HYDROELECTRIC INCENTIVE MECHANISM, SURPLUS BASELOAD GENERATION AND MAKE WHOLE PAYMENTS

1.0 PURPOSE

This evidence explains OPG's proposal for the continuation of changes to OPG's regulatory framework as a result of the implementation of IESO's Market Renewal Program ("MRP" or "Renewed Market"), as established and settled in EB-2023-0336, based on quantitative results from the first five months of OPG's experience in the Renewed Market. It also proposes changes to the sharing of Hydroelectric Incentive Mechanism ("HIM") revenues for the IR term. Additionally, as committed in EB-2023-0336, OPG has attached the Hydroelectric Surplus Baseload Generation Variance Account Study ("SBGVA Study") as Attachment 1.

2.0 OVERVIEW

In this application OPG is seeking the following approvals, as established and settled in EB-2023-0336, further supported by OPG's experience in the Renewed Market:

1. To continue to book amounts in the SBGVA based on the revised local and global Surplus Baseload Generation ("SBG") spill methodology, as described in Section 4.0;
2. To continue to be settled according to the revised HIM, which includes separate day-ahead and real-time incentives and uses locational prices based on daily average, as described in Section 5.0;
3. To continue the revised HIM adjustment for spill ("unintended benefit") as described in Section 5.0; and
4. To continue to retain Real-Time Energy Make Whole Payments as described in Section 6.0.

These approvals will continue the alignment of certain ratemaking methodologies related to production from OPG's prescribed hydroelectric generating facilities, as approved by the OEB, with the design and operations of the Renewed Market.

OPG is also seeking the approval to eliminate the sharing of HIM revenues above the threshold established in Ex. G1-1-1 as described in Section 5.0. This proposal is supported by a Market Surveillance Panel ("MSP") recommendation and is detailed in OPG's SBGVA Study as an outcome of one of the studied options. The proposed removal of HIM revenue sharing maintains OPG's incentives across all market outcomes to the benefit of ratepayers.

3.0 OVERVIEW OF THE RENEWED MARKET

While the Renewed Market introduced many operational changes,[1] the impacts on OPG's Regulated Framework addressed in this Exhibit are outlined in Chart 1 and are described further below.

Chart 1: Mapping of MRP Design Elements to Impacted OPG Regulated Framework Addressed in this Application

MRP Changes		Impacts to OPG Regulated Framework: SBGVA	HIM	Other Revenues	MWP/CMSC
Single Schedule Market	Uniform price to Locational Prices	☑	☑	☑	
	Eliminate Unconstrained schedule	☑		☑	☑
	Changes to MWP				☑
DAM & RTM	DAM & RTM Settlement		☑	☑	

3.1 Single schedule market ("SSM")

In the Legacy Market (referring to the market prior to MRP), the IESO used two dispatch algorithms: one to schedule and dispatch resources to meet demand and another to determine prices.[2] The dispatch setting "constrained" algorithm included transmission constraints and losses, while the "unconstrained", uniform price-setting algorithm did not. In comparison, the Renewed Market includes a single schedule optimization that utilizes the same dispatch algorithm for both dispatch scheduling and pricing. The Locational Marginal Prices ("LMP")

[1] A complete list of contemplated changes can be found in the IESO's high-level design documents: <https://www.ieso.ca/en/Market-Renewal/Energy-Stream-Designs/High-Level-Designs>.

[2] For purposes of this exhibit, a 'resource' refers to a single or group of generating units that connect to the IESO controlled grid at a specific node.

published in the Renewed Market incorporate the cost of congestion and losses to reflect the marginal cost of energy at each electrical node on the system. These prices typically reflect dispatch schedules received at each resource and are used for market settlement, subject to a floor price.

3.2 Financially binding Day-Ahead Market ("DAM") and Real-Time Balancing Market

Unlike the Legacy Market, where only non-quick start generators received a Day-Ahead guarantee via a day-ahead commitment process, the Renewed Market includes a financially binding Day-Ahead Market for all participants and balances deviations that occur between the day-ahead and real-time through a Real-Time Balancing Market. The IESO's stated benefits of a financially binding DAM include certainty for participating resources through a guaranteed schedule and price in the day-ahead timeframe and greater market scheduling certainty for the market operator by shifting scheduling of supply quantities to the day-ahead timeframe.[3] A real-time balancing settlement is used for deviations between a resource's day-ahead schedule and its real-time output based on the real-time LMP to incentivize market participants to respond to incremental, post day-ahead system changes.

3.3 Changes to Make Whole Payments ("MWP")

Make Whole Payments, a type of out-of-market compensation, ensure market participants are paid appropriately when resources are dispatched uneconomically in relation to their market payments. The Legacy Market used Congestion Management Settlement Credits ("CMSC") to keep market participants whole when a resource's constrained run schedule differed from the unconstrained schedule used in the uniform price setting run. As such, CMSCs facilitated revenue sufficiency for hydroelectric resources related to inefficient operation and in some instances forgone generation due to system constraints. In the Renewed Market, MWPs compensate hydroelectric resources for lost cost and lost opportunity cost in day-ahead and real-time. As the LMPs include the cost of congestion, according to the IESO's high-level

[3] IESO, Day-Ahead Market High-Level Design ("DAMHLD"), August 2019, p. 3 <https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Day-Ahead-Market>.

design,[4] the transition to the single schedule market largely removes the underlying causes of divergence between dispatch and price that previously created the need for out-of-market payments. While MWPs are a part of both the day-ahead and real-time market, the circumstances that lead to MWPs in the Renewed Market are expected to be infrequent by design.

4.0 SURPLUS BASELOAD GENERATION

While both global SBG and local SBG can lead to hydroelectric spill, this section explains why global SBG conditions were used to quantify SBG spill when calculating SBGVA entries in the Legacy Market and why global SBG conditions can no longer be differentiated from local SBG conditions in the Renewed Market. This section details OPG's proposal to continue to quantify SBG spill and make entries to the SBGVA on a total SBG basis (i.e., include spill due to global and local SBG conditions).

4.1 Overview

In its 2012 Renewable Integration Stakeholder Engagement, the IESO described that SBG conditions can occur on both a global and local level, with global SBG defined as "a condition that occurs when Ontario's electricity production from baseload facilities, if not managed, would otherwise be greater than demand".[5] Local SBG was similarly defined as "a condition that occurs when a region's electricity production from baseload facilities, if not managed, would otherwise be greater than the local demand and the transmission system's ability to move the excess generation out of the area".[6] Both types of SBG conditions can cause hydroelectric spill at OPG's hydroelectric resources when storage is not available.

4.2 SBG Spill Calculation in the Legacy Market

As explained in Ex. E1-1-1, similar to all prior applications, OPG's hydroelectric production forecast has no deductions made for SBG and therefore its ability to recover its revenue

[4] IESO, Single Schedule Market High-Level Design ("SSMHLD"), August 2019, p. 55 https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ssm/SSM-High-Level-Design-Aug2019.ashx>.
[5] SE-91 Document "Surplus Baseload Generation (SBG)", August 7, 2012.
[6] *Ibid.*

requirement is reduced when SBG conditions occur.[7] To address the impact of SBG on OPG's regulated hydroelectric production, the OEB approved the SBGVA in EB-2010-0008 and each subsequent payment amounts proceeding.

As detailed in EB-2013-0321[8] and most recently set out in the EB-2020-0290 Payment Amounts Order, OPG calculated forgone production due to SBG in the Legacy Market by starting with the total volume of spill and subtracting the volume of spill due to water conveyance constraints, production capability, market constraints and contractual obligations.

SBGVA entries were then calculated using the volume of spill remaining after excluding the spill amounts incurred by OPG that were not attributable to the impact of SBG conditions based on a comparison of OPG's Gross Revenue Charge ("GRC") and the uniform price. The uniform price is an indicator of global SBG, as it does not consider the impact of congestion.

4.3 SBG Spill Calculation in the Renewed Market

As explained in EB-2023-0336, the Renewed Market's SSM necessitated an update to OPG's methodology for calculating forgone production due to SBG conditions. Specifically, the Renewed Market does not calculate and publish a uniform, "unconstrained" price, thereby eliminating OPG's ability to evaluate market conditions without the impact of local market constraints. As a result, OPG is unable to accurately distinguish between spill due to global and local SBG conditions as defined in IESO's Renewable Integration Stakeholder Engagement.

The use of a SSM also impacts the calculation of SBG-related spill. As described in Section 4.2, in the Legacy Market OPG isolated global SBG spill from other market constraints that can cause OPG to forgo generation, which at times included spill caused by local SBG. OPG assessed market constraints by comparing the constrained and unconstrained schedules published in the Legacy Market. This process ensured that forgone generation due to market

[7] Where OPG expects that losses due to SBG will be addressed by the SBGVA as approved in EB-2010-0008 and modified in EB-2023-0336.
[8] EB-2013-0321, Ex. E1-2-1, Section 3.2 and Ex. L-5.4-17 SEC-070.

constraints, including those related to local SBG, were not booked in the SBGVA, as they may also attract CMSC payments. The Renewed Market's use of a single schedule eliminates OPG's ability to identify spill attributable to market constraints as it also eliminates CMSC payments.

To address these changes, in EB-2023-0336 OPG proposed adjustments to the methodology used to calculate spill due to SBG conditions. OPG's proposal aligned with the structure of the Renewed Market while maintaining OPG's revenue sufficiency when impacted by surplus conditions outside of OPG's control. OPG's proposal was accepted at the conclusion of OPG's MRP application in EB-2023-0336 and implemented as proposed as of May 1, 2025, the go-live date of the Renewed Market.

OPG's methodology to calculate forgone production due to SBG maintains the process of starting with the actual volume of water spilled. OPG then removes spill related to water conveyance constraints, production capability constraints and contractual obligations. This methodology differs from the one used in the Legacy Market. Specifically, spill associated with market constraints is no longer removed as these amounts are unquantifiable in the Renewed Market. This remaining spill volume is considered as potential SBG spill. SBG conditions are generally expected to be present when the applicable real-time LMP for a given resource falls below its applicable GRC price threshold.[9] OPG's use of LMP as an indicator for SBG conditions could indicate the presence of global or local SBG conditions, unlike the uniform price in the Legacy Market, which signaled the presence of global SBG.

In the course of pre-implementation testing of OPG's proposed methodology using Legacy Market proxy LMPs (also known as Shadow Prices) OPG observed instances when the locational price did not fall below GRC while GRC-based generation was scheduled down and OPG incurred spill. OPG anticipated that LMPs in the Renewed Market could be subject to similar exceptions. After the implementation of the Renewed Market, OPG continued to

[9] Per IESO's SSMHLD, p. 8, footnote 4, the applicable LMP by location is based on the connection point (node) of a market participant supplier.

observe spill ineligible for SBGVA recovery. As noted in the IESO's *Update on Renewed Market Performance and Operations*: "LMP prices do not tell the whole story and cannot always be used to determine if an offer/bid should or should not have cleared the market at their submitted prices".[10] As such, while the Renewed Market introduced LMPs that generally reflect system conditions, certain operational and optimization constraints continue to result in spill outcomes that are not captured under the SBGVA framework. This impact is included as an adjustment to OPG's hydroelectric production forecast as reflected in Ex. E1-1-1, Section 3.1.

4.4 SBG Spill and Make Whole Payments

As explained in Section 3.3, the use of a Single Schedule in the Renewed Market eliminated CMSCs but continued the general use of MWPs in instances when the IESO takes out-of-market actions. OPG notes that MWPs related to lost opportunity resulting from the IESO taking out-of-market actions can coincide with the occurrence of SBG spill at its hydroelectric facilities. To prevent duplicate payment related to the same quantity of forgone generation, OPG's SBGVA methodology identifies instances when, on an hourly resolution, a resource books SBGVA amounts and receives a MWP from the IESO. OPG reduces the SBGVA entry associated with the respective resource by the value of the MWP received, ensuring the entry does not fall below zero dollars. OPG notes that for the first five months of the Renewed Market, the MWP associated reduction of OPG's SBGVA has been negligible.

