



PUBLIC INTEREST ADVOCACY CENTRE
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October 2, 2009

VIA 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: Hydro One Networks Inc. – 2010 & 2011 Distribution Rate Application
Board File: EB-2009-0096

Please find enclosed the interrogatories submitted by VECC.

Yours truly,

Michael Buonaguro
Counsel for VECC
Encl.

**HYDRO ONE NETWORKS INC.
APPLICATION FOR 2010/2011 DISTRIBUTION RATES
EB-2009-0096**

VECC INTERROGATORIES

QUESTION #1

Issue: #1.4

Reference: Exhibit A/Tab 2/Schedule 1, page 1

- a) Please indicate where in the application Hydro One Networks outlines the rationale and implications of its proposal to implement the 2010 and 2011 rate changes on January 1st of each year, as opposed to May 1st.
- b) Please fully explain why a January 1st implementation date, as opposed to a May 1st implementation date, is required.
- c) Please provide a schedule that sets out:
 - The forecast (kWh) sales to customers by month for 2010 and 2011
 - The anticipated distribution revenue in the months of January 2010 to April 2010 based on the proposed 2010 rates as opposed to Hydro One Networks current rates
 - The anticipated distribution revenue in the months of January 2011 to April 2011 based on the proposed 2011 rates as opposed to the proposed 2010 rates.

QUESTION #2

Issue: #1.1

Reference: Exhibit A/Tab 6/Schedule 1, page 1

- a) The evidence states that the Application is “substantially consistent” with 2006 EDR Handbook and the Board’s Filing Requirements. Please provide a schedule setting out those areas where Hydro One Networks is not consistent.

QUESTION #3

Issue: #1.2 and #5.2

Reference: Exhibit A/Tab 3/Schedule 1, page 2

- a) The evidence states (lines 27-28) that the ROE and “other Cost of Capital parameters” will be updated to reflect the September 2009 Consensus forecast and Bank of Canada data available in October 2009 as part of the Draft Rate Order for 2010 rates”. Please indicate what “other cost of capital parameters” Hydro One Networks proposes to update based on the October 2009 data.

QUESTION #4

Issue: #2.1

Reference: Exhibit A/Tab 3/Schedule 1, page 7

- a) The evidence states (lines 11-12) that “growth in customer demand” is one of the reasons for the increase in revenue requirement. However, Exhibit A/Tab 14/Schedule 4, page 19 indicates that demand has been decreasing since 2006 and is projected to decrease further in 2010 and 2011. Please reconcile.

QUESTION #5

Issue: #2.2

Reference: Exhibit A/Tab 3/Schedule 2, page 5

- a) The evidence states that the Cost of Sales for 2008 was higher due, in part, to the Ohio Storm Assistance provided. Please provide a schedule that sets out the cost of the assistance that was provided and the revenues received from Ohio for the assistance.

QUESTION #6

Issue: #1.5

Reference: Exhibit A/Tab 3/Schedule 2, pages 4-6

- a) Please provide a schedule that sets out for 2008 the Board approved and actual values for Hydro One Networks' Distribution Business for the following items:
1. kWh sales
 2. Distribution Revenues (from Base Distribution Rates)
 3. Other Revenues (excluding deferral account refund/recoveries and smart meter rate adder)
 4. OM&A Expense (including taxes other than Capital and Income)
 5. Depreciation Expense
 6. Capital and Income Taxes
 7. Interest Expense
 8. Rate Base
 9. Equity Component of Rate Base
 10. Net Income (Please explain if different from 2+3-4-5-6-7)
 11. ROE

QUESTION #7

Issue: #1.2

Reference: Exhibit A/Tab 4/Schedule 1, page 3
Exhibit A/Tab 16/Schedule 1, page 6

- a) Are the Hydro One Networks' Strategic Objectives and associated 5-year goals currently used for planning purposes the same as those used for the 2008 Rate Application? If not, please identify and explain any changes.
- b) What is the time frame for the five-year period?
- c) Please provide a schedule that sets out the results for each strategic objective for 2006 to 2008 inclusive.
- d) With respect to the objective to achieve top quartile unit costs, please indicate:
- What pool of distribution utilities Hydro One Networks is comparing itself to?
 - What "unit costs" are being compared?

QUESTION #8

Issue: #1.3

Reference: i) Exhibit A/Tab 4/Schedule 1, page 18, lines 11-12
ii) Exhibit A/Tab 4/Schedule 1, pages 19-20

- a) With respect to reference (i), please explain how the deterioration in the SAIFI performance for 2007 and 2008 is “due to a shift in the customers impacted by storms in 2007 and 2008 compared to 2005 and 2006”.
- b) With respect to Figures 4 and 5, what types of events are captured under Unknown/Other?
- c) Please provide a schedule that for each year (2005-2008) sets out the contribution to SAIDI (i.e., Hours of Interruption) attributed to:
 - Tree Contacts
 - Force Majeure - Tree Contacts
 - Defective Equipment
 - Unknown/Other
- d) Please provide a schedule that for each year (2005-2008) sets out the contribution to SAIFI (i.e., Number of Interruptions) attributed to:
 - Tree Contacts
 - Force Majeure - Tree Contacts
 - Defective Equipment
 - Unknown/Other

QUESTION #9

Issue: #3.4

Reference: Exhibit A/Tab 8/Schedule 3, pages 5-6

- a) Please provide a schedule that sets out for each service the costs retained by Hydro One Networks for 2009, 2010 and 2011.
- b) With respect to the response to part (a), if the overall proportion retained by Hydro One Networks changes materially in 2010 and 2011 relative to 2009 please explain why.
- c) The proportion of Financial Services charged to Hydro One Inc. declines significantly in 2010 and 2011 relative to that charged to Remotes and Telecom – please explain why.

- d) The proportion of Financial Services charged to Brampton increases significantly in 2010 and 2011 (when compared to 2009) – please explain why.

QUESTION #10

Issue: #3.4

Reference: i) Exhibit A/Tab 8/Schedule 3, pages 5-7
ii) EB-2008-0272, Exhibit A/Tab 9/Schedule 2, pages 5-6

- a) Please explain why the 2010 fees payable by Hydro One Inc. for Financial Services have declined significantly (\$57 vs. \$18) from one Application to the next.
- b) Please explain why the 2010 fees payable by Brampton for Financial Services have increases significantly (\$267 vs. \$465) from one Application to the next.
- c) Please explain the significant increase in 2010 fees for Corporate Services charged to Remotes and Telecom from one Application to the next; while the charges to Brampton are virtually unchanged.
- d) Why, in the current Application, are there are no fees payable by Telecom for Telecom Fibre Lease and Maintenance Agreement as there were in EB-2008-0272?

QUESTION #11

Issue: Issue #3.4

Reference: Exhibit A/Tab 8/Schedule 3, pages 3 and 7

- a) Please revise Table 3 so that it also includes the fees payable by Networks to Remotes for services provided per Appendix G.

QUESTION #12

Issue: Issue #3.4

Reference: Exhibit A/Tab 8/Schedule 3 – Appendices

- a) Are there any fundamental changes in the services Hydro One Networks either receives from its affiliates or provides to its affiliates from what was outlined in Service Agreements filed in EB-2008-0272? If yes, please describe all such changes.

- b) For each of the changes outlined in part (a), please indicate how the Corporate Cost Allocation methodology (Exhibit C1/Tab 5) has been revised to accommodate the change.

QUESTION #13

Issue: #2.1

Reference: i) Exhibit A/Tab 12/Schedule 1, page 9
ii) OPA Publication – 2007 Final Conservation Results
http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=6563&SiteNodeID=139&BL_ExpandID=

- a) Please provide a schedule setting out the OPA sponsored CDM initiatives that Hydro One Networks participated in for the years 2006, 2007, 2008 and 2009 (to date).
- b) Please provide a schedule that sets out the participation by Hydro One Networks' Distribution customers by year for each of the programs identified in response to part (a). Please provide any estimates Hydro One Networks or the OPA has developed regarding the kW or kWh savings attributable to this participation by Hydro One Networks' Distribution customers.
- c) The OPA has verified the results for six of its 2007 programs. Please provide a schedule (similar to Table 4 in reference (ii)) setting out the contribution of Hydro One Networks' distribution customers to savings reported for each "verified" program. Note: For purposes of the responses please distinguish between Hydro One Networks' retail distribution customers and its embedded Directs and LDCs.
- d) For any of the other six 2007 OPA programs that Hydro One Networks participated in please provide an estimate of the 2007 savings and the full year 2008 savings attributable to Hydro One Networks' distribution customers, based on the most current assumptions available from the OPA regarding per participant savings, free-ridership, etc.

QUESTION #14

Issue: #3.8

Reference: Exhibit A/Tab 12/Schedule 2, pages 2-3

- a) Please confirm that Hydro One Networks' adoption of the amendments to the CICA Handbook regarding income taxes does not have any impact on the calculation of income taxes for purposes of establishing the 2010 or 2011 proposed revenue requirements? If it does, please explain the impact.

QUESTION #15

Issue: #1.2 and #4.6

Reference: Exhibit A/Tab 14/Schedule 1, page 2

- a) Please provide copies of the Business Plan instructions issue Q1-2009 and the Business Plan approved in June 2009.

QUESTION #16

Issue: #1.2

Reference: i) Exhibit A/Tab 14/Schedule 1, Appendix A, page 1 and Schedule 3, pages 2-3
ii) Exhibit A/Tab 14/Schedule 4, pages 6-7

- a) What is the source and date of issue for the Provincial GDP, Provincial Population, Provincial Housing, Commercial Output and Industrial Production forecasts presented in reference (ii)?
- b) Please compare the economic growth assumptions used by Hydro One Networks with the most recent projections made by the Provincial Government and the Bank of Canada.
- c) Given the ongoing changes in economic conditions worldwide, is Hydro One Networks aware of any other recent projections of economic activity for 2009-2011? If so, please provide.
- d) With respect to page reference (i), is Hydro One Networks aware of any more recent projections of inflation, cost escalation and exchange rates for 2009, 2010 and 2011? If yes, please provide.

QUESTION #17

Issue: #1.2

Reference: i) Exhibit A/Tab 14/Schedule 1, Appendix A, pages 1-2
ii) Exhibit A/Tab 14/Schedule 3, pages 3-6

- a) With respect to the methodology used for determining distribution interest capitalization rates, please provide more details on precisely what information is obtained from www.pcbond.com (Reference (ii), page 6).
- b) With respect to the methodology used for determining distribution interest capitalization rates, please provide, for each of the most recent 12 months, the actual 10-year Government of Canada bond yield, the average DEX mid-term corporate bond index yield and the resulting spread.
- c) Please compare Hydro One Networks' forecast interest capitalization rate for 2009 with the rates the OEB has prescribed for 2009.
- d) With respect to the methodology used to determine Hydro One Networks' Bond Rates for 2009-2011, please update the Hydro One's credit spreads based on the most recent month's data available.
- e) What is the sensitivity of Hydro One Networks' proposed 2010 and 2011 distribution revenue requirements to:
 - A 100 basis point change in forecast long-term interest rates. (Note: Please exclude any impact on ROE or short-term interest rates used in determining the cost of capital)
 - A 100 basis point change in the forecast interest capitalization rate for 2009-2011.
 - A 10 cent change in the forecast exchange rate (CDN\$ per US\$)?

