same way that it is at risk for revenue requirement in general." As shown above, this statement is incorrect. The use of actual production to calculate the revenue shortfall puts OPG 100% at risk for any variance between forecast and actual production during the interim period. This is the risk that OPG generally faces for recovery of its revenue requirement. Without a true-up account, the risk is greater because recovery of the interim period shortfall revenue requirement would be subject to production risk a second time during the recovery period.

5.2 THE APPROACHES ADOPTED FOR OTHER UTILITIES ARE BASED ON THEIR CIRCUMSTANCES AND ARE NOT APPROPRIATE FOR OPG

OEB staff also says that the OEB has approved interim period shortfall riders without approving a true-up account, but as demonstrated below, none of the situations cited by OEB staff are equivalent to the circumstances for OPG described above. They involved:

1) distributors and transmitters who are subject to significantly less revenue risk than OPG;
2) small fractions of the amounts of money at risk for OPG; and
3) shorter time frames for revenue recovery.

In EB-2016-0160, the OEB approved Hydro One's transmission 2017 revenue requirement with a January 1, 2017 effective date and an October 1, 2017 implementation date (EB-2016-0160 Decision and Order, September 28, 2017, pp. 115-116). To collect the foregone revenue requirement, the OEB approved "the creation of a deferral account [to] record the foregone transmission revenues over that period to capture the differences between revenue earned by Hydro One under the interim 2017 UTR [Uniform Transmission Rates] (set at the 2016 UTR level and subject to adjustment following the OEB's determination of 2017 revenue requirement applications by rate-regulated transmitters), and the revenues that would have been received under the approved final 2017 UTR." (*Ibid.*). The establishment of a deferral account meant that Hydro One, unlike OPG, was not at risk for under or over-collection of its foregone revenue requirement as balances in deferral accounts, once approved, are eventually recovered or refunded in full. Furthermore, unlike OPG, Hydro One "used forecast rather than actual 2017 charge determinants to determine 2017 foregone revenue"[14] (EB-2016-0160, Decision and Order, 2017 and 2018 Transmission Revenue Requirements and Charge Determinants, November 9, 2017, p. 18). Since Hydro One had a deferral account for its foregone revenue requirement and its lost revenue calculation was done using forecast demand, Hydro One was not at <u>any</u> risk based on differences between forecast and actual demand.

More generally, since Hydro One's transmission charges for network services are collected based on customers' peak demand during certain periods, rather than energy use, it has significantly less revenue risk than OPG.[15] Finally, the foregone revenue amounts for 2017 resulted in a credit to customers of $10.6M, which was applied during 2018 (EB-2016-0160, 2018

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[14] OEB staff's submissions on the draft rate order state: "OEB staff notes that ideally, forgone revenue (or credits) should be calculated based on actuals. Hydro One may wish to confirm in its reply whether a calculation based on actual charge determinants will have a significant impact on the amount to be credited to ratepayers." (OEB Staff Submission On Draft 2017 Revenue Requirement and Charge Determinant Order, October 16, 2017, p. 4). Hydro One's Reply Submission stated that the use of forecast rather than actual demand to estimate the revenue shortfall was consistent with past OEB practice and in any event it anticipated that the difference "would be small and well within the variance in revenues introduced as a result of rounding UTR rates." (EB-2016-0160, 2017-2018 Transmission Revenue Requirement & Charge Determinants & EB-2017-0280, Uniform Transmission 2017 Rates, Reply Submission, p. 5). The fact that the use of forecast versus actual demand has a small effect on the foregone revenues illustrates Hydro One's small exposure to revenue risk relative to OPG.

[15] Hydro One's charge determinant for Network Services is based on: "the higher of: i) The customer's demand that is coincident with the monthly system peak; or ii) 85% of the customer's non-coincident monthly system peak demand between 7 a.m. and 7 p.m. on Independent Electricity System Operator (IESO) business days."

Transmission Revenue Requirements and Charge Determinants Decision, December 20, 2017, p. 3). As discussed more fully below, OPG's foregone revenues are estimated at over $720M and are proposed to be recovered on a fully volumetric basis over a three-year period.

