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BY E-MAIL

April 2, 2015

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
BoardSec@ontarioenergyboard.ca

Dear Ms. Walli:

Re: OEB staff Interrogatories on Hydro One Networks Inc.'s Supply to Essex County Transmission Reinforcement Project, Phase 2
OEB File No. EB-2013-0421

Pursuant to Procedural Order No. 4, please find enclosed OEB staff interrogatories in the above matter.

As a reminder, responses to interrogatories are due April 23, 2015.

Yours truly,

Original signed by

Daniel Kim
Advisor

c. All parties in EB-2013-0421

1-Staff-1

Ref: Exhibit B, Tab 4, Schedule 4, page 5 (OPA Cost Responsibility Evidence)
Ref: Exhibit B, Tab 1, Schedule 5, page 35 (OPA Evidence on Need and Alternatives)

The OPA has provided two reports in support of Hydro One's application. One discuses "Need and Alternatives" and the other discusses "Cost Responsibility". The latter discusses the OEB's proposed TSC amendment (i.e., new sections 6.3.8A, 6.3.8B and 6.3.8C), as the proposed cost allocation is premised on those proposed amendments, and notes the intent of the amendment is that the transmitter shall not require customer(s) to make a capital contribution in relation to an investment in transmitter-owned connection facilities where it is determined that investment in connection facilities is more cost effective than an investment in transmitter's network facilities (or network facilities in combination with the transmitter-owned connection facilities). The other OPA report discusses the two transmission alternatives that were assessed to meet the need in the Windsor-Essex area. The higher cost alternative relative to the SECTR project is described in application as "reinforcing the existing 115 kV system".

OEB staff believes that the two potential scenarios set out in the proposed TSC amendment are correctly described by the OPA. As noted, under the proposed amendment, it must involve *connection* investments that *avoid* the need to make a less cost effective investment in a transmitter's *network* facilities for a deviation from the existing cost responsibility rules to be triggered (i.e., some connection asset costs recovered from all ratepayers). It is unclear to staff from the evidence what higher cost investment involving a network facility is being avoided by the SECTR project. Please clarify.

1-Staff-2

Ref: Exhibit B, Tab 4, Schedule 4, page 5 (OPA Cost Responsibility Evidence)

The OPA refers to the OEB's Notice issued on August 26, 2013 (the "August 2013 Notice") discussing the proposed TSC amendments. That Notice stated *"… the issue identified by Hydro One is most likely manifested in one scenario … namely, where the construction of and/or modification to … transmitter-owned connection facilities is a more cost effective means of meeting the needs of … load customers than the construction or modification of the transmitter's network facilities. Under such a scenario, it is expected that the construction or modification of network facilities can only be avoided by the construction of and/or modification to transmitter-owned connection facilities that exceed the capacity needs of the triggering load customer(s). In such a case, it is appropriate that the load customer(s) whose needs trigger the project should only bear the cost to the extent that they benefit from the construction of and/or modification to the transmitter-owned connection facilities. Any incremental costs should be …. recovered from the network pool, as the costs associated with the avoided construction of or modification to … the network facilities would have been recovered from the network pool."*

(a) OEB staff understands from the application that the SECTR project does not “exceed the capacity needs of the triggering load customer(s)”. Is that understanding correct? If not, please identify the extent that the SECTR project exceeds the needs of the triggering load customer(s).

(b) The OEB also discussed the Hydro One concern regarding a potential unfair allocation of costs under certain circumstances that led to the proposed TSC amendments in the August 2013 Notice. As described in that OEB Notice, to address that concern, Hydro One recommended that the OEB accept the notion that connecting customers should not be held responsible for the costs of facilities that are primarily required to address system needs. OEB staff understands from the application that the SECTR project is primarily required to address load customer needs. Is that understanding correct? If not, please explain.

1-Staff-3

Ref: Exhibit B, Tab 4, Schedule 4, page 6-7 (OPA Evidence on Cost Responsibility)

Table 1 discusses the needs and beneficiaries and identifies the need to minimize the impact of supply interruptions to customers in the Windsor-Essex Area (specifically, within the J3E-J4E Subsystem) as a “broader system” benefit. OEB staff’s understanding of a “system” benefit is a benefit that accrues to all ratepayers in Ontario. Please explain why those supply interruptions are characterized as a “system” benefit and not a “customer” benefit.