QUESTION #18

Issue: #9.1

Reference: Exhibit A/Tab 14/Schedule 2, pages 1-12

- a) Please confirm whether or not the Hydro One Distribution Green Energy Plan outlined in this section is meant to meet the requirements of Section 70 (2.1) – part 2 of the recently amended OEB Act.
- b) Under Section 70 (2.1) of the Act a licensed distributor is required to prepare plans, in the manner and at the times mandated by the Board or as prescribed by regulation and to file them with the Board for approval for,
 - i. the expansion or reinforcement of the licensee's transmission system or distribution system to accommodate the connection of renewable energy generation facilities, and
 - ii. the development and implementation of the smart grid in relation to the licensee's transmission system or distribution system.

Given this context, why does the plan included a CDM component?

QUESTION #19

Issue: #9.2

Reference: Exhibit A/Tab 14/Schedule 2, pages 1-12

- a) With respect to page 7 (Updated), are the numbers shown for each year cumulative or the values for that specific year?
- b) With respect to updated page 8 (lines 15-25) and page 9 (lines 16-28), please provide more details regarding the methodology that will be used to determine whether the investments required to provide for new renewable energy generators are economic.
- c) With respect to updated page 14, are the OM&A costs shown for the period 2012-2014 an annual value or the total for the period? Does the same response apply to the 2012-2014 capital costs shown on pages 15 19 and 23?
- d) Why isn't any of the OM&A spending considered to be eligible for External Funding through the GAM?

QUESTION #20

Issue: #9.1 and #9.2

Reference: Exhibit A/Tab 14/Schedule 2, pages 15-19 (Updated)

- a) The costs associated with Investment Summaries D27, D28 and D29 total more than the Gross Capital Costs set out in the table on page 19. For each of the three investment summaries, please identify precisely what activities and costs (gross and net) are incorporated in the proposed Green Energy Plan under the category "Expansion of the Distribution System to Connect Renewable Energy Generation".
- b) On page 10 (lines 8-10) Hydro One Networks notes that for the purpose of establishing its proposed spending on Expansion it has identified regions where the potential for renewable energy generation is the highest. Please provide a schedule that sets out these regions and for each region identifies i) the renewable energy generation potential and how it was determined, ii) the costs included in each of D27, D28 and D29 by region and iii) the specific types of investment activities targeted for each region/area (i.e., with reference to the types of activities listed on page 16).

- c) For each of the three regions/areas with the highest capital spending requirements, please provide copies of the assessments/analysis undertaken to identify the Expansion spending required to support renewable energy generation.
- d) With respect to Investment Summaries D27-D29 in Exhibit D1/Tab 3/Schedule 3, please confirm that the Recoverable costs shown include the anticipated recoveries from the Global Adjustment mechanism as well as those recoverable from Generators? Please reconcile the Recoverable Costs reported in D27-D29 with the Externally Funded Capital reported on page 19.
- e) Pages 16-17 discuss the “expansion” of the distribution system to connect renewable energy generation. Under the current proposed amendments to the DSC renewable generators will be responsible for cost of “expansions” in excess of the renewable energy expansion cost cap. Given this context, does the external funding shown on page 19 include any “contributions” from Generators? If not, why not? If yes, please provide a breakout for each year.

QUESTION #21

Issue: #9.3

Reference: Exhibit A/Tab 14/Schedule 2, pages 16-19

- a) Please reconcile the 1% (net) load growth used to determine load growth benefits with the fact that the load forecast presented in Exhibit A/Tab 14/Schedule 4, page 19 is declining from 2008 to 2011. If the 1% is only applied to certain areas of the Province, please provide a schedule that sets out those areas experiencing load growth and those that are not with the relevant load increases/decreases by area that reconcile with an overall annual decrease in provincial load. On the same schedule, please identify which areas are included in the Green Energy Plan for purposes of Expansion Investment (consistent with the response to Question #20, part (b)).
- b) Please provide the complete analysis supporting the 3% Load Growth benefit factor (page 19).
- c) Was the calculation of the 15% Asset Replacement benefit factor done on an area by area basis taking into account the specific investment activities proposed in the Plan for each area (page 18)?

- d) If the response to part (c) is yes, please provide the analysis for the two areas that contribute the most to the total gross capital investment on Expansions.
- e) If the response to part (c) is no, please provide the complete analysis supporting the 15% benefit factor.

QUESTION #22

Issue: #9.2

Reference: Exhibit A/Tab 14/Schedule 2, pages 20-23 (Updated)

- a) The costs associated with Investment Summaries D28-D33 total more than the Gross Capital Costs set out in the table on page 23. For each of the investment summaries, please identify precisely what activities and costs (gross and net) are incorporated in the proposed Green Energy Plan under the category “Renewable Enabling Improvements to the Distribution System” and reconcile the External Funding reported on page 23 with the total Recoverable Costs associated with Renewable Enabling Improvements associate with these ISDs. Also, please indicate the portion spending in each ISD that is associated with the three different activity areas discussed in the three paragraphs on pages 22-23.
- b) Can the proposed spending for “Renewable Enabling Improvements to the Distribution System” be attributed to the specific areas/regions of Hydro One Networks’ service area that are deemed to have the highest potential for renewable energy generation development? If not, please provide a copy of the system wide assessment/analysis undertaken to identify the required Renewable Enabling Improvements.
- c) If the response to part (b) is yes, please provide a schedule that by region/area (consistent with the response to Question #20, part (b)) sets out for each region/area i) the gross capital investment, ii) the associated investment activities, iii) the costs of activities proposed to be partially funded by ratepayers (per pages 22-23) and iv) whether the region/area is considered heavily loaded (per page 22, lines 16-19).
- d) If the response to part (b) is yes, for each of the three regions/areas with the highest capital spending requirements for Renewable Enabling Improvements, please provide copies of the assessments/analysis undertaken to identify the spending required to support renewable energy generation.
- e) With respect to Investment Summaries D30-D33 in Exhibit D1/Tab 3/Schedule 3, please confirm that the Recoverable costs include the

anticipated recoveries from the Global Adjustment mechanism and those recoverable from Generators?

- f) Please reconcile the Recoveries reported in ISD #28-33 with the Externally Funded value reported on page 23.
- g) In either case, why are there no “recoverable costs” reported?

QUESTION #23

Issue: #9.3

Reference: Exhibit A/Tab 14/Schedule 2, pages 21-23 (Updated)

- a) Please provide the documentation from Hydro One Networks’ current or previous Business Plans that demonstrates it was “considering adding DS monitoring at some of its heavily loaded distribution stations” (per page 22, lines 13-15).
- b) Please provide documentation supporting the 30% factor referenced on page 22, line 17.
- c) Does Hydro One Networks’ proposed capital spending for 2010 and 2011 (per Exhibit D1 and D2) include any spending on DS monitoring for stations other than those included in the proposed Green Energy Plan? If yes, please indicate where this is documented in the Application.
- d) Please explain more fully how the 5% factor referred to on page 23 (lines 2-3) was established.
- e) Does Hydro One Networks’ proposed capital spending for 2010 and 2011 (per Exhibit D1 and D2) include any similar work on Remote Protection and Control of Sub-Transmission Reclosers other than that included in the proposed Green Energy Plan? If yes, please indicate where this is documented in the Application.

QUESTION #24

Issue: #9.1

Reference: Exhibit A/Tab 14/Schedule 2, pages 25-30 (Updated)

- a) With respect to page 26 (lines 3-6), please explain how “automated home energy networks” and “energy storage” qualify as smart grid investments.

- b) With respect to page 25 (lines 4-6), please explain why field testing Plug-In Electric Vehicles is considered to qualify as a smart grid investment.
- c) Please provide a comprehensive schedule that sets out the technologies and applications that Hydro One Networks proposes to “test” in the Owen Sound demonstration area (page 26). Please also describe how Hydro One Networks chose these technologies/applications.
- d) Please describe how Hydro One Networks has ensured that the pilots and field testing it is proposing with respect to smart grid technologies are not duplicative of work that is being done elsewhere.
- e) Does Hydro One Networks’ proposed Smart Grid spending include any R&D activities? If so, please describe and indicate the funding involved.
- f) Are any of the Smart Grid technologies/applications that Hydro One Networks has included in its plan related solely to the connection and integration of distributed generation? If yes, please describe.

QUESTION #24

Issue: #9.2

Reference: Exhibit A/Tab 14/Schedule 2, pages 25-30 (Updated)

- a) With reference to page 29 (lines 14-21), please provide a schedule that clearly sets out the activities and costs associated with each of the referenced ISDs that are incorporated in the Smart Grid component of the proposed Green Energy Plan.

QUESTION #25

Reference: Exhibit A/Tab 14/Schedule 2, page 2

- a) Please provide a schedule that sets out the impact on the proposed 2010 and 2011 revenue requirement of Hydro One Networks planned expenditures on Renewable Energy Generation Connection and Smart Grid, as set out in its Green Energy Plan.
- b) Please provide a schedule that set out the calculation of the \$8.0 M for 2010 and \$30.7 M for 2011 referred to at lines 24-25.

QUESTION #26

Issue: #9.1

Reference: Exhibit A/Tab 14/Schedule 2, page 31 (Updated)

- a) How many core CDM programs does the OPA have for 2009 and why is Hydro One Networks only participating in four of them?

QUESTION #27

Issue: #9.2

Reference: Exhibit A/Tab 14/Schedule 2, page 31

- a) What is the annual cost of the rate-funded PowerSaver® Plus program and where is it included in the proposed revenue requirement for 2010 and 2011?

QUESTION #28

Issue: #9.4 and #9.5

Reference: Exhibit A/Tab 14/Schedule 2, page 34

- a) In Hydro One Networks' view, what are the implications of the OEB approving its proposed Green Energy Plan for the period 2010-2014? In particular, please outline what Hydro One Networks considers to be the implications of such approval for the post 2011 period?

QUESTION #29

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, page 4

- a) Lines 6-7 state that the "2010 figures represents a decrease of 4.3% over the 2008 demand forecast". Please confirm whether the comparison is to 2008 forecast or actual values and, if forecast, which forecast (e.g., Was it the 2008 forecast as filed in EB-2007-0651?).

QUESTION #30

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, pages 8-9

- a) Please confirm that the 2006-2008 values listed in Table 2 are not actual CDM impacts, but rather calculated based on a share of provincial CDM

targets as set out in the IPSP. If they are “actual results”, please provide details as to how they were determined.

- b) Please provide the numerical basis for the referenced 15% (lines 5-6) and confirm whether it is only with respect to Hydro One Networks’ retail customers or does it reflect Hydro One Networks’ total customer base including Embedded Directs and LDC customers.
- c) Re part (b), if just with respect to Hydro One Networks’ retail customers, what portion of the total provincial use is accounted for by Hydro One Networks’ Embedded Direct and LDC customers?
- d) The IPSP (EB-2007-0707, Exhibit D/Tab 4/Schedule 1/Attachment 4, page 3) reports proposed conservation resource energy savings of 2.0 TWh in 2009, 6.9 TWh in 2011 and 8.8 TWh in 2011 (weather normal at the point of generation). Please reconcile these values and those included in Hydro One Networks’ Application (Table 2) with the 15% share assumption and the need to account for losses (between point of generation and point of delivery).

QUESTION #31

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, page 10

- a) Does Hydro One Networks use any models to forecast customer count? If so, please describe.
- b) Hydro One Networks’ customer count forecast appears to be developed entirely independently of the total load forecast (e.g., none of econometric models used to forecast total load include customer count as an explanatory variable). How does Hydro One Networks ensure consistency between its customer count forecast and its total load forecast?

