ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Sch.B, as amended;

AND IN THE MATTER OF an Application by Ontario Power Generation pursuant to the *Ontario Energy Board Act* for an Order or Orders approving payment amounts for the generation of electricity for the years 2017 through 2021

SUBMISSIONS ON THE DRAFT PAYMENT AMOUNTS ORDER FROM THE SCHOOL ENERGY COALITION

January 29, 2018

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TABLE OF CONTENTS

1 GENERAL COMMENTS 3

- **1.1** INTRODUCTION 3
- **1.2** SUMMARY OF SUBMISSIONS 3

2 EFFECTIVE DATE 5

- **2.1** INTRODUCTION 5
- **2.2** REVENUE REQUIREMENT 5
- **2.3** DEFERRAL AND VARIANCE ACCOUNTS 8

3 RATE SMOOTHING 12

- **3.1** BACKGROUND AND ISSUES 12
- **3.2** OPG PROPOSAL 13
- **3.3** SEC ALTERNATIVE PROPOSAL 17
- **3.4** CONCLUSION 20

4 OTHER ISSUES 21

- **4.1** INTRODUCTION 21
- **4.2** TIMING OF RATE RIDERS 21
- **4.3** WORKING CAPITAL 21
- **4.4** CHANGE TO DVA RECOVERY AMOUNTS 22
- **4.5** REVENUE REQUIREMENT SUMMARY 22
- **4.6** REGULATORY INCOME TAXES 22
- **4.7** CALCULATION OF NUCLEAR REVENUE SHORTFALL 23
- **4.8** PENSION & OPEBS COST VARIANCE ACCOUNT - POST-2012 ADDITIONS 25
- **4.9** SRED VARIANCE ACCOUNT 25

1 GENERAL COMMENTS

1.1 ***Introduction***

1.1.1 On January 17, 2018 the Applicant Ontario Power Generation Inc. filed a draft Payment Amounts Order purporting to provide the detailed implementation of the Board's Decision with Reasons dated December 28, 2017 in this matter.

1.1.2 Pursuant to the Board's Decision, parties were invited to review and comment on the draft PAO. These are the submissions of the School Energy Coalition.

1.1.3 SEC has reviewed the draft PAO in detail, and has comments to assist the Board in three areas:

(a) ***Effective Date.*** The treatment by the Applicant of the Board's decision with respect to effective date of the new payment amounts.

(b) ***Rate Smoothing.*** The rate smoothing proposal of the Applicant pursuant to O.Reg. 53/05.

(c) ***Other Issues.*** A series of observations on other aspects of the draft PAO.

These submissions are organized under those three main headings.

1.2 ***Summary of Submissions***

1.2.1 ***Effective Date.*** These Submissions propose changes to how the impact of the Decision with respect to the effective date is presented in the PAO. They also propose that the Board specify, for each of the deferral and variance accounts listed in Appendix G that may be affected by the effective date, the baseline or reference amounts[1] that should be used for the period January to May, 2017.

1.2.2 ***Rate Smoothing.*** SEC submits that the draft PAO proposes an unacceptably high increase in bills for non-residential customers in 2018, and then a further high increase in their bills in 2020. In the latter case, the driver is the assumption – almost certainly incorrect – that there will be no new rate riders after this proceeding and prior to 2022. SEC proposes an alternative rate smoothing approach that reduces the impact in 2018 (although it remains high), and smooths the impacts over 2019-2021 by making assumptions as to the likely rate riders in 2020 and 2021.

[1] Throughout these Submissions, we have used the terms "baseline" and "reference amount" interchangeably to refer to the amounts against which variances are measured to determine entries to variance accounts.

1.2.3 ***Other Issues.*** Section 4 of these Submissions comments on eight additional items of concern, of which the two biggest are:

(a) SEC disagrees with the proposal to defer the collection of rate riders from 2018 to 2019, and amortize them over three years instead of two. SEC submits that the customers are better off if the riders go into effect immediately, and collection is completed by the end of 2019. While the immediate impact of this is muted by the rate smoothing required under O.Reg. 53/05, this would avoid a likely and substantial increase in payment amounts in 2020.

(b) SEC believes that the Applicant has calculated the nuclear revenue shortfall incorrectly, first by using the proposed smoothed nuclear payment amounts, and second by using a production figure for 2017 that is different from the one used to set payment amounts. Depending on which approach the Board takes to resolve these concerns, the shortfall OPG pegs at $700.6 million should be reduced to either $588.5 million or $560.7 million.

2 EFFECTIVE DATE

2.1 ***Introduction***

2.1.1 SEC believes there are two issues to be addressed in relation to the Board's decision to order an effective date of June 1, 2017:

(a) Is the revenue requirement for 2017 properly described, and does that carry through to all of the schedules in the draft PAO?

(b) Do the terms proposed in Appendix G for the deferral and variance accounts going forward properly account for the change in effective date, and its impact on 2017 Board-approved amounts?

2.2 ***Revenue Requirement***

2.2.1 ***Initial Presentation.*** Table 1 of Appendix A of the draft PAO sets out what the Applicant says is the approved 2017 nuclear revenue requirement.

2.2.2 SEC submits that this table sets out the nuclear revenue requirement without taking the change in effective date into account. In our submission, the approved revenue requirement for 2017 is $2,706.9[2].

2.2.3 SEC gets this figure by starting with the revenue requirement calculated by OPG, $2,973.0. Subject to our comments below, this is an appropriate method, as the Board did not make specific adjustments to individual line items to reflect pre-June amounts.

2.2.4 From this figure must be deducted the difference in January to May revenues at the existing nuclear payment amount, $59.29, as compared to the unsmoothed new 2017 payment amount, $78.03[3]. This difference is $18.74/Mwh. Since the January to May nuclear production was forecast to be 14.2 Twh[4], the reduction in revenues and therefore revenue requirement for the five months is $266.1 million.

2.2.5 As a matter of presentation, SEC submits that OPG should be required to amend Appendix A, Table 1 to add a line, after line 26, showing the $266.1 million reduction to the OEB approved revenue requirement explicitly.

[2] It appears to be entirely co-incidental that this figure is the same as the adjusted Net Fixed Assets figure.
[3] Appendix I, p. 15.
[4] Appendix C, Table 1, Note 4.

