Ontario

# ONTARIO ENERGY BOARD

## BOARD STAFF SUBMISSION

**Ontario Power Generation Inc.**

**Thunder Bay Generation Station**

**Application for Approval of Reliability Must-Run Agreement**

**Board File No. EB-2013-0061**

**June 7, 2013**

## BACKGROUND

In its Decision on Issues List and Procedural Order No. 2 issued on May 21, 2013, the Ontario Energy Board (the "Board") confirmed the following as the three key issues in relation to Ontario Power Generation Inc.'s ("OPG") application for approval of a reliability must-run ("RMR") agreement between OPG and the Independent Electricity System Operator (the "IESO") for one of the units at OPG's Thunder Bay generation station ("TB Unit G3"):

1. *Does the reliability must-run agreement comply with OPG's licence?*
2. *Are the financial provisions of the reliability must-run agreement reasonable?*
3. *What are the incentive effects, if any, of the reliability must-run agreement?*

The Board also made provision for the filing of submissions on the issues in this proceeding by Board staff and intervenors, as well as reply submissions from OPG.

The following are Board staff's submissions on each of the 3 issues in this proceeding, as well as a further submission regarding the timing of any subsequent RMR agreement that may be filed for TB Unit G3.

## BOARD STAFF SUBMISSION

### 1. Does the reliability must-run agreement comply with OPG's licence?

As noted in certain submissions on the issues list in this proceeding filed in response to the Board's April 3, 2013 Procedural Order No. 1, in the first proceeding to approve an RMR agreement for the Lennox generating station ("Lennox") (EB-2005-0490), the Board specifically referred to the following sections of the Market Rules in relation to the issue of compliance with OPG's licence: section 4.8 of Chapter 5 and sections 2.4, 9.6 and 9.7 of Chapter 7.

In its application, OPG states that it followed the same process for the RMR agreement for TB Unit G3 (the "TB RMR Agreement") as it had for the Lennox facility, a process that the Board had been satisfied complied with both OPG's licence conditions and the Market Rules. OPG further states that the terms and conditions set out in section 9.7 of Chapter 7 of the Market Rules have been satisfied in respect of the TB RMR Agreement.

Board staff notes that, in response to interrogatories ("IR") filed by the Vulnerable Energy Consumers Coalition ("VECC"),[1] both the IESO and OPG stated that they are not aware of any changes in the Market Rules or the terms and conditions of OPG's generation licence since the last time the Board approved an RMR agreement that would have any effect with respect to approval being granted in respect of the TB RMR Agreement.

Based on the evidence provided by OPG in its application and on the above-noted interrogatory responses, Board staff does not believe that there has been a failure to abide by the provisions of the Market Rules that govern the process or terms and conditions applicable to RMR agreements.

## 2. Are the financial provisions of the reliability must-run agreement reasonable?

The financial provisions of the TB RMR Agreement can be summarized as follows:

i. Variable costs (including the cost of fuel and variable maintenance costs): in accordance with Schedule D of the TB RMR Agreement, compensation for the variable costs of operating TB Unit G3 is not covered by the TB RMR Agreement; rather, those costs are recovered through revenues earned in the IESO-administered markets;

ii. Fixed costs (being the OM&A and other costs listed in Schedule D to the RMR agreement): in accordance with Schedule D of the TB RMR Agreement, the fixed costs of operating TB Unit G3 that would be avoided by OPG if the Unit was de-registered are recovered under the Agreement by means of fixed monthly payments of $3,164,000 each, for a total of $37,968,000 over the one-year term of the Agreement;

[1] IR #1-VECC-1, addressed to each of the IESO and OPG.

iii. Auxiliary boiler and regulatory testing costs: in accordance Schedule D of the TB RMR Agreement, these costs are reimbursed under the Agreement quarterly based on after-the-fact actual fuel cost submissions;

iv. Market costs (defined in section 1.2 of the RMR agreement as including all uplift and transmission charges as well as the Global Adjustment): in accordance with Schedule D of the TB RMR Agreement, these costs are reimbursed under the Agreement;

v. Net Revenue Sharing Adjustment (“NSRA”): in accordance with Schedule D of the TB RMR Agreement, OPG is permitted to retain 5% of any operating profit (described as revenues (market and non-market) less the actual cost of fuel) when the Unit is dispatched to run, determined quarterly. In accordance with Schedule E of the TB RMR Agreement, there is no NSRA when OPG is operating as an energy-limited resource (this is discussed further in relation to issue 3 below); and

vi. Performance standards: in accordance with Schedule C of the TB RMR Agreement, OPG receives a “reward” or pays a “penalty” if its performance exceeds or falls below certain performance standards, to a cap of $500,000 over the term of the Agreement. The metric used for this purpose is called EFOR-OP, which is a measure a generating unit’s reliability when it is called on to operate. The net penalty/reward is calculated and settled once at the end of the term of the Agreement.

