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**BY E-MAIL**

October 5, 2012

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

**Re: Board Staff Questions for the Technical Conference: October 12, 2012**
**Hydro One Networks Inc.**
**2013-2014 Electricity Transmission Revenue Requirement and Rates**
**Board File No. EB-2012-0031**

Please find attached Board staff questions and areas of interest for the Technical Conference to be held on October 12, 2012.

Sincerely,

*Original Signed By*

Harold Thiessen
Case Manager – EB-2012-0031
Senior Advisor - Applications

Attachment

**Hydro One Transmission 2013-14 Revenue Requirement and Rates**
**EB-2012-0031, Board Staff Questions for the Technical Conference**
**October 12, 2012**

Board staff will have Technical Conference questions requesting additional information and clarification in the following areas:

**1) Ref: Exhibit I/Tab2/Schedule 1.02 Staff 3**
When will BES definitions be finalized?
Magnitude of potential costs.
Confirm that no cost included in the test years for this application.

**2) Ref: Exhibit I/Tab2/Schedule 1.06 Staff 7**
Why are past labour contracts used for labour escalation assumption?
When do PWU and Society contracts expire?
How were the OM&A and Capital Expenditure estimates calculated?

**3) Ref: Exhibit I/Tab2/Schedule 1.07 Staff 8**
Explain the changes in the percentages in the table over time.

**4) Ref: Exhibit I/Tab2/Schedule 1.11 Staff 12**
How were the numbers (provided in the response) calculated and how do they relate to the Compensation summary provided at C1-5-2, Attachment 2?
Also, provide the data used to plot the productivity line in the Figure 2 graph.

**5) Ref: Exhibit I/Tab2/Schedule 1.06 Staff 13**
Transmission Unit Cost metric: Cause of the increase in 2012 and 2013 after several declining years.

**6) Ref: Exhibit I/Tab3/Schedule 1.01 Staff 16**
Why did the request for an update of 2012, 2013 and 2014 statistics result in a revision to 2011? Reasons for such a large revision to Transmission Cost escalation for Construction.

**7) Ref: Exhibit I/Tab3/Schedule 1.04 Staff 19**
Further exploration of the response on the CDM targets incorporated into the load forecast. Relate the response to Exhibit I/Tab3/Schedule 2.01 LPMA 2.

**8) Ref: Exhibit I/Tab5/Schedule 1.03 Staff 25**
Standard cost escalation is defined however can a specific percentage increase be

provided to account for this escalation?

**9) Ref: Exhibit I/Tab5/Schedule 1.04 Staff 26**
What is the source or definition of the O&M figures used in the table? Ie, in the rest of the application, 2013 O&M is $453.3 million. Why is the $O&M/km measure increases in the two test years and significance of this trend.

**10) Ref: Exhibit I/Tab5/Schedule 1.11 Staff 33**
Composite poles: What is the price difference between composite poles and wood poles? What is the additional life expectancy of the composite pole? How much lower are the maintenance costs? What is the current estimate of life cycle cost compared to a wood pole?

**11) Ref: Exhibit I/Tab7/Schedule 1.01 Staff 39**
Clarification of 'Burden Rate' for each class of employee.

**12)Ref: Exhibit I/Tab7/Schedule 1.07 Staff 45**

a. Please provide breakdown of estimated Corporate pension expense under the accrual method of approximately $194 million in 2013 and $182 million in 2014 into separate Transmission and Distribution components for each of the years

b. Explain impact on estimated Hydro One Total pension costs and Hydro One Transmission pension costs under the accrual method of approximately $194 million in 2013 and $182 million in 2014 of
   i. a 1% shift in the yield curve
   ii. a 20% return asset shock

c. What assumptions were used to calculate the estimated Corporate pension expense under the accrual method of approximately $194 million in 2013 and $182 million in 2014? Please explain.

d. The chart titled "Hydro One Pension Plan Employer Cash Contributions vs US GAAP Net Periodic Benefit Cost" is based on several assumptions by Hydro One:
   i. Why weren't the amortization of actuarial gains and losses included in the "US GAAP Net Periodic Benefit Cost"? Please update the chart including this amortization reflecting market conditions specific to each year of the analysis.
   ii. What "one-time special adjustments that were made to the balance sheet under CGAAP" were assumed to also have been made under US GAAP? How did they impact the cash contributions and net periodic benefit cost?
   iii. How does the chart change if the initial balance sheet position of the plan as at January 1, 2000 was not the funded status of the plan on that date?