4.5 SBG Spill Observations in the Renewed Market

Consistent with its OEB-approved EB-2023-0336 Settlement Proposal, OPG has presented SBGVA amounts from the five months in the Renewed Market as well as monthly data for the 2021-2025 period in Chart 2. This data demonstrates the expected persistence of seasonal patterns with higher SBGVA entries during freshet months. While OPG is unable to isolate spill that is attributable solely to the SBGVA methodology changes implemented under the Renewed Market, spill volumes observed to date have remained generally consistent on a

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[10] IESO, Update on Renewed Market Performance and Operations https://ieso.ca/-/media/Files/IESO/Document-Library/engage/renewed-market/rmo-20250821-presentation-renewed-market-update.pdf>.

month-over-month basis with levels recorded since 2021. OPG expects that total SBG spill will continue to remain at these recently observed lower levels, subject to hydrological conditions.

Chart 2: SBG Spill Booked to SBGVA (MWh)[11]

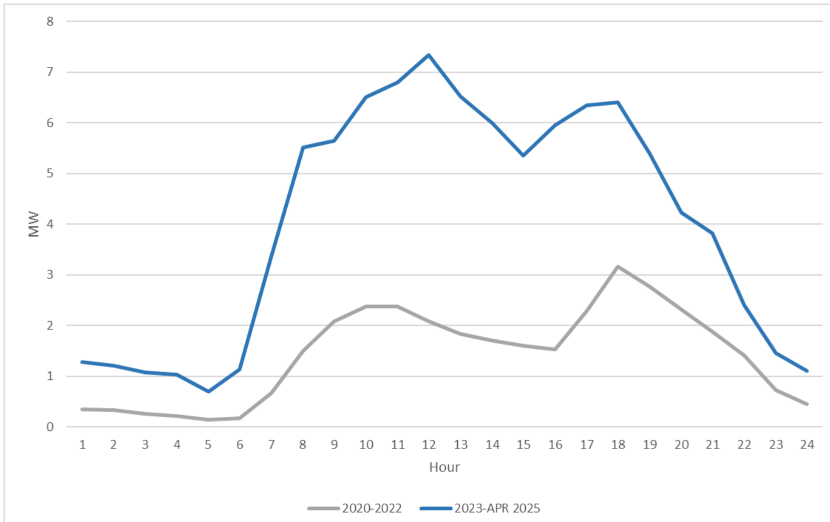
	2021	**2022**	**2023**	**2024**	**2025**	**Average**
January	195	51	54	3	5	61
February	118	72	152	15	0	72
March	258	74	85	20	48	97
April	399	276	199	77	131	216
May	299	353	289	44	**398**	278
June	134	283	31	68	**84**	121
July	108	32	1	13	**33**	37
August	32	30	18	9	**12**	20
September	130	77	9	17	**20**	58
October	99	65	92	17		68
November	48	216	40	49		88
December	62	62	6	17		37

4.6 Use of Sir Adam Beck Pump Generating Station ("PGS") During SBG Conditions

As demonstrated in the SBG and related PGS annual reporting and record-keeping requirement, Ex. H1-1-1 Attachments 3 and 4, and Chart 3 below, PGS utilization continues to increase since the SBGVA was last cleared.

[11] The SBGVA amounts associated with spill for May to September 2025 as presented in Chart 1 are subject to a monthly $0.6M reduction in accordance with the OEB-approved EB-2023-0336 Settlement Proposal, which is applicable until the effective date of the payment amounts order in this Application.

Chart 3 - Average Pumped Generating Station Output by Hour
(January 2020 - April 2025)



The number of coincident hours where SBGVA additions were made and the PGS was not pumping have decreased significantly since the 2020 high of 6,437, at 1,856 in 2023 and 1,006 in 2024. The value of SBGVA additions in coincident hours when the PGS was not operated in pump mode exclusively to prevent economic loss to OPG have also significantly decreased from the 2020 high of $11.5M to $0.7M in 2023 and $0.4M in 2024. OPG attributes the increase in PGS utilization and the concomitant decline in hours with SBGVA bookings when the PGS is not pumping to the absence of very high flows on the Niagara river and sufficient price spread in the market.

4.7 Conclusion

OPG proposes to continue to book amounts in the SBGVA based on the revised local and global SBG spill methodology as settled in EB-2023-0336 and described above. The continuation of this process is supported by data observed in the first five months of the Renewed Market. The SBGVA provides a mechanism for OPG to record the impacts of foregone generation not reflected in its forecast, and the entries are adjusted for interactions with Real-Time MWPs, ensuring no additional reductions are required.

5.0 HYDROELECTRIC INCENTIVE MECHANISM

This section sets out OPG's proposals related to the HIM. Sections 5.1-5.3 describe the HIM and OPG's proposal to continue the updates to the HIM methodology and the spill adjustment that align the HIM with the Renewed Market as settled in EB-2023-0336. Section 5.4 presents the customer benefit analysis associated with the HIM, and Section 5.5 outlines OPG's proposed revisions to HIM revenue sharing.

5.1 HIM Overview

The HIM was proposed and approved in EB-2007-0905 to provide OPG with an incentive to respond to market signals in a manner that also benefits consumers. Under the HIM, if in a given hour OPG produces more energy than a monthly average-based hourly volume, it receives market prices for this incremental amount of energy. If OPG's energy production is less than the hourly volume in a given hour, the amount payable to OPG is reduced by the production shortfall multiplied by the market price. Consumers benefit from the placement of hydroelectric energy in high priced hours, which typically reflects higher demand for electricity.

In EB-2010-0008, the OEB required OPG to address the interaction between HIM revenues and the SBGVA in its next application. In EB-2013-0321, the OEB directed OPG to include an offset to the HIM to reflect the interaction between the HIM and the SBGVA (known as the Unintended Benefit).

5.2 HIM Redesign for the Renewed Market

5.2.1 <u>Day Ahead and Real Time HIM</u>

In EB-2023-0336, OPG proposed revisions to the HIM with the objective of maintaining a similar design as the previously approved HIM while incorporating design features of the Renewed Market. Specifically, the redesigned HIM includes:

- A formula that incorporates a separate day-ahead ("DA") and real-time ("RT") incentive to reflect the new financially binding DA and RT balancing settlement design;
- Locational Market Price settlement;

- Daily production averaging to better align the HIM with daily market scheduling timeframes and operational storage horizons; and
- Continuation of a revised Unintended Benefit.

Figure 1 - Incentive Payment Calculation

$$Incentive\ Payment = DA\ Incentive + RT\ Incentive$$
$$= \sum_t \left(MW_{DA}(t) - MW_{DAavg}\right) \times LMP_{DA}(t)$$
$$+ \sum_t \left(MW_{diff}(t) - MW_{diff,avg}\right) \times LMP_{RT}(t)$$

Where:

$$MW_{diff}(t) = MW_{RT}(t) - MW_{DA}(t)$$
$$MW_{diff,avg} = MW_{RTavg} - MW_{DAavg}$$

Where:

$MW_{DA}(t)$: hourly production schedule from the IESO day-ahead market for each hour, *t*, of the day

MW_{DAavg}: average of hourly energy schedule from the IESO day-ahead market over the day

$LMP_{DA}(t)$: the day-ahead LMP for the resource for each hour, *t*, of the day

$MW_{RT}(t)$: net energy production supplied to the IESO real-time market for each hour, *t*, of the day

MW_{RTavg}: average of hourly net energy production over the day

$LMP_{RT}(t)$: the real-time LMP for the resource for each hour, *t*, of the day

OPG's HIM proposal provides an incentive for OPG to time-shift energy to high-price periods in the day-ahead timeframe in alignment the Renewed Market's financially binding DAM. The redesigned HIM also aligns with the RT Balancing Market as it provides OPG with an incentive to respond to real-time signals in the form of an incremental payment for further deviations from the day-ahead average. The use of daily averaging better aligns with the IESO's daily scheduling timeframe of resources in the Renewed Market and more closely reflects OPG's storage and time shifting capabilities. This redesigned HIM's day-ahead component is expected to be more material than the real-time one, which is consistent with the Renewed Market's intent of the Day Ahead being used to schedule most of the supply.[12]

5.2.2. Unintended Benefit

The Renewed Market does not change the potential interactions of SBG spill booked in the SBGVA and the HIM as outlined in EB-2013-0321. OPG's EB-2023-0336 application included a revised Unintended Benefit calculation that reflected the redesigned HIM and its use of a daily average and Locational Marginal Prices. Specifically, OPG proposed the following revised formula for the unintended benefit adjustment:

Figure 2: Revised Formula for Unintended Benefit Adjustment

$$Unintended\ Benefit\ Adjustment = \sum_{t} \left(MW_{Spill\ RTM}(t) - MW_{Spill\ RTM\ Avg}\right) \times LMP_{RTM\ Hourly}(t)$$

Where:

$MW_{Spill\ RTM}(t)$: hourly forgone production due to spill for each hour, *t*, of the real-time market day

$MW_{Spill\ RTM\ Avg}$: average of hourly spill over the real-time market day

$LMP_{RTM\ Hourly}(t)$: the real-time market LMP for the resource in the hour, *t*

5.3 HIM Analysis

5.3.1 HIM Results in the Renewed Market

Consistent with its OEB-approved EB-2023-0336 Settlement Proposal, OPG has presented HIM amounts from the five months in the Renewed Market in Chart 4.

[12] IESO, Day-Ahead Market High-Level Design ("DAMHLD"), August 2019, p. 3 <https://www.ieso.ca/en/Market-Renewal/Stakeholder-Engagements/Market-Renewal-Day-Ahead-Market>.

Chart 4 – HIM Payments in Market Renewal 2025 ($M)

	May	June	July	Aug	Sept
DA HIM	2.0	4.0	8.6	8.8	1.8
RT HIM	1.9	3.3	2.0	0.1	(0.3)
UIB	(4.6)	(1.0)	(0.6)	(0.1)	(0.2)
Net HIM	$(0.7)	$6.3	$10.0	$8.8	$1.3

These results capture the period immediately following the launch of the Renewed Market. OPG has taken a measured approach in interpreting these results alongside its longer-term modelled expectations of market operations. As the IESO noted in its update on Renewed Market performance and operations: the ability to draw conclusions at this point is still limited due to (1) short duration the renewed market has been in operation; (2) participants learning how the renewed market works and adjusting their strategies; and (3) experience in only two seasons.[13] OPG's observations include IESO's comments and contemplate a moderation of market outcomes as participants adjust their strategies and the IESO fine-tunes its systems based on real-life experience in the Renewed Market.

OPG's HIM observations are consistent with the overall expectation that the Day-Ahead HIM component would be higher than the Real-Time HIM, in keeping with the design of the Renewed Market. In the first month of the Renewed Market, OPG recorded negative HIM net revenue of $0.7M. This was mainly driven by high SBG spill that occurred during spring freshet which resulted in an unintended benefit adjustment that offset the DA and RT HIM payments earned during that period. In the following three summer months, OPG recorded a positive net HIM, followed by more moderate HIM revenues in September, which included a small negative RT HIM.

OPG expects an overall moderation of its HIM revenues as some of the early price volatility in the Renewed Market dampens with participants gaining experience in the new market. Further, as energy storage facilities continue to come online between 2025 and 2028, OPG expects

[13] https://ieso.ca/-/media/Files/IESO/Document-Library/engage/renewed-market/rmo-20250821-presentation-renewed-market-update.pdf

the increased arbitrage balancing supply to apply downward pressure on LMP price spreads, further moderating OPG's ability to earn HIM net revenues. Some of these assumptions are discussed further in Section 5.4, which details OPG's net HIM revenue forecast for 2027, the forward test year underpinning the regulated hydroelectric revenue requirement in this Application.

