IESO's Written Submission – OEB Consultation Regarding Incentive Rate Making Options for Ontario Power Generation's Prescribed Generation Assets

Board File No. EB-2012-0340

1. Introduction

Important discussions and opinions have already been presented and submitted on the application of IRM to OPG's prescribed assets. The IESO is supportive of objectives that the Board and stakeholders participating in the consultation are seeking to achieve. A great deal of thought has been given to the appropriateness and timing of moving from cost of service regulation to incentive regulation. However the IESO believes that irrespective of the form of regulation, establishing proper incentives for OPG to respond efficiently to price signals is integral in maximizing the value of the facilities to Ontario.

The IESO would like to highlight the importance to consumers of encouraging efficient dispatch in the hybrid market. The IESO submits that fixed rate payment amounts can distort efficient dispatch in a competitive wholesale market and that, even under a hybrid market, inefficient dispatch will impact Ontario consumers.

The wholesale electricity market produces a market signal to efficiently coordinate resources. These competitive market prices should be used to drive efficient production incentives in the regulation of OPG's prescribed nuclear and hydroelectric assets.

1.1. Background and Context

The IESO believes that the regulation of Ontario Power Generation's (OPG) prescribed assets should be guided by the following three objectives:

- To encourage OPG to operate its assets and manage its business safely and reliably and more efficiently in light of electricity system requirements;
- To maintain OPG's financial viability; and
- To maximize the benefits to Ontario consumers from the efficient use of the assets.[1]

In considering how these objectives may be furthered through Incentive Regulation Mechanisms ("IRM"), it is necessary to bear in mind that IRMs have been applied to network assets assumed to have natural monopoly characteristics, such as electricity transmission and distribution or natural gas pipelines. As is noted below, it is market failure that requires a regulator to intervene in market outcomes in order to further the public interest. In the absence

[1] Ease and cost of implementation are also important considerations in the design of an IRM for OPG's prescribed assets.

of market failure, the purpose and role of public utility regulation is less straight forward. In fact, there is little experience with the application of IRMs to potentially competitive sectors such as electricity generation.[2]

The IESO has reviewed submissions from other parties on incentive ratemaking options and observes that few options offered give due consideration to how OPG's prescribed assets operate within the competitive wholesale electricity market. Much attention has been given to encouraging enduring productivity gains from OPG, however little focus has been placed upon encouraging the efficient dispatch of OPG's assets. The IESO is of the opinion that regardless of the regulatory approach applied (i.e., IRM, cost of service, regulation by contract, etc.) effective incentives should exist for OPG generation to operate efficiently within the electricity market.

This is relevant because OPG operates within a market where there are several other generators competing to supply electricity. How OPG schedules its assets within this process (decides when and how much to produce) can affect the overall cost of operating the system. If OPG schedules its assets inefficiently or "out-of-merit" the cost of operating the system will be higher than had they operated in merit. In the current hybrid Ontario electricity market, these higher costs are ultimately borne by consumers.

Wholesale market prices reflect the efficient use of the province's electricity resources through competition. The best way to encourage OPG to schedule its assets efficiently is to design incentives, be it under IRM, COS, or otherwise, such that OPG's compensation is guided by the wholesale market prices.

Power Advisory LLC (PA) has provided the Ontario Energy Board (OEB) with a set of IRM options for OPG's prescribed nuclear assets and baseload hydroelectric assets. Various submissions have commented on the appropriateness and/or timing of applying an IRM, particularly to nuclear. The IESO appreciates many of the uncertainties associated with the upcoming years, however does not believe this changes the need to incorporate price signals.

All of the options presented for the nuclear assets involve a fixed regulated price for output produced; wholesale market prices do not factor into how OPG is compensated. In the IESO's view, using a fixed price mechanism can distort OPG's incentives to schedule the assets efficiently in certain situations, particularly during periods of surplus baseload generation (SBG). In Section 3 of this submission, the IESO discusses these types of instances.

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[2] Instead, most jurisdictions have sought to deregulate this sector preferring to rely on competitive market forces and market mechanisms to pursue the objectives of efficiency, viability and to promote the interests of consumers. See page 40 *Incentive Regulation Options for Ontario Power Generation's Prescribed Generation Assets*, Power Advisory LLC.