QUESTION #32

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, pages 21-22

- a) Please explain how the State-Space approach in the regression equation differs from the standard Ordinary Least Square approach to regression analysis. Is this a common approach used in load forecasting?

- b) Please confirm that the Distribution Load is sales to Hydro One Networks retail customers and clarify the definition of retail (i.e. is it total load excluding embedded directs and LDCs?). If not, please clarify the definition.
- c) Over what period is the Monthly Econometric Model estimated?
- d) How does the model account for the LDC acquisitions that Hydro One Networks made a number of years ago?
- e) If the estimation period includes data for 2006, 2007 and/or 2008, has Hydro One Networks made any adjustments to account for the effect of conservation on load starting in 2006?
- f) If no adjustment is made, doesn't this mean there is some double counting of conservation impacts: i) once in the Model itself and ii) again, when the explicit CDM adjustment is made per page 8? Please explain your response.
- g) Please provide the values for the explanatory variable used to estimate the model and those used to forecast 2010 and 2011.
- h) Please provide the forecast of sales for 2010 and 2011 based on Monthly Econometric Model.
- i) The equation set out on page 21 (lines 10-16) does not include any seasonal or weather-related variables. However, the details provided on the output parameters make reference (line 22) to "seasonal factors". Please reconcile. Please also explain if and/or how the model takes into account the influence of weather on monthly loads.
- j) If the estimation period for the model includes data for 2006 and/or later and no adjustments are made to the actual sales data prior to the estimation of the model to account for the impact of CDM please undertake the following:
- Re-estimate the model's "equation" – but for 2006 and beyond increase the distribution load by the estimated effect of CDM as set out at Exhibit A/Tab 14/Schedule 4, page 8.
 - Provide the results in a form similar to that found on page 21, lines 20-34.
 - Using this equation and the forecast values of the explanatory variables (page 23, lines 12-23) forecast the distribution load for 2010 and 2011.
 - Prepare a schedule contrasting the results with those from part (h).

QUESTION #33

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, pages 23-24

- a) Please confirm that the Distribution Load is sales to Hydro One Networks retail customers. If not, please clarify the definition.
- b) Over what period is the Annual Econometric Model estimated?
- c) How does the model account for the LDC acquisitions that Hydro One Networks made a number of years ago?
- d) If the estimation period includes data for 2006, 2007 and/or 2008, has Hydro One Networks made any adjustments to account for the effect of conservation on load starting in 2006?
- e) If no adjustment is made, doesn't this mean there is some double counting of conservation impacts: i) once in the Model itself and ii) again, when the explicit CDM adjustment is made per page 8?
- f) Please provide the values for the explanatory variable used to estimate the model and those used to forecast 2010 and 2011.
- g) Please provide the forecast of annual sales for 2010 and 2011 based on Annual Econometric Model.
- h) If the estimation period for the model includes data for 2006 and/or later and no adjustments are made to the actual sales data prior to the estimation of the model to account for the impact of CDM please undertake the following:
 - Re-estimate the model's "equation" – but for 2006 and beyond increase the annual distribution load by the estimated effect of CDM as set out at Exhibit A/Tab 14/Schedule 4, page 8.
 - Provide the results of in a form similar to that found on page 23, lines 25-38.
 - Using this equation and the forecast values of the explanatory variables (page 23, lines 12-23) forecast the distribution load for 2010 and 2011.
 - Prepare a schedule contrasting the results with those from part (g).

QUESTION #34

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, pages 25-26

- a) For purposes of forecasting 2010 and 2011 energy sales using the End Use Model, what assumptions did Hydro One Networks make regarding residential unit energy consumption for the years 2005 through 2011 for each major residential end use? If the unit energy is assume to change over this period, please explain the basis for such changes.
- b) For purposes of forecasting 2010 and 2011 energy sales using the End Use Model, what assumptions did Hydro One Networks make regarding changes in commercial energy use by building type for the years 2005 through 2011? What was the basis for any assumed changes?

QUESTION #35

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, page 15

- a) With respect to page 15 (lines 25-26), please provide the details of the econometric model used to forecast load for the embedded distribution utility customers, including:
 - Explanatory variables used
 - Estimated coefficients and associated statistics
 - Data period used to estimate model
 - The values of the explanatory variables used to estimate the model
- b) Please provide the forecast of embedded distribution utility customer load for 2010 and 2011 based on this model and the projected values of the underlying explanatory variables.
- c) Were these results modified/adjusted at all as are result customer survey (page 16, lines 10-11) for the purpose of preparing the "before" CDM forecast set out on page 19? If so, please explain how and why.
- d) If the estimation period includes data for 2006, 2007 and/or 2008, did Hydro One Networks make any adjustments when estimating the model to account for the effect of conservation on load starting in 2006?
- e) If not, doesn't this mean there is some double counting of conservation impacts: i) once in the Model itself and ii) again, when the explicit CDM adjustment is made per page 8?

- f) If the estimation period for the model includes data for 2006 and/or later and no adjustments are made to the actual sales data prior to the estimation of the model to account for the impact of CDM please undertake the following:
- Re-estimate the model's "equation" – but for 2006 and beyond increase the annual distribution load by the estimated effect of CDM as set out at Exhibit A/Tab 14/Schedule 4, page 8.
 - Provide the results of in a form similar to that found on page 23, lines 25-38.
 - Using this equation and the forecast values of the explanatory variables (page 23, lines 12-23) forecast the distribution load for 2010 and 2011.
 - Prepare a schedule contrasting the results with those from part (b).

QUESTION #36

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, pages 15-16

- a) Please provide details as to how the "industrial analysis" combined the input from all of the referenced information sources to forecast the load for embedded industrial customers.
- b) How did Hydro One Networks ensure that the forecasts provided through the customer survey (page 16, line 2) did not already include some/all of the CDM savings that are removed through the CDM adjustment (per page 8)?

QUESTION #37

Issue: #2.1

Reference: Exhibit A/Tab 14/Schedule 4, page 19

- a) Please provide the schedule that sets out the forecast 2009, 2010 and 2011 load (before and after CDM) by rate class as used in Exhibits G1 and G2; the forecast customer count by class and the resulting average use per customer by class for each year.
- b) Please explain how the load forecasts for individual customer classes are developed from the total load forecast.
- c) Please provide a schedule that sets out for the years 2006-2008 - the load by customer class (both actual and weather normalized), the number of

customers in each year and the resulting average use per customer (both actual and weather normalized).

QUESTION #38

Issue: #4.6

Reference: i) Exhibit A/Tab 14/Schedule 5, pages 2-17
ii) Exhibit A/Tab 14/Schedule 6, pages 4-10
iii) EB-2008-0272, Undertaking J2.7
iv) EB-2008-0187, Undertaking J1.1

- a) Reference (i) refers to the prioritization process resulting in a preliminary investment plan (page 2, lines 12-13) and Reference (ii) refers to the process establishing minimum levels of investment (page 5, lines 8-9).
- Please provide a schedule that sets out for 2010 and 2011, the preliminary capital spending proposed by management, the minimum level of capital spending established via the process and the final proposed level of capital spending proposed in the Application using a level of detail similar to that found in References (iii) and (iv).
 - Please provide a schedule that sets out for 2010 and 2011, the preliminary OM&A spending proposed by management, the minimum level of OM&A spending established via the process and the final proposed level of OM&A spending proposed in the Application using a level of detail similar to that found in References (iii).
- b) The discussion in References (i) and (ii) refers to investments without making a particular distinction between capital and OM&A spending. Does the “investment prioritization process” consider all capital and OM&A programs jointly as one group or does it prioritize OM&A and capital projects as separate groups?
- c) If the investment prioritization process considers both capital and OM&A spending as one “group”, please indicate (based on Hydro One Networks’ investment prioritization process):
- What areas of the proposed capital and OM&A spending for 2010 and 2011 would be reduced if overall funding was reduced by 10%. Please explain, with reference to the risks and impacts, why these areas were selected.
 - What areas of the proposed capital and OM&A spending for 2010 and 2011 would be increased if overall funding was increased by 10%. Please explain, with reference to the risks and impacts, why these areas were selected.

- d) If the investment planning process considers capital and OM&A spending separately, please respond to part (c) but address capital and OM&A separately.

QUESTION #39

Issue: #4.6

Reference: i) Exhibit A/Tab 14/Schedule 5, pages 7-8 and pages 13-14
ii) Exhibit A/Tab 14/Schedule 6, pages 4-6

- a) The discussion in Reference (i) indicates that after consideration of factors such as asset condition and reliability performance a replacement program for wood poles is developed and then this “final wood pole replacement plan is included in the Hydro One Investment Plan for prioritization” (page 8, lines 17-23). However, Reference (ii) suggests that wood pole programs with various levels of replacement are developed and they are all considered/evaluated in the corporate-wide Prioritization process. Please reconcile.
- b) Similarly, with respect to the example given for System Capability Reinforcement (page 13, lines 10-17), the discussion indicates that after an assessment of alternatives and evaluation against other Development capital investments, the proposed spending was include in the Hydro One Investment Plan for prioritizing. This appears to be inconsistent with Reference (ii) which suggests that alternative spending levels are evaluated on corporate-wide investment basis. Please reconcile.

QUESTION #40

Issue: #4.2 and #4.6

Reference: Exhibit A/Tab 14/Schedule 6, pages 6-7

- a) Please explain the basis for the \$120 M liability value associated with not replacing the 20,000 poles.
- b) What is the increased spending over the five year period associated with replacing the 20,000 poles?
- c) Please reconcile the comments on page 7 (lines 6-9) that the minimum level of spending is manageable as poles usually require a degree of adverse weather to cause failure with the comment on the same page (lines 14-16) that the failure of 20,000 poles has a medium likelihood of occurrence.

QUESTION #41

Issue: #4.6

Reference: Exhibit A/Tab 14/Schedule 8, page 2

- a) Have there been any delays in the execution of Hydro One Distribution's planned 2008 or 2009 work programs as a result of material and equipment availability? If yes, please indicate specifically what program areas have been impacted, what the associated materials/equipment are and what the resulting delay was.
- b) Please describe how Hydro One Networks is addressing the material and equipment availability issue.

QUESTION #42

Issue: #3.2

Reference: Exhibit A/Tab 15/Schedule 2, page 3

- a) The report noted that Hydro One Networks performed better than average in terms of hours per tree, but less than average in terms of cost per tree (lines 13-17). The report suggests that this was due to Hydro One Networks' long cycle length. However, why wouldn't a longer cycle length and greater vegetation per tree also lead to a higher hour per tree value as well?
- b) Did the consultants consider at all the fact that the better than average performance when measured based on hours but lower than average performance based on costs was due to a higher per hour labour rate for Hydro One Networks relative to the comparators? If not, please discuss whether this would explain the observed differences.

QUESTION #43

Issue: #3.2

Reference: Exhibit A/Tab 15/Schedule 2, Attachment 1

- a) With respect to page 16, please clarify whether "kilometers managed" are the total line kilometers (i.e., the kilometers managed over the total vegetation cycle) or the kilometers subject to vegetation management in a given year of the cycle.

- b) Please confirm that if the definition in part (a) is total line kilometers then utilities with longer cycles will have lower values. However, if the definition is kilometers “managed” in a given year then utilities with longer cycles could be expected to have higher values due to the cycle length problem outlined on page 18.
- c) With respect to page 23, please clarify the definition of “kilometers” used in section 4.1.5.
- d) With respect to page 27, please explain why the effect of the “cycle period” is minimized when using a system kilometer measure.
- e) With respect to page 29, please confirm that longer cycle times will tend to:
 - Increase annual vegetation management costs by virtue of the increased vegetation mass that will accumulate.
 - Decrease annual vegetation management costs by virtue of the fact less kilometers are treated each year.

