Exhibit K 4-12.

VECC Materials for

Cross Examination of Panel 4

July 15, 20008

Hydro One Networks Inc.

Distribution

EB-2007-0681

2.6 Conservation and Demand Management

Hydro One Distribution supports the Ontario Government's conservation and demand management (CDM) target to achieve a 1,350 MW of peak reduction by 2007 and a further reduction of 1,350 MW by 2010. Hydro One Distribution used the Board approved 3^{rd} tranche funding of $39.5 million to cover its CDM programs for the 2004-2007 period. After the 3^{rd} tranche funding, Hydro One will rely on the CDM funding from OPA to fund its CDM initiatives in 2008 and beyond.

Table 2 summarizes the cumulative CDM impact since 2004 assumed in Hydro One's distribution system load forecast for 2006, 2007 and 2008. The CDM impact includes programs undertaken by Hydro One Networks and programs implemented by other agencies such as federal and provincial governments, OPA and IESO. Hydro One Distribution's 2007 CDM impact is the same as the 2007 CDM impact approved by the Board for Hydro One's Transmission Rate case (EB-2006-0501) issued on August 16, 2007. A 350 MW reduction to the 2007 provincial CDM target of 1350 MW was made to account for the impact of natural conservation. The 2008 CDM impact is consistent with the OPA's IPSP filed with the Board on August 29, 2007.

Table 2

CDM Impact on Hydro One Distribution Load
(GWh)

Year	Hydro One Retail	Embedded Direct and LDC Customers	Total
2006	194	151	345
2007	311	242	554
2008	437	333	770

Ontario Energy Board (Board Staff) INTERROGATORY #102 List 1

Interrogatory

Ref: Exhibit A/ Tab 14/ Schedule 3/ page 2/ Issue 1.5

In Schedule 3, page 2, the Applicant states, "The methodology described in this exhibit is similar to Hydro One's 2006 Distribution Rate case (RP-2005-0020/EB- 2005-0378)."

a. Please explain any changes in the methodology used in the current application that have resulted from the Applicant's Board-ordered review of the methodology it uses for its transmission-related cases (EB-2006-0501, Decision with Reasons, August 16, 2007, page 88).
b. Please explain any other changes (in addition to those identified in response (a.)) to the methodology that has been adopted since the 2006 distribution case, provide the reason(s) for these changes, describe the testing done and the results achieved that showed the changes improved the expected accuracy of the resulting forecast.
c. Describe any planned or likely changes to further improve the methodology,
d. Verify that in Table 1, the mean (1997-2006) "Variance for Plan Year" and "Variance for 2nd Year" values are in the order of -0.26% and -0.50% respectively,
e. Describe any plans the Applicant has to compensate for the methodology's bias to underestimate the Bridge Year forecast by about one-quarter of one percent and the Test Year forecast by about one half of one percent, and
f. Estimate the dollar effect on revenue at the proposed rates, if the actual to be 0.5% higher than forecast.

Response

a. The only change was the CDM forecast. Hydro One followed the Board's decision (in EB-2006-0501) and reduced the Ontario peak load by 1,000 MW in 2007. The CDM impact on Hydro One Distribution in 2007 reflects this adjustment. For 2008, Hydro One used the CDM forecast from the OPA consistent with the IPSP that was filed with the Board on August 29, 2007. Hydro One Distribution did review its weather normalization methodology and found that no change was required.

b. One minor change was made in updating the econometric equation with respect to the use of dummy variables in the model. Four dummy variables were deleted from the monthly econometric model as more information became available.
The 4 deleted dummy variables are described below:

DSUM = dummy variable to distinguish between summer and other months,
D0803 = dummy variable for the August 2003 Blackout, equals 1 in that month and zero elsewhere,
D97 = dummy variables to account for shift in load pattern in 1997, equals 1 since January 1997, zero elsewhere.

D02 = dummy variable to account for Market Opening in May 2002, equals 1 since May 2002, and zero elsewhere.

One dummy variable related to the 1998 Ice Storm is kept in the monthly econometric equation. The deletion of 4 dummy variables does not affect the forecast or the forecast accuracy but marginally affects the t-ratios of the estimated model coefficients.

c. Proposed plans for future research in load forecasting methodology include the following:
   - Increase tracking and monitoring of CDM impacts on the distribution load;
   - Update equipment use information on a regular basis;
   - Assess customer behavioral changes with respective to energy use;
   - Assess the impact of TOU rates on hourly load profiles; and
   - Monitor industry trends and other LDC practices for consideration of methodology improvement.

d. The calculated mean "Variance for Plan Year" and "Variance for 2nd Year" values in Table 1 for the 1997-2006 period are -0.26% and -0.50% respectively.

e. The "bias" mentioned in (d) above is not statistically significant as it is within one standard deviation of the forecast. Since Hydro One Distribution experienced unusual events (such as Ice Storm in 1998, acquisition of almost 90 LDCs in 2001-2002 period, Sept 11 event in 2001) which affected the accuracy of the forecast performance, it will be more appropriate to focus the forecast performance achieved in more recent years (such as 2002-2006). The mean "Variance for Plan Year" and "Variance for 2^{nd} year" values in Table 1 over the 2002 -2006 period show that the forecast performed very well. Consequently, there is no need to make any bias correction.

f. The dollar effect on revenue at the proposed rates is approximately $3 million if the actual load were to be 0.5% higher than forecast.

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impact of demand response programs, which are most effective in extreme weather situations, when adjusting a weather-normal forecast.

The Board finds that Hydro One should reduce the expected impact of CDM on total Ontario peak demand by 350 MW. This adjustment is intended to address both the natural conservation and demand response issues discussed above. The Board acknowledges that this reduction is probably at the low end of an acceptable range given that it is only marginally above the 328 MW of natural conservation for 2006 referred to in the Chief Energy Conservation Officer's 2006 annual report. The Board finds there is sufficient data to support a reduction of 350 MW but also finds there is not enough reliable data to support a larger reduction as advocated by some intervenors.

The Board directs Hydro One to recalculate the average monthly forecast peak load for each charge determinant category for 2007 and 2008 based on Ontario peak load reductions of 1,000 MW in 2007 and 1,200 MW in 2008.

CDM adjustments were also addressed in Hydro One's last distribution rates case. The Decision in that case stated: "The Board was dissatisfied with the clarity and precision of the determination of the forecast CDM and expects Hydro One to provide a more sound analysis of CDM program details and reduction objectives in future applications[40]." The Board recognizes that Hydro One's transmission application was filed not long after those comments were made. It would be unfair to expect Hydro One to have rectified all of the issues identified in the distribution case. The Board does expect, however, that the CDM adjustments to the load forecast included in Hydro One's next transmission filing will be based on a much more rigorous analysis, including, where possible, load impacts attributable to specific programs.

[40] Decision With Reasons, RP-2005-0020/EB-2005-0378, April 12, 2006, para. 2.3.9.

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- GDP growth revisions: The Royal Bank of Canada's revised (October 2006) provincial economic outlook which sees a softening of this sector was used.
- Shift in contribution of individual industries: A shift away from more energy intensive (in terms of energy/GDP) industries such as textiles toward less energy intensive such as transportation equipment was incorporated.
- Incorporation of more recent data: The connection between GDP growth, physical production and energy use was further explored. More recent data suggest that GDP growth is greater than physical unit growth in some industries. For example, physical production of vehicles increased 2.5% over a period that saw associated GDP for the transportation equipment sector grow by 4%. Energy intensities were lowered to reflect this fact.

Q. How much energy efficiency is incorporated in the reference forecast?

A. Forecast use of energy is mitigated by the on-going contribution of Conservation measures taken before 2005 and by "natural Conservation" that occurs due to incremental technology improvements, changes in the economy that reduce energy intensity, and old energy-consuming assets being replaced with new and more efficient technologies. These efficiency improvements are not brought about through market intervention, but result from competition among technologies on the basis of life-cycle cost and non-financial factors that are known to affect purchasing decisions. In contrast, policy-driven Conservation measures and programs induce people and organizations to change behaviour beyond what they would have done "naturally". Base values for natural Conservation are illustrated in Table 6 below.

Table 6: Natural Efficiency Incorporated in the Reference Forecast – (MW)

Based from year	2004	2005	2006	2007	2010	2015	2020	2025
2004	0	110	350	600	1380	2375	2710	3000

Source: M.K. Jaccard and Associates/OPA
Note that natural Conservation is calculated based on 2004 as the base year.

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Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #7
List 1

Interrogatory

Issue Number: 1.5
Issue: Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected?

Ref: A/Tab 14/Sch 3/Page 8/Line 17

In the IPSP (Ex D, Tab 4, Sch 1, Attachment 2, page 1, Table 1) the OPA identifies 600MW cumulative of naturally occurring conservation by the end of 2007.

a. Please provide the calculation details as to how this 1 was accounted for in the Hydro One distribution load forecast.
b. Please provide the specific data references in the IPSP that support the statement "The 2008 CDM impact is consistent with the OPA's IPSP filed with the Board on August 29, 2007."

Response

a. Hydro One Distribution's load forecast is already net of natural conservation. Therefore, there is no need to make further adjustment to account for natural conservation.

b. Hydro One Distribution used the 2008 provincial CDM impacts provided by the OPA to calculate its share of the CDM impacts. The provincial CDM peak and energy savings for 2008 used in the IPSP are 251 MW and 0.8 TWh respectively (EB-2007-0707 Exhibit D, Tab 4, Schedule 1, Attachment 4, page 2, Table 1 and Table 2).

Table 6: Proposed Regional Energy Conservation Savings (2008-2027) (TWh)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Northwest	0.0	0.1	0.2	0.3	0.4	0.5	0.5	0.6	0.7	0.7
West	0.1	0.2	0.7	0.9	1.0	1.2	1.4	1.6	1.7	1.8
Northeast	0.1	0.1	0.6	0.7	0.8	1.0	1.1	1.2	1.3	1.4
Essa	0.1	0.1	0.5	0.6	0.7	0.8	0.9	1.1	1.1	1.2
Ottawa	0.1	0.1	0.6	0.7	0.8	1.0	1.1	1.3	1.4	1.4
East	0.0	0.1	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.0
GTA	0.3	0.7	2.5	3.2	3.8	4.5	5.1	5.8	6.2	6.5
Niagara	0.0	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.5
Southwest	0.2	0.4	1.3	1.7	2.1	2.4	2.8	3.2	3.4	3.7
Ontario	**0.8**	**2.0**	**6.9**	**8.8**	**10.6**	**12.4**	**14.3**	**16.1**	**17.2**	**18.3**

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Northwest	0.8	0.8	0.9	0.9	1.0	1.0	1.0	1.0	1.1	1.1
West	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.5	2.7	2.8
Northeast	1.5	1.5	1.6	1.7	1.7	1.8	1.8	1.9	1.9	2.0
Essa	1.3	1.4	1.4	1.5	1.6	1.7	1.7	1.8	1.9	2.0
Ottawa	1.5	1.6	1.7	1.8	1.8	1.9	2.0	2.0	2.1	2.2
East	1.1	1.1	1.2	1.2	1.3	1.3	1.4	1.4	1.5	1.5
GTA	6.9	7.3	7.6	7.8	8.1	8.4	8.7	9.0	9.4	9.8
Niagara	0.5	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.8
Southwest	3.9	4.1	4.4	4.6	4.8	5.0	5.2	5.3	5.6	5.8
Ontario	**19.4**	**20.4**	**21.5**	**22.3**	**23.2**	**24.1**	**24.9**	**25.6**	**26.8**	**28.0**

Source: OPA
Note: Forecast is at the generator and is weather normal.

Consumers Council of Canada (CCC) INTERROGATORY #20 List 1

Interrogatory

Cost of Service

CDM

20 /T13/S1/p. 8

Please confirm that beyond April 30, 2008, HON will only be undertaking CDM programs through the OPA funded framework. Are there any costs included in the 2008 revenue requirement related to CDM? If so, please identify where those costs are accounted for.

Response

It is HONI's intent to seek funding for CDM funding primarily via the OPA funded framework. HONI has included $1M in the 2008 revenue requirement within the Other Shared Services – Other category to sustain existing CDM programs and maintain a minimum capability. HONI also requires an additional $800,000 to close off the programs initiated under MARR funding.

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Pollution Probe (PP) INTERROGATORY #7 List 1

Interrogatory

Issue Number: 3.10
Issue: Is the level of H1 initiated and or delivered CDM activity and budget appropriate and should it be funded by OPA or in rates?

Ref. A/Tab 13/Sch 1- page 8

For each of the Hydro One's 2007 CDM programmes, please state:

a) its forecasted and actual savings (MW and MWh); and

b) its forecasted and actual budget.

Response

a) and b) For 2007, HONI spent $17.8M of rate funded (MARR) CDM (which is the Life to Date (LTD) spending for 2007 of $38.2M from Figure 1 shown in the response to Exhibit H, Tab 2, Schedule 7 of $20.4M). In 2007, HONI also spent $7.6M of rate funded (Global Adjustment Mechanism) CDM delivering core programs under contract with OPA.