With respect to the hydroelectric assets, PA recommends that the OEB retain the existing Hydroelectric Incentive Mechanism (HIM) with an appropriate sharing mechanism of revenues between OPG and consumers. The IESO supports the use of the HIM, as it is designed around wholesale prices and notionally provides OPG with incentives to schedule its operations efficiently. It is clear to the IESO that encouraging the efficient use of the pumped generation storage (PGS) at Beck can benefit Ontario consumers, even in a hybrid market. In Section 3, we note some areas of potential improvement to the HIM that would enhance efficient outcomes driven by the market price signal.

Before providing specific comments on the various regulatory options, we discuss the importance to consumers of encouraging efficient dispatch in Ontario's hybrid electricity market.

2. IRM's in the context of Ontario's Hybrid Generation Market

2.1. IRM's can facilitate or distort efficient dispatch in a competitive wholesale market

When a regulated firm competes against other suppliers in an industry, severing the price that the regulated firm receives from the prices that emerge in the competitive market can lead to an inefficient use of industry resources. In the context of a competitive generation market, this inefficiency would be manifest through the inefficient dispatch of generation. Specifically, unless the wholesale market price plays a part in the regulation of OPG's payment amounts, higher cost generators may be dispatched in priority over lower cost generators.

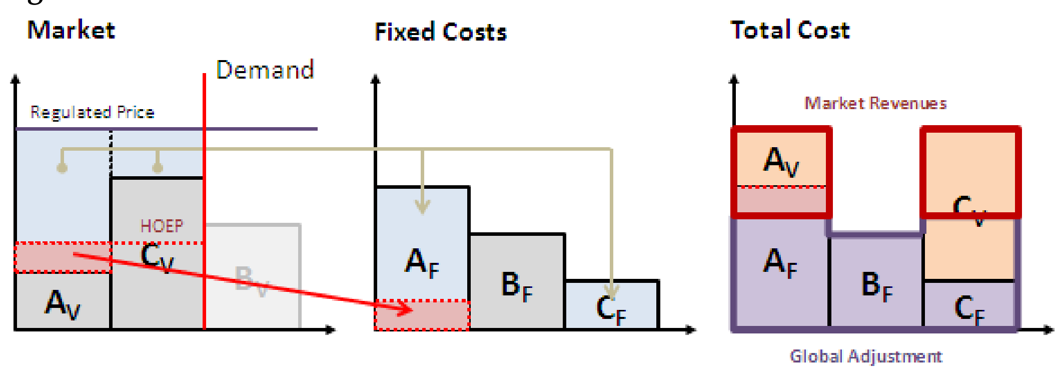
2.2. Efficient dispatch benefits consumers in Ontario's hybrid market

It should not be assumed that the hybrid nature of Ontario's electricity market diminishes the benefit to consumers of achieving efficient dispatch. In the hybrid market, consumers must pay the total cost of generation. Total generation cost includes both the fixed and variable costs incurred in meeting electricity demand. These costs are recovered from consumers through the wholesale market price (which pays generators for its variable cost and some contribution to fixed cost recovery) and from Global Adjustment (which compensates contracted generators for any fixed costs not recovered from the market). When generators are dispatched "out-of-merit" (i.e., high variable cost generators operate instead of low variable cost generators), total system cost will be higher. And while the out-of-merit dispatch may cause the wholesale market price (HOEP) to be lower, and the GA to be higher, the total payment made by consumers (HOEP plus GA) will be higher.

The following figure illustrates this concept.

Figure 1 illustrates how the fixed and variable costs are recovered through market and GA payments. Lower market revenues earned by Generator A, require a larger GA payment. Generator B will earn no market revenues, but receive a payment through the GA for its fixed costs. Generator C will earn insufficient market revenues to even cover its variable costs, however the regulated price will ensure full cost recovery through GA. While there is some shifting of where fixed costs are recovered from, it should be clear that the overall cost ultimately paid by consumers is higher under inefficient dispatch.[3]

Figure 1



2.3. The best approach to promoting efficiency is through competition, where possible

The use of market prices as the cornerstone for regulation can be complex, but its application is informed by considering some of the first principles of public utility regulation.

