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Ontario Energy Board

Setting Payments for Output from Ontario Power Generation's Prescribed Generation Assets

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Ontario Power Authority Final Comments

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INTRODUCTION

The Ontario Power Authority ("OPA") wishes to thank the Ontario Energy Board (the "Board") for the oral presentation session that the Board held on September 15, 2006 (the "Oral Presentation Session" or the "Session") and the opportunity to make a separate submission. The OPA found the Session to be very informative. The OPA formed the impression that the views of many parties are actually much closer than it may have previously appeared. The OPA, in this submission, will address the need to provide incentives for operational efficiencies, explain why the OPA believes that the regulatory contract model is the best way of arriving at these incentives, and explain the role that selling forward power from the prescribed assets could play in the future.

PART I – OPERATIONAL EFFICIENCIES

The OPA believes that it is essential to the efficient functioning of the current hybrid market that a mechanism be put in place to incent Ontario Power Generation Inc. ("OPG") to optimize the operational efficiency of its prescribed assets. Such an approach would ensure appropriate incentives to OPG with respect to maintenance scheduling, the use of storage and the maximization of output. This view appears to be shared by at least the members of the Cost of Service Group, the IESO, EMIG, and TransAlta (see transcript page 82, line 13 to page 85, line 11).

The OPA believes that the cost inputs to be used in such a mechanism must be arrived at through a transparent, quasi-judicial proceeding. This view appears to be shared by at least the members of the Cost of Service Group, EMIG, and TransAlta. The differences between the positions of the OPA and the members of the Cost of Service Group appear to be limited to the question of what process is to be used to determine the payments methodology.

Only OPG argued against a methodology to drive operational efficiencies being put in place. OPG argued that, with respect to its baseload prescribed assets, the need to generate revenue was sufficient for OPG to maximize its output from these baseload units. This ignores the fact that under the current methodology with a fixed non-time differentiated price for this baseload generation there is no incentive for OPG to optimize the availability of this generation when it is of most value to Ontario consumers. OPG has not put forward a credible argument for why it is opposed to a mechanism to incent the company to operate efficiently.

PART II – THE REGULATORY CONTRACT

The OPA believes that a key element to arriving at the mechanism to incent OPG to optimize the operational efficiency of its prescribed assets should be negotiations between the OPA and OPG. The OPA believes this for the following reasons:

(a) contractual negotiations, the outcome of which are subject to regulatory approval, are a more flexible tool for addressing complex formulae than a pure quasi-judicial proceeding model; and

(b) contractual negotiations between OPG and an organization with a public interest mandate, such as the OPA, are more likely to lead to an outcome that is in the public interest than a process that leaves it to OPG to unilaterally file a proposal for a mechanism to optimize operational efficiency as proposed by the Cost of Service Group.

The structural flexibility of a contract makes it a better tool to address the complexities of nuclear and hydro assets, and their interplay with the balance of the wholesale market. The contracting model can easily incorporate a principle of risk sharing between OPG and the consumers of electricity. Contractual provisions can be more easily structured to ensure that OPG operates its assets efficiently via incentives related to capacity optimization, energy production when it is most needed, and lower costs. Contract provisions can address complex operational issues such as maintenance scheduling for planned outages and incentives to reduce unplanned outages.

For example, consistent with the IESO proposal and the London Economics paper, specified production quantities and targets can be established on a seasonal basis. OPG would have sufficient incentives to not under-produce as it would face contractual penalties such as prescribed payments being lowered and/or requirements to replace the capacity/energy shortfall at market prices. On the other hand, OPG can have contractual incentives to produce more under the condition that it is permitted to keep additional market revenues.

Overall, this example would create the dynamic incentive for OPG to: 1) increase capacity availability and do so at peak times when the system most requires it; and 2) efficiently schedule planned outages and work to decrease the probability of unplanned outages. This results in improved market efficiency and increased system reliability – both major benefits to consumers of electricity. There are many different potential methodologies that could be designed to drive operational efficiencies and be incorporated into a regulatory contract. Some examples are discussed in Appendix A.

In general, the contracting model represents a ‘win-win’ scenario: OPG can manage operational and market risks due to the company’s experience in both regulated and unregulated environments, and consumers of electricity are better off with respect to reliability and cost.