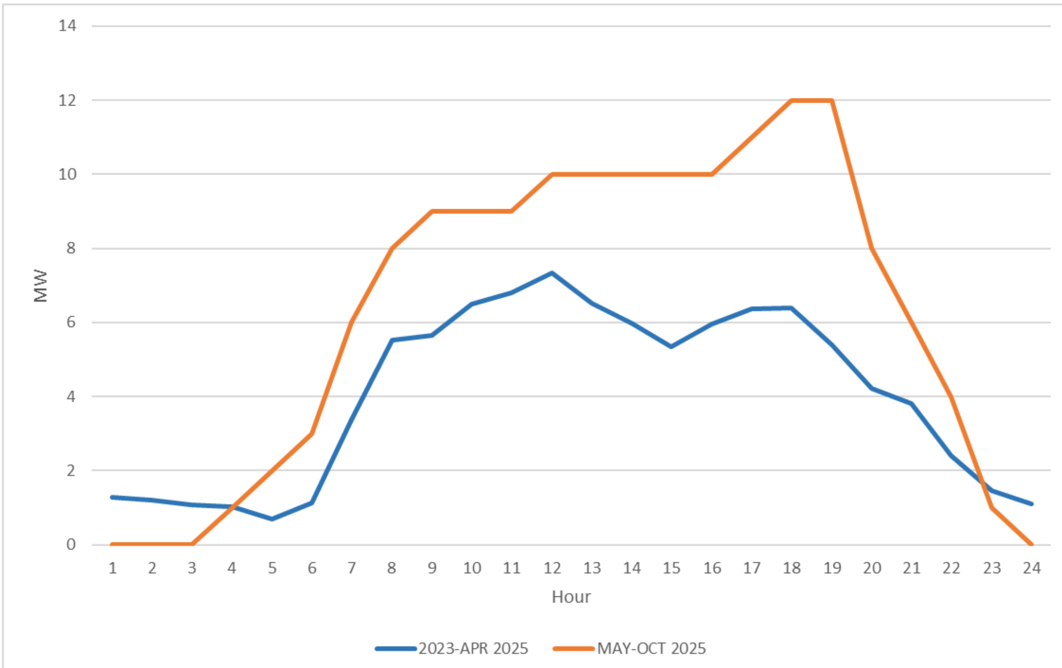
5.3.2 Impact of HIM on PGS Operating Decisions

The PGS supports the safe and efficient operation of the Sir Adam Beck complex while its time-shifting of water provides consumer benefit.[14] While the HIM approved in EB-2007-0905 was eventually applied to the additional hydroelectric stations prescribed in EB-2013-0321, its original design was specifically for the PGS to provide consumer benefit through incentivizing time shifting.

Chart 5 below illustrates that the HIM has continued to result in sustained high utilization of PGS in the first five months of the renewed market when compared to its utilization in the Legacy Market.

[14] EB-2023-0336, Ex. M1-1-1, Section 3.5 Customer Benefit.

Chart 5 - Average Pumped Generating Station Output by Hour (2023 - October 2025)



These results indicate the continued adequacy of the incentive provided by the HIM for the PGS to time-shift water. Further discussion of the impact on HIM on PGS operating decisions in the renewed market can be found in Section 5.5.

5.4 HIM Forecast Customer Benefit

Consistent with OPG's prior applications, OPG has conducted modelling analysis to forecast the HIM benefits in the Renewed Market for the test year. OPG's models use locational prices and are based on OPG's understanding of the design of the Renewed Market through IESO design documents prior to this application. By comparing to a flatter scheduling profile, OPG's model demonstrates the value of time-shifting hydroelectric resources, a relatively low-cost generation source, which displaces the need for more expensive generation sources during high price periods, and minimize system needs to curtail other sources during low price periods.

Chart 6 illustrates OPG's modelled changes in customer costs arising from the relevant factors for the test period, demonstrating that the cost of the incentive provides a net consumer benefit. These figures represent "all-in" customer costs including changes in Global Adjustment payments which reflects OPG's understanding of Ontario's hybrid market, where some suppliers are settled based on contracts.

Chart 6 – HIM Customer Benefit Analysis

Line No.	Customer Cost Changes ($M)	2026	2027*
1	Payments for Non-OPG Supplier Generation	(46)	(137)
2	Payments for OPG Generation (excluding incentive payment)	3	(13)
3	Payments for SBG-related Generation Curtailment	(7)	(3)
4	Export Revenues	2	2
5	**Change in Customer Cost excl. OPG Incentive (line 1+ line 2 + line 3 - line 4)**	**(52)**	**(154)**
6	**Additional Payments to OPG**		
7	DA HIM	19	19
8	RT HIM	7	4
9	Unintended Benefits Adjustment	(6)	(6)
10	**Total Additional Payments to OPG (line 7 + line 8 + line 9)**	**20**	**18**
11	**Net Customer Cost Change (line 5 + line 10)**	**$(32)**	**$(136)**

*Totals may not add due to rounding

OPG's assessment of consumer benefits from the HIM concludes that economic time-shifting of its regulated hydroelectric generation reduces modelled consumer costs before OPG incentive payments by $154M in the 2027 test year (See Chart 6, Line 5). The HIM-driven, incremental time-shifting of production results in a modelled net incentive payment to OPG of $18M (See Chart 6, Line 10), creating a $136M net consumer benefit (See Chart 6, Line 11).

The analysis accounts for the market effects of time shifting: the displacement of more expensive generation[15] (i.e., on-peak gas and imports) by hydroelectric production; increases in production and consequent GRC payments for additional on-peak generation at the regulated hydroelectric facilities; reduced payments for SBG-related forgone generation (as determined under OPG's proposal); and changes in exporter payments[16] made to the IESO for off-peak exports that result in changes in customer costs.

The higher customer benefit in 2027 relative to 2026 is due to forecasted increases in Ontario Zonal Prices. In 2027, OPG forecasts approximately 5 TWh of incremental demand relative to 2026, and no Pickering B generation after it comes offline for refurbishment in September 2026. Together, these factors are expected to increase reliance on gas-fired generation and imports. As a result, Ontario Zonal Prices are projected to rise, increasing the value of incremental time-shifted hydro production and the customer benefit in 2027.

Discussion on HIM forecasting can be found in Ex. G1-01-01, Section 7.0 HIM Revenue Requirement Adjustment.

5.5 Revisions to HIM Revenue Sharing

5.5.1 Impact of HIM Revenue Sharing on PGS Price Spread

OPG's SBGVA Study in Attachment 1 considered reasonable options to better incentivize OPG to minimize total system costs in consultation with stakeholders. As described in Section 3.3.3 of the study, OPG explored whether any changes to the HIM could meet this objective.

In the SBGVA Study, OPG noted that under the current HIM revenue-sharing regime, the price spread required to economically cycle the PGS would escalate when HIM revenues exceed the HIM threshold. While OPG's historic HIM revenues have not created such conditions, as

[15] The analysis accounts for impacts on generation costs resulting from displacement of generation but does not account for potential additional benefits related to carbon emission reductions.

[16] Sales of exports in the off-peak are typically made from contracted generation sources with contract prices that are independent of market prices. These volumes are effectively "take or pay". The consumer benefit arises from increasing the off-peak price for export sales so as to generate additional revenues that, in turn, reduce Global Adjustment payments by consumers.

the threshold is reset in the application, OPG believes it is important to pre-emptively address any structural barriers that may impede the operation of the PGS against the objective of reducing SBGVA entries and maximizing consumer benefit.

To illustrate the impact of sharing HIM revenues above the threshold, OPG calculated the spread required to economically cycle the PGS under two scenarios:

- **Scenario 1:** HIM net revenue sharing arrangement with 50% sharing of HIM net revenues above threshold; and
- **Scenario 2:** Alternative HIM net revenue sharing arrangement where 50% sharing above threshold is eliminated. This scenario is also reflective of PGS spread when the threshold has not been reached.

The PGS price spread is identical between both scenarios when OPG's HIM revenues are below the threshold. When the HIM revenues exceed the threshold, in both scenarios OPG continues to incur the same load charges, gross revenue charges, energy costs, and efficiency losses, but in Scenario 1 is limited to retaining only 50% of HIM net revenues to offset these costs. The resulting reduction in revenues must be recovered from the market for PGS operations to remain economic. This materially increases the spread required to justify time-shifting and, in practice, would impede the PGS's ability to shift generation, even though OPG has demonstrated that such operation provides a clear consumer benefit.

While OPG treats the sharing of forecast HIM revenues with customers as a fixed cost and does not build it into the variable cost formulas that guide market offers, once HIM net revenues exceed the threshold the obligation to share 50% effectively introduces an incremental variable cost that must be reflected in PGS offer decisions. OPG's proposal to remove the sharing of HIM revenues, ensures that PGS economics are consistent and not subject to a discrete change that impedes operations based on OPG's overall HIM revenues.

5.5.2 Market Surveillance Panel (MSP) Observations

As noted in the SBGVA Study, in its Monitoring Report 32[17] published on July 16, 2020 and a subsequent State of the Market Report 2022, the MSP expressed concern that the current revenue-sharing structure may be suppressing the efficiency benefits of the HIM. Specifically, in its Monitoring Report 32, the MSP recommended the OEB consider revisiting the sharing with consumers of HIM net revenue exceeding a threshold. The Market Surveillance Panel raised multiple arguments in support of the elimination of sharing. Consistent with OPG's analysis in Section 5.5.1, the MSP stated that the sharing is a dilution of OPG's incentive to time-shift production. The MSP also noted the lack of historical sharing of revenues on account of actual HIM revenues being lower than the threshold and raised the possibility that the sharing has had a negative impact on time-shifting.

The panel stated that eliminating or revising the revenue-sharing mechanism would give OPG a stronger, undiluted incentive to time-shift hydro production, which could improve overall market efficiency and benefit consumers through lower prices during peak periods. Additionally, although the revenue-sharing threshold has not been reached recently, because future market conditions will change, the Panel believes the HIM design should be robust for all plausible scenarios, ensuring OPG always has a clear incentive to operate efficiently.

5.6 Conclusion

Based on OPG's assessment, the enhanced HIM has demonstrated overall effectiveness in the Renewed Market. The majority of HIM revenues have been earned in Day Ahead and the PGS has operated in accordance with market signals. To position the HIM as a consistent driver for OPG to realize consumer benefits by time-shifting its flexible hydroelectric generation, OPG proposes to:

1. Establish a HIM forecast for 2027 (as described in Ex. G1-1-1);
2. Share 50% of the forecast HIM revenues with customers as an offset to the revenue requirement; and
3. Retain 100% of actual HIM revenues, including amounts above the forecast.

By eliminating the sharing of HIM revenues above the Hydroelectric Incentive Mechanism Variance Account threshold, OPG's proposal better aligns incentives with efficient market outcomes, provides customers with an upfront benefit through the forecast offset, and enhances OPG's ability to pursue cost-saving opportunities for ratepayers.

6.0 REAL-TIME ENERGY MAKE WHOLE PAYMENTS

This section explains MWPs in the Renewed Market and details OPG's proposal to continue to retain Real Time MWPs as payments that ensure OPG revenue sufficiency for events outside of its control.

6.1 Impacts of MRP on Make Whole Payments

According to the IESO's SSM high-level design, relative to the previous two schedule market, the need for MWPs in the new market is expected to be infrequent and immaterial.[17] This is due to the introduction of the single schedule market and locational marginal pricing which the IESO believes have eliminated the most significant cause of divergence between dispatch and price (congestion and losses) that resulted in out-of-market payments. CMSCs, the previous form of MWPs, have also been eliminated under MRP.

Conditions where resources are needed to be scheduled or dispatched out-of-merit that result in lost cost or lost opportunity requiring MWPs continue in the Renewed Market, albeit in a more limited way. Consequently, the introduction of a DAM and RTM have resulted in both DA MWPs and RT MWPs, for both Energy and Operating Reserve.

