Hydro One Networks Inc.
7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5393
Fax: (416) 345-6833
Joanne.Richardson@HydroOne.com

Joanne Richardson
Director – Major Projects and Partnerships
Regulatory Affairs

BY COURIER

June 14, 2019

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli:

EB-2018-0242-Hydro One Networks Inc., 1937680 Ontario Inc., Peterborough Distribution Inc. and Peterborough Utilities Services Inc., MAAD s.86 asset purchase application – Interrogatory Responses

Please find attached Hydro One Networks Inc.'s (Hydro One) responses to interrogatories received in the above-noted proceeding as part of Procedural Order No.3 dated May 9, 2019. The interrogatory responses have been organized by party as indicated below:

Tab 1	OEB Staff
Tab 2	School Energy Cooalition (SEC)
Tab 3	Energy Probe
Tab 4	Vulnerable Energy Consumers Cooalition (VECC)
Tab 5	Consumers Council of Canada (CCC)

An electronic copy of this has been filed through the Ontario Energy Board's Regulatory Electronic Submission System (RESS).

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

cc. Parties to EB-2018-0242 (electronic only)

OEB STAFF INTERROGATORY # 45

Reference:
Exhibit A-5-1

Interrogatory:
Preamble:
At Exhibit A-5-1 p. 2, the Applicants state:

> Hydro One's purchase of PDI will result in over $9 million of savings in Year 11 (i.e., the first rebasing year), as shown in Table 1 below.

Table 1: Savings Resulting from Hydro One's Acquisition of PDI ($M)

PDI Status Quo Total Cost to Serve	$26.3	*Ex. A, Tab 4, Schedule 1 – Table 4*
Total Residual Cost to Serve	17.0	*Ex. A, Tab 4, Schedule 1 – Table 4*
Ratepayer Savings (Year 11)	**$9.3**	

a) Table 1 reports a Total Residual Cost to Serve of $17.0 million. Throughout the original application, the Applicants stated that the Total Residual Cost to Serve would be $16.6 million. Please provide an explanation for the variance.

b) Please confirm that the $9.3 million savings reported in Table 1 does not reflect PDI customers' apportionment of Hydro One Shared Costs.

c) For how many years post-Year 11 are the ratepayer savings demonstrated in Table 1 expected to accrue?
   i. Please provide the estimated savings for each of these years.

Response:

a) On February 27, 2019 in addition to filing supplemental evidence Exhibit A, Tab 5, Schedule 1, Hydro One filed a blue page update. The Total Residual Cost to Serve of $16.6 million comes from Hydro One's original evidence (filed October 12, 2018) in Exhibit A, Tab 4, Schedule 1. This amount was updated to $17.0 million in the Blue Page update (filed February 27, 2019). The difference was attributable to an error in estimating Year 11 tax.

b) The $9.3M represents the difference between the status quo costs and the incremental cost to serve PDI customer and does not include any shared costs apportioned through the cost allocation process. See Exhibit A, Tab 4, Schedule 1, Section 3.0.

c) The $9.3 million savings is considered ongoing.

OEB STAFF INTERROGATORY # 46

Reference:
Exhibit A-5-1

Interrogatory:
Preamble:
At Exhibit A-5-1 p. 2, the Applicants state:

> In Exhibit A, Tab 2, Schedule 1, Table 1 of this MAAD application, Hydro One has provided the forecast incremental OM&A and capital cost to serve the customers of PDI, and commits to tracking the *actual* ***incremental OM&A and capital costs*** to serve PDI customers until the end of the ten year deferral period. This tracking will allow the Board to compare the actual incremental costs to serve PDI customers with that forecast in this application. The actual incremental OM&A and capital costs to serve PDI customers will be reflected in Hydro One's revenue requirement upon rebasing of rates at the end of the ten year deferral period. [***Emphasis added***]

a) Please fully explain what is meant by "incremental OM&A and capital costs" as referenced by the Applicants at Exhibit A-5-1 p. 2. To clarify, is it the Applicants' intention to only track the incremental costs (or marginal costs) incurred by Hydro One to serve the current PDI service territory following the proposed acquisition?

   By way of example, if Hydro One's staffing levels for certain functions, prior to the acquisition, are adequate enough to absorb the PDI service territory without the need for adding staff, would the incremental costs for that function be considered nil? What methods would Hydro One use to identify those costs that are incremental to PDI versus those that are not?

b) Please confirm if the tracking of PDI's incremental OM&A and capital costs will include the tracking of PDI's Shared Costs.
   i. If Shared Costs will not be tracked, please discuss why the tracking of these costs is not required.

c) If applicable, please discuss why only incremental OM&A and capital costs will be tracked and not the total costs to serve PDI customers until the end of the ten year deferral period.

d) At page 159 of the OEB's Decision and Order on Hydro One's Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022[1], the OEB stated:

In approving the acquisition of Norfolk, Haldimand and Woodstock,[2] the OEB directed Hydro One to maintain records of the cost to serve these utilities in order to inform the rate-setting process at the completion of the respective deferral periods. Hydro One has not maintained these records.

Please articulate why and how the Applicants' decision to track only incremental OM&A and capital costs aligns with the expectations established by the OEB through the aforementioned Decision and Order.

<u>Response:</u>

a) Incremental OM&A and capital costs means the additional costs that Hydro One will incur as a result of the acquisition of PDI after anticipated synergies and efficiency gains have been reflected. If PDI was not acquired by Hydro One, these "incremental costs" would not be incurred by Hydro One and therefore would not be included in Hydro One's revenue requirement as they are not needed to service Hydro One's legacy customers.

Hydro One has committed to track both the incremental OM&A and capital costs to service PDI up until the time of the next rebasing. In the Supplemental Evidence, Hydro One has also agreed to continue to track capital costs to serve PDI beyond the deferral period, to inform future rate-setting applications.

The example provided by Board Staff in this interrogatory outlines some of the benefits that will be achieved by this acquisition through the elimination of redundancies and inefficiencies. These align with the OEB's intended efficiencies

---

[1] EB-2017-0049
[2] EB-2013-0196/EB-2013-0187/EB-2013-0198 (Norfolk), EB-2014-0244 (Haldimand), and EB-2014-0213 (Woodstock).

gained through consolidation. Yes, Hydro One will be able absorb certain activities and functions currently required by PDI into its current staffing levels (e.g. preparation of financial statement, tax returns, human resources support, etc.) without incurring any additional costs. As there are no incremental costs resulting from these activities, the incremental cost would be nil.

During the ten year rebasing deferral period Hydro One will utilize its financial management and reporting system, the same system it uses for all Hydro One's financial business activities, to track incremental capital and OM&A costs to serve PDI's customers. Hydro One's financial system will enable the reporting of these capital and OM&A expenditures over this ten year period by setting up a specific PDI service territory cost centre. Any specific incremental cost expenditures made in PDI's service territory during that period will be recorded and tracked in that PDI cost centre.

b) Hydro One will track all incremental costs, which include any incremental costs that may also be categorized as shared costs. For instance, Hydro One has defined Shared Cost to include customer services, however some customer service activities, such as generating customer's bills will incur incremental costs to serve PDI's customers. These incremental activities will be tracked separately. Hydro One's evidence is that shared costs that will be allocated through the cost allocation process will not be tracked.

Hydro One in both its Distribution and Transmission rate cases provides evidence and justification for all of its costs including its shared costs forecast captured at a corporate level. Hydro One is unable to track actual "shared costs" for any of its customer groups. These costs are not directly charged to any of Hydro One rates classes and are therefore cannot be tracked by customer group. For instance, Hydro One's Finance department's costs (which would be captured in "shared costs") are not forecast or tracked between Hydro One's Rural, UR, GSd or Acquired Utility rate classes.

Total Shared Costs, including any incremental costs that may also be categorized as Shared Costs, will be allocated to PDI customers based on the Board's cost allocation methodology. This is discussed at Exhibit A, Tab 4, Schedule 1.

c) All incremental costs incurred to serve PDI customers will be tracked. See part b) above, which explains that costs which are shared amongst customer groups are not tracked on an individual customer group basis.

d) Hydro One is of the view that it has complied with the OEB direction in each of the previous MAAD decisions. In the previous MAAD applications, Hydro One forecast the incremental costs to serve each utility, and has reported on those costs.

Hydro One has no means of allocating Shared Costs to PDI customers in the deferral period. Currently, and during the deferral period, Hydro One's Shared Costs are 100% allocated to its existing legacy customers. The only time that Hydro One would calculate how much of its Shared Costs should be collected from PDI customers is at the time of integration of PDI customers into Hydro One's rate structures – in year 11.

OEB STAFF INTERROGATORY # 47

Reference:

Ref: Exhibit A-5-1
Ref: Appendix A
Ref: Decision and Order on EB-2017-0049

Interrogatory:

Preamble:
At Exhibit A-5-1 p. 4, the Applicants state:

> Hydro One believes that the best way to ensure that PDI customers are charged only their costs to serve is to introduce new rate classes for them.

Preamble:
At p. 6 of Appendix A (the Navigant Report), Navigant states:

> To distinguish customers in the acquired utility service territory from legacy customers, Hydro One proposed to create unique customer classes for customers from the acquired utility…To the extent that the cost to serve the acquired utility customer classes is different from the cost to serve Hydro One's legacy customer classes, this is a valid justification for creating unique classes for customers from the acquired utility.

Preamble:
At pp. 159-165 of the Decision and Order on EB-2017-0049, the OEB states, among other things:

> The OEB denies Hydro One's rates proposals with respect to the Acquired Utilities for the following reasons.
>
> 1) Hydro One's proposal contains simplistically derived and questionable estimates of revenue requirement comparisons to demonstrate adherence to the no harm requirement.

a) Please provide a description of each new rate class the Applicants anticipate creating.

i. For what time period following the acquisition do the Applicants anticipate the acquired rate classes being in effect? That is, when will rate harmonization take place? Alternatively, is it the expectation of the Applicants that these new rate classes will continue in perpetuity? Please justify the planned approach to future rate setting.

b) Please describe the assessment used by the Applicants to determine that, based on its unique characteristics, it is warranted that new rate classes be created for the current PDI service territory.

c) Please provide the results of the assessment used by the Applicants to determine that new rate classes for PDI are warranted. When responding, please clearly identify the sufficient differences that exist between the current PDI service territory and other Hydro One service areas that justify the new rate classes.

<u>Response:</u>

a) Hydro One anticipates including PDI customers in the following new rate classes:
- Acquired Residential, which will include all customers currently in the PDI residential class
- Acquired General Service < 50, which will include all customers currently in the PDI GS <50 kW class.
- Acquired General Service >50, which will include all customers currently in the PDI GS 50 to 4,999 kW class.
    i. These rate classes would come into effect when the deferred rebasing period ends (i.e. for year 11), subject to Board approval, and are anticipated to be ongoing. Hydro One believes that creating new rate classes for the PDI service territory is necessary to ensure that the rates charged to PDI customers will appropriately reflect their cost-to-serve.

b) The cost of fixed assets associated with serving PDI customers is unique to PDI's service territory (e.g. size, geography, density). Based on the experience with the allocation of costs using the Board's cost allocation model, it is known that the allocation of costs per the methodology underlying the Board's cost allocation model, which allocates Hydro One's average costs across its entire service territory, would result in an over-allocation of the fixed assets known to be required to serve customers in the PDI service territory. The over-allocation of assets required to serve

PDI would result in an over-allocation of costs and the setting of rates that do not accurately reflect the cost to serve customers located in the PDI service territory.

c) See response to b)

OEB STAFF INTERROGATORY # 48

Reference:

Ref: Exhibit A-4-1
Ref: Exhibit A-5-1
Ref: Appendix A
Ref: *Report of the Board on Application of Cost Allocation for Electricity Distributors*

Interrogatory:

Preamble:
At Exhibit A-4-1 p. 7, the Applicants state:

> Hydro One proposes within the harmonization and rebasing application following the deferral period, that it would ensure that the total cost, including a portion of Hydro One's Shared Costs, to be collected from the former PDI customers would be between, (a) the Residual Cost to Serve scenario plus [Low Voltage] charges (totaling $16.6M); and (b) the Year 11 revenue requirement under the PDI Status Quo scenario plus Year 11 [Low Voltage] charges (totaling $26.3M).

Preamble:
At Exhibit A-4-1 pp. 5-6, the Applicants state:

> If the transaction is approved, the underlying cost structures for serving the former PDI customers will be reduced by an estimated annual amount of $11.1M to a revenue requirement of $15.2M[1] under the Residual Cost to Serve scenario. However, the $15.2M revenue requirement does not reflect PDI customers paying their full share of the costs for services that Hydro One would be providing to PDI customers. Hydro One considers the costs of the functions, resources and assets used to provide such services to be its "Shared Costs". More particularly, Hydro One's Shared Costs reflect, (i) shared facilities used to provide operations and maintenance services (i.e. service centres and maintenance yards), billing and IT system costs, and other miscellaneous general plant; (ii) OM&A costs associated with shared services, such as planning, finance, regulatory, human resources,

[1] The Residual Cost to Serve of $15.2 million does not include the Applicants' cost estimate of Low Voltage charges to former PDI customers.

information technology, customer services and corporate communications; and (iii) asset and related OM&A costs associated with upstream distribution facilities used by former PDI customers (i.e. costs formerly captured under [Low Voltage] charges).

Preamble**:**
At Exhibit A-5-1 p. 5, the Applicants state:

> In order to ensure the equitable treatment of both legacy and acquired customers, Hydro One proposes to use the principles underlying the OEB's cost allocation model to determine the cost allocation to all rate classes. To the extent necessary, the OEB's cost allocation model will be adjusted to achieve the following objectives:
>
> 1. Ensure that costs allocated to the PDI rate classes reflect the fixed assets specifically used in PDI's service area.
>
> 2. Ensure that the PDI rate classes are appropriately allocated Shared Costs, which includes a share of upstream distribution assets required to provide service to PDI's service area.
>
> Hydro One fully anticipates that the cost allocation process described above, and detailed in the following sections, will result in a fair and reasonable allocation of costs to the PDI rate classes that will be less than what the cost-to-serve the PDI customers would be if PDI is not acquired.

Preamble:
At pp.1-2 of Appendix A (the Navigant Report), Navigant states:

> The proposed approach to cost allocation and rate design described in the OPDC Supplemental Evidence and the PDI Supplemental Evidence incorporates changes relative to the approach outlined in the Distribution Rate Cost Allocation Model. However, several elements are the same, and the Distribution Rate Cost Allocation Model provided Navigant with a worked, numerical, example of the approach upon which to perform a detailed review.

Preamble:

At p. 7 of the OEB's November 28, 2007 *Report of the Board on Application of Cost Allocation for Electricity Distributors*, the OEB states:

> Distributors should endeavour to move their revenue-to-cost ratios closer to one if this is supported by improved cost allocations. However, if a large increase is required to move closer to one, rate mitigation plans should be proposed by the distributor. Distributors should not move their revenue-to-cost ratios further away from one.

The Applicants' evidence specifies that the Total Residual Cost to Serve does not include Shared Costs. Further, the Applicants' evidence highlights that the portion of Hydro One's Shared Costs to be collected from current PDI customers following harmonization will be no greater than approximately $9.3 million. The $9.3 million represents the monetary value of the Applicants' estimated efficiency gains resulting from the acquisition. The Applicants also state that they will "use the principles underlying the OEB's cost allocation model" during future rate harmonization processes. The benefit of this approach, as stated by the Applicants, is that it ensures all costs, including Shared Costs, allocated to the PDI rate classes reflect the fixed assets specifically used in the current PDI service territory.

a) Please provide the following with respect to the Applicants' proposed cost allocation methodology:
    i. The Distribution Rate Cost Allocation Model reviewed by Navigant and referenced in their report.
    ii. The Applicants' proposed adjustment factors, the formula and inputs used in their calculation, as well as a description of the rationale that supports their reasonableness.

b) Using the Applicants' proposed Distribution Rate Cost Allocation Model (as referenced in the Navigant Report), please calculate the Total Residual Cost to Serve PDI ensuring that the calculation reflects all applicable costs, including, but not limited to, Low Voltage charges as well as an appropriate allocation of Shared Costs. The result of the calculation should be a reasonable estimate based on sound assumptions of the costs to serve the current PDI service territory following the rebasing deferral period (i.e., post-Year 10).

i. In response to this question, the Applicants are requested to fully describe the process used by the Applicants to determine the appropriate allocation of Shared Costs to PDI and clearly demonstrate how these Shared Costs are reflected in the allocation model.

c) If the result of the calculation undertaken in response to part a) is greater than $26.3 million, please discuss the implications of the result in terms of the proposed acquisition satisfying the conditions of the "no harm" test.

d) Please confirm, and provide reasoning/evidence, that as a result of the estimate undertaken in response to part a), legacy Hydro One customers would not be subsidizing any costs that should be allocated to current PDI customers post-rebasing deferral period.

e) Please explain and demonstrate how Hydro One's proposed allocation methodology is consistent with the guidance provided by the OEB in its *Report of the Board on Application of Cost Allocation for Electricity Distributors* with respect to moving revenue-to-cost ratios closer to one.

<u>Response:</u>

Note: The numbers quoted in the preamble and question refer to the original pre-filed evidence and do not reflect the updates to those numbers provided as part of the Blue Page update filed on February 27, 2019.

a)

i) The Distribution Rate Cost Allocation Model reviewed by Navigant and referenced in their report was provided in MS Excel format as Q-01-01-03.xlsx in Hydro One's 2018-2022 distribution rate application (EB-2017-0049) on December 21, 2017. It is also provided as a live Excel (I-01-48-01) to this response for convenience.

ii) In response to part b) of this question, Hydro One has prepared a 2030 Cost Allocation Model (2030 CAM) to show how costs would be allocated to PDI in year 11 and to estimate the Notional Post-Rebasing Deferral Period Rates (NPRDPR) for responding to Exhibit I, Tab 1, Schedule 49.