Since there was no regulatory requirement for forecasted information, annual forecasted savings and annual forecasted budgets were not developed. Instead of managing by year, HONI managed by program and targeted keeping within the approved 3rd tranche of the MARR funding envelope. The actual savings (MW and MWh) and the actual expenditures for Hydro One's 2007 CDM programmes are shown below. Hydro One's 2007 CDM Annual Report is provided as an Attachment A to this response.

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6.0 OTHER SHARED SERVICES

Table 29
Total Distribution Other Shared Services ($ Millions)

	Historic			Bridge	Test
Description	**2004**	**2005**	**2006**	**2007**	**2008**
Corporate Overhead	(45.0)	(46.2)	(59.8)	(46.6)	(47.7)
Environmental Provision	(9.5)	(7.1)	(11.6)	(6.3)	(7.9)
Indirect Depreciation	(9.0)	(9.9)	(11.6)	(10.5)	(10.3)
Deferred Pension Credit	(33.2)	(30.6)	(10.7)	0.0	0.0
Other	(10.8)	14.4	(12.6)	23.3	(12.4)
Total	**(107.5)**	**(79.5)**	**(106.3)**	**(40.1)**	**(78.3)**

6.1 Capitalized Overhead Credit

Table 30
Distribution Corporate Overhead Credit ($ Millions)

	Historic			Bridge	Test
Description	**2004**	**2005**	**2006**	**2007**	**2008**
Corporate Overhead	(45.0)	(46.2)	(59.8)	(46.6)	(47.7)

Capitalized overheads represent that portion of allocated shared corporate and/or business unit functions and services that are deemed, through the capital overhead rate, to be supportive of Capital projects as opposed to OM&A projects. OM&A expense is thus reduced by the capitalized amounts. The overhead credit has increased from the 2004 level primarily due to the higher level of Capital spending.

The capitalized OM&A costs are distributed to Capital projects based on the allocation methodology accepted by the Board as discussed in Exhibit C1, Tab 5, Schedule 2. The capital works program is further detailed in Exhibit D1, Tab 3, Schedule 1. The total amount allocated to Distribution Capital in 2008 is $47.7 million.

VARIANCE ACCOUNTS REQUESTED

This exhibit requests approval to establish new variance accounts for Hydro One Distribution as follows:

- Pension Cost Differential
- OEB Cost Differential
- Bill Impact Mitigation

The need for these accounts and the accounting and control process is described in further detail in the remainder of this exhibit.

1.0 PENSION COST DIFFERENTIAL

Hydro One Distribution proposes to track the difference between actual pension costs booked using the actuarial assessment, provided by Mercer Human Resource Consulting, and the estimated pension costs used in this rate filing. Hydro One's actuarial valuation was prepared as at December 31, 2006 and was filed with FSCO in September 2007.

2.0 OEB COST DIFFERENTIAL

This account will track the difference between the annual OEB Cost Assessments, intervenor cost awards, and costs associated with OEB-initiated studies and the amount for these expenditures approved by the OEB as part of the 2008 Distribution Rates until these rates are rebased.

Ontario Energy Board (Board Staff) INTERROGATORY #123 List 1

Interrogatory

Ref: ExhibF1/Tab3/Schedule1/ Issue 6.2

Hydro One is requesting a new deferral and variance account for the Pension Cost Differential.

a. Please provide the justification for this request, particularly identifying, when the actuarial valuation was prepared as at December 31, 2006, and when it was filed with FSCO and included in forecasted rates.
b. What is the proposed methodology for recording pension costs into this account (cash or accrual)? If Hydro One is proposing a change to the accrual method, is the company also proposing to record the difference between the expense embedded in rates and the accrual expense as per the audited financial statements, into this account?
c. In Hydro One's view what would the impact of its proposal be on the IRM 3 mechanism?
d. Can Hydro One identify any regulatory precedent in support of its proposal?
e. Please provide an estimate of the variance to be recorded in this account, if any.
f. What account number does Hydro One propose to use in the USoA?
g. What are the journal entries to be recorded?
h. When does Hydro One plan to ask for its disposition?
i. How does Hydro One plan to allocate this amount by rate class?
j. What new or additional information is available since the December 18, 2007 filing of this application that would improve the Board's ability to make a decision on this request?

Response

a. The actuarial valuation report as at December 31, 2006 was prepared during 2007, completed in August 2007 and filed with FSCO in September 2007. The actuarial report sets out the minimum funding requirements for the company that includes both a variable component as a function of base pensionable earnings, plus a fixed component for the deficiency in the plan. Given there is a variable component to the funding amount, there could be a difference between estimated pension costs being sought for recovery and actual pension costs. Since the actuarial valuation was filed with FSCO subsequent to the EB-2007-0681 evidence being filed with the OEB on August 15, 2007, the forecast amount of pension contribution was based on an estimate, rather than the final valuation. Thus, Hydro One Distribution is requesting a deferral account.

b. The Board has allowed cash payments related to pension obligations to be recorded in rates (RP-1998-0001). Consistent with its prior Distribution rate application (RP-2005-0020/EB-2005-0378), Hydro One does not use the accrual method for rate setting purposes nor in its audited financial statements. Pension costs continue to be recorded on a cash basis and as such, there is no change from this basis.

c. It is premature to speculate as the IRM3 mechanism has not yet been established.

d. On July 14, 2004 the Board issued its Decision and Order (RP-2004-0180) approving the creation of a deferral account for Hydro One Distribution to record the pension costs and related interest. A similar account was approved as part of Hydro One Transmission's rate application (EB-2006-0501).

e. The estimated amount to be recorded in the variance account for 2008 is approximately $130 thousand (liability) per month.

f. Hydro One would use Account 1508 Other Regulatory Assets; Sub Account Pension Contributions

g. Where pension costs recovered through rates are higher than actual pension costs incurred, the entry will be:

   Dr. Revenue
      Cr. Pension Deferral Account (liability)

   Where pension costs recovered are less than actual pension costs incurred, the opposite entry would apply.

h. Hydro One would ask for disposition of this account as part of the next Cost of Service hearing.

i. This amount would be allocated to all rate classes. Consistent with the proposed allocator in Regulatory Rate Rider #3 for both OM&A costs, Exhibit G1, Tab 5, Schedule 1, Page 2, lines 13 to 16, OM&A costs would be the allocator used by Hydro One to allocate the amount amongst customer classes.

j. The rate application in this filing was based on an estimate of about $104 million for pension costs in 2008. The actual pension costs for 2007 were about $95 million. While the actual pension contribution is expected to be higher in 2008 as a result of higher base pensionable earnings, the expectation is that the deferral account will be in an over-recovery (liability) position. See response to (e) above.

MR. VAN DUSEN: Sorry, the number you're looking at, 31 did you say?

MR. BUONAGURO: 31.7 is the number I have.

MR. VAN DUSEN: I'm seeing a number of 56 million corporate pension costs charged to distribution in mine.

MR. BUONAGURO: Sorry.

MS. McKELLAR: That's what I have.

MR. VAN DUSEN: I'm looking at page 2 of that exhibit and adding up the total OM&A and capital in association with the distribution system, and getting $56 million dollars, sir.

MR. BUONAGURO: Okay. It must have been a calculation error.

Well, we can say then $56 million of the total, then, so around 50 percent?

MR. VAN DUSEN: Roughly.

MR. BUONAGURO: Okay. And can you confirm that the application which includes these numbers was done prior to the completion and filing of the pension evaluation.

MR. VAN DUSEN: It certainly was done before the filing of the evaluation.

MR. BUONAGURO: All right.

MR. VAN DUSEN: The evaluation which is filed attached to -- H1-76 was filed after our distribution application was filed; yes, that's correct.

MR. BUONAGURO: Okay. And interrogatory response H12-21 says that based on this evaluation, the required pension contribution for the years 2007, 2008 and 2009 is $95 million, total, I guess, per year.

MR. VAN DUSEN: Sorry, what was the reference to the interrogatory, please?

MR. BUONAGURO: H12-21.

MS. McKELLAR: I don't have it.

MR. VAN DUSEN: Just one second, please.

MR. BUONAGURO: Sure. It's on page 2, third full paragraph.

MS. McKELLAR: Have you got it? Thank you.

MR. VAN DUSEN: Sorry, my apologies. I have it now. Sorry, could you repeat your question?

MR. BUONAGURO: Sure. In this interrogatory response at page 2, third full paragraph it says:

> "The valuation report submitted to FSCO in September 2007 will establish a level of contribution of about $95 million for the three-year period 2007 through 2009."

MR. VAN DUSEN: Yes, that's correct.

MR. BUONAGURO: Okay. Does that mean that there's a difference in the numbers between the application and the evaluation of about $9 million per year?

MR. VAN DUSEN: Yes, there is.

Please let me take you, though, to response to Board interrogatory H, tab 1, schedule 123. In the response to part A:

> "Hydro One acknowledges the difference between the amount contained in our application and the amounts indicated by the new actuarial evaluation and as such Hydro One is requesting the deferral account."

Mr. Innis, in his appearance on panel 4, will be able to talk to the deferral account specifically, but the reasoning is straightforward. The application came in based on an older estimate. We have a newer estimate in a deferral account consistent with the Board's past practice on this has been requested.

MR. BUONAGURO: Okay. So -- which is all to say that if that holds up, then we'll be paying your rates, the actual number?

MR. VAN DUSEN: Yes, that's correct.

MR. BUONAGURO: Okay. Obviously I missed that interrogatory response.

I'm thinking back to the first day. Are there any other corrections to the application that you are acknowledging similar to that that we should know about?

MR. VAN DUSEN: This isn't a correction. This is a -- part of our original application, part of our filed material.

MR. BUONAGURO: What I mean is changes in numbers for various reasons. Like, for example, that would be a change in a number because new information came out that you are accepting rather than stumbling upon it like that which is partly my fault --

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COST ALLOCATION OF REVENUE REQUIREMENT

This exhibit presents an overview of the process to allocate Hydro One Distribution related revenue requirement costs to Legacy, Acquired, and Sub-Transmission customer groups (including current Embedded LV customers).

1.0 INTRODUCTION

The 2008 revenue requirement of $1,067 million for Hydro One Distribution was derived in Exhibit E1, Tab 1, Schedule 1, and is attributed to the Retail, (Legacy and Acquired), and Sub-Transmission customers.

This revenue requirement is allocated to the proposed customer groups using the Cost Allocation methodology issued by the OEB on September 29, 2006 in the RP-2005-0317 proceeding. Hydro One modified the OEB methodology to reflect its unique circumstances related to the provision of an LV system and a very large number of rates. The modifications are detailed in Exhibit G2, Tab 1, Schedule 1, and are similar to the modifications applied in Hydro One's Cost Allocation Information Filing of January 15, 2007 as part of Proceeding RP-2007-0001.

2.0 APPORTIONMENT OF REVENUE REQUIREMENT

Hydro One used the OEB Cost Allocation Methodology to allocate the proposed $1,067 million revenue requirement to customer classes. The allocated revenue requirement was compared to the revenues that would be collected from customers at adjusted 2007 Distribution rates. The adjustment consisted of increasing the 2007 approved rates proportionally to recover the 2008 Revenue Requirement of $1,067 million. Revenue to cost ratios were then calculated. Revenue to cost ratios above 1 mean that the customer class is over-contributing and revenue to cost ratios below 1 mean that the customer class

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Ontario Energy Board (Board Staff) INTERROGATORY #124 List 1

Interrogatory

Ref: ExhibF1/Tab3/Schedule1/ Issue 6.2

Hydro One is requesting for a new deferral and variance account related to the OEB Cost Differential.

a. What is the regulatory precedent for the collection of each of the identified costs proposed to be included in this deferral account?
b. What is the justification for this account?
c. What account number does Hydro One propose to use in the USoA?
d. What are the journal entries to be recorded?
e. If the costs or fees are not known, what would be the basis of the approval to record these amounts in a deferral account?
f. What new or additional information is available that would improve the Board's ability to make a decision on this request?

