ONTARIO POWER GENERATION

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VIA RESS AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: EB-2016-0152 – Amended Response to Interrogatory L-1.3-8 GEC-64

Enclosed is an amended response to interrogatory L-1.3-8 GEC-64 as directed by the OEB in its February 15, 2017 Decision and Order on Motion Filed by Green Energy Coalition. OPG has submitted this document through the Regulatory Electronic Submissions System and is providing fourteen (14) paper copies. This material will also be available on OPG's website at www.opg.com.

Yours truly,

[Original signed by]

Barbara Reuber

cc: John Beauchamp (OPG) via e-mail
Charles Keizer (Torys) via e-mail
Crawford Smith (Torys) via e-mail

GEC Interrogatory #64

Issue Number: 1.3
Issue: Is the overall increase in nuclear payment amounts including rate riders reasonable given the overall bill impact on customers?

Interrogatory

Reference:

Please estimate the impact on payments and customer rates in each year of the 20 year deferral and recovery period, with and without the smoothing proposal, should the government require the exercise of an off-ramp in regard to the DRP at the completion of Unit 2 refurbishment.

Response

The following response was provided by OPG on October 26, 2016:

OPG is unable to provide the requested estimate and doesn't believe it is relevant to any issue on the approved Issues List. The costs that would be incurred if an off-ramp were to be exercised would depend on the timing of the decision and the specific direction from the Government regarding the future operation of Darlington. Any attempt to calculate 20 years of payment amounts without this information would be speculative, as it would be entirely dependent on assumptions that have no basis in fact. In the event the Government exercises an off-ramp during the period covered by this application, OPG would inform the OEB and seek direction.

In its Decision and Order on GEC's motion with respect to this interrogatory, the OEB required OPG to respond to the following more defined question: "Assuming that the costs are consistent with the release quality estimate, but work stops at the completion of Unit 2, which is currently planned to be completed in 2020, what would the customer bill impact be both with and without smoothing using the same period for recovery as in the original analysis? For comparison, please provide the customer bill impacts if all four units were to proceed to completion as planned (both smoothed and unsmoothed)."

OPG has not undertaken an assessment of the business strategies it would employ in the scenario posed in the above question. OPG made assumptions necessary to provide a response to the question.

Contextual assumptions made in this analysis include:

- The Pickering units are shut down in 2022/2024, as reflected in OPG's application
- Bruce refurbishment takes place as scheduled, per the 2015 amended refurbishment agreement between Bruce Power and the IESO

- No changes to CNSC or other regulatory requirements, notwithstanding single-unit station operation at Darlington
- No changes to nuclear decommissioning and waste management costs[1]
- No changes to cost of capital impacts (e.g., financing costs, capital structure resulting from changes in OPG's risk profile)
- To provide a consistent basis of comparison with the base case, no changes to OPG's rate smoothing proposal per the pre-filed evidence (i.e. 11%/yr nuclear rate smoothing)

OPG has assumed that work on Darlington refurbishment stops in February 2020, which is the currently planned completion date of Unit 2, and that there is no impact on OPG costs or firm financial commitments prior to that date. The assumed costs resulting from the discontinuation of the refurbishment include expenditures incurred and commitments made to that point with respect to the remaining units, and estimated demobilization costs. The analysis is based on cost flows consistent with the DRP release quality estimate.

The assumed unit shutdown sequence is as follows, with depreciation expense adjusted accordingly: Unit 3 in June 2020, Unit 1 in October 2022, Unit 4 in March 2024 (refer to Ex. L-4.3-8 GEC-009) and Unit 2 in February 2050. OPG has assumed that technical considerations associated with running a four-unit nuclear station with only one operating unit would be overcome without significant operational or cost impacts.

As the non-refurbished units are shut down, OPG has assumed step reductions in Darlington station base and project OM&A expenses, nuclear support and corporate support OM&A expenses, and capital spending. Assumed outage plans have been adjusted to reflect major outage requirements of the non-refurbished units.

Severance and related costs would be incurred in relation to incremental headcount reductions as the non-refurbished units shut down. These have been assumed to be proportional to the Pickering extended operations assumptions. No other changes in labour strategies have been assumed.