1-Staff-4

Ref: Exhibit B, Tab 1, Schedule 5, page 8-11 (OPA Evidence on Need and Alternatives)

Figure 2 shows historical electricity demand in the Windsor-Essex Area has decreased since 2006 by almost 25% (from 1060 MW to 800 MW). That reduction in historical demand occurred while a major customer (Heinz) was in operation. As explained on page11, the closure of that “large food processing facility” was recently announced. On page 10, the application also notes the significant growth in forecast demand in east Essex is due to the planned expansion of greenhouse customers based on customer connection requests to Hydro One distribution. Please set out in a table the forecast demand of each greenhouse customer that has requested a connection and the peak demand of the Heinz facility in 2013.

1-Staff-5

Ref: Exhibit B, Tab 4, Schedule 4, page 8-9 (OPA Cost Responsibility Evidence)

OEB staff finds the discussion related to the OPA’s “Recommended Cost Allocation Treatment” confusing. It discusses the costs if the limitations on the operation of Brighton Beach GS and supply capacity needs of the load customers in the Windsor-Essex area were to be individually addressed. It notes that three transmission upgrades would be required in relation to Brighton GS at a total cost of approximately $22.5 million. At the same time, the OPA notes that the

SECTR project would still be implemented at a total cost of approximately $77.4 million to address the load customer supply capacity needs in the Windsor-Essex. As a result, the OPA notes the total cost of individually addressing system and customer needs in the Windsor-Essex area is approximately $99.9 million.

(a) The application notes the SECTR project would address the Brighton Beach GS limitations. If that is the case, why would Hydro One subsequently request approval of the three additional transmission upgrades noted above with a later expected need date of 2019 (i.e., after the SECTR project is in place)?

(b) Is there a lower cost transmission solution that would meet the load customer needs in the Windsor-Essex area that could be implemented but would not also address the Brighton Beach GS limitations?

(c) Please identify where the need for transmission upgrades associated with Brighton Beach GS has been demonstrated.

1-Staff-6
Ref: Exhibit B, Tab 4, Schedule 4, page 8 (OPA Cost Responsibility Evidence)
Ref: Exhibit B, Tab 1, Schedule 5, page 30 (OPA Evidence on Need and Alternatives)

In the OPA “Need and Alternatives” evidence, the OPA notes their provincial forecast shows Ontario will experience a capacity shortfall beginning around 2019 and the 180 MW constrained capacity at Brighton Beach GS could advance the need for system capacity resources. The OPA also notes that the capital cost of supplying 180 MW of peaking capacity is approximately $160 million based on the cost of a simple cycle gas-fired generator. As such, the OPA further notes that removing limitations on Brighton Beach GS would reduce the longer-term need for additional peaking resources elsewhere in the province and would reduce costs for all ratepayers. In the OPA “Cost Responsibility” evidence, it notes that if the broader system restoration needs and limitations on the operation of Brighton Beach GS were to be individually addressed, approximately $22.5 million in transmission upgrades would be required.

(a) In the absence of the SECTR project, why would the OPA consider a new $160 million simple cycle gas-fired generation facility to be a viable option, when the evidence notes a $22.5 million investment in transmission upgrades – a cost that is over seven-fold lower – would address the limitations at the existing Brighton Beach generation facility?

(b) Within the context of the above question, please explain the statement “would reduce costs for all ratepayers.”

1-Staff-7
Ref: Exhibit B, Tab 4, Schedule 4, page 9 (OPA Cost Responsibility Evidence)

The OPA notes that in accordance with the beneficiary pays principle, approximately 77.5% of the SECTR costs should be paid for by local load customers and approximately 22.5% of the connection asset costs should be paid for by all transmission ratepayers under its proposed allocation. The basis for that is the hypothetical scenario whereby the load customer needs and Brighton Beach GS limitations are addressed separately through separate sets of transmission upgrades.

(a) Is OEB staff's understanding correct that the sole rationale for allocating 22.5% of the SECTR project cost to all ratepayers is it would have the ancillary benefit of addressing the Brighton Beach GS forecast limitations?

(b) If OEB staff's understanding is correct and the OEB were to approve the proposed cost allocation set out in the application but it is ultimately found that the forecast additional supply from Brighton GS is not needed in 2019 (i.e., no ratepayer benefit), should the cost allocation then be revised based on the beneficiary pays principle. If not, please explain why?