How do unamortized and amortized actuarial gains and losses impact the chart?

**13)Ref: Exhibit I/Tab7/Schedule 1.08 Staff 46**

a. Hydro One has recorded a regulatory asset for OPEB in its financial statements but has not received a rate order by the Board to report such an asset. ASC 980-715-25-5 requires an order by the regulator. Why did Hydro One not apply for such an order from the Board? Does Hydro One plan to apply for such an order from the Board? Please clarify if this OPEB regulatory asset was $153 million as at January 1, 2011, as noted in the response to IR #46 part a). If this was not the number, please provide the correct number.

b. How has Hydro One recovered the following in past rates and how does Hydro One propose to recover the following in future rates:
   i. Transitional asset/obligation generated on transition to CICA HB Section 3461. Please disclose initial amount and date and unamortized amount to date.
   ii. Transitional asset/obligation generated on transition to US GAAP. Please disclose initial amount and date and unamortized amount to date. Please confirm that these amounts were $297 million regulatory asset for pension and $153 million regulatory asset for OPEB as at January 1, 2011 under USGAAP.
   iii. Recognizing unamortized actuarial gains and losses and past service costs on the balance sheet under US GAAP

c. USGAAP does not recognize transitional assets/obligations generated from the transition to CICA HB Section 3461. How did Hydro One treat the unamortized amount on the transition to USGAAP? If this is not the case, please explain.

d. Please confirm that Hydro One could recognize the funded status of benefit plans as a regulatory asset or liability instead of AOCI on transition date under the USGAAP accrual method of accounting. If this is not the case please explain.

e. Please confirm that under USGAAP pension cash accounting, Hydro One performs similar journal entries as the one below (at a high level). If this is not the case, please explain and provide correct journal entry.

DR Pension Expense (on a cash basis)
DR Regulatory Asset
    CR Pension Liability (on an accrual basis)

**14) Ref: Exhibit I/Tab7/Schedule 3.23 EP 49 and Exhibit C2/Tab5/Schedule 1/Attachment 1/p1**

a. Please explain why Hydro One did not update its application to reflect the December 31, 2011 Actuarial Valuation that was finalized in May 2012 by Mercer, as it seems as though Hydro One's application was filed with the Board around the same time (May 28, 2012).

b. Is Hydro One planning to update its evidence to reflect the December 31, 2011 Actuarial Valuation? If this is not the case, please explain.

c. Please explain why estimated employer's current service cost is $91 million as at December 31, 2009 and $99 million as at December 31, 2011 as per the May 2012 Actuarial Valuation but the 2013 total Corporate Pension Costs is $154 million in 2013 and $158 million in 2014, as per Exh.C2/T5/S1/Att1/P1.

d. Please explain the minimum annual special payments of $48 million as at December 31, 2009 and $60 million as at December 31, 2011 as per the May 2012 Actuarial Valuation.
    a. When were these payments made?
    b. Does Hydro One propose any of these amounts in rates? If so, how?

e. Please provide a schedule that shows the amortization of the Funding Shortfall of ($434 million) as at December 31, 2009 and ($498 million) as at December 31, 2011 over the prescribed 15 year period. Please tie the amounts in the schedule to the minimum annual special payments of $48 million as at December 31, 2009 and $60 million as at December 31, 2011 as per the May 2012 Actuarial Valuation.

f. Please explain why discount rate used in valuation as at December 31, 2011 of 5.50% did not change from previous valuation as at December 31, 2009 when market conditions have changed and interest rates have dropped. Please provide an analysis of the impact on the amounts reported in the May 2012 valuation if the discount rate was decreased by 1%.