In EB-2016-0231, the OEB approved the 2017 revenue requirement for Five Nations Energy Inc. effective January 1, 2017 (EB-2016-0231, Decision and Order, December 14, 2017, p.28). Since the approval was not issued until mid-December 2017, the OEB authorized the collection of the foregone 2017 revenue requirement in 2018 (*Ibid.)*. The amount to be collected was calculated as $1.8M (EB-2016-0231, Revenue Requirement and Charge Determinant Order, January 18, 2017, p. 2). As in the case of Hydro One, this revenue requirement amount was relatively small and was collected over a one-year period. Since the revenue requirements of all Ontario transmitters are recovered through Uniform Transmission Rates, Five Nations Energy Inc., is subject to significantly less revenue risk than OPG, as explained above for Hydro One.

In EB-2015-0003, PowerStream's rates were made effective January 1, 2016 and implemented on October 1, 2016 (EB-2015-0003, Decision and Order, August 4, 2016, p. 32). The total amount of foregone revenue was about $2.4M and it was collected over a three month period (October through December 2016) (EB-2015-0003, Draft Rate Order Revision, September 23, 2016, pp. 6-7).[16] As over 70% of the foregone revenues were collected through fixed rate riders, PowerStream had only a small risk of a revenue shortfall or over-collection during the three-month recovery period (*Ibid.*).[17] Again, the relatively small amounts involved, the short recovery period and the significantly reduced revenue risk all distinguish PowerStream from OPG.

In EB-2011-0354, Enbridge's Rates were made effective January 1, 2013 and implemented on April 1, 2013 (EB-2011-0354, Rate Order, 2013 Rates, March 5, 2013, p. 3). The revenue shortfall for this three-month interim period was a credit to customers of less than $1M (EB-2011-

[16] The OEB approved the rates and charges shown in this draft rate order revision, including those related to foregone revenue, in its Decision and Rate Order, September 27, 2016, at p. 1.
[17] This percentage is calculated by looking at the revenues derived from the residential and GS<50 kW rate classes, which are recovered entirely through a fixed rider. As the remaining rate classes have a mix of fixed and volumetric riders, the percentage of revenues collected through fixed rate riders is actually somewhat higher than the 70% figure shown (EB-2015-0003, Draft Rate Order Revision, September 23, 2016, p. 7, Table 4).

0354, Final Rate Order, February 14, 2013, PDF p. 145, Working Papers to Rider E). This amount was refunded to customers through Rider E over a single month (April 2013)[18] (Rate Order, 2013 Rates, March 5, 2013, Appendix B, Rate Handbook p.58). Moreover, Enbridge's residential rates have a significant fixed component unlike OPG's payment amounts. In 2013, Enbridge forecast that 51% of its revenues would be collected through fixed charges (EB-2011-0354, Decision on Equity Rate and Order, February 7. 2013, p. 10). For all these reasons, the approach adopted in this proceeding does not provide useful guidance as to the appropriate approach for OPG.

In EB-2011-0210, the OEB approved Union Gas' rates effective January 1, 2013 and implemented them on February 1, 2013 (EB-2011-0210, Decision and Rate Order, January 17, 2013, p. 20). As Union's smaller customers were then billed every two months, Union was able to charge them the new rates effective January 1, 2013 with their first bill. For the larger customers with monthly billing, Union collected the revenue foregone during the month of January 2013 "through a temporary charge or credit in rates between February 1, 2013 and December 31, 2013" (*Ibid.*). Here again, the circumstances are in no way similar to those facing OPG. The interim period was one month and applied only to the larger customer classes who are billed monthly. The total revenue shortfall for these customers was approximately $4 million (EB-2011-0210, Draft Rate Order, Appendix H, line 21). The recovery period was eleven months, not the 3 years that OPG proposes. Finally, Union is subject to significantly less revenue recovery risk than OPG for the reasons described above with respect to Enbridge.

In summary, none of the proceedings cited by OEB staff involve utilities facing circumstances anything like those facing OPG in this proceeding. For OPG:

- The amounts in question are much larger than those involved in any of the cited proceedings;[19]
- The recovery risk is much greater; and
- The proposed recovery period is much longer.

[18] April was used as the disposition month because consumption is not generally less variable than in the cold winter months.
[19] The revenue shortfalls for OPG are approximately $701M for nuclear and $21M for hydroelectric (See draft PAO, Appendix F, Table 1, line 10 and Table 2, line 5).

