*PUBLIC INTEREST ADVOCACY CENTRE*
*LE CENTRE POUR LA DEFENSE DE L'INTERET PUBLIC*
**ONE Nicholas Street, Suite 1204, Ottawa, Ontario, Canada K1N 7B7**
Tel: (613) 562-4002. Fax: (613) 562-0007. e-mail: piac@piac.ca. http://www.piac.ca

Michael Buonaguro
Counsel for VECC
(416) 767-1666

November 2, 2010

**VIA MAIL and E-MAIL**

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Dear Ms. Walli:

**Re: EB-2010-0002–Hydro One Networks Inc Transmission**
**Vulnerable Energy Consumers Coalition (VECC)**

Please find enclosed the submissions of VECC in the above noted proceeding.

Yours truly,

Michael Buonaguro
Counsel for VECC
Encl.

# Hydro One Networks Inc.

## 2011 and 2012 Transmission
## Revenue Requirement and Rates

# EB-2010-0002

# Final Submissions
# Vulnerable Energy Consumers' Coalition

**November 2, 2010**

**Hydro One Transmission**
**2011/2012 Revenue Requirements EB-2010-0002**

**Final Submissions of VECC**

## TABLE OF CONTENTS

**Revenue Requirement Reductions Summary**

1. The table below summarizes the submissions of VECC with respect to those areas in which VECC submits specific reductions to the Revenue Requirement requested by Hydro One Networks Inc (Hydro One) can and should be made:

| **Cost Area** | **Proposed SPECIFIC RR Reductions** | | |
|---|---|---|---|
| | **2011** | **2012** | **Paragraph(s)** |
| **OM&A Costs** | | | |
| **Average Compensation Costs** | **$6.2 million** | **$6.9 million** | **107** |
| **Head count related OM&A** | **$3.75 million** | **$3.75 million** | **104** |
| **Corporate Communications** | **$5.0 million** | **$5.0 million** | **128** |
| **Development OM&A** | **$5.2 million** | **$5.2 million** | **123** |
| **Other Revenue** | | | |
| **External Revenue* (Stations Maintenance)** | **$8.6 million** | **$10.4 million** | **33** |
| **Ratebase and Capital Expenditures** | | | |
| **Working Capital (HST) (approx.)*** | **$1 million** | **$1 million** | **147** |
| **CWIP in Ratebase** | **$43.6 million** | **$26 million** | **250** |
| **Cost of Capital** | | | |
| **Cost Of Debt** | **$2.3 million** | **$4.1 million** | **161** |
| **Deferral and Variance Accounts** | | | |
| **HST Tax Change Credit*** | **$9 million** | **$9 million** | **180** |
| **Other** | | | |
| **Apprenticeship Tax Credits** | **$1 million** | **$1 million** | **134** |
| **TOTAL** | **$85.65M** | **$72.35M** | |

***Any difference between forecast and actual to be recorded in the appropriate variance accounts**

2. In addition VECC has made submissions on other areas of the application, including the Load Forecast, the Export Tariff Issue, and general levels of Capital Spending which may have an impact on the Revenue Requirement but which have not been separately identified on this table.

## INTRODUCTION

3. This is the Final Argument of the Vulnerable Energy Consumers' Coalition ("VECC") in the Hydro One Networks Inc. Application for 2011 and 2012 transmission rates, EB-2010-0002. It is organized in the same manner as the Issues List, with numbering and sub-numbering that matches the issues list numbering scheme.

4. Where VECC has not made submissions with respect to an issue raised in the proceeding, either through IRs or in the oral hearing, it should not be assumed that VECC agrees with the proposal in the application.

## 1. GENERAL

### 1.1 Has Hydro One responded appropriately to all relevant Board directions from previous proceedings?

5. Hydro One states in its response to VECC IR 1[1] that it is fully compliant the following Board Directive from EB-2008-0272:

> The Board has directed Hydro One to continue its key performance indicator development and to improve on its cost allocation accounting processes with the objective of being able to demonstrate improvements in efficiency and the value for dollar associated with its compensation costs.[2]

*VECC Submission*

6. VECC disagrees with Hydro One and will address this issue in its submissions regarding OM&A Cost Effectiveness Tests and Total Compensation Costs.

### 1.3 Is the overall increase in 2011 and 2012 revenue requirement reasonable?

7. Hydro One's as filed Revenue requirements are $1,217.7M and $1405.8M for 2011 and 2012 respectively.[3]

8. The biggest increase in the 2011 Revenue requirement is the Cost of Capital ($115.5M). Out of the Cost of Capital driven revenue requirement increase, approximately 50% ($55.9M) is due to the higher ROE on an increased 2011 rate base. The rest includes CWIP on Bruce to Milton ($45.5M) and higher debt costs ($6.9M).

---

[1] Exhibit I Tab 4 Schedule 1
[2] EB-2008-0272 Decision Page 31
[3] Exhibit E1 Tab 1 Schedule 1 Tables 1, 2 and 3

9. A great number of interrogatories and much cross-examination focused on the changes to the Application resulting from both the Board's EB-2009-0096 Distribution Decision and Ministry concerns about the increase in Hydro One TX 2011 and 2012 revenue requirements. The actual changes are discussed at BS IR 38[4] and CME IR I[5] and numerous places in the Transcript of Proceeding.

10. With regard to OM&A the magnitude of the cut is highlighted in the following exchange:

> MR. WARREN:: In response to the directive to cut your rates -- not the Board's decision in distribution -- in response to the direction to cut your revenue requirement and therefore your rates, that the cut you made was 13 million out of 436 million.
> Have I got those numbers correctly?
> MR. STRUTHERS: If you include the OM&A costs within the $434 million, you would be technically correct.
>
> MR. WARREN: Can you tell me, sir, looking at J2.2 -- the changes that are reflected in J2.2, my understanding was that all of them were related to changes in timing in green energy projects. I obviously have misunderstood that.
> Can you tell me which of the figures on J2.2 are not related to the changes in timing in the green energy projects?
> MR. STRUTHERS: Certainly the shared services and other costs numbers are not reflective of the Green Energy Act.
> MR. WARREN: And they are a total of $1 million. Have I got that right? [6]
> MR. STRUTHERS: Yes, you would be correct. But the other items, I don't have enough familiarity with or knowledge of to determine which were specifically related to the Green Energy Act and which were related to where we had gone back and looked at program need.

11. To put the cuts in perspective, this exchange provides the appropriate context:

> MR. WARREN: And what you are seeking approval for in this case for transmission is capital spending in the neighbourhood of roughly $1.15 billion. Take that subject to check?
> MR. STRUTHERS: I will take that subject to check.
> MR. WARREN: And the OM&A levels for transmission we have already discussed in 2011 would be some $436 million. Take that subject to check?
> MR. STRUTHERS: I will.
> MR. WARREN: So if I put all of those numbers together, am I correct in understanding that Hydro One Networks plans to spend a total of OM&A and

[4] Exhibit I Tab 1 Schedule 38
[5] Exhibit I Tab 3, Schedule 1
[6] Tr. Vol. 6 p 39

capital in 2011 some $3 billion, roughly; fair?
MR. STRUTHERS: Roughly, that would be correct, yes. It is a significant amount of money that is being invested in the systems.[7]

12. VECC suggests that the evidence is clear that the reductions to OM&A (and revenue requirements) of about $6.5M in Shared Services OM&A were a result of the Board's Distribution decision in EB-2009-0096. The other Sustaining OM&A reductions amounted to $13M and in VECC's view these were for the most part already included in Hydro One's planning. The "cuts" still left OM&A levels for the test years well above minimum levels.

13. The Capital Expenditure reductions asserted by Hydro One are directly related, almost entirely, to the "hold" on Green Energy Plan Projects, as opposed to specific reductions proposed by Hydro One.

14. VECC submits that the resulting Revenue Requirement and rate increases are still too high and do not reflect any attempt by Hydro One at austerity given the fragile state of Ontario's economic recovery or real consideration of the impact on electricity customers.

*Bill Impacts*

15. Hydro One's evidence is that the current monthly bill for a Hydro One Distribution R1 residential customer, consuming 1000 kWh, as of Sept. 1, 2010, would be $154.35 before taxes and $174.42 after taxes.[8]

16. The equivalent monthly bill as of Sept. 1, 2009 for the same customer using the same 1000 kWh would have been $141.13 before taxes and $148.18 after taxes.[9]

*VECC Submission*

17. VECC suggests that these historic increases are material and the bill impacts resulting from this application if approved without reductions in the revenue requirements are too high.

18. VECC has reviewed the submissions of CCC with respect to the relationship between Total Bill Impact and the process undertaken by the applicant entering into this application, and generally supports the submissions and conclusions of CCC in that regard. Accordingly the remainder of VECC's submissions are focused on specific reductions the Board should make, which should be taken by the Board as specific reductions that also should form subcomponents of larger, overall reductions that should be imposed by the Board.

---

[7] Tr. Vol. 6 p 45
[8] Exhibit 1 Tab 3 Schedule 6, Attachment 1.
[9] Undertaking J6.4

## 2. LOAD FORECAST and REVENUE FORECAST

### 2.1: Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

19. Hydro One Networks derives its forecast of charge determinants from its forecast of Ontario peak demand. Various modeling/forecasting techniques are used to develop the Ontario peak demand forecast.[10] In addition specific adjustments are made to the forecast to account for embedded generation and CDM.[11] For the years 2010 through 2012, the reductions in Ontario peak demand (i.e., the overall one-hour system peak) attributed to CDM are assumed to be 2,007 MW, 2,486 MW and 3,064 MW respectively.[12] While the 2012 value is consistent with the OPA's 2007 IPSP, the values for the earlier years are somewhat lower to account for the recent economic recession.[13]

*VECC Submissions*

20. In its EB-2008-0272 Report[14] the Board found that it was appropriate for Hydro One Networks to base its CDM adjustment on the OPA's information and analysis. In its Application, Hydro One Networks has shifted 400 MW of CDM from 2010 as forecasted per the OPA's IPSP to 2011 and 2012[15] due to the recent economic downturn. In response to interrogatories, Hydro One Networks indicated that the OPA had not published any detailed projections of CDM for 2008-2013 since the release of the IPSP.[16]

21. In June of this year the Board initiated a consultation process with respect to the 2011-2014 CDM Targets for Electricity Distributors (EB-2010-0218). As background to this process, the OEB's June Letter included an OPA Consultation Paper[17] which discussed the process used in developing the proposed targets and specifically indicated that "In late 2008 through early 2009, the OPA revised its near term (2008-2013) provincial conservation projections, as set out in the IPSP"[18]. Furthermore, it is clear from the appended list of distributors who provided input to the OPA that Hydro One Networks participated in the OPA consultation.

[10] Exhibit A Tab 12 Schedule 3, page 2 and pages 13-18
[11] Exhibit A Tab 12 Schedule 3, page 4 and pages 6-9
[12] Exhibit A Tab 12 Schedule 3, page 7, Table 2
[13] Exhibit A Tab 12 Schedule 3, page 7
[14] Page 8
[15] Tr. Vol. 8, page 101, lines 25-27
[16] Exhibit I Tab 4 Schedule 11 c)
[17] Section 4.0 – Appendix A
[18] Appendix B, page 12

22. VECC assumes that it was this revised projection that led to Hydro One Networks' 400 MW shift in CDM from 2010 to 2011/12. However, materials recently filed as part of Hydro Ottawa's current rate application (EB-2010-0133) [19] indicate that the OPA's revised CDM projection calls for lower CDM savings all the way through to 2014 relative to what was in the IPSP. Indeed, for 2011 and 2012 the revised CDM energy savings are less than half of that in the original IPSP. VECC recognizes that the revised CDM MW savings may represent a different proportion of the original IPSP but submits that 2011 and 2012 values are likely to be materially less than what Hydro One Networks is projecting.

23. As a result, VECC is concerned that Hydro One Networks' current load forecast does not reflect the latest information and analysis from the OPA. VECC acknowledges that the information has not been formally filed in this proceeding. However, in VECC's submission, it is Hydro One Networks who was most likely to be aware of its existence and it was Hydro One Networks who should have incorporated the information into its Application and, if not there, in its interrogatory responses; the material was not known to VECC until provided by Hydro Ottawa. Given this context and the Board's previous direction that Hydro One Networks' forecast should be based on the OPA's information, VECC believes it is appropriate for the Board to consider it in establishing the load forecast for 2011 and 2012.

24. VECC submits that after allowing for the pre-2007 savings of 1,000 MW which Hydro One Networks has reflected (along with its revised IPSP values) in its CDM projections for 2011 and 2012, it would be reasonable to assume a cumulative CDM impact for 2011 of no more than 1868 MW, as opposed to the 2486 MW assumed by Hydro One Networks[20]. This number was derived by assuming the cumulative post-2007 CDM MW savings would be 868 MW. This is one-half of the post-2007 CDM MW savings included in the initial IPSP. In contrast, the OPA's revised CDM energy savings are less than 40% of the original IPSP value for the same period.

25. Similarly, VECC submits that for 2012, it would be reasonable to assume a cumulative CDM impact of no more than 2377 MW, as opposed to the 3064 assumed by Hydro One Networks. Again, this value was derived by assuming the cumulative post-2007 CDM MW savings would be 1377 MW – which is 2/3's of the savings included in the original IPSP. Again, it should be noted that, the OPA's revised CDM energy savings for 2012 are less than half of the original IPSP value.

26. VECC also notes that Hydro One Networks was unable to provide any details as to how the peak MW savings attributed to each type of CDM program were translated into average monthly MW savings[21] as this information was not provided by the OPA. Rather, all that the OPA apparently provided was the aggregate impact of CDM on

---

[19] EB-2010-0133 Undertaking JT1.1 (filed September 30, 2010). The updated near term IPSP projection for CDM energy savings are 3,306 GWh and 5,005 GWh for 2011 and 2012 respectively as compared to 8,800 GWh and 10,700 GWh in the initial IPSP.

[20] Exhibit A Tab 12 Schedule 3, page 7

[21] Undertaking J8.1.

the monthly system peaks. The Minister's directives to the OPA regarding CDM are with respect to system peak and overall energy use. As a result, it reasonable to assume these metrics are the OPA's primary focus. VECC accepts that, consistent with the Board's findings from EB-2008-0272, it is appropriate for Hydro One Networks to obtain its CDM information from the OPA (as opposed to developing its own). However, VECC also submits that Hydro One Networks has the responsibility to obtain sufficient supporting details so as to be able to satisfy both itself and other participants in these proceedings that CDM has been properly incorporated into its load forecast. Hydro One Networks has acknowledged that different types of CDM programs will have different impacts on the average monthly peak demand.[22] In VECC's view, it should be incumbent upon Hydro One Networks to be able to understand and address the impacts of each on its proposed load forecast. Furthermore, this matter will become increasingly important at the electricity distributors pursue the new CDM targets they are about to be assigned.