OPG's application provides customer bill impacts on a smoothed basis and unsmoothed basis[2] for the 2017 to 2021 period, and on a smoothed basis for the entire 2017 to 2036 forecast rate smoothing and recovery period[3]. Attachment 1 summarizes the customer bill

[1] Decommissioning of the three non-refurbished units would be assumed to occur after the Unit 2 safe storage period; therefore, the assumed timing of decommissioning would be similar to the current four-unit refurbishment assumptions. A reduction would occur in assumed lifecycle fuel and other nuclear waste due to earlier shutdown of Units 3, 1, and 4. OPG is unable to provide an impact on the costs given the complex nature of the calculations, underlying information requirements and time available to respond.
[2] For purposes of calculating the impact on an unsmoothed basis, nuclear payment amounts are assumed to increase at a uniform annual rate for 2017-2021 such that no revenue requirement amount is deferred for recovery in the Rate Smoothing Deferral Account at end of the five-year period. For 2022-2036, average five-year unsmoothed rates were used (see footnote 3).
[3] As explained in OPG's response to JT3.11, the rate smoothing model underpinning the application is based on the proposed annual revenue requirements for 2017-2021 (Ex. I1-1-1 Table 1, line 26), and five-year averages of estimated revenue requirements and production forecasts for the 2022-2036 period. These indicative five-year

impacts based on information used to prepare OPG's May 27, 2016 application and supporting evidence ("DRP as Proposed"). These same impacts, adjusted to reflect the above assumptions with respect to the assumed discontinuation of DRP after completion of Unit 2 in February 2020, are provided in a consistent format in Attachment 1 ("DRP Discontinued").

Consistent with the approach to calculating customer bill impacts in the pre-filed evidence, changes to non-OPG system costs arising from changes in OPG's generation are not assumed. Therefore, replacement energy and capacity costs that would be required in the absence of the three Darlington units after their end of their original life are not reflected.

OPG does not believe that the scenario analyzed is a realistic one. Assessment of the business strategies OPG would employ in such a scenario are far more complex than reflected in the indicative assumptions provided above to prepare this response. As OPG noted in its response to Ex. L-4.3-1 Staff-044, "OPG would expect that any decisions regarding the on-going feasibility of the [Darlington Refurbishment Program] schedule or the plan would only be made after a rigorous process of evaluation similar to the one which was undertaken on the decision to proceed with the refurbishment of the Darlington (and the Bruce) units. OPG expects the evaluations and decision-making would involve OPG, the Independent Electricity System Operator, the Ministry of Energy, the Ministry of Finance, other relevant Ministries, and the Cabinet".

averages were calculated using average rates and production for the 2022-2036 period absent rate smoothing, as provided in Ex. A1-3-3, p. 7, Chart 2.

Customer Bill Impacts: DRP as Proposed vs. DRP Discontinued

		Combined Customer Bill Impacts						Customer Bill Impacts (4)
Description	**Notes**	**2017**	**2018**	**2019**	**2020**	**2021**	**2017-2021**	**2017-2036**
DRP as Proposed:								
Unsmoothed Bill Impact ($)	1	$ (0.77)	$ 2.39	$ 1.91	$ 2.81	$ 2.97	$ 1.86	$0.51
Unsmoothed Bill Impact (%)	1	-0.5%	1.6%	1.3%	1.9%	2.0%	1.2%	0.3%
Smoothed Bill Impact ($)	2	$ (1.29)	$ 1.73	$ 1.07	$ 1.86	$ 1.89	$ 1.05	$0.42
Smoothed Bill Impact (%)	2	-0.9%	1.1%	0.7%	1.2%	1.3%	0.7%	0.3%
DRP Discontinued								
Unsmoothed Bill Impact ($)	3	$ (0.38)	$ 2.92	$ 2.61	$ 4.25	$ 4.78	$ 2.84	$0.84
Unsmoothed Bill Impact (%)	3	-0.3%	1.9%	1.7%	2.8%	3.2%	1.9%	0.6%
Smoothed Bill Impact ($)		$ (1.29)	$ 1.73	$ 1.07	$ 2.24	$ 2.34	$ 1.22	$1.58
Smoothed Bill Impact (%)		-0.9%	1.1%	0.7%	1.5%	1.6%	0.8%	1.1%

Notes

1: Annual unsmoothed bill impacts supporting the 2017 to 2021 amounts in Ex. A1-3-3, Page 2, lines 10 to 13.

2: Annual smoothed bill impacts supporting the 2017 to 2021 amounts in Ex. I1-2-1 Table 2, lines 4 and 5.

3: Annual unsmoothed bill impacts from annual average nuclear payment amount increases of 18% per year over the 2017 to 2021 period to recover the revised nuclear revenue requirement over the revised production levels for the 2017 to 2021 period. Approach is consistent with approach used in footnote 1 above.

4: Reflects the year-over-year average of the annual customer bill impacts.