QUESTION #44

Issue: #3.1 and #4.2

Reference: Exhibit A/Tab 16/Schedule 1, pages 3-4

- a) Please provide the results of the most recent First Quartile and CEA benchmarking studies that Hydro One Networks has participated in dealing with its Distribution Business (page 4).
- b) Please indicate those areas where Hydro One Networks has solicited information on best practices over the past two years and what changes have been adopted based on this information (page 3, lines 20-21).

QUESTION #45

Issue: Issue #3.1 and #4.2

Reference: Exhibit A/Tab 16/Schedule 1, page 5

- a) Please indicate what initiatives gave rise to the 2009 non-Cornerstone savings shown for OM&A and Capital.

QUESTION #46

Issue: #1.1

Reference: i) Exhibit A/Tab 18/Schedule 1, pages 2-3
II) EB-2008-0272 Decision, page 21

a) Please provide a schedule identifying the planned 2009 capital spending included in the current Application for each of the projects included in the Directive from EB-2008-0187.

b) In Reference (ii) the Board made the following finding:

However, the Board finds that Hydro One's evidence as it relates to the factors driving the spending levels has been insufficient. In addition to the demographic data that was filed, Hydro One should have filed more real-life data samples related to the determinative factors referenced in the company's investment plan process. This need not have been a reproduction of all the company's documentation related to its internal decision-making but rather an illustrative cross-sectional sampling related to the determinative factors and pertaining to various asset groupings.

Since Hydro One Networks uses the same investment planning prioritization process for transmission and distribution, please indicate how Hydro One Networks has refined the current application to address the concern expressed by the Board.

QUESTION #47

Issue: #5.1

Reference: Exhibit B1/Tab 1/Schedule 1

a) Please confirm that, under Hydro One Networks' proposal, the Board-approved ROE and deemed short-term debt rate for its distribution business for 2010 and 2011 will likely differ from that applicable to the balance of the electricity distributors in the province who are regulated by the OEB.

b) What are Hydro One Networks' views regarding the establishment of a variance account to track the revenue requirement impact of such differences?

QUESTION #48

Issue: #1.2 and #5.2

Reference: Exhibit B1/Tab 2/Schedule 1, pages 6-7

- a) If there is a more recent forecast available from Consensus Forecasts for 10-year government of Canada bond yields for 2009, 2010 and/or 2011, please update the Hydro One forecast yields set out in Table 4 using this forecast and the Hydro One credit spreads for the month the forecast was issued.

QUESTION #49

Issue: #5.2

Reference: Exhibit B2/Tab 1/Schedule 2, page 4

- a) The Updated Schedule shows two 10-year issues in 2009 – one in June and a second in September. Please confirm that the values shown are the actual values.

QUESTION #50

Issue: #3.1

Reference: Exhibit C1/Tab 2/Schedule 2, pages 4-10

- a) With respect to Planned Station Maintenance (page 6), will the planned spending on PCB testing and retro-fills in 2010 and 2011 complete Hydro One Networks' obligations to retire PCBs in excess of 500 ppm?
- b) The investment prioritization process indicates that various levels of spending are assessed during the planning process (Exhibit A/Tab 14/Schedule 6, page 5). Please describe the different levels of funding for Station Sustaining OM&A that were considered during the prioritization process and identify the risks attributed to each.

QUESTION #51

Issue: #3.1

Reference: Exhibit C1/Tab 2/Schedule 2, pages 10-27

- a) Please explain why the provision for storm-related OM&A expense was increased from the \$6 M included in 2008 rates (EB-2007-0681, C1/2/2, page 10) to \$8 M for 2010 and \$8.3 M for 2011 (page 13).
- b) The level of 2008 costs for Trouble Calls included in Hydro One Networks 2008 Rate Application was \$58.9 M. The increased allowance for storm-related OM&A expenses explains some but not all of the higher \$65.3 M and \$68.2 M values forecast for 2010 and 2011. Please explain the

balance of the increase, given that “trouble call volumes have remained relatively stable” (page 13, line 25).

- c) Underground Cable Locate costs are forecast to increase from the Board approved level of \$10.5 M in 2008 (EB-2007-0681, C1/T2/S2, page 10) to \$12.8 M in 2010 and \$13.3 M in 2011 (i.e., 22% between 2008 and 2010). At the same time the number of cable locates is forecast to increase from 75,800 to 82,250 per annum (8.5%). Please explain the remaining 12% plus increase over the two year period.
- d) Service Disconnect costs are forecast to increase from the Board approved level of \$7.5 M in 2008 to \$8.9 M in 2010, more than 18%. At the same time the number of service disconnects is forecast to increase from 10,600 to 11,600 – 9.4%. Please explain the remaining 8.5% increase over the two years.
- e) Please explain the reason for the higher level of spending on Line Patrols, Wood Pole Assessment & Asset Data Collection (\$16.7 M) in 2009 relative to the approved 2008 level of \$13.4 M and the actual 2008 spending level of \$11.4 M (pages 16-19).
- f) The level of spending proposed on Line Patrols, Wood Pole Assessment & Asset Data Collection for 2010 is \$15.4 M (when the needed spending on TDR is excluded). Please explain the reason for this increase over the 2008 Board-approved spending level of \$13.4 M (pages 16-19).
- g) Please explain why the actual Waste Management costs for 2008 are more than 20% higher (\$3.7 M vs. \$3.0 M) than the Board approved value (page 22).
- h) The cost of customer inquiries for 2010 is \$4.4 M relative to the Board approved cost of \$3.5 M for 2008. However, the referenced number of inquiries in the current Application is 8,000 (page 25) versus 9,000 in EB-2007-0681 (C1/2/2, page 22). Please reconcile and provide the reasons for the increase in costs given the decline in inquiries.
- i) The investment prioritization process indicates that various levels of spending are assessed during the planning process (Exhibit A/Tab 14/Schedule 6, page 5). Please describe the different levels of funding for Line Sustaining OM&A that were considered during the prioritization process and identify the risks attributed to each.

QUESTION #52

Issue: #3.1 and #6.1

Reference: Exhibit C1/Tab 2/Schedule 2, pages 27-32

- a) Please confirm that the Metering OM&A does not include any OM&A costs for smart meters installed after the end of 2008 (page 30). If it does, what are costs included for 2010 and 2011?
- b) Please explain why there is no Smart Meter OM&A reported for 2008 and 2009 (page 28) given that in EB-2007-0681 the Board approved the inclusion of smart meter installed up to December 31, 2007 in the 2008 rate base.
- c) What were the 2008 and 2009 actual OM&A expenses associated with these meters (i.e., smart meters installed prior to December 31, 2007) and were any of these costs recorded in the Smart Meter Deferral Account?
- d) The Application states (page 30) that the OM&A costs for this period (presumably 2010-2011) cover work needed to operate the data collection network and deliver the necessary meter data to the MDM/R.
 - What are Hydro One Networks' assumptions regarding when the MDM/R will be up and running and Hydro One Networks will be required to "deliver" data to it?
 - What is the basis for these assumptions?
 - Please indicate what portion of the \$6.7 M for 2010 and \$6.9 M for 2011 is for OM&A related directly to the smart meters installed prior to December 31, 2008 and what portion is due to the work associated with the data collection network.
- e) Please explain how the "increases in 2010 and 2011 of \$1.2M and \$1.3 M respectively" were calculated (page 32, lines 17-19).
- f) Please provide an estimate of the 2008 actual Customer Retail Meter and Wholesale Revenue Meters OM&A excluding the expenditures on Telecom and Control (page 32, lines 4-6).

QUESTION #53

Issue: #3.2

Reference: Exhibit C1/Tab 2/Schedule 2, pages 32-41

- a) Please provide a schedule that sets out the number of km of line cleared in each year from 2006-2009 relative to the 14,300 km planned for 2011.

- b) The proposal states that the 2007 and 2008 spending levels were commensurate with an eight-year cycle whereas the 2011 spending is reflective of a seven-year cycle. What cycle period is the 2009 spending reflective of?

QUESTION #54

Issue: #3.1 and #9.2

Reference: i) Exhibit C1/Tab 2/Schedule 3
ii) Exhibit A/Tab 14/Schedule 2, page 12

- a) Are any of the costs for Data Collection, Engineering and Technical Studies recoverable from either load or generator customers?
- If yes, what is the expected cost recovery for 2010 and 2011 from load customers and from generator customers? How do these recovery amounts compare with the OEB-approved and actual amounts for 2008?
 - If no, why not?
- b) Hydro One Networks' Green Energy Plan includes \$3 M in Development OM&A related to renewable generation connection for 2010 and 2011. Is this the \$2.8 M referred to in reference (i) at page 3 (lines 24-27)? If not, please indicate how the \$3 M is split between the cost categories shown in Table 1.
- c) Is the \$3 M in Development OM&A related to renewable generation that is included in Hydro One Networks' Green Energy Plan recoverable through the GAM under Ontario Regulation 330/09? If not, please explain why?
- d) Is any of the increased spending on R&D related to generation connections included in the Green Energy Plan (reference (i), page 6, lines 5-6)? If not, why not? If yes, why is the spending not included in the Green Energy Plan?

QUESTION #55

Issue: #3.1 and #9.2

Reference: Exhibit C1/Tab 2/Schedule 4

- a) Please explain more fully how Operations costs vary based on storm activity and planned outage quantities (page 8).

- b) Please explain more fully how distributed generation and smart meters lead to an increase in the cost of Operations from the approved 2008 level of \$9.5 M to \$12.4 M in 2010.
- c) Given that the increases in Operations costs and Operating Support costs are, in part, attributed to greater distributed generation – why aren't any of these cost increases captured in the proposed Green Energy Plan? How much of these increases is attributable to renewable distributed generation?
- d) The investment prioritization process indicates that various levels of spending are assessed during the planning process (Exhibit A/Tab 14/Schedule 6, page 5). Please describe the different levels of funding for Operations OM&A that were considered during the prioritization process and identify the risks attributed to each.

QUESTION #56

Issue: #3.1

Reference: Exhibit C1/Tab 2/Schedule 5

- a) Please explain more fully how the forecasted bad debt expense of \$17.1 M for 2010 was established (page 11).
- b) What are the year-to-date bad actual bad debt expenses for 2009?
- c) Please explain more fully the basis for the \$3 M increase in Customer Service Operations attributed to managing planned customer demand from distributed generation customers (page 4).
- d) Please provide a schedule that breaks out the annual spending on Customer Service Operations into its components (as set out on pages 5-10) for the years 2006 to 2011.

QUESTION #57

Issue: #3.3

Reference: Exhibit C1/Tab 2/Schedule 7, pages 1-22

- a) The investment prioritization process indicates that various levels of spending are assessed during the planning process (Exhibit A/Tab 14/Schedule 6, page 5). Please describe the different levels of funding for Corporate Functions and Services that were considered during the prioritization process and identify the risks attributed to each.