Response

a. The regulatory precedent can be found in a letter from the Board dated December 20, 2004 to electricity distributors. In that letter the Board authorized the establishment of a deferral account to record OEB cost assessments that may not be included in rates. Hydro One Distribution established the deferral account pursuant to the Board letter and received approval for recovery of costs recorded in the deferral account in RP-2005-0020 (EB-2005-0378) Hydro One Networks Inc., Electricity Distribution Rates 2006. In that same decision, the Board approved Hydro One Distribution's request for establishment of a new variance account for the OEB Cost Assessment Differential.

b. Hydro One Distribution budgets for costs associated with the annual OEB assessment, intervenor awards, and OEB-initiated studies. However the actual amounts of these payments are subject to variability and are outside of the Company's control. As such, it is appropriate that any differences between budgeted and actual costs be tracked and recovered from or paid back to customers.

c. Hydro One Distribution proposes to use USofA 1508.

d. The journal entry will be as follows, if the amount of the payment to be made is greater than the amount approved in rates:

Debit: Regulatory Asset OEB Cost Assessment (Balance Sheet Account),
Credit: OM&A Program Account recording the payment

The amount of the journal will be calculated as the difference between the actual annual OEB Cost Assessments, intervenor cost awards, and costs associated with OEB-initiated studies and the amount for these expenditures approved by the OEB as part of 2008 Distribution Rates.

e. Costs or fees would only be booked to this account once they are known.

f. The support and precedent for this request is provided in the Exhibit F1, Tab 3, Schedule 1 and in the response to (a) above.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #41 List 1

Interrogatory

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

Question:

a) Please confirm that there were no former R2 Legacy customers that were reclassified as R1. If there were, please revise Table 2 accordingly.

b) If part (a) is confirmed, please indicate whether or not a comprehensive review was done of R2 Legacy customers to see if any qualified for R1 status. If no such review was done, please explain why.

c) Please provide a schedule that shows for each of the 88 Acquired Utilities, the split of current Residential customers between the new Urban and R1 customer classes. Note: For Caledon please also include R2.

d) What are the current criteria that a customer must meet to qualify for RRRP (per page 3, lines 8-9)?

e) Will any of the Acquired Utilities customers (e.g. Caledon customers) reclassified as R2 qualify for RRRP? If not, why not?

f) The text suggests that all energy billed Farm customers were reclassified as R2 Residential (per page 3, lines 7-8). Is this correct? If so:
- Do all current energy billed Farm customers fall in the R2 density zone?
- Do all current energy billed Farm customers qualify for RRRP?
- Do all current energy-billed Farm customers meet the definition of a Residential customer as set out at Exhibit G2, Tab 5, Schedule 1, pages 2-3? If not, how many do not and why are they reclassified as R2?

Response

a. Confirmed, no former R2 Legacy customers have been density reclassified as R1.

b. No study was done to determine if R2 Legacy customers qualify for R1 status. It was decided to wait for when better customer connectivity and lines detail is available in our GIS system to do a full Density Review of Hydro One Distribution's entire service territory. With existing data and resources, it was decided an Urban review of high density areas could be accomplished and was undertaken.

c. The decomposition of the residential customers of the Acquired Distributors is listed below based on 2006 Active year end customer counts.

Distributor	**Urban**	**R1**	**R2**
Ailsa Craig	-	348	
Arkona	-	217	
Arnprior	2,848	286	
Arran-Elderslie	-	1,675	
Artemesia	-	412	
Bancroft	-	1,001	
Bath	-	737	
Blandford-Blenheim	-	838	
Blyth	-	382	
Bobcaygeon	-	1,641	
Brighton	-	2,320	
Brockville	8,146	192	
Caledon OH 01	8,794	-	
Caledon CH 02	-	2,118	
Caledon OH 06	-	-	7,266
Campbellford-Seymour	-	1,427	
Carleton Place	3,618	93	
Cavan-Millbrook-North Monaghan	-	560	
Centre Hastings	-	647	
Chalk River	-	376	
Champlain	-	1,715	
Cobden	-	469	
Deep River	-	1,741	
Deseronto	-	664	
Dryden	2,526	108	
Dundalk	-	687	
Durham	-	1,110	
Eganville	-	545	
Erin	-	904	
Exeter	-	1,986	
Fenelon Falls	-	970	
Forest	-	1,167	

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GBE	7,638	195	
Georgina	-	1,132	
Glencoe	-	850	
Grand Bend	-	1,038	
Hastings	-	503	
Havelock	-	510	
Kirkfield	-	107	
Lanark Highlands	-	337	
Larder Lake	-	383	
Latchford	-	186	
Lindsay	6,347	167	
Lucan Granton	-	850	
Malahide	-	243	
Mapleton	-	722	
Markdale	-	632	
Marmora	-	579	
McGarry	-	297	
Meaford	-	2,026	
Middlesex Centre	-	398	
Napanee	-	2,036	
Nipigon	-	728	
North Dorchester	-	713	
North Dundas	-	1,509	
North Glengarry	-	1,901	
North Grenville	-	1,359	
North Perth	-	2,416	
North Stormont	-	335	
Omemee	-	506	
Perth	2,745	100	
Perth East	-	548	
Prince Edward	-	3,092	
Quinte West	5,657	1,005	
Rainy River	-	378	
Ramara	-	99	
Red Rock	-	354	
Rockland	-	3,536	
Russell	-	847	
Schreiber	-	593	
Severn	-	577	
Shelburne	-	1,703	
Smiths Falls	3,637	99	
South Glengarry	-	440	
South River	-	473	
Springwater	-	735	
Stirling-Rawdon	-	808	
Thedford	-	295	

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Thessalon	-	550	
Thorndale	-	134	
Thorold	5,963	1,139	
Tweed	-	660	
Wardsville	-	143	
Warkworth	-	258	
West Elgin	-	989	
Whitchurch Stouffville	3,228	66	
Wiarton	-	893	
Woodville	-	320	
Wyoming	-	829	
Terrace Bay		1,025	
Totals	61,147	72,682	7,266

d. The criteria that the customer must meet is to have received RRRP before market opening. The criteria for applying RRRP was established before market opening. Our rate classes of R2 and Farm (where there is a residence on the property) receive the RRRP credit.

e. Yes, the entire R2 rate class receives the RRRP credit including the Caledon customers mapped to R2.

f. No, only energy-billed farms with RRRP are being consolidated in the new R2 rate class.

Not all energy-billed farms fall into R2 Rate Class. Some have been identified as being in an Urban density zone and they will be moving to UR or UGe.

Not all energy-billed farms qualify for the RRRP credit.

The energy-billed farms with RRRP who are being mapped to R2 will meet the Residential criteria since they must be residential to receive the RRRP credit.

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Table 8
Distribution
Retail Settlement Variance Accounts
$ million

Description	May 1, 2006	Dec 31, 2006	Dec 31, 2007	April 30, 2008
RSVA Wholesale Market Services	0.6	(23.8)	(60.3)	(72.6)
RSVA Tx Network & Tx Network Aggregation	1.4	7.6	12.5	1.4
RSVA Tx Connection & Tx Connection Aggregation	1.6	5.4	7.5	2.5
RSVA Provincial Benefit	5.6	7.8	0.0	0.0
RSVA Low Voltage	0.0	0.8	3.0	3.8
Total RSVA	9.2	(2.2)	(37.3)	(64.8)

2.7 Accounts Not Being Requested For Recovery

2.7.1 <u>RCVA and RRRP Accounts</u>

RCVA and RRRP deferral accounts are currently being tracked by Hydro One Distribution but are not being requested for recovery as part of this proceeding. Balances in these accounts will continue to be filed with the Board on a quarterly basis per the Electricity Reporting and Record Keeping Requirements and included in the Board's annual review of deferral account balances.

2.7.2 <u>Regulatory Asset Recovery Account – Phase I</u>

Ontario's local electricity distribution companies (LDCs or distributors) incurred costs in preparation for the competitive market which opened in May 2002. In addition to these transition costs, utilities incurred other costs associated with regulatory directives related to market restructuring and the ongoing competitive market.

SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY
NAME OF CONTACT
E-mail Address
VERSION NUMBER v3.0
Date

LICENCE NUMBER ED-XXXX-XXXX
DOCID NUMBER EB-200X-XXXX

PHONE NUMBER
(extension)

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset accounts for each account in the appropriate cells below.
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application.

		2005								
Account Description	Account Number	Opening Principal Amounts as of Jan-1-05 [1]	Transactions (additions) during 2005, excluding interest and adjustments [6]	Transactions (reductions) during 2005, excluding interest and adjustments [6]	Adjustments during 2005 - instructed by Board [2]	Adjustments during 2005 - other [3]	Closing Principal Balance as of Dec-31-05	Opening Interest Amounts as of Jan-1-05	Interest Jan-1 to Dec31-05	Closing Interest Amounts as of Dec-31-05
RSVA - Wholesale Market Service Charge	1580	$ 465,000	$ 8,325,000				$ 8,810,000	$ 24,000	$ 171,000	$ 195,000
RSVA - One-time Wholesale Market Service	1582	$ 1,011,000	$ 1,238,000				$ 2,249,000	$ 45,000	$ 113,000	$ 158,000
RSVA - LV	1550									
RSVA - Retail Transmission Network Charge	1584	$ (11,324,000)	$ (7,730,000)				$ (19,054,000)	$ (481,000)	$ (1,196,000)	$ (1,677,000)
RSVA - Retail Transmission Connection Charge	1586	$ (14,062,000)	$ (10,324,000)				$ (24,496,000)	$ (608,000)	$ (1,528,000)	$ (2,136,000)
Sub-Totals		$ (23,910,000)	$ (8,491,000)		$ -	$ -	$ (32,401,000)	$ (1,020,000)	$ (2,440,000)	$ (3,460,000)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 1,179,000	$ 2,211,000				$ 3,390,000	$ 18,000	$ 128,000	$ 146,000
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 33,218,000	$ 38,248,000				$ 71,466,000	$ 1,164,000	$ 3,866,000	$ 5,030,000
Other Regulatory Assets - Sub-Account - Other [1]	1508	$ 2,352,000		$ (3,159,000)			$ (807,000)	$ (75,000)	$ 69,000	$ (6,000)
Other Regulatory Assets - Sub-Account - Other [1]	1508	$ -	$ 825,000				$ 825,000	$ -	$ 21,000	$ 21,000
Other Regulatory Assets - Sub-Account - Other [7]	1508						$ -			$ -
Retail Cost Variance Account - Retail	1518	$ (432,000)	$ (130,000)				$ (562,000)	$ (45,000)	$ (40,000)	$ (85,000)
Retail Cost Variance Account - STR	1548	$ 147,000	$ 186,000				$ 333,000	$ 5,000	$ 18,000	$ 23,000
Misc. Deferred Debits	1525	$ 88,487,000		$ (7,059,000)			$ 81,428,000	$ 25,544,000	$ 2,933,000	$ 28,477,000
LV Variance Account	1550	$ 24,964,000	$ 24,392,000				$ 49,356,000	$ 902,000	$ 2,772,000	$ 3,674,000
Smart Meter Revenue Requirement (Min Funct to May 31, 2007)	1555/1556									
Smart Meter Revenue (Min Funct to May 31, 2007)	1555									
Smart Meter Revenue Requirement (Exceeding Min Funct)	1555/1556									
Smart Meter Revenue Requirement (Min Funct between June 1, 2007 and April 30, 2008)	1555/1556									
Smart Meter Revenue (Min Funct between June 1, 2007 and April 30, 2008)	1555									
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555						$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555						$ -			$ -
Smart Meter OM&A Variance	1556						$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ 1,037,000		$ (24,864,000)			$ (23,827,000)	$ 9,000	$ 16,000	$ 25,000
CDM Contra	1566						$ -			$ -
Qualifying Transition Costs [5]	1570		n/a	n/a			$ -			$ -
Pre-Market Opening Energy Variances Total [5]	1571		n/a	n/a			$ -			$ -
Extra-Ordinary Event Costs	1572						$ -			$ -
Deferred Rate Impact Amounts	1574						$ -			$ -
Other Deferred Credits	2425						$ -			$ -
Sub-Totals		$ 150,952,000	$ 65,732,000	$ (34,872,000)	$ -	$ -	$ 181,812,000	$ 27,522,000	$ 9,783,000	$ 37,305,000
Deferred Payments in Lieu of Taxes	1562				see PILs reconciliation requested					
2006 PILs & Taxes Variance	1592				see PILs reconciliation requested					
Sub-Totals					see PILs reconciliation requested					
Total		$ 127,042,000	$ 57,241,000	$ (34,872,000)	$ -	$ -	$ 149,411,000	$ 26,502,000	$ 7,343,000	$ 33,845,000
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account [8]	1563				see PILs reconciliation requested					
RSVA - Power (including Global Adjustment)	1588						$ -			$ -
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -	$ (4,926,000)				$ (4,926,000)	$ -	$ (216,000)	$ (216,000)
Recovery of Regulatory Asset Balances	1590	$ 121,954,000		$ (40,871,000)			$ 81,083,000	$ (725,000)	$ 7,877,000	$ 7,152,000

[1] As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
[2] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
[3] Provide supporting statement indicating nature of this adjustments and periods they relate to
[4] Not included in sub-total
[5] Closed April 30, 2002
[6] For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
[7] Please describe "other" components of 1508 and add more component lines if necessary.
[8] 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.
[9] Interest projected on December 31, 2006 closing principal balance.
Note 1 Values reflect interest adjustments requested by the Board in RP-2005-0020 for Deferred Pension account and MEU Rate Mitigation account

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SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY
NAME OF CONTACT
E-mail Address
VERSION NUMBER v3.9
Date