g. Please provide impact on the proposed Hydro One Transmission annual pension cost of $70 million in 2013 and $75 million in 2014 and total annual pension cost of $154 million in 2013 and $158 million in 2014:
    i. a 1% shift in the yield curve
    ii. a 20% return asset shock

h. Has Mercer or another actuary ever prepared an Actuarial Valuation for Hydro One based on the accrual basis of accounting for pension expense? If so, please provide the latest valuation.

i. The Mercer Actuarial Valuation Report for the Hydro One Pension Plan issued in May 2012 stated the following on page 3:

> "This valuation reflects the provisions of the Plan as at December 31, 2011. The Plan was amended effective April 1, 2011 to increase employee contributions for members of the Power Workers Union by 0.5% of pensionable earnings. The Plan has not otherwise been amended since the date of the previous valuation, and we are not aware of any pending definitive or virtually definitive amendments coming into effect during the period covered by this report. The Plan provisions are summarised in Appendix F."

The Hydro One Tx Decision, EB-2010-0002, stated the following on page 20:

> "While the Board has approved an overall OM&A envelope and given Hydro One the freedom to apply that spending according to its own priorities, the Board expects that Hydro One will revisit the proposed increases allocated to compensation. This should provide a signal for upcoming bargaining. With respect to pension contributions, it is the Board's view that in subsequent applications, Hydro One must demonstrate measurable progress towards having its pension contributions reflect those prevailing in the public sector generally. The evidence suggests that an employee contribution level of 50% is the norm."

Please outline Hydro One's strategy to get to the end state as per the page 20 of the Board's EB-2010-0002 Decision quote, "…an employee contribution level of 50% is the norm" generally prevailing in the public sector. Please explain and provide details of this strategy.

**15) Ref: Exhibit C1/Tab5/Schedule 3/p2 and EB-2010-0002 Exhibit C1/Tab3/Schedule 2/Appendix A p2**

a. Please explain why annual corporate pension costs for Hydro One Transmission and Hydro One Total have increased from

- $47 million (Tx) and $114 (Total) approved 2011 and
- $48 million (Tx) and $118 (Total) approved 2012, as per EB-2010-0002 C1/T3/S2/ApA/P2, to
- $70 million (Tx) and $154 (Total) proposed 2013 and
- $75 million (Tx) and $158 (Total) proposed 2014, as per Exh.C1/T5/S3/P2

b. If the above numbers are not correct, please provide updated numbers. Please explain the large increases.

c. Please explain why a larger proportion is capitalized in 2013 and 2014 compared to 2011 and 2012.

**16)Ref: Exhibit C2/Tab5/Schedule 1/p1 and EB-2010-0002 Exhibit C2/Tab5/Schedule 1/Attachment 1/p1**

**Table 1**
**Annual OPEB Cost (millions)**

| | **Hydro One Transmission** | **reference** |
|---|---|---|
| **Approved 2011 OPEB Costs** | | |
| OM&A | $20.8 | EB-2010-0002 C2/T5/S1/Att1/P1 |
| Capital | | |
| Total | | |
| **Approved 2012 OPEB Costs** | | |
| OM&A | $22.0 | EB-2010-0002 C2/T5/S1/Att1/P1 |
| Capital | | |
| Total | | |
| **Proposed 2013 OPEB Costs** | | |
| OM&A | $25.1 | Exh.C2/T5/S1/Att1/P1 |
| Capital | | |
| Total | | |
| **Proposed 2014 OPEB Costs** | | |
| OM&A | $27.8 | Exh.C2/T5/S1/Att1/P1 |
| Capital | | |
| Total | | |

a. Please clarify if the numbers and references reported in the lightly shaded boxes are correct. If they are not correct, please provide the correct numbers and references in the table.

b. Please provide the correct numbers and references in the darkly shaded boxes in the table.

c. Please provide totals in the table.

d. Please provide explanations for the increases in each of OPEB OM&A, OPEB Capital, and OPEB Total from 2011 through 2014.

e. Please explain if a larger proportion is capitalized in 2013 and 2014 compared to 2011 and 2012.