As indicated, the regulation of the price of power generated from OPG's facilities is different than the regulation of rates of transmission and distribution companies. One of the main ways in which it is different is that the premise of transmission and distribution rates is that those services are marked by market failure. The economic reason for public utility regulation is thus that while efficient markets will, on the whole, produce efficient outcomes, there are special cases where market failure prevents that outcome. In the case of market failure, the market price will not be in the public interest and it is necessary for the regulator to intervene and impose an outcome that is consistent with the public interest. In other words, market failure is a large cause of regulation and a key goal of regulation is to seek to repair that outcome. The Board has expressed this point as follows:[4]

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[3] It should also be recognized that the fact Ontario residential ratepayers pay regulated rates does not change the actual cost savings realized. While RPP rates are set semi-annually, cost savings do eventually accrue to ratepayers, as the forecast market and global adjustment costs used in the setting rates are trued-up against actual costs.

[4] EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, December, 11, 2009, at p. 15.

> "In competitive markets, the outputs of the goods and services of the economy and the prices for these outputs are determined in the market place, in accordance with consumers' preferences and incomes, as well as producers' minimization of cost for a given output. In such a market, the outcome is the efficient allocation of resources, including capital, and social welfare is maximized.
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> However, in some situations, markets fail to achieve such efficient outcomes. Market failure refers to situations in which the conditions required to achieve the market-efficient outcome are not present. Common examples of market failure are the existence of significant externalities, the exercise of market power by a small number of producers or buyers, natural monopolies, and information asymmetry between producers and their customers.
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> Electric transmission and distribution companies and natural gas distribution utilities are natural monopolies and are subject to rate regulation in Ontario by the Ontario Energy Board. In this context, the purpose of rate regulation, among other things, is to create or emulate an efficient market solution that cannot otherwise be achieved due to the presence of one or more market failures."

In the case of electricity generation, the problem of market failure is not present. There are several generators providing offers into a competitive market, which produces a market price, the HOEP. The HOEP reflects, to use the Board's language, "the efficient allocation of resources." Therefore, there is no reason for the Board to try to replicate what a market price would be: the HOEP is a transparent market price that can be incorporated into OEB regulation of OPG prices.

The OEB's recognition that a market price reflects an efficient allocation of resources reflects the general premise an efficient outcome is more likely to result from competition than regulation. This has support in both the OEB's statutory mandate and in the scholarly literature.

With respect to the OEB's statutory mandate, s. 29 of the OEB Act provides that where the Board makes a factual determination that "a licensee, person, product, class of products, service or class of services is or will be subject to competition sufficient to protect the public interest", the Board shall refrain from regulating. This recognizes that, if the public interest can be met either through competition or through regulation, the Board's mandate is to prefer competition.

With respect to the scholarly literature on the topic, Stephen Breyer (now Justice Stephen Breyer of the Supreme Court of the United States), observed that "the regulatory process – even when it functions perfectly – cannot reproduce the price signals that a workably competitive marketplace would provide."[5]

As a result, to the extent that a workably competitive market – such as the IESO administered market – creates a price signal, that price signal is more likely to reflect an efficient market outcome than a price that results from a regulatory process. This suggests that the most effective way to promote efficiency is through using competition, where possible. The point here is not to argue in favour of forbearance of regulating OPG. Rather, the point is that the Board can use prices that derive from a competitive market to inform its interpretation of the public interest, when no market failure is present.

3. Specific Comments on the PA Report

3.1. IRM Options for OPG's Nuclear Facilities

The PA report considers several IRM options for nuclear, each of which are designed to encourage OPG to do two things: (i) increase output by increasing the units' availability and (ii) find cost savings in the way it operates its business. The IESO believes that these are improvements worth pursuing.

However, each of the options identified incorporate a form of price cap regulation that pays OPG a fixed regulated price for output produced. Under this form of regulation, market prices do not affect OPG's compensation and hence prices do not influence its decisions when to produce. This can encourage OPG to schedule its nuclear units in the competitive wholesale market at times when it is not efficient to do so. As outlined in Section 2.2, the cost of this inefficiency is ultimately borne by Ontario consumers in the form of higher overall electricity rates.