6.1.1 MWP Observations Since MRP Implementation

Chart 7 covers total make whole payments received by OPG's regulated hydroelectric facilities since market opening:

[17] SSMHLD, p. 50.

Chart 7 – OPG Regulated Hydroelectric MWPs ($M)

	May 2025*	June 2025	July 2025	Aug 2025	Sept 2025
RT Energy MWP	0.8	2.2	2.6	0.5	0.2
RT OR MWP	1.7	3.2	2.3	0.5	0.5
DA Energy MWP	0.0	0.0	0.0	0.0	0.0
DA OR MWPs	0.1	0.0	0.0	0.0	0.0
Total MWP	**$2.5**	**$5.4**	**$4.9**	**$1.0**	**$0.7**

*Total may not add due to rounding

As seen in Chart 7, the overall trend in MWPs points to a decrease in MWP magnitude since the start of the market. OPG is generally unable to isolate specific causes of instances when hydroelectric generators receive MWPs in day-ahead, which may be due to a variety of reasons, including constraint violations, co-optimization of energy with operating reserve, or the commitment of a non-quick start resource in the reliability pass of the DAM engine.[18] OPG notes that all day-ahead MWPs received by its regulated hydroelectric facilities in the Renewed Market have been immaterial as demonstrated in Chart 7.

Real-Time Energy and Operating Reserve comprise the majority of MWP revenues received by OPG's regulated hydroelectric resources in the Renewed Market. MWPs may occur in real-time for a variety of reasons, including special instructions related to constraint violations, multi-interval optimization, co-optimization with operating reserve, or emergency control actions. These dispatch instructions may be issued automatically by the IESO's optimized dispatch tools or manually by the control room in response to real-time operating conditions. In the Real Time Market, OPG's OR MWPs have exceeded Energy MWPs in four out of the five months in the Renewed Market. While OPG attributes this trend to a number of possible market factors including joint optimization and the introduction of an Operating Reserve Demand Curve, OPG has taken a measured approach in its expectation of how MWPs may develop as the Renewed Market matures. Operating Reserve MWPs ("OR MWPs") are part of OPG's Operating Reserve revenues, as discussed in Ex G1-1-1.

[18] SSMHLD, p. 50.

Similarly, while OPG received comparatively higher Energy MWPs in two summer months, its longer-term view is informed by IESO's expectation of these payments to be infrequent and immaterial as well as the IESO's recognition that certain aspects of the market may require fine tuning before reaching a steady state. On November 21, 2025, the IESO launched a stakeholder engagement that identified targeted corrections to the Market Rules that would be made to address specific circumstances under which unwarranted MWPs are calculated. While the engagement is still in preliminary stages, OPG expects the outcome of these changes to further lower MWPs.

Overall, OPG expects that day-ahead MWPs will remain immaterial and real-time MWPs will moderate with experience in the new market to levels that meet IESO's expectations of infrequency and low materiality.

6.2 Continuation of Current Treatment of Make Whole Payments

In EB-2023-0336, OPG proposed and received approval to retain Real-Time Energy MWPs consistent with the principle that OPG is compensated with respect to output generated at its regulated facilities in accordance with Section 78.1 of the *Ontario Energy Board Act, 1998*. OPG did not seek approval with respect to the treatment of Day-Ahead Energy MWPs as they form part of the Day-Ahead Market settlement and have no impact on OPG's actual output. OPG's proposal included an underlying assumption that OPG will receive OR MWPs – both Day-Ahead and Real-Time as part of its Operating Reserve revenues. During implementation, the IESO raised certain consideration regarding the calculation and settlement of MWPs, which led to OPG receiving all MWPs, including Day-Ahead Energy MWPs as presented in Chart 6. To fulfill its obligations under the OEB-approved EB-2023-0336 Settlement Proposal, OPG has been crediting all received Day-Ahead Energy MWPs in the Ancillary Services Net Revenue Variance Account, which records OPG's OR Day-Ahead and Real-Time MWPs.

OPG proposes that the treatment of Real-Time Energy MWPs under OPG's Regulated Framework as settled in EB-2023-0336 continue throughout the upcoming rate-setting period. Such payments are not reflected in the setting of payment amounts and would serve to compensate OPG for IESO dispatch related losses from inefficient operation or possible loss of production in the form of hydroelectric spill. OPG also expects to continue to receive Real-Time OR MWPs as part of its OR revenues. Given the insignificant Day-Ahead Energy and OR MWPs received in the first five months of the Renewed Market – $0.1M and $0.2M total, respectively – for administrative efficiency, OPG proposes to forgo receiving all Energy and OR MWPs during the IR term.

LIST OF ATTACHMENTS

Attachment 1: Surplus Baseload Generation Variance Account Study

Surplus Baseload Generation Variance Account Study

Response to EB-2023-0336 Settlement Agreement

ONTARIO POWER GENERATION

1.0 Introduction and Purpose of Study

In EB-2023-0336, OPG applied to the Ontario Energy Board ("OEB") for approval to dispose of balances in several deferral and variance accounts, including the Surplus Baseload Generation Variance Account ("SBGVA"). In that application OPG also sought approvals to address impacts of the Independent Electricity System Operator's ("IESO") Market Renewal Program ("MRP") on its regulated framework, including revisions to calculation of amounts booked to the SBGVA. Specifically, OPG sought approval to record the financial impact of foregone production due to global and local surplus baseload generation conditions using locational marginal prices ("LMP").

Following a settlement conference, the parties reached an agreement on all issues in the proceeding, including the disposal of the SBGVA balances as of December 31, 2022. This agreement was documented in a Settlement Proposal filed with the OEB and was adopted through a Decision and Order.[1]

As part of the Settlement Proposal, OPG committed to conduct and file, as part of its next rebasing application, a study assessing options to reduce SBGVA amounts on a forward-looking basis:

> *OPG shall study options to reduce SBGVA amounts on a going forward basis and in light of the MRP with the aim of minimizing total electricity system costs to ratepayers including market payments and regulated payments, with assistance from the IESO as available and necessary. The study shall consider reasonable options to better incentivize OPG to minimize total system costs, utilizing the Sir Adam Beck Pump Generating Station ("PGS") to reduce spillage at OPG's hydroelectric facilities, and other structural changes, including changes that may require OEB approval. OPG shall fund a stakeholder process to obtain input on options to be considered in the study. OPG shall file its report as part of its next rebasing application for the prescribed facilities.*[2]

This study is in response to the OEB-approved Settlement Proposal. The study primarily considers options to reduce SBGVA amounts on a going forward basis by adjusting economic

[1] EB-2023-0336, Decision and Order, June 13, 2024.
[2] Ibid., page 5

factors to increase output at the existing PGS facility in its existing configuration. Results of the study should be viewed in the context of PGS's primary function within the Sir Adam Beck Complex, where it supports safety, operational efficiency and provides capacity by time-shifting water to the benefit of the ratepayer.[3]

2.0 Stakeholder & Rightsholder Engagement

On March 21, 2025, OPG hosted a Stakeholder and Rightsholder Engagement Process to inform the scope of this study. OPG circulated the meeting notes and materials for this session to participants on April 24 and May 27, respectively (see also Appendix A). Chart 1.0 below summarizes the action items assigned to OPG at that session (#1-4), as well as an action received from Environmental Defence via email following the stakeholder session (#5). The chart further describes how OPG has responded to each of those actions and provides a cross reference to where further details are provided within this study.

In September 2025, OPG met with the IESO to provide an overview of the study's findings and share a draft of the SBGVA study for feedback. The IESO has reviewed this report and provided their comments in Appendix B.

Chart 1.0: Action Items from Stakeholder and Rightsholder Engagement

#	Action Item	OPG's Response	Reference
1	Consider whether changes to the HIM would meet the study's objectives.	*Eliminating the requirement to share HIM net revenues[4] beyond a threshold would better incentivize OPG to time-shift water to the benefit of the ratepayer in all market conditions.*	See **Section 3.3.3** *The Hydroelectric Incentive Mechanism*
2	Consider the best available information available at the time of conducting the study, including the	*This study uses the most up-to-date market inputs available & assumptions are aligned with the*	See **Section 3.0**

[3] EB-2023-0336, M1-1-1, section 3.5 Customer Benefit
[4] Net of unintended benefit adjustment

	potential impact of tariffs on the system, if applicable.	*business plan that underpins OPGs EB-2025 application to the OEB.*	*Methodology & Study Options*
3	Consider whether and how Global Adjustment could be included as a factor in the evaluation of the study options.	*Impacts to Global Adjustment are calculated as part of OPG's analysis and incorporated into the results in this report.*	See **Section 3.0** *Methodology & Study Options*
4	Clearly link how each study option meets the study objective(s) outlined in the settlement agreement, including whether and how it reduces spillage, and what structural changes would or would not be required.	*Options 1 & 2 include sections to discuss the impacts on PGS utilization, SBG spill, Total Customer Cost (TCC), and implementation considerations. Option 3 analyzes the price spread required to economically time-shift water using the PGS under different HIM net revenue sharing scenarios. More frequent time-shifting of water has been demonstrated by OPG to be beneficial to the ratepayer.*	See **Section 3.3** *Study Options*
5	With respect to the GRC, Environmental Defence asks that OPG's analysis account for the fact that the GRC is returned to ratepayer pockets via the provincial government as it displaces other tax revenue.	*OPG's analysis shows reducing GRC payable by PGS yields incremental reduced total customer cost when combined with the removal of load charges. OPG has accounted for displaced GRC payments as a reduction in TCC benefit for the ratepayer.*	See **Sections 3.3.2.2** *Results and* **3.3.2.3** *Implementation*

3.0 Methodology & Study Options

OPG conducted this study in accordance with guiding principles ensuring that outcomes are consistent with the EB-2023-0336 Settlement Agreement and considering the authority and mandate of each of the OEB and the IESO. OPG first developed the necessary guiding principles of the study and then identified study options that adhered to these principles and presented both as part of the Stakeholder and Rightsholder Engagement Process.

3.1 Guiding Principles

The IESO is responsible for the reliability of Ontario's power system and the efficiency of the electricity market. In the early 2010s, the IESO established a "dispatch order for generation"[5] to optimize generation dispatch during SBG conditions by introducing floor prices for variable generation. As noted in the IESO stakeholder engagement that set these floor prices, OPG's hydroelectric offer strategy uses Gross Revenue Charge ("GRC")-based offers to reflect storage unavailability. OPG follows the IESO's dispatch in accordance with the IESO Market Rules.

Additionally, based on fundamental principles of rate regulation, OPG must be provided with a reasonable opportunity to recover its approved revenue requirement and should not be required to operate at an economic loss, due to system-level operating decisions or market outcomes that are beyond its control.

With consideration to the above, OPG created the following four guiding principles to help identify viable study options:

1. Recognize the IESO's fundamental role in managing SBG.
2. Recognize that the objective of IESO's dispatch scheduling and optimization algorithm is to "maximize the gains from trade to ensure consumers of electricity receive the highest value based on electricity supply offers.[6] OPG supports this objective by offering its resources economically into the IESO's market.

[5] IESO, Dispatch Order for Baseload Generation, A Discussion Paper for Stakeholder Engagement 91 (Renewable Integration), dated November 2, 2011
[6] 1. IESO Market Rules Chapter 7, ss 4.3.2

3. Ensure OPG is following IESO market signals and dispatches.
4. Maintain OPG's ability to recover its approved revenue requirement and not operate at an economic loss.

