UNDERTAKING JT1.2

Undertaking

WITH REFERENCE TO SEC-02(D) ATTACHMENT 3, NO. 8, TO PROVIDE A COST BREAKDOWN SPECIFIC TO THE WINDING ISSUE, INCLUDING SCHEDULE DELAY, AND WHETHER OPG WAS SUCCESSFUL IN ANY LIQUIDATED DAMAGE RECOVERY.

Response

OPG understands that the undertaking is intended to refer to Ex. L-H-SEC-01, Attachment 3, item no. 8.

OPG has obtained liquidated damages in the amount of [redacted] for the windings issue and associated delay to the Sir Adam Beck I Generating Station – Unit G10 Major Overhaul and Upgrade project. This payment was applied to reduce the total project cost and is therefore already accounted for in the amounts OPG seeks to recover through the Capacity Refurbishment Variance Account in this proceeding.

UNDERTAKING JT1.3

Undertaking

WITH REFERENCE TO ATTACHMENT 6, TO ADVISE WHETHER OR NOT THEY WERE SUCCESSFUL IN ACHIEVING LIQUIDATED DAMAGES DUE TO POOR CONTRACTOR SCHEDULED PERFORMANCE, AND CONFIRM THAT IT HAS BEEN CONSIDERED IN THE COST THAT OPG IS TAKING TO RECOVER.

Response

In reference to Ex. L-H-SEC-01, Attachment 6, OPG pursued liquidated damages and will receive compensation with respect to the Manitou Falls GS – Auto Sluice System Replacement project ("Manitou Falls project"). The contractor will compensate OPG, [redacted], no later than [redacted]. The compensation, [redacted], will be applied against future regulated hydroelectric work as the Manitou Falls project will have been completed.

UNDERTAKING JT1.4

Undertaking

ON A BEST-EFFORTS BASIS, WITH RESPECT TO THE ENTRIES IN THE CAPACITY REFURBISHMENT VARIANCE ACCOUNT, TO ADVISE THE TOTAL COVID COST BY YEAR FOR THESE PROJECTS, BROKEN OUT INTO CAPITAL AND NON-CAPITAL; TO PROVIDE A BEST-EFFORTS DISCUSSION OF THE SCHEDULE DELAY IMPACT ON INTEREST COSTS AS PART OF THE PROJECTS THAT ARE LAID OUT IN THIS EVIDENCE, AS WELL AS WHERE THERE IS REFERENCE TO ADDITIONAL OPG MANAGEMENT COSTS IN THE CONTEXT OF THOSE SCHEDULED DELAYS.

Response

Set out below are the regulated hydroelectric projects for which OPG is seeking recovery through the Capacity Refurbishment Variance Account in this proceeding that OPG estimates incurred direct costs as a result of the COVID-19 pandemic (e.g., costs associated with additional cleaning, quarantine and supplies) over the period. A summary of these costs, by year, is provided in Chart 1. All of these costs are capital in nature. Cost impacts resulting from the schedule extensions due to the COVID-19 pandemic are included in the overall schedule impacts provided in the latter part of this response and are not separately available.

Chart 1: Estimated COVID-19 Direct Costs

Project ($M)	2020	2021	Total
Sir Adam Beck I Generating Station – Unit G5 Major Overhaul	0.5	0.1	0.6
Whitedog Falls Generating Station – Sluicegate #1, #4, #5, #6 Replacement	0.2	0.1	0.3
Aguasabon Generating Station – Surge Tank Replacement	-	0.9	0.9
Abitibi Canyon Generating Station – Unit G5 Stator Winding Replacement	0.1	-	0.1
Caribou Falls Generating Station – Sluicegate #4 and #6 Replacement	-	0.1	0.1
Sir Adam Beck I Generating Station – Units G1, G2 Replacement	0.4	0.5	0.9
Ranney Falls Generating Station G3	0.0	-	0.0

R.H. Saunders Generating Station – Replacement of Westinghouse Excitation	0.0	-	0.0
Total	**1.2**	**1.7**	**2.9**

Numbers may not add due to rounding

Set out below are the regulated hydroelectric projects for which OPG is seeking recovery through the Capacity Refurbishment Variance Account in this proceeding that OPG estimates incurred costs in excess of the First Execution BCS estimate as a result of schedule delays over the period. A summary of these costs is provided in Chart 2. All of these costs are capital in nature. Cost impacts resulting from the schedule delays due to the COVID-19 pandemic are included in these impacts.