The PA report recognizes this possibility but concludes that because the nuclear units are low marginal cost assets that cannot reduce output for short periods of time, "the pricing for the nuclear output should not depend on the market prices during the particular hours when it is generated."[6] The IESO agrees that the technology of the nuclear facilities is such that it is efficient most times for these assets to produce at full capacity. However, there are instances in which the lack of exposure to wholesale market prices can induce OPG to make operating decisions that are inefficient. The IESO can identify at least three.

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[5] Stephen Breyer, *Regulation and its Reform* (Harvard, 1982, at p. 59.

[6] *Incentive Regulation Options for Ontario Power Generation's Prescribed Generation Assets*, Power Advisory LLC, page 47.

Outage Planning

A fixed rate payment amount encourages OPG to minimize the time that its units are on outage including planned outages. However, because the fixed rate severs the link between OPG's revenues and market prices, OPG has no financial incentive to schedule its outages when it is most efficient from an overall system perspective.

As PA states at page 48, "good industry practice is to schedule generation outages at times of low demand and therefore low price." PA also states that "OPG is required to coordinate its outage schedule with the IESO, so there is not likely to be a need for an incentive to influence OPG's outage scheduling."

First, it is important to clarify the role the IESO plays in coordinating generator outages. As long as the IESO projects that it will have sufficient output potentially available to reliably meet demand over the forthcoming period, it will not influence outage schedules. The IESO can only accept an outage request or deny the return of a generation asset if there is a reliability reason for doing so. While OPG coordinates its outages with the IESO with respect to maintaining reliability, this coordination does not consider the implication of the outage on overall system cost. A generator will consider the impact of taking an outage on its financial performance. Exposed to market prices, the generator will target outages during times when prices are expected to be low. Done effectively, this will lower total system costs.

OPG does engage in good utility practice by scheduling its nuclear outages during shoulder months when demand is typically at its lowest. However, market prices are not always at their lowest during shoulder periods, as prices are influenced by both supply and demand factors. If all firms planned outages over the same period, the system could have a relatively thin supply of low cost generation available, exposing the potential for high cost resources to be dispatched.

A firm whose revenues depend on market prices may result in outages being taken a few weeks earlier or later than what it might have done had it only looked at demand factors. Arguably, if OPG's revenues were affected by market prices, it would have stronger incentives to consider all market factors when planning its outages, aligning with overall system efficiency.

Returning a unit to service during a period of SBG

Under a fixed rate payment amounts, OPG is encouraged to bring a unit on outage back to service as soon as it is ready to produce. In most instances, this would be the efficient thing to do. However, during prolonged periods of SBG, this may not be the case. Situations may occur when it is optimal for a unit to slightly delay its return, and avoid triggering another nuclear unit shutting down and being unavailable for several days.

For example, suppose that OPG determines that a nuclear unit currently on extended outage will be ready for service the next day. At the same time the unit could return, the market is signalling SBG conditions throughout the day. Since OPG only receives revenue when it is producing and indifferent to anticipated negative prices, it will want to bring the unit back to service as soon as it can.

However, the return of the OPG nuclear unit will exacerbate the SBG conditions. In the extreme, this could trigger the shutdown of another nuclear unit to temporarily manage the surplus. This shutdown could potentially render the unit unavailable to produce for the next three days. As long as the IESO projects that it will have sufficient remaining available capacity (with the shutdown) to still reliably meet demand over the next three days, it must allow OPG to return its nuclear unit.

The shutdown of the unit to manage the temporary SBG conditions will mean that when the SBG conditions subside, higher cost generation (likely gas-fired generation) will be required to run in its place. This will lead to higher cost for Ontario consumers. From the ratepayer perspective, the efficient decision may be for OPG to delay the start of its nuclear unit for a few hours to avoid incurring higher costs when surplus subsides.

Exposure to the potential negative market prices would incentivize OPG to economically consider when it would choose to bring a unit back from outage, relative to system conditions.