The fixed asset adjustment factors used in the 2030 CAM for the PDI rate classes are listed in Tables 1 and 2.

Table 1: GFA Adjustment Factors*

Rate Class	Residential (AUR)	GS < 50kW (AUGe)	GS > 50 kW (AUGd)
Factor	31.8%	18.4%	11.5%

Table 2: NFA and NFA Excluding Capital Contributions Adjustment Factors

Rate Class	Residential (AUR)	GS < 50kW (AUGe)	GS > 50 kW (AUGd)
Factor	33.7%	20.2%	14.4%

** The GFA adjustment factors are also used to adjust the deprecation amounts allocated to the PDI rate classes.*

The derivation of Hydro One's proposed adjustment factors used in the 2030 CAM to modify the gross fixed asset (GFA), net fixed assets (NFA) and depreciation expense allocated to PDI customer classes in year 11 is provided as a live Excel (I-01-48-02).

The following is a description of the worksheets in I-01-48-02:

Tab "1. Forecast PDI GFA": Provides the derivation of the 2030 GFA associated with USofA accounts 1815-1860 for PDI. Hydro One's 2030 GFA forecast for PDI used in this worksheet is calculated using PDI's 2019 Year-end forecast of GFA as the starting value. From 2020 until Year 11 (2030) the GFA includes capital expenditures as forecast by Hydro One as outlined in Exhibit A, Tab 2, Schedule 1, Table 1.
Tab "2. PDI last CAM outputs": Provides information from PDI's most recent Cost Allocation Model (filed in EB-2012-0160) used to determine how much of each USofA account 1815-1860 was allocated to the various rate classes.
Tab "3. Allocated Forecast PDI GFA": Provides the proportion of the total 2030 GFA for accounts 1815-1860 that is associated with PDI residential and general service rate classes.
Tab "4. Non Adj 2030 CAM outputs": Provides information on the 2030 GFA associated with USofA accounts 1815-1860 that is allocated to the PDI rate classes by the CAM, and also distinguishes the bulk assets included in those accounts, from those that specifically serve the new PDI rate classes
Tab "4.5. PDI Upstream DX factor": Using PDI's 2019 IRM Rate Generator Model (EB-2018-0067) filed on March 18, 2019, this worksheet determines the share of PDI

load that is supplied through upstream distribution facilities to properly allocate upstream distribution costs to the PDI rate classes.

Tab "5. Determine Alloc for PDI": Provides the derivation of the GFA Adjustment Factor for PDI rate classes based on comparing the GFA that should be allocated to each new PDI rate class against the GFA allocated to those classes by the CAM prior to any adjustments. The share of PDI load supplied through upstream distribution facilities derived in worksheet 4.5 is used in this worksheet to determine the amount of upstream distribution ("bulk") assets allocated to the PDI rate classes.

Tab "6. NFA": Provides the derivation of the NFA Adjustment Factors for each PDI rate class based on the ratio of NFA to GFA as determined in the CAM.

Tab "7. Depn5705": Provides the derivation of the adjusted annual depreciation costs for the PDI rate classes.

Given the critical role of fixed assets in the allocation of costs within the cost allocation model, and the fact that PDI's customers are located within a defined service area, the use of adjustment factors within the cost allocation model is a way to ensure that the amount of fixed assets allocated to the PDI rate classes matches the amount of fixed assets specifically used to serve the customers within their service area.[2] At the time of harmonization of PDI, Hydro One will know the amount of fixed assets being used to serve the former PDI service area. The use of adjustment factors will effectively directly allocate local fixed assets to PDI rate classes in the cost allocation model to ensure a more accurate reflection of the fixed assets, and associated costs, required to serve PDI customers.

b) Hydro One has prepared a 2030 Cost Allocation Model (2030 CAM) to calculate the costs to serve PDI customers in year 11. While the results from the CAM are indicative of what the results could be in 2030, as detailed further below, a number of assumptions were required to estimate the CAM inputs in 2030 for both Hydro One legacy and PDI rate classes.

The results of the 2030 CAM for the acquired rate classes are shown in the table below:

---

[2] Further rationale on the use of adjustment factors is provided in this application at Exhibit A, Tab 5, Schedule 1, section 4.0 (b) and Exhibit A, Tab 5, Schedule 1, Appendix A, page 5 to 6, and in EB-2017-0049 at Exhibit G1, Tab 3, Schedule 1, section 2.2.3 and Exhibit Q, Tab 1, Schedule 1, section 2.2.1

	Residential (AUR)	GS < 50 kW (AUGe)	GS > 50 kW (AUGd)	Total
Allocated Costs	$14,111,869	$4,077,833	$4,806,102	$22,995,804
R/C Ratio from CAM*	0.74	0.67	0.69	

** The CAM R/C ratios for all rate classes will be adjusted as part of the rate design process provided in the response to Exhibit I, Tab 1, Schedule 49 to bring them within the Board's approved R/C ratio range.*

The total costs allocated to the PDI Residential and GS acquired rate classes is $23.0M. A further $1.5M[3] in costs are estimated to be allocated to the PDI customers that will be included in the Hydro One Street Lights, Sentinel Lights, USL and ST (large user) rate classes ("combined classes"). The total cost of $24.5M for PDI customers is below the PDI cost to serve (Status Quo cost plus LV charges) of $26.3M.

The 2030 CAM allocates Hydro One's total revenue requirement, which includes the Residual Cost associated with serving PDI customers, to all rate classes using the principles embedded in the OEB's cost allocation model. To appropriately allocate costs to the PDI rate classes, Hydro One uses adjustment factors (as described in part a) to effectively directly allocate the amount of local fixed assets (USofA 1815 to 1860) used in serving the PDI rate classes in 2030. The accurate allocation of fixed assets to the PDI classes is key to ensuring that an appropriate share of Hydro One's total costs are allocated to the PDI classes using the principles embedded in the OEB's cost allocation model.

Shared assets associated with upstream distribution facilities used by PDI customers are allocated to the PDI rate classes as described above in part a) ii). All remaining Shared costs are allocated to all rate classes, including both legacy and PDI rate classes, on the same basis using the principles and allocators embedded within the OEB's cost allocation model for the allocation of such costs.

[3] This amount is determined based on PDI's forecast electricity usage of the Street Lights, Sentinel Lights, USL and ST classes relative to Hydro One's forecast electricity usage for these classes.

The following is a description of the key inputs and assumptions used to populate the 2030 CAM. The 2030 CAM is based on the 2021 CAM used in EB-2017-0049, with the following modifications:

- 2030 Revenue Requirement:
  - Hydro One legacy customers: The average annual growth rate from 2017[4] to 2022 as approved in the EB-2017-0049 Decision[5] is used to project the 2030 revenue requirement.
  - PDI customers: Used the 2030 Residual revenue requirement as per Exhibit A, Tab 4, Schedule 1, Table 4.
- 2029 Rates (used to determine Revenue at Existing Rates in CAM):
  - Hydro One legacy customers: The average annual growth in rates, by class, over the period from 2018 to 2022 as approved in the EB-2017-0049 Decision are used to project the 2029 rates.
  - PDI customers: The 2029 rates are based on current (2019) rates that are held constant for 2020-2024 and then increased by 1.55% under IRM for 2025 to 2029.
- Fixed Assets/Rate Base:
  - Hydro One legacy customers: The average annual growth rate from 2017 to 2022 as approved in EB-2017-0049 Decision is used to project the 2030 fixed asset and rate base values.
  - PDI customers: Used the_2030 Residual asset values as per Exhibit A, Tab 2, Schedule 1, Attachment 18.
- Charge Determinants and CP/NCP Demand Data:
  - Hydro One legacy customers: The annual growth rate from 2018 to 2022 as per EB-2017-00049 Decision is used to project the 2030 values.
  - PDI customers: Used the 2030 forecast consistent with forecast used in the Earning Sharing Mechanism model. The CP/NCP values from PDI's last cost allocation model (2013) were scaled to match the growth in PDI's 2013 to 2030 load forecast.
- New PDI Rate Classes:
  - o Acquired Urban Residential (AUR) - All PDI Residential customers go to AUR

[4] 2017 approved revenue requirement as per EB-2016-0081.
[5] As submitted in Hydro One's Draft Rate Order filed April 5, 2019.

- Acquired Urban General Service less than 50kW (AUGe) – All PDI GS <50 kW customers go to AUGe
- Acquired Urban General Service 50 to 4,999kW (AUGd) – All PDI GS 50 to 4,999kW customers go to AUGd

The 2030 CAM is provided as a live Excel (I-01-48-03) to this response.

c) The total cost allocated to PDI customers, as discussed in part a), is less than the PDI cost to serve (Status Quo plus LV charges) of $26.3 million.

d) Hydro One's legacy customer classes will not subsidize the PDI acquired classes. Following the adjustment to bring the R/C ratios for all PDI rate classes within the Board's approved R/C ratio as part of the rate design process (as shown in Exhibit I, Tab 1, Schedule 49), a total revenue of $20.6M will be collected from PDI customers. Since the total Residual Cost to serve including LV charges is $17.0M and the PDI 2030 Status Quo cost including LV charges is $26.3M, the collection of $20.6M from PDI customers means that legacy customers are benefitting from a reduction of $3.6M ($20.6 - $17.0) in revenue collected, while PDI customers are benefitting from a reduction of $5.7M ($26.3 - $20.6) relative to what they would pay if PDI is not acquired.

e) The OEB's *Report of the Board on Application of Cost Allocation for Electricity Distributors* issued March 31, 2011 premises the move of R/C ratios closer to 1 as being conditional on improved cost allocations. Hydro One does not contemplate any substantive changes to the cost allocation model for its existing rate classes and the introduction of new classes within the model further complicates the process of allocating costs across all of Hydro One's rate classes. As such, Hydro One believes the existing R/C ratio ranges are appropriate and provide utilities the needed flexibility to manage the rate impacts to their customers. Hydro One is also cognizant, and supportive, of the Board's view as expressed on page 4 of in their Report on *Application of Cost Allocation for Electricity Distributors* (EB-2007-0067) which states " a revenue-to-cost ratio of one may not be achievable or desirable for other reasons (for example, to accommodate different rate design objectives)". In this case, Hydro One believes the Board's approved R/C ratio ranges provide Hydro One the flexibility to ensure that the rates established for PDI at the time of harmonization

(Year 11) will reflect a sharing of the acquisition benefits between Hydro One legacy and PDI customers.

OEB STAFF INTERROGATORY # 49

Reference:
Exhibit A-5-1

Interrogatory:
Preamble:
At Exhibit A-5-1 p. 1, the Applicants state:

> The purpose of this Supplemental Evidence is to explain in detail Hydro One's proposed cost allocation and rate design for PDI customers at the end of the rebasing deferral period. The Supplemental Evidence demonstrates that the application of Hydro One's proposed cost allocation and rate design to PDI customers in a Year 11 rebasing will: (a) result in an allocation of costs to PDI customers that reflects the cost to serve them; (b) ***result in rates that collect costs from PDI customers that are less than what those customers would have paid in the absence of the proposed transaction***; and (c) leave Hydro One legacy customers unharmed or slightly better off than they would have been in the absence of the proposed transaction. In fact, the outcome of the cost allocation model and rate design reflects the sharing of cost savings in Year 11 and beyond for the benefit of both PDI and Hydro One legacy customers. **[*Emphasis added*]**

OEB staff's focus is on understanding how the application of the proposed cost allocation, as defined by the Applicants in response to OEB Staff-4, is likely to impact the post-rebasing deferral period electricity bills of current PDI customers.

To illustrate post-rebasing deferral period impacts, the Applicants are requested to create what OEB staff refers to as a Notional Post-Rebasing Deferral Period Rate (NPRDPR). The NPRDPR serves a fundamental purpose: it will allow the Applicants to forecast, based on their proposed allocation methodology, the monthly bill of a typical PDI customer post-rebasing deferral period. The intent of the NPRDPR is to enable a legitimate forecast comparison between the typical PDI customer's current and post-acquisition monthly bill. In-turn, a determination on the performance of the proposed transaction against a primary component of the "no harm" test can be made.

Below, OEB staff describes the methodology the Applicants should follow to produce the NPRDPR and subsequent bill comparison.

Computing the NPRDPR and Performing the Comparison

The NPRDPR will be used by the Applicants to demonstrate the bill impacts of the proposed acquisition if the post-rebasing deferral period electricity rate ***came into effect today***.

At Attachment 7 of the original application, the Applicants provided bill impact tables for the following PDI customer types:

1. Residential
2. General Service Less Than 50kW
3. General Service 50 to 4,999 kW
4. Large Use

Specifically, for each of the four customer types listed above, the Applicants are requested to compare the current typical monthly bill with that calculated using the NPRDPR methodology.

Components of the NPRDPR Comparison

The NPRDPR requires the Applicants to quantify both the savings and costs that they reasonably believe will be experienced by PDI customers at the end of the rebasing deferral period. OEB staff's expectation is that the savings and costs used to develop the NPRDPR will be the same as those used by the Applicants to inform their response to OEB Staff-4.

Boxes 1 and 2 demonstrate the inputs the Applicants can use when developing the estimates for the pre- and post-acquisition bill impacts.

Box 1: Current Customer Bill Calculations

- For purposes of illustrating the current typical monthly PDI customer bill, OEB staff expects that the Applicants can rely on the values already provided in the Customer Bill Impacts Tables found at Attachment 7 of the original application.
  - i.e., no additional calculations are likely required given that the columns labelled "Current Rates" and "Current Charges ($)" in these tables already demonstrate the typical inputs into the PDI customer's monthly bill.
- The Applicants may elect to update the values in these tables for items such as current time-of-use electricity prices. If updates to values are made, OEB staff requests that the Applicants fully explain the rationale for the change.

Box 2: NPRDPR Calculations

- The NPRDPR represents the Current Typical Monthly Bill (inclusive of Low Voltage charges), adjusted to reflect the financial impacts of acquisition-related efficiencies (e.g., OM&A cost reductions) and Hydro One loss factors ***as well as*** an appropriate allocation of Hydro One Shared Costs to each customer group.

  Importantly, the calculation of the NPRDPR should ***not*** include any acquisition related short-term customer benefit such as the Applicants' proposed guaranteed earnings sharing mechanism or the 1% distribution rate discount.

- For demonstrative purposes, the Residential bill impacts table provided at Attachment 7, page 1 of the original application, has been recreated below to illustrate how the results of the NPRDPR analysis can be presented. When responding, the Applicants may choose to revise the tables as appropriate to clearly demonstrate how the NPRDPR monthly bill calculation reflects both the savings and costs experienced by PDI customers as a result of the acquisition.
  - Below, within the reproduced Attachment 7 table, OEB staff have highlighted in green the values that are likely to change as a result of this comparative exercise. Cells highlighted in grey represent values that OEB staff do not anticipate the comparison will impact. Note that these are assumptions only and the Applicants should update NPRDPR values as necessary to ensure an accurate comparison of pre- and post-rebasing deferral period bill impacts is created.

Questions:

a) Applying the same cost allocation approach created in response to OEB Staff-4, calculate the typical monthly bill for each of the four customer types shown in Attachment 7.

b) Please provide the resultant revenue to cost ratios for each of the four customer types/rate classes.

Example Comparison Reporting Table

	Residential					
	Volume	**Current Rates**	**Current Charges ($)**	**Rates as per NPRDPR**	**Charges per NPRDPR ($)**	**% Change**
Monthly Consumption (kWh)	750			750	750	
Total Loss Factors	1.0548					
TOU - Off Peak Consumption	488	$0.065	$ 31.69	$0.065	$ 31.69	
TOU - Mid Peak Consumption	128	$0.094	$ 11.99	$0.094	$ 11.99	
TOU - On Peak Consumption	135	$0.132	$ 17.82	$0.132	$ 17.82	
Total: Commodity			**$ 61.49**		**$ 61.49**	
DX Fixed Charge	1	$18.9800	$ 18.98			
DX Fixed Charge Rate Riders	1	$0.0000	$ -			
DX Vol. Charge ($/kWh)	750	$0.0047	$ 3.53			
DX Low Voltage Charge ($/kWh)	750	$0.0010	$ 0.75			
DX Vol. Rate Riders ($/kWh)	750	-$0.0009	$ (0.68)			
Distribution Rates Only			**$ 22.58**			
Smart Meter Entity Charge	1	$0.57	$ 0.57	$0.57	$ 0.57	
Cost of Losses	41	0.082	$ 3.37			
Distribution Pass Through Charges			**$ 3.94**			
Total: Distribution			**$ 26.52**			
TX - Network ($/kWh)	791	$0.0073	$ 5.78			
TX - Connection ($/kWh)	791	$0.0061	$ 4.83			
Total: Transmission			**$ 10.60**			
WMSC ($/kWh)	791	$0.0036	$ 2.85			

RRRP ($/kWh)	791	$0.0003	$ 0.24			
SSA ($)	1	$0.25	$ 0.25			
Total: Regulatory			**$ 3.34**			
Total Bill (Before Taxes)			$ 101.95			
HST		13%	$ 13.25			
OREC		-8%	$ (8.16)			
Total Bill (Including HST and OREC)			**$ 107.05**			

Response:

Hydro One has provided an estimate of the 2030 rates using the NPRDPR assumptions provided in the question but does not believe that comparing rates based on estimates made for both utilities that far into the future is required to satisfy the No Harm Test.