2.2.6 Similarly, on Table 6 the 2017 revenue requirement should be reduced in the same manner[5].

2.2.7 The situation for Table 8 is less obvious. While it is misleading to show the revenue requirement as $2,973.0, and thus the deficiency as $714.1, that calculation is necessary to determine the unsmoothed payment amount for the period June to December. SEC believes that there should at least be a note to this table explaining the actual 2017 revenue requirement, and the actual deficiency of $448.0 million.

2.2.8 ***Treatment of Annualized Adjustments***. The Board made a number of adjustments to 2017 approved spending by the Applicant. For some of those adjustments, like opening rate base and capital additions, those adjustments are clearly annualized in nature. They cannot be allocated to either the first five months, or the last seven months, of the calendar year.

2.2.9 That is not true of the OM&A adjustments. The OM&A adjustments are specific amounts, and the Board has not stipulated in the Decision that they should be pro-rated for the period after the effective date of June 1st.

2.2.10 While SEC ultimately agrees with the approach taken by the Applicant, we feel it is important to flag this in these Submissions, so that the Board has an opportunity to confirm this approach expressly. The dollar impact is substantial.

2.2.11 OPG has taken the approach of deducting the 2017 OM&A adjustments from the annualized 2017 revenue requirement. Once the 2017 revenue requirement is adjusted further to take account the later effective date, the result of the OPG approach is to pro-rate all of the Board's 2017 adjustments to revenue requirement based on the split in nuclear production between pre and post effective date. By way of example, the effect of this approach is to reduce the $100 million overall 2017 OM&A reduction in the Decision to $62.7 million, the portion arising on 23.9 Twh of nuclear production out of 38.1 Twh for the calendar year.

2.2.12 It is also possible to make all of the 2017 adjustments only to the revenue requirement proposed by OPG for the June to December period. That revenue requirement is $1,975.6 million ($3,149.4 x 23.9/38.1) on a production-weighted basis. If one then deducts all of the Board's adjustments, $176.4 million) from that figure, the net is $1,799.2 for the seven months. When you add the $841.9 million for the first five months (at $59.29/Mwh), the resulting 2017 revenue requirement would be $2,641.1, or $65.8 million less than OPG's proposal.

2.2.13 A further possible approach would be to limit only the OM&A adjustments to the June to December costs. If you do that, the OPG proposed revenue requirement of

[5] See our comments in Section 4.5 on the presentation of Table 6.

$2,706.9 would be reduced by $37.9 million to $2,669.0 million.

2.2.14 SEC has reviewed the Decision to find any specific guidance in this regard. We have been unable to find any. However, our read of the Board's comments, for example on page 53, suggests that the Board is intending its adjustments to be on an annualized basis.

2.2.15 For example, the statement that OM&A should be reduced by $100 million per year is more comprehensible if the five years to which it applies are all 12 month years. If one year, 2017, was only a seven month year, one would have expected the Board to explain why the reduction is effectively so much higher in 2017, relative to the underlying costs.

2.2.16 Similarly, the Board disallowed the $41 million of Fitness for Duty costs. That figure covers sixty months, not 55 months. If the Board intended to distinguish between pre and post effective date, it would have been more logical for that $41 million to have been adjusted.

2.2.17 SEC therefore submits that the approach taken by OPG of effectively pro-rating the adjustments by the Board for 2017 is the appropriate one. While the effect is to reduce the impact of the 2017 disallowances by $65.8 million, the reason for that is that portion of those disallowances is already captured in the cost of the later effective date.

2.2.18 ***Taxes and Loss Carryforwards***. A more difficult issue arises in the calculation of regulatory taxes and the resulting application of tax loss carryforwards. It is not obvious how that should be treated by the Board.

2.2.19 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. The net amount will be a loss for tax purposes, as shown in Table 16, where there is already a $33 million tax loss. That amount would become a $299.1 loss, with that amount being added to the Applicant's non-capital losses available for future use.

2.2.20 If that were the treatment determined by the Board, there would be no actual impact during the five year test period, because the OEB-approved revenue requirements for each of the following years do not produce net taxable income in excess of already available loss carryforwards[6].

2.2.21 The problem here is that this result arises only if OPG spends for the full year 2017

[6] Table 21 does not appear to SEC to be correct in this regard. See our later discussion in Section 4.6 of these submissions.

as if the effective date had been January 1, 2017, as proposed, but then only gets a revenue increase from June 1st. That is what drives the tax loss in 2017. The Applicant will argue – perhaps legitimately – that if it spends on the basis of its requested effective date, the excess tax loss should not benefit the customers because the additional costs were not funded by the customers.

2.2.22 This would seem relatively simple to resolve, except that it ties into the question of January to May baselines and incremental spending relative to OPG's many deferral and variance accounts. If OPG claims that it is spending the excess money for January to May costs out of the shareholders' funds, then it can hardly claim any of those excess amounts in deferral and variance accounts. If the Applicant will, as we suspect, seek to claim some of that excess spending through the DVA process, then it will be ratepayer funded, and the customers should get the benefit of the additional 2017 tax loss in their future rates.

2.2.23 SEC submits that the appropriate resolution of this question is to leave the tax calculation as set out by the Applicant. While this means that the actual higher tax loss for 2017 is not applied for the benefit of customers, it also implies that the shareholder is bearing all January to May costs up to the annualized Board-approved 2017 costs, which would then be treated as the DVA baseline for all of 2017.

2.3 ***Deferral and Variance Accounts***

2.3.1 Much of the Applicant's spending is protected by deferral and variance accounts, statutory and otherwise. The Applicant has shown in the past that it believes it is able to recover all or virtually all of the impact of a later effective date through a clawback via DVAs[7].

2.3.2 The later effective date in this proceeding could have the same result, unless the Board makes specific determinations on the DVAs to ensure that the customers receive the full benefit of the later effective date[8].

2.3.3 ***Disclosure Requirement.*** SEC believes that an appropriate first step in ensuring the integrity of the Board's decision is to require the Applicant, with their response to the submissions on the draft PAO, to file a full breakdown of all entries in all deferral and variance accounts for the period January 1, 2017 to May 31, 2017. All of that data is currently available, and indeed would have to be accounted forin OPG's books already as the OPG financial yearend has now passed.