### 2.2 Are Other Revenue (including export revenue) forecasts appropriate?

*Third Party Revenues*

27. Hydro One Networks Application includes a forecast of external revenues from third parties which are used as an offset to the revenue requirement. The projected amounts are $31.3 M for 2011 and $24.7 M for 2012[23]. On a related issue, Hydro One Networks is proposing to discontinue the variance accounts established by the Board in EB-2008=0272 with respect to Secondary Land Use revenues[24], Station Maintenance revenues[25], and Engineering & Construction revenues[26].

*VECC Submissions*

28. Third party external revenues arise from Secondary Land Use and Work for Third Parties (Station Maintenance and Engineering & Construction). In the case of Secondary Land Use the forecast revenues for 2011 and 2012 are $12.6 M and $12.5 M respectively.[27] These forecast levels are in line with the current forecast for 2010 ($12.5 M) but less than the actual revenues for 2009 ($14.2M).[28] This forecast does not include any allowance for one-time events, which sometimes do occur and can only serve to increase revenues.[29]

[22] Tr. Vol. 8, page 103, lines 7-15
[23] Exhibit E1 Tab 1 Schedule 1, page 6
[24] Exhibit I Tab 6 Schedule 9 a)
[25] Exhibit I Tab 6 Schedule 9 b)
[26] Exhibit I Tab 6 Schedule 9 b)
[27] Exhibit E1 Tab 1 Schedule 2, page 2
[28] Exhibit I Tab 6 Schedule 8 a) & b)
[29] Exhibit E1 Tab 1 Schedule 2, page 3, lines 24-28

29. In the case of Station Maintenance, forecast revenues are $4.6 M in 2011 and $3.0 M in 2012.[30] In contrast, actual revenues for 2009 and 2010 totaled $14.6 M and $5.6 M respectively.[31] Hydro One Networks attributes the decrease to an expected shift in resources to its own work programs.[32] However, VECC notes that declining forecasts supported by similar rationale were made in EB-2005-0501 and in EB-2008-0272 and, in both cases, actual revenues have turned out higher than forecast.[33]

30. In the case of Engineering & Construction, forecast revenues are $11.0 M in 2011 and $6.0 M in 2012[34]. In contrast, actual revenues for 2009 and 2010 totaled $3.2 M and $11.0 M respectively[35]. The forecast is based on anticipated activities related to revenue metering projects and traditional work performed for OPG[36].

31. In its EB-2008-0272 Decision the Board recognized[37] the uncertainty associated with forecasting revenue in these three areas and the one-time events that can increase revenues. In order to ensure that ratepayers receive the benefit of these revenues (and at the same time Hydro One Networks is protected), the Board established variance accounts for each. Overall, it appears to VECC the circumstances have not changed and VECC submits that the Board should again direct Hydro One Networks to maintain/establish 2011 and 2012 variance accounts for each of these activities.

32. VECC notes that much of the Station Maintenance work is for other regulated utilities and our view there will be a loss of efficiencies and higher overall aggregate costs if Hydro One withdraws its services.

33. VECC submits that Hydro Ones forecast for Station Maintenance work for third parties and associated revenue should be rejected by the Board and a forecast based on the historic three year average of $13.4M be substituted for 2011 and 2012. This reduces the TX revenue requirement for 2011 and 2012 by $8.6M and $10.4M respectively before tax, with any differences being recorded in the External Station Maintenance and E&CS Revenue Account.

34. The existence of the External Station Maintenance Account is helpful but does not address the issue of under-forecasting. The fact that additional revenues are collected and then cleared does not provide for stability, whereas using a three year historic average would achieve this to a greater degree.

---

[30] Exhibit E1 Tab 1 Schedule 2, page 2
[31] Exhibit I Tab 6 Schedule 8 a) and b)
[32] Exhibit E1 Tab 1 Schedule 2, page 4
[33] Exhibit E3 Tab 1 Schedule 1, pages 4-5
[34] Exhibit E1 Tab 1 Schedule 2, page 2
[35] Exhibit I Tab 6 Schedule 8 a) and b)
[36] Exhibit E1 Tab 1 Schedule 2, page 5
[37] Page 15

*Export Revenues (and Tariffs)*

35. As part of a Settlement Agreement approved by the Board in EB-2006-0501, parties agreed that the IESO would undertake a study of alternative Export Transmission Service (EST) tariffs and make its report available no later than June 2009 for inclusion in the 2010 transmission rate-resetting process. The Study was completed and filed with the OEB in August 2009. Accompanying the Report was a recommendation from the IESO that the ETS tariff be maintained at $1/MWh.[38] For purposes of the current Application, Hydro One Networks' has based its proposed ETS tariff for 2011 and 2012 on the IESO's recommendation.[39] In making this proposal Hydro One Networks made no specific comments regarding the IESO's recommendation other than to state that, if directed by the Board, it would file any required changes to the existing ETS rate resulting from the review of the IESO's recommendation.[40]

36. Based on the existing ETS tariff, the revenue requirement offset is $10.1 M and $10.2 M in 2011 and 2012 respectively from the export transmission tariff revenues.[41] Also, similar to the proposal regarding Third Party revenues, Hydro One Networks is proposing to discontinue the variance account established by the Board in EB-2008-0272 with respect to Export Tariff revenues.[42]

*IESO Study and Recommendation*

37. The IESO tariff study was initiated in December 2008 with the release of the first draft of the IESO's proposed stakeholder engagement plan.[43] The study considered four tariff options and following principles were used to assess the options.[44]

- Simplicity of administration,
- Consistency with rates in neighbouring jurisdictions,
- Fair and equitable (i.e., tariff should reflect cost to provide service), and
- Net Ontario benefit.

38. For each option analysis was undertaken by Charles River Associates to determine the impact on export/import volumes, ETS tariff revenues, HOEP and cross border emissions. From these results, conclusions were drawn regarding the likely impact on market efficiency The IESO also undertook a qualitative assessment as to whether there were any expected regulatory or legal impediments

---

[38] Exhibit H1 Tab 5 Schedule 2, Attachment 1, page 9
[39] Exhibit H1 Tab 5 Schedule 1, pages 1-2
[40] Exhibit H1 Tab 5 Schedule 1, page 2
[41] Exhibit H1 Tab 5 Schedule 1, page 2
[42] Exhibit I Tab 6 Schedule 11 c)
[43] Tr. Vol. 9, page 52
[44] Exhibit H1 Tab 5 Schedule 2, Attachment 1, page 6

to the implementation of the ETS tariffs under consideration or whether the options created operational challenges in the administration of the electricity markets or maintaining reliability.[45]

39. Based on the results of this analysis, the IESO determined that Option #2 (ETS based on average Network tariff) was the preferred option.[46] This conclusion was presented to stakeholders on August 10, 2009.[47] However, IESO management subsequently observed that a number of factors had changed since the study began including a) load deterioration due to economic conditions and b) the transformation of Ontario's supply mix due to the Green Energy and Green Economy Act. In the view of IESO management, both of these factors serve to increase the occurrence of surplus base load generation and highlighted the need for exports which would help alleviate such conditions. As a result, the final recommendation of the IESO was to maintain the ETS tariff at $1 / MWh. In its final submission[48], the IESO also recommended that that current ETS tariff be maintained at least until the spring of 2013.

*VECC Submissions*

*Adequacy of IESO Study/Stakeholder Process*

40. VECC has serious concerns about the stakeholder process that was carried out in support of the IESO's ETS tariff study. VECC's participation in the overall study was limited due to funding constraints however it did comment on the initial Stakeholder Engagement Plan and followed the process through postings on the IESO web-site and contact with other participants. Up to August 10, 2009 VECC was fairly satisfied with the stakeholder process in that there was an established framework for addressing the issues raised by Export Transmission Tariffs, and the IESO attempted to address issues raised by parties during the process and the conclusions of the study reflected the results of the quantitative and qualitative analysis undertaken. Furthermore, an opportunity was provided on August 10$^{th}$ for parties to comment and clarify the basis for the conclusions reached.

41. VECC's concerns are directly related to the post-August 10$^{th}$ process and the fact that the IESO's final recommendations were fundamentally different from the conclusions reached by the study. VECC recognizes the prerogative of the IESO management to make a recommendation that differs from the results of the Study. However what VECC objects to is the manner in which the final recommendations made by the IESO were arrived at and communicated to participants.[49] No explanation was provided in the report as to why the two factors listed (surplus

[45] Exhibit H1 Tab 5 Schedule 2, pages 2-4
[46] Tr. Vol. 9, page 55, lines 6-14 and Exhibit H1 Tab 5 Schedule 2, pages 4-5
[47] Tr. Vol. 9, page 55
[48] Page 5
[49] Tr. Vol. 9, pages 55-56

situations in low load periods and an increasingly volatile supply/demand balance) were sufficiently compelling to dismiss the findings of the Study and the IESO's original recommendations. Also, no opportunities were provided for stakeholders to understand the rationale for the 180 degree change in direction or to suggest other possible alternatives. Indeed it does not appear that any other options were considered.[50]

42. VECC also questions the IESO's contention that it was not until after the release of the Study's finding on August 10th that true magnitude and import of the changing conditions was understood sufficiently to warrant a fundamental change to the recommendations regarding the ETS tariff. The decline in load, the development of renewable generation and the emergence of surplus base load generation were all events that were on the radar screen starting early in 2009.[51] VECC submits that these are issues that could have (and should have) been raised by the IESO during the course of the study. VECC notes the IESO had already delayed the start of the study for 20 months[52] and asked the OEB for an extension.[53] Given the nature of changes and the IESO's concerns it should have approached the Board for more time.

*IESO Recommendation*

43. The IESO believes that the operational benefits of having a lower export tariff (i.e., to allow it to mitigate and avoid surplus base load generation events) outweigh the benefits of Option #2 – the $5/MWh tariff.[54] In fact, the IESO suggests these benefits ($20 M in 2010) are small when taken in the context of the overall Ontario system.[55] However, VECC notes that these benefits are significantly larger than the benefits Power Advisory has associated[56] with AMPCO's High Five proposal ($2 M).

44. Furthermore, the IESO has indicated that it has a number of other tools at its disposal to manage surplus base load generation.[57] It has not stated that higher levels of exports are necessary in order to manage such surpluses but rather that higher export levels are another tool that they could use.[58] Clearly, higher export levels are something that the IESO believes will make its job of managing the Ontario's electricity system easier. In VECC's view, this is the key factor underlying the IESO's recommendation.

---

[50] Exhibit I Tab 4 Schedule 19 d)
[51] Tr. Vol. 9, pages 62-63
[52] Tr. Vol. 9, page 52
[53] Tr. Vol. 9, page 53
[54] Tr. Vol. 9, page 44
[55] Exhibit H1 Tab 5 Schedule 2, Attachment 1, page 9
[56] Power Advisory Report, page 63
[57] Tr. Vol. 9, pages 45 and 70-71
[58] Tr. Vol. 9, page 46

45. However, in VECC's submission, there is no evidence to suggest that higher export levels are absolutely necessary in order for the IESO to do its job.

46. Also, since the majority of surplus base load generation occurs in the off-peak periods[59], VECC submits there are other ETS tariff options (such as higher peak period ETS tariffs) that could address much of the IESO's operational concerns while providing additional revenues to offset transmission costs for Ontario consumers. While some variations were analyzed as part of the study[60] others (e.g. $5/MWh in peak period $1/MWh in the off-peak) have not. The IESO has acknowledged that such alternative rates are feasible[61].

47. The current ETS tariff rate of $1/MWh has remained unchanged since first approved by the Board in 2000 (EB-1999-0044). One of the key reasons for setting the rate at this (low) level was the view that "open power markets" would eventually evolve.[62] However, this has not occurred and the IESO has indicated that for most of Ontario's neighbouring jurisdictions establishing reciprocal transmission pricing agreements is not a priority.[63] Based on this, the IESO has indicated that it is not proposing to undertake any further discussions on this matter in the near future and the issue is effectively on the "back burner".[64]

48. Based on this lack of interest (both historically and for near term future) in reciprocal agreements, VECC submits that there is no reason to maintain an artificially low ETS tariff based on the view it will eventually be eliminated. Indeed, in VECC's view, this low ETS tariff eliminates most of the incentive for neighbouring jurisdictions to actually pursue reciprocal transmission pricing arrangements.

49. In light of the foregoing, VECC submits that there is no compelling reason to maintain the ETS at its current level. Ontario consumers are facing increasing transmission costs. There is no reason why export customers should bear part of the burden. VECC submits that, <u>at a minimum</u>, the ETS tariff should be increased in line with the increases experienced by Ontario customers paying the Network charge. This would result in an ETS tariff of $1.24 / MWh in 2011 and $1.33/MWh in 2012.[65]

50. VECC submits that the Board should also give serious consideration to approving a time-of-use based export tariff starting in either 2011 or 2012. VECC would recommend a tariff of $2/MWh in peak period and $1/MWh in the off-peak period. Such an approach would retain the existing tariff in the off-peak when most of the surplus base load generation occurs while attempting to capture for Ontario

---

[59] Tr. Vol. 9, page 54
[60] Tr. Vol. 9, pages 66 and 89
[61] Tr. Vol. 9, page 11
[62] Tr. Vol. 9, pages 81-82
[63] Exhibit H1 Tab 5 Schedule 2, page 4
[64] Tr. Vol. 9, pages 83-84
[65] Exhibit I Tab 9 Schedule 2

consumers some of the benefits higher ETS tariffs provide. The choice of 2011 versus 2012 depends on whether the Board believes further input is required from the IESO prior to adopting such a tariff. In VECC's view such an approach is appropriate as it places the onus on the IESO to clearly demonstrate why the tariff should not be adjusted.

*Future Study*

51. VECC has two issues with respect to any future study of ETS tariffs. The first is timing and the second is who should have lead responsibility.

52. The IESO has recommended that the current tariff be maintained at least until the spring of 2013.[66] This is predicated on the view that the first major wave of FIT wind resources will not come on-line until mid way through 2012. Given Hydro One Networks' two-year cycle for its Transmission applications this means that the matter would not be reviewed again until the application for years 2015-2016.

53. VECC finds the suggestion of putting off any further study or consideration of ETS tariffs until this time as unacceptable, particularly if the Board decides to maintain the existing $1/MWh tariff in the interim. The issue of ETS tariffs was first raised in Hydro One Networks' application for 2007-2008 (EB-2006-0501). Parties agreed to a more fulsome study based on the view that there was some opportunity to establish reciprocal arrangements with other jurisdictions and, given this view, the IESO was tasked with the initiative. VECC submits that had the reluctance of neighbouring jurisdictions to pursue such agreements been understood, events may well have unfolded differently and different ETS tariffs could well have been in place by now.