While Hydro One has provided the requested comparison in the response to part a), a more appropriate assessment of the impact of the acquisition on customer rates is to compare Hydro One's estimated 2030 rates with the 2030 Status Quo rates if PDI had not been acquired, which is provided in Exhibit I, Tab 2, Schedule 43.

a) Attachment 1 to this response provides the requested bill impacts. Hydro One has added columns to the table to show Year 10 (2029) rates, with consolidation, in order to accurately reflect the bill impacts that PDI customers are forecast to see in 2030. PDI's 2029 customers' rates are their existing 2019 rates plus five years of IRM increases (the 5-year period after the rate freeze).

b) Using the output results from the 2030 CAM (as described in Exhibit I, Tab 1, Schedule 48), Hydro One has prepared a 2030 Rate Design model to calculate the rates and revenue-to-cost (R/C) ratios in year 11 (see Attachment 2 to this response). The table below provides the "proposed" R/C ratios for the requested rate classes, which are all within the Board's approved R/C ratio ranges.

Rate Class	R/C Ratio from CAM	Proposed R/C Ratio from Rate Design	Board Approved R/C Ratio Range
Residential	0.74	0.85	0.85 to 1.15
GS < 50kW	0.67	0.80	0.80 to 1.20
GS 50-4,999 kW	0.69	0.80	0.80 to 1.20
Large Use*	1.00	1.00	0.80 to 1.20

** Large Use Customers are proposed to be moved to Hydro One's Sub-Transmission Rate Class*

At the proposed R/C ratios, the estimated revenue collected from PDI customers in 2030 will be $20.6M ($19.1M from customers in the PDI rate classes and an estimated $1.5M from PDI customers in the "combined" rate classes). The amount to be collected from PDI customers is between the year 11 total Residual cost to serve including LV charges ($17.0M) and the total PDI Status Quo including LV charges ($26.3M). Since the revenue collected from the PDI customers falls between these two amounts, both Hydro One legacy and PDI customers will benefit from the acquisition of PDI. Hydro One legacy customers will see a benefit of $3.6M ($20.6 - $17.0) in revenue that would otherwise be collected from them if PDI is not acquired. PDI customers will see a benefit of $5.7M ($26.3 - $20.6) that would otherwise be collected from them if PDI is not acquired.

	Residential								
	Volume	Current (2019) Rates	Current (2019) Charges ($)	Year 10 (2029) Rates	Year 10 (2029) Charges ($)	Rates as per NPRDPR (2030)	Charges per NPRDPR (2030) ($)	% Change (Year 11 over Current Rates)	% Change (Year 11 over Year 10)
Monthly Consumption (kWh)	**750**								
Total Loss Factors	**1.0548**								
TOU - Off Peak Consumption ($/kWh)	488	$0.065	$31.69	$0.065	$31.69	$0.065	$31.69		
TOU - Mid Peak Consumption ($/kWh)	128	$0.094	$11.99	$0.094	$11.99	$0.094	$11.99		
TOU - On Peak Consumption ($/kWh)	135	$0.134	$18.09	$0.134	$18.09	$0.134	$18.09		
Total: Commodity			**$61.76**		**$61.76**		**$61.76**	**0.0%**	**0.0%**
DX Fixed Charge ($)	1	$22.62	$22.62	$24.42	$24.42	$27.16	$27.16		
DX Fixed Charge Rate Riders ($)	1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
DX Vol. Charge ($/kWh)	750	$0.0000	$0.00	$0.0000	$0.00	$0.00	$0.00		
DX Low Voltage Charge ($/kWh)	750	$0.0010	$0.75	$0.0019	$1.43	$0.00	$0.00		
DX Vol. Rate Riders ($/kWh)	750	$0.0000	$0.00	$0.0000	$0.00	$0.00	$0.00		
Distribution Rates Only			**$23.37**		**$25.85**		**$27.16**	**16.2%**	**5.1%**
Smart Meter Entity Charge	1	$0.57	$0.57	$0.57	$0.57	$0.57	$0.57		
Cost of Losses	41	$0.082	$3.38	$0.082	$3.38	$0.082	$3.38		
Distribution Pass Through Charges			**$3.95**		**$3.95**		**$3.95**		
Total: Distribution			**$27.32**		**$29.80**		**$31.11**	**13.9%**	**4.4%**
TX - Network ($/kWh)	791	$0.0067	$5.30	$0.0067	$5.30	$0.0067	$5.30		
TX - Connection ($/kWh)	791	$0.0055	$4.35	$0.0055	$4.35	$0.0055	$4.35		
Total: Transmission			**$9.65**		**$9.65**		**$9.65**	**0.0%**	**0.0%**
WMSC ($/kWh)	791	$0.0034	$2.69	$0.0034	$2.69	$0.0034	$2.69		
RRRP ($/kWh)	791	$0.0005	$0.40	$0.0005	$0.40	$0.0005	$0.40		
SSA ($)	1	$0.25	$0.25	$0.25	$0.25	$0.25	$0.25		
Total: Regulatory			**$3.34**		**$3.34**		**$3.34**	**0.0%**	**0.0%**
Total Bill (Before Taxes)			$102.07		$104.55		$105.86		
HST		13%	$13.27	13%	$13.59	13%	$13.76		
OREC		-8%	-$8.17	-8%	-$8.36	-8%	-$8.47		
Total Bill (Including HST and OREC)			**$107.18**		**$109.78**		**$111.16**	**3.7%**	**1.3%**

	General Service Less Than 50 kW								
	Volume	Current (2019) Rates	Current (2019) Charges ($)	Year 10 (2029) Rates	Year 10 (2029) Charges ($)	Rates as per NPRDPR (2030)	Charges per NPRDPR (2030) ($)	% Change (2030 over 2019)	% Change (2030 over 2029)
Monthly Consumption (kWh)	**2,000**								
Total Loss Factors	**1.0548**								
TOU - Off Peak Consumption ($/kWh)	1300	$0.065	$84.50	$0.065	$84.50	$0.065	$84.50		
TOU - Mid Peak Consumption ($/kWh)	340	$0.094	$31.96	$0.094	$31.96	$0.094	$31.96		
TOU - On Peak Consumption ($/kWh)	360	$0.134	$48.24	$0.134	$48.24	$0.134	$48.24		
Total: Commodity			**$164.70**		**$164.70**		**$164.70**	**0.0%**	**0.0%**
DX Fixed Charge ($)	1	$31.36	$31.36	$33.86	$33.86	$39.55	$39.55		
DX Fixed Charge Rate Riders ($)	1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
DX Vol. Charge ($/kWh)	2,000	$0.0089	$17.80	$0.0094	$18.80	$0.0110	$22.00		
DX Low Voltage Charge ($/kWh)	2,000	$0.0009	$1.80	$0.0017	$3.40	$0.0000	$0.00		
DX Vol. Rate Riders ($/kWh)	2,000	$0.0000	$0.00	$0.0000	$0.00	$0.0000	$0.00		
Distribution Rates Only			**$50.96**		**$56.06**		**$61.55**	**20.8%**	**9.8%**
Smart Meter Entity Charge	1	$0.57	$0.57	$0.57	$0.57	$0.57	$0.57		
Cost of Losses	110	$0.082	$9.03	$0.082	$9.03	$0.082	$9.03		
Distribution Pass Through Charges			**$9.60**		**$9.60**		**$9.60**		
Total: Distribution			**$60.56**		**$65.66**		**$71.15**	**17.5%**	**8.4%**
TX - Network ($/kWh)	2,110	$0.0062	$13.08	$0.0062	$13.08	$0.0062	$13.08		
TX - Connection ($/kWh)	2,110	$0.0050	$10.55	$0.0050	$10.55	$0.0050	$10.55		
Total: Transmission			**$23.63**		**$23.63**		**$23.63**	**0.0%**	**0.0%**
WMSC ($/kWh)	2,110	$0.0034	$7.17	$0.0034	$7.17	$0.0034	$7.17		
RRRP ($/kWh)	2,110	$0.0005	$1.05	$0.0005	$1.05	$0.0005	$1.05		
SSA ($)	1	$0.25	$0.25	$0.25	$0.25	$0.25	$0.25		
Total: Regulatory			**$8.48**		**$8.48**		**$8.48**	**0.0%**	**0.0%**
Total Bill (Before Taxes)			$257.36		$262.46		$267.95		
HST		13%	$33.46	13%	$34.12	13%	$34.83		
OREC		-8%	-$20.59	-8%	-$21.00	-8%	-$21.44		
Total Bill (Including HST and OREC)			**$270.23**		**$275.58**		**$281.35**	**4.1%**	**2.1%**

	General Service 50-4,999 kW								
	Volume	**Current (2019) Rates**	**Current (2019) Charges ($)**	**Year 10 (2029) Rates**	**Year 10 (2029) Charges ($)**	**Rates as per NPRDPR (2030)**	**Charges per NPRDPR (2030) ($)**	**% Change (2030 over 2019)**	**% Change (2030 over 2029)**
Monthly Consumption (kWh)	**182,500**								
Peak (kW)	**250**								
Total Loss Factors	**1.0548**								
12-Month Average WAHSP (2018) ($/kWh)	192,501	$0.1157	$22,278.78	$0.1157	$22,278.78	$0.1157	$22,278.78		
Total: Commodity			**$22,278.78**		**$22,278.78**		**$22,278.78**	**0.0%**	**0.0%**
DX Fixed Charge ($)	1	$160.31	$160.31	$173.08	$173.08	$195.33	$195.33		
DX Fixed Charge Rate Riders ($)	1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
DX Vol. Charge ($/kW)	250	$2.7323	$683.08	$2.9500	$737.50	$3.3293	$832.33		
DX Low Voltage Charge ($/kW)	250	$0.3277	$81.93	$0.6298	$157.45	$0.0000	$0.00		
DX Vol. Rate Riders ($/kW)	250	$0.0000	$0.00	$0.0000	$0.00	$0.0000	$0.00		
Total: Distribution			**$925.31**		**$1,068.03**		**$1,027.66**	**11.1%**	**-3.8%**
TX - Network ($/kW)	250	$2.4893	$622.33	$2.4893	$622.33	$2.4893	$622.33		
TX - Connection ($/kW)	250	$1.9217	$480.43	$1.9217	$480.43	$1.9217	$480.43		
Total: Transmission			**$1,102.75**		**$1,102.75**		**$1,102.75**	**0.0%**	**0.0%**
WMSC ($/kWh)	192,501	$0.0034	$654.50	$0.0034	$654.50	$0.0034	$654.50		
RRRP ($/kWh)	192,501	$0.0005	$96.25	$0.0005	$96.25	$0.0005	$96.25		
SSA ($)	1	$0.25	$0.25	$0.25	$0.25	$0.25	$0.25		
Total: Regulatory			**$751.00**		**$751.00**		**$751.00**	**0.0%**	**0.0%**
Total Bill (Before Taxes)			$25,057.85		$25,200.57		$25,160.19		
HST		13%	$3,257.52	13%	$3,276.07	13%	$3,270.82		
OREC		0%	$0.00	0%	$0.00	0%	$0.00		
Total Bill (Including HST and OREC)			**$28,315.37**		**$28,476.64**		**$28,431.02**	**0.4%**	**-0.2%**

	Large Use								
	Volume	Current (2019) Rates	Current (2019) Charges ($)	Year 10 (2029) Rates	Year 10 (2029) Charges ($)	Rates as per NPRDPR (2030)	Charges per NPRDPR (2030) ($)	% Change (2030 over 2019)	% Change (2030 over 2029)
Monthly Consumption (kWh)	**3,650,000**								
Peak (kW)	**5,000**								
Total Loss Factors	**1.0172**								
12-Month Average WAHSP (2018) ($/kWh)	3,712,780	$0.1157	$429,692.41	$0.1157	$429,692.41	$0.1157	$429,692.41		
Total: Commodity			**$429,692.41**		**$429,692.41**		**$429,692.41**	**0.0%**	**0.0%**
DX Fixed Charge ($)	1	$6,440.97	$6,440.97	$6,954.11	$6,954.11	$1,629.52	$1,629.52		
DX Fixed Charge Rate Riders ($)	1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
DX Vol. Charge ($/kW)	5,000	$0.7524	$3,762.00	$0.8123	$4,061.50	$1.6923	$8,461.50		
DX Low Voltage Charge ($/kW)	5,000	$0.4014	$2,007.00	$0.0000	$0.00	$0.0000	$0.00		
DX Vol. Rate Riders ($/kW)	5,000	$0.0000	$0.00	$0.0000	$0.00	$0.0000	$0.00		
Total: Distribution			**$12,209.97**		**$11,015.61**		**$10,091.02**	**-17.4%**	**-8.4%**
TX - Network ($/kW)	5,000	$2.9328	$14,664.00	$2.9328	$14,664.00	$2.9328	$14,664.00		
TX - Connection ($/kW)	5,000	$2.3544	$11,772.00	$2.3544	$11,772.00	$2.3544	$11,772.00		
Total: Transmission			**$26,436.00**		**$26,436.00**		**$26,436.00**	**0.0%**	**0.0%**
WMSC ($/kWh)	3,712,780	$0.0034	$12,623.45	$0.0034	$12,623.45	$0.0034	$12,623.45		
RRRP ($/kWh)	3,712,780	$0.0005	$1,856.39	$0.0005	$1,856.39	$0.0005	$1,856.39		
SSA ($)	1	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		
Total: Regulatory			**$14,479.84**		**$14,479.84**		**$14,479.84**	**0.0%**	**0.0%**
Total Bill (Before Taxes)			$482,818.22		$481,623.86		$480,699.27		
HST		13%	$62,766.37	13%	$62,611.10	13%	$62,490.90		
OREC		0%	$0.00	0%	$0.00	0%	$0.00		
Total Bill (Including HST and OREC)			**$545,584.59**		**$544,234.96**		**$543,190.17**	**-0.4%**	**-0.2%**

2030 Rate Design (EB-2018-0242)

	Number of Customers	GWh	kWs	Revenue	Allocated Costs		Misc Rev	Revenue from Rates	2022 R/C Ratio	R/C Ratio from the CAM	Target 2030 R/C Ratio	Total rev to be collected	Shifted Rev	% Change in revenue from rates	Fixed Charge ($/month)	Revenue from Fixed Charge	Fixed Rev %	Revenue from Volumetric Charge	Volumetric Charge ($/kWh)	Volumetric Charge ($/kW)
				(A)	(B)	(%)	(C)	(D=A-C)	(E)	(F=A/B)	(G)	(H=BxG)	(I=H-A)	(J=I/D)		(K)		(L=H-C-K)		
UR	261,362	1,993		$ 137,278,669	$ 121,452,732	6.31%	$ 4,736,591	$ 132,542,078	1.12	1.13	1.11	134,691,875	(2,586,794)	-2.0%	$ 41.44	$ 129,955,284	100%	$ -	$ -	
R1	495,300	4,676		$ 432,699,237	$ 392,477,147	20.39%	$ 12,376,223	$ 420,323,014	1.12	1.10	1.10	432,699,237	-	0.0%	$ 70.72	$ 420,323,014	100%	$ -	$ -	
R2	349,752	3,869		$ 676,174,964	$ 676,682,752	35.15%	$ 14,422,222	$ 661,752,743	0.97	1.00	1.00	676,174,964	-	0.0%	$ 157.67	$ 661,752,743	100%	$ -	$ -	
Seasonal	151,486	489		$ 135,650,149	$ 126,249,424	6.56%	$ 2,731,349	$ 132,918,799	1.07	1.07	1.07	135,650,149	-	0.0%	$ 73.12	$ 132,918,799	100%	$ -	$ -	
GSe	86,717	1,849		$ 184,653,062	$ 193,725,852	10.06%	$ 4,350,795	$ 180,302,268	0.94	0.95	0.95	184,653,062	-	0.0%	$ 35.02	$ 36,441,264	20%	$ 143,861,003	$ 0.0778	
GSd	5,775	2,264	7,401,712	$ 171,472,438	$ 212,288,066	11.03%	$ 2,600,708	$ 168,871,730	0.88	0.81	0.81	171,472,438	-	0.0%	$ 115.21	$ 7,983,747	5%	$ 160,887,983		$ 21.7366
UGe	19,046	561		$ 28,030,967	$ 29,642,792	1.54%	$ 788,340	$ 27,242,627	0.99	0.95	0.95	28,030,967	-	0.0%	$ 28.26	$ 6,459,480	24%	$ 20,783,148	$ 0.0370	
UGd	1,829	975	2,323,345	$ 31,931,011	$ 38,589,389	2.00%	$ 530,242	$ 31,400,769	0.87	0.83	0.83	31,931,011	-	0.0%	$ 103.36	$ 2,268,538	7%	$ 29,132,230		$ 12.5389
St Lgt	5,930	102		$ 13,563,371	$ 14,573,224	0.76%	$ 266,535	$ 13,296,837	0.93	0.93	0.93	13,563,371	-	0.0%	$ 4.01	$ 285,541	2%	$ 13,011,295	$ 0.1270	
Sen Lgt	20,950	12		$ 5,632,574	$ 5,689,992	0.30%	$ 1,953,687	$ 3,678,887	0.94	0.99	0.99	5,632,574	-	0.0%	$ 3.96	$ 996,202	27%	$ 2,682,685	$ 0.2190	
USL	5,899	31		$ 3,715,403	$ 3,679,421	0.19%	$ 113,316	$ 3,602,087	1.11	1.01	1.01	3,715,403	-	0.0%	$ 39.22	$ 2,776,418	77%	$ 825,669	$ 0.0263	
DGen	3,043	39	284,678	$ 11,807,782	$ 10,908,665	0.57%	$ 276,493	$ 11,531,289	0.87	1.08	1.08	11,807,782	-	0.0%	$ 196.16	$ 7,163,667	62%	$ 4,367,622		$ 15.3423
ST	843	14,930	33,322,764	$ 76,187,693	$ 76,357,502	3.97%	$ 1,113,836	$ 75,073,857	0.99	1.00	1.00	76,187,693	-	0.0%	$ 1,387.95	$ 14,046,487	19%	$ 61,027,370		$ 1.8314
AUR	35,211	286		$ 10,494,493	$ 14,111,869	0.73%	$ 520,329	$ 9,974,163		0.74	0.85	11,995,089	1,500,596	15.0%	$ 27.16	$ 11,474,759	100%	$ -	$ -	
AUGe	3,925	118		$ 2,718,627	$ 4,077,833	0.21%	$ 107,895	$ 2,610,732		0.67	0.80	3,262,266	543,639	20.8%	$ 39.55	$ 1,862,653	59%	$ 1,291,719	$ 0.0110	
AUGd	403	352	852,167	$ 3,302,323	$ 4,806,102	0.25%	$ 63,353	$ 3,238,970		0.69	0.80	3,844,882	542,558	16.8%	$ 195.33	$ 944,437	25%	$ 2,837,092		$ 3.3293
	1,447,471	**32,546**	**44,184,667**	**$ 1,925,312,763**	**$ 1,925,312,763**	**100%**	**$ 46,951,913**	**$ 1,878,360,850**					**$ 0**			**$ 1,437,653,033**		**$ 440,707,816**		

Total Rev (K+L)	**$ 1,878,360,850**
Misc Rev (C)	**$ 46,951,913**
Total Rev Req	**$ 1,925,312,763**

SEC INTERROGATORY # 29

Reference:
[Ex. A/5/1, p. 2 and Ex. A/4/1, Table 4, and Ex. I/1/27, p. 3]

Interrogatory:
SEC is concerned with understanding the underlying drivers of the claimed ratepayer savings. With respect to Table 1 in the Update and Table 4 in the pre-filed evidence, please provide a detailed breakdown, for each year, of the components of the "ratepayer savings" of $9.3 million.