It is also worth noting that the proposed interim shortfall riders represent a significant fraction of OPG's total nuclear payment amounts. Over the 2019 through 2021 proposed recovery period, the proposed smoothed nuclear payment amounts average $79.85/MWh[20] and the proposed nuclear interim period shortfall rider is $6.27/MWh.[21] Thus under OEB staff's approach, for each MWh that OPG exceeds forecast production during recovery period, customers would pay on average approximately 8% more than the approved payment amounts.[22]

For all these reasons, the approach that the OEB approved for OPG in EB-2007-0905 remains appropriate and should be adopted here.

6.0 RATE SMOOTHING

6.1 SUMMARY

In the draft PAO, OPG introduced a revised rate smoothing proposal intended to produce annual increases of approximately $0.65 or 0.4%[23] for residential customers' monthly bills during the IR Term, with a total interest cost of approximately $1.1B over the deferral and recovery period (the "OPG Proposal").

In their submissions on the draft PAO, OEB staff and SEC propose alternative smoothing approaches (the "OEB staff Proposal" and "SEC Proposal" respectively, collectively the "alternative proposals"). AMPCO supports the SEC Proposal (AMPCO Submission, pp.1-2). CME conditionally supports the SEC Proposal, "assuming that SEC's calculations are accurate" (CME Submission, p. 2).[24]

OPG has reviewed the alternative proposals, as described in Section 6.2, below. Based on that review, OPG continues to believe that its proposal best satisfies the rate smoothing principles that the OEB endorsed in the Decision (Decision, p. 155).

[20] The smoothed payment amounts that OPG proposes are: $76.17/MWh in 2019; $79.70/MWh in 2020 and $83.67/MWh in 2021, which average to $79.85/MWh (draft PAO, Appendix C, Table 1, line 4).
[21] Draft PAO, Appendix F, Table 2, line 7.
[22] $6.27/$79.85 = 7.9%.
[23] Draft PAO, Appendix I, Table 1.
[24] As OPG demonstrated in Section 6.4, several elements of SEC's calculations are not accurate.

The OEB staff Proposal strikes a different balance than the OPG Proposal. It would require OPG to defer recovery of less revenue requirement and would result in moderately lower interest costs over the full deferral and recovery period. However, it would also result in greater year-over-year variation in customer bills and higher transition impacts at the end of the recovery period. While both approaches are reasonable, OPG believes that the consistent year-over-year increase in bills under its proposal offers better value for customers.

On the other hand, the SEC Proposal is inconsistent with the OEB-endorsed rate smoothing principles and has significant adverse impacts. In order to reduce 2018 bill impacts, SEC proposes that the OEB defer approximately $2.7B[25] over the IR Term. Although SEC does not specify the carrying costs associated with its proposal in its submissions, OPG calculates that the SEC Proposal would result in total interest costs of $2.7B over the full deferral and recovery period, an increase of almost 250% over the OPG Proposal. In OPG's submission, the long term cost of SEC's proposal more than outweighs the short term benefit of reducing 2018 bill impacts.

6.2 COMPARISON OF PROPOSALS

To assist the OEB in comparing the relative merits of each proposal, OPG presents the outcomes of each proposal in Chart 3.

[25] SEC states that its proposal would increase deferred revenue to $2B, but OPG cannot validate this number and the SEC Proposal does not include annual deferral amounts (as required by O. Reg. 53/05). This issue is discussed in Section 6.4.

Chart 3: Outcomes of Rate Smoothing Proposals[26]