According to OPG, the financial provisions of the TB RMR Agreement represent an improvement relative to the financial provisions of the RMR agreements that were approved by the Board in respect of Lennox in the following three respects:

i. as noted above, under the TB RMR Agreement, variable costs are recovered through the market while fixed costs are recovered through fixed monthly payment amounts that have been determined based on a mutually agreed forecast of fixed costs. In the case of Lennox, these costs were all recovered under the RMR agreement based on after-the fact actual cost submissions;

ii. the NRSA under the TB RMR Agreement is less generous to OPG, yet maintains a sufficient incentive to offer TB Unit G3 efficiently into the IESO-administered markets; and

iii. the provisions pertaining to fuel management under the TB RMR Agreement require OPG to offer TB Unit G3 in such a way as to manage OPG's limited fuel supplies in order to meet the IESO's reliability needs and minimize its stranded fuel costs at the termination of the Agreement.

Board staff agrees that the features of the TB RMR Agreement identified in items (ii) and (iii) above can tend to enhance the reasonableness of the financial provisions of the TB RMR Agreement relative to the financial provisions of the RMR agreement for Lennox, and that the same is true in respect of the treatment of variable costs under the TB RMR Agreement (the issue of the recovery of fixed costs noted in item (i) is discussed separately below).

Based on OPG's application and its responses to interrogatories ("IR") filed by intervenors and Board staff, Board staff believes that the financial provisions of the TB RMR Agreement that are equivalent or comparable to provisions in the Board-approved RMR agreements for Lennox are no less reasonable. Board staff also notes that, with respect to costs or payments other the fixed monthly payment amounts, the IESO has the right to conduct audits of OPG's financial records and operations and OPG is required to assist in any such audit.

As noted above, OPG's fixed costs are recovered under the TB RMR Agreement based on a forecast of fixed costs. As such, the risk of forecast deviations where actual costs are lower than forecast lies with ratepayers and not with OPG, while the opposite is true if actual costs are higher than forecast. Board staff notes that, in its response to VECC's IR #2-VECC-2, the IESO confirmed that it had independently reviewed OPG's cost estimates and found them to be reasonable and allocated to the TB RMR Agreement appropriately. This, in Board staff's view, is of assistance in mitigating any forecast deviation risk to which ratepayers may be exposed.

Board staff has also attempted to quantify the order of magnitude of the potential forecast deviation that might be involved using historical actual cost information provided by OPG in its responses to Board staff's IRs. Based on OPG's response to Board staff IR # 5, OPG's actual fixed costs for January, February and March 2013 were $2,816,000, $2,857,000 and $2,940,000, respectively. Board staff notes that actual costs were therefore below the fixed monthly payment amount by anywhere from $224,000 to $348,000 per month, a deviation of approximately 7% to 11%.

Board staff does note, however, that the fixed monthly payment amounts were calculated by taking the annual budget and dividing it by 12. As noted by OPG in its response to Board staff IR #5, the calculation does not reflect the variability of planned expenditures during the year. Board staff also notes that there is a cost to auditing after-the-fact cost submissions (which costs are borne by the IESO) that is avoided by recovering fixed cost on a forecast basis.

### 3. What are the incentive effects, if any, of the reliability must-run agreement?

As noted in certain submissions on the issues list for this proceeding filed in response to the Board's April 3, 2013 Procedural Order No. 1, in the first proceeding to approve an RMR agreement for Lennox the Board described the relevant incentive effects as follows:

a. Does the RMR Contract provide incentives that may cause OPG to alter its offering behaviour?
b. If OPG's offering behaviour is altered, what is the potential impact on wholesale electricity prices and other market participants?

Board staff's submission on the issues list indicated that Board staff is not aware of other incentive effects that would require consideration in the context of this proceeding, and Board staff confirms that this remains its view.

Section 3.3 of the TB RMR Agreement addresses the manner in which OPG is required to participate in the wholesale markets. Specifically:

> …[OPG] shall participate in the *IESO-administered* markets and in other electricity markets…in a commercially reasonable manner and in accordance with [OPG's] mandate, including in accordance with Schedule A. For greater certainty, acting in a "commercially reasonable manner" with respect to any given activity includes, other than in exceptional circumstances, that [OPG] will

> offer a unit economically over a sustained period of time based on its costs and in a manner consistent with how [OPG's] coal-fired generation is being offered pursuant to [OPG's] $CO_2$ Implementation Strategy, as amended from time to time.