Response:
Table 1 in Exhibit A, Tab 5, Schedule 1 shows the savings for PDI customers in Year 11. The LV charges under the status quo will be recovered through a separate rate whereas in the residual cost to serve these costs are recovered in revenue requirement.

The table below provides a breakdown of all revenue requirement components plus LV Charges that make up the savings levels discussed above. OM&A and LV Charges make up approximately 88% of the ratepayer savings. Please refer to Exhibit I, Tab 4, Schedule 7c) for an explanation of the OM&A driver savings.

($000s)	**Hydro One**	**PDI**	**Savings**
OM&A	4,311	12,269	(7,958)
Depreciation	4,106	6,193	(2,087)
Cost of Capital – Debt	2,679	2,350	329
Cost of Capital – Equity	3,717	3,494	223
Tax	807	607	200
Revenue Requirement (without LV Charges)	**15,620**	**24,913**	**(9,293)**
LV Charges	-	1,411	(1,411)
Cost to serve	**15,620**	**26,324**	**(10,704)**

SEC INTERROGATORY # 30

Reference:
[A/5/1, p. 3]

Interrogatory:
Please explain how, once the rates are harmonized, customers can be confident that they will continue to benefit from savings from the acquisition into the future, if the costs to serve the acquired customers are no longer being tracked.

Response:
The savings that Hydro One has forecast in OM&A are ongoing savings which will benefit PDI customers into the future. Hydro One has committed to track capital costs to serve the PDI service territory beyond the deferral period which will be used to substantiate the rates for PDI customers. Please see Exhibit I, Tab 4, Schedule 32.

The rebasing in Year 11 locks in the acquisition savings in the Year 11 rates established for the PDI customers. Any rate adjustments beyond the first rebasing period (i.e. 16 years into the future and beyond) will be in accordance with the OEB's cost allocation and rate design policies in effect at the time.

Given that PDI's Year 11 rates will result in rates below the status quo, Hydro One has no reason to believe that future rates will be in excess of what the customers of PDI would have faced in absence of the transaction. Hydro One will track all capital expenditures associated with serving PDI's customers; these expenditures will be reviewed by a future OEB panel for need and prudency. Hydro One expects that any future investments required in the PDI service territory to ensure the safe and reliable supply of electricity, and satisfy all applicable standards at the time, would have been required whether or not PDI was purchased by Hydro One. There is also no basis for reliably establishing what the PDI status quo costs would have been 16 years into the future and beyond.

All cost allocation and rate design proposals in subsequent years will be reviewed and tested by the OEB as part of a future rates application.

SEC INTERROGATORY # 31

Reference:
[A/5/1, p. 3]

Interrogatory:
The Applicants state that they are unable to "track…the costs associated with certain Hydro One resources that PDI customers will enjoy the benefit of". Please confirm that the Applicants can track the amounts with respect to those costs that would be allocated to the PDI customers if they were allocated on the same basis as the legacy customers.

Response:
This question is confusing tracking costs and cost allocation to determine rates.

The quoted statement was referencing the capital costs that Hydro One would be tracking to serve the customers of PDI. These are costs that Hydro One would not incur if the transaction did not proceed. During Hydro One's recent Distribution Rates proceeding (EB-2017-0049), concerns were raised that Hydro One would not track capital costs for the Acquired Utilities beyond the time "Hydro One applies for new rates"[1]. In Exhibit A, Tab 5, Schedule 1, page 2, Hydro One commits to continue to track capital costs to serve PDI customers after the rebasing period, which ensures that rates for PDI customers and any fixed asset adjustment factors that will be used, will be informed by the most up-to-date asset cost data.

Hydro One is unable to track actual "shared costs" for any of its customer groups. These costs are incurred at the corporate level and are not directly charged to any of Hydro One's rates classes. For instance, Hydro One's Finance department's costs (which would be captured in "shared costs") are neither forecast nor tracked between Hydro One's Rural, UR, GSd or Acquired rate classes. Shared costs for all Hydro One customers have always only been recorded at a corporate level.

[1] EB-2014-0213 – Decision and Order, page 21; EB-2014-0244 – Decision and Order, page 3; EB-2013-0196/0187/0198 – Decision and Order, page 25.

In Hydro One's Distribution Rates Application (EB-2017-0049), it was clear that legacy OM&A costs were not impacted by the integration of the Acquired Utilities[2]; this is also true for the integration of PDI. Shared legacy OM&A costs will not increase as a result of the acquisition of PDI nor will they decrease if PDI is not acquired.

Shared costs are allocated between all customer rates classes, both legacy and any new acquired classes, on the same basis as part of the cost allocation process.

[2] EB-2017-0049 – Exhibit A, Tab 3, Schedule 1, Page 7, Table 2. Line 9 of this table shows that Hydro One's legacy OM&A costs are only inflated by the CPI index. The additional costs to serve the Acquired Utilities of $10.7M is the only addition to OM&A revenue requirement - the $10.7M is the residual cost to serve those customers.

SEC INTERROGATORY # 32

Reference:
[A/5/1, p. 4, 7]

Interrogatory:
In the EB-2017-0049 Decision with Reasons, at p. 161/2, the Board said:

> *"As SEC argued, Hydro One's rate proposal is based on a snapshot of the existing asset base in the acquired service area. The OEB agrees and based on Hydro One's failure to demonstrate that its costs are the same or lower in its evidence,[308] finds that the proposal will result in one of the two following negative outcomes.*
>
> *a) In the absence of recalibration of the adjustment factors, an undue subsidy from Hydro One's legacy customers would be required.*
>
> *b) In the situation where the calibration of the adjustment factors is commensurate with asset renewal at Hydro One's higher costs, harm in the form of relatively higher rates to the customers of the Acquired Utilities would need to be imposed."*

Please explain how the current proposal for PDI will not produce either

a. A situation in which legacy customers bear part of the costs fairly attributable to PDI customers, or

b. As PDI assets are replaced with higher cost Hydro One assets over time, and the adjustment factor is reduced, the PDI customers will be harmed by higher longer term rates.

Response:
a) With respect to item a), Hydro One's legacy customers will not be charged costs that are directly attributable to serving the customers of PDI. The opposite is true – legacy customers will benefit from the allocation of Hydro One's Shared Costs to the acquired PDI rate classes. In the absence of this transaction, legacy customers would

not benefit from having those costs shared – instead, they would be 100% recovered from legacy customers. With respect to item b), Hydro One is proposing to track the capital cost to serve PDI customers beyond rate harmonization at the end of the deferred rebasing period, which will inform the fixed asset adjustment factors that will be used to determine the costs that will be allocated to their rate classes to set rates.

b) Hydro One disagrees with the statement that PDI assets will be replaced with "higher cost Hydro One assets over time" and there is no evidence on the record to support this assertion. Any asset that is replaced after its useful life has expired; often 30 or more years hence, will be replaced at a higher cost than it was constructed at – regardless of which distributor replaces the asset.

It is not possible to know what the asset replacement costs for Hydro One and PDI will be beyond the deferred rebasing period (i.e. after 2030). In its recent Distribution Application, Hydro One demonstrated its commitment to finding efficiencies and productivity savings that will further reduce Hydro One's asset replacement cost and asset replacement rate (e.g., exploring a pole refurbishment program).

SEC INTERROGATORY # 33

Reference:
[A/5/1, p. 4-6]

Interrogatory:
In the EB-2017-0049 Decision with Reasons, at p. 162, the Board said:

> *"The OEB has provided clear guidance with respect to its expectations that evidence of lower cost structures relied on in acquisition proposals are expected to result in concomitant lower rates. <u>Hydro One would be expected to apply any distinguishable cost causation analysis relied on in an acquisition application to any customers that met the identified cost causation criteria whether they are new or legacy customers.</u> The OEB did not direct Hydro One to isolate the Acquired Utilities in its cost allocation methodology. Hydro One has not demonstrated that its proposal is equitable to all customers." [emphasis added]*

Please confirm that, under the Applicants' new proposal, Customers in towns like Brockville, Smith's Falls, Ancaster and other Hydro One service areas of a similar size and density to Peterborough will also have their costs allocated using adjustment factors similar to those being applied to PDI. If that is not confirmed, please explain how the Applicants' current proposal complies with the direction of the Board as set forth above.

Response:
Hydro One is not proposing to create new rate classes for customers in the specific communities referenced. Other than using adjustment factors to specifically allocate the fixed assets associated with serving customers in the PDI service territory, Hydro One will use the same cost causation principles implicit in the Board's cost allocation model to allocate costs to all rate classes, including legacy and any new acquired classes. The distinguishing characteristic of the new acquired classes is that they relate to a specific geographic area for which specific assets required to serve are known, given that PDI existed as a separate utility prior to being acquired. This will allow rates to be set for the PDI acquired classes that best reflect their specific cost-to-serve. Hydro One does not track the cost to serve its legacy customers on a geographic basis, therefore the same information is not available for the individual communities referenced, and in any case, it

would not be feasible for Hydro One to establish separate rate classes for each of the large numbers of communities it serves.

SEC INTERROGATORY # 34

Reference:
[A/5/1, p. 6]

Interrogatory:
Please confirm that all of the examples of adjustment factors cited apply to all customers with similar characteristics, and are all designed to ensure that like customers are allocated costs in a consistent manner. Please explain how the proposed adjustment factors for PDI achieve a similar result.

Response:
Adjustment factors are intended to improve the accuracy of the allocation of costs to an established class of “like” customers. In the case of the PDI acquired rate classes, the adjustment factors effectively directly allocate the fixed assets required to serve the PDI classes. The PDI classes have similar characteristics in that they contain customers associated with the geographic area of the PDI service territory.

SEC INTERROGATORY # 35

Reference:
[A/5/1, p. 7]

Interrogatory:
SEC is seeking to better understand how the adjustment factors will change over time as Hydro One replaces PDI assets. For each of the categories of assets to which the adjustment factors are proposed to apply, please provide

a. The most recent actual unit costs to Hydro One of new assets in each of those categories, and the most recent actual unit costs to PDI of new assets in each of those categories, and an explanation as to any material differences in unit costs.

b. The current PDI book value per customer, by rate class, for each of those asset categories, and the current Hydro One book value per customer, by rate class, for each of those asset categories, plus any further information (such as weighted average vintage data) that can help the Board and parties understand any material differences in book value per customer for those asset categories.

Response:
a) The requested unit cost data is not available by USofA to which the adjustment factors apply.

b) The current PDI book value per customer by rate class is not available. The Hydro One 2018 forecast book value per customer[1], by rate class, for each of the USofA asset categories to which the adjustment factors are proposed to apply are provided in the table below:

[1] As per EB-2017-0049, Draft Rate Order Exhibit 3.1, filed April 5, 2019

HONI 2018 Forecast Gross Book Value of USofAs 1815-1860 by Rate Class (per EB-2017-0049) ($/per Customer)

Rate Class	1815	1820	1825	1830	1835	1840	1845	1850	1855	1860
UR	30	115	-	671	394	5	486	358	-	377
R1	67	240	-	1,447	846	10	943	538	-	377
R2	215	848	-	4,591	2,650	30	2,492	1,075	-	377
Seasonal	43	20	-	1,489	887	11	1,649	717	-	377
GSe	228	1,290	-	4,963	2,783	31	4,302	-	-	676
GSd	3,871	29,189	-	60,780	40,421	494	110,632	-	-	6,752
UGe	124	913	-	2,839	1,562	18	3,018	-	-	676
UGd	2,293	18,359	-	35,067	23,366	283	61,619	-	-	6,752
St Lgt	94	1,038	-	5,763	3,152	42	4,260	-	-	-
Sen Lgt	3	3	-	508	290	4	630	-	-	-
USL	35	27	-	1,154	689	9	1,268	-	-	-
DGen	180	121	-	1,467	1,103	10	1,139	-	-	8,016
ST	62,511	55,492	-	171,292	135,807	1,990	39,560	-	-	25,670

SEC INTERROGATORY # 36

Reference:
[A/5/1, p. 7]

Interrogatory:
Please provide a run of the cost allocation model for 2018, using Board-approved costs, book value, and all other necessary assumption, to show how costs would be allocated to PDI on a harmonized basis under the Hydro One proposal if that allocation took place in 2018. For the purposes of this sample allocation, please assume that all of the cost savings expected over the next ten years as a result of the PDI acquisition have been realized.

Response:
A 2018 cost allocation model run, using Hydro One 2018 data and PDI data that reflects the savings expected over the next ten years would not appropriately reflect Hydro One's proposals in this application. The best way to capture all of the costs savings expected over the next ten years, and appropriately allocate costs to all legacy and PDI customers, is to run a cost allocation model that reflects both what Hydro One and the PDI costs would be at the end of the deferred rebasing period. The response to Exhibit I, Tab 1, Schedule 48 provides a cost allocation run showing an estimate of "the costs that would be allocated to the new PDI acquired rate classes on a harmonized basis under Hydro One's proposal" as requested in this interrogatory.

SEC INTERROGATORY # 37

Reference:
[A/5/1, p. 7]

Interrogatory:
In the EB-2017-0049 Decision with Reasons, at p. 162, the Board said:

> *"Hydro One's cost allocation evidence indicates that in the absence of adjustment factors, Hydro One's long term costs to serve the Acquired Utilities are higher than the costs of those previous utilities. This is in direct contradiction to the evidence relied on in its acquisition proposals."*

Please confirm that this statement is true with respect to PDI as well, i.e. that absent any adjustment factors the costs normally allocated to PDI customers would be higher than status quo costs.

Response:
The proposed adjustment factors ensure that only the actual local fixed assets used to serve the PDI service territory are allocated to the PDI acquired classes. Without the adjustment factors, the PDI acquired classes would be allocated the average costs associated with serving Hydro One's entire service territory, which would not be an accurate reflection of the cost to serve the specific geographic area associated with the PDI service territory. This inaccurate allocation of costs would be higher than the PDI status quo.

SEC INTERROGATORY # 38

Reference:
[A/5/1, p. 7]

Interrogatory:
Please provide a detailed list of the current Shared Costs of Hydro One, and provide the amount of each such Shared Cost currently allocated to each UR, UGe, UGd, R1, GSe, and GSd customers as of the most recent cost allocation by Hydro One.

Response:
Not all Shared Costs are specifically identified as such within the cost allocation model, and in many cases are bundled together with costs that would be directly associated with providing local service. However, the bulk of the costs included in the "Customer and Related Costs (cu)" and "General and Administration (ad)" categories in Sheet O1 of the cost allocation model would be Shared costs. A summary of the 2018 OM&A costs included in the "cu" and "ad" categories is provided in the table below.