	OPG Proposal	SEC Proposal	OEB staff Proposal
2017-2021 Average Change in WAPA	**2.7%**	**9.2%**	**2.0%**
2022-2026 Average Change in WAPA	**8.0%**	**8.0%**	**8.0%**
2027-2036 Average Change in WAPA	**(1.5)%**	**(1.1)%**	**(2.4)%**
Peak RSDA Balance ($B)	**$2.7**	**$4.9**	**$1.9**
2017 - 2021 RSDA Additions ($M)*	**$732**	**$2,705**	**$515**
2017 - 2021 Interest ($M)*	**$21**	**$313**	**$41**
Total Interest ($B)	**$1.1**	**$2.7**	**$0.5**
Interest Cost / Deferred Revenue Ratio	**0.4**	**0.6**	**0.2**
FFO Interest Coverage > = 3 (2017-2021) & (2022-2026)	**4.3 / 4.6**	**2.6 / 3.9**	**4.2 / 5.0**
DEBT to EBITDA < = 5.5 (2017-2021) & (2022-2026)	**6.5 / 5.4**	**7.0 / 6.3**	**6.7 / 5.4**
Nuclear Payment Amount Transition Impact ($/MWh)	**($0.19)**	**($13.28)**	**$12.27**
Average Annual Bill Impact (2017-2021) in %	**0.4%**	**0.3%**	**0.3%**
Average Annual Bill Impact (2017-2021) in $	**$0.65**	**$0.39**	**$0.52**
Average Annual Bill Impact (2017-2036) in %	**0.3%**	**0.3%**	**0.2%**
Average Annual Bill Impact (2017-2036) in $	**$0.45**	**$0.45**	**$0.29**

* Additional rows to reflect submissions by OEB staff and SEC

[26] Chart 3 is consistent with Chart 6 in the draft PAO, Appendix I, and with Chart 3 in Ex. A1-3-3 and Ex. N3-1-1. Beyond including the OEB staff and SEC proposals, the only structural change is the addition of two rows as noted, to reflect these parties' submissions. As OPG has no basis to propose alternatives, Chart 3 maintains an average WAPA increase of 8% in the 2022-2026 period for the alternative proposals, consistent with the OPG Proposal.

OPG discusses the relative merits and shortcomings of the alternative proposals in Sections 6.3 and 6.4 below.

6.3 OEB STAFF PROPOSAL

The OEB staff Proposal trades-off lower overall cost for greater year-over-year volatility in residential customer bills when compared to the OPG Proposal. It defers moderately less revenue requirement than the OPG Proposal during the IR Term (approximately $515M, compared to $732M proposed by OPG). As a result, the peak Rate Smoothing Deferral Account ("RSDA") balance is lower and it has the lowest total interest costs over the full deferral and recovery periods.

The OEB staff Proposal substantially increases volatility. In 2018 and 2019, the residential bill impact of the OEB staff Proposal is twice that of the OPG Proposal.[27] The transition impact at the end of the recovery period is also greater, resulting in an increase of over $12/MWh in nuclear payment amounts in 2037.

In OPG's view, the OEB staff Proposal is a reasonable alternative to the OPG Proposal. However, on balance, OPG continues to believe that its proposal produces the best value for customers by maintaining a constant year-over-year increase in monthly bills for residential customers during the IR Term. The OEB staff Proposal would allow customer bills to vary more each year, and may result in greater "rate shock" at the end of the recovery period.

6.3.1 OEB Staff Bill Impact Calculation

OEB staff endorses the methodology that OPG used to calculate the $0.65 impact on residential customers' monthly bills (OEB staff Submission, p. 13). OEB staff also notes that, throughout the course of this proceeding, OPG used an average residential total bill value of $150, which was current when the application was filed in May 2016 (*Ibid*.). As OEB staff also notes, the average total bill has changed over the course of this proceeding. To allow for consistent comparison between smoothing proposals, OPG continues to calculate residential customer bill impacts against a total bill of $150.

[27] OEB staff Submission, Schedule A, line 25.

For 2019 through 2021, OEB staff concurs with the 0.5% year-over-year bill impacts for medium/large and industrial customers calculated by OPG (OEB staff Submission, p. 14).[28] For 2018, OEB staff calculates bill impacts from a lower starting point,[29] and concludes that the bill impact for non-RPP customers would be 4% in 2018. Since OEB staff does not supply the calculation supporting its conclusions for 2018 bill impacts, OPG is unable to validate the result. While OPG does not agree that it is appropriate to view the March 2018 bill impacts in isolation as discussed in Section 6.4.2 below; otherwise, OEB staff have at least identified bill impacts that appear to be calculated on a comparable basis to those provided by OPG.