Board staff notes that, other than in respect of the reference to OPG's $CO_2$ Implementation Strategy, this section mirrors a provision that was in the RMR agreement for Lennox.

In its IR #4, Board staff requested that OPG identify and explain (i) any incentive effects of the TB RMR Agreement in terms of the impact on OPG's offer behaviour and on the quantity of energy or operating reserve to be produced/scheduled in respect of the Thunder Bay GS Unit; and (ii) the potential impact on prices in the IESO-administered markets of any such incentive effects. In its response, OPG stated that it does not expect the TB RMR Agreement to affect its offer strategy. Specifically, OPG noted that the NRSA contemplated in the TB RMR Agreement allows OPG to retain 5% of the operating profit (market revenue less actual fuel costs) when TB Unit G3 is dispatched to run, and that there is no NRSA when there is an operating loss (where actual fuel costs exceed market revenues). According to OPG, the NRSA ensures that OPG:

> continues to offer the facility into the IESO-administered market in the same manner as before; that is, at a price to recover the variable costs associated with operations to produce energy and operating reserve. The unit will be dispatched by the IESO if it is economical or if it is constrained on by the IESO to meet local system reliability or adequacy needs.

In its IR #8, Board staff requested clarification in relation to the various concepts covered in section 3.3 of the TB RMR Agreement. Based on OPG's response to that IR, Board staff has no concerns regarding any of the elements of section 3.3 that are similar to those in the RMR agreement for Lennox.

For the reasons set out below, Board staff does not believe that the TB RMR Agreement creates incentives for OPG to alter its offer behaviour in a manner that would have adverse consequences for prices in the market or for other market participants, although as also noted below one feature of the TB RMR Agreement may have an effect on prices.

### Incentive Effects of the TB RMR Agreement Generally

In Board staff's view, two features of the RMR agreement for TB Unit G3 are key in considering any incentive effects that the TB RMR Agreement might have.

First, as noted above and unlike the RMR agreement that was in place for Lennox, the compensation provisions of the RMR agreement for TB Unit G3 provide for the recovery of fixed costs but leave variable costs to be recovered through market revenues. This is important because:

(a) a generator is expected to offer its production at prices that cover its marginal costs of production, and hence it is *[principally]* the marginal costs that influence the generator's offer behaviour; and

(b) except when energy-limited or emissions-limited (discussed further below), a generator's variable costs are what determine its marginal costs of production (marginal costs are the changes in total variable costs brought about by a change in the rate of output).

Because the TB RMR Agreement does not compensate OPG for its variable costs, TB Unit G3's marginal costs will be the same regardless of the TB RMR Agreement. In Board staff's view, there is therefore no incentive in the TB RMR Agreement for OPG to change its offer behaviour.

As also noted above, the NRSA provisions of the TB RMR Agreement allow OPG to retain 5% of TB Unit G3's operating profit, described in Schedule D of the TB RMR Agreement as revenues (market and non-market) minus the actual cost of fuel. In Board staff's view, OPG's offer behaviour in terms of maximizing its operating profit is the same whether OPG retains 5% or all of the operating profit. Board staff therefore does not believe that the NRSA element of the TB RMR Agreement raises significant incentive effect concerns.

### Incentive Effects Relating to Fuel Management and OPG's CO2 Implementation Strategy

Board staff notes that the TB RMR Agreement has two features that were not in place in the RMR agreement for Lennox; namely, provisions relating to fuel management and provisions relating to OPG's $CO_2$ implementation strategy.  Board staff has therefore also considered the potential incentive effects of these features of the TB RMR Agreement.

*Fuel Management*

The provisions relating to fuel management are set out in Schedule E of the TB RMR Agreement, which is described by OPG in its response to Board staff IR # 9 as follows:

> The purpose…is to establish a methodology for OPG to manage its limited fuel supplies in order to meet the IESO's reliability needs and to minimize its stranded fuel costs at the expiration or termination of the agreement.
>
> Schedule E requires OPG to provide information to the IESO on a monthly basis to enable the IESO to assess if the remaining fuel inventory at the plant is sufficient to manage the IESO's forecasted reliability requirements for the remaining term of the agreement.  The IESO has the right, under the agreement, to declare that the facility is energy limited and to direct OPG to curtail the use of coal and/or purchase additional coal if required.
>
> If the IESO issues a direction in this regard, OPG will operate the facility as an energy-limited resource and during the period of this direction, OPG will no longer receive an operating profit through the [NRSA] calculation.  If the parties do not enter into a new reliability must-run contract, the IESO shall be responsible for the disposition of any amounts of remaining coal resulting from this direction at the termination of the agreement.