Inefficient incentives to invest in manoeuvring capabilities

Nuclear units are designed to operate as baseload units producing at full capacity. However on occasion, nuclear units have been required to reduce output during low demand periods. The flexibility of these plants can help the efficient and reliable dispatch of the system. Increased partial manoeuvring capability from nuclear units can prevent the costly shut-down of full units during times of surplus.

Currently, OPG's Pickering and Darlington units have no manoeuvring flexibility. To enable this capability, it is understood that some level of capital investment would be necessary. Nonetheless, a fixed rate payment amount provides OPG no incentive to manoeuvre these units since reducing output reduces its revenues. Thus, a fixed rate payment amount provides OPG with no incentive to even consider making a capital investment that would enable manoeuvring.

If exposed to the potential of negative prices during prolonged SBG periods, OPG would be encouraged to consider reducing output during times of surplus to the extent of its operational capability. OPG would have an incentive to consider investing in manoeuvring capabilities if it was privately profitable, and socially efficient to do so. This investment would be profitable for OPG if the cost of the investment was less than the projected negative revenue it would earn when it produced at negative prices. In this case, this would also be an efficient investment.

At a minimum, this type of investment could be considered in the context of the Darlington refurbishment. To be clear, this would not necessarily require the development of manoeuvring capability, but rather provide OPG the incentive to reasonably consider and evaluate the viability of such a project to the extent practical.

3.2. How price signals can be integrated into the regulation OPG's nuclear assets

Regardless of whether an IRM, COS or other regulatory approach is applied to OPG's nuclear assets, the IESO believes that market price signal should be used to influence OPG's production decisions. Providing OPG with improved incentives to schedule its resources efficiently within the wholesale market would achieve the broader objects of the province in regulating OPG's prescribed assets.

The IESO looks to the "deemed dispatch" payment mechanism[7] used by the Ontario Power Authority (OPA) in some of its procurement contracts, as one example of how this could be applied. These contracts are designed to provide the financial viability of the asset to the owner, encourage the efficient scheduling of the assets, and return any "excess" profits earned on the assets to consumers. The Market Surveillance Panel has recognized that these types of contracts "are designed in a way that maintains dispatch efficiency."[8]

Simply put, the deemed dispatch model provides a monthly revenue requirement from which assumed market revenues earned are subtracted. The net amount is paid to the generator. When the market price is above the deemed marginal cost, the generator is assumed to have produced and collected market revenues. This gives the generator certainty of cost recovery (and return on investment), provided they can produce efficiently within the wholesale market.

How the level of the monthly revenue requirement is established, through IRM or COS, does not affect how efficient production is facilitated.

[7] For a description of how this "deemed dispatch" mechanism works for OPA Clean Energy Supply or "Early Mover" contracts refer to Market Surveillance Panel Report *Monitoring Report on the IESO-Administered Electricity Markets May 2007- October 2007*, p 172-174.

[8] Market Surveillance Panel Report, *Monitoring Report on the IESO-Administered Electricity Markets May 2007-October 2007,* p.171

Given its low marginal cost, OPG nuclear should be presumed to be operating in most hours (i.e., all positive priced hours).[9] For most of the year, the deemed dispatch mechanism would prompt OPG to maximize its availability and production. However during SBG periods with anticipated negative prices, OPG would not be deemed to have produced. Therefore, under this structure OPG would be motivated to respond economically and consider its exposure to having to pay a negative market price to produce.

The IESO offers this mechanism as one example of how the three issues from fixed rate payment amounts (outage planning, return during SBG and manoeuvring investments) could be ameliorated. The IESO acknowledges this puts some additional financial risk for OPG to manage, by motivating them to produce only when efficient, but suggests the generator is in the best position to evaluate all risk and revenue factors. As other submissions have also recognized, the IESO believes the assignment of risks and rewards between the shareholder and ratepayers is an important consideration for the Board.

3.3. IRM Options for OPG's Hydroelectric Facilities

The PA report recognizes that efficient operation and maximizing efficient production are key objectives that will benefit Ontario (while maintaining safety and reliability). The IESO believes that these are objectives worth pursuing, and that the wholesale market price presents a fundamental apparatus for this to be achieved.