54. The IESO has acknowledged that conditions (including government policy direction) are continually changing and that at any point in time it is necessary to make assumptions.[67] As result, VECC submits that while there may be more information on the impact of FIT-driven renewable generation by 2013 there will likely arise other factors for which the implications are uncertain and need to be taken into account. Furthermore, system operating conditions is only one of the factors to be taken into account when setting tariffs. VECC submits that the subject of ETS tariffs should be subject to further study and proposals brought back to the OEB as part of Hydro One Networks' 2013/14 Application.

55. VECC also submits that Hydro One Networks (and not the IESO) should be tasked with the responsibility for this initiative. As noted earlier, the IESO's responsibility for the current study was predicated by the view that the initiative should include discussions with neighbouring jurisdictions regarding reciprocal

[66] IESO's Written Submissions, page 5
[67] Tr. Vol. 10, pages 96-97

agreements.  In VECC's view this should not be a primary focus of the next study and therefore the IESO does not need to take the lead.

56. Clearly, issues of administration of the tariff and impacts of the tariff on system operation are matters that need to be considered and, on these issues, the IESO's input should be solicited.  However, first and foremost, the initiative should be viewed as a rate design study with the objective of determining the appropriate design for ETS tariffs.  The IESO has acknowledged that rate design is not its area of expertise.[68]  Indeed, it is clear from the evidence that economics and not rate design principles were the primary focus of the IESO in the current study.[69]  This should not be considered a fault on the IESO's part, its responsibility as administrator of electricity market does not require it to have such expertise.  However, VECC submits that such considerations are key in the assessment of appropriate ETS tariffs and that Hydro One Networks (who staff are well versed in such principles) should be accountable for any future study.

*ETS Revenue Variance Account*

57. Hydro One Networks asserts that it has sufficient history to allow for a more accurate forecast of this stream of revenue and continuation of the Export Service Credit Revenue variance account is not necessary.[70]

58. In determining export revenues Hydro One Networks uses the export volume forecast by the IESO.[71]  AMPCO interrogatory #1 sets out the revenues received from export transmission service over the period 2005-2009 and also shows the IESO's forecast for each year.  From this it can be seen that the variance between forecast and actual is still significant.  As a result, VECC submits there is still value maintaining the ETS Revenue Variance Account for 2011 and 2012 and recommends that the Board do so.

59. VECC notes that continuation of the variance account will also address any increased revenue uncertainty that may arise should the Board decide to adopt an ETS tariff for 2011 and/or 2012 that differs from the $1/MWh.

[68] Tr. Vol. 10, page 40
[69] Tr. Vol. 10, page 21, lines 19-24
[70] Exhibit I Tab 6 Schedule 11 c)
[71] Exhibit I Tab 6 Schedule 1 b)

## 3. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

### 3.1 Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

60. Hydro One's evidence[72] is that the 2011 OM&A increase to $436.4 million is $10.2 million or 2.4 % over the 2010 level approved in the last Hydro One transmission rates case ($426.2 million). The 2012 increase to $450.0 million represents 5.6% over two years.

61. In response to Board Staff IR 38[73], Hydro One indicated that it had made reductions of $19.4 million in OM&A costs from the originally planned proposal for 2011. These OM&A reductions were made up of a $12.9 million reduction in Sustaining OM&A and a reduction of $6.5 million in Shared Services and Other Costs. The related reductions for 2012 were a $11.3 million reduction in Sustaining and $8.6 million reduction in Shared Services & Other Costs, for a total OM&A reduction of $19.9 million.[74]

*VECC Submissions*

62. VECC notes that no reductions were made in the Development and Operations OM&A budgets in either test year.

> MR. BUONAGURO: Okay. Can you tell me off the top of your head if any of the amounts came from development? Any of the adjustments, for example, of the 19 million would have come out of these line items under development?
> MR. GREGG: No. It was all sustainment.
> MR. BUONAGURO: Okay. Thank you. [75]

63. Board staff note that, with reference to Exhibit J2.3, the proposed OM&A budget is still $34.5 million above the Hydro One defined "minimum" requirements for 2011 and $37 million above "minimum" requirements for 2012. Board Staff submits that the evidence suggests that further reductions in OM&A spending could be made, in the areas of

64. Development and Operations Costs (excluding compensation), Compensation Costs and Pension Costs.[76]

65. VECC agrees with Board Staff's conclusion with respect to the availability of further reductions in OM&A spending. It is clear from the evidence that although Hydro One has made reductions to OM&A for the test years between its original

---

[72] Exhibit C1 Tab 2 Schedule 1 p. 3
[73] Exhibit I Tab 1 Schedule 38
[74] Tr Vol 7, p. 130
[75] Tr Vol 2 p 162
[76] Board Staff Submissions p 5

levels and its current request, the levels for both test years are well above minimum levels and should be reduced further.

66. To reinforce this conclusion VECC will also make submissions on Hydro One's performance under OM&A cost effectiveness measures and its total compensation costs; in VECC's view the ability of Hydro One to make further cuts to its OM&A budget as set out in this section are in addition to the cuts that VECC submits should be made with respect to compensation costs.

*OM&A Cost Effectiveness Measures and Key Performance Indicators (KPIs)*

67. As noted earlier, VECC IR 1[77] asks for how HONI is compliant with the following Board Directive:

> The Board has directed Hydro One to continue its key performance indicator development and to improve on its cost allocation accounting processes with the objective of being able to demonstrate improvements in efficiency and the value for dollar associated with its compensation costs.[78]

68. Current Key Performance Indicators (KPIs) are listed in response to VECC IR 8. One of the major KPIs that Hydro One focuses on is Tx unit Costs (Capital and O&M) per asset as a major KPI related to Productivity.

$$\text{Transmission Unit Cost} = \frac{\text{Operations and Maintenance (O\&M) costs + Total Capital}}{\text{Asset Value (Gross Fixed Asset (GFA))}}$$

69. This indicator was cited as 10.1% in 2009. The response to Board Staff IR 3 revealed that the transmission unit cost had risen from the 6% level in the 2004 – 2006 period to 10.1% in 2009.[79]

> MR. BUONAGURO: So if we go over the page to table 1, on that simple view of what the measure represents, it looks like in 2004, 2005, 2006, you were hovering around six percent, and that's lower than 2007, 2008 and certainly 2009. So on that simple view of the measure, it looks like you were doing well in the early years, and it's getting worse; is that fair?
> MR. MARCELLO: I think your assessment is fair. However, what you have highlighted is the difficulty with creating a new measure and some of the unattended consequences, and this is one of the subject areas within the benchmarking community, for lack of a better word.[80]

---

[77] Exhibit I Tab 4 Schedule 1
[78] Exhibit A Tab 14 Schedule 1
[79] Exhibit I-1-3 Table 1
[80] Tr. Vol. 4 p 87

70. Hydro One now appears to be rejecting TUC as a relevant measure. VECC suggests that if the TUC results were showing improvements, Hydro One would not be looking for a new measure as it has indicated in response to SEC IR 2.[81] In this IRR Hydro One provided a similar measure, using only sustaining spending.

71. VECC notes that it appears that this measure was showing performance exceeding target, but not changing from 2007 to 2009. Also unit cost indicators appeared to be rising in the test years, showing deterioration in cost performance.

72. Hydro One indicated that it was the sustaining measure that Hydro One would now be using to evaluate transmission unit costs. Undertaking J4.5 showed this measure compared to a composite of CEA transmission utilities with Hydro One showing poorer performance in 2008, the last year data was available.

73. In response to Board staff IR 8[82] Hydro One provided additional detail on benchmarking results in a survey undertaken by First Quartile Consulting in 2009. While there was some confusion as to the actual measures highlighted, Exhibit J4.6 provided some clarity on these measures.

74. VECC notes that other Common KPIs include unit costs/customer and per Gw transmitted. These unit cost indicators are rising in the test years, showing deterioration in cost performance. [83]

Another measure is OM&A per line km:

> MS. LEA: Then the last interrogatory I wanted to refer you to was Board Staff Interrogatory No. 37, Exhibit I, tab 1, 37, please.
> And here we see an O&M per cost of kilometre transmission line, and also per gross fixed assets.
> It looks to us that the O&M per gross fixed assets is pretty steady, but the O&M per kilometre of line seems to be increasing, which would indicate, I guess, a deterioration of performance.
> Have you any comment to make as to why this is? And in your answer, could you consider whether -- again, is it this build-out question? Is it partly driven by how much is coming into service in any given time?
>
> MR. JUHN: I can speak to this. I guess if we are looking at OM&A per kilometre for 2008, if you recall, there was a Bernard fire and -- a transformer fire, and we received a credit of about close to $9 million. That skews the number slightly. So in terms of -- in terms of the increase, yes, there is an increase, but it doesn't fall to the extent that one would look -- that one would see from the OM&A per kilometre.

[81] Exhibit I-7-2,
[82] Exhibit I-1-8,
[83] Exhibit I/4/21

> And then if you take that out, the increase, 2010-2011 or so, we are looking at in the neighbourhood of close to three percent, somewhere in that neighbourhood. That sort of aligns with our OM&A needs.[84]

75. VECC submits that the Board Directive[85] was specifically focused on improved productivity and compensation costs:

> The Board directs Hydro One to continue its key performance indicator development and to improve on its cost allocation accounting processes with the objective of being able to demonstrate improvements in efficiency and the value for dollar associated with its compensation costs.[86]

76. In VECC's submission, the evidence is clear, despite Hydro Ones gloss, that Hydro One Tx is not demonstrating improved operational productivity performance. VECC submits that the Board should take this conclusion into consideration when deciding on the appropriateness of reductions in Hydro One's total compensation, as suggested Total Compensation costs are addressed under Issue 3.3 below.

**3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?**

**3.5 Are the methodologies used to allocate Shared Services and Other O&M costs to the transmission business and to determine the transmission overhead capitalization rate for 2011/12 appropriate?**

77. Hydro One Shared Services are comprised of Common Corporate Functions and Services ("CCFS"), Asset Management Services, Information Technology ("IT"), Cornerstone, Cost of Sales to external parties and Other OM&A.[87] The total Shared Services costs for the test years are $297.2M for 2011 and $309.8M for 2012.

78. The major increases in Shared Services costs relative to 2009/2010 are: CCFS, $7.8M for 2011 and $14.8M for 2012 and Information Technology, $11.3M for 2011 and $12.3M for 2012. Other OMA is an offset is comprised of Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs.[88]

*CCFS Costs*

79. Shared Services CCFS OM&A costs are common costs shared within the HO Corporation. The costs allocated to each entity are based on the Rudden (now Black

[84] Tr. Vol. 4 p 143
[85] Exhibit A Tab 16
[86] EB-2008-0272 Decision Page 31
[87] Exhibit C1 Tab 2 Schedule 6
[88] Exhibit C1 Tab 2 Schedule 7 Page 27 Table 11

and Veatch) methodology. The 2011-12 costs were reviewed in 2009 by B&V. HONI is the main service provider but also pays for services to Corporate and Telecom.[89]

80. The main areas of Total CCFS cost increases relative to 2009 are: Corporate Communications, $2.3 million for 2011 and $6.5 million for 2012; General Counsel and Secretariat $2.6M for 2011 (with a $0.6 million decrease in 2012); and Real Estate and Facilities, $3.4M in 2011 and $4.4M in 2012.

.

*VECC submissions*

81. Hydro One has provided reasonable explanations for several of these cost increases.[90] Nonetheless VECC submits there is no evidence of constraint being applied.

82. VECC submits that one particular area that warrants a reduction is the $5 million increase in corporate communications related to GEGEA activities.[91] Given the uncertainties about the resumption of work on GEGEA projects these costs should be removed from the OM&A budget and any required expenses recorded in the deferral account.

*Service Level Agreements for the Test Years*

83. The Affiliate Relations Code (ARC) requires that services between affiliates are performed under Service Level Agreements. The 2011 and 2012 Affiliate Services Agreements have not been provided to support changes in costs for 2011-2012. Hydro Ones position is:

> As noted in Exhibit I, Tab 4, Schedule 33, affiliate service agreements for shared services are only signed for a one year term (current year). During Hydro One's annual planning process the cost allocation model is updated using the common cost methodology described in Exhibit C1, Tab 5, Schedule 1. The allocated costs from this model are incorporated into the signed affiliate service agreements (Exhibit A, Tab 7, Schedule 3 Appendices A & B) for the first year of the planning cycle (2010 – for this application). Cost allocation results for the remaining years of the planning cycle (2011-12 in this application) are used for business planning purposes.[92]

*VECC Submissions*

84. VECC notes that the CCFS Costs and the allocation to the corporate family[93] for 2011 incorporate changes from the 2010 Service Level Agreement [94] and Schedule

---

[89] Exhibit C1 Tab 2 Schedule 7 Page 2 Table 1
[90] Exhibit C1Tab 2 Schedule 7 Pages 1-30
[91] Ibid page 13
[92] Undertaking J5.5
[93] Exhibit I Tab 4 Schedule 34 Page 4 part e

A thereto. For example, for HO Brampton the 2011 service costs have gone down from 2010 $674,000 to $624,000 (- $50,000) and for 2012 to $587,000 (-$87,000). These changes are not reflected in the 2010 Service Level Agreement for obvious reasons and the draft 2011 and 2012 SLAs have not been filed. The impact of this is that higher costs will be retained by Hydro One (and lower costs charged to HONI Brampton) and there is no support for the change in level of service related to this.

85. The ARC requires utilities to file Service Level Agreements or the fee schedules thereto in order to support the costs being charged between affiliates in the rate year. The existence of an approved cost allocation methodology does not address changes in individual service levels.

86. As noted above, Hydro One has 4 affiliates and several SLAs are executed each year. VECC submits that it is not appropriate that the Board does not have the 2011 Service Level Agreements or even the 2011 and 2012 Pricing Schedules on the record. Therefore neither intervenors nor the Board can easily ascertain how/why the costs and levels of service will change in 2011 and 2012.

87. VECC submits that in accordance with ARC Hydro One should file draft SLAs (or the service cost schedules to these) for each forward test year that correspond to the CCFS costs being claimed and allocated to each member of the Corporate filing in those test years.

*Business Telecom Services*

88. One of the areas of past concern under CCFS continues to be Business/Telecom Services. Hydro One sets out its position in the response to VECC IR 31:[95]

> a) The increases in Telecom Services cost in 2011 and 2012 are due to increases in labour costs as per collective agreements and increases in service capacity to continue to meet HON business and power system operations demands.
>
> b) The annual cost for Telecom Services (in $Thousands) is: 9,002 in 2008; 9,567 in 2009; 10,208 in 2010; 10,739 in 2011; and 11,297 in 2012.
>
> c) The year over year percentage increase is 6.3% from 2008-09, 6.7% from 2009-10, 5.2% from 2010-11, and 5.2% from 2011-12. This equates to a 25.5% overall increase for the five years from 2008 to 2012.