Chart 2: Estimated Interest and Project Management Costs Due to Schedule Extension

Project ($M)	Interest Costs	Project Management Costs
Sir Adam Beck I Generating Station – Unit G10 Major Overhaul and Upgrade	0.8	0.1
Stewartville Generating Station – Sluicegate Replacement	0.0	0.0
Manitou Falls Generating Station – Auto Sluice System Replacement	0.1	0.1
Sir Adam Beck I Generating Station – Unit G5 Major Overhaul	0.7	0.1
Pine Portage Generating Station – Auto Sluice System Replacement	0.1	0.2
Caribou Falls Generating Station – Auto Sluice System	0.1	0.1
Total	**1.8**	**0.6**

Numbers may not add due to rounding

As noted in Ex. JT1.2, for the Sir Adam Beck I Generating Station – Unit G10 Major Overhaul and Upgrade project, OPG recovered liquidated damages in the amount of [redacted] for the windings issues and associated schedule delays, which was applied to reduce the total project cost and therefore the amounts OPG seeks to recover through the Capacity Refurbishment Variance Account in this proceeding. As the payment was not specifically allocated, the benefit of the liquidated damages is not included in Chart 2.

UNDERTAKING JT1.17

Undertaking

TO CLARIFY THAT DURING PERIODS OF SBG OPG WOULD NOT HAVE PUMPED THE PGS, NOT HAVE UTILIZED THE PGS MORE.

Response

OPG understands this undertaking to be a request to clarify whether, during periods of surplus baseload generation (“SBG”), OPG would have utilized the Sir Adam Beck Pump Generating Station (“PGS”) more if OPG’s hydroelectric incentive mechanism (“HIM”) revenues were not shared (Tr. Tech. Conf., April 4, 2024, p. 84, lines 17-21).

For the periods for which OPG is seeking disposition of SBGVA balances in this proceeding, HIM revenue sharing did not impact PGS utilization and the PGS would not have been utilized more in the absence of such sharing because the HIM revenues remained below the Hydroelectric Incentive Mechanism Variance Account sharing threshold.[1]

[1] As described at Ex. H1-1-1, p. 8, the Hydroelectric Incentive Mechanism Variance Account "records a credit to ratepayers of 50% of OPG’s HIM revenues above an OEB-specified threshold, currently set at $54.5M based on the forecast of HIM revenues reflected in the hydroelectric payment amounts approved in EB-2013-0321.” Actual HIM revenues, as presented in Ex. L-M-SEC-08, Chart 1, remained below the OEB-specified threshold amount in the applicable years.

UNDERTAKING JT1.18

Undertaking

TO PROVIDE A MORE DETAILED RESPONSE FOR IR IESO-02B, ON THE MEANING OF "BEING CONSTRAINED OFF AS A RESULT OF THE OPERATION OF THE MARKET."

Response

OPG understands this undertaking to refer to OPG's response in Ex. L-M-IESO-02, part a), where OPG stated:

> If OPG is not compensated for the revenue lost from foregone generation due to being constrained off, OPG would incur a revenue loss that is unrelated to its operation of the prescribed facilities and instead is due to the operation of the market.

OPG's reference to "operation of the market" in the response was broad and intended to capture the impact of physical constraints of the power system that are present during the operation of the market, as distinguished from factors within OPG's control as captured by the reference to "its [OPG's] operation of the prescribed facilities".

UNDERTAKING JT1.19

Undertaking

TO PROVIDE A MORE DETAILED RESPONSE TO STAFF-23.

Response

OPG understands this undertaking to be a request for whether the back-test method described in Ex. L-M-SEC-06, or the forecast method described in Ex. L-M-SEC-10, could be used to provide a more detailed response to Ex. L-M-Staff-23, which asked for a quantification of the impact on the SBGVA additions in the new market design under Market Renewal (Tr. Tech. Conf., April 4, 2024, p. 101).