[7] EB-2014-0370.
[8] SEC dealt with this issue in its Final Argument, Section 11.1, and the main concern, the RSVA, appears to have been dealt with by the Board in the Decision. We are still concerned, however, that the wording of the other DVA accounts could result in inappropriate clawbacks of the impact of the Board's Decision.

2.3.4 The requirement, in our view, should be that OPG provide to the Board all entries to all DVAs for that period, and in each case provide an explanation that includes: a) the baseline and how it was calculated, b) the actuals and the basis for those amounts, and c) the aggregate impact, if any, of their approach to the DVAs on the $266.1 million difference between existing nuclear payment amounts and unsmoothed 2017 payment amounts.

2.3.5 SEC submits that the Board will be in a better position to determine how to deal with Appendix G of the draft PAO if it has the actual entries for the period prior to the effective date.

2.3.6 ***Impact of Effective Date on Specific Deferral and Variance Accounts.*** In Appendix G, page 2 of the draft PAO the Applicant includes a direction by the Board to OPG to continue to record amounts in all DVAs on the basis of previous Board orders, and the regulation, until June 1, 2017.

2.3.7 SEC submits that it would be better for the Board in its order deals with the impact of effective date in each of the descriptions of the accounts and their entries. This general statement appears to imply that all affected spending over prior approved amounts is recoverable through the DVAs, thus substantially negating the impact of the later effective date. Where, if at all, that is appropriate in specific cases, the Board should so specify with respect to those individual accounts.

2.3.8 ***Hydroelectric Water Conditions Variance Account and Hydroelectric Surplus Baseload Generation Variance Account.*** SEC submits that the description for each account should make clear that, for 2017, the "approved hydroelectric payment amount" is $41.09 for January to May, 2017, and is $41.67 for the remainder of the year.

2.3.9 ***Ancillary Services Net Revenue Variance Account - Nuclear.*** As the monthly reference amount does not appear to change in any material way from 2016 to 2017, it would appear to us that no specifics of the 2017 treatment are required.

2.3.10 ***HIM Variance Account.*** It would appear to us that this continues to be calculated on an annualized basis during the hydroelectric IRM period, without reference to the effective date, and so no 2017 specifics are required.

2.3.11 ***Income and Other Taxes Variance Account – Nuclear.*** If the Board accepts SEC's view of baselines, then the baseline for this account would be, as proposed, $1.533 million per month for all of 2017.

2.3.12 However, if the Board accepts OPG's view that the baseline prior to the effective date is the prior approved baseline, then it would appear to us that the January to

May baseline is that approved in EB-2013-0321, which in Table 3 of the Payment Amounts Order in that proceeding appears to be ($9.4) per year. This would generate a baseline of ($3.92) for the first five months of 2017, leaving ($10.73) for the remaining seven months, and a total baseline for the year (taxes being calculated on an annual basis) of ($14.65), not ($18.4) as proposed by OPG.

2.3.13 SEC submits that the Board's order should make clear which baseline is applicable to the January to May period.

2.3.14 ***Capacity Refurbishment Variance Account – Hydroelectric.*** The Applicant proposes[9] that the baseline for capital spending on hydroelectric in 2017 should be prorated between pre and post effective date. SEC disagrees.

2.3.15 The Board's decision with respect to the capital spending baseline for CRVA was part and parcel of the review of the appropriate IRM increase for 2017 and each subsequent year. The Board calculated the increase in the payment amounts on a formula that applied to the full year, and then determined not to apply that increase for the first five months of the year.

2.3.16 The result is that implicit in the $41.67 figure is an assumption that, in 2017, $144.2 million of CRVA-eligible spending is funded in rates. Only spending above that amount should be the basis for entries in the hydroelectric CRVA.

2.3.17 The alternative is either a) essentially all capacity refurbishment spending by OPG in the first five months of the year can be added to the CRVA, or b) the baseline is reduced from $144.2 million to $84.1 million for the whole year, and all capacity refurbishment spending above that amount will be recoverable through the CRVA. Neither of these results appears to SEC to be appropriate.

2.3.18 ***Capacity Refurbishment Variance Account – Nuclear.*** The draft PAO on page 8 of Appendix G appears to suggest that the reference amount for 2017 for nuclear CRVA is the amount approved by the Board in this proceeding. This does not appear to be consistent with page 2, where it is clear that the EB-2013-0321 reference amount would be applied for the first five months of the year.

2.3.19 As these could be very significant amounts, SEC believes that the PAO should spell out the precise reference amount (Board-approved amount) for each period in 2017, and in each of the subsequent years. In SEC's view, that amount for 2017 should be the full amount for the year, and should apply to the entire year. However, if the OPG view that the prior approved amount is applicable until the end of May, then the PAO should so stipulate. In either case, the actual dollar amounts should be spelled out in the PAO to avoid the potential for confusion or debate in the future.

[9] Appendix G, p. 8.

2.3.20 ***Pension and OPEB Cash Payment Variance Account – Nuclear.*** The draft PAO does not make clear whether the monthly reference amounts for January to May, 2017 are intended to be the amounts of $16.67 million and $7.59 million approved for calendar 2017 in this proceeding, or the $23.38 million and $6.66 million respectively approved for nuclear in EB-2013-0321.

2.3.21 If the Board accepts SEC's view of the baselines prior to the effective date, the baselines will be the lower amounts approved in this proceeding, and any amounts contributed in that period above or below those amounts will be debited or credited, as the case may be, to the account.

2.3.22 Conversely, if the Board accepts OPG's view of the baselines prior to the effective date, then notwithstanding the wording on Appendix G, page 11, the EB-2013-0321 baselines would continue to be applied for January through May. The amount of the baseline would increase from an aggregate of $121.3 million, to $150.4 million, for those five months, with a resulting improvement in the net position of the customers of $29.1 million, whether by way of reduced debit to the account, or increased credit.

2.3.23 ***Pension & OPEB Cash vs. Accrual Differential Deferral Account.*** It would appear to SEC that, as both the cash and the accrual amounts for this account are actual amounts rather than Board-approved, the entries to this account cannot be affected by the effective date.