*VECC Submissions*

89. Since neither VECC nor the Board have the 2011 and 2012 SLAs it is not possible to check the veracity of the claimed increase in service level.

---

[94] A/7/03 Appendix B

[95] Exhibit I Tab 4 Schedule 31 parts a, b ,c

90. VECC's concerns about the cost effectiveness of the Telecom Services are answered by Hydro One pointing to a two year old report:[96]

> e) Hydro One Networks engaged the Shpigler Group, a strategy management consulting firm specializing in telecommunication and technology, in 2006 and 2008 to perform an independent service review and market benchmarking assessment for the services provided by its telecom affiliate. The report concluded the contracted costs are indicative of fair market value. The reports reaffirmed the conclusion that Hydro One obtains commercial and operations benefit through its relationship with Hydro One Telecom. These costs were deemed acceptable by the Board in the EB-2008-0272 Transmission proceedings. *Considering the services in 2011 and 2012 are an extension of existing services provided by Hydro One Telecom, Hydro One Networks feels the costs are consistent with the findings of the previous reports. [emphasis added]*

91. VECC suggests that the evidence on fair market value to support the 2011/2012 increase in Business Telecom Costs for the test years is inadequate and the Board should direct Hydro One to provide another independent benchmarking study in the next rates case. (Dx or Tx)

**3.3 Are the 2011/12 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?**

92. As noted earlier Hydro One has been directed to reduce costs in this area and states it is fully compliant with the Board's Directive in this regard.

*VECC Submissions*

93. VECC submits that Hydro One's 2011 and 2012 Total Compensation costs are not in compliance with the Board's Direction in the EB-2008-0272 case.[97] Also HONI is still not able/willing to provide an estimate of Total Compensation costs that relates to the applied-for revenue requirement including an appropriate allocation to Dx and Tx.

*Compliance with the Board's direction re reducing payroll/total compensation costs*

94. From the evidence VECC suggests that the primary driver of higher 2011/2012 compensation costs is increases in headcount, secondary is the fact that salaries continue to be above industry norms based on Mercer Compensation studies and thirdly that salaries are increasing at a rate above inflation.

[96] Ibid part e
[97] Exhibit ATab14 Schedule 1

95. VECC's first concern regarding increases in headcount is illustrated by this exchange:

> MR. SHEPHERD: Witnesses, I wonder if you could turn up Exhibit I, tab 1, schedule 54. I am moving into a new area, the number of staff you have and your staff additions.
> I take it this is you, Mr. Goldie?
> MR. GOLDIE: Yes, I am there.
> MR. SHEPHERD: Thanks. So this interrogatory response appears to say that your total number of employees is increasing over six years from 5,301 to 8,938, a total of 3,637 people, almost 70 percent; is that right?
> MR. GOLDIE: That's correct.
> MR. SHEPHERD: So on average, you are adding just a little over 600 people a year, right?
> MR. GOLDIE: Yes. [98]

96. Hydro One plans to add over 500 employees to their head count from 2010 to 2012[99]. Another contributing factor to higher headcounts and Payroll costs than forecast is the fact that forecast retirements have been dramatically overstated.[100]

97. Accordingly VECC submits that total Head Counts required to perform the Sustaining and Operations OM&A and Capital programs are likely to be overstated and the headcount increases should be reduced by about 50 FTEs to recognize lower retirement rates.

*Historic in year increases in headcount and costs -lack of control*

98. VECC asked Hydro One to provide actual and Board Approved Total Compensation Cost comparisons for 2009 and 2010. [101]

99. The Total Wages in VECC IRR 35 show a difference between Board approved EB-2008-0272 forecast and actual for 2009 of over $34.2M; for 2010 the difference between actual and forecast is $125.2M. The driver for these variances is increases in headcount.

100. VECC submits that this historic data clearly demonstrate a lack of control of compensation costs primarily due to not forecasting and controlling in-year increases in headcount.

101. VECC notes again that HONI is still not either able/willing to provide an estimate of Total Compensation Costs that relates to the applied for revenue requirement including an appropriate allocation to Dx and Tx. VECC submits that the Total

[98] Tr. Vol 5 p 61
[99] Exhibit I Tab 4 Sch 35
[100] Tr. Vol. 5 Pages 91-98 and Undertaking J5.3
[101] Ibid 26 Attachment 2

Compensation data and headcount data filed in support of the test year revenue requirement cannot be relied on by either intervenors or the Board.

> MR. SHEPHERD: So I am looking at the (I/4/35) interrogatory response on page 1, and it says -- with respect to attachment 1, it says:
>
> > "Refer to Attachment 1 which is an updated version of the EB-2008-0272 Exhibit..."
> >
> > And then it says, and by the way:
> >
> > "The Total Wages for 2010 found at Exhibit C1 Tab 3 Schedule 2 page 9 Table 3 should read $745.1 M and it has been updated in this Attachment."
>
> But you are saying that regardless of that, this attachment simply doesn't relate to your rate application?
>
> MR. McDONELL: We had to make -- yes, that is correct. As I said before, we have not revised the head count as a result of our original planning in March.
> MR. SHEPHERD: I am not asking you about the head count now. I am asking you about the dollars. These three pages are full of dollar figures. None of those are right either?
> MR. McDONELL: Well, when you say "right", I mean, I keep going back to these dollar figures are not tied to our revenue requirements. They're there to show directionally where we are headed. [102]

102. VECC submits that VECC IR 35 and this transcript exchange clearly illustrate that in order for the Board to exercise control over Hydro One's Total Compensation costs there has to be a test year forecast for each of Distribution and Transmission that can provide the evidentiary basis for approval of the revenue requirements for each operating company and against which ratepayers can assess the actual to forecast historic costs.

103. VECC notes that the Boards Filing Guidelines[103] at Section 2.5.4 include the requirement to provide a breakdown of employee compensation and to complete Appendix 2L *for <u>each applicant</u>.* VECC urges the Board to require Hydro One to file historic and test year Total Compensation Costs separately for DX and TX in accordance with the Board's Filing Guidelines.

*Reduction of 2011 and 2012 Headcount*

104. For all of the reasons discussed above, the Board should reduce approved 2011 and 2012 headcounts by 50 FTEs and reduce Compensation-related OM&A by average Base Pay of $75,000 per FTE.[104] This amounts to about a $3.75 million reduction in OM&A in each year.

---

[102] Tr. Vol. 5 p 66
[103] May 27,2009 Chapter 2
[104] Exhibit I-4-35 Attachment 1

*2011 and 2012 average compensation levels*

105. In its EB-2008-0272 Decision the Board noted that Hydro One's average compensation levels as found a Mercer Study were 17% above median. Hydro One confirmed that the Mercer study as filed in the EB-2009-0272 proceeding was not updated as the data is still "quite recent and the study would be very costly to update.[105]

106. In Undertaking J5.10, Hydro One provided a current estimate for a reduction in compensation costs comparable to the (Mercer study related) OM&A reduction of $4 million ordered by the Board in the EB-2008-0272 case.

107. Board Staff suggest that the comparable reduction in this proceeding should be $6.2 million in 2011 and $6.9 million in 2012. [106]

*VECC Submission*

108. VECC asks the Board to adopt the reductions indicated in Undertaking J5.10, estimated at $6.2 million in 2011 and $6.9 million in 2012. [107]

*Benchmarking to industry-wide compensation levels*

109. HONI uses data from OPG and Bruce Power to demonstrate that it has done a better job mitigating wage increases.[108]

110. VECC suggests that this is the wrong comparison, and that industry wide comparisons are more meaningful. These are discussed in the evidence and recent examples provided in Undertaking J4.7. This shows Hydro One to be at about the median of the utilities surveyed. However VECC suggests that to be meaningful, a wage comparison survey should include annual cost of living data for the comparator group.

111. VECC submits that Hydro One should be directed to provide in the next rates case (Dx or Tx) a new wage comparison study that includes cost of living data for the cohort.

*Pension Costs*

112. HONI pension costs are allocated to Dx and Tx. Also the Inergi outsourcing contract contains provision for payment of pension costs to former HONI employees.[109]

[105] Exhibit I Tab1 Schedule 56
[106] Board Staff Submissions p 6
[107] Undertaking J5.10
[108] Exhibit C1Tab3Schedule 2

113. VECC questions why Inergi has not taken over the pension obligations as part of the contract renewal.

114. Hydro One's last Pension plan actuarial valuation was prepared as at December 31, 2009 and filed with FSCO in September 2010. The valuation depends on investment returns, changes in benefits, and actuarial assumptions. A summary is attached to Board staff IR 60.

115. This Summary shows a deficit of $140Mcompared to $114M in the last valuation. Accordingly, HONI will need to increase annual payments by $26M in 2011 and by $22M in 2012.

116. Hydro One indicated that for 2010 the actuarial evaluation would result in approximately $20Mbeing placed in a deferral account. However, for 2011 and 2012 the company would absorb the O&M portion of the additional cost resulting in no impact in 2011 or 2012 or in the future.[110]

117. The issue was addressed again in the hearing:

> MR. STRUTHERS: No, we are not. What we are asking for variance – what we are asking for in the variance accounts is differences from the 100 and -- I think it is $139 million, because it will change based on number of employees and other items.
> Sorry, the 2010 number goes into variance, but the -- sorry, I am looking forward into 2011.
> MR. SHEPHERD: Yes.
> MR. STRUTHERS: So 2011 and 2012, what we are proposing is that where it differs off of the 140, as a result of other changes -- number of employees, whatever -- that we would put that into variance. But the difference between the 120 and 140 we would not put into the variance account in 2011.
> As I say, there are other gives and takes.
> MR. SHEPHERD: Wonderful. I have no further questions, then.[111]

118. Hydro One's evidence is that employees contribute about 20% of the cost of the pension plan. In response to Undertaking J7.2, Hydro One provided some information on other pension plans with regard to employee contributions, which showed Hydro One to be at about the median of the companies surveyed.

119. Board staff submits that Hydro One, as part of its collective bargaining process, should consider an increase in employee contribution share of pension plan costs. In addition, in terms of performance, a ranking at the 61st percentile is also a concern. Board Staff, while not submitting that the Board should deny Hydro One recovery of

[109] Exhibit C1 Tab3 Schedule 2 Appendix A
[110] Tr. Vol. 7, page 136
[111] Tr. Vol. 7 .p 101

its pension costs at this time, suggests that the Board should encourage Hydro One to continue to take steps to improve the performance of the plan so as to reduce costs and the resulting burden on ratepayers.

120. VECC submits that Hydro One is a public corporation and should aim to fund 50% of pension contributions and proceed to make this an issue in negotiating collective agreements.

*Development OM&A Cost Increases*

121. Hydro Ones 2011 budget for Research, Development and Demonstration is $6.4 million. For 2012 the budget is $6.6 million. The RD&D budget is for testing the feasibility of emerging technologies. It involves pilot and demonstration projects and partnerships with Universities etc. Under cross examination HON admitted that these expenditures are set out at a high level with no definitive project by project analysis.[112]

122. In addition, HON has a $4 million budget in the test years for Smart Grid Development. However there is nothing on the record in this case which provides a business case analysis for these Expenditures. [113]

123. VECC submits that in the interests of cost containment and in the absence of any business case analysis these budgets can and should be reduced by 50%, for a total reduction of $5.2M per test year.

*OM&A Costs -Summary of Submissions*

124. VECC agrees with Board Staff's assessment that additional reductions in OM&A costs can be achieved with minimal impact on service performance. This conclusion is based on:

- Current reductions instituted to address rate impact concerns are small as a proportion of total costs;
- No cuts were made in development and operations budgets despite the growth of these budgets for both areas and in some cases presumed reduced development work load;
- Unit cost measures show more efficiency can be achieved (e.g. OM&A per km of line, transmission unit costs trends and transmission substation expense);
- Reliability measures show good performance, and additional resources to further enhance performance at this time may not be warranted; and
- Compensation costs continue to exceed reasonable levels.[114]

---

[112] Tr. Vol. 2 p 129-131
[113] Ibid p 131
**[114]** Board Staff Submissions page 9

125. VECC asks the board to reduce the OM&A envelopes closer to minimum levels for 2011 and 2012. Specific areas of reductions include compensation, Corporate Communications and the Development OM&A for RD&D and Smart Grid Development.

126. As noted above, test year headcounts are likely overstated and VECC also asks the Board to reduce approved head counts by 50 FTEs for each of the test years. The OM&A reduction related to this is $3.75M based on average compensation of $75,000 per FTE and is in addition to reductions to recognize above average compensation costs per employee.

127. In addition, VECC asks the Board to adopt the specific reductions indicated in Undertaking J5.10, comparable to the (Mercer study related) OM&A reduction of $4 million ordered by the Board in the EB-2008-0272 case. The comparable reduction in this proceeding was estimated at $6.2 million in 2011 and $6.9 million in 2012.[115]

128. VECC also submits that Corporate Communications costs should be reduced by $5M due to uncertainties about the GE Plan.

129. As noted above, VECC submits that the RD&D and Smart Grid Budgets should each be reduced by 50% for a total reduction of $5.2M in each of the test years.

130. VECC also asks the Board to direct Hydro One to bring its pension contribution cost (share) in line with public sector norms as an objective during collective bargaining.

### 3.6 Are the amount proposed to be included in the 2011 and 2012 revenue requirements for income and other taxes appropriate

*Apprentice Training Tax Credits*

131. Hydro One has estimated the amount that it will receive in tax credits from apprenticeship training support programs:[116]

> MR. AIKEN: Okay. My final area of questioning is related to the tax credits, the apprenticeship training tax credit, the federal training tax credit and the co-op education tax credit.
> My understanding is that Hydro One has calculated the tax credits for 2011 and 2012 related to these items to be $2.2 million. This figure is shown in Exhibit C2, tab 5, schedule 1 at attachment 1, I believe.
> MR. STRUTHERS: Yes, I see it on line 21.
> MR. AIKEN: Yes.