6.3.2 Responses to OEB Staff Requests

OEB staff requests that OPG confirm the interest charges it expected to result from the OPG Proposal during the IR Term (OEB staff Submission, p. 10).[30]

OPG forecasts that the total interest charges resulting from the OPG Proposal during the IR Term will be approximately $21M[31], as estimated by OEB staff. Under the OPG Proposal, interest charges are approximately $19M less than the OEB staff Proposal and $292M less than the SEC Proposal during the IR Term.[32] The forecast differences over the total deferral and recovery period are set out in Chart 3.

OEB staff also requests that OPG identify any significant calculation errors in the OEB staff Proposal (OEB staff Submission, p. 11).

[28] As discussed in Section 6.3, OEB staff also endorsed the methodology that OPG used to calculate residential customer bill impacts.
[29] The OEB staff Proposal uses a starting point WAPA of $50.72/MWh, reflecting the end of prior period payment riders on December 31, 2016.
[30] In the draft PAO, OPG provided total interest charges associated with the OPG Proposal across the full deferral and recovery period, but did not specify the specific interest charges during the IR Term.
[31] For the purpose of comparing smoothing proposals, a simplified methodology has been applied consistently to the OPG, OEB staff, and SEC proposals to estimate interest. OPG confirms that $21M is a reasonable estimate using this simplified methodology. However, the OEB approved methodology calculates interest on deferral and variance account balances on a monthly basis, and using this methodology would result in interest cost of approximately $22M.
[32] As shown in Chart 3, Total IR Term interest charges under the OEB staff Proposal and the SEC Proposal are approximately $41M and $313M, respectively.

OPG has identified no such errors. However, OPG notes that the OEB staff Proposal includes interim period shortfall riders in the calculation of WAPA. SEC's calculations also include these riders in WAPA. As OPG identified in the draft PAO, under O. Reg. 53/05, WAPA does not include the impact of such riders (draft PAO, Appendix I, p. 13). However, this issue does not affect the deferral amounts or bill impacts that OEB staff identify.

6.4 SEC PROPOSAL

Any short-term benefits of the SEC Proposal are dwarfed by its long-term cost. The SEC Proposal will cost customers billions of dollars more than either the OPG Proposal or the OEB staff Proposal. Although SEC did not provide total carrying costs in its submission, OPG calculates that total interest costs under the SEC Proposal will be approximately $2.7B, an increase of $1.6B over the OPG Proposal and $2.2B over the OEB staff Proposal. The only benefit that customers receive for this substantial cost increase is lower bill impacts in 2018 when compared against the artificially low rates that resulted from the expiry of payment riders at the end of 2016 (a comparison that OPG believes is misleading, as discussed in Section 6.4.2 below).

Nuclear rate smoothing requires that the OEB take a long-term view of OPG's payment amounts. The Darlington Refurbishment Program is a decade-long enterprise, and O. Reg. 53/05 requires that the OEB contemplate the trajectory of payments over the span of at least twenty-years. The rate smoothing principles endorsed by the OEB reflect the fact that the OEB must balance competing long-term issues when approving rate smoothing deferral amounts.

In contrast, the SEC Proposal focuses on a much smaller period of time: the months between the expiry of OPG's prior payment riders and the implementation of the payment amounts and riders approved by the OEB in this application. Consequently, the SEC Proposal results in poor value for customers in the long-term.

OPG identifies other specific flaws in the SEC Proposal in the following subsections.

6.4.1 SEC Selectively Conflates WAPA with Bill Impacts

SEC's submissions generally use changes in WAPA as a stand-in for bill impacts. SEC repeatedly cites an increase of 27.05% in the commodity portion of non-RPP customers' bills in 2018, based on annual changes in WAPA, starting from the reduced 2017 WAPA of $50.72/MWh (SEC Submission, paras. 3.2.4 and 3.2.11). In OPG's view, this approach is unhelpful and potentially misleading. WAPA and bill impacts are not equivalent or interchangeable.

Where SEC does refer to bill impacts, it does so selectively. Without evidentiary support, SEC provides annual impacts, in dollars, for one customer: the Toronto District School Board. The only customer class for which SEC cites a specific bill impact is a typical large industrial customer in the Alectra PowerStream rate zone, for which SEC cites a bill impact amount in absolute dollars on an annual basis.[33] When the OEB assesses customer bill impacts, it typically focuses on the percentage change on monthly bills. Consistent with that practice and with its response to undertaking J20.1, OPG has identified year-over-year bill impacts of the OPG Proposal for medium/large and industrial customers on a monthly basis, across three distinct service areas (draft PAO, Appendix I, p. 16 and Tables 1B, 1C, and 1D). SEC's selective, annualized examples do not reflect bill impacts on customers across Ontario, nor do they situate those impacts in the context of customers' total bills.