Account Description	Account Number	2006 Opening Principal Amounts as of Jan-1-06	Transactions (additions) during 2006, excluding interest and adjustments [6]	Transactions (reductions) during 2006, excluding interest and adjustments [6]	Adjustments during 2006 - instructed by Board [2]	Adjustments during 2006 - other [3]	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Principal Balance as of Dec-31-06	Opening Interest Amounts as of Jan-1-06	Interest Jan-1 to Dec31-06	Transfer of Board-approved amounts to 1590 as per 2006 EDR	Closing Interest Amounts as of Dec-31-06
											Note 1	
RSVA - Wholesale Market Service Charge	1580	$ 8,810,000	$ (35,838,000)				$ 3,533,000	$ (23,495,000)	$ 165,000	$ (253,000)	$ (290,000)	$ (348,000)
RSVA - One-time Wholesale Market Service	1582	$ 2,249,000	$ -				$ (2,249,000)	$ -	$ 158,000	$ 56,000	$ (214,000)	$ -
RSVA - LV	1550		$ 832,000				$ -	$ 832,000		$ 15,000	$ -	$ 15,000
RSVA - Retail Transmission Network Charge	1584	$ (18,054,000)	$ 3,126,000				$ 23,159,000	$ 7,231,000	$ (1,677,000)	$ (314,000)	$ 2,321,000	$ 330,000
RSVA - Retail Transmission Connection Charge	1586	$ (24,406,000)	$ 28,000				$ 29,468,000	$ 5,090,000	$ (2,136,000)	$ (483,000)	$ 2,965,000	$ 346,000
Sub-Totals		$ (32,401,000)	$ (31,862,000)		$ -	$ -	$ 53,911,000	$ (10,342,000)	$ (3,460,000)	$ (879,000)	$ 4,782,000	$ 343,000
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ 3,380,000	$ 759,000				$ (4,876,000)	$ (827,000)	$ 146,000	$ 39,000	$ (234,000)	$ (49,000)
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ 71,466,000	$ 12,167,000				$ (83,633,000)	$ -	$ 5,030,000	$ (934,000)	$ (4,096,000)	$ -
Other Regulatory Assets - Sub-Account - Other [7] (RRRP)	1508	$ (807,000)	$ 1,784,000					$ 977,000	$ (6,000)	$ 2,000		$ (4,000)
Other Regulatory Assets - Sub-Account - Other [7] [illegible]	1508	$ 835,000	$ 367,000				$ (1,192,000)	$ -	$ 21,000	$ 13,000	$ (34,000)	$ -
Other Regulatory Assets - Sub-Account - Other [7] [illegible]	1508	$ -	$ 367,000					$ 367,000	$ -	$ 3,000		$ 3,000
Retail Cost Variance Account - Retail	1518	$ (562,000)	$ (451,000)				$ 525,000	$ (488,000)	$ (85,000)	$ (26,000)	$ 96,000	$ (15,000)
Retail Cost Variance Account - STR	1548	$ 333,000	$ 107,000				$ (407,000)	$ 33,000	$ 23,000	$ 9,000	$ (31,000)	$ 1,000
Misc. Deferred Debits	1525	$ 81,426,000		$ (11,581,000)				$ 69,847,000	$ 28,477,000	$ 3,043,000		$ 31,520,000
LV Variance Account	1550	$ 49,356,000	$ 8,096,000				$ (57,452,000)	$ -	$ 3,574,000	$ 1,315,000	$ (4,889,000)	$ -
Smart Meter Revenue Requirement (Min Funct to May 31, 2007)	1555/1556		$ 6,053,000					$ 6,053,000	$ -	$ 139,000		$ 139,000
Smart Meter Revenue (Min Funct to May 31, 2007)	1555			$ (2,490,000)				$ (2,490,000)	$ -	$ (57,000)		$ (57,000)
Smart Meter Revenue Requirement (Exceeding Min Funct)	1556/1556		$ 627,000					$ 627,000	$ -	$ 14,000		$ 14,000
Smart Meter Revenue Requirement (Min Funct between June 1, 2007 and April 30, 2008)	1555/1556		$ -					$ -	$ -			$ -
Smart Meter Revenue (Min Funct between June 1, 2007 and April 30, 2008)	1555		$ -					$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -						$ -	$ -			$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555	$ -						$ -	$ -			$ -
Smart Meter OM&A Variance	1556	$ -						$ -	$ -			$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ (23,617,000)	$ 4,524,000					$ (19,093,000)	$ 25,000	$ -		$ 25,000
CDM Contra	1566	$ -						$ -	$ -			$ -
Qualifying Transition Costs [5]	1570	$ -	n/a	n/a				$ -	$ -			$ -
Pre-Market Opening Energy Variances Total [5]	1571	$ -	n/a	n/a				$ -	$ -			$ -
Extra-Ordinary Event Costs	1572	$ -						$ -	$ -			$ -
Deferred Rate Impact Amounts	1574	$ -						$ -	$ -			$ -
Other Deferred Credits	2425	$ -						$ -	$ -			$ -
Sub-Totals		$ 181,812,000	$ 34,400,000	$ (14,071,000)	$ -	$ -	$ (147,135,000)	$ 65,006,000	$ 37,305,000	$ 3,560,000	$ (9,288,000)	$ 31,577,000
Deferred Payments in Lieu of Taxes	1562						see PILs reconciliation requested					
2006 PILs & Taxes Variance	1592						see PILs reconciliation requested					
Sub-Totals							see PILs reconciliation requested					
Total		$ 149,411,000	$ 2,548,000	$ (14,071,000)	$ -	$ -	$ (93,224,000)	$ 44,664,000	$ 33,845,000	$ 2,581,000	$ (4,506,000)	$ 31,920,000
The following is not included in the total claim but is included on a memo basis:												
Deferred PILs Contra Account [8]	1563						see PILs reconciliation requested					
RSVA - Power (including Global Adjustment)	1588	$ -						$ -	$ -			$ -
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ (4,926,000)	$ 12,579,000					$ 7,653,000	$ (216,000)	$ 380,000	$ -	$ 164,000
Recovery of Regulatory Asset Balances	1590	$ 81,083,000		$ (47,937,000)			$ 93,224,000	$ 126,370,000	$ 7,152,000	$ 13,136,000	$ (4,506,000)	$ 15,782,000

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SHEET 1 - Regulatory Assets - Continuity Schedule

NAME OF UTILITY
NAME OF CONTACT
E-mail Address
VERSION NUMBER v3.0
Date

Account Description	Account Number	Projected Interest on Dec 31 -06 balance from Jan 1, 2007 to Dec 31, 2007 [2]	Projected Interest on Dec 31 -06 balance from Jan 1, 2008 to April 30, 2008 [3]	Claim before Forecasted Transactions	Forecasted Transactions, Excluding Interest from Jan 1, 2007 to Dec 31, 2007	Forecasted Transactions, Excluding Interest from Jan 1, 2008 to April 30, 2008	Projected Interest from Jan 1, 2007 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2007 to December 31, 2007	Projected Interest from Jan 1, 2008 to April 30, 2008 on Forecasted Transx (Excl Interest) from Jan 1, 2008 to April 30, 2008	Total Claim	Ex F1/Tab 1/Sch 1/ Pg 2
RSVA - Wholesale Market Service Charge	1580	$ (1,111,000)	$ (400,000)	$ (25,354,000)	$ (34,555,000)	$ (11,250,000)	$ (1,335,000)	$ (96,000)	$ (72,590,000)	$ (72,590,000)
RSVA - One-time Wholesale Market Service	1582	$ -	$ -	$ -	$ -	$ -			$ -	$ -
RSVA - LV	1550	$ 40,000	$ 14,000	$ 901,000	$ 2,028,000	$ 830,000	$ 65,000	$ 7,000	$ 3,831,000	$ 3,831,000
RSVA - Retail Transmission Network Charge	1584	$ 342,000	$ 123,000	$ 8,020,000	$ 4,479,000	$ (11,210,000)	$ 230,000	$ (95,000)	$ 1,430,000	$ 1,430,000
RSVA - Retail Transmission Connection Charge	1586	$ 241,000	$ 87,000	$ 5,764,000	$ 1,740,000	$ (5,010,000)	$ 56,000	$ (43,000)	$ 2,507,000	$ 2,507,000
Sub-Totals		$ (488,000)	$ (176,000)	$ (10,663,000)	$ (26,308,000)	$ (26,640,000)	$ (984,000)	$ (227,000)	$ (64,822,000)	$ (64,822,000)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ (39,000)	$ (14,000)	$ (929,000)					$ (929,000)	$ (929,000)
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			N/A					N/A	
Other Regulatory Assets - Sub-Account - Other [7] (RSRP)	1508			N/A					N/A	
Other Regulatory Assets - Sub-Account - Other [7] (Overrate mitigation)	1508			N/A					N/A	
Other Regulatory Assets - Sub-Account - Other [7] (Call Late)	1508			N/A					N/A	
Retail Cost Variance Account - Retail	1518			N/A					N/A	
Retail Cost Variance Account - STR	1548			N/A					N/A	
Misc. Deferred Debits	1525			N/A					N/A	
LV Variance Account	1550			N/A					N/A	
Smart Meter Revenue Requirement (Min Funct to May 31, 2007)	1555/1556	$ 265,000	$ 103,000	$ 6,580,000	$ 4,292,000	$ 1,025,000	$ 99,000	$ 8,000	$ 12,004,000	$ 12,004,000
Smart Meter Revenue (Min Funct to May 31, 2007)	1555	$ (117,000)	$ (42,000)	$ (2,706,000)	$ (2,340,000)	$ -	$ (54,000)		$ (5,100,000)	$ (5,100,000)
Smart Meter Revenue Requirement (Exceeding Min Funct)	1555/1556	$ 30,000	$ 11,000	$ 682,000	$ 2,645,000	$ 2,300,000	$ 61,000	$ 18,000	$ 5,706,000	$ 5,706,000
Smart Meter Revenue Requirement (Min Funct between June 1, 2007 and April 30, 2008)	1555/1556	$ -	$ -	$ -	$ 11,217,000	$ 9,977,000	$ 265,000	$ 180,000	$ 21,639,000	$ 21,639,000
Smart Meter Revenue (Min Funct between June 1, 2007 and April 30, 2008)	1555	$ -	$ -	$ -	$ (7,613,000)	$ (4,382,000)	$ (180,000)	$ (79,000)	$ (12,254,000)	$ (12,254,000)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555			$ -					$ -	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555			$ -					$ -	
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter Costs	1555			$ -					$ -	
Smart Meter OM&A Variance	1556			$ -					$ -	
Conservation and Demand Management Expenditures and Recoveries	1565			N/A					N/A	
CDM Contra	1566			N/A					N/A	
Qualifying Transition Costs [5]	1570			N/A					N/A	
Pre-Market Opening Energy Variances Total [5]	1571			N/A					N/A	
Extra-Ordinary Event Costs	1572			N/A					N/A	
Deferred Rate Impact Amounts	1574			N/A					N/A	
Other Deferred Credits	2425			N/A					N/A	
Sub-Totals		$ 159,000	$ 58,000	$ 3,627,000	$ 8,201,000	$ 8,920,000	$ 191,000	$ 127,000	$ 21,066,000	$ 21,066,000
Deferred Payments in Lieu of Taxes	1562								$ (4,963,000)	$ (4,963,000)
2006 PILs & Taxes Variance	1592									
Sub-Totals				$ -					$ (4,963,000)	$ (4,963,000)
Total		$ (328,000)	$ (118,000)	$ (7,036,000)	$ (18,107,000)	$ (17,720,000)	$ (793,000)	$ (100,000)	$ (48,719,000)	$ (48,719,000)
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account [8]	1563									
RSVA - Power (including Global Adjustment)	1588			$ -					$ -	
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ 362,000	$ 130,000	$ 8,309,000	$ (7,653,000)	$ -	$ (656,000)	-	$ -	
Recovery of Regulatory Asset Balances	1590			$ 142,152,000					$ 142,152,000	

L:\Governance and Oversight\...\Regulatory Assets\...continuity schedule

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<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #44 List 1</u>

<u>Interrogatory</u>

Reference: i) Exhibit G1, Tab 2, Schedule 4
ii) Exhibit G2, Tab 3, Schedule 1, page 3

Question:

a) Who should a customers contact if they believe their density classification is incorrect?

b) What process has Hydro One established to address queries by either individual customers or local municipalities that their density classification is incorrect?

c) Page 3 of Reference (ii) provides a list of communities analyzed under the density review. How was the density classification of customers in the other acquired utilities established?

<u>Response</u>

a. Customers should contact the Hydro One Customer Communications Centre, if they have a question regarding their rate classification. The Centre's number is printed on the customer's bill. (1-888-664-9376.)

b. The Hydro One process in response to density classification customer inquiries is for our Customer Communications Centre representatives to issue an investigation order to our field staff. The rate will be checked by our field staff and the customer will be informed via letter of the results of the investigation. If the account meets the criteria for a different density rate, the rate will be changed on their bill going forward. If the account does not meet the criteria, then the billing rate will remain the same.

c. Please see Exhibit H, Tab 1, Schedule 134.
Per Acquired Distributor, the customer counts and customer per line kilometre metrics were analyzed. Since the non-urban Acquired Distributors have at least 100 customers with a line density of at least 15 customer per km, they all meet the requirements for the Medium Density Zone.