- b) With respect to Corporate Management (pages 3-4), please explain more fully how the requirements of the GEGEA increase the costs for this category and precisely what the cost increases are for (e.g., staff increases, external consulting, etc.).
- c) With respect to Finance (page 5), the EB-2007-0681 Application included Finance costs for 2008 of \$26.9 M (Total) and \$12.1 M (Dx Allocation). Please restate both of these values so that they exclude Outsourcing and Enablement and are comparable to the 2010 and 2011 costs in the current Application. Please indicate how much of the adjustment is due to the transfer of Outsourcing versus Enablement.
- d) Please explain the increase in (Total) Finance costs from 2008 Approved (adjusted per part (c)) to \$30.4 M in 2010.
- e) Please explain the increase in Hydro One Inc. Insurance Premiums from \$4.9 M in 2008 to \$6.5 M in 2010 (page 8).
- f) Please explain the increase in (Total) Human Resource cost from 2008 Approved (\$12.6 M per EB-2007-0681) to \$18.1 M in 2010, particularly since many of the issues raised in the current application (e.g., staff demographics, training for new hires, etc.) were also referenced in the previous application.
- g) How many new hires is Hydro One Inc. planning for 2010 and 2011 and how does this compare with the planned (per EB-2007-0681) and actual hires for 2008?
- h) With respect to First Nations and Métis Relations, what are the 2008 (approved and actual) and projected 2009 costs – both Total and Distribution (pages 13-14)?
- i) With respect to Regulatory Costs (page 17, lines 21-23), the Application states that the \$2.1 M and \$4.8 M for 2008 and 2009 respectively were included in “Other Distribution Costs” but then goes on to state that the values include the costs of Transmission rate applications. Please reconcile and clarify what the Distribution Business’ share of Incremental and Major Rate Hearing Costs was for 2008 and 2009.
- j) With respect to Corporate Security (page 21), has the new Theft of Electricity Investigation Program led to increased recoveries for theft of power or an (implicit) reduction in losses? If yes, please indicate where these “savings” are captured in the application. If not, what is the justification for the program?

QUESTION #58

Issue: #9.2

Reference: Exhibit C1/Tab 2/Schedule 7, pages 1-22

- a) For a number of the CFFS cost areas the GEGEA is cited as a reason for cost increases in 2010 and 2011. However, the proposed Green Energy Plan does not include any of these costs or associated activities. Please reconcile.
- b) Please provide a schedule that sets out for each CCFS function/service area the 2010 and 2011 Total Cost and Dx Allocation attributable to the GEGEA and, more specifically, smart grid and renewable energy generation.

QUESTION #59

Issue: #3.1

Reference: Exhibit C1/Tab 2/Schedule 7, pages 22-25

- a) With respect to the Environmental Provision, the Application states that the “resultant impact on OM&A expense is nil”. In Exhibit C1/Tab 2/Schedule 2 the increase in 2010 OM&A costs attributed to the new Federal Government’s PCB regulations is \$3.8 M for Stations (page 8) and \$5.5 M for lines (page 22). However, the increase in the provision from 2008 is only \$3.7 M – please reconcile.

QUESTION #60

Issue: #3.4

Reference: Exhibit C1/Tab 2/Schedule 8

- a) Please confirm that the totals shown in Table 1 for 2006-2011 are for Hydro One Networks. Please also confirm that the Asset Management function does not provide any services/support to Hydro One Remotes Inc. or other affiliates.
- b) For Strategy and Business Development (page 5), please explain the new activities that lead to an increase in costs from \$6.3 M in 2008 to \$11.0 M in 2010.

- c) With respect to System Investment (page 7), please confirm that for the EB-2007-0681 Application the cost of “Processes and Policies” were part of System Investment.
- d) With respect to System Investment (page 7), please explain what leads to the increase in the portion of costs allocated to Distribution from less than 25% in 2008 (EB-2007-0681, C1/T2/S6, page 41) to almost 50% in 2010.
- e) Real Estate and Facilities costs increase between 2008 and 2010 by 38% (page 16). The application makes reference to expanded work space needs due to increased staff levels (page 18). Please provide increases in year-end staff count or other metrics over the same period that would support this level of increase.
- f) With respect to Contracts and Business Relations, please explain the more than 25% increase between 2008 and 2010 (page 20).
- g) The investment prioritization process indicates that various levels of spending are assessed during the planning process (Exhibit A/Tab 14/Schedule 6, page 5). Please describe the different levels of funding for the following functions/services that were considered during the prioritization process and identify the risks attributed to each:
- Strategy and Business Development
 - System Investment
- If Asset Management OM&A was considered on an envelop basis during the investment prioritization process, please describe the different levels of overall funding that were considered during the prioritization process and the relative risks attributed to each.

QUESTION #61

Issue: #9.2

Reference: Exhibit C1/Tab 2/Schedule 8

- a) The Application states (page 4) that the GEGEA has an impact on the Asset Management spending for 2010 and 2011. However, none of the costs associated with Asset Management are included in the proposed Green Energy Plan. Please reconcile.
- b) Please provide a schedule that sets out for each Asset Management function/service area the 2010 and 2011 Total Cost and Dx Allocation attributable to the GEGEA and, more specifically, smart grid and renewable energy generation.

QUESTION #62

Issue: #3.4

Reference: Exhibit C1/Tab 2/Schedule 9

- a) The 2009 review undertaken by Black and Veatch (Exhibit C1/Tab 5/Schedule 1) addresses CCFS costs and Asset Management costs but does not appear to cover Shared Services for IT. Please confirm if this is the case.
- If IT costs were addressed, please indicate where the discussion and conclusions can be found.
 - If not, why not and what process was used to assess the reasonableness of the allocation of IT costs to Distribution.
- b) For OMS Incremental Sustainment, the total costs for 2010 are less than those included in EB-2007-0681 for 2008 (\$6.1 M vs. \$6.6 M). However, the Distribution portion of the costs increases from \$3.8 M to \$4.9 M. Please explain the significant shift in cost responsibility to the Distribution business.

QUESTION #63

Issue: #3.3

Reference: Exhibit C1/Tab 2/Schedule 9

- a) With respect to IT Sustainment, please explain why the actual 2008 costs are 20% higher (i.e., \$51.4 M vs. \$42.8 M) than those forecast in EB-2007-0681 (C1/T2/S6, page 59).
- b) What was the COLA cost factor for 2008 – both the value used for EB-2007-0681 and the actual value?
- c) Does a change in the COLA cost factor from \$9.9 M in 2009 to \$11.3 M in 2010 mean that Base IT Sustainment Costs increase by \$1.4 M? If not, please explain how the change in COLA cost factor influences annual costs.
- d) If the response to part b) is yes, please explain why the changes for Base IT Sustainment costs in 2010 and 2011 do not reconcile with the changes in the “cost factor”.

- e) With respect to Other Incremental Sustainment (page 4), please explain why the actual costs for 2008 (\$14.8 M) are 45% higher than those forecasted for 2008 in EB-2007-0681 (C1/T2/S6, page 59).
- f) How much of the overall increase in Other Incremental Sustainment between 2008 (actual) and 2010 is due to Cornerstone Phase 1 and Phase 2?
- g) With respect to Voice Services, what are the “new site builds” (page 18)? How do they plus the increased head count (page 18, line 20) result in an almost 80% increase in costs over approved 2008 levels from EB-2007-0681 (i.e., \$6.1 M vs. \$3.4 M)?
- h) With respect to IT Management & Project Control Expenditures, costs increase by more than 30% between 2008 and 2009 even after excluding the new Enablement costs for 2009. Please explain the reason for the increase.
- i) With respect to IT Management & Project Control Expenditures, what is the additional cost allowance included in 2010 and 2011 related to the Inergi Outsourcing contract reaching end of term (page 21, lines 11-12) and what was the cost of this contract for 2008 and 2009?
- j) With respect to IT Management & Project Control Expenditures and the \$16.4 M increase between 2008 and 2010 (\$23.9 M vs. \$7.5 M), how much of this increase remains unexplained after consideration is given to i) the transfer of the Enablement Department (\$6.6 M), ii) the transfer of the Information Assets Department (\$5.2 M) and iii) the increased allowance for the termination of the Inergi contract? If more than \$0.5 M – please provide an explanation.
- k) With reference to page 22 (lines 15-20), please indicate where in Exhibit C1/Tab 2/Schedule 8 (i.e., Asset Management) it is acknowledged that the Information Asset Department was transferred out to IT and the costs for 2010 (and onward) reduced accordingly.

QUESTION #64

Issue: #2.2

Reference: Exhibit C1/Tab 2/Schedule 11

- a) For each Cost of Sales Category (page 1), please indicate what the corresponding revenue is for the work. In particular, is the \$3.0 M in revenue for 2010 New Connects/Upgrades shown in Exhibit E1/Tab 1/Schedule 2, page 3 directly associated with the \$2.7 M in costs shown

here? Similarly, is the 2010 Other External Work of \$6.2 M directly associated with the Lines-Contestable Work shown here? If not, please explain the differences.

QUESTION #65

Issue: #3.7

Reference: Exhibit C1/Tab 2/Schedule 12

- a) Please explain the decrease in Rights Payments for 2008 and why it is not maintained going forward.

QUESTION #66

Issue: #3.5

Reference: i) Exhibit C1/Tab 3/Schedule 2
ii) EB-2008-0272, Exhibit I/Tab 1/Schedule 19
iii) EB-2008-0272, Exhibit I/Tab 6/Schedule 37

- a) Please update the schedule provided in Reference (ii) so that it covers the years 2006 to 2011.
- b) Please update the schedule provided in Reference (iii) – part a-i) (i.e. Splitting Wages between Capital and OM&A) so that it covers the period 2006-2011.
- c) With respect to Reference (i), page 9 (lines 20-22), please indicate the basis for the 33% and 16% figures (i.e., show the data values used and their sources).
- d) If practical, please prepare comparisons between Hydro One Networks and Hydro One – Brampton Networks for PWU Staff and MP Staff positions similar to those found on pages 14 and 15.

QUESTION #67

Issue: #3.5

Reference: Exhibit C1/Tab 3/Schedule 2, Appendix A

- a) Please explain how the pension costs are allocated between transmission and distribution (page 2).

- b) Could a similar methodology be used to reasonably split Hydro One Networks' Total Wages cost between transmission and distribution? If not, why not?
- c) If the response to part (b) is yes, please perform the analysis to split the Hydro One Networks' wages as presented in response to Question #66, part (b).

QUESTION #68

Issue: #3.4

Reference: Exhibit C1/Tab 5/Schedule 1

- a) The Application states that B&V was commissioned to update the methodology used to allocate common costs (page 1). The Application goes on (page 2) to discuss the impact of updating the cost drivers. Please clarify whether the referenced to "updating the cost drivers" means i) simply that the values of the defined drivers were updated to reflect more recent data or ii) the actual cost drivers used were reviewed.
- b) With respect to part (a), please provide a schedule that sets out all instances where the actual cost driver used (as oppose to simply the value of the driver) was changed and in each case indicate:
- The cost category involved
 - The total 2010 and 2011 costs
 - The impact on the allocation of distribution of changing the driver
 - The rationale for the change.
- c) Please provide a schedule that breaks down the \$148 M in 2010 Distribution CF&S costs reported in Exhibit C1/Tab 5/Schedule 1/Attachment 1, page 10 into sufficient detail that it can be reconciled with the OM&A costs proposed in the Application and provide the reconciliation. For example, the schedule should show the contribution of the CF&S costs assigned to Distribution to each of the Shared Services costs proposed for Distribution as set out at Exhibit C1/Tab 2/Schedule 6, page 3. Similarly, it should show the contribution of allocated CF&S costs to the OM&A proposed for Asset Management and Customer Care.