USoA Account #	Accounts	O1 Grouping	"Shared" OM&A Costs per Hydro One's 2018 CAM (EB-2017-0049 Draft Rate Order, Exhibit 3.1, filed on April 5, 2019)						
			Total	UR	UGe	UGd	R1	GSe	GSd
5065	Meter Expense	cu	$14,137,661	$2,170,502	$308,323	$78,008	$4,278,036	$1,505,649	$235,550
5070	Customer Premises - Operation Labour	cu	$26,252,103	$4,571,095	$362,430	$34,935	$9,009,581	$1,769,873	$105,490
5075	Customer Premises - Materials and Expenses	cu	$3,360,287	$585,103	$46,391	$4,472	$1,153,233	$226,545	$13,503
5310	Meter Reading Expense	cu	$5,046,045	$27,674	$68,552	$156,981	$194,712	$655,153	$603,704
5315	Customer Billing	cu	$24,603,908	$4,094,841	$649,338	$219,069	$8,070,889	$3,170,947	$661,494
5320	Collecting	cu	$5,016,934	$834,971	$132,405	$44,670	$1,645,719	$646,581	$134,884
5335	Bad Debt Expense	cu	$21,835,117	$3,102,925	$520,763	$297,643	$7,612,575	$2,248,388	$1,543,290
5340	Miscellaneous Customer Accounts Expenses	cu	$4,255,666	$708,273	$112,314	$37,892	$1,395,998	$548,469	$114,417
5410	Community Relations - Sundry	ad	$609,399	$45,356	$9,094	$9,377	$134,104	$65,741	$46,146
5420	Community Safety Program	ad	$303,426	$14,885	$4,609	$7,224	$54,947	$35,428	$37,283
5605	Executive Salaries and Expenses	ad	$9,804,593	$729,733	$146,316	$150,872	$2,157,589	$1,057,709	$742,437
5610	Management Salaries and Expenses	ad	$32,849,459	$2,444,909	$490,220	$505,483	$7,228,820	$3,543,764	$2,487,473
5615	General Administrative Salaries and Expenses	ad	$46,437,125	$3,456,207	$692,993	$714,568	$10,218,909	$5,009,586	$3,516,378
5625	Administrative Expense Transferred Credit	ad	($76,323,252)	($5,680,562)	($1,138,991)	($1,174,452)	($16,795,621)	($8,233,669)	($5,779,458)
5630	Outside Services Employed	ad	$16,607,065	$1,236,025	$247,831	$255,547	$3,654,535	$1,791,552	$1,257,544
5635	Property Insurance	ad	$4,172,723	$204,701	$63,383	$99,351	$755,627	$487,205	$512,718
5655	Regulatory Expenses	ad	$11,894,496	$885,280	$177,504	$183,031	$2,617,491	$1,283,165	$900,692
5665	Miscellaneous General Expenses	ad	$16,863,651	$1,255,122	$251,660	$259,496	$3,710,999	$1,819,232	$1,276,973
5670	Rent	ad	$9,173,049	$682,729	$136,892	$141,154	$2,018,612	$989,579	$694,615
5675	Maintenance of General Plant	ad	$73,362,373	$5,460,190	$1,094,805	$1,128,891	$16,144,053	$7,914,253	$5,555,250
6105	Taxes Other Than Income Taxes	ad	$4,523,302	$221,710	$70,829	$108,162	$813,067	$541,079	$559,165
6205	Donations	ad	$4,038,000	$300,539	$60,260	$62,136	$888,598	$435,615	$305,771
	Total		**$258,823,131**	**$27,352,208**	**$4,507,924**	**$3,324,509**	**$66,962,473**	**$27,511,845**	**$15,525,319**

SEC INTERROGATORY # 39

Reference:
[A/5/1, p. 8, 10, 11]

Interrogatory:
Please describe in detail the principles Hydro One proposes to apply in determining the revenue to cost ratios of the rate classes to which former PDI customers would be allocated, including any changes to those principles over time (for example, five years after harmonization, ten years after harmonization, etc.).

Response:
Hydro One proposes to follow the same process both at the time of rate harmonization and in all subsequent rebasing applications (e.g. five years after harmonizations, ten years after, etc.). At the cost allocation stage, Hydro One will follow the Board's normal process implicit within the CAM to determine the R/C ratio for all rate classes, including PDI rate classes, by comparing the "Total Revenue at Status Quo Rates" against the revenue requirement (i.e. costs) allocated to each rate class. At the rate design stage Hydro One will adjust the R/C ratios for each class if necessary to bring them within the Board's approved R/C ratio range.

This is the approach that has been followed in the response to interrogatories at Exhibit I, Tab 1, Schedules 48 and 49, the results for which are summarized below.

Class	R/C Ratio Resulting from CAM	R/C ratio Resulting from Rate Design Process
Acquired Residential	0.74	0.85
Acquired GS <50	0.67	0.80
Acquired GS >50	0.69	0.80

SEC INTERROGATORY # 40

Reference:
[A/5/1, p. 9]

Interrogatory:
SEC is seeking to understand the purpose and import of the Navigant evaluation. Please explain the expertise that Navigant purported to apply in its evaluation that is not already the expertise of the Board itself.

Response:
Navigant has considerable experience developing and implementing cost allocation methods and models in general, and more specifically for utilities that operate in service territories that span multiple regulatory jurisdictions (see Exhibit I, Tab 3, Schedule 25). The principles used in those instances are relevant to Hydro One's proposal to establish separate classes for the customers of the acquired utility. Navigant was asked to focus on Hydro One's proposed method of cost allocation and rate design after the 10-year rate stabilization period, given that there appeared to be some concerns about Hydro One's proposal with respect to its previous Acquired Utilities (as highlighted in the OEB's decision and order regarding Hydro One's 2018 to 2022 distribution rate application, OEB proceeding EB-2017-0049). The scope of Navigant's review is noted in response to Exhibit I, Tab 3, Schedule 23. Hydro One believes an independent third-party analysis of its cost allocation and rate design proposal would be of assistance to the Board and to the participants in the proceeding.

SEC INTERROGATORY # 41

Reference:
[A/5/1, p. 10]

Interrogatory:
Please explain how costs will be allocated at any time if the "Post-Consolidation Cost to Serve" PDI customers is greater than the status quo revenue requirement for those customers. Please calculate at what percentage allocation of Shared Costs to PDI customers will result in total cost to serve being greater than status quo.

Response:
No special treatment is required if the "Post-Consolidation Cost to Serve" PDI customers is greater than the status quo revenue requirement provided that the costs proposed to be collected in rates from the acquired classes, based on the revenue to cost ratios established by the cost allocation and rate design process, do not exceed the status quo revenue requirement.

However, as shown in Exhibit I, Tab 1, Schedule 48, this is not expected to be an issue for PDI given that both the "Post-Consolidation Cost to Serve" and the costs to be collected from the acquired classes based on the revenue to cost ratios established by the rate design process are below the status quo revenue requirement.

Given the year 11 status quo cost (including LV charges) is $26.3M and the residual cost is $15.6M, an allocation of more than $10.7M of Shared Costs being borne by the PDI acquired classes will result in costs that exceeds the status quo. $10.7M of shared costs represents 69% of residual costs, or 41% of status quo.

SEC INTERROGATORY # 42

Reference:
[A/5/1, App. A]

Interrogatory:
SEC is seeking to better understand the report of Navigant. In its EB-2017-0049 Decision with Reasons, at p. 161-2, the Board said:

> *"The OEB denies Hydro One's rates proposals with respect to the Acquired Utilities for the following reasons.*
>
> *1) Hydro One's proposal contains simplistically derived and questionable estimates of revenue requirement comparisons to demonstrate adherence to the no harm requirement. The OEB accepts VECC's submission that given the wide range of past rate adjustments, the rebasing rate increase for any utility can vary widely from the 6.3% average.*
>
> *2) Hydro One's proposal is based on a cost allocation approach that recognizes the existing assets of the Acquired Utilities as being distinguishable and at a lower cost than its legacy assets by using adjustment factors. It intends to revisit this approach and proposes to recalibrate the adjustment factors over time as assets are renewed in the acquired service areas. The new assets will be included in Hydro One's existing asset pool at a higher cost and result in a lowering of the adjustment factors over time.*
>
> *OEB staff submitted that Hydro One's proposal is reasonable because the adjustment factors are, in effect, performing a direct allocation of assets and depreciation to the Acquired Utilities. OEB staff accepted that where costs associated with specific rate classes are known, direct allocation is appropriate. OEB staff submitted that Hydro One's proposal to use the adjustment factors for capital and the allocation of OM&A costs based on the cost allocation model is a reasonable proxy for reflecting the cost to serve.*

The OEB accepts that Hydro One's proposal adheres to some basic cost allocation principles that may be acceptable in a general sense. However, it is not acceptable to ignore the basis on which the approvals for acquiring the utilities were granted.

As SEC argued, Hydro One's rate proposal is based on a snapshot of the existing asset base in the acquired service area. The OEB agrees and based on Hydro One's failure to demonstrate that its costs are the same or lower in its evidence,[308] finds that the proposal will result in one of the two following negative outcomes.

a) In the absence of recalibration of the adjustment factors, an undue subsidy from Hydro One's legacy customers would be required.

b) In the situation where the calibration of the adjustment factors is commensurate with asset renewal at Hydro One's higher costs, harm in the form of relatively higher rates to the customers of the Acquired Utilities would need to be imposed.

3) Hydro One argued that its proposal adheres to previous OEB determinations with respect to treating the Acquired Utilities as separate rate classes and that its proposal to do so is in response to OEB direction. The OEB does not accept Hydro One's contention. The OEB has provided clear guidance with respect to its expectations that evidence of lower cost structures relied on in acquisition proposals are expected to result in concomitant lower rates. Hydro One would be expected to apply any distinguishable cost causation analysis relied on in an acquisition application to any customers that met the identified cost causation criteria whether they are new or legacy customers. The OEB did not direct Hydro One to isolate the Acquired Utilities in its cost allocation methodology. Hydro One has not demonstrated that its proposal is equitable to all customers.

4) Hydro One's cost allocation evidence indicates that in the absence of adjustment factors, Hydro One's long term costs to serve the Acquired

> *Utilities are higher than the costs of those previous utilities. This is in direct contradiction to the evidence relied on in its acquisition proposals."*

With respect to each of the reasons of the Board set forth above, please provide Navigant's expert opinion explaining how the current Hydro One proposal complies with the Board's conclusions and expectations.

Response:

Navigant was engaged to evaluate whether the cost allocation and rate design approaches described in Hydro One's supplemental evidence in this proceeding are appropriate and consistent with accepted regulatory practices, including, with respect to rate design, whether the adjustment of the revenue-to-cost ratio as described in the evidence is appropriate and consistent with accepted regulatory practices.

With respect to each of the Board's reasons for denying Hydro One's rates proposal as cited in its EB-2017-0049 Decision with Reasons, Navigant responds as follows:

1) Navigant was not asked to review Hydro One's assumption about the rate escalation for the status quo scenario.

2) a) Hydro One's supplemental evidence acknowledges (Exhibit A, Tab 5, Schedule 1, Page 7) the need to update the adjustment factors with each subsequent cost of service application.

   b) Updating the adjustment factors to reflect the continued tracking of gross fixed asset costs to serve the acquired customers does not necessarily mean that the total cost to serve or the rates paid by the acquired utility customers will be higher than what they would have been under the status quo.

   Utilities in general (Hydro One is not unique) have higher asset replacement costs than historical costs. Hydro One's replacement cost may be higher than the acquired utility's replacement costs, but they also may be the same or lower. As stated in Navigant's evidence (Page 8), Hydro One's proposal, to continue to recognise the OEB-approved revenue-to-cost ratio ranges, provides flexibility when setting rates that protects the acquired customers from rates that could exceed the status quo cost of service.

3) Hydro One's proposal to create separate customer classes for the acquired utilities' customers is a mechanism through which the lower cost structure resulting from the acquisition is reflected in the rates for the acquired utility customers' and the legacy Hydro One customers.

   Isolating the acquired utility customers by creating separate rate classes allows Hydro One to identify and directly assign the gross fixed asset costs to serve them, which in turn is used to allocate the majority of the other distribution related costs, such as operating, maintenance, and administrative costs, interest expenses, depreciation costs, and net income. Directly assigning the gross fixed asset costs to the acquired utility customer classes, and allowing the remainder of the costs to flow through the CAM using the standard allocation factors implicitly results in the same cost causation principles being applied to all customers.

   As stated in Navigant's evidence (Page 8), Hydro One's proposal, to continue to recognise the OEB-approved revenue-to-cost ratio ranges, provides flexibility when setting rates through which the benefits of the acquisition can be shared between the acquired and legacy customers.

4) Direct assignment is generally preferred to cost allocation as a way of attributing costs to customer classes. Hydro One's approach acknowledges this and incorporates adjustment factors into the CAM to recognize that the direct assigned costs of gross assets to serve the acquired customers are lower than the allocated gross assets derived using the standard allocation factors in the CAM.

SEC INTERROGATORY # 43

Reference:
[I/1/1, p. 2]

Interrogatory:
Please update the table on this page to reflect the proposals in A/5/1, including the proposed allocation of Shared Costs. If this table remains valid, please explain why. In either case, please provide details of each adjustment factor applied to the Year 11 figures and the dollar impact of those adjustment factors.

Response:
An update to the table provided in Exhibit I, Tab 1, Schedule 1 is provided below.

The Year 11- With Consolidation figures provided in the Table reflect the output of the cost allocation run provided in the response to Exhibit I, Tab 1, Schedule 48, which includes details of the assumptions and allocation process for estimating the PDI acquired classes' rates.

Please refer to Exhibit I, Tab 1, Schedule 48 for details on the calculation of the Year 11 figures.

PDI	Today - 2019		Year10 - With Consolidation[1]		Year10 - Without Consolidation[2]		Year11 - With Consolidation[3]		Year11 - Without Consolidation[2]	
	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[4]
Residential (750kWh)	$23.37	$107.18	$25.85	$109.78	$36.58	$121.04	$27.16	$111.16	$37.67	$122.19
GS < 50kW (2,000kWh)	$50.96	$270.23	$56.06	$275.58	$79.74	$300.45	$61.55	$281.35	$82.14	$302.97
GS 50 to 4,999 kW (250kW)	$925.31	$28,315.37	$1,068.03	$28,476.64	$1,468.19	$28,928.82	$1,027.66	$28,431.02	$1,508.51	$28,974.38

[1] Indicative distribution rates for year 10 (with consolidation) have been calculated by applying -1% to PDI's exsting rates then holding them constant for 2020-2024 and then applying IRM increase of 1.55% for 2025-2029.
[2] Indicative distribution rates for year 10 and year 11 (without consolidation) have been calculated using the percentage increase in rates revenue requirement compared to 2019 (refer to Exhibit I, Tab 2, Schedule 44).
[3] Indicative distribution rates for year 11 (with consolidation) per Exhibit I, Tab 1,Schedule 49, Attachement 2.
[4] Commodity, Smart Metering Entity Charge, RTSR and Regulaotry charges have been held constant, at values currently in effect, throughout the analysis period.

Hydro One	Today - 2019		Year10 - With Consolidation[1]		Year10 - Without Consolidation[1]		Year11 - With Consolidation[2]		Year11 - Without Consolidation[1]	
	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]	Base Monthly Distribution Charges ($)	Monthly Total Bill ($)[3]
Residential (UR 750kWh)	$34.26	$121.77	$43.72	$131.71	$43.72	$131.71	$41.44	$129.32	$44.87	$132.92
GS < 50kW (UGe 2,000kWh)	$81.60	$306.91	$105.88	$332.41	$105.88	$332.41	$102.26	$328.61	$108.84	$335.52
GS > 50 kW (UGd 250kW)	$2,559.27	$30,087.07	$3,347.54	$30,977.82	$3,347.54	$30,977.82	$3,238.09	$30,854.14	$3,440.78	$31,083.18

[1] Indicative distribution rates for year 10 (with and without consolidation) and year 11 (without consolidation) have been calculated using the compound annual growth rate between 2018 and 2022 and then applying it to 2022 rates.
[2] Indicative distribution rates for year 11 (with consolidation) per Exhibit I, Tab 1,Schedule 49, Attachement 2.
[3] Commodity, Smart Metering Entity Charge, RTSR and Regulaotry charges have been held constant, at values currently in effect, throughout the analysis period.

SEC INTERROGATORY # 44

Reference:
[I/1/3, p. 2,3]

Interrogatory:
Please update the tables on these pages to reflect the proposals in A/5/1, including the proposed allocation of Shared Costs. If these tables remain valid, please explain why. In either case, please provide details of each adjustment factor applied to the Year 11 figures and the dollar impact of those adjustment factors.

Response:
Below is an update to the tables provided in Exhibit I, Tab 1, Schedule 3 to reflect the assumptions and output from the cost allocation and rate design completed in the response to Exhibits 1, Tab 1, Schedules 48 and 49:

PDI	Today (2019)[1,2,3]	Year 10 (2029) with consolidation[2,3,4]	Year 10 (2029) without consolidation[2,3,5]	Year 11 (2030) with consolidation[6]	Year 11 (2030) without consolidation[2,3,7]
Revenue Collected					
Residential	$9,972,113	$10,778,546	$14,864,540	$11,995,089	$15,259,604
GS < 50kW	$2,654,781	$2,882,231	$3,988,616	$3,262,266	$4,096,265
GS 50-4,999 kW	$3,551,950	$3,904,773	$5,308,166	$3,844,882	$5,449,494
Other	$990,062	$1,078,764	$1,479,201	$1,447,995	$1,518,637
Total	**$17,168,906**	**$18,644,315**	**$25,640,523**	**$20,550,232**	**$26,324,000**
Revenue Collected per Customer					
Residential	$300	$308	$424	$341	$433
GS < 50kW	$749	$741	$1,026	$831	$1,044
GS 50-4,999 kW	$9,567	$9,763	$13,272	$9,543	$13,525
Other	$107	$109	$150	$145	$153
Total	**$370**	**$379**	**$521**	**$415**	**$532**

[1] Total revenue collected from rates is derived by applying approved IRM increases between 2013 and 2019 to the approved revenue collected from rates in 2013.
[2] External revenues are held constant at 2013 approved values.
[3] Estimated values for revenues related to LV charges have been added to the total distribution revenue collected as described in Exhibit A-4-1, pg 3.
[4] Total revenue collected from rates for Year 10 (with consolidation) is derived by holding 2019 rates revenue requirement constant for 2020-2024 and then applying IRM factor of 1.55% for 2025-2029.
[5] Total revenue collected (including external revenues) per Exhibit I, Tab 1, Schedule 10, part (d).
[6] Total revenue collected (including external revenues) from the acquired rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (plus $1.5M in estimated revenue collected from the "combined classes").
[7] Total revenue collected (including external revenues) per Table 2, Exhibit A, Tab 4, Schedule 1, pg 4.