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MITIGATION OF BILL IMPACTS ACQUIRED LDC CUSTOMERS

This exhibit presents the proposed impact mitigation plan for Acquired LDC customers. As per the guidelines in the 2006 Electricity Distribution Rate Handbook, LDCs have to present a mitigation plan if as a result of the proposed rate increase customer classes, or group of customers, have impacts higher than 10 percent on total bill.

1.0 INTRODUCTION

As was shown in Exhibit G1, Tab 7, Schedule 2, customer classes of Acquired LDCs prior to mitigation would see impacts higher than 10 percent on total bill resulting from the proposed increase in 2008 Revenue Rates, harmonization of distribution rates, Regulatory Asset Rate Rider # 3, and RTSR changes.

Hydro One Distribution proposes the following mitigation initiatives to address the impacts on the Acquired LDC customer classes that could see impacts, on average, of over 10 percent on total bill.

1. The target distribution rates are being phased-in over a period of four years. Average total bill impacts have been limited to a maximum of 10% in 2008, 8% in 2009, and 7% in 2010. These maximums leave some room to accommodate third generation Incentive Rate Mechanism increases. Increases in 2011 reflect the remaining increases resulting from the multi-year proposed harmonization process and result in average total bill impacts below 10%. The volumetric charges were adjusted as necessary each year to limit total bill impacts in 2008, 2009 and 2010. Any shortfall in revenues resulting from this mitigation measure is being absorbed first by the Acquired LDC in subsequent years, and if this is not possible, then by the Legacy

customer classes in the same group as the Acquired customer classes requiring mitigation.

2. Regulatory Rate Rider # 3 is being refunded over 4 years consistent with Hydro One approved past practices with respect to Regulatory Rate Riders and to provide for a smoother bill impacts over the 4 year period.
3. The target revenue to cost ratio range proposed is between 0.7 and 1.2 instead of proposing revenue to cost ratio of 1. This is consistent with the Board's Report issued November 28, 2007.
4. Proposed rates in 2010 and 2011 were adjusted to provide for a smoother set of impacts in those years.
5. A deferral account is being set up to recover the shortfall in 2008 proposed Revenue Requirement that results from Hydro One's proposed Revenue to Cost Ratios by customer class. The Revenue to Cost ratios are consistent with the Board's recommended Revenue to Cost ratios.

Table 1, below shows the initial 2008 Distribution rates derived in Exhibits G1, Tab 4, Schedule 3, and the adjusted 2008 Distribution rates after taking into account the rate mitigation initiative above for the customer classes.

The complete 2008 Rate Schedules are provided in Exhibit G2, Tabs 6 to Tab 93.

Table 1
2008 Distribution Rates

	Residential				GS<50				GS>50			
Acquired LDC	**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**		**2008 Initial**		**2008 Mitigated**	
	SrChg	¢/kWh	SrChg	¢/kWh	SrChg*	¢/kWh	SrChg*	¢/kWh	SrChg	$/kW	SrChg	$/kW
Ailsa Craig	12.13	2.71	12.13	1.85	20.41	3.21	20.41	2.34	24.36	9.22	24.36	9.00
Arkona	8.30	2.71	8.30	1.50	9.94	3.21	9.94	1.98	13.89	9.22	13.89	9.22
Arnprior	12.88	2.71	11.70	2.40	23.40	3.21	18.74	2.00	27.34	9.22	22.95	7.33
Arran-Elderslie	11.51	2.71	11.51	1.90	13.53	3.21	13.53	1.90	17.48	9.22	17.48	8.00
Artemesia	13.58	2.71	13.58	2.35	21.84	3.21	21.84	3.21	25.78	9.22	25.78	9.22
Bancroft	14.39	2.71	14.39	2.10	25.64	3.21	25.64	2.30	29.59	9.22	29.59	8.50
Bath	14.42	2.71	14.42	2.35	15.08	3.21	15.08	2.55	19.03	9.22	19.03	9.00
Blandford-Blenheim	12.85	2.71	12.85	2.30	24.78	3.21	24.78	2.40	28.73	9.22	28.73	8.90
Blyth	9.96	2.71	9.96	2.00	23.33	3.21	23.33	2.20	27.28	9.22	27.28	8.50
Bobcaygeon	15.14	2.71	15.14	2.05	24.94	3.21	24.94	2.50	28.89	9.22	28.89	9.22
Brighton	12.86	2.71	12.86	2.20	24.02	3.21	24.02	2.50	27.96	9.22	27.96	9.22
Brockville	13.68	2.71	12.50	2.40	23.33	3.21	18.67	2.00	27.28	9.22	22.89	6.70
Caledon OH 01	-	2.71	16.95	2.15	-	3.21	-	-	-	9.22	-	-

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Table 6
Examples of Development of Harmonized Residential group rates
Urban and R 1

Residential - Urban	**LDC 1**	**LDC 2**
Target rates	$14.32/month & 2.29 ¢/kWh	$14.32/month & 2.29 ¢/kWh
LDC 2007 rate	$6.58/month	$18.52/month
LDC increase/(decrease)	$7.74/month	$(4.20)/month
LDC Yearly increase/(decrease)	$1.94/month	$(1.05)/month
LDC year 1 rate	$6.00 + $1.94 = $7.94/month & 2.40 ¢/kWh	$18.00 - $1.05 = $16.95/month & 2.40 ¢/kWh
LDC Year 2 rate	$7.94 + $1.94 = $9.88/month & 2.38 ¢/kWh	$16.95 - $1.05 = $15.90/month & 2.38 ¢/kWh
LDC Year 3 rate	$9.88 + $1.94 = $11.82/month & 2.36 ¢/kWh	$15.90 - $1.05 = $14.85/month & 2.36 ¢/kWh
LDC year 4 rate	$14.32/month & 2.29 ¢/kWh	$14.32/month & 2.29 ¢/kWh

Residential – R1	**LDC 1**	**LDC 2**
Target rates	$19.04/month & 2.60 ¢/kWh	$19.04/month & 2.60 ¢/kWh
LDC 2007 rate	$3.78/month	$20.81/month
LDC increase/(decrease)	$15.26/month	$(1.77)/month
LDC Yearly increase/(decrease)	$3.82/month	$(0.44)/month
LDC year 1 rates	$3.00 + $3.82 = $6.82/month & 2.71 ¢/kWh	$20.00 - $0.44 = $19.56/month & 2.71 ¢/kWh
LDC year 2 rates	$6.82 + $3.82 = $10.64/month & 2.68 ¢/kWh	$19.56 - $0.44 = $19.12/month & 2.68 ¢/kWh
LDC year 3 rates	$10.64 + $3.82 = $14.46/month & 2.65 ¢/kWh	$19.12 - $0.44 = $18.68/month & 2.65 ¢/kWh
LDC year 4 rates	$19.04/month & 2.60 ¢/kWh	$19.04/month & 2.60 ¢/kWh

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #53 List 1

Interrogatory

Reference: i) Exhibit G1, Tab 4, Schedule 3, page 1, lines 21-22
ii) Exhibit G1, Tab 7, Schedule 1, page 1, lines 3-5
iii) Exhibit G1, Tab 8, Schedule 2, pages 1-4

Question:

a) Please explain what is meant by "total average bill impacts" (per References (i) and (ii)). Is this meant to be:
- The average bill impact for all customers in the class?
- The bill impact for an average customer?

b) If the response to (a) is the bill impact for an average customer – please provide the consumption characteristics assumed for the average customer in each of Hydro One's proposed customer classes.

Response

a. The term "total average bill impacts" refers to the projected bill impact for an average customer per rate class.

b. The average consumption per rate used in the Bill Impact analysis is contained in the table below. The numerous levels of DGen are presented since the average was narrowed to sub-groups.

		kWh	kW	Load Factor
UR		1,000		
R1		1,000		
R2		1,000		
Seasonal		400		
GSe		2,000		
GSd		43,164	133	45%
UGe		2,000		
UGd		43,164	133	45%
St Lgt		1,440		
Sen Lgt		62		
Dgen	D-Billed G3	35,000	90	54%
	D-Billed T	7,700	200	5%
	E-Billed G3	802	8	14%
	E-Billed T	846	26	5%
	Acquireds	6	1	1%

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #47 List 1

Interrogatory

Reference: Exhibit G1, Tab 2, Schedule 5, pages 7- 9

Question:

a) Please confirm whether the results set out in Table 3 are based on:
   - The first year's results of the four year implementation plan, or
   - The results assuming the harmonization was accomplished in one year.

b) If the response to part (a) is that its represents the impact of harmonization in one year, please re-do Table 3 based on the 2008 results expected from the four year implementation plan.

c) Do the impacts set out in Table 3 include the changes in Rate Riders proposed for 2008? If not, please re-do Table 3 to reflect both the impact of the proposed change in rate riders for 2008 and (if necessary) the first year of the four year harmonization plan.

d) With respect to page 9 (lines 16-18), please clarify what is meant by the statement that "all Acquired customers would, on average, have a total yearly bill of less than 10%, including the impact of the 2008 revenue requirement increase".

e) Does the statement referenced in part (e) also include the impact of the proposed changes in the rate riders? If not, please indicate the impact of including the changes proposed to the rate riders.

Response

a. The impacts presented in Exhibit G1 Tab 2 Schedule 5 Table 3 are at the end of the 4 year implementation plan. This can also be described as assuming the harmonization is accomplished in one year

b. The impact ranges for 2008: the first year of the proposed 4 year implementation plan are:

Residential	2.2 to 9.7%
General Service	0 to 8.9%

c. The impacts are inclusive of the changes in Rate Riders proposed for 2008.

d. The paragraph is stating that the 2008 total bill increase for an average Acquired customer will be limited to 10% inclusive of the harmonization impacts, regulatory rate rider changes, Retail Transmission Service rate changes, loss factor changes and the increased Distribution Revenue Requirement.

e. The reference is assumed to refer to part d not e. Assuming that the reference is to part d, the answer is the 10% limit is inclusive of the proposed Rate Riders for 2008.

RUD Model, is \$0.0062/kWh. Conceptually it represents the cost of providing the next kWh and includes incremental operating and maintenance expenses, incremental capital investment, and incremental financing charges. The IDC value was derived in a 1980's joint Ontario Hydro-Municipal Electric Utility ("MEU") study and is the value that was included in the MEU's rate setting under Ontario Hydro's regulatory regime. As such, \$0.0062/kWh is the IDC value included in the electricity distribution utilities' existing rates.

Where a utility has its own IDC value, it should use it in filing for initial rates and include justification for that value.

3.3.1 Impact on Total Bill Resulting from Change in Rate Design

In moving to a two-part distribution rate structure, some small volume customers may see a significant rate impact. The impact increases with the size of the monthly service charge. The service charge should be set so that rate impact resulting from the change in rate structure does not exceed 10 per cent of total bill (relative to annual bill using current bundled rates), for the small volume customers group in a rate class (see Chapter 4). In mitigating the impact on total bill, the monthly service charge should be lowered and the volumetric charge raised to a point where the impact on the small volume customers group within a rate class is less than 10 per cent. Class revenue requirement neutrality must be maintained in meeting the rate impact mitigation requirement.

The RUD Model, described in Appendix C, will assist electricity distribution utilities in ensuring that the impact on the small volume customers group does not exceed 10 per cent of total bill, on an annualized basis. If an electricity distribution utility cannot attain the 10 per cent limit while maintaining total class revenue neutrality, it must highlight this in its evidence in support of initial rates.

3.4 ADJUSTMENTS TO INITIAL REVENUE REQUIREMENTS

Procedures described above yield an initial estimate of the revenue requirement to cover distribution expenses. However, an adjustment needs to be made to allow for returns up to the MBRR, if the electricity distribution utility chooses to do so.

3.4.1 Market-Based Rate of Return

With respect to the MBRR, electricity distribution utilities may choose to base their rates at

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The above methodology must be followed by all distributors in Run 1 and Run 2 of the filing.

A distributor may use 12 NCP in its optional Run 3, provided that the distributor also provides supporting justification in its Filing Summary based on the cost characteristics of its distribution system. In such cases, the Filing Summary should highlight the impacts of the different NCP allocator used in Runs 1 and 2, versus Run 3.

8.3 Coincident Peak ("CP") Method

8.3.1 Background

CP is the generally preferred demand allocator for distribution assets designed to serve a distributor's system peak. In the cost allocation filings, assets identified as >50 kV and bulk (if any)[12] by a distributor must be allocated based on CP.

The Federal Energy Regulatory Commission has developed various tests to determine the appropriate CP to be used when allocating transmission costs. This approach has been adapted for use in the current cost allocation filings. The test below has been designed so that a 20% peak will warrant use of 1 CP rather than 4 CP. The type of CP allocator used can impact the cost allocated to a rate classification. For example, street lights may benefit from 12 CP as opposed to 1 CP under certain circumstances.