A mechanism for incenting OPG to operate efficiently that arises out of negotiations between the OPA and OPG, and is reviewed by the Board, is much more likely to reach a conclusion that is optimal from a public interest perspective than mechanisms determined via alternative approaches. The OPA is an organization with a public interest mandate that has significant and current experience in crafting arrangements with plant operators to ensure maximum and efficient output to the benefit of the electricity system’s users.

This experience also gives the OPA the knowledge base to negotiate contracts with OPG that interact appropriately with the other contracts to which the OPA is a counterparty. Looking to OPG to file a proposed mechanism for the Board's review without any negotiations with the OPA as is suggested by the Cost of Service Group, is likely to result in a less than optimal outcome.

Concerns:

A number of concerns have been raised about the proposed contractual negotiation process. These are that:

(i) it is not sufficiently transparent;
(ii) the process is too lengthy and complex;
(iii) having the filing seeking Board approval after a negotiation puts the Board in an impossible position; and
(iv) this approach is too new and untested.

Transparency:

The OPA has proposed the following process to allow for a high level of transparency. Listed below is an outline of the steps to be taken in order to conclude the contract and achieve Board approval. These steps are taken to ensure the benefits of consistency and regulatory efficiency are balanced against transparency and fairness.

- Board sets draft guidelines for negotiation and contract parameters, and for guidelines on its own regulatory proceedings;
- Stakeholders comment on draft negotiation guidelines, contract parameters, and procedural guidelines;
- Board issues final negotiation guidelines and contract parameters (including updates with reporting milestones), and procedural guidelines;
- OPA and OPG begin contract negotiations;
- OPA and OPG provide milestone reports for Board and stakeholders;
- Board and stakeholders comment on milestone reports;
- OPA and OPG conclude contract negotiations;
- OPG files with Board;
- Board proceedings transpire; and
- Board issues decision(s).

A timeline with respect to these proposed steps is set out at Appendix B.

In the OPA's submission, this approach provides much more transparency than if it was merely left to OPG to unilaterally develop a methodology and file it with the Board for approval. As well, the cost of service approach to the first instance of determining payments will also add a level of transparency to the process.

Length and Complexity:

All of the proposed approaches advocated by the various parties to this process are complex and lengthy. A number of parties have advocated approaches that involve a variety of steps taken over several years.

Board Staff have proposed that a form of incentive regulation be introduced based on the current payment levels. Board staff then envisions that the Board could move to cost of service based rates over time as more information becomes available. The Cost of Service Group puts forward the view that not all of the issues that would normally be addressed in a cost of service proceeding may be able to be addressed in the first proceeding.

Establishing the framework for setting the payment levels for power from the prescribed assets requires that a complex series of issues be addressed. Some of these assets have been serving Ontario consumers for almost a century and have potential value for another hundred years if operated in a cost efficient and optimum manner. Spending two or three years to structure the framework for these payments is a small investment with a significant upside benefit for Ontario. The OPA agrees with the Cost of Service Group that it is worth taking the time to get it right.

The OPA outlines in Appendix B the timeline for parallel staged processes for establishing OPG payment levels. The upper part of the diagram sets out a possible cost of service process and the lower part of the diagram addresses a possible process for the negotiation and review of the regulatory contracts. It is proposed that new payment levels based on a cost of service process could be in place for April 1, 2008. The methodology for incenting OPG operational efficiency could be in place and used in the calculation of payment levels by April 1, 2009. While the OPA believes that the April 1, 2008 date for new cost of service based rates is achievable, as was noted at the Oral Presentation Session, there is no deadline in the statute by which new rates must be in place. The cost of service proceeding should take the length of time that the Board believes is necessary to achieve a satisfactory result.

The OPA believes that negotiation of the regulatory contracts can commence while the cost of service proceeding is still ongoing. Negotiation of the methodology is not dependent on knowledge of the cost inputs that will ultimately feed into the methodology. The OPA acknowledges though that the contract negotiations cannot be completed until after the Board issues its decision in the cost of service proceeding.