2.3.24 ***Nuclear Liability Deferral Account.*** Based on the Decision, it would appear to SEC that there can be no entries to this account in 2017. It would be useful if, in Reply, the Applicant confirmed this.

2.3.25 ***Nuclear Development Variance Account.*** As with some of the other accounts, it is unclear from OPG's description whether it is intended that the reference amounts should be applied from the beginning of 2017, or whether the previous reference amounts should applied for the first five months.

2.3.26 While the impact is small ($1.34 million for the five months using the new reference amount, $0 using the old reference amount), it would appear to us that for completeness the Board should specify which reference amounts are used for the first five months.

2.3.27 ***Bruce Lease Net Revenues Variance Account – Non-Derivative Sub-Account.*** It would appear to us that there can be no entries to this account during 2017. It would be useful if, in Reply, the Applicant confirmed this.

3 RATE SMOOTHING

3.1 *Background and Issues*

3.1.1 O.Reg 53/05 requires the Board to determine the appropriate method of smoothing the weighted average payment amounts (WAPA) of the Applicant under a set of specific criteria. Assuming those criteria are satisfied, the Board is given the discretion under the Regulation to determine the smoothing approach that it feels is most appropriate in keeping with its objectives under the OEB Act.

3.1.2 During the proceeding, the Applicant made multiple smoothing proposals, with significant changes resulting from a change to the actual regulation. In its Decision, the Board agreed with many parties that the consideration of rate smoothing would best be done after the unsmoothed payment amounts have been calculated in keeping with the Decision.

3.1.3 In the Decision, the Board also provided guidance to assist the Applicant in developing its smoothing proposal. Three aspects of that guidance stand out[10]:

(a) The Applicant should consider the impacts of the proposed rates not just on residential customers, but on all customer classes. Residential customers generally acquire the commodity under the RPP, but that already contains a component of rate smoothing that does not arise for other customers. Non-residential customers also do not have the beneficial effects of the Fair Hydro Plan.

(b) The primary goal is not to have a smooth increase in the nuclear payment amounts. The smoothing should be looked at from the customer side, even if the payment amounts are not being increased at an even pace.

(c) Rate smoothing should avoid rate shocks at any point in the test period.

3.1.4 SEC is concerned that the Applicant's proposal does not follow this guidance fully. In addition, SEC is concerned that the Applicant has inappropriately assumed that there will be no future rate riders. As a result, the Applicant has proposed to defer collection of existing DVAs, and the revenue shortfall until implementation of the Decision, as if those deferred riders could be implemented at a time when no other riders are in effect.

3.1.5 Not only is that almost certainly incorrect. It's worse, because the Applicant is engaged in its largest ever project, with its greatest ever risk of cost overruns that will,

[10] Decision, p. 155.

under the regulation, be recoverable from ratepayers as rate riders as long as the Board determines they were prudently incurred.

3.1.6 SEC's submissions are in two parts. First, we look critically at the OPG proposal and its implications for customers. Second, we propose an alternative rate smoothing method that accomplishes the goals, but minimizes the negative impacts, of the OPG proposal.

3.1.7 Both the analysis of the OPG proposal, and the details of the SEC proposal, assume that the unsmoothed payment amounts in the draft PAO, and the proposed treatment of deferral and variance accounts going forward, are accepted by the Board. SEC has made a number of comments on those payment amounts and the DVA, and others will as well. Both the OPG proposal and the SEC proposal will need to be adjusted and re-analyzed by the Board to the extent that the Board alters the unsmoothed payment amounts or the proposed treatment of deferral and variance accounts.

3.2 ***OPG Proposal***

3.2.1 The Applicant has included in its draft PAO Appendix I, Table 2, which calculates the proposed WAPA and shows the impact of the rate smoothing proposal.

3.2.2 SEC has made two adjustments to Table 2.

3.2.3 First, we have broken out the actual payment amounts in effect for 2017 and 2018, assuming implementation of the Decision as of March 1, 2018. Table 2 as filed by the Applicant says that the WAPA for 2016 is $60.97/Mwh, which is correct, but then says that the WAPA for 2017 is $62.87, which is not consistent with what actually happened in 2017.

3.2.4 The actual payment amounts for the Applicant for 2017 were $40.72 for hydroelectric and $59.29 for nuclear, and there were no riders. As a result, the calculated WAPA was $50.67. The same is true for January and February of 2018, with a slight adjustment in the weighting due to new load forecasts, producing a WAPA of $50.72 for production purchased by customers in those months.

3.2.5 These corrections are important because they dramatically change the rate impacts for customers (other than residential customers) in 2018.

3.2.6 Second, the Applicant's draft PAO assumes that the only rate riders in effect in 2019-2021 are the ones currently proposed to deal with December 31, 2015 DVA clearances, and the revenue shortfall riders covering the period June 2017 to February 2018, to be implemented 2019-2021 under the Applicant's proposals.

3.2.7 SEC has instead included in 2020 and 2021 additional riders reflecting the average rate riders in effect for hydroelectric and nuclear since they were regulated by the Board, \$2.45/Mwh and \$7.93/Mwh respectively. We have assumed they start in 2020 because we see it unlikely that OPG can file an application for clearance of 2017 or 2018 balances (the next likely clearance) in time to have it considered and implemented before the end of 2019.

3.2.8 SEC notes that assuming the average riders will apply in 2020 and 2021 is conservative, given the substantial risk of large amounts accruing in the Capacity Refurbishment Variance Accounts.