8.3.2 Direction - Tests for Use of CP in Filings

For distribution assets and related O&M accounts that are solely designed to meet the distributor's system demand, CP will be used as the demand allocator. For the filings, this will consist of all costs related to >50 kV and bulk assets (if any).

CP for each rate classification will be further subdivided into transmission transformation CP ("TCP") and distribution CP ("DCP"). Transmission transformation CP represents the coincident peak of all customers that use the >50kV assets deemed to be distribution assets.

The choice of 1 CP, 4 CP or 12 CP will be determined by the application of the test described below. As with the NCP test, the CP test will be incorporated into the filing model.

[12] See Chapter 6 (for example, guidance is provided there as to when a distribution station serves a bulk function and therefore its costs should be allocated using CP).

If costs or assets are directly allocated, the direct allocation should capture all the associated accounts; for example, in the case of assets, the gross value, accumulated depreciation and depreciation expense, and any contributed capital.

Direct allocation must also be used where identifiable O&M activities can be directly allocated to one customer classification, and where supporting documentation in terms of sub-account records and explanations as to the related activities can be provided.

When direct allocation is used, the distributor should consider whether it needs to adjust the appropriate allocation factors so that the rate classification to which costs for a specific function are directly allocated is not allocated further costs related to that function, except where there are joint costs that apply to the customer classification. For example, if a customer classification has all its assets and O&M costs directly allocated to the classification, then the load data used to allocate "common" assets and O&M costs should exclude the load data associated with this customer classification. There may be other instances in which no adjustment is needed. The Filing Summary should address whether or not an adjustment was considered appropriate by the distributor and confirm it was undertaken where warranted.

The filing model will allow a distributor to define which costs in the trial balance that supports the 2006 approved rates should be directly allocated to a specific rate classification.

A stakeholder suggested that use of fixed assets, with no adjustment for contributed capital,[16] is a better measure of the scope of the assets that General Plant is supporting and therefore from a cost causality perspective should be the allocation factor used.

10.2.2 Direction – Allocation of General Plant

General Plant should be allocated on a pro rata basis using a composite of distribution net fixed assets (average of opening and closing balances for the test year), with no adjustment for contributed capital.

Distributors that have detailed analysis on the allocation of General Plant, however, must use this information in all runs of the cost allocation model filed and provide supporting explanation and documentation in the Filing Summary. For example, identifiable CIS assets could be segregated out and allocated to each rate classification in the same manner as billing and collecting costs.

10.3 Administrative and General Expenses ("A&G")

10.3.1 Background

This category includes costs that support all aspects of the overall organization such as executive, management and general administration salaries and expenses, employee pensions and benefits, office supplies, franchise requirements and regulatory affairs.

10.3.2 Direction – Allocation of A & G

Except for property insurance and community safety program costs, a *pro rata* allocation of O&M with backing out of A&G will be the common methodology for allocating general expenses.

For property insurance and community safety programs that serve to safeguard the distributor's assets, these costs should be allocated on a pro rata basis using a composite of distribution net fixed assets (average opening and closing balances for the test year), with no adjustment for contributed capital.

[16] Contributed capital is handled separately (see Chapter 6).

$31.6 million moved from USoA 5715 to USoA 5645 reflecting amortization of OPEB, [$23.6million] and to USoA 5112/5114 reflecting land reclamation around stations [$8million].

Billing and Settlement Costs directly attributable to Interval Metered customers was determined for further direct assignment to classes using number of interval meters by delivery point by customer class. Balances direct assigned are: $59k from USoA 5610, $600k from USoA 5615, $11k from USoA 5630, $284k from USoA 5665 and $190k from USoA 5675.

Asset Breakout (Input Sheet 4)

Created sub-accounts for USoA 1815 1-5 Transformer Station Equipment to take into account that Hydro One owns High Voltage Distribution Stations and Low Voltage Distribution Stations. The stations can be shared between Low Voltage (LV) system customers and other end-use customers, or used exclusively by one customer group.

Created sub-accounts for USoA 1830-3 Poles, Towers and Fixtures – Sub-Transmission Bulk Delivery to provide a split between LV and other end use customers.

Created sub-accounts for USoA 1830-4 Poles, Towers and Fixtures - Primary to provide a split between LV and other end use customers.

Created sub-accounts for USoA 1835-3 Overhead Conductors and Devices – Sub-Transmission Bulk Delivery to provide a split between LV and other end use customers.

Created sub-accounts for USoA 1835-4 Overhead Conductors and Devices - Primary to provide a split between LV and other end use customers.

Used Hydro One specific Meter Reading weighting factors based on Hydro One Meter Reading Optimization analysis. The weights range between values of 1 to 4.

Demand Data (Input Sheet 8)

Total Loss Factor by class introduced in cells C16 to W25 to calculate load data at different delivery levels: TS, Bulk, Primary, and Secondary. The LT NCPs were developed using the ratio of the billed demand for customers that receive transformer ownership allowance over the total customer class billed demand as shown in Input Sheet 6.

Direct Allocation (Input Sheet 9)

The following USoA accounts were directly allocated:

5065 Meter Expense ($4.5 million),
5610 Management Salaries and Expenses ($59,000),
5615 General Administrative Salaries and Expenses ($0.6 million),
5630 Outside Services Employed ($11,000)
5665 Miscellaneous General Expenses ($1.8 million)
5675 Maintenance of General Plant ($0.19 million).

These expenses relate to interval meters and to staff dealing with this type of larger customers and Sentinel Light costs.

The allocation factor used for all these accounts is number of Interval Meter by delivery point by class except for Sentinel Lights included in account 5665 ($1.48 million) that has been allocated directly to Sentinel Lights..

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Ontario Energy Board (Board Staff) INTERROGATORY #140 List 1

Interrogatory

Ref: Exhibit G2 / Tab 1 / Schedule 1 / p. 9

a. Please provide a brief description of the basis for Direct Allocation of accounts 5610, 5615, and 5665.
b. If applicable, please provide a description of how the following types of costs are allocated in the Hydro One model:
   i) management salaries and expenses in account 5610 that are not directly allocated
   ii) administrative salaries and expenses in account 5615 that are not directly allocated,
   iii) general expenses in account 5665 that are not directly allocated.

Response

a. The basis for the Direct Allocation of accounts 5610 and 5615 is the number of Interval Meter Delivery points per Rate Class. The costs captured in these accounts mainly relate to the salaries of personnel dealing with the Large Customers who are all Interval Metered.

   For Account 5665, Sentinel Light expenses are directly mapped to the Sentinel Light Rate Class and the non-Sentinel Light expenses are then allocated to the Rate Classes by the number of Interval Meter Delivery points.

b. The costs in Accounts 5610, 5615 and 5665 which are not handled as part of I9 Direct Allocation are allocated to the Rate Classes based on the default allocator of O&M as listed in E4 TB Allocation Details.

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<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #75 List 1</u>

Interrogatory

Reference: i) Exhibit G2-1-1, Attachment A, pages 35 and 47
ii) OEB RP-2005-0317, Section 10.3

Question:

a) Please confirm that Hydro One followed the Board's direction regarding the allocation of Administrative and General Costs.

b) Please breakdown Hydro One's A&G Expenses ($122,080,727) between:
- Property Insurance
- Community Safety Programs
- Remaining A&G Expense

c) Please indicate where in Exhibit G2-1-1, Attachment A the allocation of each of these components of A&G Expenses to customer classes is shown.

d) Unless fully set out in Exhibit G2-1-1, Attachment A, please provide a schedule that show the allocation of each of the components described in part (b) to customer classes including the definition and values for the allocator used in each case.

e) With respect to Reference (i), page 35, please provide a schedule that shows the costs directly allocated to each customer class (Total = $7,169,250) by USOA account.

f) Please confirm that the O&M costs directly allocated to customer classes were included in the Allocation Base used to pro-rate the "Remaining A&G" costs from part (b) above to customer classes. If this is not the case, please provide an alternate Cost Allocation Run where remaining A&G costs are pro-rated to customer classes based on the O&M costs allocated to classes (including directly allocated O&M).

g) If the response to part (f) is confirmed in the positive, please reconcile the following:
- The General and Administration costs allocated to UR represent 31.8% of Distribution and Customer Related Expenses assigned to the Class.
- The General and Administration costs allocated to ST represent 23.5% of Distribution, Customer-Related and Directly Allocated expenses assigned to the Class – a significantly lower percentage.

Response

a. The Administrative and General Costs are allocated based on the defaults per the Cost Allocation Model per E4 TB Allocation Details.

b. The Cost Allocation Model summed General and Administration total of $1,222,080,727 is decomposed for the two accounts as requested.
Full details by USoA can be found in Exhibit H, Tab 12, Schedule 55

- Property Insurance USoA 5635 $2,715,447
- Community Safety Programs USoA 5420 $864,318

c. The allocation for the USoA accounts are outlined in the Cost Allocation Model sheet E4 TB Allocation Details which is provided in Exhibit G2, Tab 1, Exhibit 1, Attachment A on page 125 to 134. The requested USoA of 5420 and 5635 are allocated based on the defaults of "NFA ECC" [Net Fixed Assets Excluding Contributed Capital] found on page 133.

d. All the General and Administration related accounts are contained in the Cost Allocation Model O4 Summary by Class and Accounts [page 50 of Exhibit G2, Tab 1, Schedule 1, Attachment A]. They can be identified with the O1 Grouping flag of using "ad". These "ad" USoA accounts are allocated to the rate classes based on the default allocators in the Cost Allocation Model E4 TB Allocation Details[Attachment page 125]. Finally, all the allocator values can be found it Cost Allocation Model E2 Allocators [Attachment page 118].

e. The requested details by USoA account and Rate Class can be found in Exhibit G2, Tab 1, Schedule 1, Attachment A Cost Allocation Model I9 Direct Allocation page 31 to 34.

f. No, only the non-directly allocated O&M costs are used to develop the allocator for the other O&M accounts. This is as per the Cost Allocation Model provided by the Board, which does not develop its generic O&M allocator based on total costs including those directly allocated using I9 Direct Allocation sheet. The request to develop a new O&M allocator inclusive of these directly allocated costs would require extensive changes in the model that cannot be accomplished within the response time frame.

g. Not applicable based on response to Part f above.

Item	Ref.	Request	Response
56	5.2 Direct Allocation Methodology	Address whether or not an adjustment to the class allocation factors was considered appropriate to eliminate double charging and confirm it was undertaken where warranted.	HONI did eliminate double charging by adjusting allocation factors when allocating costs directly to customer classes, e.g. Use of Low Voltage assets, Interval metering costs, Account executives costs
57	5.2 Specific Questions	Support any direct allocation with a summary of supporting accounting records for the specific facility in question.	Sentinel lights, account executive and interval meter costs were directly assigned to Sentinel Lights and Interval meter customers
58	ibid	Provide single line diagram/schematic indicating the facility concerned, the customers served, and any other facilities serving the same customers.	 Diagram of DX System
59	ibid	If a direct assignment is applied to a customer that also receives back-up service, the filing must include an explanation and supporting documentation on how an appropriate share of back-up serve was determined and allocated.	Low Voltage assets are allocated amongst all customers using the assets based on unit costs, distance, and consumption, regardless if it is for direct or back-up services
60	ibid	If a direct assignment is applied to a customer that also receives back-up service, the filing must include an explanation and supporting documentation if an allocator other than the customer's NCP is used.	Low Voltage assets are allocated to customer groups using coincident peak as this assets are sub-transmission assets.
61	6.2.2.6 Filing Requirements	Explain how the distributor applied the Board's bulk asset test to its system, and why it concluded it did or did not have bulk assets.	Hydro One's Low Voltage assets are sub-transmission assets between 44 kV and 13.8 kV, that in HONI's view, perform a similar function to Bulk Assets. As a result of HONI's geographic service territory, these "Bulk" assets were not designed to meet the total LDC's peak, but were designed to deliver bulk power to large customers and to HONI DSs (substations) which then distribute locally via the Primary system
62	ibid	All distributors will be required to include in their filings a single line diagram or schematic of their distribution system.	See response to item 58

Item	Ref.	Request	Response
63	ibid	Where a distributor believes it has assets that serve a bulk function under the Board's test, an explanation must also be added to the diagram or schematic filed indicating which specific assets have been identified as bulk and the customers by rate classification that are served from such bulk assets.	See response to item 58
64	6.2.2.7 Hydro One	Hydro One is to provide an explanation (including supporting schematic diagram or equivalent) and justification of its LV cost pool, if this sub-Functionalization is employed.	The Cost Allocation for HONI's LV Facilities and the customers that use these facilities were described in Exhibit E, Tab 2, Schedule 2 of RP-2000-0023 and the initial unbundled LV rates were approved by the OEB in that proceeding. Customers served by the Low Voltage assets use High Voltage DSs, (High and Low), Low Voltage DSs and are served at voltages between 44 kV and 13.8 kV. HONI also serves LDCs at voltages below 13.8 kV using Shared LVDSs. Customers supplied between 44 kV and 13.8 kV provide their own transformation.
65	ibid	Hydro one must discuss the impact(s) on its filing from using a "subtransmission" cost pool compared to the standard "bulk" asset cost pool, if employed.	The impact of not using a subtransmission cost pool is that customers that use this system will be allocated $19 million more than the $32 million allocated to them when using the subtransmission cost pool. Customers using only subtransmission assets are Embedded Directs, Embedded LDCs, Large Users and T-class customers.
66	ibid	If Hydro One wishes to use CP to allocate the subtransmission cost pool it must provide justification.	Low Voltage assets are subtransmission assets. Transmission assets are allocated using CP in traditional Cost Allocation studies, therefore, HONI is of the opinion that the subtransmission assets should follow the same approach of using CP as allocator
67	6.3.1 Bulk, Primary, and Secondary	Explain how the distributor broke out its costs between bulk, primary and secondary assets.	HONI used unit costs, distance and load to differentiate between Low Voltage, Primary and Secondary assets. It was also assumed that three-phase General Service and Farms are served exclusively from Primary assets. All remaining small customers are served from Secondary assets.
68	6.6 Capital Contributions - recommended approach	A distributor is to provide its methodology and supporting information to the detailed analysis of capital contributions by either rate class or asset type..	Hydro One records contributions by asset type. The contribution is generally booked to a specific project, then allocated amongst the assets charged to that project. On occasion, a contribution may be directly booked to a particular asset if the contribution was specific to it.