QUESTION #69

Issue: #3.4

Reference: Exhibit C1/Tab 5/Schedule 2

- a) Page 1 (lines 20-23) makes reference to B&V being commissioned to update the capital overhead methodology. It also refers to the 2010-2011 rates being calculated consistent with this revised methodology. The B&V Report (Attachment 1, page 1) states that the methodology used conforms to the OEB-accepted methodology as opposed to stating that the OEB-accepted methodology is used.
- Is the methodology (as opposed to the data inputs) used in this application the same as that used in EB-2007-0681 and accepted by the OEB?
 - If not, please provide a description of any changes to the “methodology” (as opposed to the inputs) used for this Application versus the methodology used in EB-2007-0681. In doing so, please explain the reasons for the changes and the overall impact on the capitalization rates for 2010 and 2011. Note: If B&V prepared a separate report outlining the revised methodology please provide it.
- b) With respect to Attachment 1, Appendix A, page 1 – please provide the equivalent schedule with the years 2008 (actual) and 2009 (forecast).

QUESTION #70

Issue: #4.4

Reference: Exhibit C1/Tab 5/Schedule 3, Attachment 1, page 1

- a) The B&V report states that “no common assets are allocated to Telecom and Remote Businesses, because these amounts would be very small”. Please provide the order of magnitude involved.

QUESTION #71

Issue: #3.6 & #8.3

Reference: Exhibit C1/Tab 6/Schedule 1

- a) With respect to page 2, Table 1, please explain why there are no Smart Meter Exclusion costs for 2006-2008, as in each of these years depreciation costs for that year (and in some cases earlier years) were tracked in a deferral account.
- b) Please confirm that the Smart Meter Exclusions costs for 2009 and beyond are for Smart Meters installed after December 31, 2008. If not please explain. Also, please indicate if the “exclusion” includes any smart meter program costs besides those directly related to the meter installed (e.g., communication system costs, central data management costs, etc.).

- c) Please confirm that the Depreciation and Amortization expense for 2010 and 2011 does not include any depreciation/amortization for conventional meters subject to replacement under the Smart Meter Program. If any such costs are included please explain.

QUESTION #72

Issue: #3.1

Reference: Exhibit C2/Tab 1/Schedule 1, page 1

- a) Please clarify Footnote #1 by indicating the Smart Meter OM&A costs included and excluded from each year's reported OM&A. For example, does the 2008 value include the OM&A for smart meters installed in 2006 and 2007 but not that for the smart meters installed in 2008? Similarly, does the 2006 and 2007 OM&A exclude all Smart Meter OM&A?

QUESTION #73

Issue: #4.1 and #8.3

Reference: Exhibit D1/Tab 1/Schedule 1, pages 2-3

- a) Please clarify whether the In-Service Additions and Gross Asset Balance values reported in Table 2 included the capital cost for smart meter additions after December 31, 2008.
- b) Please clarify whether the Accumulated Depreciation values reported in Table 1 include the depreciation for smart meter additions after December 31, 2008.
- c) The footnote to Table 1 explains that the Smart Meter adjustment is meant to exclude from the Revenue Requirement the depreciation associated with Smart Meters that is currently tracked in a deferral account.
- Is the reference to "currently" include the depreciation for smart meter additions in 2008?
 - Please explain more clearly how the \$2.3 M for 2010 and 2011 was calculated and how the values relate to the Smart Meter Exclusions of \$16.5 for 2010 and \$24.2 M for 2011 discussed in Exhibit C1/Tab 6/Schedule 1, page 2.
- d) Please confirm that the Distribution Rate Base set out in Tables 1 and 2 does not include any costs for conventional meters subject to replacement under the Smart Meter Program. If any such costs are included please explain.

QUESTION #74

Issue: #9.2

Reference: Exhibit D1/Tab 1/Schedule 3

- a) Are the Development capital additions shown in Table 1 net of the external funding to be provided by the GAM? What is the external (GAM) funding associated with the capital additions for 2010 and 2011?
- b) The text on page 3 suggests that capital additions are increasing in 2010 and 2011 relative to historic years due to a higher level of New Connections and Upgrades activity. However, Exhibit D1/Tab 3/Schedule 3, page 5 (lines 12-15) states that the level of customer contributions is expected to remain at historic levels (prior to Update and adjustment for proposed DSC changes). Please reconcile.

QUESTION #75

Issue: #4.5

Reference: Exhibit D1/Tab 1/Schedule 4, page 3

- a) Please provide a schedule setting out the calculation of Cost of Power values for 2010 (\$2,008.4 M) and for 2011 (\$1,994.6 M). In doing so please provide the rates and volumes assumed for each cost of power component.
- b) Are any of Hydro One Networks' customers (i.e., Retail customers or Embedded LDCs & Directs) registered as "Market Participants" with the IESO? If yes, what percentage of total forecast load for 2010 and 2011 do these customers represent and has this been taken into account in the Cost of Power calculations?

QUESTION #76

Issue: #4.6

Reference: Exhibit D1/Tab 2/Schedule 1

- a) With respect to Section 4.2 (pages 19-26), please comment on the change in asset condition for each of the P2 categories from that documented for purposes of EB-2007-0681.

QUESTION #77

Issue: #4.1

Reference: Exhibit D1/Tab 3/Schedule 1

- a) Please provide a schedule setting out the 2008 Board approved capital spending consistent with Table 1 (page 2).

QUESTION #78

Issue: #4.2

Reference: Exhibit D1/Tab 3/Schedule 2, page 3

- a) Please explain the increase in 2008 capital spending (over the Board approved values) for Stations and Lines.

QUESTION #79

Issue: #4.2

Reference: i) Exhibit D1/Tab 3/Schedule 2, pages 6-8
ii) Exhibit D2/Tab 2/Schedule 3 – ISD #S1
iii) EB-2007-0681, D2/T2/S1, IJD #S1

- a) According to Reference (iii) the capital spending proposed in EB-2007-0681 for 2008 was to address the current gap in the number of spare transformers. However, Reference (ii) suggests that the gap still exists and, indeed, includes the purchase of more transformers than the 2008 Rate Application. Please reconcile.

QUESTION #80

Issue: #4.2

Reference: i) Exhibit D1/Tab 3/Schedule 2, pages 10-13
ii) Exhibit D2/Tab 2/Schedule 3 – ISD #S3 & #S4
iii) EB-2007-0681, D2/T2/S1, IJD #S3 & #S4

- a) Please confirm that there was no allowance for Spill Containment projects (Reference (i), page 11) in the EB-2007-0681 Application. If there was, what was the proposed 2008 capital spending?
- b) With respect to Station Refurbishment projects, please explain why the Iroquois Dam DS is one of the projects in the current Application

(Reference (ii), S#4) when it was also included in the 2008 Rate Application (Reference (iii), S#3).

- c) Please explain the increase in Station Refurbishment costs from 2008 approved (\$2.5 M) to \$3.2 M in 2010 and \$3.4 M in 2011, particularly when the number of stations being refurbished in each year (per Reference (ii), S#4) appears to be less than the number that were included for 2008 in Reference (iii), S#3.
- d) Please explain why the 2010 and 2011 spending on Component Replacement and Demand is higher (i.e., \$3.8 M and \$4.0 M) than that proposed and approved for 2008 - \$2.6 M.

QUESTION #81

Issue: #4.2

Reference: i) Exhibit D1/Tab 3/Schedule 2, pages 20-22
ii) EB-2007-0681, D1/T3/S2, page 20

- a) The 2008 Application projected 7,000 pole replacements at a cost of \$39.8 M. Actual replacements were 6,736 at a cost of \$43.0 M. Please explain the variance and whether the higher unit cost is carried forward in the projections for 2010 and 2011.
- b) How many of the pole replacements planned for 2011 are attributable directly to the red pine pole problem?

QUESTION #82

Issue: #4.2

Reference: i) Exhibit D1/Tab 3/Schedule 3, page 5

- a) Please confirm that the Customer Connections referred to in Section 2.1.1 are load customer connections. If not, please discuss the relationship between this Section and Section 2.2.
- b) Please reconcile the increase in customer connection costs (2010 vs. 2008) when the number of connections in 2010 is actually forecast to be less than in 2008.
- c) Please confirm that the impact of the DSC changes (per lines 14-18) is to reduce the estimated capital contributions by \$2 M per annum. If not correct, please provide the impact.

- d) Please discuss what types of investment activities Hydro One Networks considers to be “enhancements” as opposed to “expansion” for the purpose of applying the cost recovery provisions of the DSC, particularly with respect to load and non-renewable energy generation customers.

QUESTION #83

Issue: #4.2

Reference: i) Exhibit D1/Tab 3/Schedule 3, pages 7-10
ii) Exhibit D2/Tab 2/Schedule 3

- a) With respect to ISD #D3, when is the feeder expected to reach “overloading” conditions?
- b) Why are none of the costs of the new transformers required in ISD #D7 recoverable from the new customer?
- c) Why are none of the costs for ISD #D8, D13, and D16 recoverable from the new customers?
- d) Why is none of the costs of ISD #D15 recoverable from Orillia Power Corporation or the cost of ISD #D24 recoverable from Wasaga Distribution or the cost of ISD #26 recoverable from the Midland or Newmarket LDCs?
- e) Many of the ISD descriptions make reference to ongoing load growth (D3, D4, D5, D6, D7, D10, D11, D12, D13, D15, D16, D17, D18, D19, D20, D21, D24, D25, and D26). At the same time, Hydro One Networks is forecasting a steady decline in total distribution load from 2006 to 2011. Please reconcile and, in doing so, indicate those areas of Hydro One Networks’ service area where load is forecast to decline sufficiently to produce a net year over year reduction in total distribution load.

QUESTION #84

Issue: #4.2 and #9.3

Reference: Exhibit D1/Tab 3/Schedule 3, pages 12-14

- a) The discussion does not distinguish between the treatment of renewable energy generation projects and non-renewable energy generation projects.
- Please indicate any differences that exist in the cost responsibility treatment of the two types of projects.
 - Is Hydro One Networks assuming that all new generators will be renewable energy generation facilities?

- b) The text on page 12 (lines 8-11) describes connection assets as assets that lie between the point of connection on the distribution system and the facilities on the customer's property. The text on page 12 (lines 22-28) suggests that "connection" spending could i) include the replacement of existing assets and ii) be of benefit to other customers.
- Please reconcile this classification of "replacement" costs as connection costs with the OEB's September 11, 2009 DSC (section 3.2.30) amendments which classify such costs as "expansion".
 - Please explain how connections could involve replacement of existing assets when (by Hydro One Networks' own definition) connections start at the point of connection to the distribution system.
- c) Please clarify whether the Total Capital costs in Table 4 are just the cost for "connections" as defined on page 12 or whether they also include the costs for "expansion" and "enabling improvements" as defined on the same page.
- d) How does Hydro One Networks distinguish between the enhancement spending reported in Table 4 and that reported in Table 5?

QUESTION #85

Issue: #9.3

Reference: Exhibit D1/Tab 3/Schedule 3, page 16

- a) Please explain how the ratepayer funded portion was determined for the first two categories in Table 5.

QUESTION #86

Issue: #4.2 and #9.2

Reference: Exhibit D1/Tab 3/Schedule 3

- a) Please provide a schedule that maps the Generation Connection Program and Generation Connection Enhancement costs set out in Tables 4 & 5 into the cost categories used in Hydro One Networks' Green Energy Plan (i.e., Connection Assets, Expansion and Renewable Enabling Improvements) and reconcile the totals (both gross and net).