Hydro One	Today (2019)[1]	Year 10 (2029) with consolidation[2,3]	Year 10 (2029) without consolidation[2,3]	Year 11 (2030) with consolidation[4]	Year 11 (2030) without consolidation[2,3]
Revenue Collected					
Residential (UR)	$97,456,815	$121,420,723	$121,420,723	$134,691,875	$135,017,893
GS<50kW (UGe)	$23,037,678	$28,770,504	$28,770,504	$28,030,967	$28,101,853
GS>50kW (UGd)	$28,548,646	$35,752,868	$35,752,868	$31,931,011	$32,017,420
Other	$1,348,816,751	$1,685,459,484	$1,685,459,484	$1,710,108,678	$1,714,555,596
Total	**$1,497,859,890**	**$1,871,403,579**	**$1,871,403,579**	**$1,904,762,530**	**$1,909,692,763**
Revenue Collected per Customer					
Residential (UR)	$424	$469	$469	$515	$517
GS<50kW (UGe)	$1,276	$1,520	$1,520	$1,472	$1,475
GS>50kW (UGd)	$16,413	$19,665	$19,665	$17,458	$17,506
Other	$1,275	$1,504	$1,504	$1,519	$1,523
Total	**$1,146**	**$1,337**	**$1,337**	**$1,353**	**$1,356**

[1] Total revenue collected per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.
[2] Total revenue collected is derived using the compound annual growth in total revenue requirement between 2017 and 2022.
[3] External revenues are held constant at 2022 values per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.
[4] Total revenue collected for Hydro One legacy rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (minus $1.5M in estimated revenue collected from the "combined classes").

Please refer to Exhibit I, Tab 1, Schedule 48 (b) for details on the adjustment factors applied in calculating the Year 11 figures.

SEC INTERROGATORY # 45

Reference:
[I/1/7, p. 2,3]

Interrogatory:
Please confirm that, under the Board's current ten year deferred rebasing policy, Hydro One's legacy customers will subsidize the rates of PDI customers during that period with respect to 100% of the Shared Costs properly attributable to the PDI customers, and after the end of the deferred rebasing period under the current Hydro One proposal Hydro One's legacy customers will continue to subsidize the rates of PDI customers with respect to part of the Shared Costs properly attributable to the PDI customers.

Response:
Not confirmed, Hydro One's legacy customers will not subsidize PDI customers during or after the deferred rebasing period. During the deferred rebasing period, PDI customers will continue to the be charged PDI's OEB-approved base distribution rates, with a 1% reduction in Years 1 to 5 followed by price cap adjustments in years 6 – 10. Hydro One's legacy customers are not "subsidizing" PDI customers over that period. Hydro One legacy customers will continue to pay rates over the deferral period that they would have if the transaction did not occur – they are not paying any additional cost (e.g. "subsidy") than they would have in absence of this transaction.

After the rebasing period, PDI customers will be allocated a portion of Hydro One's shared costs, up to the amount of the goal post as defined in Exhibit A, Tab 4, Schedule 1. Any allocation of costs to PDI customers' rates, benefits legacy customers as those costs will no longer be included in their revenue requirement. Hydro One is forecasting $9.3M of savings that both customer groups will benefit from.

SEC INTERROGATORY # 46

Reference:
[I/1/12 (d) and I/2/22]

Interrogatory:
Please explain why the PDI rebasings are assumed to be four years apart, while the Hydro One rebasings are assumed to be five years apart. If this is an error, please recalculate Status Quo on page 2 of I/2/22 based on five year rebasings.

Response:
The migration from 4 year rebasing to 5 years was not codified until sometime in 2014. PDI's last rate application was made in 2013 before this change was enacted by the OEB. PDI has not submitted any rate applications since 2013, except for IRM in 2017. Therefore the movement to the 5 year schedule has not been adopted by PDI.

The model provided does indicate rebasing on the 4 year timetable, however moving the provided financial data to the 5 year rebasing schedule does not materially change the provided exhibit. With the suggestion of moving to a 5 year rebasing schedule, PDI will still reflect three rate rebasing periods as provided in the document and will not materially affect the end result as stated in 2030.

Hydro One anticipates that it will be on a five-year rate rebasing schedule over the next 10 years.

SEC INTERROGATORY # 47

Reference:
[I/1/15 (a)]

Interrogatory:
Please restate Ex. A/2/1, Table 1 on the basis that overheads are not capitalized by PDI, i.e. on the same basis as the Hydro One comparison.

Response:
This interrogatory appears to be based on the incorrect assumption that overhead costs are not capitalized by Hydro One.

To clarify, the PDI Status Quo and the Hydro One Forecast in Table 1 reflect the capitalization policies of each respective organization, both of which allow for capitalization of overhead costs. In the Hydro One Forecast, overheads were excluded as they were assessed to be non-incremental – not due to capitalization policy differences.

Hydro One does not understand why the requested restatement is of value to SEC. PDI under the Status Quo, will continue to capitalize overheads to follow their current capitalization accounting policy. Therefore, the numbers as presented in Table 1 do reflect an accurate representation of PDI's costs incurred in the absence of this transaction

However in order to provide a response to the question asked, regardless of the merit, PDI has provided an indicative breakout of Status Quo forecast revised as if it did not capitalize overheads.

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
OM&A										
Status Quo Forecast	10.1	10.4	10.5	10.7	11.1	11.3	11.6	11.9	12.2	12.5
Hydro One Forecast	8.7	4.5	4.3	3.8	3.9	3.9	4.0	4.1	4.2	4.2
Projected Savings	1.4	5.9	6.2	6.9	7.2	7.4	7.6	7.8	8.0	8.3
Capital										
Status Quo Forecast	5.8	6.0	5.6	5.8	6.0	6.0	6.2	6.4	6.5	6.7
Hydro One Forecast	6.0	7.5	5.4	5.1	5.7	7.1	5.4	5.6	5.7	5.9
Projected Savings	-0.2	-1.6	0.2	0.7	0.3	-1.1	0.8	0.8	0.8	0.8

SEC INTERROGATORY # 48

Reference:
[I/1/16 (c) and I/1/18 (b) and I/2/6]

Interrogatory:
Please provide the amount of the deferred tax asset, including all supporting calculations, and the proposed treatment of the FMV Bump for PDI and Hydro One revenue requirements and rates. Please identify the short and long term tax impacts of this FMV Bump on both PDI customers and Hydro One legacy customers. Please update Ex. A/3/1, Table 2 to reflect the impact of the tax shelter arising out of the FMV Bump.

Response:
On an asset purchase, deferred tax asset generally arises from two sources: (1) the excess of fair market value of net assets over their net tax carrying amount (FV Increment) and (2) the deductible purchase price premium (goodwill). The purchase price allocation is required to determine the fair market value of net assets and the purchase price premium. As the purchase price allocation is not available until the transaction closes, the deferred taxes asset cannot be calculated at this time.

Please note that the deferred tax asset arising from the acquisition of PDI is not included in rates and consequently has no impact to PDI customers and Hydro One customers. Please refer to Exhibit I, Tab 1, Schedule 16 which states "recovery of the FV Increment and the purchase price premium will be through the realization of synergies and other cost savings arising from the transaction and it is not a cost that is recoverable in rates."

SEC INTERROGATORY # 49

Reference:
[I/1/19 and I/1/27]

Interrogatory:
Please confirm that Hydro One plans to change the depreciation rates for PDI rate base after the acquisition. Please confirm that, to the extent that the depreciation rates are lower than those used by PDI, the difference each year will be credited to account 1576 and refunded to PDI customers on rebasing. If that is not the case, please provide a detailed explanation of the proposed ratemaking treatment of the change in depreciation rates. Please confirm that, on current forecasts, Hydro One proposes to have take $15.6 million less depreciation than would arise at the PDI depreciation rates, resulting in rate base on rebasing that is $15.6 million higher than under a PDI status quo, all other things being equal.

Response:
Confirmed, Hydro One plans to change the depreciation rates for PDI after the acquisition. Accounting standards (including USGAAP) would require that depreciation rates reflect management's best estimate for asset depletion. Post-acquisition, the PDI assets would be under Hydro One's asset management and maintenance policies, and therefore the expected useful lives and resultant depreciation rates would be updated to reflect this.

Hydro One does not confirm that, if its depreciation rates are lower than those used by PDI, the differences would be credited to account 1576 or refunded to PDI customers on rebasing. Account 1576 (Accounting Changes under CGGAP) was established to record the financial differences arising as a result of changes to accounting depreciation or capitalization policies permitted by the Board under Canadian GAAP in 2012 or as mandated by the Board in 2013[1]. It was not established in the context of a MAAD application.

[1] https://www.oeb.ca/oeb/_Documents/Regulatory/Board_Ltr_Acct_Policy_Changes_1575_1576_20130625.pdf

Hydro One regards items such as depreciation as part of the synergy savings of the acquisition, which will ultimately benefit PDI customers through lower rates after the deferral period, as discussed in Exhibit A, Tab 4, Schedule 1.

The forecast depreciation expense that will be recorded by Hydro One on PDI's assets is $2.8M in Year 2020 (the first year post-acquisition), and over the 10-year deferred rebasing period totals $33.8M. These numbers can be found in Hydro One's PDI ESM Model, filed at Exhibit I, Tab 1, Schedule 19, Attachment 1, in Row 50 of the Tab named "ESM Model". The depreciation included in PDI's current rates[2] is $2.7M or $26.7M over the 10-year deferred rebasing period. Because the higher total depreciation expense that will be recorded by Hydro One will not be reflected in rates during the deferred rebasing period, PDI customers will not be charged the additional $7.0M in depreciation expense over the deferral period.

Hydro One believes that items such as changes in depreciation (either increases or decreases) are part of the deferral period synergies associated with the acquisition, which are at the shareholders risk. Therefore, Hydro One will not record an amount in account 1576 relating to depreciation.

Hydro One is not aware of how the $15.6M depreciation number referenced in the question was derived.

[2] EB-2012-0160

SEC INTERROGATORY # 50

Reference:
[I/1/32, Attach. 1, and I/4/13]

Interrogatory:
Please provide a detailed estimate of the charges to PDI customers in each of the deferred rebasing years using a) the current PDI specific service charges, and b) the proposed Hydro One specific service charges.

Response:
The PDI estimate of the charges to PDI customers in each of the deferred rebasing years is provided as Attachment 1. Given that the charges for the services anticipated in the PDI estimate do not materially differ between the PDI and Hydro One, only one estimate is provided to illustrate the anticipated charges to PDI customers in the deferred rebasing period.

PDI Customer Charges

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Pole rentals	490	495	500	505	510	515	520	525	530	535	540
Change of occupancy charges	167	169	171	173	175	177	179	181	183	185	187
Late payment charges	233	235	237	239	241	243	245	247	249	251	254
Other - Administrative charges	392	396	400	404	408	412	416	420	424	428	432
	1,282	1,295	1,308	1,321	1,334	1,347	1,360	1,373	1,386	1,399	1,413

Source	Rate - 2019	
Joint use poles	43.63	per pole
Customer Administration charges	30.00	
Non-payment of Account charges	1.50%	per month
Customer Administration charges	15.00 - 30.00	per item

PDI - Other Revenue

Other Revenue	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Building rental	15	15	15	15	15	15	15	15	15	15	15	15	15
Pole rentals	480	485	490	495	500	505	510	515	520	525	530	535	540
Change of occupancy charges	163	165	167	169	171	173	175	177	179	181	183	185	187
Late payment charges	229	231	233	235	237	239	241	243	245	247	249	251	254
Other - Administrative charges	384	388	392	396	400	404	408	412	416	420	424	428	432
Contributed capital revenue recognize	470	475	480	485	490	495	500	505	510	515	520	525	530
Miscellaneous	67	68	69	69	69	69	70	71	71	72	74	75	76
	1,808	1,827	1,846	1,864	1,882	1,900	1,919	1,938	1,956	1,975	1,995	2,014	2,034

Source	Rate - 2019	
Interco - Lakefield building		
Joint use poles	43.63	per pole
Customer Administration charges	30.00	
Non-payment of Account charges	1.50%	per month
Customer Administration charges	15.00 - 30.00	per item

SEC INTERROGATORY # 51

Reference:
[I/1/44 (a)]

Interrogatory:
Please explain how 1937680 Ontario Inc. will comply with section 11(2) of the Ontario Business Corporations Act.

Response:
There is no concern regarding s.11(2) of the Business Corporations Act, because during the transitional integration period where 1937680 Ontario Inc. will own and operate the distribution assets (a period that may be to 18 months) all public-facing business interactions are intended to utilize the branding "Peterborough Distribution" and will not use the words "Limited", "Incorporated" or "Corporation" or any abbreviation thereof in any such branding.

SEC INTERROGATORY # 52

Reference:
[I/2/1 through I/2/5]

Interrogatory:
SEC is seeking to better understand the refusal of the Applicant to file the requested documents, which as the Applicants are aware were provided freely to SEC in 2018 by PDI to assist SEC's counsel in reporting to our client. As we have seen the documents, we are aware of the many statements in the documents that estimate the costs and benefits of the proposed transaction to the customers of PDI, and the many other items in the documents relating to whether customers will be better off after the transaction takes place. We have in fact asked a number of questions related to those issues. Therefore, please provide a further and more detailed explanation as to the refusal to provide the documents and answer questions related to the documents or, in the alternative, provide full and complete responses to these five previous interrogatories.

Response:
This interrogatory refers back to SEC Interrogatories filed as Exhibit I, Tab 2, Schedules 1 through 5 filed on February 27, 2019.

PDI will address each of these interrogatories individually:

- *Exhibit I, Tab 2, Schedule 1*

PDI notes that SEC posed no questions for this interrogatory but instead identified a series of documents. In response to Energy Probe IR 1 (Exhibit I, Tab 3, Schedule 1) filed on February 27, 2019, PDI provided approximately 175 pages of information including Peterborough CAO reports and Navigant Studies relating to the sale of PDI, even though this type of information is out of scope in terms of the Board's application of the No Harm test. PDI has no record of providing any documents to SEC in 2018, as referenced in this question.

- *Exhibit I, Tab 2, Schedule 2*

Parts a), b), c), e) and f) are not relevant to the Board's application of the No Harm test.

d) The reduced Transfer Tax rate of 22%, as provided by the Provincial Government to motivate consolidation, results in an approximate tax reduction of 11% (33% reduced to 22%) on proposed proceeds of $105,000 or approximately $11.5 million.

- *Exhibit I, Tab 2, Schedule 3*

The report was verbally provided at City Council in a discussion format with City Council on April 30, 2018. There were no written reports. The video of that discussion can be found on the City of Peterborough website.

- *Exhibit I, Tab 2, Schedule 4*

a) The City/COPHI interprets that Page 5 of the Navigant Report outlines by general comparison only, the possible savings and synergies that could occur to explain in general terms the basis for why Hydro One is able to make an offer. There has been no specific need to compare to Orillia rates or their cost structures or savings, as their rates, cost structures and asset conditions are unique to that utility. We also note that the proposed PDI transaction is an asset purchase, and not a share purchase.

b) Page 11 of the Navigant report illustrates the approximate net proceeds that will be available to the City upon completion of the proposed transaction. As the net transaction proceeds are not relevant to the No Harm Test, the update will not be provided.

c) Page 15 of the Navigant report, for illustration purposes, outlines the current arms-length market rate for low-risk corporate A-rated bonds. The investment opportunity outlined in the Bignell letter of October 26, 2016, is to finance through COPHI the unregulated renewable generation business which, as an industry, is riskier and as a result not A-rated. The rate of return available to the City in the COPHI business would reflect that risk profile.

- *Exhibit I, Tab 2, Schedule 5*

a) PDI can confirm that at that time the presentation was made, Hydro One was no longer tax-exempt and the analysis on Page 14 reflects that state.

b) Please refer to page 20 of the Navigant Report of November 24, 2016.

SEC INTERROGATORY # 53

Reference:
[I/2/11]

Interrogatory:
Please provide an updated response to this interrogatory consistent with the Updated Evidence and with the Board's Decision with Reasons in EB-2017-0049 (including the Board's statements quoted in SEC-33 above).

Response:
No update is required to parts a, b, d, or e of the response in Exhibit I, Tab 2, Schedule11. The Hydro One urban classes' rates shown in the Table provided in part c) of the question could be updated to reflect the rates proposed in the draft rate order submitted by Hydro One in response to the Board's Decision in EB-2017-0049. The updated table is provided below, however note that these rates are still subject to final approval by the Board.

As Hydro One wrote in the referenced interrogatory response, the below table is not an appropriate or fair comparison since it is not Hydro One's proposal to move PDI customers to Hydro One's existing urban density classes in Year 11.

Comparison of 2018 Monthly Distribution Bills

Customer	H1 Urban			PDI			Difference	
	Fixed	Variable	Total	Fixed	Variable	Total	Amount	%
Residential 700 kwhr.	$25.20	$7.63	$33.83	$18.98	$3.29	$22.27	$11.56	51.91%
UGe/GS<50 2000 kwhr.	$23.95	$55.20	$79.15	$31.36	$17.80	$49.16	$29.99	61.00%
UGd/GS>50 150 kW	$96.08	$1,427.99	$1,524.07	$160.31	$409.85	$570.16	$953.91	167.31%

SEC INTERROGATORY # 54

Reference:
[I/3/19 (a)]

Interrogatory:
Please provide a full and complete answer to this question, or provide a more detailed explanation as to why the level of Shared Costs that would otherwise be applicable to PDI customers is not relevant.