[115] Undertaking J5.10

[116] Exhibit C2 Tab 5 Schedule 1 Attach 1

And now if I could have you turn up Exhibit I, tab 6, schedule 18, so this is BOMA 18. The response to this interrogatory indicates that the 2.2 million of tax credits was estimated in November 2009 at approximately 120 percent of the 2008 tax credits claimed by Hydro One in your 2008 tax return.
If you look at attachment 1 to BOMA 18, in the middle table -- that shows 2008 -- there are transmission tax credits of 1.79 million. And so I take it that by increasing by the 120 percent, that is how the $2.2 million was arrived at; is that correct? MR. STRUTHERS: I believe that's correct, yes.
MR. AIKEN: Am I also correct that the actual transmission tax credits for 2009 were more than 3.1 million?
MR. STRUTHERS: Yes, that's what is shown on that schedule.[117]

132. In Undertaking J6.13 Hydro One estimates the number of apprenticeship positions for transmission that may qualify for the Federal and Ontario Apprenticeship Tax Credit:

| | **2011** | **2012** |
|---|---|---|
| Ontario Apprenticeship Tax Credit | 273 | 270 |
| Federal Apprenticeship Tax Credit | 140 | 107 |

133. HONI notes that the certain additional factors are to be considered when calculating the actual amount of the tax credit for each eligible position.

134. Based on the evidence VECC submits that Hydro One has underestimated the Apprentice Training tax credit by at least $1M, for each test year, a reduction over the test period of approximately $2M.

## 4. CAPITAL EXPENDITURES and RATE BASE

### 4.1 Are the amounts proposed for rate base in 2011 and 2012 appropriate?

135. Hydro One's Total Rate base for 2011 and 2012 is $8,378.5M and $9,134.6M respectively. For 2011, the proposed rate base is 9.7% higher than the approved rate base for 2010 of $7,636M. Forecast 2010 bridge year rate base is $7,336M, 3.9% below 2010 approved.[118]

136. Working capital is forecast to be $24.5M for 2011 (11.7% of OM&A and Cost of Power expenses) and $26.7M for 2012.

137. In service capital additions are forecast at $798.2M for 2010, $870.6M for 2011 and $1,618.8M for 2012.

[117] Tr. Vol. 6 Page122
[118] Exhibit A Tab 14 Schedule 1 and Exhibit D1 Tab 1 Schedule 1&2

138. VECC submits that the ratebase amounts proposed for 2011 and 2012 are too high and should be reduced based on lower Capital Expenditures and Working Capital allowances as addressed below.

**4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?**

139. Hydro One's planning process includes determination of minimum spending levels for Capital Expenditures in each category of expense.

140. VECC IR 29 ostensibly shows these levels for Capital Expenditures for the two test years.[119] The May 13th 2010 memo[120] and attachment 1 shows the 2011 Capital Expenditure Plan. The changes from the original plan are shown in Undertaking J2.2.

141. VECC submits that the evidence is clear that in the Sustaining Capital area Hydro One made no reductions and the Minimum Level is $84.2 million below the requested level of $424.9 million for 2011:[121]

> MR. BUONAGURO: Thank you. Maybe I just want to clarify. Was the potential for cuts in sustaining looked at as part of the process? I am just trying to see what level of direction, or -- I think it was suggested to you, for example, that you may have been told to cut 20 million, and you said, No, that's not the case. You were told to look at the budget and see where you might make cuts.
> Were you given that same direction in the capital side of the sustaining and just reached the conclusion that you didn't think there was anything to recommend, or did you just focus on the OM&A?
> MR. JUHN: In terms of direction I was given, was to reduce or see where there were potential reductions and --
> MR. BUONAGURO: Without any specification one way or the other, OM&A versus capital?
> MR. JUHN: There was a leaning towards OM&A, but it didn't exclude capital.
> MR. BUONAGURO: Thank you.[122]

142. VECC submits that the Board should infer that the proposed 2011/2012 spending remains at a level sufficiently in excess of minimum level spending to allow for further reductions in the spending (through reduced workplans) in recognition of the need to control spending escalation in the current economic climate, This approach is parallel to the Board's Decision regarding Hydro One's Dx Application (EB-2009-0096).

---

[119] Exhibit I Tab 4 Schedule 29
[120] Exhibit I Tab 3, Schedule 1
[121] Undertaking J2.3 (update of Exhibit I Tab 4 Schedule 29)
[122] Tr. Vol. 4 p 96

**4.5 Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?**

143. The test year working calculation as filed[123] is based on the Navigant Report.

*Impact of GST/HST change on Working Capital for 2010 -2012*

*VECC Submission*

144. VECC notes that Hydro One has not reflected the impact of the GST/HST change in the Working Capital requirement for the test years.

145. The response to VECC IR 41 (Table 1 of which corresponds to D1-01-03 with details in Table 2 of response) shows that the GST/HST change will result in a significant reduction in Working Capital for test years 2011-12,[124] as discussed at the oral hearing:

> MR. AIKEN: Now, the revenue requirement impact of the net reduction in rate base is about 6.3 million in 2011 and 8.4 million in 2012 related to these changes, primarily HST driven.
> Is Hydro One proposing to track, in deferral account 1592, the impact on the revenue requirement, or are you actually now -- or are you now proposing to reflect the change in the working cash of the change because of the HST in the current application?
> [Witness panel confers]
> MR. FRASER: There we go. Sorry.
> I think the company's view was that the revenue requirement impact of the HST would go into the deferral account, so that would be a comprehensive impact coming off the rate base.
> So this would be a rate base impact. It would be recorded there, as well.[125]

146. VECC submits that the impact of the HST/PST Tax change on Working Capital requirements for 2010, 2011 and 2012 should be reflected *directly* in a reduced 2011 and 2012 rate base and revenue requirement help mitigate rate impacts for customers, with only the variation in those impacts to be recorded in the tax variance account.

147. This results in Revenue Requirement reductions of approximately $1 million in each test year.

---

[123] D1-01-03 and Attachment (Navigant Report on WC for 2011-2011)
[124] Exhibit I Tab 4 Schedule 41
[125] Tr. Vol. 6 p 114

## 5. COST OF CAPITAL/CAPITAL STRUCTURE

### 5.1 Is the proposed capital structure appropriate?

### 5.2 Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?

148. VECC has no submissions on the 2011/2012 Capital Structure and Return on Equity or cost of short term debt, except to note that Hydro One has indicated that the latter forecast rates will be updated prior to the issuance of the rate orders for 2011 and 2012.

149. Hydro One has assumed that the return on equity for each test year will be updated in accordance with the Cost of Capital Report. For rates effective January 1, 2011, the Board would determine the ROE for Hydro One Transmission based on the September 2010 Consensus Forecasts and Bank of Canada data which would be available in October 2010 and the change in the spread of the A-rated Utility Bond Yield. For rates effective January 1, 2012 a similar update would take place in the fall of 2011.[126]

150. VECC is satisfied with this undertaking.

### 5.3 Is the forecast of long term debt for 2010-2012 appropriate?

*Historic Debt Forecasts 2009-2010*

151. The response to VECC IR 48 shows Historic 2009-2010 Total Debt and Carrying Cost Forecast (Board approved) New Debt as $1,722.2M with annual carrying cost of $69.7M. The Actual New 2009-2010 Debt (forecast from to September 2010) is $1,275Mwith annual carrying costs of $46.06M, a difference of $23.7M.[127]

*2011 and 2012 Forecast Medium-Long Term Debt Forecast[128]*

152. HONI has declined to update its 2011-2012 interest rate forecast for new debt to match the latest economic forecast supplied in response to BS, BOMA and VECC interrogatories.[129]

153. However HONI has provided an Updated forecast in BOMA IR 33. The Actual 2010 issues and rates have been provided By Hydro One:

> MR. AIKEN: Can you provide the amounts and the rates?
> MR. STRUTHERS: The amount would have been $250 million, blended, I

[126] Exhibit I Tab 4 Schedule 49
[127] Exhibit I Tab 4 Schedule 48
[128] Exhibit B1 Tab 2 Schedule 1Table 4; Exhibit B2 Tab 1 Schedule 2/Page
[129] VECC IRR#49 c)

believe, at about 3.95 percent. But we can provide you with the exact numbers. It was two issues, 250 each, and then they get allocated.
MR. AIKEN: Okay. Yes, I would like to have those numbers provided, please.
MR. STRUTHERS: I can actually give you the amounts.
It was 500 million at 2.95 percent. That was the five-year –- sorry, 250 million at 2.95. 250 million at 4.95, and that was the 30-year.So it is a matter of how they get blended.[130]

*Board Staff Submission*

154. Board Staff notes in its submission[131] that in response to VECC IR 49 Hydro One indicated that it would not be updating its 2011 and 2012 debt costs.

155. Board Staff submitted that the cost of long-term debt used by Hydro One should be updated to reflect the actual debt instruments used by the utility as noted on page 53 of the Cost of Capital Report.

156. Board Staff also submitted that, as shown in response to BOMA IR 33, Hydro One Networks has executed some of the new debt forecast and Board staff submits that actual interest expense in the test years based on the actual terms for this recent debt, rather than the forecast expense in the application, should be reflected in the determination of the test year revenue requirement and distribution rates in compliance with the Cost of Capital Report.[132]

157. VECC IR 49 d) indicates that based on the 2011 and 2012 financing plan, the revenue requirement impact of a 10 basis point change in the average effective coupon rate for new debt is $0.5M and $1.3M in 2011 and 2012, respectively.

*2011 and 2012 Weighted Average Debt Costs*

158. VECC submits that there are two approaches to updating the cost of debt for 2011 and 2012 other than ordering Hydro One to provide an updated forecast. The first is to estimate the coupon rates and debt issues and costs forecast for 2011 and 2012 based on the rates experienced in 2010 as Board Staff suggest. However, Board Staff have not estimated the impact of this approach.

159. The second is to use the information provided in BOMA IR 36:

MR. AIKEN: When I look at the second page of attachment 1, which shows that the costs of long-term debt for 2011, I see a projected average embedded cost rate of 5.62 percent, and that is compared to the original evidence at Exhibit B2, tab 1, schedule 2, page 5, that shows a rate of 5.67 percent. Would you accept, subject to check, that applying this five-basis-point reduction to the deemed

[130] Tr. Vol. 6 p 117
[131] Board Staff Submissions page 20
[132] Ibid page 21

amount of long-term debt of almost 4.7 billion shown in Exhibit B2, tab 1, schedule 1, results in a reduction in debt costs of about 2.3 million in 2011?
MR. STRUTHERS: Subject to check, yes, I will accept that.
MR. AIKEN: Yes. In 2012, the original evidence shows a rate of 5.64 percent. Page 3 of attachment 1 shows a reduction to 5.56 percent.
MR. STRUTHERS: Yes.
MR. AIKEN: So it's eight basis points times 5.1 billion is about 4.1 million?
MR. STRUTHERS: Yes, subject to check.[133]

160. VECC submits that that Hydro One had ample opportunity to update its 2011 and 2012 forecast debt costs and has chosen to rely on outdated forecasts. It also has a history of overestimating new debt costs.[134] Accepting Hydro Ones forecast will result in charging ratepayers too much for new debt until the next rate case in 2013.

161. VECC submits that based on the evidence, the Board should reduce the allowed Medium-Long Term embedded weighted average debt costs for 2011 and 2012 by $2.3 million and $4.1 million respectively.

## 6. DEFERRAL/VARIANCE ACCOUNTS

### 6.1 Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Hydro One is proposing to continue its existing deferral accounts with the exceptions as noted below.

*Disposition of Deferral Account Balances*

162. Hydro One has requested disposal of a credit balance of $7.4 million in each of the two test years:[135]

> Hydro One is requesting disposition of negative regulatory asset balances (credit to customers) over a twelve month period, rather than a twenty-four month period, in order to mitigate rate impacts to customers in 2011. Where the regulatory asset is positive, (debit to customers) Hydro One is requesting to recover the balance over twenty-four months for rate smoothing purposes.[136]

163. VECC questions what smoothing effect is achieved by disposition of $5.1Mover 24 months as opposed to 12 months. VECC's preference in the circumstances of this particular case would be to match the credits and the debits in the same period to, as much as possible, offset the two impacts, rather than possibly create an increase in

[133] Tr. Vol. 6 page 118
[134] Exhibit I Tab 4 Schedule 48
[135] Exhibit F1 Tab 2 Schedule 1
[136] Exhibit I Tab 4 Schedule 51

total rates in 2012 as a result of the credit being advanced for only 12 months and the removed, while the debit continues to be collected for an additional 12 months.

*Continuation of External Revenue Accounts*

164. Hydro One proposes to discontinue the following 3 variance accounts in 2011 and 2012:

- Export Service Credit Revenue
- External Secondary Land Use Revenue
- External Station Maintenance and E&CS Revenue

165. VECC agrees with Board Staff's recommendation that Hydro One continue to track the variances for the above 3 revenue accounts and refers the Board to VECC's submissions under the heading Other Revenues.

**6.3 Are the proposed new Deferral and Variance Accounts appropriate?**

166. Hydro One requests approval to establish 7 new deferral accounts for Hydro One Transmission as follows:[137]

- Impact for Changes in IFRS Account (2012 only)
- IFRS - Gains and Losses Account (2012 only)
- IFRS Incremental Transition Costs Account
- Pension Cost Differential Account
- Long-term Project Development OM&A Account
- Tax Rate Changes Account
- OEB Cost Differential Account

*VECC Submissions*

167. VECC's submissions the proposals to continue/establish these accounts in 2011 or, in the case of IFRS, for 2012 are detailed below.

*Changes in IFRS Accounting*

168. Some Distributors expect to experience an offsetting reduction in their revenue requirement calculation from reduced depreciation expense. Hydro One states it will not experience this offset as it already uses an asset hierarchy which is IFRS-compliant in respect of asset componentization. Further, service lives under Canadian generally accepted accounting principles have been based on previously

[137] Exhibit F1 Tab 1 Schedule 2

approved independent asset service life studies, the recommendations of which were implemented in 2007.[138]

169. There are two exceptions to IFRS accounting requested by Hydro One:

The first requested exception is to allow Hydro One Transmission to continue to capitalize expenditures such as training, CSF&S and line supervision that would not be capitalizable under IAS 16. This is necessary in order to mitigate a likely material classification shift of Hydro One's expenditures from capital to OM&A, and the consequential increase in Transmission rates, which would result from following the requirements of IAS 16.

The second exception requested is for a new variance account to hold gains and losses on tangible and intangible asset sales or losses resulting from premature asset retirements. Under CGAAP, using group depreciation, most asset losses were charged to accumulated depreciation and recovered over the remaining service life of other related assets. Group depreciation was an efficient and fair mechanism for ensuring that the costs of PP&E assets were fully recovered from customers. However, its use is not consistent with IFRS. Under IAS 16, each item of PP&E must be separately depreciated and gains and losses on sales, and losses on premature retirements, for every asset component will be reflected as a current period charge in the Statement of Operations.