(c) Given Brighton Beach GS would also benefit, please explain why the application does not propose allocating any coats to Brighton Beach GS, in accordance with the beneficiary pays principle.

1-Staff-8
Ref: Exhibit B, Tab 1, Schedule 4, page 5 (Evidence on Need)

Hydro One notes under "Need Classification", that *"the SECTR Project is considered non-discretionary, as it will: (1) enable ORTAC requirements to be met; (2) accommodate new load; and, (3) mitigate circuit overloading where the load level has exceeded capacity."*

(a) Are any of those reasons for it being non-discretionary not related to meeting the needs of load customers in the Windsor Essex area? If any are not related to load customer needs, please identify.

(b) Given the proposed allocation of connection asset costs, please explain why addressing the limitations associated with Brighton Beach GS is not included in the list above.

1-Staff-9
Ref: Exhibit A, Tab 3, Schedule 1, page 5 (Evidence on Methodology and on Cost Allocation)

As part of the relief sought in this application, Hydro One requests that "*the Board endorse the methodology for allocation of upstream costs at the distribution level as set out in this Application*".

(a) OEB staff observes that Hydro One is asking the OEB to "endorse" the proposed methodology. Please clarify what is meant by "endorse the methodology" in this context.

(b) By seeking endorsement of the above referenced methodology, is it Hydro One's intention to apply the proposed methodology for other projects?

(c) In Hydro One's view is its proposed methodology in keeping with the provisions of the current TSC and DSC. Please provide the relevant sections of the codes as they pertain to the proposed methodology. Please also comment on the amendments, if any, that may be required to the codes.

(d) Did Hydro One seek and receive input from the affected LDCs or affected large customers (such as greenhouses) when developing the proposed methodology?

(e) If the affected LDCs were consulted, please provide (i) a description of the consultation process specifically in respect of the above referenced methodology, (ii) a summary of LDC views/concerns as submitted to Hydro One and (iii) the steps Hydro One took to address these concerns.

(f) If affected LDCs and large customers were not consulted in the development of the cost allocation proposal, then please explain why they were not consulted.

1-Staff-10
Ref: Exhibit B, Tab 1, Schedule 5 (OPA Evidence on Need and Alternatives)

At the reference on page 18, a schematic diagram shows 3 generating units of the Brighton Beach Generating Station are connected to Keith TS, with two of these generating units are connected to the 230 kV buses and the third generating unit is connected to the 115 kV bus.

At the reference on page 20, Table 1 shows the contract capacity and the summer effective capacity for all three generating units of Brighton Beach Power Station to be 514 MW, and 526 MW respectively.

(a) Please provide a breakdown of the total Brighton Beach contract capacity of 514 MW and effective capacity of 526 MW, between the corresponding two voltage levels i.e., 230 KV and 115 kV, by completing the table below:

Technology	Generating Station Name	Contract Expiry	Connection Point	Contract Capacity (MW)	Summer Effective Capacity (MW)
Combined Cycle Generation Facility	Brighton Beach Power Station	December 31, 2014	Keith TS at 230 kV Level		
			Keith TS at 115 kV Level		

1-Staff-11
Ref: Exhibit B, Tab 4, Schedule 3, pages 2-4. (Evidence on Hydro One Proposed Cost Responsibility)

In the reference at page 3, lines 6 – 19, Hydro One indicated that:

- with the establishment of Leamington TS sufficient load will be transferred from Kingsville TS to the proposed Leamington TS. This will reduce the need for the current four transformers at Kingsville TS to two transformers.
- three of the transformers at Kingsville TS are at end-of-life with planned replacement in 2015, only one of these three transformers will need to be replaced at a cost of $ 6 million;
- the estimated cost to replace one transformer and reconfigure the station to a two-transformer station is $12M. <u>This represents a $6M reduction in cost due to the SECTR Project</u>.
- given that 77.5% of the cost of SECTR is assigned to the customer, this same percentage of the savings due to SECTR is to be credited to the customer at the transformation pool - for economic evaluation purposes.

In the reference, at page 4 Hydro One summarized the results of the cost responsibility in table form.

(a) Please indicate how the treatment of the “6M transformer reduction” is consistent with the overall cost allocation methodology that is being put forward.