PA suggests production incentives for these assets should be aligned with likely customer benefits, giving consideration to GA and SBG costs ultimately borne by consumers (Goal #1). The net effect to consumers is complex under the hybrid system, however an assessment should focus on the impact to total variable costs (as previously discussed in Section 2.2). The IESO believes the design of an effective incentive mechanism for OPG's prescribed hydro assets that is driven by market prices should align OPG's private incentives with those that are publically efficient.

Consistent with Goal #1, PA advocates that options should be intended to maximize production during periods when electricity prices are highest (Goal #2) and shift production from off-peak to peak periods when doing so contributes to a lower total cost of electricity to Ontario consumers (Goal #3). The IESO believes these goals should coincide with incentivizing efficient dispatch. However, the IESO does not agree that trying to maximize pumping at Beck PGS (when SBG conditions are present and storage isn't full) is necessarily consistent with Goal #1, but can instead at times undermine efficient outcomes.

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[9] The deemed dispatch mechanism takes into account allowances for required planned outages. This could be further modified to reflect instances where units were shutdown to help manage SBG, but unavailable to return when system conditions quickly subside

3.2.1 Current Hydroelectric Incentive Mechanism (HIM)

The IESO believes the incentive structure under the HIM positively recognizes the merit of dispatch efficiency. The incentive to shift production results in lower variable cost resources being utilized, and thus lowering total overall costs. As discussed in Section 2.2, consumers will realize these benefits, even with contracts and regulation in the hybrid market.

Prior proceedings on the HIM have focused on impacts to average HOEP and not the impacts to total system costs. OPG has submitted that the impact of its response to the HIM resulted in a modest increase in market prices during off-peak hours but larger decreases in market prices during on-peak hours. The net effect was estimated to be a $1.14 reduction in average market prices between December 2008 and 2009. In its report, PA observes that the operation of PGS does indeed impact market prices and this "is the primary motivation for the incentive mechanism."[10] However, the Board has appeared to be sceptical of net benefits being realized by consumers resulting from the HIM, suggesting "the net benefits to consumers are likely substantially less than estimated by OPG on the basis of market price differentials alone."[11]

PA summarizes one of the Board's concerns with respect to the HIM:

"OPG incentive is a function of the HOEP, the total price paid by Ontario consumers includes the GA. Thus, there is a misalignment between the value of the incentive to OPG and to consumers that is caused by the fact that the HOEP and the GA tend to move, by design, in opposite directions."[12]

The IESO believes that an assessment of the benefits derived by consumers from the HIM should instead focus upon considering the effect on system costs, rather than solely on changes to average market prices. The efficiency benefit occurs as a higher marginal cost resource is displaced by output from Beck during on-peak hours. The variable cost of the displaced on-peak resource should be lower than the additional variable cost incurred from a resource needed to replace reduced Beck output during off-peak hours. As a result, the HIM driven by market prices should result in a lower total system cost, and as noted in section 2, lower total consumer cost across all hours.

PGS Operation during Surplus and Efficient Spill

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[10] *Incentive Regulation Options for Ontario Power Generation's Prescribed Generation Assets*, Power Advisory LLC, p.67

[11] *OEB, Decision with Reasons, EB-2010-0008, Page 146*

[12] A footnote in the report goes on to say: *"Increases in the HOEP result in credits to the GA for energy provided by OPG's prescribed assets and for renewable contracts. Reductions in the payment levels for OPG's assets result in direct reductions to the GA and are not associated with an increase in the HOEP." Incentive Regulation Options for Ontario Power Generation's Prescribed Generation Assets*, Power Advisory LLC, p.67

The Board's second concern regarding the HIM pertained to the incentives during SBG conditions. The establishment of an SBG deferral account recognizes that there may be instances when maximum output is not desired due to system conditions. While seemingly unconvinced of significant HIM benefits accruing to ratepayers, the Board appeared to conclude some benefits could occur if SBG conditions could be mitigated through the use of PGS.