170. With regard to the first exception the impact is discussed below:

MR. AIKEN: Okay. And if the Board does not approve your exemption request, that amount or the actual amount would be recorded in the deferral account that you are requesting; is that correct?
MR. FRASER: I should point out we are still working on the -- on refining that. It is a very -- somewhat tortuous process that we have to get approval from our external auditors as to which elements of overhead they will accept as capital. So it is a bit of an iterative process, but we've gotten most of it dealt with now and we have solid positions. So the $200 million is a fairly solid number. It is subject to further revision and -- well, just to make it more precise, order of magnitude, I would say it is fairly -- we're fairly confident that is the amount.[139]

171. The second exception requested by Hydro One is for a new variance account to hold gains and losses on tangible and intangible asset sales or losses resulting from premature asset retirements.[140]

172. Hydro One stated that under CGAAP, using group depreciation, most asset losses were charged to accumulated depreciation and recovered over the remaining service life of other related assets. However using group depreciation is not

[138] Exhibit A Tab 11 Schedule 3 and Exhibit 1Tab 1 Schedule 19
[139] Tr. Vol. 6 p 122
[140] Exhibit A Tab 11 Schedule 3 and Exhibit ITab1Schedule 92

consistent with IFRS. Hydro One states that it has requested this account because it cannot reasonably forecast the losses to be incurred upon premature asset retirements under IFRS, and Hydro One expects the amounts to be material.

173. VECC agrees with Board Staff that Hydro One should record gains and losses on premature retirements in a deferral account, which would be subject to Board review prior to disposition.

174. VECC notes that Hydro One agrees that if the requested variance account is approved by the Board, the variance account should be credited for any depreciation expense in rates that is attributable to prematurely retired assets. The depreciation credit would be calculated based on amount of depreciation in approved revenue requirement that will not be incurred as a result of an asset premature retirement.[141]

*Tax Change Deferral Account*

175. HONI has not reflected the impact of the HST/PST changes in the 2011 RR and proposes to record the revenue requirement impact of the estimated reduction in the proposed 2011 and 2012 expenditures in deferral account 1592.[142]

176. VECC IR 53 asks why this is appropriate since the HST Tax Change will have occurred in 2010 and no new changes to the rate are contemplated.

177. HONI's response is:

> As noted in Exhibit I, Tab 1, Schedule 91, part d, Hydro One is in the process of establishing the methodology that will capture the revenue requirement impact driven by the harmonization of the PST and GST in order to return the net savings to ratepayers in a future proceeding.

178. The impact on the revenue requirement is discussed below:

> MR. AIKEN: So if the variance account approach were taken, it would have a revenue requirement reduction of about $10 million per year?
> MR. STRUTHERS: I believe it is lightly less than that. Again, I look to the Board for how it wishes us to proceed to deal with it. [143]

179. The issue was discussed again later in the hearing:

> MR. SHEPHERD: Okay. So all I am asking is if there is some reason why a deferral account and the ratepayers paying more in those two years, and then getting it back later. If there is some reason why that is a good idea, I am asking

[141] Exhibit I Tab 4 Schedule 51

[142] Exhibit F1 Tab 1 Schedule 2/Page 4 of 5 and Exhibit I Tab 1 Schedule 91

[143] Tr. Vol. 6 p 113

you to give it to us.
MR. STRUTHERS: And what I am suggesting is we would look to the Board for a decision as to whether they wanted to address it in a variance account or revenue reduction.[144]

180. VECC submits that there is no reason why the actual 2010 (1/2 year) and forecast 2011 and 2012 impact of the HST change cannot be used directly to mitigate the 2011/2012 rate increases for consumers and only the variation in those impacts be recorded in the tax account variance account. As note earlier, this impact should be combined with the impact of the HST related changes in the Working Capital, which itself has an impact of approximately $1M, for a combined revenue requirement reduction related to HST impacts for each test year of approximately $10M or $20M over the test period, subject to true up through the existing deferral account.[145]

*OEB Cost Differential Account*

The purpose of this account would be to track the difference between approved and actual costs for 2010 and 2011 regarding OEB cost assessments, intervenor costs and costs associated with OEB-initiated studies[146]. VECC notes that the Board[147] denied a similar request in Hydro One Networks recent Distribution Rate Application and limited the scope of the account to OEB assessment costs. VECC submits that nothing has changed and there is no reason to grant Hydro One Networks' request in this proceeding.

## 7. COST ALLOCATION

### 7.1 Is the cost allocation proposed by Hydro One appropriate?

181. Hydro One Networks' Cost Allocation methodology is the same as that accepted by the OEB in its EB-2008-0272 Decision.[148]

*VECC Submissions*

182. During the interrogatory phase VECC sought explanations for the changes in functional designation of assets as between the EB-2008-0272 and the current

---

[144] Tr. Vol. 7 p 76
[145] The total projected reduction attributable to the HST impact in the test years is approximately $10M as discussed, consisting of approximately $1M in working capital reduction related revenue requirement impact, and approximately $9M in direct HST impact.
[146] Exhibit F1 Tab 1 Schedule 2 page 4
[147] EB-2009-0096, page 58
[148] Exhibit G1 Tab 1 Schedule 1, page 2

proceeding.[149] In VECC's view, Hydro One Networks has adequately explained the changes that have occurred as between the two applications.

183. During the interrogatory phase VECC also sought explanations for some of the more material changes (since EB-2008-0272) in costs assigned to function, in order to ensure that the costs were being assigned on a consistent basis. One area of note is the "Other" functional category. In this case, part of the increase is due to a reassignment of assets from the Network to the Common category – which has no impact on the eventual revenue requirement by rate pool.[150] However, Hydro One Networks acknowledged[151] that the majority of the difference was due to an error in the assignment of some assets to this function that led to a significant increase in the assets assigned in the current Application. The impact on the revenue requirement for each rate pool is expected to be minor and Hydro One Networks has indicated it will reflect the proper assignment in the determination of rates subsequent to the Board's Decision.

184. Finally, VECC sought to understand what were perceived to be inconsistencies between the changes in Gross Book Value of assets and the changes in depreciation assigned to each functional category as between EB-2008-0272 and the current Application.[152] Hydro One Networks has suggested that the implicit depreciation rate (e.g. Deprecation/GBV) were generally the same for each functional category in both EB-2008-0272 and the current Application[153] and, as result, the values presented are consistent. VECC has undertaken the suggested calculations for each functional category and, while there are differences, VECC acknowledges that they could be the result of rounding.

185. Subject to the adjustment to the "Other" functional category, VECC submits that the Board should accept Hydro One Networks' proposed Cost Allocation.

## 8. CHARGE DETERMINANTS

### 8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network Services?

*AMPCO's Proposal*

186. During the course of EB-2008-0272 the Association of Major Power Consumer of Ontario (AMPCO) filed evidence**[154]** (including an Expert Report by Dr. Anindya Sen[155]) putting forward an alternative proposal which they characterized as the "High

[149] Exhibit I Tab 4 Schedules 56-59
[150] Tr. Vol. 8, page 112
[151] Exhibit I Tab 4 Schedule 60
[152] Exhibit I Tab 4 Schedule 61
[153] Tr. Vol. 8, page 116, line 28 to page 117, line 10.
[154] "The Benefits of Improvements n Transmission Rate Design" – "the AMPCO Evidence"
[155] "Do Firms Shift Demand In Response to High Prices? An Empirical Analysis"

Five" approach. AMPCO's proposal[156] for the Network Connection charge determinant is that:

> The customers' charge for demand on the network would be based on their coincident peak demand on the five highest days of demand in the previous year, regardless of when those five days occur. If they occur all in January or three of them occur in August, they still count. It's not the one-day-a-month system we currently have.
> Those -- the average of the customers' demand for those five days becomes their demand level that's calculated for the following year. The transmitter recovers their revenue requirement through their rate. The rate is basically the revenue requirement for the network, divided by the sum of all customers' average demands for those five days.

187. The AMPCO proposal also called for the elimination of the "85% of the customer's non-coincident peak" consideration.

188. In its EB-2008-0272 Decision[157] the Board concluded that while the proposal had merit there were a number of outstanding concerns in that:

- The Board had limited confidence that the level of load shifting or the level of commodity savings would be as high as AMPCO estimated.
- The Board was uncertain as to the resulting impact on customers.

189. The Board directed Hydro One Networks to come forward in its next Application with a) further analysis of AMPCO's proposal and b) a suitable proposal for implementation in the event the Board decides to change the charge determinant. In this proceeding, Hydro One Networks has filed a report prepared by Power Advisory LLC addressing part (a) of the Board's direction.[158]

190. In the current proceeding AMPCO has also filed evidence updating its EB-2008-0272 submission and further elaborating on its arguments for changing the design of the Network charge determinant.[159] Included as part of this evidence is an updated analysis by Dr. Sen which addresses some of the methodological concerns with his analysis as raised in the previous hearing and in the Power Advisory Report.

*Hydro One Networks' Position*

191. Hydro One Networks proposal is to continue with the status quo as approved by the OEB in its RP-2006-0501 Decision.[160] Under the status quo approach Network

---

[156] EB-200-0272, Tr. Vol. 6, page 20
[157] Pages 68-70
[158] Exhibit H1 Tab 3 Schedule 1, Attachment 1
[159] "Potential efficiencies from improving transmission rate design in Ontario"
[160] Tr. Vol. 11, page 20, lines 12-15

Connection customers are billed monthly based on the higher of the customer's demand coincident with the monthly system peak or 85% of the customer's non-coincident monthly demand between 7 AM and 7 PM.[161]

192. As noted above, in response to the Board's EB02008-0272 Decision, Hydro One Networks filed a report by Power Advisory LLP that looked at the costs and benefits of the "High Five" proposal. Overall, Power Advisory concluded that:

- It is not apparent that (current) transmission investment is largely determined by system peaks.[162]
- "With respect to the recovery of past investments …. the High 5 proposal is also inconsistent with the cost causality principle".[163]
- "Power Advisory's estimates of the net commodity cost reductions are significantly smaller than AMPCO's (from one-tenth to less than a quarter)".[164]
- "On balance, Power Advisory concludes that the High 5 methodology is likely to have a net benefit only to the directly connected transmission customers and power station customers".[165]
- "It is unlikely that future transmission investment would be deferred".[166]
- "Significant costs would be shifted from direct customers and generators to customers of LDCs, without justification in terms of cost causation".[167]
- "The benefits to electricity consumers from reductions in commodity costs of electricity due to load shifting will be much less than the transmission costs shifted to them".[168]

*VECC's Submissions*

193. In both the previous proceeding (EB-2008-0272) and the current one, AMPCO has put forward a number of arguments in support of why the Networks charge determinant should be changed to the "High 5" proposal.

194. In EB-2008-0272, AMPCO's arguments[169] included:

- The assertion that its proposal provides better signals to customers regarding the costs their consumption imposes on the system,
- The assertion that its proposal promotes more efficient demand management and specifically peak shifting,

[161] Exhibit H1 Tab 3 Schedule 1, pages 1-2
[162] Page (iv)
[163] Page (iv)
[164] Page (v)
[165] Page (vii)
[166] Page 77
[167] Page 77
[168] Page 77
[169] EB-2008-0272, AMPCO Evidence, page 2

- The assertion that its proposal provides benefits to all customers through lower commodity (HOEP) prices[170],
- The assertion that its proposal allocates transmission costs more fairly among customers, and
- The existence of the 85% ratchet mutes the price signal during the peak period.[171]

195. In the current proceeding, AMPCO evidence included:[172]

- The assertion that capacity prices should be borne by consumers based on their contribution to peak demand,
- The assertion that minimizing inefficiency is best achieved by raising prices in inverse proportion to demand elasticities (i.e., Ramsey Pricing),
- The assertion that the design of network charges should reinforce the tendency of the HOEP to produce a price signal that reflects the scarcity value of electricity (i.e., peak electricity is more expensive than off-peak electricity).
- The assertion that all customers will benefit from the change.[173]

196. AMPCO's 2010 evidence also included refined explanations/analysis regarding the price elasticity of various industrial sectors and the likely impact of load changes in the peak and off-peak period on commodity prices and the global adjustment. The purpose of this analysis was to reinforce the conclusions reached in its earlier evidence that: a) customers do respond to price and shift load[174] and b) load shifts from the peak to the off-peak period will lead to reductions in the peak period prices that exceed the increase that will be experienced in off-peak peak prices.[175]

197. In VECC's view, AMPCO's High Five proposal should be rejected by the Board. The following submissions respond to the various points raised by AMPCO.

*a) Capacity Prices Should be Borne by Consumers Based on Their Contribution to System Peak Demand.*

198. This argument is comparable to the argument put forward by AMPCO in EB-2008-0272 that its proposal provides better signals to customers regarding the costs their consumption imposes on the system. To support the principle, AMPCO has referenced quotes from works by both Alfred Khan and Arthur Lewis.[176] However, VECC notes that in the quoted publication Alfred Khan also states[177]: "*The principle is clear, but is more complicated than might appear at first reading… Notice first the*

[170] EB-2008-0272, AMPCO Evidence, page 11
[171] EB-2008-0272, AMPCO Evidence, page 3
[172] Pages 3-4
[173] Exhibit N-1 Tab 4 Schedule 11
[174] Page 9
[175] Pages 9-10
[176] AMPCO Evidence, page 3
[177] Exhibit N-1 Tab 1 Schedule 1, part a) – Attachment, page 89

*qualification "if the same type of capacity services all users"*". Furthermore, the referenced quote by Arthur Lewis does not refer to "system peak" but rather "*station peak*" suggesting one must look at the timing of the peak for specific facilities whose costs the utility is seeking to recover.

199. Network facilities include investments in: a) Inter-Area Transfer Capability, b) Bulk and Regional Transmission, c) Station Upgrades and Additions for Renewables, d) Protection & Control for Distribution Connected Generation and e) Risk Mitigation.[178] In Hydro One Networks case, these Network facilities address a variety of user needs and the same facilities do not service all users/needs:

- Both the Power Advisory Report[179] and Hydro One Networks planners[180] have confirmed that virtually all Inter-Area investments over the next few years are being driven by the need to incorporate new (renewable/nuclear) generation. For the associated transmission facilities the "peak" that drives investment is not the system peak but rather the "peak" associated with the output of the related generation. In the case of Bruce to Milton, the line must be able to carry the relatively constant output from Bruce as well as that of new wind developments which typically peak in the winter months.[181] In the case of the NorthxSouth transmission, the facilities must be sized to carry new hydro generation where the maximum instantaneous output can occur at anytime.[182] As a result, while the investment in these projects is driven by "peak use", the peak that drives the need for the investments is not necessarily at the time the system peak.
- To the extent load drives the need for Network facilities, Hydro One Networks has indicated[183] that regional loads are relevant in the planning of such facilities. Different regions in Ontario peak at different times.[184] Indeed, if one were to apply the "High Five" principle to the various regions of the province as defined by the IESO for operating purposes, the High Five would have captured nine out of the 12 months of the year in 2008[185]. As a result, the "High Five" proposal will not capture the "peaks" that drive regional considerations.