Item	Ref.	Request	Response
104	ibid	If there are no costs in Account 1855, explain why.	Hydro One has no costs charged to USoA 1855. Historically, there was never a business need for HONI to differentiate between primary and secondary systems. Consequently, as processes were streamlined/automated, no attempt was made to differentiate between primary and secondary systems. All costs are recorded within our fixed assets system as conductor in USoA 1835. For overhead services, HONI's cost is the cost incurred from the primary tap point to the mast head, if the distance is 30 metres or less. The customer is responsible for any cost beyond the 30 metres. Accordingly, HONI would at most only record in account 1855 up to 30 metres of secondary conductor per connection and the associated installation costs.
105	ibid	Services (Account 1855): What facilities are included in this account?	See response to issue 104 above
106		Services (Account 1855): Do these facilities match the definition in the USoA?	See response to issue 104 above
107	ibid	Services (Account 1855): If the accounting treatment is different than described in the USoA, explain the accounting treatment of this account and estimate the impact on the account.	See response to issue 104 above
108	ibid	Services (Account 1855): Does this account capture the service drops for all customers or only the costs of service drops operated at secondary voltage (<750 volts)?	See response to issue 104 above
109	ibid	Services (Account 1855): Are there any distributor-owned service drops to customers served from primary or bulk facilities and, if so, where are the costs of these facilities reported?	USoA 1835 and USoA 1830 would have dollars included in them for secondary services
110	ibid	Services (Account 1855): If there are distributor owned primary or bulk drops, but not recorded in this account, where are the costs of these facilities reported?	USoA 1835 and USoA 1830 would have dollars included in them for secondary services

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #69 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1, page 7, lines 13-16

Question:

a) Please provide an explanation as to what stations (in terms of voltages (high and low side) and customers served) are assigned to each of the five breakout groups for Transformation Station Equipment (page 7, lines 13-16).

b) Please provide a schedule that indicates how these five groups align with the HVDS-high; HVSD-low and Shared LVDS charge categories proposed for the ST class.

c) Are there any assets in this category that are "shared" between ST and Other Retail customers? If yes, into which sub-accounts are they assigned? If not, please reconcile this situation with that presented in RP-2000-0023 (Exhibit E, Tab 2, Schedule 2, page 19) where a portion of the both HVDS and LVDS stations were shared.

d) How were the breakout percentages for Transformer Station Equipment (Account #1815 per Exhibit G2-1-1, Attachment A, page 16) determined?

e) In its RP-2000-0023 Application, Hydro One separated out Regulating Stations and treated them similar to LV lines (see Exhibit E, Tab 2, Schedule 2, page 19). How are Regulating Stations treated in the current Cost Allocation?

f) Please clarify what facilities are included in Account #1815 versus #1820.

g) Please clarify what facilities are included in #1820-2 versus #1820-3. How was the cost split between the two sub-accounts established?

Response

a. Umbrella account:
1815 – Transformer Station Equipment – Normally Primary above 50 kV

Sub-accounts:
1815-1 HVDS – Rural ---- is for all HVDSs which supply no ST customers, plus the non-ST portion of HVDSs shared between ST and non-ST customers
1815-2 HVDS – low LV Specific ---- is for HVDSs which supply solely one ST customer, and whose low voltage side is 12.5 kV or less
1815-3 HVDS – high LV Specific ---- is for HVDSs which supply solely one ST customer, and whose low voltage side is 13.8 kV or more
1815-4 HVDS – low LV Shared ---- is for the ST portion of HVDSs shared between ST and non-ST customers, for HVDSs whose low voltage side is 12.5 kV or less
1815-5 HVDS – high LV Shared ---- is for the ST portion of HVDSs shared between ST and non-ST customers, for HVDSs whose low voltage side is 13.8 kV or more

HVDSs are supplied from either 115 kV or 230 kV.

b. Sub-accounts:
1815-1 HVDS – Rural ---- does not align with any ST rate
1815-2 HVDS – low LV Specific ---- aligns with the HVDS-low ST rate
1815-3 HVDS – high LV Specific ---- aligns with the HVDS-high ST rate
1815-4 HVDS – low LV Shared ---- aligns with the HVDS-low ST rate
1815-5 HVDS – high LV Shared ---- aligns with the HVDS-high ST rate

c. Some assets in the "umbrella" 1815 category are shared between ST and non-ST customers. However, there is no such sharing within any of the five 1815 sub-accounts.

To reconcile this situation with that of the reference to RP-2000-0023:

1815-1 HVDS – Rural
would correspond to the "HVDS – Networks Retail" in RP-2000-0023, except for the asset values associated with some of the customers and their energy that in EB-2007-0681 are ST customers. These ST customer asset values would be in 1815-4 or 1815-5 in EB-2007-0681.

The accounts:
1815-2 HVDS – low LV Specific
1815-3 HVDS – high LV Specific

1815-4 HVDS – low LV Shared
and
1815-5 HVDS – high LV Shared
would correspond to "HVDS – LDCs & Directs" in RP-2000-0023 plus some of the asset values associated with some of the customers and their energy that in EB-2007-0681 are ST customers but in RP-2000-0023 are Retail (non-LDC non-Direct).

Account "1820-2 Distribution Station Equipment – Normally Primary below 50 kV Primary"
would correspond to "LVDS (Networks Specific)" and "LVDS – Shared" in RP-2000-0023. There are no longer any "LVDS (LDC-specific)" in Hydro One's system.

d. Determination of the breakout percentages:
1815-1 HVDS – Rural ---- the remainder, after the other sub-accounts have taken their portions
1815-2 HVDS – low LV Specific ---- consistent with gross asset value of the specific station(s)
1815-3 HVDS – high LV Specific ---- consistent with gross asset value of the specific station(s)
1815-4 HVDS – low LV Shared
and
1815-5 HVDS – high LV Shared ---- the gross asset values of all the shared HVDSs were allocated to ST and non-ST in proportion to the kWh of the two customer groups, Then the percent of the ST portion over the gross asset value of all HVDSs (shared and not shared) was split equally between 1815-4 and 1815-5

e. Regulating stations are included with the ST lines.

f. Account "1815 – Transformer Station Equipment – Normally Primary above 50 kV" includes HVDS equipment, while "1820 – Distribution Station Equipment - Normally Primary below 50 kV" includes LVDS equipment.

g. Account 1820-2 is for LVDS equipment itself, while account 1820-3 is for wholesale meters. The cost split between the two sub-accounts is based on fixed assets.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #70 List 1

Interrogatory

Reference: Exhibit G2, Tab 1, Schedule 1, page 7, lines 18-22
Exhibit G2, Tab 1, Schedule 1, Attachment A, page 16

Question:

a) Please provide a schedule setting out how was Account 1830 (Poles, Towers and Fixtures) broken out into: i) Sub-transmission Bulk Delivery, ii) Primary and iii) Secondary? In describing the approach used please clarify the following:
   - The definition of the each of the three breakout groups (i.e., what are the different voltages for the lines carried by each group?
   - How the breakout methodology captured any differences in costs of the types of poles and towers used for each of the three groups?

b) What types (e.g., size/class) of Poles/Towers are used for i) Sub-transmission Bulk Delivery, ii) Primary and iii) Secondary facilities? Please provide a schedule that for each of the three groups indicates the number of poles/towers by type.

c) Please provide a schedule that sets out the current replacement cost for each size/class of pole employed by Hydro One Networks per part (b).

d) Based on the results from (b) and (c) please calculate:
   - The weighted (by km) average replacement cost of for a Sub-transmission, Primary and Secondary pole/tower.
   - A revised percentage split between Sub-transmission, Primary and Secondary using the km associated with each and the average cost per pole as determined in the preceding bullet.

e) The additional Sub-Accounts created for 1830-3 and 1830-4 suggest that Sub-transmission (Bulk) and Primary facilities are used exclusively by either the ST class or Other Classes. A similar observation applies to sub-accounts #1835-3 and #1835-4:
   - Please confirm if there are any Sub-transmission or Primary facilities in these accounts that are shared as between the ST customers and the Other customers.
   - If yes, how is this accounted for in the cost allocation methodology?
   - If no. please reconcile this circumstance with that presented in RP-2000-0023 (Exhibit E, Tab 2, Schedule 2, page 13) where a substantial portion of the then LV Lines were shared.

Response

a. Sub-transmission Bulk Delivery lines are between 44 kV and 13.8 kV inclusive. Primary lines are between 12.5 kV and 4.16 kV inclusive. Secondary lines are under 750 V.

The percentages of 20% Sub-transmission Bulk, 65% Primary and 15% Secondary are proportional to lengths of line for the three groups weighted by the relative unit costs of the three groups. Any differences in the costs of the types of poles or conductor used for each of the three groups was inherent in the relative unit costs.

Estimates were obtained for the relative construction costs of different types of line (depending on whether the line is on road allowance or not, the number of phases and some inherent broad voltage-related aspects). The estimates included poles, conductor, forestry and other requirements. The relative cost estimates were blended to estimate the relative unit cost for each of Sub-transmission Bulk, Primary and Secondary (1, 0.78 and 0.40 respectively). These relative unit costs weighted the length of line for Sub-transmission Bulk, Primary and Secondary (25k km, 94.4k km and 47.8k km respectively). Multiplying the relative unit cost by line length produced the splits of 20%, 65% and 15% for Sub-transmission Bulk, Primary and Secondary respectively.

b. The size and class of poles are not determined by their utilization as sub-transmission, primary or secondary, but rather by the strength and clearance requirements set out as per engineering analysis. Both size and class will be impacted by the length of distances between poles, size of conductors, other utilities on the pole through joint use, equipment requirements on the pole and various clearances required as per standards.

The size and class and poles would typically range from 35' Class 4 to 65' Class 2 poles, although larger and stronger poles are required for individual circumstances. Due to the general characteristics of sub-transmission lines (e.g., larger conductor and in some cases under-built with primary) the poles are generally somewhat larger.

Hydro One does not have the number of poles broken down by sub-transmission, primary and secondary.

c. Hydro One does not have the replacement cost for poles broken down by sub-transmission, primary or secondary. Replacement costs could vary from $4,500 to over $10,000 depending on factors such as ground conditions, accessibility to the pole location, and work equipment required.

d. Lack of data for parts "b" and "c" prevents calculations following the exact process requested. However, the calculation of the percentages used to break down accounts

1830 and 1835 was analogous to the combination of that requested in this question regarding poles plus that requested in Exhibit H, Tab 12, Schedule 71 part c) regarding conductor. Please see the response to part a) above.

e. The created sub-accounts for Bulk and Primary are shared between by all the rate classes including ST. These Bulk and Primary sub-accounts are then further delineated to isolate the ST component from the Retail Class component. This was accomplished by creating another level of sub-account as can been seen in Exhibit G2, Tab 1, Schedule 1, Attachment A, page 16 for USoA 1830 which is initially decomposed into Bulk-Primary-Secondary via sub-accounts 1830-3, 1830-4 and 1830-5, respectively. Then the Bulk and Primary sub-accounts are further decomposed into their ST and their Retail components using additional sub-accounts 1830-3A and 1830-3B.

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500 kVA is also the threshold used in determining at what voltage customers should be connected. At 500 kVA or higher, a sub-transmission voltage connection is required, e.g. 13.8 kV to 44 kV.

m. There is only one stage of transformation whose high voltage side is lower than Transmission* voltage and whose low voltage side is higher than Secondary** voltage: the "LVDS" stage. In Hydro One's Distribution system, feeders at 12.5 kV and below are extremely likely to be supplied by an LVDS, and feeders at 13.8 kV and above are extremely likely to not be supplied by an LVDS. This extra stage of transformation makes a good demarcation point.