"The Board therefore expects OPG to use the PGS to the maximum extent possible to mitigate this additional direct cost on ratepayers. When assessing the circumstances which give rise to lost production due to SBG, the Board will examine the use of PGS and OPG will have to fully justify any instances in which the PGS is not used. If the Board finds that OPG could have, or should have, used the PGS to mitigate SBG, the Board will adjust the balance in the SBG account accordingly." [13]

OPG's operation of the PGS is to arbitrage economic opportunities in off-peak/on-peak differentials. This is a complex calculation, taking into consideration (among other things) anticipated energy withdrawal costs, impact to downstream units through water availability, energy return efficiency, water rental fees and anticipated on-peak market prices.

The IESO believes that OPG is in the best position to evaluate the efficiency of its pumping decision based upon its understanding of the facilities and the price signals sent out through the market reflecting the marginal value to the system. Therefore, on balance it would seem that the HIM, based on upon market prices, should send an appropriate signal to OPG to pump or not pump. OPG should have natural incentives to respond to surplus conditions characterized by expected very low or negative market prices. This should create the necessary price arbitrage opportunities for OPG to pump efficiently.[14]

If SBG conditions did exist, and OPG elected not to maximize pumping, PA accepts that OPG may be better off based on its forecast of relative on-peak and off-peak energy prices, and the impact of GRC.[15] This is a privately efficient outcome for OPG. This should also be publically efficient.

However by linking incremental HIM revenues to the performance of pumping activities during SBG, the Board appears to have assumed that pumping during surplus must unequivocally benefit consumers. Indeed, Goal #4 (maximize pumping to the Sir Adam Beck PGS when SBG conditions are present and storage isn't full) characterizes this as an intended objective.

[13] Decision with Reasons, OPG Payment Amounts p.147

[14] Though the GRC may cause a distortion of OPG's marginal costs. This is discussed subsequently

[15] Power Advisory Report, p.74

It is not clear why this would necessarily be efficient or to the benefit to the consumer in circumstances where market price signals do not induce pumping. There may be instances where anticipated price spreads between off-peak and on-peak hours are relatively small. This implies little incremental benefit to the system (and thus consumers) would result from reducing generation output during off-peak and re-injecting it on-peak. Once energy return efficiency losses are considered (i.e., half of what is withdrawn can be injected later), requiring the use of PGS during a prolonged period of low, flat prices may in fact raise total system costs.[16]

Instead of pumping, OPG could choose to spill water and forego production. As noted above, the Board has expressed concern with OPG potentially not minimizing its foregone output and spilling too much. In contrast, the Market Surveillance Panel has commented that under the HIM, "OPG may still have little incentive to spill water at hydroelectric stations when it is efficient to do so"[17] (in other words, the Panel is worried that OPG won't spill enough).[18]

The IESO believes that the effective incentives that exist under the HIM should not be encumbered by additional SBG provisions, as the market price signals should enable efficient outcomes. The IESO also acknowledges there is the potential for the HIM to create muted incentives for efficient production when market prices are very low, as identified by the MSP.

Gross Revenue Charge (GRC)

The GRC, calculated in accordance with O. Reg 124/02, applies a charge payable by OPG on production from its covered hydroelectric facilities. The two components (property tax and water rental) apply rates to a fixed "gross revenue" amount of $40/MWh. The total GRC rate is graduated, increasing with station production, to a maximum of 36% or $14.40/MWh. This effectively represents a per unit tax on hydroelectric output.

The IESO understands that OPG views the GRC as a marginal cost of production, a factor to be considered in its decision to operate under the HIM. While not a direct cost of withdrawing, this

[16] Pumping activities may have precluded the management of SBG conditions through manoeuvring of a nuclear unit, curtailment of imports or spilling of water at other facilities, though it is ambiguous whether these instances would have resulted in higher system costs.

[17] Market Surveillance Panel Report, *Monitoring Report on the IESO-Administered Electricity Markets*, November 2008-April 2009, p. 213

[18] "When HOEP is negative in an hour, this may be a signal to spill. However if HOEP in some hours is only moderately negative, in a month with low average HOEP, the payment structure may not induce the efficient outcome. The intuition is that by not spilling OPG will receive a regulated rate of $38.84/MWh (the first term in the payment formula) but the revenue will be adjusted down by the amount of the second term. If the HOEP in the negative priced hour is within $38.84/MWh of the monthly average HOEP, the incentive is to produce (assuming minimal water rental charges for production)." Market Surveillance Panel Report, *Monitoring Report on the IESO-Administered Electricity Markets,* November 2008-April 2009, p. 213

charge will clearly enter into OPG's assessment in deciding whether to pump or not, requiring the on-peak to off-peak price spread to be sufficiently large.