**17)Ref: Exhibit I/Tab9/Schedule 1.03 Staff 49**
In this response, Hydro One stated that there is a difference between:

i. Depreciation and amortization expense added back to utility income in the book to tax adjustments used to calculate utility taxable income of $346.7 million in 2013 and $374.7 million in 2014.
ii. Depreciation and amortization expenses included in the revenue requirement of $348.9 million 2013 and $377.0 million in 2014.

Hydro One stated that this difference represents the amortization of regulatory assets. This amortization is included in the book to tax adjustments but not included in depreciation and amortization expense calculated for revenue requirement purposes. The difference between the two amounts is ($2.2 million) for 2013 and ($2.3 million) for 2014.

Board policy as stated in the Board's EB-2008-0381Decision, where the Board accepted the Settlement Agreement for Issue #4, is that regulatory assets and regulatory liabilities are not to be incorporated in the calculation of the regulatory income tax provision.

Please recalculate the regulatory income tax provision for 2013 and 2014 excluding the impact of the amortization of regulatory assets and regulatory liabilities.

**18) Ref: Exhibit I/Tab11/Schedule 1.04 Staff 53**
Further clarification of Part (b) response – treatment of projects that were supposed to be in-service in 2011/2012 and have been delayed.

**19) Ref: Exhibit I/Tab12/Schedule 1.03 Staff 56**
Clarification of footnote on page 2 and meaning of the term Gross Costs versus "Total Costs".

**20) Ref: Exhibit I/Tab12/Schedule 1.04 Staff 57**
Clarification questions in relation to parts a, b and c.

**21) Ref: Exhibit I/Tab12/Schedules 1.05 Staff 58 to 1.08 Staff 61, including Schedule 1.11 Staff 64, Schedule 1.13 Staff 66 and Schedule 1.16 Staff 69**
Clarification of what appears to be an error in the evidence references that are provided in response to these questions. Also, clarification of the project costs, project scope and linkage with the previous Tx application (EB-2010-0002).

**22) Ref: Exhibit I/Tab12/Schedule 1.12 Staff 65**
Clarification questions in relation to part (b).

**23) Ref: Exhibit I/Tab12/Schedule 1.18 Staff 71**
Clarify the term “in-flight” project in part (a).

**24) Ref: Exhibit I/Tab22/Schedule 1.01 Staff 82**
Clarification pertaining to GEP projects that have been delayed.

**25) Ref: Exhibit I/Tab19/Schedule 1.04 Staff 80**

a. If Hydro One is granted continuance of the Board of the Pension Cost Differential Account, does Hydro One propose to include the actual pension annual special payments in addition to the actual annual service cost in the variance reported in the account?

b. Please give reasons as to why Hydro One should be granted a Pension Cost Differential Account when
    i. no other components of the revenue requirement are trued up to actual expense; and
    ii. comparable companies regulated by the Board do not have permission to use a similar variance account.

c. Please provide a breakdown of the Pension Cost Differential Account forecasted principal balance of $12.4 million, specifically the debits and credits. Ie what are the respective actual pension amounts per year (the debits) compared to the amounts in embedded rates per year (the credits)?

**26) Ref: Exhibit I/Tab20/Schedule 1.01 Staff 81**

a. “External Revenue – Partnership Transmission Projects deferral account”:

    i. How does Hydro One expect that the proposed amounts recorded in the deferral account will be neutral to ratepayers when the underlying expenses associated with the provision of these services cannot be examined or quantified?

    ii. Does Hydro One agree that it may be more appropriate to allocate the actual amounts representing the expenses and capitalized amounts embedded in the 2013 and 2014 revenue requirement for these services as credits to the deferral account? This may be done instead of recording revenue equal to the amount invoiced to partnership companies for work performed by Hydro One Transmission employees as credits in the deferral account. Please explain.

b. “Long-Term Transmission Future Corridor Acquisition and Development deferral account”:

    i. Why is this account needed and the situation is different than dealing with past corridor expansions?

ii. If this situation has been known since 2005 (Ontario Provincial Policy Statement of 2005), why has this deferral account not been considered to be created in prior Hydro One Tx proceedings?

iii. What circumstances have changed that give rise for the need for this account now?

iv. Would costs associated with this account not be generally incorporated into rate base?

v. What is the chance that the proposed costs that would be recorded in the deferral account not go into rate base in the future based on a risk analysis performed on previous preliminary studies and reviews associated with corridor expansion?