QUESTION #87

Issue: #4.2 and #9.2

Reference: i) Exhibit D1/Tab 3/Schedule 4
ii) EB-2007-0681, D1/T3/S4, page 2

- a) Please explain why the level of Operations Capital spending in both 2008 and 2009 (per Reference (i), Table 1) was less than the Board Approved 2008 level of \$3.6 M.
- b) Please provide a schedule that sets out how much of the Operations Capital spending in 2010 and 2011 is related to i) renewable energy generation (per Reference (i), page 2, lines 12-20) and ii) smart meters (per Reference (i), page 2, lines 22-28).
- c) Why isn't any of the Operations Capital Spending attributable to distributed generation included in the Renewable Generation portion of the Green Energy Plan?

QUESTION #88

Issue: #4.3

Reference: i) Exhibit D1/Tab 3/Schedule 8, pages 3-4
ii) Exhibit D2/Tab 2/Schedule 3, IED #C1

- a) Please provide a schedule that breaks down the projected spending on Field Facilities Requirements between i) spending on new facilities and additions to accommodate staff increases and ii) replacement/renovation of existing facilities.
- b) Please indicate the top 5 field locations experiencing staff increases that give rise to the need for new facilities and explain the reasons for the staff increases in each.
- c) What has "changed" in the last year that gives rise to the material increase in spending requirements to maintain existing facilities in Field Facilities?

QUESTION #89

Issue: #4.3

Reference: i) Exhibit D1/Tab 3/Schedule 8, pages 4-5

- a) What is the current Head Office space currently leased (square footage) and how many staff positions did it accommodate as of December 31, 2008? Note – Please include positions that are vacant but for which there is "space" provision.

- b) Please provide an organization chart outlining those business areas accommodated at the Head Office Facility and the number of staff in each (including approved vacant positions) as of December 31, 2008.
- c) Please provide an organization chart outlining the business areas that will be accommodated at the newly leased Head Office Facility and indicate the number of staff in each, including the planned growth of 500 staff.

QUESTION #90

Issue: #4.3

Reference: Exhibit D1/Tab 3/Schedule 8, page 6

- a) Why is there no capital spending on security infrastructure prior to 2010?

QUESTION #91

Issue: #4.3 and #9.2

Reference: Exhibit D1/Tab 3/Schedule 9, page 5

- a) Please document how the \$83 M capital spending on TWE attributed to the GEGEA was determined. Why is none of this included in the Green Energy Plan?

QUESTION #92

Issue: #4.5

Reference: Exhibit D2/Tab 4/Schedule 1

- a) Please explain why the “smart meter adjustment” was included in the determination of working capital.

QUESTION #93

Issue: #1.1 and #1.5

Reference: Exhibit E1/Tab 1/Schedule 1, Attachment 1
OEB Filing Requirements for Transmission and Distribution
Applications, May 2009, page 18

- a) Please revise the schedule so that it sets out 2010 and 2011 distribution revenues at current (2009) rates and the revenue sufficiency/deficiency for each year excluding rate riders.

QUESTION #94

Issue: #2.2

Reference: Exhibit E1/Tab 1/Schedule 2

- a) With the increased distributed generation (arising from the GEGEA) does Hydro One Networks expect to receive revenues from Standby Charges (pages 6-7) in 2010 and 2011? If not, why not.
- b) Would external revenues from New Connections and Upgrades include work done for new generator customer connections? If not, why not and where is such revenue captured? If yes, why is there no additional revenue shown for 2010 and 2011 given the projected increase in new generator connections?
- c) For what portion of the new generator connections projected for 2010 and 2011 (D1/T3/S3, page 11) will generation studies be completed by year end 2009?
- d) With respect to the projected volume of Generation Studies for 2010 and 2011, the Green Energy Plan indicates (A/T14/S2, page 7) the recent changes introduced by the GEGEA and the OPA will lead to increased interest in renewable distributed generation. Based on this, why isn't the number of requests for generation studies forecast to increase during the test period (page 10)?

QUESTION #95

Issue: #1.1 and #6.1

Reference: Exhibit F1/Tab 1/Schedule 1, pages 2-6
OEB Filing Requirements for Transmission and Distribution Applications, May 2009, Section 2.10.1

- a) For each of the accounts listed in Table 2, please provide a continuity schedule for the period January 1, 2005 to present showing the opening balance, annual adjustments, accruals, interest and closing balance for each year.
- b) For the RSVA accounts please provide a continuity schedule (per part (a)) for each separate account. In doing so, please provide a separate schedule for the RSVA Power – Global Adjustment SubAccount.

QUESTION #96

Issue: #8.2

Reference: Exhibit F1/Tab 1/Schedule 1, pages 3-6

- a) For the Minimum Functionality January 1-December 31, 2008 Account, please provide a schedule that sets out the determination of the revenue requirement recorded in the account. Please also explain how any “revenues” recorded in the account were determined.
- b) For the Smart Meter Exceeding Minimum Functionality January – December 2008 Account, please provide:
 1. A schedule that sets out the determination of the revenue requirement recorded in the account.
 2. Details regarding the nature of the activities/equipment for which costs were recorded in this Account.
 3. How any revenues recorded in the Account were determined.
- c) Please provide a schedule that compares the actual 2008 capital and OM&A spending for Smart Meters (as recorded for recovery) and the number of smart meters actually installed in 2008 with that forecast for 2008 in EB-2007-0681 and explain any variances of more than 5%.

QUESTION #97

Issue: #1.1 and #6.1

Reference: i) Exhibit F1/Tab 1/Schedule 1, page 8
ii) OEB Filing Requirements for Transmission and Distribution Applications, May 2009, Section 2.10.1
iii) Report of the Board on Electricity Distributors’ Deferral and Variance Account Review Initiative, July 2009

- a) For each of the accounts listed in Section 3.0, please provide a continuity schedule for the period January 1, 2005 to present showing the opening balance, annual adjustments, accruals, interest and closing balance for each year.
- b) Please indicate when each of the Rate Riders #2-#4 is scheduled to terminate.
- c) There is no reference here to a Rate Rider #5. However, the proposed recovery of the current outstanding balances is designated as Rate Rider #6 (G1/5/1, page 7). Please indicate if there was a Rate Rider #5 and, if

so, what the status of the Rate Rider is, including the current Deferral/Variance account balance.

- d) In accordance with Reference (iii), page 13, please explain why Hydro One Networks is not proposing disposition of the following accounts:
- Rural or Remote Electricity Rate Protection
 - Deferred Pension
 - Bill Impact Mitigation

QUESTION #98

Issue: #6.2

Reference: Exhibit F1/Tab 1/Schedule 2

- a) Please explain how the requested Pension Cost Deferral Account differs from the existing Deferred Pension Account.
- b) If the Pension Cost Deferral account had existed in 2008, please provide the amount that would have been recorded in the account and the supporting calculations.
- c) With respect to the Pension Cost Deferral Account:
- Why is the Account required?
 - Why should these costs be treated differently from other cost in the revenue requirement?
 - Is this request just for 2010 and 2011 or for a permanent account?
 - What are the 2010 and 2011 costs included in the application?
- d) If the OEB Cost Differential Account had existed in 2008, please provide the amount that would have been recorded in the account and the supporting calculations.
- e) Please provide a schedule that sets out the 2010 and 2011 expenditures include in the current Application and requested revenue requirement for:
- Annual OEB Assessments
 - Intervenor Cost Awards
 - OEB-initiated Studies.
- f) With respect to the OEB Cost Differential Account, please clarify what is meant by OEB-initiated studies. For example, would Hydro One Networks' costs associated with sponsoring Concentric Energy Advisors participation in the current Cost of Capital review be considered an "OEB-initiated study"?

- g) With respect to the Bill Impact Mitigation Account, please explain what types of “incremental costs associated with implementing any additional mitigation measures” would be recorded in the account. Were there any such costs associated with implementing the bill impact mitigation measures adopted for the 2008 rates and, if so, what were they?

QUESTION #99

Issue: #8.1

Reference: Exhibit F1/Tab 1/Schedule 3

- a) Please provide a schedule that sets out for the years 2010 and 2011 the capital spending broken down as follows:
- Spending on Residential Smart Meters – per page 3, lines 13-14
 - Spending on Smart Meters for >50 kW customers – per page 3, lines 15-16
 - Spending on the AMRC and the AMCC – per page 3, lines 18-2
- b) Please provide a schedule that sets out the capital spending on smart meter installation, the number of smart meters installed and the average capital cost per installed smart meter incurred annually from 2006 to 2010 (forecast). Please explain any year over year variances.
- c) Please explain why there is capital spending for Meter Installations in 2011 (Table 3) when all smart meters will be installed by the end of 2010.
- d) Is the OM&A shown in Table 1 – i) the OM&A expense associated with installing Smart Meters each month (assuming all such costs are not capitalized); or ii) the OM&A associated with maintaining the Smart Meters that are in-service. If the later, is it just for the Smart Meters installed in 2010 or for all in-service Smart Meters?
- e) Please provide a schedule that sets out the total Smart Meter related OM&A incurred annually for the period 2006-2011 and for each year provide the average number of smart meters in-service. In the same schedule provide a breakdown between the OM&A required: i) to maintain the smart meters in-service; ii) to maintain supporting related hardware, software, telecommunication systems and iii) to install smart meters and related equipment (i.e., assuming all such costs are not capitalized).

QUESTION #100

Issue: #7.1

Reference: i) Exhibit G1/Tab 2/Schedule 3, page 2, lines 2-6

- ii) EB-2007-0681, Exhibit H/Tab 12/Schedule 41, part (b)
- iii) EB-2007-0681, Exhibit H/Tab 12/Schedule 44, part (b)

Preamble: In Reference (ii) Hydro One Indicated that a study had not been undertaken to determine if R2 Legacy customers qualify for R1 status and that the Company would wait until better information was available from its GIS system. Reference (iii) outlines the process customers should follow if they want to question their density classification.

- a) With respect to Reference (ii), was such a study undertaken for the current Application?
- b) If yes, please provide the results.
- c) If no, what initiatives have been undertaken to improve the customer connectivity and lines detail in the GIS system and when will such a review be performed?
- d) With respect to Reference (iii), how many customers reclassified in 2008 as a result of customer queries?

QUESTION #101

Issue: #7.1

Reference: Exhibit G1/Tab 2/Schedule 3, page 9

- a) Please explain how generators that meet the eligibility requirements under the OPA's FIT and microFIT programs will be "classified" for purposes of cost allocation and rates.
- b) What assumptions has Hydro One made in the current Application regarding the number of such customers in 2010 and 2011 (i.e., number, load, etc.)?
- c) Please reconcile the response to part (b) with the number of new generator connections assumed in Exhibit D1/Tab 3/Schedule 3, pages 10-11.

QUESTION #102

Issue: #7.3 and #7.4

Reference: Exhibit G1/Tab 2/Schedule 4, pages 3-5

- a) Please confirm that the “group” referred to on page 4 (lines 12-14) refers to all Urban Residential customers including both the Legacy and Acquired UR customers.
- b) Please explain why the current acquired fixed charges are “truncated downward” as opposed to simply using the actual and adjusting it ½ the way to the target rate (page 3).

QUESTION #103

Issue: #7.4

Reference: Exhibit G1/Tab 2/Schedule 4, pages 6-7

- a) Does the General Service class in Table 3 include all four GS classes?
- b) Are the impacts shown in Table 3 based on specific customer consumption profiles and, if so, what is the profile used for each class?
- c) Please produce a comparable table for 2011.
- d) With respect to page 7 (lines 24-27), please explain what is meant reference to “on average” when discussing 2010 bill impacts.