According to paragraph 6 of Schedule E of the TB RMR Agreement, where the IESO has issued a direction to OPG, OPG will operate TB Unit G3 as an energy-limited resource by offering the Unit at the maximum market clearing price.  This will effectively preclude TB Unit G3 from being dispatched.  When the IESO requires the Unit to run for reliability reasons, OPG is required to adjust its offer price to reflect its best estimate of the actual cost of fuel and other related costs (in other words, the marginal costs of fuel).

While a generator is energy limited, it cannot expect to operate in all hours, and it will therefore seek to save its fuel for use in hours where prices are high. In order to achieve this result, such a generator will raise its offer prices to the level that it expects will keep it out of the market for all but the highest-priced hours in which it can operate with available fuel. In other words, the generator no longer views its marginal costs as the market value of the fuel and other inputs that would be depleted in generating electricity. Rather, its marginal costs become the energy prices expected to prevail in the targeted high value hours. Thus, the generator's offer price rises above its direct costs of fuel.

This is a normal and efficient response to energy limitations, at least when there is no reliability concern. However, it is not the response that the IESO necessarily wants from TB Unit G3 for reliability reasons. High-priced hours do not necessarily coincide with hours where TB Unit G3 needs to run for reliability reasons. Schedule E of the TB RMR Agreement has the effect of superseding the offer behavior that would normally be expected from OPG when TB Unit G3 is energy limited. In essence, that Schedule allows the IESO to effectively remove TB Unit G3 it from the market until the IESO identifies a reliability reason for the plant to run.

To the extent that the energy-limited hours identified by the IESO as requiring TB Unit G3 to run for reliability reasons do not coincide with high-priced hours, Board staff submits that Schedule E would have effects on market prices and other participants. The high-priced hours in the energy-limited period would tend to exhibit even higher prices as TB Unit G3 would no longer be available in those hours. In Board staff's submission, however, this is not an "incentive" for OPG to alter its offer behaviour; rather, it is the consequence of the IESO making decisions about the operation of TB Unit G3 for reliability reasons. Board staff also submits that those decisions are properly left to be made by the IESO.

*OPG's $CO_2$ Implementation Strategy*

In essence, TB Unit G3 has the potential to be emissions-limited given that OPG's coal-fired facilities operate under an annual $CO_2$ emission target imposed by resolution of the government, in its capacity as shareholder of OPG. OPG's $CO_2$ Implementation Strategy is designed to meet the annual $CO_2$ emissions requirements on a forecast basis, and does so based on procedures derived from those that are used in operating an energy-limited facility.

Emissions-limited facilities are similar to energy-limited facilities because they too cannot expect to operate in all hours and will therefore seek to operate only in the most highly valued or highest priced hours. In the case of OPG, it will apply a uniform "emissions adder" to its offer prices to ensure that its facility does not run in low-priced hours so that its fuel (or emissions quota) is saved for use in higher priced hours. In its response to Board staff IR #8, OPG has stated that no $CO_2$ emissions adder will be needed to meet the 2013 emission target on a forecast basis, as OPG anticipates that $CO_2$ emissions will be well below target.

In Board staff's view, there are no adverse incentive implications arising from the interaction of the TB RMR Agreement and OPG's $CO_2$ Implementation Strategy. Board staff believes that this is the case regardless of whether or not a positive emission adder was to be applied. As noted earlier, raising offer prices above the direct costs of fuel is a normal and efficient response to emissions limits for any generator, and Board staff does not see any reason why the TB RMR Agreement would affect OPG's behaviour in that regard.

## 4. Other

In its submissions on the issues list for this proceeding filed in response to the Board's April 3, 2013 Procedural Order No. 1, OPG confirmed that, if IESO market conditions do not change, it would expect to file another de-registration request for TB Unit G3 later this year. In accordance with Schedule E of the TB RMR Agreement, OPG must notify the IESO no later than September 1, 2013 if OPG wishes to de-register that Unit. In its response to Board staff IR #10, OPG stated that it would need to make its de-registration request by July 30, 2013 in order for any application for approval of a subsequent RMR agreement to be filed with the Board by October 15, 2013. OPG further stated that it was not aware of any technical reasons that would prevent the filing of a de-registration request by July 30, 2013.

Board staff submits that OPG should use all reasonable efforts to ensure that an application for approval a subsequent RMR agreement for TB Unit G3 – if one is required – is filed with the Board with sufficient lead time to enable the Board to conduct its review of the agreement prior to the date on which the agreement is expected to come into effect (presumably, January 1, 2014). Among other things, this will enable the costs of the RMR agreement (if approved) to be recovered over a 12-month period rather than over a shorter one.

All of which is respectfully submitted.