Board Review of Negotiated Outcome:

The argument is made that it would be extremely difficult for the Board to change the negotiated outcome of an agreement as that would unravel the tradeoffs that each party had made in coming to a deal. However, the review by the Board of a negotiated outcome is not novel. The Board recently approved the terms and conditions of a Reliability Must-Run Contract ("RMR") related to the Lennox Generating Station in EB-

2005-0490. Another proceeding is underway, EB-2006-0205, by which OPG is seeking Board approval of a second RMR contract also with respect to Lennox. Both contracts have been negotiated between OPG and the IESO. The OPA is not aware that anyone in the first proceeding considered the Board to be in an impossible position. The OPA submits that, in this case, a process that had the IESO, an entity with a public interest mandate, first negotiate the terms of this contract with OPG, resulted in a better outcome from a public interest perspective than an approach that did not include such a step. In addition to the OPA and OPG undertaking a similar exercise (or set of exercises) they will be guided by pre-set Board guidelines and parameters which will mitigate such "unraveling". This is more than what the IESO and OPG had available to them in negotiating the RMR contracts.

Ultimately, the Board must address the public interest while balancing the interests of ratepayers and shareholders. The OPA is confident that the Board will exercise its prudence and authority to reject those elements of any agreement that it does not consider to be just and reasonable.

Novelty of Approach:

Ontario is not the first jurisdiction to deal with value capture from assets similar to the prescribed assets through a regulatory contract process, as most restructured electricity jurisdictions have dealt with issues related to "heritage assets". The Alberta Energy Utilities Board ("AEUB") played a regulatory oversight role with respect to the development of the Power Purchase Arrangements ("PPAs") in Alberta. In particular, the AEUB reviewed the standard terms and conditions of the PPAs once they had been developed by an independent group called the Independent Assessment Team.

The Board has not been afraid in recent years to try new and innovative approaches to developing policy and making regulatory decisions. The Board should decide on the appropriate methodology for setting rates on the real merits. It should not be persuaded by the spurious argument that because something has not been tried in Ontario, it should not be tried in Ontario.

PART III – FORWARD CONTRACTING

Forward contracting is defined as a cash market transaction in which delivery of the commodity is deferred until after the contract has been made. Although the delivery is made in the future, the price or price formula is determined on the initial trade date. The regulatory contract itself neither requires nor results in the forward sale by the counterparty (the OPA in this context) of any output.

The OPA believes that provisions in the regulatory contract allowing for the ability to sell forward are a desirable component of any regulatory contracts. Provisions that allow for power to be sold forward by the OPA are currently found in a number of the procurement contracts to which the OPA is a counterparty. There may also be other options to allow for forward sales by OPG that should be explored.

As noted at the Session, the OPA is proposing that no power could be sold forward under the regulatory contracts until specific approval to do so is given by the Board after a transparent, quasi-judicial process. The OPA would, in seeking such Board approval, need to provide detailed information on its strategy and methodology for selling forward. An application to the Board for such approval may not happen for several years or it may never happen. However, such provisions would give the regulator a great deal of flexibility to move towards a more competitive market if and when a policy decision is made that this is the appropriate course of action.

Should the direction be toward greater market sector development, then the negotiated contracts become the basis for the sale of energy and/or other rights into the forward market. Selling electricity from the prescribed assets in the forward market could assist in the development of a more competitive market that is less reliant on OPA procurement contracts due to increasing liquidity. Selling forward could also enable Ontario consumers to capture the value of the assets at a secure forward price rather than at a differential which is at risk to the volatility of the hourly market.

OPG could, subject to Board approval, continue to receive the payments provided for under the regulatory contracts. Under this approach, OPG's revenue stream would be unaffected by the fact that some of the power from the prescribed assets had been sold forward. Ontario consumers would receive or pay the net difference between the payments to OPG, as set out in the regulatory contracts, and the sale price into the forward market. Power could be sold forward over a variety of contract terms all of which can be designed to optimize value for consumers.

Auction:

There are a number of differences between a potential future sale of power forward under the regulatory contracts and the auction process administered by the OPA earlier in 2006. These include the fact that the potential amount of power being sold forward under the regulatory contracts could be much greater and that the OPA was not a counterparty in the 2006 auction process. However, the auction process still provides an insight into some of the potential benefits for consumers. The Phase 2 Auction was operated by NGX on behalf of the OPA on April 19, 2006. OPG made available 300 MW of the April 1 to December 31, 2006 baseload production from its non-prescribed assets. These assets were being sold into the hourly IESO market capturing the HOEP price, and were operating under the existing rate cap of $46.00/MWh. All amounts collected by OPG above the price cap of $46.00/MWh are credited to the Global Adjustment ("GA").