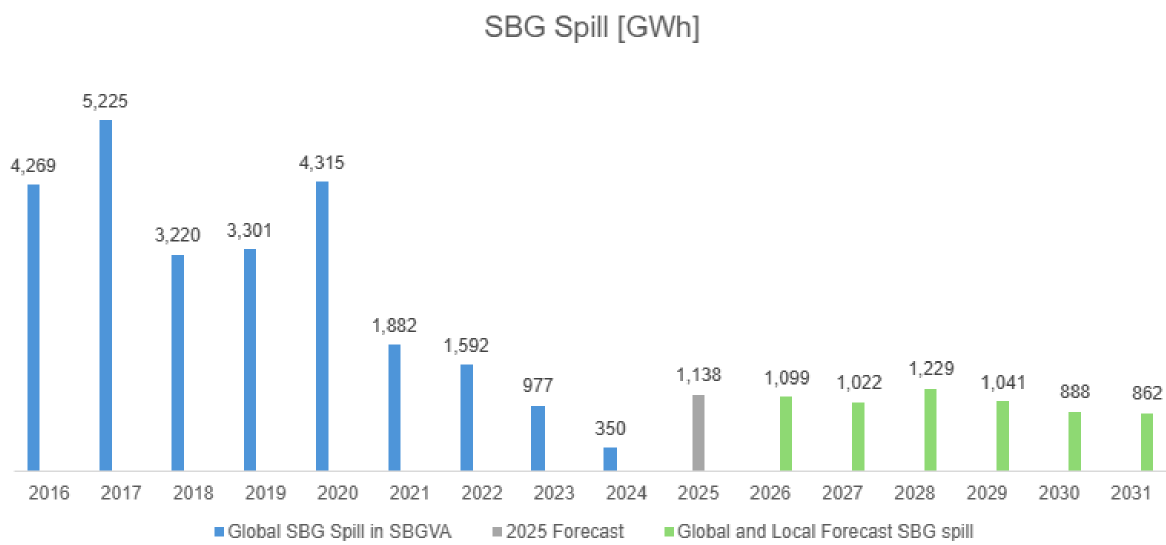
3.2 Surplus Baseload Generation in the Renewed Market

The IESO's Market Renewal Program ("MRP") replaced the previous two-schedule market with a single schedule market ("SSM") and introduced Locational Marginal Prices ("LMP"). Where SBG conditions were previously a global condition indicated by the Hourly Ontario Energy Price ("HOEP"), the replacement of HOEP with LMP under the Market Renewal Program eliminated OPG's ability to differentiate between global and local SBG conditions. As a result, OPG updated its methodology for making entries to the SBGVA, basing it on instances where a resource's LMP falls below the level of its GRC. This approach was approved by the OEB in EB-2023-0336[7] and forms the basis for OPG's forecast of SBG Spill (see Figure 1.0).

Using the EB-2023-0336 approved methodology, OPG projects total SBG spill to remain significantly below historical levels for the remainder of the study period. The reduction in forecast SBG spill is primarily due to changes in the supply and demand outlook in the province combined with expected efficiencies in the renewed market.

[7] EB-2023-0336 Decision and Order, issued June 13, 2024

Figure 1.0 - OPG Surplus Baseload Generation Spill: Historical Actuals and Forecast[8]



3.3 Study Options

This study examined the following three options based on the guiding principles outlined in Section 3.1:

1. Potential benefit of removing variable load charges applicable to PGS cycling;
2. Potential benefit of removing GRC applicable to PGS generation; and
3. Potential modifications to the HIM.

Options 1 and 2 focus specifically on the PGS and the economic considerations that could impact its utilization. These options assess economic reasons PGS does not cycle, which have been discussed in prior applications and are presented in OPG's PGS Reporting and Record-keeping Requirements. Other factors that limit PGS utilization (e.g., physical limitations, safety, equipment, or applicable law) were not considered in scope for this study.

Options 1 and 2 use an analytical framework designed to measure the impact of changes to PGS load charges and PGS GRC on PGS utilization, SBGVA additions, and TCC, when

[8] 2016-2024 shows actual SBG spill amounts included in SBGVA on a global basis. 2025 is an OPG forecast value based on global SBG conditions pre-MRP, and both global and local SBG conditions post-MRP. 2026-2031 OPG forecasts are based on both global and local SBG conditions.

compared to a base case.[9] The base case is a calculation of PGS utilization, SBGVA additions and TCC based on OPG's business plan. TCC is a calculation of all payments made by the IESO to generators including the impact of imports and exports, equal to market payments plus Global Adjustment costs. The negative TCC values in this report represent a reduction in customer cost while positive values represent an increase in customer cost.

Options 1 and 2 are calculated using the same assumptions as the base case, with only one independent variable changed: the load charge factor in PGS economics for option 1 ("The Load Charge Case"), and the GRC factor in PGS economics in option 2 ("The GRC Case").

Option 3 was identified as part of the Stakeholder and Rightsholder Engagement Process and considers whether changes to the HIM would meet the study's objectives. As described in section 3.3.3.4, the analytical framework to assess option 3 differs from the TCC based approach used for Options 1 and 2. For Option 3, the price spread required to economically cycle the PGS was calculated and compared under two HIM net revenue sharing scenarios.

3.3.1 Option #1: Potential benefit of removing variable load charges applicable to PGS cycling

The PGS is subject to variable load charges when operating in pump mode. Network Service Rate charge ("NSC") applies when the PGS operates in pump mode on weekdays between 7am and 7pm. If operated in pump mode during a NSC applicable hour, the PGS can incur significant NSC based on the NSC rate, the efficient operating point of a PGS pump, and the number of PGS pump units. As such, OPG does not operate the PGS in pump mode during NSC hours, unless it must do so for safety or operational reasons such as crossover control during periods of low diversion, equipment testing or rescue procedures.

The PGS operating in pump mode is also subject to the IESO Administration Charge in the form of a rate applied to the total PGS load in each month. Other market uplifts applicable to PGS load are subject to offsetting settlement reimbursements and are therefore excluded from

[9] The framework assumes the normally expected weather variations and unit commitments with no real-time price volatility owing to discrete events.

PGS economics. The NSC and IESO Administration Charges incurred by OPG are collectively referred to as the “PGS load charges” and are included as a single variable in the PGS economic formulas.

To determine the economics of generating with the PGS, OPG compares the breakeven generation price to the latest LMP. If that LMP is greater than the breakeven generation price, OPG concludes it is economic to generate. The formula for the breakeven PGS generation price is provided below, with the PGS load charges highlighted:

$$\frac{\begin{gathered}\textit{PGS Pump Efficiency} \times (\textit{Forecast Pump Price} + \underline{\textbf{\textit{PGS Load Charges}}}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Pump Price} - \textit{Beck GRC}) + \\ (\textit{PGS Gen Efficiency} \times \textit{PGS GRC}) + (\textit{Beck Gen Efficiency} \times \textit{Beck GRC})\end{gathered}}{\textit{PGS Gen Efficiency} + \textit{Beck Gen Efficiency}}$$

To determine the economics of pumping with the PGS, OPG compares the breakeven pump price to the latest LMP. If that LMP is less than the breakeven pump price, OPG concludes it is economic to pump. The formula for the breakeven PGS pump price is provided below, with the PGS load charges highlighted:

$$\frac{\begin{gathered}\textit{PGS Gen Efficiency} \times (\textit{Forecast Gen Price} - \textit{PGS GRC}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Gen Price} - \textit{Beck GRC}) + \\ (\textit{Beck Gen Efficiency} \times \textit{Beck GRC}) - (\textit{PGS Pump Efficiency} \times \underline{\textbf{\textit{PGS Load Charges}}})\end{gathered}}{\textit{PGS Pump Efficiency} + \textit{Beck Gen Efficiency}}$$

For the purpose of this study, OPG has examined the impact of PGS load charges on pumping and generating at the PGS.

3.3.1.1 Methodology

The results in Section 3.2.1.2 were derived by comparing the forecast values for PGS utilization, SBGVA additions, and TCC for the base case and Load Charge Case.[10]

[10] The analysis includes impact of battery energy storage systems expected to come online between 2025-2028.

3.3.1.2 Results

The results of the Load Charge Case compared to the base case are presented in Chart 2.0 and Chart 3.0 and discussed below.

Chart 2.0: Results of Option #1: Load Charge Case

	Incremental PGS Generation		Impact on SBG Spill	
	GWh	%	GWh	%
2026	4.1	11.4%	(5.3)	(1.7%)
2027	0.7	2.1%	(9.2)	(4.1%)
2028	0.6	3.6%	2.9	0.7%
2029	5.7	27.0%	(6.9)	(2.9%)
2030	3.6	16.7%	(2.1)	(2.7%)
2031	5.6	24.8%	(4.6)	(5.5%)
Total	**20.3**		**(25.2)**	
Average Annual	**3.4**		**(4.2)**	

<u>*Impact on PGS Generation*</u>

OPG's analysis indicates that removing variable load charges from PGS cycling economics would increase PGS generation by an average of 3.4 GWh annually, primarily due to the following two factors:

1. The PGS would be free to operate in pump mode at all hours of the day; and
2. The price spread required to economically cycle the PGS is reduced.

The inability to economically pump during NSC hours is the most significant impediment to incremental PGS cycling. As OPG does not operate the PGS in pump mode during NSC hours, the PGS is unable to pump during midday price dropouts which may allow the reservoir to be refilled before the evening peak.

<u>*Impact on SBGVA additions*</u>

The Load Charge Case results in 4.2 GWh average annual decrease of SBG spill when compared to the base case. This is primarily related to the incremental PGS pump mode operations during NSC hours, which reduced instances of on-peak SBG spill during those applicable hours.

Impact on Total Customer Cost

OPG's analysis also measures the impact on the TCC. The impact on TCC in the Load Charge Case compared to the base case is shown in Chart 3.0 and discussed below:

Chart 3.0: Option # 1 Impact to TCC: Load Charge Case

	2026	2027	2028	2029	2030	2031	Total	Annual Avg
Incremental Values:	$M	$M	$M	$M	$M	$M	$M	$M
(a) HIM payments to OPG	0.4	0.8	0.3	0.5	0.3	0.5	2.7	0.5
(b) SBGVA entries	0.1	(0.3)	0.3	(0.6)	(0.1)	(0.2)	(0.7)	(0.1)
(c) Imports and gas cost	(0.5)	4.1	0.7	(14.0)	(0.4)	0.3	(9.9)	(1.6)
(d) Incremental other costs	(0.2)	(0.5)	(0.2)	0.4	0.0	0.0	(0.6)	(0.1)
(e) Incremental export revenue	0.0	0.2	0.2	0.0	(0.1)	(0.0)	0.4	0.1
(f) Impact on TCC [a + b + c + d - e]	**(0.3)**	**3.8**	**0.8**	**(13.7)**	**(0.0)**	**0.6**	**(8.8)**	**(1.5)**

OPG's analysis of the Load Charge Case shows a cumulative $8.8M reduction in TCC over the study period when compared to the base case.

The largest contributor to the reduction in TCC in the Load Charge Case is the reduction in imports and gas generation. OPG's analysis demonstrates that incremental PGS utilization means a greater quantity of less expensive water is available to offset more expensive gas for more hours of the day when compared to the base case. This effect is especially prevalent in years where there are greater price spreads and more gas generation in the base case, as seen in 2029.

The other contributor to the reduction in TCC in the Load Charge Case is the reduction in SBG spill, as explained in the "Impact on SBGVA additions" section above.

The decrease in TCC related to reductions in imports, gas generation and SBG spill is partially offset by higher OPG HIM revenues associated with incremental on-peak generation at Sir Adam Beck 1 and 2 GS and the PGS.

3.3.1.3 Implementation

On March 27, 2025, the OEB issued a Decision and Order in EB-2022-0325 which ordered "transmission-connected energy storage facilities shall be exempt from transmission charges under any of the following circumstances: when scheduled to provide operating reserve, when providing reactive support, when providing regulation service, when responding to an IESO energy dispatch in the real-time electricity market, or when responding to an IESO directive in support of transmission system reliability."[11]

OPG is in the process of determining the feasibility of implementing an NSC exemption for PGS by designating it as an energy storage facility. If the PGS receives the transmission charge exemption, the PGS would be available to pump in all hours of the day without incurring the NSC, and the load charge factor in the PGS economic formulas would be reduced. OPG expects a decision to be reached in 2026. OPG is also in the process of evaluating the feasibility of an IESO Administration Charge exemption for the PGS.