3.2.9 The revised table is as follows:

Revised OPG Table 2 from PAO

Ln.	Description	2016	2017	Jan/Feb 2018	Mar/Dec 2018	2019	2020	2021
1	Hydroelectric Pmt Amt (HPA)	\$40.72	\$40.72	\$40.72	\$42.05	\$42.43	\$42.81	\$43.20
2	Hydroelectric Pmt Rider (HPR)	\$3.83				\$0.96	\$0.96	\$0.96
3	Additional Expected Riders						\$2.45	\$2.45
4	Hydroelectric Rev. Shortfall Rider					\$0.23	\$0.23	\$0.23
5	Total Hydroelectric	\$44.55	\$40.72	\$40.72	\$42.05	\$43.62	\$46.45	\$46.84
6	Nuclear Pmt Amt (NPA)	\$59.29	\$59.29	\$59.29	\$83.10	\$76.17	\$79.70	\$83.67
7	Nuclear Pmt Rider (NPR)	\$13.01				\$1.95	\$1.95	\$1.95
8	Additional Expected Riders						\$7.93	\$7.93
9	Nuclear Rev. Shortfall Rider					\$6.27	\$6.27	\$6.27
10	Total Nuclear	\$72.30	\$59.29	\$59.29	\$83.10	\$84.39	\$95.85	\$99.82
11	Hydroelectric Prod. Forecast (HPF)	33.0	33.0	5.5	27.5	33.0	33.0	33.0
12	Nuclear Production Forecast (NPF)	47.8	38.1	6.4	33.0	39.0	37.4	35.4
13	Total Production	80.8	71.1	11.9	60.5	72.0	70.4	68.4
14	Hydroelectric Portion of WAPA	\$18.19	\$18.90	\$18.79	\$19.11	\$19.99	\$21.77	\$22.60
15	Nuclear Portion of WAPA	\$42.77	\$31.77	\$31.93	\$45.33	\$45.71	\$50.92	\$51.66
16	WAPA	\$60.97	\$50.67	\$50.72	\$64.44	\$65.70	\$72.69	\$74.26
17	% change in Hydroelectric		-8.60%	0.00%	3.27%	3.73%	6.49%	0.84%
18	% change in Nuclear		-17.99%	0.00%	40.16%	1.55%	13.58%	4.14%
19	% change in WAPA		-16.89%	0.10%	27.05%	1.96%	10.64%	2.15%

3.2.10 As can be seen, the addition of rider assumptions for 2020 and 2021 is important because it demonstrates that, under the Applicant's proposal, the customers will almost certainly receive another large rate increase in 2020 (10.64% or more) due to the proposed smoothing between now and then, and the proposed deferral of collection of the current DVAs and revenue shortfalls.

3.2.11 The effect of the OPG proposal is to ask customers to pay a 27.05% increase in the largest part of their bill in 2018, then a lower increase in 2019, then another 10.64% increase in 2020, then a lower increase in 2021.

3.2.12 SEC does not believe this qualifies as "rate smoothing", nor do we believe that this meets the spirit, intent, and technical requirements of O.Reg.53/05.

3.2.13 To give the Board a sense of the magnitude of this, SEC has calculated the impact of this proposal on Toronto District School Board, the largest school board in Ontario with in excess of 550 schools and school buildings. TDSB has an annual load of about 265 Gwh, as reported in the BPS data base.

3.2.14 The Applicant is proposing to increase their bill to TDSB (through the global adjustment) by $1,880,000 in 2018 relative to 2017[11]. This is not only a 27.05% increase over 2017 actual costs, but it is substantially in excess of 2016 as well. Under the Applicant's proposal, that would be followed by a smaller ($175K) increase in 2019, another million dollar increase in 2020, and then another smaller ($215K) increase in 2021. When all are combined, OPG seeks to have TDSB pay an incremental amount of almost $10 million over the next four years, relative to 2017 rates.

3.2.15 This is, of course, in addition to increases in transmission and distribution rates, and other parts of the bill, over that period. It is not possible to estimate the aggregate impact with any precision, but without a doubt there will be a lot less money actually available to educate children over that period.

3.2.16 Lest we be thought of as looking only at the interests of schools, SEC has also looked at the impact on the typical large user described by OPG in Appendix I, Table 1b of the draft PAO. This large user is described as having about 35 Gwh of annual load.

3.2.17 Like TDSB, this large user faces a 27.05% increase in its charges from OPG in 2018. OPG says, in Table 1b, that the impact on this customer in 2018 is $28,676 in total ($2389.66 x 12).

3.2.18 This is not correct.

3.2.19 In fact, OPG is purporting to charge this typical industrial customer $248,000 more in

[11] All of these calculations are included in the live Excel model that includes Revised OPG Table 2.

2018 than in 2017. That is followed by increases of $23,000 in 2019, $126,000 in 2020, amd $28,000 in 2021. By 2021, this customer's bill from OPG will be at least $426,000 per year higher than today, and cumulatively OPG is asking this customer to pay a further $1.3 million over that four year period.

3.2.20 SEC is not in a position to estimate the economic impact of the proposed OPG rates on industrial customers and therefore the Ontario economy over this four year period. What we can say is that, given the load from industrial customers, OPG is proposing to force those customers to pay an incremental $3.3 billion over that four year period (and about a billion in each of 2020 and 2021). The economic impacts of that – coming on top of increases in many other energy costs - cannot be good for those companies, for their employees and customers, or for the Ontario economy. It also cannot be good for the electricity sector, which in SEC's submission is one of the reasons that the rate smoothing requirements of O.Reg. 53/05 were enacted in the first place.

3.2.21 SEC is aware that OPG will argue it is fairer to compare 2018 rates to 2016, since rates went down in 2017 as rate riders expired. It is undoubtedly true that rates went down in 2017, largely as a result of delays by the Applicant in bringing its own application forward in a timely manner.

3.2.22 What is more important, though, is that customers had certain rates for the whole of 2017, and now OPG proposes a very significant jump in their energy costs. It matters not that energy costs were higher in the past[12]. Most companies (and institutions like schools) budget annually, and use recent information to assess budgets from year to year. The OPG bill to TDSB (although hidden in the global adjustment within the distribution bill), went down by about $1.4 million from 2016 to 2017. That money was not placed in a bank account. Like most enterprises, TDSB used it on its most critical spending priorities. Meanwhile, its budget for the following year from the provincial government will reflect actual 2017 energy costs.

3.2.23 The same is true of an industrial concern. If that typical industrial customer had a reduction in its energy bill of $185,000 in 2017, that first was probably lost in the noise of increases in transmission, distribution, and other costs, so little if any actual reduction would have been apparent. The industrial customer was probably not even aware that the OPG portion of the bill was lower. However, to the extent that it flowed through, that industrial customer will either use it to keep prices down, or spend it on other priorities. Then, in budgeting for 2018, it will use actual 2017 energy costs to forecast 2018 costs.