Essentially the value of the non-prescribed assets with respect to Ontario consumers was the risk differential between the HOEP price and the $46.00/MWh maximum being paid to OPG. By agreeing to sell the energy in the forward auction OPG was relieved of its risk to the hourly price and was provided a fixed additional return of $5.00/MWh sold in the auction. That is, this $5.00/MWh margin above the price cap was retained by OPG and not credited to the GA.

OPG also had the ability to ensure a proper value capture for consumers by being able to set the reserve (i.e., minimum) price at auction, and by ensuring that any successful buyer met the credit standards of OPG. The result was that 125 MW were sold at an average forward price of $62.55/MWh for a 7 X 24 product from April 1 to December 31, 2006. In effect 825,000 MWh (275 days X 24 hours X 125 MW) were sold for an additional fixed amount of $11.55/MWh or just over $9.5 million in contribution to GA to the benefit of consumers.

This can be contrasted with the normal operation of selling into the hourly market for the same time period. From April 1 to September 26, the average HOEP price has been $46.19/MWh. However, if the 125 MW of non-prescribed assets had not been sold at auction the net contribution to GA would have been just $0.19/MWh, the rate above the price cap of $46.00/MWh. On 537,000 MWh (179 days X 24 hours X 125 MW) the net value is roughly $102,000, compared to the $6.2 million that has been banked year-to-date for consumers.

The decision to sell a contract forward in the case of the OPA forward auction was in the hands of OPG. The company determined the reserve price at which it was prepared to sell, and ensured that only credit worthy parties could bid on the energy. Both of these conditions were part of the auction rules as set out by the OPA.

As this example illustrates, the benefits from selling output in the forward market include the certainty achieved in the revenue stream and the clarity it provides to the forward price curve. However, forward sales do have risks. If there had been a very hot summer in 2006, and another round of hurricanes, HOEP may have been much higher due to these upward pressures on price. Under this scenario HOEP could have been, on average, higher than $62.55/MWh.

Appendix A

Contract Alternatives:

There are a number of contract terms and conditions that can be considered within the regulatory contract process. These include a broad range of topic items such as the duration of the contract, the effects of changes in law, output targets and operating reserve offer strategies.

The OPA would negotiate with OPG with respect to each of the generation categories within the prescribed assets, such as:

- Baseload Nuclear units
- Baseload Hydro Units
- Peaking Hydro Units
- Expansions >50 MWs

These negotiations would, consistent with any negotiating parameters that have been established by the Board, establish the normal contractual rights and obligations that exist between the two parties, and the rules, failure conditions and dispute mechanisms needed to ensure the performance of the contracts.

There are many contractual mechanisms that can be used within the context of a regulatory contract. Some examples are the OPA CES contracts, the IESO-proposed regulated CfDs, and Alberta's PPAs. Each has relative merits and shortcomings that need to be considered. Some provisions that have been developed to address a particular type of generation would clearly be different when addressing nuclear and hydro.

- CES/Early Movers:
  - Fixed monthly capital payment per MW of capacity
  - fixed heat rate - variable fuel cost
  - deemed dispatch
  - ability to direct dispatch
  - ability to assign

- IESO CfD:
  - Fixed payments per/MWh of output
  - Deemed dispatch
  - Dispatch responsibility stays with the owner

- Alberta PPAs
  - Buyer gets dispatch rights
  - Incentive targets for extra volumes and costs
  - Payments for monthly access - $/MW
  - Payments for variable costs based on usage

<u>**Appendix B**</u>

<u>**Regulatory Contracts Proposed Timeline**</u>

<u>Cost of Service</u>

December 2006
Board Issues Filing Requirements

→

April 2007
OPG filing
Stakeholders to participate in review

→

February 2008
Board Decision

→

April 2008
Payments Year 1

<u>Regulatory Contract Process</u>

November 2006
Workshop on Regulatory Contracts
Stakeholders to participate

→

February 2007
Board Staff Paper on Contract Parameters

→

March 2007
Oral Presentations Session on Board Staff Paper
Stakeholders to participate

→

May 2007
Board Issues Guidelines on Contract Parameters

→

June 2007
Negotiations between OPA and OPG Commence

October 2007
OPA and OPG Issue Milestone Report

→

November 2007
Stakeholders Comment on Milestone Report

→

March 2008
Negotiations between OPA and OPG Conclude

→

May 2008
Application for Approval of Regulatory Contracts filed with the Board
Stakeholders to participate in review

→

January 2009
Board Decision on Regulatory Contracts

→

April 2009
Payments Year 2 based on Regulatory Contracts, if approved