3.3.2 Option #2: Potential benefit of removing GRC applicable to PGS cycling

Gross Revenue Charge is calculated on an annual basis based on the actual production of any hydroelectric generating station in Ontario, including the PGS and the Sir Adam Beck complex. The GRC is a variable cost of generation and is expressed in the PGS economic decision making as a single value.

To determine the economics of generating with the PGS, OPG compares the breakeven generation price to the latest LMP. If that LMP is greater than the breakeven generation price, OPG concludes it is economic to generate.
The formula for the breakeven PGS generation price is provided below, with the GRC impacts highlighted:

[11] EB-2022-0325 Decision and Order, issued March 27, 2025, section 4.2 Implementation of Decision on Issue 5

$$\frac{\begin{gathered}\textit{PGS Pump Efficiency} \times (\textit{Forecast Pump Price} + \textit{PGS Load Charges}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Pump Price} - \textit{Beck GRC}) + \\ (\textit{PGS Gen Efficiency} \times \underline{\textbf{\textit{PGS GRC}}}) + (\textit{Beck Gen Efficiency} \times \textit{Beck GRC})\end{gathered}}{\textit{PGS Gen Efficiency} + \textit{Beck Gen Efficiency}}$$

To determine the economics of pumping with the PGS, OPG compares the breakeven pump price to the latest LMP. If that LMP is less than the breakeven pump price, OPG considers it economic to operate in pump mode.

The formula for the breakeven PGS pump price is provided below, with the PGS GRC impacts highlighted:

$$\frac{\begin{gathered}\textit{PGS Gen Efficiency} \times (\textit{Forecast Gen Price} - \underline{\textbf{\textit{PGS GRC}}}) + \\ \textit{Beck Gen Efficiency} \times (\textit{Forecast Gen Price} - \textit{Beck GRC}) + \\ (\textit{Beck Gen Efficiency} \times \textit{Beck GRC}) - (\textit{PGS Pump Efficiency} \times \textit{PGS Load Charges})\end{gathered}}{\textit{PGS Pump Efficiency} + \textit{Beck Gen Efficiency}}$$

For the purpose of this study, OPG has examined what the impact GRC has on pumping and generating at the PGS.

3.3.2.1 Methodology

Option #2 was studied using the same methods, inputs, and assumptions as described in Section 3.2.

The GRC Case results in Section 3.2.2.2 below were derived through a separate analysis by setting the “PGS GRC” factor, as shown in the equations in Section 3.2.2, to zero. The forecast values for PGS utilization and SBGVA additions for the GRC Case were then compared to the base case and included in the charts in Section 3.2.2.2.

3.3.2.2 Results

The results of the GRC study case compared to the base case are presented in Chart 4.0 and discussed below.

Chart 4.0: Results of Option #2: GRC Case

	Incremental PGS Generation		Impact on SBG Spill	
	GWh	%	GWh	%
2026	2.6	7.2%	(0.5)	(0.2%)
2027	2.6	8.6%	0.1	0.1%
2028	1.2	6.8%	1.8	0.4%
2029	2.5	11.7%	(0.7)	(0.3%)
2030	0.9	4.3%	0.2	0.2%
2031	2.7	11.6%	0.2	1.1%
Total	**12.5**		**1.1**	
Average Annual	**2.1**		**0.2**	

While the GRC Case results in 2.1 GWh average annual increases in PGS generation compared to the base case, it does not result in SBG spill reduction. OPG notes that the analysis has accounted for decreased GRC payments to the provincial government as a reduction of TCC benefit. This additional TCC adjustment accounts for Environmental Defense's argument that higher GRC revenues for the provincial government offset other tax revenue and as such are not ultimately realized as final ratepayer savings.

In this GRC Case, the PGS was only able to operate in pump mode during non-NSC hours to avoid prohibitively high NSC. As such, the GRC Case resulted in a reduction in the price spread required to economically cycle the PGS, deriving only a marginal increase in PGS generation, with no significant TCC benefit when evaluated on its own (see Chart 5.0 below).

Chart 5.0: Option # 2 Impact to TCC: GRC Case

	2026	2027	2028	2029	2030	2031	Total	Annual Avg
Incremental Values:	$M	$M	$M	$M	$M	$M	$M	$M
(a) HIM payments to OPG	(0.0)	(0.1)	(0.2)	(0.1)	(0.1)	(0.2)	**(0.7)**	**(0.1)**
(b) SBGVA entries	0.0	0.1	0.2	(0.2)	0.0	0.0	**0.1**	**0.0**
(c) Imports and gas cost	(0.1)	0.1	0.0	0.8	0.1	(0.0)	**1.0**	**0.2**
(d) Other costs	(0.1)	(0.1)	(0.1)	0.2	0.0	(0.0)	**(0.1)**	**(0.0)**
(e) Export revenue	0.1	0.0	0.0	0.0	0.0	0.0	**0.2**	**0.0**
(f) Impact on TCC [a + b + c + d - e]	(0.2)	0.0	(0.2)	0.7	(0.0)	(0.2)	**0.1**	**0.0**
(g) Displaced GRC revenue	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	**(0.9)**	**(0.2)**
(h) Impact on TCC net of displaced GRC revenue [f - g]	**(0.0)**	**0.2**	**(0.1)**	**0.8**	**0.1**	**(0.0)**	**1.0**	**0.2**

3.3.2.3 Potential Benefit of Removing Variable Load Charges and GRC Applicable to PGS Cycling

OPG evaluated a scenario where both variable load charges and GRC applicable to PGS cycling were removed from the PGS formulas and observed the following results:

Chart 6.0: Combined Impacts of Option #1 and Option # 2

	Incremental PGS Generation		Impact on SBG Spill	
	GWh	%	GWh	%
2026	9.0	24.7%	(8.5)	(2.8%)
2027	3.4	11.2%	(9.4)	(4.2%)
2028	3.8	22.1%	(0.5)	(0.0%)
2029	7.3	34.6%	(6.0)	(2.5%)
2030	5.6	26.2%	(1.9)	(2.4%)
2031	8.6	37.6%	(9.0)	(10.7%)
Total	**37.7**		**(35.3)**	
Average Annual	**6.3**		**(5.9)**	

In this combined scenario, OPG calculated an incremental TCC savings net of GRC of $6.0M (see Chart 7) over the study period when compared to Load Charge Case alone. This more favourable result is driven by the reduced spread (from removing GRC) applied to PGS in all hours of every day and removal of pumping restrictions during NSC hours (from removing load charges).

Chart 7.0: Combined Impact of Option #1 and Option #2 to TCC

	2026	2027	2028	2029	2030	2031	Total	Annual Avg
Incremental Values:	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**	**$M**
(a) HIM payments to OPG	0.6	1.6	0.4	0.2	0.2	0.6	**3.6**	**0.6**
(b) SBGVA cost	(0.2)	(0.2)	0.1	(0.5)	(0.0)	(0.2)	**(1.1)**	**(0.2)**
(c) Imports and gas cost	(0.7)	3.6	0.1	(20.1)	(0.4)	0.3	**(17.2)**	**(2.9)**
(d) Other costs	(0.0)	(0.6)	(0.1)	0.3	(0.0)	(0.1)	**(0.5)**	**(0.1)**
(e) Export revenue	0.1	0.3	0.4	(0.1)	(0.1)	0.0	**0.7**	**0.1**
(f) Impact on TCC [a + b + c + d - e]	(0.4)	4.1	0.1	(19.9)	(0.2)	0.5	**(15.9)**	**(2.6)**
(g) Displaced GRC revenue	(0.3)	(0.2)	(0.1)	(0.2)	(0.2)	(0.2)	**(1.0)**	**(0.2)**
(h) Impact on TCC net of displaced GRC revenue [f - g]	**(0.2)**	**4.2**	**0.2**	**(19.8)**	**0.0**	**0.7**	**(14.8)**	**(2.5)**
(i) Impact to TCC of option 1 [Chart 3.0, line (f)]	(0.3)	3.8	0.8	(13.7)	(0.0)	0.6	**(8.8)**	**(1.5)**
(j) Incremental TCC reduction from GRC removal when combined with load charge removal [h - i]	**0.1**	**0.4**	**(0.6)**	**(6.1)**	**0.0**	**0.1**	**(6.0)**	**(1.0)**

OPG has accounted for the impact of removing GRC in the same manner as in section 3.3.2.2.

3.3.2.4 Implementation

OPG would require a GRC exemption for the PGS in order to exclude GRC from the economic decision making for PGS cycling. OPG will explore the feasibility of this option.

3.3.3 The Hydroelectric Incentive Mechanism

This section explores potential changes to the HIM that may satisfy the objective of reducing SBGVA amounts.

3.3.3.1 HIM Background

The HIM supports the efficiency of the wholesale electricity market by providing OPG's regulated hydroelectric generators with the appropriate driver to follow market signals while receiving a regulated payment for their output. While the HIM formula has necessarily evolved with the changing design of the Ontario electricity market since its initial approval in EB-2007-0905, this fundamental objective has not changed. This mechanism ultimately benefits customers by creating an economic driver for OPG to shift hydroelectric generation from low-price hours to high-price hours.[12]

Since the HIM was first approved in EB-2007-0905, OPG receives the applicable OEB-approved payment amount for the average hourly net energy produced ("hourly volume") from its regulated hydroelectric facilities. If OPG produces more energy than the hourly volume in a given hour, it is compensated at market prices for the incremental amounts of energy above this hourly volume. If OPG's actual energy production from its regulated hydroelectric facilities is less than the hourly volume in a given hour, the amount payable to OPG at the regulated hydroelectric payment amount is reduced by the production shortfall multiplied by the market price.

In EB-2010-0008, the OEB required that 50% of the forecast amount of HIM proceeds be returned to customers and incorporated this as a reduction to the revenue requirement. OPG was allowed to retain 50% of the HIM net revenue with any excess above the retained amount tracked in the Hydroelectric Incentive Mechanism Variance Account ("HIMVA") and shared equally between OPG and ratepayers. The OEB also required OPG to address the interaction between HIM revenues and SBGVA in its next application. In EB-2013-0321, the HIM was expanded to include the newly prescribed facilities, using the same formula. The OEB also increased the variance account threshold to reflect the inclusion of the newly regulated facilities,[13] a 50% revenue requirement offset and a 50% sharing of additional net revenues above the threshold. In the same decision, the OEB directed OPG to include an adjustment to the HIM to reflect the interaction between the HIM and the SBGVA (the unintended benefit).

In EB-2023-0336, OPG proposed an updated HIM formula to reflect the impact of MRP. OPG's HIM formula was adopted as part of a settlement agreement in this case and was implemented with the launch of the Renewed Market on May 1, 2025. OPG's HIM calculation is discussed further in Section 3.3.3.2.

[12] EB-2023-0336, M1-1-1, section 3.5 Customer Benefit
[13] EB-2013-0321 Decision with Reasons, November 20, 2014, p. 13.

Under the current framework, OPG shares 50% of HIM net revenues with customers as established in EB-2010-0008 and EB-2013-0321. Under the HIM sharing approach, if the annual HIM net revenues exceed the pre-determined threshold, OPG records 50% of the HIM net revenues in the HIMVA as a credit to ratepayers. OPG's HIM net revenues have never exceeded the current applicable threshold that was established in EB-2013-0321.