[12] Or lower, for that matter. In 2006 the payment amounts were half what is being proposed for 2018. Is that relevant to the customers today? While they may care that they are paying a lot more for nuclear energy today, for example, the practical impact they face right now arises out of the change from last year to this year.

3.2.24 It doesn't matter how you slice it, in 2018 OPG is asking customers to pay an additional 27.05% of this, the largest single component of their energy bill. Actions have consequences, and this will have consequences.

3.2.25 SEC is also aware that OPG believes no amount should be included for future rate riders, because no riders are being requested in this proceeding[13]. In our view, this is disingenuous.

3.2.26 In every year since it has been regulated, OPG has had rate riders, usually at significant levels. The only exception has been years in which rate riders expired, and new ones had not yet been established. A large proportion of the recovery of costs by OPG from customers is through rate riders. It is, in fact, for that very reason that O.Reg. 53/05 specifically includes rate riders in the rate smoothing requirements and the WAPA formula[14].

3.2.27 It is possible that the Applicant will be able to file in 2018 for clearance of accounts for 2019, but we think that unlikely. More probable is an application in 2019 for clearance of 2017 or 2018 balances starting in 2020. There is little doubt those amounts will be significant, and if there are cost overruns on capital projects, they could be even larger than normal.

3.2.28 By proposing the deferral of the rate riders from this Application until 2019, and assuming that there will be no further rate riders prior to 2022, the Applicant is setting the customers up for a substantial and unsmoothed rate hike in 2020. SEC believes that the Board, in determining the best way to smooth rates, should take this into account, and adopt a smoothing trajectory that would avoid this large 2020 increase.

3.3 ***SEC Alternative Proposal***

3.3.1 SEC believes that it is more appropriate to design a smoothing trajectory that limits the impact in 2018 to a more reasonable level, and takes the expected 2020 and 2021 rate riders into account.

3.3.2 To that end, we have proposed the smoothing approach set forth in the following table. It does four things that are different from the OPG proposal:

(a) The 2015 DVA rate riders and the revenue shortfall rate riders start in 2018, and are amortized over two years instead of three. This leaves room for new

[13] Appendix , p. 9.
[14] See Appendix D, Table 1, and Appendix E, Table 1, which show that even without taking into account entries after December 31, 2015, there will be hundreds of millions of dollars of unmortized balances in deferral and variance accounts as of the end of 2021, and even more at the end of 2018 or 2019. Entries for 2016 and following years, which will be substantial, will just add more to the future bills awaiting the customers.

riders in 2020 and beyond. We have estimated the amount of those riders over the March 2018 to December 2019 period.

(b) The increase in WAPA for 2018 is limited to slightly more than the 2016 actual WAPA, a reduction from the substantial additional increase proposed by OPG. This limits the immediate rate shock, although obviously it is still a large one year increase.

(c) New rate riders have been assumed for 2020 and 2021 at the average levels of rate riders since OPG has been regulated.

(d) Nuclear payment amounts have been estimated to ensure that there is a regular and manageable increase in WAPA each year after the significant increase in 2018. The 2020 level is deliberately kept a little lower, to leave room in case the rate riders introduced in 2020 are higher than the average. To give an idea of the impact, if the nuclear rate riders in 2020 and 2021 are $10.00/Mwh, the WAPA increase under that proposal is 4.56% in 2020, and 3.36% in 2021.

3.3.3 The SEC proposal would produce the following results:

Revised OPG Table 2 from PAO - SEC Alternative

Ln.	Description	2016	2017	Jan/Feb 2018	Mar/Dec 2018	2019	2020	2021
1	Hydroelectric Pmt Amt (HPA)	$40.72	$40.72	$40.72	$42.05	$42.43	$42.81	$43.20
2	Hydroelectric Pmt Rider (HPR)	$3.83			$1.50	$1.50		
3	Additional Expected Riders						$2.45	$2.45
4	Hydroelectric Rev. Shortfall Rider				$0.37	$0.37		
5	Total Hydroelectric	$44.55	$40.72	$40.72	$43.92	$44.30	$45.26	$45.65
6	Nuclear Pmt Amt (NPA)	$59.29	$59.29	$59.29	$63.00	$67.00	$75.00	$80.00
7	Nuclear Pmt Rider (NPR)	$13.01			$3.05	$3.05		
8	Additional Expected Riders						$7.93	$7.93
9	Nuclear Rev. Shortfall Rider				$9.65	$9.65		
10	Total Nuclear	$72.30	$59.29	$59.29	$75.70	$79.70	$82.93	$87.93
11	Hydroelectric Prod. Forecast (HPF)	33.0	33.0	5.5	27.5	33.0	33.0	33.0
12	Nuclear Production Forecast (NPF)	47.8	38.1	6.4	33.0	39.0	37.4	35.4
13	Total Production	80.8	71.1	11.9	60.5	72.0	70.4	68.4
14	Hydroelectric Portion of WAPA	$18.19	$18.90	$18.79	$19.96	$20.30	$21.22	$22.02
15	Nuclear Portion of WAPA	$42.77	$31.77	$31.93	$41.29	$43.17	$44.06	$45.51
16	WAPA	$60.97	$50.67	$50.72	$61.25	$63.48	$65.27	$67.53
17	% change in Hydroelectric		-8.60%	0.00%	7.86%	0.87%	2.17%	0.86%
18	% change in Nuclear		-17.99%	0.00%	27.68%	5.28%	4.05%	6.03%
19	% change in WAPA		-16.89%	0.10%	20.77%	3.62%	2.83%	3.46%

3.3.4 The two most obvious results of this proposal are that the 2018 increase is reduced from 27% to 21%, and the 11% increase in 2020 is reduced to a level more similar to the prior and subsequent years.

3.3.5 For TDSB, with 265 Gwhrs of load, the effect is that their OPG bill through the global adjustment will increase by $1.4 million, slightly more than the reduction from 2016 to 2017. While this is still a substantial shock, it is more manageable than the $1.9 million proposed by OPG.