QUESTION #104

Issue: #1.1

Reference: i) Exhibit G1/Tab 2/Schedule 5
ii) Exhibit G1/Tab 2/Schedule 5, Attachment 1

- a) On page 2 Hydro One Networks states that it believes “a staged approach to addressing the Board direction is a reasonable way to proceed”. Please indicate what Hydro One Networks considers to be the various stages in its approach and when they will be undertaken.
- b) Does Hydro One Networks agree that there is a distinction between incorporating density considerations in the cost allocation process and defining customer classes based on density as Elenchus has done on pages 2-4 of Reference (ii)? For example, one could not use density-based customer class definitions but still include density considerations in the cost allocation methodology in order to more fairly allocate the costs between customer classes. If not, please explain.
- c) Please indicate whether or not ERA’s survey of other jurisdictions (Reference (ii), page 3) examined whether density was used elsewhere in

utilities' cost allocation methodologies as opposed to in their definition of customers. If yes, what were the findings?

QUESTION #105

Issue: #7.1

Reference: Exhibit G1/Tab 2/Schedule 5

- a) On pages 2-3 Hydro One Networks notes that the weighting factor for Seasonal customers was set to one, as is done for other customer classes that have no density based weighting.
- Please confirm that the setting of the Seasonal class weighting factor to one was done for purpose of Cost Allocation. If not, please explain.
 - Please confirm that that the reference to other customer classes that have no density based weighting was with regard to other customer classes "definition".
- b) Please indicate the impact on the cost allocation results shown at Exhibit G1/Tab 3/Schedule 1, page 3 if the density weightings were retained for the Seasonal class.

QUESTION #106

Issue: #7.1

Reference: Exhibit G1/Tab 3/Schedule 1

- a) With respect to page 1 (lines 17-20), please indicate where in its Decision regarding EB-2007-0681 the Board explicitly discusses and approves Hydro One Networks' modified cost allocation methodology.
- b) Please confirm that the "Revenue Adjusted at Current Rates" row in Table 1 is net of any discounts for transformer ownership or the USL meter credit.

QUESTION #107

Issue: #7.3

Reference: i) Exhibit G1/Tab 4/Schedule 1
ii) Exhibit G1/Tab 4/Schedule 2, page 2

- a) With respect to Reference (i), page 1 (lines 21-23), please provide a schedule that sets out for each customer class (except DG and R2)

whether the proposed fixed charges (per Reference (ii)) were set based on i) avoided cost from the cost allocation study or ii) the service charge from the predominant class. If the latter, please indicate what was considered to be the “predominant class” and whether the proposed fixed charge is based on the current (2009) service charge or the 2009 service charge escalated by the average rate increase for the class.

- b) For DG and R2 customers please clarify whether the fixed charge is set at the current 2009 level or at the 2009 level escalated by the average rate increase for the class.
- c) The Application states (Reference (i), page 2, line 3) that the only incremental facility required for a micro-generator is a meter.
 - This assumes that all micro-generators situated at the same location as the customer’s main account. Please explain why this assumption is reasonable and how Hydro One will treat the micro-generator if this is not the case.
 - Please confirm that the USL credit includes OM&A costs for meter reading. Does it also include any allowance for billing cost and, if not, should the charge to micro-generators reflect such costs?

QUESTION #108

Issue: #7.3

Reference: Exhibit G1/Tab 4/Schedule 2, pages 2-3

- a) Please confirm that the proposed fixed and variable charges set out in Table 1 will recover revenue requirement allocated to each class per the proposed revenue to cost ratios set out at Exhibit G1/Tzab 3/Schedule 1, Table 1 (after also allowing for the recovery of the USL and CSTA credits).

QUESTION #109

Issue: #7.3

Reference: i) Exhibit G1/Tab 4/Schedule 3, pages 2-7
ii) Exhibit G2/Tab 4/Schedule 1

- a) With respect to Reference (i), please confirm that the difference between the energy rates set out in Tables 1 and 2 for each class is due to the fact the rates in Table 2 have been increased to recover the revenue shortfall due to the phase-in of the target service charges.

- b) Please confirm that in principle the energy rates set out in Reference (i), Table 2 for each class should be the same as those proposed for the same class in Reference (ii) and any differences are due to rounding.

QUESTION #110

Issue; #7.4

Reference: Exhibit G1/Tab 4/Schedule 7

- a) It is noted that the harmonization period for the Low Use Secondary Customer rate is 5 years as opposed to the 4 years used for other classes. Please provide a schedule that sets out the 2010 bill impacts for these customers of using a 4 year versus a 5 year period.

QUESTION #111

Issue: #7.6

Reference: Exhibit G1/Tab 5/Schedule 1

- a) Are the factors used to allocate the balances to customer classes consistent with the Board's Direction in its July 2009 Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EB-2008-0046)?
- b) If there are instances where the response to (a) is no, please recalculate the allocation and the resulting adders based on the Board's direction.
- c) Please explain more fully what the RSVA Provincial Benefit represents and why it is allocated to non-market participants.
- d) Why is there no RSVA-Power (excluding the Global Adjustment Sub-Account) or RSVA –Global Adjustment Sub-Account balances to be refunded or recovered?

QUESTION #112

Issue: #7.4

Reference: Exhibit G1/Tab 7/Schedule 1

- a) Please provide the average customer definition used for each Rate Class (per page 1, lines 15-16).

- b) Please confirm that the rate impacts discussed in this section are prior to any phase-in or impact mitigation plan.

QUESTION #113

Issue: #7.4

Reference: i) Exhibit G1/Tab 7/Schedule 2

- a) Please confirm that the rate impacts discussed in this section are prior to any phase-in or impact mitigation plan.

QUESTION #114

Issue: #7.4

Reference: Exhibit G1/Tab 4/Schedule 1

- a) How many customers are there in the new Seasonal class in total and, with respect to page 1 (lines 13-15), how many customers in the new Seasonal class fall into each of the following categories:
- Were formally R3 customers and have an average monthly usage greater than 1,500 kWh
 - Were formally R4 customers and have an average monthly usage greater than 2,000 kWh
 - Were formally Caledon OH 07 customers and have an average monthly usage greater than 1,000 kWh.
- b) The text on pages 2-3 states that the volumetric charges were lowered so as to meet the 10% bill impact limit. Why were the volumetric charges reduced as opposed to reducing the fixed service charge?
- c) The text on page 3 states that the revenue short fall from this specific initiative is being absorbed by the Legacy customers.
- What is the amount of the shortfall?
 - Does this mean that the volumetric Rate for Legacy customers will be different (i.e., higher) than for Acquired LDC customers assigned to the same class who are not subject to this specific mitigation initiative?
 - What is the impact on the volumetric rates for each Legacy customer class?
- d) Please provide a Schedule that lists the number of R1 customers (per new classification) in the Hydro One's Legacy System and in each Acquired LDC.

- e) On the Schedule provided in response to part (d) please indicate of those customers now in the new R1 class:
- The number of former Ailsa Craig residential customers that use less than 250 kWh per month.
 - The number of former Arkona residential customer that use less than 500 kWh per month.
 - The number of former Fenelon Falls residential customers that use less than 500 kWh per month.
 - The number of former Kirkfield residential customers that use less than 250 kWh per month
 - The number of former Perth East residential customers that use less than 500 kWh per month
 - The number of former Quinte West residential customer that use less than 250 kWh per month.
 - The number of former Thorndale residential customer that use less than 250 kWh per month.
 - The number of former Tweed residential customers that use less than 250 kWh per month
 - The number of former Woodville residential customers that use less than 250 kWh per month.

QUESTION #115

Issue: #7.4

Reference: Exhibit G1/Tab 9/Schedule 1

- a) What is Hydro One Networks' proposal for 2010 and 2011 regarding interim TOU rates and the treatment of the one remaining customer?

QUESTION #116

Issue: #7.7

Reference: Exhibit G1/Tab 10/Schedule 1

- a) Starting at page 3, line 13 the Application describes the treatment of losses for a number of specific situations. For each situation, please clarify whether the treatment described reflects current practice as approved by the Board or whether it describes a treatment that Hydro One Networks is proposing to apply starting in 2010. If the latter, please outline the current treatment of losses for the circumstance concerned.

QUESTION #117

Issue: #7.1

Reference: Exhibit G2/Tab 1/Schedule 1, page 1 (lines 21-22) and Section 4.0

- a) The description of the model changes implemented for this application differs from that included in EB-2007-0681. Please provide a schedule that lists all model changes that were implemented between EB-2007-0681 and the current Application.

QUESTION #118

Issue: #7.1

Reference: i) Exhibit G2/Tab 1/Schedule 1, page 10, lines 18-19
ii) Exhibit G2/Tab 1/Schedule 1, Sheet O1
iii) Exhibit E1/Tab 1/Schedule 2, pages 2-3

- a) Using the originally filed version of Reference (iii) please show how the various categories of external revenues map into Row 89-95 of Sheet O1 in Reference (ii).
- b) For each of the seven categories of External Revenue set out in Reference (ii) please describe the allocation factor used and explain why it was selected.
- c) Based on the updated version of Reference (iii), please indicate how the external revenue assigned to each of the seven rows (Row 89-95) in reference O1 would change.
- d) In the calculation of the Revenue to Cost Ratio based on the “unique” allocation of Miscellaneous Revenue (Sheet O1, Row 100), please explain why the value for Costs used in the denominator (O1, Row 97) is not the allocated Revenue Requirement (O1, Row 35) but is adjusted for the change in Miscellaneous Revenue allocation.

QUESTION #119

Issue: #7.1

Reference: i) Exhibit G2/Tab 1/Schedule 1, pages 1-2
ii) EB-2007-0681, Exhibit H/Tab 12/Schedule 66

- a) Please update the response to Reference (ii) – part (b).
- b) Please re-do the density factor derivation (for both lines and transformers) but instead of just including the Residential, General Service – Energy and

General Service – Demand in the analysis please include all of Hydro One Networks’ customer classes.

QUESTION #120

Issue: #7.1

Reference: i) Exhibit G2/Tab 1/Schedule 1, page 9
ii) Exhibit G2/Tab 1/Schedule 1, Attachment 1

- a) Reference (i) lists the various costs that Hydro One Networks states are directly allocated which total \$7.797 M. However, in Reference (ii) (Sheet O1, Row 33) the costs directly allocated are reported as \$7.948 M. Please reconcile.
- b) Please confirm that Administration and General costs (excluding Property Insurance and Community and Safety Programs) are allocated to customer classes using the “O&M Allocator” as set out in Reference (ii) (Sheet O6, Row 173). If not, please indicate the Sheet and Row reference for the allocator used.

QUESTION #121

Issue: #7.1

Reference: i) Exhibit G2/Tab 1/Schedule 1, pages 17 & 19
ii) EB-2007-0681, Exhibit G2/Tab 1/Schedule 1, Attachment B

- a) For conductors, the Minimum System Study assumes that all existing conductors are replaced by the “minimum system conductor” (Reference (ii), page 9). However, for purposes of determining the PLCC adjustment the Study assumed that each distribution station would supply a single feeder (page 12). Please reconcile this inconsistency.
- b) Please indicate the actual number of feeders served by Hydro One Networks’ distributing stations.
- c) Please re-do the PLCC calculation (Reference (ii), page 13) using the actual number of feeders as opposed to assuming one feeder/distributing station.
- d) Please re-do the cost allocation based on the PLCC calculations from part (c).