**27) Ref: Exhibit I/Tab22/Schedule 1.02 Staff 83**
Clarification questions in relation to the table of GEP projects provided in the response.

**28) Ref: Exhibit I/Tab23/Schedule 1.04 Staff 87**
The uplift is assumed to be $3.33 per MWh, which is described as an average.

a. Given that uplift is an average rather than a constant amount, how does the actual uplift charge vary – by location / line segment, annually or within a given year, by congestion or other circumstances on the transmission system?
b. Confirm that none of the uplift revenue goes to Hydro One.

29) **Ref: Exhibit I/Tab23/Schedule 1.02 Staff 85 Attachment 1 "Review of Rates in Neighbouring Markets", Appendixes I – V; Exhibit H1-5-2/Appendix B/p15**

The descriptions of rate adders in the neighbouring jurisdictions do not include enough information to understand:

a) why they are all lower than the average uplift in Ontario,

b) why the uplift in Ontario is higher than the Ontario export charge (whereas in nearly all other cases the uplift is lower).

If possible, please provide additional information about the neighbouring rate adders to understand whether these comparisons are valid.

**30) Ref: Exhibit I/Tab23/Schedule 1.02 Staff 85 Attachment 1 "Review of Rates in Neighbouring Markets", Appendixes I – V; Exhibit H1-5-2/Appendix B/p24**

Several of the numbers in the response (p. 17 and in Appendixes I – V) are higher than the corresponding rates in the H1-5-2 Appendix (Table 2 on p.15 of the CRA study). Was the detailed study done more recently than the CRA study, such that the difference is due to rate increases? Or is there some other reason?

31) **Ref: Exhibit I/Tab23/Schedule 1.02 Staff 85 Attachment 1 "Review of Rates in Neighbouring Markets", pp 13-14**

The study indicates that FERC and certain RTOs continue to discuss efficiency gains that could be enjoyed by ending "pancaking" across neighbouring jurisdictions.

a. Confirm that if IESO were to participate in such discussions, any changes would be in the direction of the EANC scenario or at least a lower ETS rate?

b. Would the IESO's participation in such discussions be facilitated if it were responsible for the ETS rate, rather than being required to seek OEB approval through a proceeding such as the present one?

**32) Ref: Exhibit I/Tab23/Schedule 1.02 Staff 85 Attachment 1 "Review of Rates in Neighbouring Markets", p. 17 Appendixes I – V**

Is it possible to make a generalization across the various RTOs and transmitters, on the matter of whether the rates shown determine the revenue gained by the transmitters (as in the case of ETS in Ontario), as opposed to being revenue to the RTOs shown at p. 17.

33) **Ref: Exhibit H1/Tab5/Schedule 1/p 3**

The monthly payments by the IESO to Hydro One are calculated on a three-year average basis.

a. Does this method of calculation result in a time lag in how much revenue Hydro One will actually receive in the rate year 2013?

b. Has IESO or CRA made a forecast of the amount that would be paid to Hydro One annually, over the period 2013 – 2015, under each of the ETS rate scenarios, with and without the assumption that Ontario participates in the Western Climate Initiative? If so, please provide the forecasts.

34) **Ref: Exhibit I/Tab23/Schedule 1.04 Staff 87 Attachment 1 "Review of Rates in Neighbouring Markets"**

Part a) Confirm that friction is a modeling refinement (or shortcut) and that it does not represent an out-of-pocket cost or a revenue stream for any party.

Part b) Approximately what proportion of the time was Intertie Congestion a non-zero amount in 2011? What was its highest amount per MWh?

35) **Ref: Exhibit I/Tab23/Schedule 1.01 Staff 84**

Part b) Is it reasonable to conclude that current capacity and reliability of Hydro One's facilities are not a significant factor in causing export transaction failures?

Should Hydro One be doing anything to reduce the risk of failures, or the cost of compensating parties for failures?

Board staff may also ask some follow up questions under the above noted issue areas after intervenors have finished their questions.