3.3.3.2 HIM Calculation

The HIM is calculated using the following formula, established in EB-2023-0336:

$$\begin{aligned} Incentive\ Payment &= DA\ Incentive + RT\ Incentive \\ &= \sum_t \left(MW_{DA}(t) - MW_{DAavg}\right) \times LMP_{DA}(t) \\ &+ \sum_t \left(MW_{diff}(t) - MW_{diff,avg}\right) \times LMP_{RT}(t) \end{aligned}$$

Where:

$$MW_{diff}(t) = MW_{RT}(t) - MW_{DA}(t)$$

$$MW_{diff,avg} = MW_{RTavg} - MW_{DAavg}$$

Where:

$MW_{DA}(t)$: hourly production schedule from the IESO day-ahead market for each hour, *t*, of the day

MW_{DAavg}: average of hourly energy schedule from the IESO day-ahead market over the day

$LMP_{DA}(t)$: the day-ahead LMP for the resource for each hour, *t*, of the day

$MW_{RT}(t)$: net energy production supplied to the IESO real-time market for each hour, *t*, of the day

MW_{RTavg}: average of hourly net energy production over the day

$LMP_{RT}(t)$: the real-time LMP for the resource for each hour, *t*, of the day

An illustrative example of the HIM calculation for two hours is provided in Chart 8.0 below.

Chart 8.0: Illustrative Example for 2 hours of HIM Calculation including Adjustment for Unintended Benefit

Hour	Day-ahead Price	Day-ahead Schedule	Real-time Price	Real-time Output	SBG Spill	Daily Avg. Day-ahead Dispatch	Daily Avg. Real-time Output	Daily Avg. SBG Spill	Day-ahead HIM Payment	Real-time HIM Payment	Adjustment for Unintended Benefit
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
A	$5/MWh	0MW	$5/MWh	0MW	60	80MW	85MW	10MW	$(400)	$(25)	$250
B	$30/MWh	300MW	$40/MWh	300MW	0	80MW	85MW	10MW	$6,600	$(200)	$400

Sources for actual monthly calculation:

- **(a)** Published in IESO reports
- **(b)** Published in IESO reports
- **(c)** Published in IESO reports
- **(d)** OPG revenue meter data (utilized in settlement statements)
- **(e)** Per OEB approved SBG methodology
- **(f)** Daily simple average of (b) for all hours of the day
- **(g)** Daily simple average of (d) for all hours of the day
- **(h)** Daily simple average of (e) for all hours of the day
- **(i)** Calculated as: (b-f)*a
- **(j)** Calculated as: [(d-b)-(g-f)]*c
- **(k)** Calculated as: (e-h)*c

3.3.3.3 LMP Spread Required to Economically Cycle the PGS

Under the current HIM net revenue sharing arrangement, the price spread required to economically cycle the PGS will notably increase if actual HIM net revenues exceed the HIM threshold. To illustrate this, OPG calculated the spread required to economically cycle the PGS under two scenarios, summarized in Chart 9 below. Both scenarios assume that 50% of the forecast amount of HIM proceeds have already been returned to customers as a reduction to the revenue requirement, and that actual HIM net revenues have exceeded the threshold.

Scenario 1: HIM net revenue sharing arrangement with 50% sharing of HIM net revenues above threshold; and

Scenario 2: Alternative HIM net revenue sharing arrangement where 50% sharing above threshold is eliminated. This scenario is also reflective of PGS spread when the threshold has not been reached.

Section 3.3.1 provides the formulas governing PGS economics. The components of this formula were categorized as costs or revenues, as seen below.

Cost Components:
- Pump energy costs[14]
- Load charges
- GRC
- Adjustment for Incremental HIM Net Revenue Sharing*

Revenue Components:
- PGS revenue
- SAB revenue

*included once HIM net revenues exceed HIM threshold

Chart 9.0: Illustrative Calculations of Economic Price Spreads when HIM Net Revenues Exceed HIM Threshold

	Scenario 1 (50% HIM Sharing above threshold)	**Scenario 2 (No HIM Sharing)**
Energy Cost to SAB GRC	$14.40	$14.40
Revenue	Regulated Rate X Generation + (HIM Net Revenue X 50%)	Regulated Rate X Generation + HIM Net Revenue
Resulting Economic Offer Price	$29.30	$22.60
Economic Price Spread	$29.30-$14.40 = $14.90	$22.60-$14.40 = $8.20

In Scenario 1, OPG is required to share 50% of HIM net revenues on a variable basis with the ratepayer, while incurring the same amount of load charges, GRC, energy charges and efficiency losses. With OPG retaining only half of the incremental HIM net revenue, these costs must be recovered in the market to ensure OPG does not incur an economic loss when cycling the PGS. As such, a higher spread is required to economically cycle the PGS when the threshold is exceeded.

In Scenario 2, OPG continues to retain all HIM net revenues and does not need to adjust the economic spread for the PGS if HIM net revenues exceed the threshold. This scenario reflects the historical operation of the PGS as HIM net revenues have never exceeded the current

[14] Efficiency losses are inherently reflected in pump energy costs

applicable threshold that was established in EB-2013-0321. Compared to this Scenario 2, OPG estimates it would need to increase the spread by approximately 80%[15] when HIM net revenues exceed the threshold. Such an increase may impede the ability for PGS to time-shift under certain market conditions and will directionally lead to a higher SBG spill and reduced customer benefit.[16] OPG expects to reset its HIM forecast and associated threshold as part of its current application.

3.3.3.4 Market Surveillance Panel Monitoring Report 32 Summary

In its Monitoring Report 32[17] published on July 16, 2020 and a subsequent State of the Market Report 2022, the Market Surveillance Panel (MSP) expressed concern that the current revenue-sharing structure may be suppressing the efficiency benefits of the HIM. The MSP recommended “the OEB consider revisiting the sharing with consumers of net HIM net revenue exceeding a threshold” citing the following reasons:

- **Dilution of Incentive**: The Panel finds that sharing HIM net revenues above the threshold (i.e., the 50/50 split) reduces OPG’s incentive to time-shift production because OPG bears all the costs and risks but only receives half the benefit above the threshold. This could lead OPG to pass up profitable and efficient time-shifting opportunities, diminishing the intended efficiency gains of the HIM.
- **Recent Revenue Trends**: Actual HIM net revenues have consistently fallen short of the 2013 forecast used to set the sharing threshold. Since at least 2016, OPG has not generated enough incentive payments to cover the first 50% of the forecast, meaning the revenue-sharing provision has not been triggered in recent years.
- **Market Changes**: Factors such as flatter price curves, increased environmental regulations, and higher water levels have contributed to the decline in time-shifting, but the Panel cannot rule out that the revenue-sharing mechanism itself is a significant factor.

[15] Based on a pump energy cost of $14.40
[16] EB-2023-0336, M-1-1-1, section 3.5, Customer Benefit
[17] Market Surveillance Panel Report 32 - July 16, 2020

The panel stated that eliminating or revising the revenue-sharing mechanism would give OPG a stronger, undiluted incentive to time-shift hydro production, which could improve overall market efficiency and benefit consumers through lower prices during peak periods. Additionally, although the revenue-sharing threshold has not been reached recently, because future market conditions will change, the Panel believes the HIM design should be robust for all plausible scenarios, ensuring OPG always has a clear incentive to operate efficiently.

3.3.3.5 Changes to the HIM

OPG treats the sharing of the HIM net revenue forecast with the ratepayer as a fixed cost and as such, has not built it into the variable costs included in the economic formulas that govern how PGS is offered in the market. However, if HIM net revenues were to exceed the HIMVA threshold, the requirement to share 50% of HIM net revenues with the ratepayer represents an incremental variable cost that would have to be considered when offering the PGS to the market.

While the benefits of options 1 and 2 were analyzed by changing specific input variables and assessing changes in TCC, OPG cannot assess the benefits of removing the requirement to share HIM net revenues beyond the HIM threshold using the same method. As the probability of OPG's HIM net revenues exceeding the threshold differs over a large range of possible outcomes, OPG's model cannot deterministically produce an assessment of benefit. Instead, OPG relies on the conclusions from option 1, specifically that minimizing the price spread required to cycle the PGS increases PGS cycling which lowers TCC. OPG's analysis of a typical scenario demonstrates that including the marginal cost of sharing increases the spread required to cycle the PGS from $8.20 to $14.90[18]. This increase in spread can be demonstrated across the full range of pump energy prices as the overall need to earn more market revenues to offset the reduced marginal 50% HIM is consistent.

Based on the above, OPG concludes that eliminating sharing of HIM net revenues that exceed the HIMVA threshold would meet the study objectives by more effectively incentivizing OPG to engage in cost-saving opportunities for the ratepayer and would be consistent with MSP's Monitoring Report 32, which recommended that "… the OEB consider revisiting the sharing

[18] Based on a pump price of $14.40

with consumers of net HIM net revenue exceeding a threshold". OPG has thus proposed to eliminate sharing of HIM net revenues that exceed the HIMVA threshold in this application.

4.0 Conclusions

This study was undertaken in accordance with the OEB-approved Settlement Proposal in EB-2023-0336 to assess and recommend options to reduce SBGVA amounts on a forward-looking basis, with the aim of minimizing total electricity system costs to ratepayers. The analysis was conducted in the context of the MRP, with input from stakeholders and rightsholders, and with the support of the IESO as required. Stakeholder engagement played a critical role in shaping the study's scope and recommendations. Key action items from the engagement process were addressed, including ensuring the study's alignment with the latest market information, considering the impact of tariffs and Global Adjustment, and clearly linking each option to the study objectives.

The study evaluated three options: (1) removing load charges applicable to PGS cycling, (2) removing the GRC as a PGS pumping cost, and (3) modifying the HIM. Each option was assessed for its impact on PGS utilization, SBGVA reductions, and Total Customer Cost. Results from OPG's analysis are summarized in the following key findings:

- **Removing the Network Service Charge and IESO Administration Fees** as a PGS pump costs would increase PGS generation by 20.3 GWh and reduce SBG spill by 25.2 GWh over the study period, resulting in a forecast $8.8M reduction in Total Customer Costs. This would be achieved primarily by enabling more flexible, economic use of the PGS, particularly during hours currently restricted by the Network Service Rate charge. OPG is currently exploring the feasibility of implementing this option.
- **Removing GRC** as a PGS generation cost does not have a material impact on Total Customer Cost when done so in isolation, but when removed in addition to load charges, an incremental reduction in Total Customer Costs of $6.0M is calculated over the study period. OPG will explore the feasibility of this option.

- **Eliminating HIM sharing** above the established HIMVA threshold would provide a clear and consistent incentive for OPG to time-shift water, including if HIM net revenues are higher than the threshold. This proposed change is supported by the MSP as the Panel has previously stated that the current sharing mechanism may dilute OPG's incentive to time-shift hydro production for system benefit.

In conclusion, the options presented in this study offer pathways to reduce SBGVA amounts and total system costs, while respecting the operational realities of Ontario's electricity system. The findings demonstrate that targeted adjustments to PGS cost treatment and HIM net revenue sharing can improve incentives for OPG to time-shift generation in ways that lower spill and benefit ratepayers.

Appendix A

Ontario Power Generation (OPG) Stakeholder and Rightsholder Consultation – Surplus Baseload Generation (SBG) Study

→ Meeting Minutes

Table of Contents

1.0 Meeting Details

Date: March 21, 2025

Duration: 10:00 AM – 10:45 AM ET

Modality: Virtual (Microsoft Teams)

Facilitator: Ishma Zahur, Optimus SBR

2.0 Meeting Minutes

2.1 Introductions and Opening Remarks

Ishma Zahur from Optimus SBR welcomed attendees and introduced the Ontario Power Generation (OPG) staff present on the call, including Herman Mo (Senior Manager, Regulatory Affairs) and Saba Zadeh (Vice President, Regulatory Affairs). Ishma invited attendees to introduce themselves and outlined the agenda, which included:

1. A land acknowledgement
2. Purpose of the meeting
3. Facilitated discussion
4. Next steps

2.2 Purpose of the Meeting

Ishma explained that the meeting is part of OPG’s commitment under the EB-2023-0336 settlement agreement. She highlighted that the agreement requires OPG to conduct and file a study assessing options to reduce Hydroelectric Surplus Baseload Generation Variance Account (SBGVA) amounts on a forward-looking basis. She emphasized that today's meeting is to gather input on options to be considered in the study. It was noted that two proposed study options were included in OPG's March 7 invitation and participants will have an opportunity to provide input on these. Ishma clarified that the study has not yet been conducted, and so there may be questions that OPG may not be able to answer at this stage. She also confirmed that feedback outside of the proposed options is welcome.