3.3.6 Over the subsequent years, the TDSB bill will still be $2.3 million per year higher by 2021, but it will have avoided the second million dollar rate increase in 2020. Cumulatively, TDSB will have to pay $7.3 million more to OPG over the four years, somewhat less than the almost $10 million proposed by the Applicant.

3.3.7 The results for the typical large user are similar. The increase in 2018 is about $190,000, and by 2021 their bill has increased by about $300,000. The cumulative impact is still almost a million dollars over four years, but it is lower than the $1.3 million proposed by OPG.

3.3.8 From an economic point of view, this proposal would reduce the impact on industrial and commercial users across the province from $3.3 billion to $2.4 billion over the 2018-2021 period. Further, it would spread that impact more evenly over those four years.

3.3.9 This SEC proposal comes with consequences, though. The aggregate deferral over 2018-2021 proposed by OPG in its latest rate smoothing proposal is $700 million, down from its original proposal of $1.6 billion (which OPG said at the time was OK for them financially[15]).

3.3.10 The SEC proposal would increase the deferred revenue to about $2.0 billion, although much of that ($740 million) is the result of including additional assumed rate riders in 2020 and 2021. OPG, by ignoring those rate riders, either assumes that further smoothing will be required at that time (increasing the deferred revenue), or assumes that smoothing will end at the end of 2019. Either way, the SEC proposal is more realistic, and more in keeping with the spirit and intent of the regulation under which the smoothing is mandated.

3.4 ***Conclusion***

3.4.1 SEC therefore submits that, subject to any changes to the unsmoothed payment amounts arising out of the Board's consideration of the draft PAO, the Board should implement the SEC rate smoothing proposal rather than the OPG rate smoothing proposal.

[15] Ex. A1/Tab3/Schedule 3, p. 2.

4 OTHER ISSUES

4.1 *Introduction*

4.1.1 SEC has identified a number of other questions and concerns in the draft PAO, and outlines them in separate headings in this section.

4.2 *Timing of Rate Riders*

4.2.1 The Applicant has proposed to delay the collection of the rate riders for the December 31, 2015 DVA clearance, and for the revenue shortfalls, until January 1, 2019, and then amortize them over three years instead of two[16]. The riders would be in effect in 2019, 2020, and 2021, instead of 2018 and 2019. The apparent intent is to allow a greater increase in the nuclear payment amount under the rate smoothing proposal.

4.2.2 SEC disagrees with this proposal.

4.2.3 The only way a deferral of these collections makes sense is if there are no new rate riders expected prior to 2022. That is not likely to be true, as there are already substantial balances in accounts that will have to be cleared in those years[17]. There will certainly be additional amounts added to those accounts in 2016, 2017, and 2018.

4.2.4 As we note in our alternative rate smoothing proposal, the better way to approach this from the point of view of the customers is to pay the rate riders at the normal times (which would be 2018 and 2019, typically), and adjust the nuclear payment amount to implement the rate smoothing required by O.Reg. 53/05. This ensures that the smoothing mechanism accounts for future rate riders, thus avoiding a large spike in rates in 2020.

4.3 *Working Capital*

4.3.1 In Appendix A, Table 1, the Applicant lists working capital as unchanged from the Application to the Board-approved rate base. We have reviewed once again Exhibit B, Tab 1, Schedule 1 of the Application, and it is not clear to us why, given the substantial changes in the components of revenue requirement in the Decision, there is no material impact on the working capital component of rate base.

4.3.2 It would be useful if, in Reply, the Applicant explained why the changes have no impact on working capital.

[16] PAO, p. 3, 5, and Appendix G.
[17] Appendix D, Table 1 and Appendix E, Table 1.

4.4 ***Change to DVA Recovery Amounts***

4.4.1 Tables 1 through 5 of Appendix A imply, in line 27, that the Board has ordered a change to the timing of the DVA rate riders. While we understand that this is a draft of an order of the Board, and thus if the Board agrees the Board would be so ordering, as presented it looks like the deferral of the DVA collections is responsive to something in the Decision.

4.4.2 In our view, the tables should make clear that this is an OPG-proposed adjustment.

4.5 ***Revenue Requirement Summary***

4.5.1 Table 6 of Appendix A, which follows Tables 1-5, appears to be a summary of the final approved revenue requirements in those tables, but the figures are instead the OPG proposed amounts for those years. SEC is unable to determine the purpose of this table, if that is what it in fact is intended to present. On the other hand, if it is intended to summarize Tables 1-5, then the figures in this table are incorrect.

4.5.2 SEC believes that this Table should be replaced with one that correctly summarizes Tables 1 to 5. In addition, for 2017 the additional line to reflect the impact of the effective date should be added.

4.5.3 We note that this issue does not appear to arise in most of the other Tables, but it pops up again in Tables 21 and 21a, with the same issues as above.

4.6 ***Regulatory Income Taxes***

4.6.1 ***Depreciation and Capital Cost Allowance (CCA).*** Tables 16, 17, 18, 19, and 20 of Appendix A have figures on line 2 for Depreciation, and line 12 for CCA. Although we understand that these figures will be affected by the particular composition of the depreciable assets in each year, there is no discernable pattern to the relationship between Depreciation and CCA in the tables.

4.6.2 SEC submits that the Applicant should explain in each case and in detail the substantial differences in column (b) of these tables between the impact of the Board's Decision on Depreciation, and the impact on CCA.

4.6.3 ***Loss Carryforwards***. The draft PAO applies non-capital loss carryforwards in the tax tables, line 21, for each of the years.

4.6.4 SEC submits that these loss carryforward amounts, which are substantial, would be more comprehensible if the Applicant filed with the draft PAO the non-capital loss continuity schedule on which they are based.

4.7 *Calculation of Nuclear Revenue Shortfall*

4.7.1 ***Assumed Production.*** The impact of the effective date is calculated, for nuclear revenue requirement purposes, using the original forecast nuclear production for 2017, 38.1 Twh, and the split between 14.2 Twh of production prior to the effective date, and 23.9 Twh of production after May. The effect, as we discuss in section 2 of these Submissions, is to calculate revenue requirement on the basis that 62.73% of costs are incurred after May, and 37.27% of costs are incurred prior to the effective date.