6.4.2 Methodological Flaws in the 2018 Bill Impact Calculations

SEC's method of calculating bill impacts ignores the decrease in payments amounts from which customers have benefitted since January 1, 2017. SEC's bill impact calculation begins with the 2017 interim payment amounts (without riders), the effect of which is to exaggerate the impact of new payment amounts and riders.

As described in the draft PAO, OPG believes that bill impacts should be viewed on a cumulative basis, starting on January 1, 2017.[34] Chart 4 illustrates the annualized bill impact for residential and non-RPP customers in 2017 and 2018.

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[33] SEC cites a monthly increase of approximately $21,000 (or $248,000 annually) for a large industrial customer in the Alectra PowerStream Rate Zone in 2018 (SEC Submission, pp. 15-16). As discussed in Section 6.4.2, OPG also disputes the starting point from which SEC has calculated 2018 bill impacts.
[34] Draft PAO, Appendix I, Section 6.4.

Chart 4: Cumulative 2017-2018 Customer Bill Impacts under OPG Proposal

Line No.	Customer Class	Measure	2017	2018		2017 & 2018 Average Impact
				Jan - Feb	Mar - Dec	
1	Residential Customers	($/Month)	-$4.20	$0.00	$4.59	$0.65
2		(%)	**-2.8%**	**0.0%**	**3.0%**	**0.4%**
3	Non-RPP Customers	($/Month)	-$14,200	$0	$15,500	$2,200
4		(%)	**-3.3%**	**0.0%**	**3.6%**	**0.5%**

SEC's approach to bill impacts considers only the difference between payments on February 28, 2018 and those on March 1, 2018. By focusing exclusively on this single transition, SEC creates the inaccurate impression that OPG's payment amounts are increasing by 27%, which in turn is used to provide justification for SEC's extremely expensive rate smoothing proposal.

It is OPG's view that bill impacts are properly calculated on a cumulative basis, as shown in Chart 4 and as filed in the draft PAO.

6.4.3 Assumed Future Payment Riders

SEC states that OPG has not followed the OEB's guidance, in that the OPG Proposal does not reflect future riders for recovery of deferral and variance account balances that the OEB may approve in future applications (SEC Submission, p. 12).

Absent OEB approved balances and recovery periods, OPG does not believe it is appropriate or consistent with the definition of WAPA in O. Reg. 53/05 to determine deferral amounts based on speculative payment riders for future periods.

OPG does not understand the OEB's findings in the Decision to require that a rate smoothing proposal should include speculative riders based on decisions the OEB may make in future proceedings, as SEC suggests. As stated in Ex. N3-1-1 and Appendix I of the draft PAO, the OPG Proposal does not reflect payment riders for recovery of deferral and variance account balances after December 31, 2015, as none are proposed in this Application (draft PAO, Appendix I, p. 9).

The OEB will have tools to address bill impacts of any potential future payment riders in the proceeding where they are approved. In OPG's submission, the OEB would be better able to consider such impacts in a future proceeding, at which time it would have on a complete record on which to assess the bill impact of potential payment riders for recovery (or refund) of any amounts approved, including appropriate recovery periods.

6.5 RATE SMOOTHING CONCLUSION

The alternative proposals present two very different approaches to rate smoothing. The OEB staff Proposal is a reasonable alternative to the OPG Proposal, focused on minimizing deferral amounts and carrying costs at the expense of more stable year-over-year customer bill impacts and post-recovery transition impacts. In contrast, SEC focuses entirely on mitigating short term bill impacts, the price of which is billions of dollars of deferred revenue and carrying costs.

OPG believes that its own proposal continues to provide the best value for customers, producing stable year-over-year bill impacts during the IR Term and minimal post-recovery transition impact. The SEC Proposal does not provide value for customers. As OEB staff observed, customer bill impacts for both residential and non-RPP customers are well below the 10% threshold the OEB applies to trigger rate mitigation for electric distributors and are “not sufficiently significant to warrant mitigation.” (OEB staff Submission, p. 14). OPG concurs with OEB staff’s assessment.