Ishma introduced Herman Mo from OPG to provide further context.

2.2.1 Presentation of Guiding Principles and Study Options

Herman outlined the following four guiding principles used to select OPG's proposed study options:

1. Recognizes the Independent Electricity System Operator's (IESO) fundamental role in managing Surplus Baseload Generation (SBG).
2. Recognizes that the objective of IESO's dispatch scheduling and optimization algorithm is to "maximize the gains from trade to ensure consumers of electricity receive the highest value based on electricity supply offers". OPG supports this objective by offering its resources economically into the IESO's market.
3. Ensures following IESO market signals and dispatch.
4. Maintains OPG's ability to recover its approved revenue requirement and not operate at an economic loss.

Herman explained that based on these principles, OPG proposes to study two scenarios related to reducing the price spread needed for economic cycling of the Sir Adam Beck Pump Generating Station (PGS). Currently the PGS is subject to variable load charges when it operates as a load, and to the Gross Revenue Charge (essentially a fuel cost for the water used for generation) when it operates as a generator. Both of these charges contribute to the market price spread required between pumping and generating so that OPG can recover these costs. Below are the two options that OPG proposes to study:

- Option 1: Study the potential benefit of removing variable load charges applicable to PGS cycling.
- Option 2: Study the potential benefit of removing Gross Revenue Charge ("GRC") applicable to PGS generation.

2.3 Facilitated Discussion

Ishma presented two discussion questions to participants:

1. What feedback or considerations for OPG do stakeholders and rightsholders have specific to the two options OPG proposes to study?
2. Do stakeholders and rightsholders have any other input for OPG outside of the two options OPG proposes to study?

2.3.1 Consideration of Additional Study Options

One participant questioned whether OPG had considered other study options that were ultimately not pursued beyond the two presented. In particular, OPG was asked why revisions to the Hydroelectric Incentive Mechanism (HIM) had not been included among the proposed study options.

OPG explained that a list of excluded options was not available but noted that the two selected options were identified based on the guiding principles. However, OPG confirmed it is open to considering additional suggestions and agreed to revisit whether incremental changes to the HIM could meet the study's objectives.

2.3.2 Evaluation Criteria and Ratepayer Impacts

There was discussion around how the proposed options would be evaluated and whether the study would analyze impacts on ratepayers.

OPG confirmed that the primary criterion, as defined in the EB-2023-0336 settlement agreement, is to reduce SBGVA amounts on a forward-looking basis, in light of the new market, with the aim of minimizing total electricity system costs to ratepayers. OPG confirmed that the study will demonstrate how each option satisfies that objective.

2.3.3 Scope of OPG's Control and IESO's Role

Stakeholders asked whether the study would also examine actions that the IESO could take to minimize SBG. Additionally, there were comments on how variable generation, such as wind generation and solar, influence SBG events.

OPG confirmed that the study will only focus on actions within OPG's control, in line with the first guiding principle.

2.3.4 Role of IESO in Supporting the Study

Some participants interpreted the settlement language—referring to IESO assistance—as an indication that OPG would engage the IESO on all scenarios, including those involving potential actions outside of OPG's control but within the IESO's purview and inquired whether either of OPG's proposed study options seeks to do that. Participants also suggested there may be options that fall within both OPG and IESO's shared control, and that collaboration could help enable such options. Furthermore, some participants understood the intent to be that while OPG can account for its own costs, it lacks visibility into total system costs. For example, when time-shifting generation using PGS, OPG may know how its own costs change, but not who is next in the dispatch order or how the shift would affect overall system costs. In such cases, participants suggested that OPG would require the IESO's assistance to gather the necessary data and model broader system cost impacts—believing this to be the primary reason for consulting the IESO as part of the study.

In response, OPG clarified that the study will focus on options within its control but emphasized the need to ensure that the proposed options do not conflict with the design of the new market. Since this is a forward-looking study, OPG's modelling will utilize OPG's assumptions and not be dependent on IESO data which would be commercially sensitive. Engagement with the IESO is intended as a check and balance—to confirm that OPG's proposals align with the IESO's framework. The study is not intended to examine options that fall entirely outside of OPG's control. OPG also reiterated that it will ensure the proposed options do not conflict with the IESO's principles or market rules.

2.3.5 Consideration of Tariffs

Participants raised the potential impact of tariffs, noting that although tariffs may only affect a small portion of OPG's operations, they are a growing concern among manufacturers and could become a factor that indirectly impacts the study.

OPG acknowledged this point and stated that the study would be based on the best available information at the time. OPG recognized if there is a known impact of tariffs, they may be considered in ongoing discussions.

2.3.6 Inclusion of Other Hydroelectric Facilities

Participants were interested to know if OPG is considering time-shifting opportunities beyond the PGS—such as other hydroelectric assets with time-shifting capability—and whether those were part of the study options.

OPG clarified that the HIM applies to PGS as well as other OPG hydroelectric assets. OPG stated that its review of changes to the HIM will include all hydroelectric resources subject to the incentive mechanism.

2.3.7 Global Adjustment as a Factor

Participants highlighted the distinction between minimizing system costs and minimizing Global Adjustment (GA) charges. They noted that even if a proposed option results in a reduction in total system costs, it does not necessarily translate into a benefit for some ratepayers due to the way GA is allocated.

OPG stated that the study will focus on minimizing total system costs, in accordance with the language in the settlement agreement. However, OPG acknowledged the point about GA and confirmed it will consider whether and how it could be included as an evaluation factor for the study options.

2.3.8 Market Renewal Program and Operational Considerations

Participants noted that the Market Renewal Program (MRP) has not yet come into effect, and the operation of the market in the future may differ from current expectations. Additionally, stakeholders raised the need to examine operational trade-offs between maximizing output through the Niagara tunnel and optimizing the use of the PGS facility.

In response, OPG confirmed that the study will be forward-looking and based on the best available information regarding how the new market is expected to operate. OPG clarified that the modeling will incorporate up-to-date physical attributes of the Beck complex, including the Niagara tunnel infrastructure. OPG also noted that it already optimizes operations across the entire Beck complex.

Following a prior comment that GA may change under MRP, one participant clarified that MRP affects only market prices and, therefore, only the quantum of GA would be impacted. OPG acknowledged this distinction and re-confirmed that it would consider whether and how GA could be included as a factor in the evaluation of study options.

2.3.9 Scope of Structural Changes

Referring to the settlement agreement language regarding the study, participants requested clarification on how OPG interpreted “structural changes” and whether this included potential future infrastructure changes (e.g., transmission) that may be required depending on how the plant continues to operate going forward.

OPG explained that the term encompasses a broad range of possibilities but clarified it has not considered capital investments or changes to physical assets. Instead, OPG believes the focus as being on regulatory or market mechanisms, including those requiring further approval by external entities such as those in OPG's two proposed options.

2.3.10 Jurisdiction and Feasibility of Proposed Options

Participants commented that the proposed options – removal of variable load charges and GRC – fall outside the OEB's jurisdiction. Participants suggested that OPG consider including options it can pursue unilaterally or with OEB approval, with the possibility there may be none, to ensure that actionable options are included in the final report.

In response, OPG agreed to consider the point raised.

2.3.11 Expectations for Final Report

Participants requested that the final report explicitly demonstrate how each proposed option meets the objectives outlined in the settlement agreement, including whether and how it reduces spillage, and what structural changes would or would not be required.

OPG confirmed that the final report will address how each option satisfies the settlement requirements, and that if an option requested by intervenors does not meet those requirements, the report will explain why. OPG also noted that both of its proposed options are intended to support increased PGS cycling, which could result in reduced spillage, and that this assumption would be validated during the modeling phase of the study.

2.4 Next Steps

Ishma thanked participants for their feedback and outlined the following next steps:

1. Meeting minutes will be issued and shared with attendees.
2. OPG will assess all feedback and incorporate it into the study design.
3. OPG will engage IESO as available and needed.
4. A final study report will be drafted.
5. The report will be filed as part of OPG's upcoming rate application.

3.0 Summary of Action Items

The table below captures the action items for OPG to consider following the meeting.

#	Action Item
1.	Consider whether changes to the HIM would meet the study's objectives.
2.	Consider the best available information available at the time of conducting the study, including the potential impact of tariffs on the system, if applicable.
3.	Consider whether and how Global Adjustment could be included as a factor in the evaluation of the study options.
4.	Clearly link how each study option meets the study objective(s) outlined in the settlement agreement, including whether and how it reduces spillage, and what structural changes would or would not be required.

4.0 Participant List

4.1 Attended

Organization / Affiliation	Stakeholder
Association of Major Power Consumers in Ontario (AMPCO)	Shelley Grice
Coalition of Concerned Manufacturers and Businesses of Canada (CCMBC)	Tom Ladanyi
Environmental Defense (ED)	Amanda Montgomery
Power Workers Union (PWU)	Bayu Kidane
Quinte Manufacturers Association (QMA)	Michael D. McLeod
School Energy Coalition (SEC)	Mark Rubenstein
Society of United Professionals (SUP)	Bohdan Dumka
Vulnerable Energy Consumers Coalition (VECC)	Mark Garner
Ontario Energy Board (OEB)	Chris Cincar
	Thomas Eminowicz
	Jeffrey Sauer
	Fiona O'Connell
On behalf of Minogi Corp., a wholly owned subsidiary of Mississaugas of Scugog Island First Nation ("MSIFN")	Daniel Vollmer
Six Nations Council	Peter Graham
Ministry of Energy (MOE)	Shehrzad Shehrzad
	Maya Super
Independent Electricity System Operator (IESO)	Phillip Chisulo
Ontario Power Generation (OPG)	Herman Mo, Senior Manager, Regulatory Affairs
	Saba Zadeh, Vice President, Regulatory Affairs

Organization / Affiliation	Stakeholder
	Other observing members
Optimus SBR	Ishma Zahur, Facilitator (Principal, Industries & Government Practice)
	Vrinda Oberoi, Note-taker (Senior Analyst, Industries & Government Practice)

4.2 Did Not Attend

Organization / Affiliation	Participant
Consumers Council of Canada (CCC)	Julie Girvan
Ontario Energy Board	Michael Millar
	Ritchie Murray
	Tina Li
	Musab Qureshi
	Theodore Antonopoulos
Chiefs of Ontario	Chris Hoyos

Appendix B

Connecting Today.
Powering Tomorrow.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, ON M5H 1T1
t 416.967.7474
www.ieso.ca

November 24, 2025

Herman Mo
Senior Manager, Regulatory Affairs
Ontario Power Generation
1908 Colonel Sam Dr.
Oshawa, ON L1H 8W8

Dear Mr. Mo:

Re: Surplus Baseload Generation Variance Account (SBGVA) Study

In preparation for its 2027-2031 Payment Amounts for Prescribed Assets application, Ontario Power Generation (OPG) engaged the Independent Electricity System Operator (IESO) beginning in September 2024 regarding its requirement to prepare an SBGVA study.

In March 2025, OPG conducted a stakeholder session to gather input from stakeholders and rights holders on two proposed study options related to the SBGVA study, as well as to invite feedback on any additional considerations beyond the proposed options. This process allowed all participants – including the IESO – the opportunity to provide feedback on the options to be explored as part of the SBGVA study.

In September 2025, OPG met with the IESO to provide an overview of the study's findings and shared a draft of the 2025 SBGVA study. Following our review of the study, from a market efficiency perspective, the IESO acknowledges that the proposed options appear directionally appropriate. However, we would like to clarify that the IESO did not participate in the development or execution of the study and while the IESO has no concerns with OPG's analysis, we have not conducted an independent validation of the results.

If you have any questions or would like to discuss further, please let us know.

Sincerely,

Carrie Aloussis

Carrie Aloussis
Senior Manager, Regulatory Affairs