4.7.2 Put another way, the unsmoothed payment amounts applicable to June to December are calculated on the basis of the 23.9 Twh production assumption, producing the $78.03/Mwh unsmoothed figure.

4.7.3 However, in Table 2 of Appendix F, the revenue shortfall is based on actual production of 24.8 Twh for the period in 2017 after the effective date. If that number had been used in the calculation of the unsmoothed payment amount, the nuclear payment amount would be $76.23[18].

4.7.4 SEC submits that using either actual production or forecast production can be justified for the seven months of new payment amounts applicable to 2017. However, whichever is chosen, it should be applied to the allocation of costs to the period after the effective date, the calculation of the unsmoothed payment amounts, and the calculation of the lost revenues for the seven months of 2017. Using different assumptions for some of those calculations produces a mismatch, and produces unfair results.

4.7.5 ***Smoothed vs. Unsmoothed Rate.*** The Applicant calculates its revenue lost between effective date and implementation date based on the smoothed nuclear payment amount. SEC believes this is not appropriate.

4.7.6 The issue is the extent to which the Applicant has lost revenue during that nine month period. Their position is that, since they would collect (if the implementation date and the effective date were the same) on the basis of the smoothed rates, that is what should be compared to the previous rates still in effect.

4.7.7 What this ignores is the fact that the smoothing is not of the nuclear payment amounts, but of WAPA. Thus, for example, the effect of shifting the collection of the DVAs, and the revenue shortfall rider, from 2018 to 2019, and the effect of proposing a sharp increase in 2017 that is collected in subsequent years, would be to increase the revenue shortfall recovered by OPG.

4.7.8 By way of example, if the Decision had been implemented June 1, 2017, and the rate

[18] See Appendix I, p. 19. The revised figure is $2,973/39.0 rather than 38.1.

riders put in place at that time (to end December 31, 2019), the nuclear payment amounts would have been $71.40/Mwh for the last seven months of 2017 (to get to OPG's targeted WAPA of $62.56/Mwh), and $73.85/Mwh for 2018 (to get to OPG's targeted WAPA of $64.15). In that scenario, the revenue loss is actually $300 million in 2017, and $104.8 million in the first two months of 2018. This is essentially entirely because the riders are included in the WAPA calculation[19].

4.7.9 SEC submits that the approach to the calculation of the revenue shortfall should not be driven by a decision whether to defer rate riders, or indeed any aspect of the rate smoothing mechanism ultimately approved by the Board. That is, in our view, an artifact of the method used to calculate WAPA and to smooth that amount.

4.7.10 The better approach, in our view, is to calculate the revenue shortfall by reference to the unsmoothed payment amount. That way it is unaffected by any rate smoothing decisions, and accurately reflects the shortfall amounts actually allocable to the time periods in question.

4.7.11 We note that this has no ultimate impact on the amount OPG collects from customers. Using the smoothed amount as the comparison for revenue shortfall purposes has the effect of shifting some of the smoothing deferral amount into the interim period revenue shortfall. The total remains the same. It just ends up in a different pot.

4.7.12 Put another way, the difference between the $80.65/Mwh proposed by OPG for 2017, and the unsmoothed amount of $78.03/Mwh, $2.62/Mwh, or $65.0 million in aggregate, is the result of the rate smoothing mechanism. It is not a result of the difference between effective date and implementation date. If the effective date and the implementation date were the same, that $65.0 million would be part of the rate smoothing deferral amount.

4.7.13 ***Impacts.*** The effect of using the actual production vs. the forecast production can be valued two ways. Using the original unsmoothed nuclear payment amount, and the actual production, the 2017 revenue shortfall is $464.8 million. Using the forecast production, it is $447.9 million, a difference of $16.9 million. This is the impact of using the same production figure as in the calculation of the payment amounts.

4.7.14 On the other hand, if the Board is to use actual production for both the shortfall and the calculation of the unsmoothed payment amount, then the new unsmoothed payment amount should be $76.23, and the revenue shortfall would be $420.1 million.

[19] The calculation is, of course, circular because the riders include the revenue shortfall rider, which in any case would not apply if the implementation date and the effective date were the same. WAPA calculations can thus only be estimated, and then only by trial and error. However, the effect cited is still correct. The NPA figures used by OPG, $80.65 and $83.10 respectively, are based on the assumption that all rate riders are deferred until 2019.

4.7.15 For 2017, OPG used the smoothed payment amount to calculate a revenue shortfall of \$529.0 million. Depending on whether the Board adjusts the production figure or the unsmoothed nuclear payment amount to get to a consistent set of figures, the 2017 revenue shortfall should be either \$447.9 million or \$420.1 million. This is the result when the combined effect of using unsmoothed rather than smoothed payment amounts, and using consistent production figures, is calculated.

4.7.16 The recalculation of the 2018 component is easier, because the only variable is using the smoothed vs. unsmoothed rate. The unsmoothed rate for 2018 is \$78.82/Mwh[20]. When that is applied to 7.2 Twh of production for January and February of 2018, the revenue shortfall is \$140.6 million, not the \$171.6 million calculated by OPG.

4.7.17 SEC therefore submits that the nuclear revenue shortfall to the end of February, 2018, should, depending on the approach the Board takes to the production assumption, be either \$588.5 million or \$560.7 million, not the figure of \$700.6 million proposed by the Applicant.

4.8 ***Pension & OPEBs Cost Variance Account - Post-2012 Additions***

4.8.1 At page 9 of Appendix G, the Applicant notes that this component of this account is due to be fully recovered as of June 30.2021. The Applicant proposes to include this in a fixed rate rider that continues until December 31, 2021.

4.8.2 SEC submits that the Applicant should show the Board how the extension of recovery of this account remains consistent with the original term of the account.

4.9 ***SRED Variance Account***

4.9.1 The proposed accounting order for this account, found at Appendix H, p. 4, appears to correctly set out the entries, subject to one concern. SEC notes that this calculates the variance in the actual tax credits, which are an after-tax amount. There is no description of the method by which the net tax impact is then grossed up before being recovered from or paid to customers.

4.9.2 SEC submits that the accounting order should made clear how this will be done.

All of which is respectfully submitted.

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[20] Appendix I, p. 15