Concordance Table

Base Document	Submission Reference	Submission	Change	Change Reference
Order	Staff 2.3	Revise Order number 5 to be consistent with order number 4 for 2017	Changed as requested	Order, Page 4
Appendix A	SEC 4.6.4	File a non-capital loss continuity schedule	Filed as requested	Appendix A, Table 22
Appendix C	Staff 2.3	Line 3, Table 1 should be listed as <u>Smoothed</u> Nuclear Payment Amount	Changed as requested	Appendix C, Table 1, line 3
Appendix C	Staff 2.3	Units in footnote 4 of Table 1 should be TWh	Changed as requested	Appendix C, Table 1, footnote 4,
Appendix F	Staff 2.3	Title for line 6 of table 2 should read 2021, not 2031	Changed as requested	Appendix F, Table 2, line 6
Appendix G	Staff 3.2	Specify descriptions proposed for the continuing accounts are effective as of the effective date of the Decision, namely June 1, 2017	Added sentence with requested specification	Appendix G, Page 2
	Staff 3.2	Pension & OPEB Cash Versus Accrual Differential Deferral Account	Changed description from variance account to deferral account	Appendix G, Page 13
	Staff 3.2	Bruce Lease Net Revenues Variance Account	Added purpose and general operation description from Ex H1-1-1. Also Deleted “had”	Appendix G, Page 14, 15
	OPG correction	“…calculated as set out in EB-2013-0321 per EB-2016-0152…”	Deleted “per EB-2013-0321”	Appendix G, Page 8
	SEC 2.3.7, 2.3.8, 2.3.9 2.3.11, 2.3.17, 2.3.18, 2.3.19, 2.3.20, 2.3.25, 2.3.26	Specify the impact of the effective date where it is appropriate in specific cases	OPG has indicated the impact of the effective date Specified calculations for monthly reference amounts in	Appendix G, Pages 2, 3, 4, 5, 6, 8, 9, 10, 12, 14, 16 Appendix A, Tables 1a, 2a, 3a, 4a, 5a,

Concordance Table

			Appendix A tables, where appropriate	16a, 17a, 18a, 19a, 20a
	SEC 2.3.19	Provide the annual reference amounts for each year	Added approved reference amounts	Appendix G, Page 9, 10
	SEC 4.8	Pension and OPEB Cost Variance Account: Recovery date of June 30, 2021 is inconsistent with OPG's proposal to recover hydro and nuclear Deferral and variance account balances by December 31, 2021	Revised Account description to reflect approved recovery in months as discussed in Reply	Appendix G, Page 10 Appendix D, Table 1 line 8 col (d), Appendix E, Table 1, line 11, col (d)
Appendix H	SEC 4.9	Add requirement to include tax impacts	Included the requirement to include tax impacts	Appendix H, Page 4
General	N/A	Headers, footers and Order reflect January 17, 2018 filing date of Draft Order	Filing date updated to February 5, 2018	Throughout document

Table 1
Calculation of 2017 Capital Cost Allowance

			CCA Impact
	Description	**2017**	**2017**
(a)	OPG Proposed Depreciation (line 17, col. (a))	$ 367.0	$ 394.1
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 8 + line 10 + line 11 less J21.1 Att. 1, Table 5, col. (b) + (c), line 8 + line 10 + line 11)	$ (19.0)	$ (34.9)
(c)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 10, line 5, col. (b))	$ (0.8)	$ (1.9)
(d)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 10, line 6, col. (b))	$ (0.2)	$ (0.4)
(e)	Subtotal (a) + (b) + (c) + (d)	$ 347.0	$ 356.9
(f)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 10, col. (b) line 7)	$ (0.7)	$ (4.1)
(g)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 13 less J21.1 Att. 1, Table 5, col. (b), line 13)	$ (3.1)	$ -
(h)	OEB Approved Depreciation (e) + (f) + (g)	$ 343.2	$ 352.8