Also, for a customer to be in the ST class, Hydro One would not own any local transformation (transformation to a Secondary voltage). Hydro One Networks' policy is that the maximum transformer size it supplies is 500 kVA. Customers would supply and own transformers larger than that. Hydro One Networks' policy is also that service sizes over 500 kVA are to be supplied at 13.8 kV and above. This is an additional reason for the voltage demarcation point to separate 13.8 kV and above from 12.5 kV and below.
Also, 13.8 kV is the lowest voltage supplying a Direct customer.
* Transmission voltage is above 50 kV
** Secondary voltage is under 750 V

n. Yes, there are some, for example those customers whose load has declined below 500 kW, and those who chose to have a non-standard transformer, which would mean that the customer, not Hydro One, would own the transformer.

o. Hydro One does not have this detailed information readily available. For cost allocation purposes, Hydro One has assumed that all demand billed customers are served from the Primary system and all energy billed customers are served from the Secondary system

p. Hydro One does not have this detailed information readily available. For cost allocation purposes, Hydro One has assumed that all demand billed customers are served from the Primary system and all energy billed customers are served from the Secondary system

Response

a. The percentages of 20% Sub-transmission Bulk, 65% Primary and 15% Secondary are proportional to lengths of line for the three groups weighted by the relative unit costs of the three groups.

b. The basis for the estimates, as described in the response to part a), does include a weighting of relative cost of line between groups (Primary vs. Secondary).

c. For the Primary System, the minimum component is based on #2 ASCR two-wire system (one conductor and one neutral). Other conductor materials include #2 Triplex, 266.8 buss wire and 266.8 pre-spun buss wire.

d. For #2 Triplex, the cost is estimated to be approximately $21,000 per km.
For 266.8 buss wire, the cost is estimated to be approximately $31,000 per km.
For 266.8 pre-spun buss wire, the cost is estimated to be approximately $24,000 per km.

e. In the Minimum System Study, the Primary System Minimum System ratio was 45.50%. Detailed information on the composition of the Primary system based on km of each material was not available, and a precise answer is not possible, but a range can be provided. If the Primary system were exclusively 266.8 buss wire (the costliest component identified above), the Primary System Minimum System ratio would be 29.3%, which represents the lowest value possible for the Primary System Minimum System ratio.

If the Primary system were 50% by length #2 ASCR (the Minimum Component) and 50% #2 Triplex, the Primary System Minimum System ratio would be 60.5%.
These are hypothetical numbers that are intended to show a range and not to provide a definitive answer.

f. The cost of service drops at voltages greater than 750 V would be in
1835 – Overhead Conductors and Devices
1845 – Underground Conductors and Devices 1830 – Poles, Towers and Fixtures
1840 – Underground Conduit

These facilities would be allocated to customers in the same manner as the above accounts.

g. The Secondary / Services system comprises conductors operating at voltages under 750 kV and is primarily service drops. The material and length, and therefore cost, of service drops vary based on the customers' requirements, and service drops are typically classified as 100% customer-related; that is, the minimum component is

100%. This was the method applied in a recent cost of service study performed for Duquesne Light Company, and is also consistent with the Electric Utility Cost Allocation Manual, January 1992, National Association of Regulatory Utility Commissioners, page 96.
The Secondary / Services Minimum System Ratio was determined to be 95% to reflect that a small portion of the system is not service drops, and would have a minimum system ratio of less than 100%. A precise breakdown between Secondary and Services was not available, therefore a more precise ratio could not be determined.

h. See response to part g) above.

Hydro One Distribution: 12 Rate Classes

This sheet shows what accounts are included in the COSS, and how they are grouped into working capital and rate base. It shows how accounts are categorized in the customer and demand related costs. It will then show how the categorized costs are allocated to customer and demand related components. It will also show how Miscellaneous Revenue and General Plant and Administration costs are allocated. Finally, it will show how costs are being grouped together for presentation purposes.

System of Accounts -					Classification and Allocation			Demand Related	Customer Related	Allocation A&G Related	Allocation Misc Related					
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID		cp	ncp	non-demand	FINAL
1565	Conservation and Demand Management Expenditures and Recoveries	CDM Expenditures and Recoveries	dp			O&M			O&M							
1608	Franchises and Consents	Other Distribution Assets	gp							NFA ECC						
1805	Land		dp	DDCP												
1805-1	Land Station >50 kV		dp	TCP	TCP12			TCP12					TCP12			TCP12
1805-2	Land Station <50 kV		dp	BCP	BCP12AA			BCP12AA				DCP	BCP12			BCP12
1806	Land Rights		dp	DDCP												
1806-1	Land Rights Station >50 kV		dp	TCP	TCP12			TCP12					TCP12			TCP12
1806-2	Land Rights Station <50 kV		dp	BCP	BCP12AA			BCP12AA				DCP	BCP12			BCP12
1808	Buildings and Fixtures		dp	DDCP												
1808-1	Buildings and Fixtures > 50 kV		dp	TCP	TCP12			TCP12					TCP12			TCP12
1808-2	Buildings and Fixtures < 50 KV		dp	BCP	BCP12AA			BCP12AA				DCP	BCP12			BCP12
1810	Leasehold Improvements		dp	DDCP												
1810-1	Leasehold Improvements >50 kV		dp	TCP	TCP12			TCP12					TCP12			TCP12
1810-2	Leasehold Improvements <50 kV		dp	BCP	BCP12AA			BCP12AA				DCP	BCP12			BCP12
1815	Transformer Station Equipment - Normally Primary above 50 kV		dp	TCP	TCP12			TCP12					TCP12			TCP12
1815-1	HVDS - Rural		dp	BCP	BCP12B			BCP12B					BCP12			BCP12
1815-2	HVDS - lo LV Specific		dp	TCP	1815-2D			1815-2D					TCP12			TCP12
1815-3	HVDS - hi LV Specific		dp	TCP	1815-3D			1815-3D					TCP12			TCP12
1815-4	HVDS - lo LV Shared		dp	TCP	1815-4D			1815-4D					TCP12			TCP12
1815-5	HVDS - hi LV Shared		dp	TCP	1815-5D			1815-5D					TCP12			TCP12
1820	Distribution Station Equipment - Normally Primary below 50 kV		dp	DCP	DCP12			DCP12					DCP12			DCP12
1820-1	Distribution Station Equipment - Normally Primary below 50 kV (Bulk)		dp	BCP	BCP12			BCP12					BCP12			BCP12

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Attachment A
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System of Accounts -					Classification and Allocation			Demand Related	Customer Related	Allocation A&G Related	Allocation Misc Related				
USoA Account #	Accounts	Explanations	Grouping for Sheet O1 Revenue to Cost	Demand Grouping Indicator	Demand	Customer	Joint	Demand ID	Customer ID	A & G ID	Misc ID	cp	ncp	non-demand	FINAL
1820-2	Distribution Station Equipment - Normally Primary below 50 kV (Primary)		dp	PNCP	PNCP4AA			PNCP4AA					PNCP4		PNCP4
1820-3	Distribution Station Equipment - Normally Primary below 50 kV (Wholesale Meters)		dp			cen2			cen2						
1825	Storage Battery Equipment		dp	DDCP											
1825-1	Storage Battery Equipment > 50 kV		dp	TCP	TCP12			TCP12				TCP12			TCP12
1825-2	Storage Battery Equipment <50 kV		dp	DCP	DCP12			DCP12				DCP12			DCP12
1830	Poles, Towers and Fixtures		dp	DDNCP											
1830-3	Poles, Towers and Fixtures - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1830-3A	Bulk-LV Fixtures		dp	BCP	1830-3A			1830-3A				BCP12			BCP12
1830-3B	Bulk-Retail Fixtures		dp	BCP	BCP12-DlinesB			BCP12-Dlines				BCP12			BCP12
1830-4	Poles, Towers and Fixtures - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1830-4A	Primary-LV Fixtures		dp	PNCP	1830-4AD	1830-4AC	x	1830-4AD	1830-4AC				PNCP4		PNCP4
1830-4B	Primary-Retail Fixtures		dp	PNCP	PNCP4-DlinesB	CCP-DlinesC	x	PNCP4-Dlines	CCP-DlinesC				PNCP4		PNCP4
1830-5	Poles, Towers and Fixtures - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1835	Overhead Conductors and Devices		dp	DDNCP											
1835-3	Overhead Conductors and Devices - Subtransmission Bulk Delivery		dp	BCP	BCP12			BCP12				BCP12			BCP12
1835-3A	Bulk-LV Conductors		dp	BCP	1835-3A			1835-3A				BCP12			BCP12
1835-3B	Bulk-Retail Conductors		dp	BCP	BCP12-DLinesB			BCP12-DLines				BCP12			BCP12
1835-4	Overhead Conductors and Devices - Primary		dp	PNCP	PNCP4	CCP	x	PNCP4	CCP				PNCP4		PNCP4
1835-4A	Primary-LV Conductors		dp	PNCP	1835-4AD	1835-4AC	x	1835-4AD	1835-4AC						
1835-4B	Primary-Retail Conductors		dp	PNCP	PNCP4-DlinesB	CCP-DlinesC	x	PNCP4-Dlines	CCP-DlinesC				PNCP4		PNCP4
1835-5	Overhead Conductors and Devices - Secondary		dp	SNCP	SNCP4	CCS	x	SNCP4	CCS				SNCP4		SNCP4
1840	Underground Conduit		dp	DDNCP											
1840-3	Underground Conduit - Bulk Delivery	Land and Buildings	dp	BCP	BCP12			BCP12				BCP12			BCP12

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h) Please confirm that for the Transformer Customer Density weightings the NBV of the transformers on each feeder were assigned to customer classes proportional to the number of customers by class using the feeder. Please provide an illustrative example.

Response

a. The following USoA accounts are allocated with density weights.

1830-3B	Bulk Fixtures - Retail
1830-4B	Primary Fixtures - Retail
1835-3B	Bulk Conductors - Retail
1835-4B	Primary Conductors – Retail
1850-2	Rural Transformers

The resultant Net Fixed Assets [NFA] and Operations & Maintenance [O&M] are thus also impacted because these asset accounts impact the NFA calculation while O&M allocation "piggy-backs" on the relevant asset.

A full listing impacted USoA accounts is contained in Exhibit G2, Tab 1, Schedule 1, Attachment A, E2 TB Allocation Details pages 124 to 134.

b. The density factors per rate class are presented below:

	Lines			Transformers	
	Customer	Demand		Customer	Demand
UR	0.19	0.18		0.77	0.75
R1	0.66	0.64		0.93	0.88
R2	1.61	1.42		1.23	1.12
Seasonal	1.20	1.60		0.87	1.28
GSe	1.11	1.15		1.00	1.04
GSd	1.14	1.18		1.05	1.01
UGe	0.24	0.18		1.03	0.79
UGd	0.31	0.30		0.76	0.94
Dgen	1.00	1.00		1.00	1.00
ST	1.00	1.00		1.00	1.00
St Lgt	1.00	1.00		1.00	1.00
Sen Lgt	1.00	1.00		1.00	1.00

c. All lines were included in the analysis to derive density weights. A feeder is a distribution line. Yes, feeders are voltage specific in that they connect from a station.

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d. The following is a simplified overview of the density weights derivation.

Connectivity data exists to connect customer by rate class to feeders. The length of the feeder is also known. Based on the share of customer per rate class, a portion of the feeder is allocated to the rate class. This process is done for all over 3,000 feeders and total allocated kms per rate class are determined.

Based on the total allocated feeder kms per rate class, the km/cust metric is derived.

The weights are then determined by weighing the km/cust by total customers as outlined below for each class grouping, (ie. Residential, General Service energy billed, General Service demand billed).

Connectivity Data

	Feeder	Km	Class 1	Class 2	Class 3	Total Class
	1	10	5	20	10	35
	2	20	10	10	20	40
	3	30	15	5	20	40
	4	40	20	5	10	35
A	Totals	100	50	40	60	150

Allocated km

	Feeder	Km	Class 1 km	Class 2 km	Class 3 km
	1	10	1.4	5.7	2.9
	2	20	5.0	5.0	10.0
	3	30	11.3	3.8	15.0
	4	40	22.9	5.7	11.4
B	Total km	100	41	20	39

C=B/A	km/cust		0.81	0.50	0.65
A	Cust	150	50	40	60
D*	**Wts**		**1.22***	**0.76**	**0.98**
E=DxA (Check)	Wted Cust	150	60.8	30.3	58.9

D*= Wts 0.81x150/[0.81 x 50 + 0.5 x 40 + 0.65 x 60]=1.22

e. The transformation assets captured under USoA 1850-2 for the Rural retail customers are density weighted. The small transformation balance that has been isolated to serve the ST class as part of USoA 1850-1 is not density weighted.