Response:
The response provided in Exhibit I, Tab 3, Schedule 19 (a) is complete. In 2020, there will be no allocation of Shared Costs to PDI. If the transaction is approved in 2019/20, PDI will be in the first year of its deferral period and will continue to be charged its OEB-approved rates as approved by the OEB on March 28, 2019 under docket EB-2018-0067, including the requested rate rider to reflect the 1% discount in base distribution rates, if approved. To allocate Hydro One's Shared Cost, which are already being fully recovered from legacy customers, to PDI customers in addition to their current rates is unfair to those customers, and would benefit Hydro One's shareholder.

SEC INTERROGATORY # 55

Reference:
[I/3/20]

Interrogatory:
Please describe the “standard Hydro One processes for tracking and reporting costs (OM&A and Capital)…”, and describe how those standard processes are currently applied to other geographically distinct parts of the Hydro One franchise area.

Response:
Please see Exhibit I, Tab 1, Schedule 46. With the exception of tracking costs for the previous Acquired Utilities - Norfolk, Haldimand and Woodstock – Hydro One does not track costs geographically. Hydro One’s postage stamp rate structure does not create a need to have geographically distinct cost structures.

SEC INTERROGATORY # 56

Reference:
[I/4/8 (a)]

Interrogatory:
Please explain in detail how the Hydro One forecast was arrived at if not through a bottom up forecast.

Response:
Please refer to Exhibit I, Tab 1, Schedule 17 part a).

SEC INTERROGATORY # 57

Reference:
[I/4/20 (c)(i)]

Interrogatory:
Please restate the table in this response on a per customer basis.

Response:
The table below provides the requested information.

Rate Class	Total OM&A per Customer	"Direct" OM&A per Customer	"Shared" OM&A per Customer
UR	$192	$65	$127
UGe	$475	$215	$260
UGd	$5,452	$3,035	$2,416
AUR	$188	$73	$115
AUGe	$383	$163	$221
AUGd	$4,831	$1,198	$3,633

SEC INTERROGATORY # 58

Reference:
[I/7/13]

Interrogatory:
Please provide a full and complete response to this interrogatory, but with the documentation provided limited to those documents that include references to the impacts of the proposed transaction on PDI or Hydro One legacy customers.

Response:
Hydro One declines to provide the requested information, for the original reasons set out in Exhibit I, Tab 7, Schedule 13. The attempt to narrow the original CCC request to documents related to “impacts of the proposed transaction on PDI or Hydro One legacy customers” does not change the reasons provided. The evidence of Hydro One on the impact of the proposed transaction on PDI and legacy customers is fully set out in the record of this proceeding.

ENERGY PROBE INTERROGATORY # 21

Reference:
Exhibit A, Tab 5, Schedule 1, Page 2

Interrogatory:
Please explain the mechanism that Hydro One will use to track capital costs and incremental OM&A costs to serve PDI customers after the rebasing period. Please provide a numerical example with illustrative numbers.

Response:
For clarification, Hydro One has only committed to tracking capital costs for the former PDI service territory after the rebasing period, as per Exhibit A, Tab 5, Schedule 1, pages 2 and 3. As described in that exhibit, the cost allocation model used to determine rates for customer classes uses fixed assets as the primary allocator to distribute OM&A costs amongst rate classes. Therefore, the tracking of OM&A beyond the deferral period is not required.

Hydro One will utilize its financial management and reporting system, the same system it uses for all Hydro One's financial business activities, to track PDI's capital costs. Hydro One's financial system will enable the reporting of future PDI capital costs in perpetuity by setting up a specific PDI service territory cost centre. Any specific capital cost expenditures made in service territory going forward will be recorded and tracked in the PDI Cost Centre.

A numerical example of how Hydro One tracks cost is provided below.

$000s	**QX 20XX Actual**
Capital Costs	
Number of Labour Hours	48
Labour Rate	$77
Labour Cost Total	**$3,707**
Fleet costs	$1,059
Total Cost	**$4,766**

ENERGY PROBE INTERROGATORY # 22

Reference:
Exhibit A, Tab 5, Schedule 1, Pages 6 and 7

Interrogatory:
Please provide more information on Hydro One's proposed adjustment factors by providing the following information.

a) Please list the proposed adjustment factors.

b) Please explain how each adjustment factor will be calculated.

c) Please provide a numerical example of each adjustment factor.

Response:
a) to c) Please see the response to Exhibit I, Tab 1, Schedule 48, part a).

ENERGY PROBE INTERROGATORY # 23

Reference:
Exhibit A, Tab 5, Schedule 1, Page 9

Interrogatory:

a) Why did Hydro One find it necessary to engage Navigant Consulting to evaluate its cost allocation approach?

b) Did Hydro One issue an RFP for this work? If the answer is yes, please provide the RFP. If the answer is no, please explain why not.

c) Please file the statement of work or any similar document that Hydro One used to communicate to Navigant the consulting assignment.

Response:

a) Hydro One in its Distribution Rates Proceeding set out its cost allocation and rate design approach for the previously Acquired Utilities. Hydro One had concerns as to the Board's understanding and interpretation of this approach and as such, Hydro One sought an independent expert review of the cost allocation and rate design evidence based on industry experience. Please see Exhibit I, Tab 2, Schedules 40 and 42.

b) No, Hydro One did not issue an RFP for this work. Navigant Consulting is a noted expert in the area of cost allocation and rate design. Hydro One and PDI wished to file the supplement evidence as soon as possible. To go through an RFP process would have added considerable time and delay to the applications.

c) Please see below.

3. **Scope of Services and Work Product**

The Consultant will:

(a) evaluate whether the cost allocation and rate design approaches described in the Supplemental Evidence are appropriate and consistent with accepted regulatory practices, including, with respect to rate design in particular, whether the adjustment of the revenue-to-cost ratio as described in the Supplemental Evidence is appropriate and consistent with accepted regulatory practices (the "Study");

(b) if requested by Counsel, produce a report detailing the Study's methodology, analysis performed and the Consultant's findings and recommendations (the "Report"), which may be filed with the Board in the applicable Proceeding; and

(c) if requested by Counsel, provide support during the hearing of the applicable Proceeding and testify before the Board in that Proceeding, in connection with the scope of the services provided hereunder ("Application Support" and, together with the Study and the Report, the "Services").

ENERGY PROBE INTERROGATORY # 24

Reference:
Exhibit A, Appendix A, Navigant Report, Page 1

Interrogatory:
Are the documents listed on Page 1 a complete list of all documents that were provided to Navigant by Hydro One? If the answer is no, please list the documents that were provided by Hydro One to Navigant but are not listed on Page 1.

Response:
Hydro One provided Navigant the following list of documents that were not explicitly identified on Page 1 of Navigant's Report.

From its Distribution Rates Application (EB-2017-0049):

- G1-02-01: Pre-filed evidence that includes discussion/rationale for new acquired rate classes
- G1-03-01: Pre-filed evidence that discusses cost allocation, including for new acquired classes (use of adjustment factors)
- Q-01-01: Updated evidence filed in Dec. 2017 that discusses (starting at page 15) changes made to the allocation of costs to acquired classes (basically included local distribution stations as part of the fixed asset costs subject to the adjustment factors) and also discusses changes made to R/C ratios in order to align with OEB approved ranges.
- Acquired Fixed Assets Summary XLS: The detailed calculations that derive the adjustment factors used in the cost allocation model
- Rate Design 2021 XLS: Calculation of the rates for all classes in 2021
- I-46-VECC-090: An interrogatory response that in part d) describes what is provided in each of the tabs of the "Acquired Fixed Assets" spreadsheet [Should refer to this when looking at that spreadsheet]
- JT3.26-3: A technical conference response where part c) of the response discusses our approach to changing the adjustment factors over time.

All of these documents are available on the OEB's website.

ENERGY PROBE INTERROGATORY # 25

Reference:
Exhibit A, Appendix A, Navigant Report, Page 6

Interrogatory:

a) Please discuss Navigant's experience with adjustment factors in other jurisdictions.

b) Did Hydro One provide Navigant with any adjustment factor alternatives? If the answer is yes, please list and explain the alternatives. If the answer is no, please explain how Navigant was able to reach its conclusions in absence of alternatives.

Response:

a) Navigant has considerable experience developing and implementing cost allocation methods and models in general, and more specifically for utilities that operate in service territories that span multiple regulatory jurisdictions. Navigant's expert, Benjamin Grunfeld, has filed evidence on matters related to Hydro One's cost allocation and rate design (e.g., in Ontario proceedings EB-2012-0136 and EB-2013-0416). Furthermore, the Navigant team involved in the review Hydro One's proposal and the development of the evidence in this proceeding, consisted of individuals who filed evidence and, in some instances, testified in cases involving PacifiCorp's multi-jurisdictional cost allocation as it related to revenue requirement determinations (e.g., Wyoming docket 20000-405-ER-11, Utah docket 10-035-89, Idaho docket PAC-E-08-07) or power supply cost modelling and adjustment mechanisms (Oregon docket UE 307, Wyoming docket 20000-469-ER-15, Utah docket 15-035-03, Idaho docket PAC-E-14-01), Enbridge's multi-jurisdictional corporate cost allocation methodology (Ontario proceeding EB-2012-0459), Enmax's inter-affiliate cost review as part of the company's distribution tariff application (Alberta proceeding 1609784), Gazifere's corporate shared service cost model (Quebec proceeding R-3924-2015), and Nova Scotia Power's cost-of-service and allocation approaches (Nova Scotia M05473), among others.

   Direct assignment of costs to customer groups (e.g. jurisdictions or classes) is a common element of such methods and models. OEB staff recognized and the OEB appeared to accept (in its EB-2017-0049 Decision with Reasons, at p. 161-2) that the adjustment factors are a mechanism to represent a direct assignment of assets and depreciation within the OEB's standard Cost Allocation Model (CAM).

b) No, Hydro One did not provide Navigant with alternatives to the use of adjustment factors. However, Navigant did internally consider alternatives such as:
   - direct assignment of costs associated with specific USofA accounts within a single CAM that covers both the acquired and legacy customer classes; and
   - separate CAMs for both the acquired and legacy customer classes.

   Navigant believes that the level of effort and added complexity associated with these alternatives would be more onerous and the result would not be materially different.

VECC INTERROGATORY # 23

Reference:
Exhibit A/T5/S1, page 1

Preamble:
The Supplemental Evidence states:

"On October 12, 2018 Hydro One filed a MAAD application to purchase PDI and on February 27, 2019 Hydro One updated Exhibit A, Tab 4, Schedule 1 and Attachment 18. Interrogatory responses on the original evidence were filed on February 27, 2019. Included in that Application was an exhibit, "Future Cost Structures" (Exhibit A, Tab 4, Schedule 1), to assist the Board in understanding Hydro One's rate plans for PDI's customers after the deferred rebasing period. The purpose of this Supplemental Evidence is to explain in detail Hydro One's proposed cost allocation and rate design for PDI customers at the end of the rebasing deferral period".

Interrogatory:

a) Do any of the interrogatory responses provided to date require updating/revision as result of the Supplemental Evidence?

b) If yes, please identify the relevant interrogatory responses and provide the necessary revisions/updates.

Response:

a) No, the responses to interrogatory questions filed February 27, 2019 included the information provided in the Blue Page Update. The information filed in Exhibit A, Tab 5, Schedule 1 will not impact the responses previously provided.

b) N/A.

VECC INTERROGATORY # 24

Reference:

April 26, 2019 Cover Letter to the Supplemental Evidence
OEB Decision and Order, EB-2017-0049, pages 161-165

Preamble: The Cover Letter states:

"This exhibit is being provided to address some of the conclusions reached by the OEB in its Decision and Order on Hydro One's distribution rate application EB-2017-0049".

Interrogatory:

a) Are the proposals set out in the Supplemental Evidence with the respect to the cost allocation and rate design for acquired utilities at the time of rebasing different from those proposed by Hydro One Networks in EB-2017-0049?

b) If yes, please provide a schedule that: i) specifically indicates those areas where the cost allocation and rate design proposals in the Supplemental Evidence differ from those in EB-2017-0049; and ii) documents the change(s) that have been made.

c) Is it Hydro One Networks' view that the proposals set out in the Supplemental Evidence address the concerns and conclusions of Board regarding its EB-2017-0049 cost allocation and rate design proposals for acquired utilities? If yes, please explain how the Supplemental Evidence specifically addresses the Board's various concerns and conclusions.

Response:

a) Yes.

b) Hydro One has made two changes to the methodology proposed in EB-2017-0049:
   - The determination of upstream distribution assets required to serve the acquired classes will take into consideration the extent to which the acquired utility's load was previously embedded within Hydro One versus being directly supplied from the transmission system. This will ensure that the PDI classes are only assigned upstream distribution costs consistent with the extent to which upstream distribution facilities are used to supply the PDI service territory.

- Hydro One will continue to track the capital in-service additions for the acquired utilities after the rebasing period (i.e. Year 11 onwards) in order to inform the calculation of the adjustment factors in future cost of service applications.

c) The concerns of the Board regarding Hydro One's EB-2017-0049 cost allocation and rate design proposals for acquired utilities were discussed on p. 161-2 of the Board's Decision. Below is Hydro One's response to those cost allocation and rate design concerns raised.

1. *The Board was concerned that Hydro One's proposed adjustment factors were based on a "snapshot" of the existing asset base in the acquired service area and that not recalibrating the adjustment factors would result in an undue subsidy from legacy customers.* This has been addressed by Hydro One's proposal to continue tracking the capital in-service additions for the acquired utilities after the rebasing period (i.e. Year 11 onwards) which will allow a recalibration of the adjustment factors in future cost of service applications.

2. *The Board was concerned that re-calibration of the adjustment factors commensurate with asset renewal "at Hydro One's higher costs" would harm the acquired utilities.* Hydro One disagrees with the view that Hydro One's asset renewal costs will be higher. Any asset that is replaced after its useful life has expired, often 30 plus years, will be replaced at a higher cost than it was constructed at – regardless of which distributor replaces the asset. It is not possible to know what the replacement costs for Hydro One or PDI will be beyond the deferred rebasing period (i.e. after 2030). See Exhibit I, Tab 2, Schedule 32.

3. *The Board noted that it did not direct Hydro One to isolate the Acquired Utilities in separate rate classes.* While Hydro One agrees that the Board did not direct Hydro One to create separate rate classes, it did state that it expected that future rates for acquired customers would be reflective of the costs to serve them. Hydro One's proposal to create separate acquired rate classes for residential and general service customers will allow Hydro One to more accurately identify the specific costs of serving the PDI customers by virtue of being apply to "directly allocate" the local fixed assets associated with serving the PDI acquired classes, which in turn drives the bulk of all other costs.

4. *The Board indicated that Hydro One would be expected to apply any distinguishable cost causation analysis relied on for the acquired classes to all of Hydro One's customers.* Hydro One agrees, and by creating acquired classes within the OEB's cost allocation model, Hydro One is in fact using the same cost causation principles implicit within the model to allocate costs across all rate classes. The only difference is that the acquired classes represent a defined service territory for which certain cost drivers are known (i.e. local fixed assets used to serve that service territory). As such, Hydro One is able to directly allocate (via the adjustment factors) the fixed assets to those acquired classes in order to allocate costs that most accurately reflect their cost-to-serve. Hydro One's legacy rate classes include customers from across Hydro One's entire service territory and as such it is not possible to specifically assign costs for serving those customers. It is also not possible, or practical, to apply the approach used for the acquired classes to specific regions of Hydro One's service territory (e.g. specific communities) where we have historically provided service given that we do not have information on the amount of fixed assets specifically associated with serving those regions.

5. *The Board stated that Hydro One did not demonstrate that its proposals for harmonizing the Acquired Utilities was equitable to all customers.* Hydro One's proposal to use the Board's cost allocation model for allocating costs across all rate classes, both legacy and acquired classes, ensures the equitable treatment of all customers consistent with acceptable regulatory principles for allocating costs and setting rates (i.e, setting rates within the Board's approved revenue to cost ranges). Hydro One has further demonstrated that its commitment to establish rates for the PDI acquired classes that will collect revenues between the Residual Cost for serving PDI customers and the Status Quo costs that PDI customers would have paid had they not been acquired, will ensure that both legacy and PDI customers share in the cost reductions resulting from the acquisition.

6. *The Board indicated their concern that in the absence of adjustment factors, Hydro One's long term costs to serve the Acquired Utilities are higher than the costs of those previous utilities.* Hydro One's use of adjustment factors ensure that the costs allocated to the acquired classes accurately reflect their cost to serve by directly assigning the local fixed assets used to serve the acquired classes. The Navigant report indicates that direct assignment, where possible, is generally preferred to

cost allocation as a way of attributing costs to customer classes. Hydro One's use of adjustment factors within the cost allocation model recognizes that the allocation of fixed assets based on the standard allocation factors in the cost allocation model would significantly over-allocate the fixed assets know to be required to serve the acquired customers, resulting in an artificially high cost to serve .

VECC INTERROGATORY # 25

Reference:
Exhibit A/T5/S1, page 2 (lines 10-14)

Preamble: The Supplemental Evidence states:

"In Exhibit A, Tab 2, Schedule 1, Table 1 of this MAAD application, Hydro One has provided the forecast incremental OM&A and capital cost to serve the customers of PDI, and commits to tracking the actual incremental OM&A and capital costs to serve PDI customers until the end of the ten year deferral period. This tracking will allow the Board to compare the actual incremental costs to serve PDI customers with that forecast in this application."