200. VECC submits that focusing the recovery of transmission costs solely on the five days of the year with the highest peak demands will not provide a better signal as to when usage imposes transmission costs on the system. Indeed, by focusing narrowly on the peak use in these five days, VECC submits that AMPCO's High Five proposal could be encouraging customers to shift to other peak period hours that are critical from a local supply perspective and/or the delivery of renewable generation.

[178] Exhibit I Tab 4 Schedule 65 c)
[179] Pages 18 and 68-70
[180] Tr. Vol. 2, page 176
[181] EB-2008-0272, Tr. Vol. 1, pages 28-29
[182] EB-2008-0272, Tr. Vol. 1, page 29
[183] Tr. Vol. 8, pages 134-135
[184] Tr. Vol. 8, page 135 and Exhibit I Tab 6 Schedule 36
[185] Exhibit N-1 Tab 4 Schedule 5 c)

201. In VECC's view the current transmission rate design which focuses on all twelve months of the year and encourages customers (through the 85% factor) to be mindful of their peak use throughout the entire peak period provides a better signal to customers regarding cost causation.

*b) Encourages Efficient Demand Management and Peak Shifting*

202. In VECC's view there are four related issues involved in this assertion:

- Will customers shift load in response to transmission pricing that focuses more on system peak times?
- How much will they shift?
- To what hours will customers shift?
- Is the load shifting "efficient" from an economic perspective?

203. With respect to the first question, in EB-2008-0272 there was considerable concern raised regarding the reliability and robustness of the elasticity estimates developed by Dr. Sen and the resulting load shifts calculated by AMPCO.[186] These concerns were confirmed by Power Advisory in its report.[187] In the evidence filed this year Dr. Sen has addressed some but all of the concerns raised regarding his earlier analysis.[188] In its Report, Power Advisory used a range of elasticity estimates available from past literature to test the reasonableness of Dr. Sen's earlier results and concluded that network rate design can influence customers to shift their demands to off-peak periods.[189] This is consistent with AMPCO's current evidence that "industrial customers will reduce demand during peak periods in response to higher prices in the peak periods".[190]

204. VECC agrees with this general proposition. However, VECC also notes that not all consumers have the same capacity to shift load. This is evident from Dr. Sen's analysis where the price elasticity estimates vary across the different industries examined.[191] VECC submits that the capability to shift is also likely to vary even more when other types of consumers (e.g. residential, institutional and commercial) are also considered.

205. The second issue is how much load will customers shift and where will they shift it to. Power Advisory's analysis includes a number of scenarios and results in a range of load shifting for industrial customers of 40 MW to 151 MW.[192] While these MW values are greater than those estimated by AMPCO the number of hours over

[186] EB-2008-0272 Decision, pages 67 and 69
[187] Tr. Vol. 8, pages 2-3
[188] Tr. Vol. 8, pages 4-5
[189] Page 76
[190] AMPCO Evidence, page 9
[191] Dr. Sen's Report, page 17
[192] Page 50

which the load shift occurs is less. However, these results are based on the assumption that the customer's current transmission pricing reflects 85% of NCP such that the current shadow price for transmission is $8.50 / MWh.[193] Over one-half of the transmission bills for direct industrial customer delivery points are based on demands coincident with the system peak[194] where the shadow price for transmission is $102.80 / MWh. Using this value, the range for load shifting changes to 30 MW to 128 MW.[195]

206. As noted earlier, Dr. Sen evidence in this proceeding sought to re-estimate the industrial elasticity estimates using analyses that addressed a number of concerns raised in EB-2008-0272. When asked, Power Advisory indicated[196] that Dr. Sen's new analysis had addressed a number of their original concerns and that the results were reasonable. However, in Power Advisory's view, there are still issues (namely the form of the production function used and the use of own-price as opposed to substitution elasticities[197]), and the results are not robust enough to be used as "point estimates".[198] It should be noted that AMPCO has not provided any updates to its earlier (EB-2008-0272) estimates for load shifting based on Dr. Sen's new results.

207. Overall, VECC submits that this issue (i.e., how much load will be shifted) cannot be answered with a high degree of certainty. However, Power Advisory's results (included those provided in Exhibit J7.5) provide a reasonable range.

208. Dr. Sen's analysis defined the peak period as the 7 am to 7 pm for all days of the year[199] and the off-peak as the balance of the hours in the year. As a result, his analysis supports the proposition that there will be load shifting to the off-peak if the average price in the peak period (as so defined) increases. However, the proposal before the Board is significantly different and involves increasing the price for what is effectively a much smaller number of hours. Overall, VECC submits that the analysis, as undertaken by Dr. Sen, provides little insight into how customers will respond to a pricing scheme such as the "High Five" which focuses on a very limited number of hours.

209. Indeed, it is clear from the testimony of the industrial customer representatives on the AMPCO panel that the load shifting will not simply be from peak to off peak, but could also involve seasonal load shifting[200] and the shifting of load within the 7 am to 7 pm peak period.[201] In fact, at this point in time there is a great deal of

193 Power Advisory Report, pages 48-49.
194 Exhibit I Tab 4 Schedule 62
195 Exhibit J7.5
196 Tr. Vol. 8, pages 3-5
197 Tr. Vol. 8, pages 5 & 7
198 Tr. Vol. 8, page 5, lines 21-22
199 Tr. Vol. 10, page 77
200 Tr. Vol. 10, page 30
201 Tr. Vol. 10, page 45

uncertainty as to how industrial customers will precisely respond.[202] Also, the fact that customers may shift loads within the peak period accentuates the concern that the load shifts in response the High Five proposal could trigger the need for investments where current transmission facilities peak are driven by other considerations (as discussed earlier) thereby reducing/negating any “efficiency” improvement.

210. In VECC’s view, the final issue – Is the load shifting efficient? – is the most important. To achieve “efficient” results requires that prices be close to the marginal value of providing service.[203] Indeed, this matches with AMPCO’s claim that “with our proposal on 5CP, really what we are striving for here is to convert the current price signal, if you want to call it that, that is implicit in the network charge determinant and to transform that into a price signal that actually bears some relationship to the cost of network service and will promote efficient demand response”.[204]

211. However, VECC submits that it is equally important that the prices charged do not overstate the value of service. Again, this is a point on which AMPCO agrees.[205] AMPCO indicates that it has not undertaken any analysis regarding the marginal cost/value of transmission.[206] Indeed, the most recent estimates of the marginal value of transmission are those published by the Board for use by electricity distributors in evaluating the societal benefits of CDM.[207] Based on these estimates it would appear that the value of transmission at the time of system peak is roughly $6.00 / kW for 2011. However, the AMPCO proposal would produce a price signal equivalent to $38.68 / kW[208] which would substantially overstate value of load shifting in terms of transmission investment savings. This price signal is important as customers will incur costs in order to achieve load shifting[209] and too high a price means customers will likely spend more than what the shifting is worth – leading to an inefficient result overall.

212. During the proceeding AMPCO suggested the value was dated.[210] However, it is the value currently prescribed by the Board for purposes of CDM evaluation.[211]

213. Furthermore, in its Report, Power Advisory concludes that the industrial load shifting which is likely to occur under the High Five proposal would have no ability to

[202] Tr. Vol. 10, page 44
[203] Tr. Vol. 10 , page 50
[204] Tr. Vol. 10 , pages 52-53
[205] Tr. Vol. 10, page 53
[206] Tr. Vol. 10, page 58
[207] Exhibit K10.5
[208] Tr. Vol. 10, page 60
[209] Tr. Vol. 8, pages 11-12 and Volume #10, page 46
[210] Tr. Vol. 10, page 59
[211] Tr. Vol. 10, page 58

defer transmission investments.[212] This conclusion was confirmed by Hydro One Networks during the proceeding.[213] Given this conclusion, it is VECC's submission that adopting the High Five proposal will lead to inefficient investment/spending on part of consumers with no equivalent (or greater) reduction in transmission costs to offset these customer-incurred costs.

214. AMPCO also argues that the High Five Proposal will reinforce the relative peak/off peak price signal provided by the HOEP with respect to the value of generation.[214] VECC questions the appropriateness of using transmission charges to purportedly correct the commodity price signal. In VECC's view transmission pricing should focus on ensuring the cost of transmission are recovered from customers in a manner that is fair and efficient from a transmission cost perspective. If there are issues with commodity pricing they should be addressed in terms of how commodity related costs are recovered from customers.

215. VECC also notes that in terms of the electricity commodity, there is no evidence before the Board that the current peak/off-peak prices are inappropriate. AMPCO has made claims that the current peak/off-peak variations in HOEP only reflect differences in variable costs.[215] However, elsewhere they have acknowledged that the peak/off-peak differential in HOEP also captures supply contingencies and the value will therefore exceed variable cost of production.[216]

216. Finally, the proposed change in the recovery of the Global Adjustment as envisioned under the amendment currently being considered to Ontario Regulation 429/04 could increase the price signal during critical peak period by considerably more than the change in transmission pricing would under the High Five proposal.[217] As a result, VECC submits that any consideration of the need to use transmission pricing to reinforce the commodity price signal currently provided by the HOEP should await the outcome of the proposed amendment.

*c) All Customers Will Benefit*

217. According to AMPCO, this assertion is not based on the view that all customers will be able to shift load but rather on the view that some customers will shift load and this will lead to reductions in losses, commodity costs, etc. that will benefit all customers.[218] VECC notes that AMPCO's claim regarding reduced commodity costs is based on the proposition that a shift in load from the peak to the off-peak period

---

[212] Page 71
[213] Tr. Vol. 8, page 128
[214] AMPCO Evidence, page 3
[215] Exhibit N-1, Tab 4 Schedule 1 a) and Tr. Vol. 10, page 52
[216] Tr. Vol. 10, page 48
[217] Tr. Vol. 8, page 27
[218] Tr. Vol. 10, pages 70-71

will reduce peak period prices by more than the corresponding increase in off-peak prices.[219] VECC has a number of concerns regarding this claim.

218. AMPCO relies on analysis performed by Dr. Sen to support this proposition. This analysis considered impact on price (HOEP) of shifting load from the broadly defined 7 am to 7 pm period to the 7 pm to 7 am off peak period[220] and reflects the view that the load vs. price relationship changes as between these peak and off peak periods.[221] However, as noted above, it is not evident that customers will shift their load to the off-peak period (as defined by Dr. Sen) in response to the High Five proposal. Dr. Sen's analysis does not provide any insight into the likely impact on price if load is simply shifted around within his broadly defined peak period. Another concern with Dr. Sen's analysis is that he looked only at the relationship between load and HOEP. However, the relationship between load and the Global Adjustment tends to go in the opposite direction.[222]

219. VECC also questions the claim that all customers will benefit. As Power Advisory has demonstrated the High Five proposal results in a significant shift in transmission costs from Directs and Power Producers to the LDCs[223] in the order of $28.5 M, due to a combination of the methodology change ($25.3 M) and the anticipated load shifting by industrial customers (an additional $3.2 M). In contrast, Power Advisory estimates that reduction in commodity costs that will arise from direct customer load shift is in the order of $2M.[224]

220. What is even more telling is that the load shifting by the Directs results in a lowering of their allocated transmission cost by some $3.2 M[225] while creating roughly only some $2 M in commodity savings[226] which will be shared across all customers. This suggests that commodity savings due to load shifting will not offset the increased transmission costs customers will allocated as result of such load shifting. When this result is combined with the fact that there is virtually no deferral of transmission investment due to such shifting and that some customers will experience significant cost shifts (up to 92% for Directs and 83% for lDCs) due the methodology change[227], VECC submits that it is far from obvious that all customers will benefit.

---

[219] AMPCO Evidence, pages 9-10
[220] Tr. Vol. 10, page 77
[221] AMPCO Evidence, Attachment 1, Figure 1
[222] AMPCO Evidence, page 10 and Exhibit N-1, Tab 4 Schedule #9
[223] Power Advisory Report, page 55
[224] Power Advisory Report, page 63
[225] Power Advisory Report, pages 54-55 – Calculated as the difference between the Direct impacts set out in Tables 14 and 15.
[226] Power Advisory Report, page 63, Table 16
[227] Exhibit I Tab 1 Schedule 96

*d) The 85% Factor Mutes the Price Signal*

221. VECC acknowledges that in principle this may be correct but submits that there are other valid reasons for maintaining the 85%. As discussed above, not all areas of province “peak” at the same point in time. If Ontario is to maintain a common transmission rate it is important that the rate signal to customers the need to manage their loads over a broader period than just the few hours around the system peak. The “85% ratchet” does this.

222. Overall, VECC submits that the evidence does not support AMPCO’s arguments for a change and the Board should accept Hydro One Networks proposal to maintain the status quo in terms of the billing determinant applicable to Network Connection Service. Furthermore, VECC submits that the shortcomings in AMPCO’s proposal go beyond just uncertainties regarding the degree of load shifting and commodity price reduction that will occur. As seen in the discussion under parts (a) and (b) – by focussing too narrowly on five “Peak days” - the proposal is inconsistent with Hydro One Networks’ current transmission cost drivers and the generally accepted principles of cost causality and economic efficiency that typically underpin the establishment of rates.

## 9. GREEN ENERGY PLAN

### 9.1 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

223. Hydro One is seeking approval for a capital budget of $126.7M in 2011 and $198.1M in 2012 for Green Energy Plan projects. This includes spending on two “Schedule A” projects and several “Schedule B” projects. However, only $11.4 million in 2011 and $198 million in 2012 will be included in rate base. These amounts are related to capital expenditures on Short Circuit upgrades to Leaside TS and Hearn TS, and In-Line Circuit Breakers and Protection and Control (“P&C”) upgrades. The resultant revenue requirement is $0.9M in 2011 and $10.3M in 2012.[228]

224. VECC notes that Hydro One also proposes to spend $35.7M in 2011 and $46.7M in 2012 on OM&A for development work. These OM&A costs are recorded in a deferral account and therefore are not included in the test year revenue requirements. On May 7, 2010, the Minister sent a letter to the OPA requiring new advice regarding transmission planning. As a result of a Ministers Letter of May 7, 2010 letter, pending updated instructions from the OPA and Minister, Hydro One suspended work on all projects. Hydro One is not seeking approval for these amounts at this time. However there could be a resumption of development work resulting in major additional costs being deferred.