The back-test method described in Ex. L-M-SEC-06 can only approximate how the SBGVA balances would have differed in a historical period if entries were made under the SBGVA methodology proposed in this proceeding for the new market design. Since historical spill amounts are not indicative of the future and, as discussed in Ex. L-M-Staff-23, do not reflect efficiencies of reduced spill that are expected in the new market, this method is not appropriate for approximating impacts on the SBGVA on a forward-looking basis.

Regarding the forward-looking total customer cost analysis provided in Ex. L-M-SEC-10, OPG's model is unable to discern between local and global curtailment amounts. As explained in Ex. L-M-IESO-03, the model considers SBGVA additions by including both local and global spill amounts in both modelled scenarios. Hence, OPG's total customer cost modelling approach is unable to and does not model the difference between the current SBGVA methodology and the proposed SBGVA methodology for the new market design.

UNDERTAKING JT1.20

Undertaking

TO PROVIDE A FURTHER RESPONSE TO L-H-ED-08, USING IESO DATA FOUND AT THE IESO POWER DATA DIRECTORY; IF THIS IS NOT POSSIBLE, TO EXPLAIN WHY.

Response

The information requested in this undertaking is not relevant to assessing the recoverability of the requested balances in the Hydroelectric Surplus Baseload Generation Variance Account ("SBGVA") or any other issue before the OEB in this proceeding.

The SBGVA records the financial impact of foregone production resulting from SBG conditions in accordance with the OEB's decisions and orders. In support of the amounts sought through the SBGVA, OPG has provided evidence in this proceeding regarding the basis for its decision-making with respect to PGS utilization during the times for which entries have been made to the SBGVA. The status of gas generation facilities at a time when such entries were made is not relevant to OPG's compensation for foregone hydroelectric production resulting from SBG conditions through the SBGVA because market operations including generator dispatch are in the purview of the IESO and not OPG. The IESO manages SBG conditions as an element of ensuring the reliability and efficiency of Ontario's power grid. As discussed in section 2.4 of the SBG Study (Ex. M1-1-1, Attachment 1), during periods of SBG, the IESO utilizes a "dispatch order for baseload generation which will produce real-time dispatch outcomes that promote market efficiency, achieve cost-effectiveness, [and] minimize environmental impacts".

UNDERTAKING JT1.21

Undertaking

FOR EACH HOUR WHERE WATER IS BEING SPILT AND GAS IS OPERATING IN THE PROVINCE, CAN YOU PROVIDE A TABLE THAT NAMES THE HYDRO FACILITIES RESPONSIBILITY FOR THE SBGVA ENTRIES AND THE NAME OF THE GAS GENERATORS THAT ARE RUNNING IN THOSE HOURS, SUBJECT TO BEING ABLE TO FIND THE NECESSARY DATA IN THE ONLINE IESO POWER DATA DIRECTORY, WITH THE SAME CAVEATS AS GIVEN IN JT1.20.

Response

Refer to Ex. JT1.20.

UNDERTAKING JT1.22

Undertaking

TO CONFIRM WHETHER OPG IS AWARE OF CIRCUMSTANCES OR SITUATIONS WHEN HYDROELECTRIC SPILL IS OCCURRING WHEN GAS-FIRED GENERATION IS RUNNING.

Response

OPG can only speculate as to the reasons why gas-fired generation is running while hydroelectric spill is occurring, as such analysis requires access to the IESO's dispatch algorithm and dispatch data. Based on OPG's experience in operating in the Ontario market, below are some examples of circumstances when gas-fired generation may be running while OPG is foregoing generation in the form of hydroelectric spill as a result of SBG conditions. OPG notes that this list is not intended to be exhaustive.

- **Operational Constraints:** Gas-fired generation facilities have operational constraints such as minimum run times representing the duration gas units must be online in order to ramp to a minimum loading point and meet the facility's minimum generation block run-time.
- **System Reliability:** Gas-fired generation facilities play an important role in maintaining system reliability. At times, these facilities are online at minimum loading points to be available to respond to ramping requirements for hourly changes in variable generation such as wind and solar.
- **Cogeneration Facilities:** Cogeneration facilities produce both electricity and steam for downstream processes and often run continuously.
- **Testing:** Gas-fired generation facilities may be required to perform periodic testing.
- **Local Reliability Needs:** Gas-fired generation facilities may be required to be online at minimum loading points in order to meet local needs.