Table 2
Calculation of 2018 Capital Cost Allowance

			CCA Impact
	Description	**2018**	**2018**
(a)	OPG Proposed Depreciation (line 17, col. (a))	$ 395.0	$ 504.4
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 15 + line 17 + line 18 less J21.1 Att. 1, Table 5, col. (b) + (c), line 15 + line 17 + line 18)	$ 3.5	$ (13.8)
(c)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 10, line 15, col. (b))	$ (0.8)	$ (1.9)
(d)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 10, line 16, col. (b))	$ (0.2)	$ (0.4)
(e)	Subtotal (a) + (b) + (c) + (d)	$ 397.5	$ 488.3
(f)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 10, col. (b) line 17)	$ (2.0)	$ (9.2)
(g)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 20 less J21.1 Att. 1, Table 5, col. (b), line 20)	$ (3.1)	$ -
(h)	OEB Approved Depreciation (e) + (f) + (g)	$ 392.4	$ 479.2

Table 3
Calculation of 2019 Capital Cost Allowance

			CCA Impact
	Description	**2019**	**2019**
(a)	OPG Proposed Depreciation (line 17, col. (a))	$ 400.3	$ 571.1
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 22 + line 24 + line 25 less J21.1 Att. 1, Table 5, col. (b) + (c), line 22 + line 24 + line 25)	$ 21.1	$ (0.1)
(c)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 10, line 25, col. (b))	$ (0.8)	$ (1.8)
(d)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 10, line 26, col. (b))	$ (0.2)	$ (0.4)
(e)	Subtotal (a) + (b) + (c) + (d)	$ 420.3	$ 568.7
(f)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 10, col. (b) line 27)	$ (3.1)	$ (11.5)
(g)	Adjustment for Ex. J21.1 - Asset Reitrement Costs (J21.1 Att. 2, Table 7, col. (b), line 27 less J21.1 Att. 1, Table 5, col. (b), line 27)	$ (3.1)	$ -
(h)	OEB Approved Depreciation (e) + (f) + (g)	$ 414.0	$ 557.2

Table 4
Calculation of 2020 Capital Cost Allowance

	Description	2020	CCA Impact 2020
(a)	OPG Proposed Depreciation (line 17, col. (a))	$ 541.2	$ 594.8
(b)	Adjustment for Ex. J21.1 - Excluding Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 29 + line 31 + line 32 less J21.1 Att. 1, Table 5, col. (b) + (c), line 29 + line 31 + line 32)	$ 57.5	$ 2.4
(c)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 10, line 35, col. (b))	$ (0.8)	$ (1.8)
(d)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 10, line 36, col. (b))	$ (0.2)	$ (0.4)
(e)	Subtotal (a) + (b) + (c) + (d)	$ 597.6	$ 595.1
(f)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 10, col. (b) line 37)	$ (4.1)	$ (12.9)
(g)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 34 less J21.1 Att. 1, Table 5, col. (b), line 34)	$ (3.1)	$ -
(h)	OEB Approved Depreciation (e) + (f) + (g)	$ 590.3	$ 582.2

Table 5
Calculation of 2021 Capital Cost Allowance

	Description	2021	CCA Impact 2021
(a)	OPG Proposed Depreciation (line 17, col. (a))	$ 316.7	$ 597.0
(b)	Adjustment for Ex. J21.1 - Excluding Asset retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 36 + line 38 + line 39 less J21.1 Att. 1, Table 5, col. (b) + (c), line 36 + line 38 + line 39)	$ (22.2)	$ (7.9)
(c)	Reduction in Auxiliary Heating System in-service amount (PAO App. A, Table 10, line 45, col. (b))	$ (0.8)	$ (1.6)
(d)	Reduction in Operations Support Building in-service amount (PAO App. A, Table 10, line 46, col. (b))	$ (0.2)	$ (0.4)
(e)	Subtotal (a) + (b) + (c) + (d)	$ 293.4	$ 587.1
(f)	10% reduction to nuclear operations and support services in service additions (PAO App. A, Table 10, col. (b) line 47)	$ (4.8)	$ (12.7)
(g)	Adjustment for Ex. J21.1 - Asset Retirement Costs (J21.1 Att. 2, Table 7, col. (b), line 41 less J21.1 Att. 1, Table 5, col. (b), line 41)	$ (0.2)	$ -
(h)	OEB Approved Depreciation (e) + (f) + (g)	$ 288.3	$ 574.4