The IESO believes that by factoring in the GRC into this arbitrage calculation, the efficient operation of the PGS facility can be at times distorted. This could lead to PGS engaging in pumping activities less frequently than would otherwise be efficient, but for the manner that this forms of tax is collected. Therefore, the IESO recommends that the Board consider possible mechanisms or modifications to the current HIM, which would remove such distortions (obviously recognizing applicable taxes would still be subject to payment).

Equal Sharing Mechanism

In the most recent version of the HIM, the opportunity for OPG to keep revenues above a capped amount was modified. The Board expressed some concern that the incentive structure was excessive, given its understanding of the potential benefits ultimately accrued to ratepayers.

The 50/50 sharing mechanism of the HIM returns some of the financial gains earned by OPG to consumers. The IESO believes that the current allocation can increase the benefit to consumers, but would caution that the degree of sharing should not undermine OPG's incentives to produce efficiently.

A mechanism that leaves little residual incentive to the regulated firm (i.e., 99% back to consumers, 1% left to OPG) is unlikely to drive the firm to achieve efficiencies. Depending on the administrative effort and uncertainty involved in chasing the residual incentive, the firm may choose to instead "play it safe" and be satisfied with its capped amounts. This would result in a foregone opportunity for both consumers and the firm.

3.4. How price signals can be integrated into the regulation of OPG's hydroelectric assets

As previously indicated, the IESO believes the current HIM generally provides positive incentives for OPG to operate efficiently in response to market price signals, with some minor issues. Regardless of the regulatory approach used to set the revenue requirement, the sharing mechanism within the HIM allows for both the shareholder and ratepayers to capture realized benefits from efficient operation.

Sharing mechanisms are also used in the incentive structures for generation contracts in other jurisdictions. For example in California, revenue sharing is applied in the procurement of flexible capacity at risk of retirement.[19] The contract offers net revenue certainty to maintain such capacity reliably and efficiently with a reasonable rate of return. The contract also provides the generator with a provision to retain a percentage of net market revenues earned. This provides incentives for the plant to maximize its efficient participation within the market.

The IESO offers this example as a variation on the revenue sharing mechanism currently employed. The mechanics of setting reasonable revenue requirements would still need to be determined through the appropriate regulatory approach (i.e., IRM, COS). The setting of the degree of revenue sharing would also require careful review, balancing risk and return to both OPG and the ratepayer. However, efficiently responding to market prices would remain an integral part, if not enhanced. Depending on its application, a more direct revenue sharing mechanism could help to decouple the HIM from the average monthly hourly production, preserve efficient spill during surplus and facilitate efficient pumping decisions.

4. Conclusions

The IESO supports the goals that the Board and stakeholders are seeking to achieve through this consultation. Important discussion has occurred on the appropriateness and timing of moving from a cost of service to IRM. However the IESO believes regardless of the application of IRM, establishing proper incentives for OPG to respond efficiently to price signals are integral in maximizing the value of the facilities to Ontario.

In this submission, the IESO has argued the importance to consumers of encouraging efficient dispatch in Ontario's hybrid electricity market. Fixed rate payment amounts, set either through IRM or COS, can distort efficient dispatch in a competitive wholesale market. Even under a hybrid market with contracts and regulation, inefficient dispatch will impact Ontario consumers.

OPG operates within a competitive wholesale electricity market that produces a market price signal to efficiently coordinate resources. Therefore, production incentives based on market price signals can encourage efficient dispatch. Such incentives exist within the HIM, though some improvements can be made. In particular, the influence of GRC on efficient use of pumped storage should be deliberated upon. For the nuclear assets, exposure to negative prices could encourage efficient outage management and production during SBG conditions.

All of which is respectively submitted.

[19] http://www.caiso.com/Documents/Decision_on_FlexibleCapacityProcurement-Memo-Sep2012.pdf