225. The Impact on the 2011 and 2012 revenue requirements are summarized on the

[228] Exhibit I Tab 3 Schedule 12

record By Hydro One's Counsel: [229]

> So to summarize, then, for 2011 and 2012, the rate period, the direct green energy-related costs impact on the revenue requirement is as follows. For 2011, there is the $1 million from the deferral account which is sought to be collected, and, in addition, there is the $0.9 million relating to projects which will be coming into service in 2011.
>
> In 2012, it will be the second half of the deferral account, the $2 million - that is, $1 million in 2012 for the deferral account - and an additional $10.3 million, which is the result of additional projects coming into service in 2012.
>
> And that is, I believe, the only direct impact of the green energy projects on the rate application.

226. Recognizing the significant uncertainty associated with the GE Plan, in argument-in-chief, Hydro One stated it is not seeking Board approval for the individual projects in the GE Plan, but is asking the Board to approve the GE Plan conceptually. Hydro One further submitted that at a minimum, the Board should approve the capital expenditures on Schedule B projects expected to go ahead in the test years.[230]

227. Board Staff submits that there are no guarantees that the two planned Schedule A projects will proceed and the costs of the projects should be removed from the capital budget. The project costs will be reviewed when approval is sought for these projects in a future application. Board staff also notes that pending instructions from the Minister, Hydro One suspended development work on both projects. If the projects were expected to continue, Hydro One would not have suspended this work.[231]

228. VECC shares Board Staff's concerns:

> MR. BUONAGURO: Right. Thank you.
> And lastly, Exhibit D1, tab 3, schedule 3, appendix A, so the same again, but page 8. Here you are listing the spending on station upgrades and additions to facilitate renewables. Can you confirm that all the spending in this category is driven by the need to address transmission capacity constraints, so as to allow the connection of renewable generation in certain areas of the province?
> MR. YOUNG: Yes, that's correct.
> MR. BUONAGURO: And we note that two of the projects, D37 and D38, come into service within the 2011-2012 test period and are listed as category 2, which means you are seeking approval to include them in rate base?
> MR. YOUNG: Yes.

[229] Tr. Vol. 6 p 4-6
[230] TR Vol. 11, p. 8
[231] Board Staff Submissions page 13

> MR. BUONAGURO: But we note that from Exhibit D2, tab 2, schedule 3, our reading of that is that from projects -– that projects D37 and D38, as of the time of the application, had no recommendation or confirmation from the OPA; is that fair?
> MR. YOUNG: That is correct.
> MR. BUONAGURO: Has there been any communication from the OPA since then?
> MR. YOUNG: So the estimate of -- so we conservatively took an estimate of two out of the seven for inclusion in the test years, and our experience now with the FIT projects which have been issued contracts have beared that out.[232]

229. VECC suggests that it is premature to provide any Board Approval of the GEP. If instruction from the Minister occurs Hydro One can proceed to develop projects and request Section 92 approval of those projects in the normal course.

230. With respect to expenditure on Schedule B projects that will be in-service in the test years, Hydro One is proposing to spend $122 million on Short Circuit upgrades to Leaside TS and Hearn TS, $41 million on two In-line Circuit Breakers and $39.8 million on P&C upgrades.[233]

*Board Staff Submission Schedule B Projects*

231. Board Staff note that the need for the Short Circuit upgrades to Leaside TS, Hearn TS and Manby TS were confirmed by the Board in Hydro One's last rate filing (EB-2008-0272). With respect to the In-line Circuit Breakers and P&C upgrades, D43 and 44 these are needed to enable the connection of FIT connections that have already received a contract from the OPA. Therefore, subject to staff's submissions below regarding cost responsibility for the Short Circuit upgrades and the P&C upgrades, Board Staff submits that the need for spending in the test years has been demonstrated for these projects .

*Cost Responsibility for Schedule B Projects*

232. Board Staff's submission is that Hydro One's proposal to recover all the costs of the short circuit upgrades at Leaside and Manby from transmission ratepayers is not compliant with the TSC requirements. If the Board accepts this interpretation and chooses to require compliance with the TSC in this situation, Board Staff submit that the Board should reduce the proposed capital budget by $10.8M (sum of the advancement costs of $4.9M + $5.9M) to recognize the contributions that should be sought from Toronto Hydro for the advancement of the work. However, as noted above, it appears to Board Staff that the operation of the TSC in this situation may be unfair to Toronto Hydro and its ratepayers.

[232] Tr. Vol. 2 p180
[233] Exhibit I Tab 1 Schedule 64, p.6

233. Hydro One seeks to recover the costs of the P&C projects D43 and D44 from transmission ratepayers. Board staff submits that the Board should consider reducing the requested capital budget by $10M in 2011 and $29.8M in 2012 to recognize that the facilities in question are classified as connection, and that the TSC prescribes a user-pay approach for such facilities.

234. VECC agrees with Board Staff's submissions regarding cost responsibility for P&C projects D43 and D44.

**9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for Green Energy projects appropriate?**

235. Hydro One has applied for accelerated cost recovery for the Bruce to Milton transmission project during the construction phase, before the project is in service, It proposes that 100% of CWIP expenditures would be included in the transmission rate base (using the half year rule in 2011), and that the carrying costs of this rate base addition be recovered from ratepayers.[234]

236. Hydro One relies on the January 15, 2010 EB-2009-0152 Report of the Board: The Regulatory Treatment of Infrastructure Investment in Connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario (the "Report") in proposing this alternative mechanism for cost recovery.

237. At page 21 of the Report, the Board listed several factors it would consider in determining whether an alternative mechanism such as CWIP in rate base should be applied:

- the need for the project (if not already demonstrated through another process as discussed in section 3.5 below);
- the public interest benefits of the project and of granting the alternative mechanism(s) requested;
- the overall cost of the project in absolute terms;
- the cost of the project in proportion to the current rate base of the utility;
- the risks or particular challenges associated with the completion of the project;
- the reasons given for not relying on conventional cost recovery mechanisms; and
- whether the utility is otherwise obligated to undertake the project.

238. Board Staff's submission reviews the criteria for granting Hydro One Accelerated CWIP for the Bruce to Milton project. Board Staff concludes that:

[234] Exhibit A Tab 11 Schedule 5 Tables 1,2,6

The Board should carefully consider whether the accelerated cost recovery mechanisms in the Report are an appropriate regulatory tool for all complex, capital intensive projects, which clearly involve a variety of risks, or should be reserved for unique risks that are not common to all projects. For example, one risk of some *Green Energy Act* investments may be the cancellation of renewable generation projects after the transmission project has been partially developed or constructed. The evidence suggests that this is not a risk of the Bruce to Milton project. The risks cited for the Bruce to Milton project appear to be common to all large transmission construction investments in Ontario at the present time. The Board could find that the risks associated with this project are not unique, and that conventional cost recovery methods are sufficient to address these risks.

239. The second driver cited by Hydro One for Accelerated CWIP treatment by Hydro One is the impact on ratepayers. Board Staff concludes that:

> In determining whether it is in the ratepayer's interest to grant the proposed accelerated cost recovery mechanism for this project, the advantage of rate smoothing must be balanced against the immediate concern of mitigating rate impacts in 2011 and 2012. The Board may wish to consider whether the present concern of ratepayers over rising total electricity costs is sufficiently pressing to discount the benefits of the rate smoothing over a longer period provided by the accelerated recovery of CWIP proposal.[235]

240. In Hydro One's view ratepayers will experience lower rate impacts if the B to M project is accorded CWIP in ratebase treatment rather than conventional AFDUC treatment:[236]

> Based on the results above, Hydro One's position is that CWIP in ratebase is the approach that provides the greatest overall benefit to ratepayers due to its rate smoothing effects, lower lifetime costs and risk mitigation. These benefits are especially important for large projects like Bruce to Milton where the costs are large and significant schedule risks are present.

*VECC Submissions*

*Eligibility for Accelerated recovery of CWIP- Board Criteria*

241. VECC suggests a key factor in Hydro One's Request for accelerated CWIP for B to M is that the tool is available to them as a result of the Board's Report:

> MR. CROCKER: Okay. So we've talked about the benefits already, but I suppose, then, if I can paraphrase your answer, your answer is you want it because you can; correct? You are asking for it because you can?
> MR. GREGG: We wouldn't be proposing the approach would it not be a benefit

[235] Board Staff Submissions page 20
[236] Exhibit I Tab 1 Schedule 122 and Attachments and Tr Vol 2, p. 73

to ratepayers. I want to underline that. This is a benefit to ratepayers using the CWIP approach. Yes, it is true that it is a tool made available to us by this Board, and other transmitters, I would presume.

So when it was not available in 2006, we had suggested, like other jurisdictions, that perhaps it should be available back in 2006. We were told it was not. Subsequent to that, it became a tool to be used in Ontario.[237]

*Ratepayer or Hydro One Benefit?*

242. Hydro One's evidence was that ratepayers would benefit by the rate smoothing due to the recovery of these costs commencing earlier and being spread over a longer recovery period. Hydro One claims that as confirmed in Undertaking J3.5, ratepayers will pay more cumulatively in the first twelve years of a fifty year recovery period, and cumulatively less from that point on. The cross-over year is 2024. However, according to that same undertaking, on a nominal basis, the impact of Bruce to Milton on rates using the accelerated CWIP methodology will be less starting in 2013 when compared to the AFUDC alternative ($60.3 million versus $66.2 million).[238]

243. Hydro One's evidence was that the total cost of the project, and therefore the total recovered from ratepayers, would be lower by $68 million under the accelerated recovery of CWIP approach than under conventional recovery methodologies.[239]

244. The company's evidence on this point was challenged:

MR. AIKEN: Now, staying with the Bruce-to-Milton analysis for a moment, is it fair to say that the calculations shown in attachments 1 and 2 show the net present value to Hydro One of the incremental revenue generated by this project under the two competing approaches?
MR. STRUTHERS: What it shows is the net present, if you want, cost of the project to -- net present revenue for Hydro One, yes, that would be a fair description.
MR. AIKEN: Would it also be fair to say that the calculations do not show the net present value of the cost to ratepayers of the two competing approaches?
MR. STRUTHERS: It would not show the cost. It would only show the revenue. The issue with showing the cost is determining what the appropriate discount rates would be for customers, and they would vary considerably.[240]

245. Undertakings J6.8 and 6.9 show the results of different discount rates on the revenue requirement and lifetime Net present value of the project. Hydro One's position was for all three discount rates considered above the "AFUDC Capitalized"

[237] Tr. Vol. 2 p74
[238] Exhibit J3.5
[239] Exhibit I Tab1 Schedule 122 & Tr. Vol. 11, p. 9
[240] Tr. Vol. 6 p 105

approach does not provide a more favourable result to ratepayers than the “CWIP in Ratebase” proposal.

246. VECC notes that in all cases the CWIP in rate base assumed a full Weighted Average Cost of Capital (WACC) of 7.8%.

*CWIP in Rate Base -Return on Ratebase Full Cost of capital or ACMT Bond rate*

247. This issue that VECC is raising is whether if the assets are capitalized under the CWIP in Rate Base Approach HONI should earn the full return on Capital including the ROE until the assets are in service (estimated by HONI as December 31, 2012).

248. Attachment 1 to BS IR 122[241] shows that under Hydro Ones proposal, the return on rate base is $25M in 2011 and $50.5M in 2012.

249. VECC IR 75 shows that using the All Corporate Medium Term (ACMT) Bond Rate ACMT rather than WACC is $44.8M.[242] The difference in return cost over the two test years is) **$**30.7M ($75.5M-$44.8M).

**Table 1**
**BxM Project “Accelerated Cost Recovery of CWIP” Revenue Requirement Impact**
**Using All Corporate Mid-Term Average Weighted Bond Yield**
($ millions)

| Cash Flows ($M) | 2009 Life To-Date | 2010 | 2011 | 2012* | Total (incl Future Years) |
|---|---|---|---|---|---|
| Annual Expenditures | 202.6 | 191.0 | 184.4 | 94.3 | 695.5 |
| CWIP (Year End) | 202.6 | 393.6 | 577.9 | 0.0 | |
| "Accelerated Cost Recovery of CWIP" Rate Base | | | 485.8 | 289.0 | |

| % Return on Rate Base | 2011 | 2012 |
|---|---|---|
| All Corporate Mid-Term Average Weighted Bond Yield* | 5.60% | 6.10% |
| ** See Table 1 of D1-4-1, p. 1* | | |
| **$ Return on Rate Base** | 27.2 | 17.6 |
| Tax Rate | 28.25% | 26.25% |
| Income Tax | 0.0 | 0.0 |

| Revenue Requirement Impact | | | 2011 | 2012 |
|---|---|---|---|---|
| OM&A | | | 0.0 | 0.0 |
| Depreciation | | | 0.0 | 0.0 |
| Return on Debt | | | 27.2 | 17.6 |
| Return on Equity | | | 0.0 | 0.0 |
| Income Tax | | | 0.0 | 0.0 |
| **Total** | | | 27.2 | 17.6 |

MR. SHEPHERD: I just have one other question on this, and that is

[241] Exhibit I Tab 1 Schedule 122
[242] Exhibit I Tab 4 Schedule 75

It is correct, isn't that, that under the CWIP in rate base approach, the amount you collect from ratepayers is higher in the early years and it is lower in the later years; right?
MR. GREGG: That's correct.
MR. SHEPHERD: Is it correct that under the CWIP in rate base approach, the ratepayers continue to be out of pocket on a cumulative basis - that is, they will continue to have paid more cumulatively - until 2024; right? I wonder if you could undertake to confirm that?
MR. GREGG: I think we will, yes.
MR. ROGERS: Yes.
MS. LEA: J3.5.[243]

250. Exhibit A Tab 11 Schedule 5 page 8 of 11 show the revenue requirement impact of rejecting CWIP in ratebase in favor of continuing with AFDUC, a reduction of $43.6M in 2011, and $26.0M in 2012.

251. VECC submits that the Bruce to Milton Project does not qualify as a high risk project for which Accelerated CWIP treatment is required and it is not in the public's interest to grant accelerated CWIP treatment. Accordingly VECC submits that the Board should deny Hydro One's request for CWIP in ratebase treatment for the Bruce to Milton Project.

252. VECC also submits that if, however, the Board wishes to consider CWIP in ratebase for the Bruce to Milton line as a measure for reducing the ratepayer impact of the project over the long term, then, as the assets are not used or useful until in service in 2013, it should also find that the applicable return allowed should be the ACMT Bond Rate rather than WACC (until the in-service date) in accordance with the analysis in VECC IR 75.

**Costs**

253. VECC has participated fully in this proceeding and cooperated with other intervenors to the maximum extent possible. Accordingly VECC requests reimbursement of 100% of its legitimately incurred costs.

**ALL OF WHICH IS RESPECTFULLY SUBMITTED THIS 2nd DAY OF NOVEMBER, 2010**

[243] Tr. Vol. 3 p 49