Interrogatory:

a) In order to allow for such a comparison, please provide a schedule that breaks down the Hydro One Forecast OM&A (per Exhibit A, Tab 2, Schedule 1, Table 1) by USOA account – at the same level of detail as used in Hydro One's cost allocation model (Tab I3).

b) In order to allow for such a comparison, please provide a schedule that breaks down the Hydro One Forecast Capital Expenditures (per Exhibit A, Tab 2, Schedule 1, Table 1) by USOA account – at the same level of detail as used in Hydro One's cost allocation model (Tab I3).

Response:

a) The Hydro One Forecast of OM&A and Capital cost was not based on identifying work at a USofA account level. An allocation of the PDI incremental OM&A and Capital costs to the requested USofA account level used in Tab I3 of the allocation model would not accurately reflect the work captured in the forecast amounts.

   In Attachment 1 to this response, Hydro One has provided further breakdown of the three largest Hydro One Forecast line items in Exhibit A, Tab 1, Schedule 17 Attachment 1 (Operations, Customer Care and Capital line items).

b) See part a) above.

Attachment 1

Hydro One Forecast Select Line Items	2020 Year 1	2021 Year 2	2022 Year 3	2023 Year 4	2024 Year 5	2025 Year 6	2026 Year 7	2027 Year 8	2028 Year 9	2029 Year 10
OM&A Expenditures										
Existing Customers[1]	143	352	361	371	380	390	400	410	421	431
Lines Infastructure	375	924	948	972	997	1,023	1,049	1,076	1,103	1,132
Stations	617	365	345	324	333	341	350	359	368	378
Operations	1,135	1,641	1,654	1,667	1,710	1,754	1,799	1,845	1,892	1,941
Collections	102	251	258	252	255	257	260	263	266	268
Billing	260	603	603	633	639	645	652	658	665	671
Call Center	377	919	931	940	950	960	970	981	991	1,002
Bad Debt	109	260	261	257	259	262	265	268	270	273
Customer Care	848	2,033	2,053	2,082	2,103	2,125	2,147	2,170	2,192	2,215
Capital Expenditures										
Existing Customers[1]	373	713	644	661	678	624	640	657	673	691
Lines Infastructure	621	1,530	1,569	1,609	1,651	1,693	1,737	1,781	1,827	1,874
Stations	986	3,696	1,617	1,259	1,791	3,124	1,358	1,393	1,429	1,465
Growth	616	1,513	1,549	1,585	1,623	1,662	1,701	1,742	1,784	1,826
Capital	2,596	7,452	5,379	5,115	5,744	7,103	5,437	5,573	5,713	5,856

Note:
[1] The bulk of the costs in “Existing Customers” relates to metering sustainment activities.

VECC INTERROGATORY # 26

Reference:

Exhibit A/T5/S1, page 3 (lines 6-20) and page 7 (lines 23-24)
EB-2017-0049, Exhibit C1/Tab 1/Schedule 1, page 2, Table 1

Preamble:

The Supplemental Evidence states: "The OEB's cost allocation model uses fixed assets as the primary allocator for the costs of operating and maintaining distribution assets and since Hydro One proposes to use the principles embedded within the cost allocation model to allocate all other OM&A costs (e.g., customer, and administration and general costs), Hydro One will only track PDI's incremental OM&A costs until the time that PDI is harmonized into Hydro One's rate structure."

It also states: "Hydro One cannot track, on an actual basis, either during the deferral period or after, the costs associated with certain Hydro One resources that PDI customers will enjoy the benefit of (i.e., those resources that are also required by and paid for by legacy customers). These costs, referred to as Shared Costs in Exhibit A, Tab 4, Schedule 1 (page 6 of 12) of this Application, include 17 costs that cannot be directly associated with serving a specific group of customers."

The Supplemental Evidence further states: "Included in Shared Costs are the costs associated with upstream distribution facilities used by former PDI customers (i.e. costs formerly captured under LV charges").

In EB-2017-0049, Hydro One broke its OM&A expenditures down into five major categories: i) Sustainment, ii) Development, iii) Operations, iv) Customer Care, v) Common Corporate and vi) Property Taxes and Rights Payments.

Interrogatory:

a) Other than the inclusion of "the costs associated with upstream distribution facilities", are the "Shared Costs" referred to in the Supplemental Evidence synonymous with the "Common Corporate Costs" as defined in EB-2017-0049?

b) If not, specifically what are the differences and, in particular, do Shared Costs include costs other than those considered to be Common Corporate Costs per EB-2017-0049?

c) It is noted that, in Hydro One's cost allocation model, Customer Care costs are not allocated based on fixed assets. Do the incremental costs that Hydro One has identified as being associated with PDI include any Customer Care costs (e.g. LEAP, incremental meter reading and billing costs, etc.) or are Customer Care costs all considered to be a Shared Cost?

d) If all Customer Care costs are not considered to be Shared Costs, please separately identify: i) the incremental Customer Care costs included in the PDI's Year 11 Residual Cost to Serve and what activities the costs are associated with and ii) the Customer Care activities (if any) that are considered to be part of Shared Costs.

e) Do the incremental costs that Hydro One has identified as being associated with PDI include Property Taxes and Rights Payments attributable to PDI's service area?

Response:

a) No. The two types of costs are not synonymous.

Common Corporate Costs as defined in Exhibit C1, Tab 1, Schedule 1, page 4 in EB-2017-0049 includes costs associated with common corporate functions and services (including corporate management, finance, people and culture, corporate relations, general counsel and corporate secretariat, regulatory affairs, security management, internal audit, and real estate and facilities), planning, information technology and cost of external revenues.

In Exhibit A, Tab 4, Schedule 1, page 6 of this application, Hydro One has defined Shared Costs to include: (i) shared facilities used to provide operations and maintenance services (e.g. service centres and maintenance yards), billing and IT systems, and other miscellaneous general plant; (ii) OM&A costs associated with shared services, such as planning, finance, regulatory, human resources, information technology, customer service and corporate communications; and (iii) asset and related OM&A costs associated with upstream distribution facilities used by former PDI customers (e.g. costs formerly captured under LV charges).

b) Item (ii) in the paragraph above most closely aligns with Common Corporate Costs as defined in EB-2017-0049. Parts (i) and (iii) are additional costs beyond what is included in the Distribution Rates application definition of Common Corporate Costs.

c) and d)

The incremental Customer Care costs associated with serving PDI customers include activities such as LEAP, meter reading, billing costs, collections, bad debt and any call centre operating costs forecast as needed to serve PDI customers.

The incremental Customer Care costs included in PDI's residual cost to serve for years 1 through 10 was provided at page 3 of Exhibit I, Tab 1, Schedule 17 Attachment 2. In Year 10, Hydro One Forecast customer care OM&A is approximately $2.2 million. The year 11 costs included in the Residual Cost to Serve can be derived by inflating the Year 10 forecast by 2%, resulting in approximately $2.3 million.

All Hydro One's Customer Care costs are considered Shared Costs for the purpose of cost allocation and include the cost of all customer care services.

e) Yes

VECC INTERROGATORY # 27

Reference:
Exhibit A/T5/S1, page 4 (lines 3-9)
EB-2017-0049, Exhibit G1/Tab 2/Schedule 1, pages 3-4

Preamble:
The Supplemental Evidence states: "Hydro One believes that the best way to ensure that PDI customers are charged only their costs to serve is to introduce new rate classes for them".

In EB-2017-0049 Hydro One proposed: "For a small number of customers (i.e., USL, Street Lights, Sentinel Lights and Large Users), Hydro One proposes that they be merged into existing Hydro One rate classes".

Interrogatory:
a) Is Hydro One now proposing that there would be new separate rate classes for all of PDI's existing customer classes, including its current USL, Street Lights, Sentinel Lights and Large Use classes?

Response:
a) No. Hydro One proposes that customers in the PDI Street Light, Sentinel Light and USL classes be merged with Hydro One's equivalent classes, and that PDI customers in the Large User class would be merged into Hydro One's ST class. See Exhibit I, Tab 1, Schedule 47 for a description of the new rate classes being proposed for the remaining PDI customers.

VECC INTERROGATORY # 28

Reference:

Exhibit A/T5/S1, page 5 (lines 12-14)
EB-2017-0049, VECC's Final Submissions

Preamble:

The Supplemental Evidence states: "Hydro One fully anticipates that the cost allocation process described above, and detailed in the following sections, will result in a fair and reasonable allocation of costs to the PDI rate classes that will be less than what the cost-to-serve the PDI customers would be if PDI is not acquired." (emphasis added)

Interrogatory:

a) In Hydro One's view, is there any possibility that the cost allocation methodology used at the time of rebasing will result in an allocation of cost to customers that is more than what the cost-to-serve the PDI customers would be if PDI is not acquired"?

b) If Hydro One is of the view that there is no possibility of such a result, please explain why?

c) If Hydro One is of the view there is no possibility of such a result, please reconcile this view with the cost allocation results for acquired utilities in EB-2017-0049 where the allocated costs were higher (per VECC's Final Submissions, page 76) that the stand-alone costs to serve the acquired utilities.

Response:

a) Yes, there is always that possibility. However, given the amount of savings expected from the transaction and Hydro One's proposal for cost allocation and rate design in this application, Hydro One is confident that the customers of PDI will benefit from this acquisition both in the short and long term. An estimate of the costs that would be allocated to the PDI classes is provided in Exhibit I, Tab 1, Schedule 48, and shows that the estimated Year 11 costs allocated to PDI customers would be $24.5M, which is less than the status quo cost to serve of $26.3M.

b) Not applicable.

c) See part a) above.

VECC INTERROGATORY # 29

Reference:
Exhibit A/T5/S1, page 6 (lines 14-17)

Preamble:
The Supplemental Evidence states: "This is effectively a direct allocation of locally-used fixed assets to PDI customers. In other words, the adjustment factor ensures a more accurate reflection of the fixed assets, and associated costs, required to serve PDI customers."

Interrogatory:

a) Does Hydro One accept that the OM&A costs attributed to the local assets used to serve PDI customers using the cost allocation model will differ from the incremental OM&A costs related to the same assets as tracked by Hydro One?

b) Based on the cost allocation proposed for the acquired utilities in EB-2017-0049, what were i) the incremental OM&A costs included in the Residual Cost and ii) the equivalent OM&A costs allocated to the fixed local assets attributed to the acquired utilities via Hydro One cost allocation model for the same rate year?

Response:

a) Yes.

b) i) The incremental OM&A costs included in the Residual Cost for the three acquired utilities were $10.7M[1].

ii) The Table below provides the allocated OM&A costs attributed to the three acquired utilities, consistent with the values provided in EB-2017-0049, Exhibit Q, Tab 1, Schedule 1, Attachment 3 (O1 Sheet of the Cost Allocation Model (CAM)).

[1] EB-2017-0049, Exhibit A, Tab 3, Schedule 1, Page 7 – Table 2.

Rate Class	"Direct" OM&A Costs	"Shared" OM&A Costs	Total Allocated OM&A Costs
AUR	$1.1	$1.8	$2.9
AUGe	$0.2	$0.3	$0.5
AUGd	$0.2	$0.7	$0.9
AR	$3.9	$4.9	$8.8
AGSe	$0.9	$1.0	$1.8
AGSd	$0.8	$0.7	$1.4
Combined Classes (i.e. St Lgt, Sent Lgt, USL and Woostock's GS>1,000kW)*	$0.3	$0.3	$0.6
Total	$7.4	$9.6	$17.0

** Per Response to I-56-SEC-90, part (e), EB-2017-0049*

The "Direct" OM&A shown in the Table are the amounts identified as "Distribution (di)" costs in the 'O1' sheet of the CAM. These values include the allocated OM&A costs associated with distribution fixed assets, which includes the cost of local fixed assets, as well as certain Shared Costs (e.g. OM&A associated with upstream and shared distribution facilities). The "Shared" OM&A costs shown in the table above are the amounts identified as "Customer Related Costs (cu)" and "General and Administration (ad)"in the 'O1' sheet of the CAM, and include some costs that are also part of the Residual Cost.

VECC INTERROGATORY # 30

Reference:

Exhibit A/T5/S1, pages 7-8
Exhibit I/Tab 1/Schedule 7 d)

Interrogatory:

a) Based on EB-2017-0049, what were: i) the total cost allocated to the acquired utilities customers via Hydro One's cost allocation model and ii) the Residual costs attributed to the acquired utilities customers. Please include the relevant EB-2017-0049 references for the values provided.

b) Based on the ratio of these values please estimate the total allocated costs for PDI customers in year 11 based on PDI's forecast Residual Cost to Serve.

Response:

a) i) The total cost allocated to the Acquired Utilities' customers via Hydro One's cost allocation model was $42.7M, as referenced in EB-2017-0049, Exhibit I, Tab 56, Schedule SEC 96 part e) iii). This amount includes $41.2M for the six acquired rate classes plus an estimated $1.5M for the combined rate classes (i.e. St Lgt, Sen Lgt, USL and Large Use).
ii) The Residual costs attributed to the acquired utilities customers were $25.6M as referenced in Exhibit I, Tab 56, Schedule SEC 96 part e) ii).

b) In Exhibit I, Tab 1, Schedule 48, Hydro One has produced a Cost Allocation Model (CAM) for year 11 (i.e. harmonization year). Based on the results of the CAM, the total allocated costs for PDI in year 11 are $24.5M (refer to Exhibit I, Tab 1, Schedule 48, part (b)).

Given that a CAM run has been completed specific to PDI, Hydro One does not believe the requested calculation using the ratio of the values from part a) is relevant. However, if calculated per the requested approach, the estimated total costs for PDI would be $26.0M:

PDI year 11 residual costs = $15.6M

Ratio of Allocated costs/Residual Costs for the three acquired utilities (EB-2017-0049) = 42.7/25.6 = 1.67

PDI’s year 11 allocated costs = $15.6*1.67 = $26.0M

VECC INTERROGATORY # 31

Reference:
Exhibit A/T5/S1, page 8 (lines 18-22)
Exhibit I/T1/S 8
Exhibit A/T1/S1/Appendix A, page 8

Preamble:
The Supplemental Evidence states: Hydro One fully anticipates that it will be possible to set rates for the PDI rate classes that result in an R/C ratio that both falls within the Board's approved ranges and results in an allocation of savings to both legacy and PDI customers. As discussed in Exhibit A, Tab 4, Schedule 1, Hydro One is committing to charge PDI customers no more than the higher goal post amount of $26.3M 21 and no less than their residual cost to serve of $17.0M." (emphasis added)

Interrogatory:

a) In Hydro One's view, is there any possibility that it will not be able to set rates for the PDI rate classes that result in an R/C ratio that both falls within the Board's approved ranges and results in an allocation of savings to both legacy and PDI customers? If not, please explain why.

b) Please confirm that, in accordance with the response to Staff IR #8 and lines 20-22, if achieving both objectives is not possible then Hydro One would set the rates for PDI customers such that the cost to be borne would not exceed $26.3 M (the forecast standalone cost to serve) – even if the R/C ratio results fell outside the Board's approved revenue to cost ranges. If not confirmed, how would Hydro One set the rates for PDI customers in such circumstances?

c) Navigant's review and endorsement of Hydro One's rate design proposals appears to be predicated on Hydro One recognizing and adhering to the Board's approved revenue to cost ranges. Please reconcile this premise with the response to part (b).

Response:

a) While theoretically possible, the results of the cost allocation and rate design for the PDI acquired classes provided in Exhibit I, Tab 1, Schedule 48, as well as Hydro One's experience with the proposed cost allocation and rate design of the Acquired

Utilities in Hydro One's recent Distribution Application, indicate that this is a highly unlikely scenario.

b) Confirmed, however, Hydro One's proposal would be subject to OEB approval.

c) As indicated in the response to part a), the scenario is theoretically possible, but highly unlikely.

Navigant's review was premised on both criteria being satisfied – i.e., Hydro One's rate design process resulting in rates that: (i) fall within the Board's approved revenue-to-cost (R/C) ratio range (in existence at the time); and (ii) are able to recover revenues from PDI customers that will be between the goal posts described in Exhibit A, Tab 4, Schedule 1. Navigant was not asked to assess the highly unlikely scenario posited in VECC's question.

Hydro One believes that, in the highly unlikely case posited by VECC, the rate design objective of ensuring that neither Hydro One legacy or PDI customers are harmed as a result of integrating PDI into Hydro One's rate structure would justify a temporary departure from the Board's approved R/C ratio range. As noted in Exhibit I, Tab 1, Schedule 8, Hydro One believes that this would ensure that: (i) Hydro One legacy customers do not get *more* than the total savings available as a result of the PDI acquisition; and (ii) PDI customers' rates do not collect more than the revenue that would have been collected from them had they not been acquired.

The emphasis of Navigant's evidence is not that the specific OEB R/C ratio range is the only appropriate range, but rather that: (i) allowing a utility flexibility to deviate from a R/C of 1 is an appropriate response to the imprecisions of the cost allocation process and to balance competing rate design objectives; and (b) the Board has acknowledged this, and has altered its R/C ranges over time, based on the circumstances.

VECC INTERROGATORY # 32

Reference:
Exhibit A/T5/S1, pages 8-9
Exhibit I/T4/S21 b)

Interrogatory:

a) Please confirm that the rate design proposals set out on pages 8-9 (in particular the commitment to charge PDI customers no more than the standalone cost to serve) only apply to the rebasing that will occur at the end of the 10-year deferral period and not to any subsequent rebasing applications. If not confirmed, please reconcile with the response to VECC 21 b).

b) If confirmed, what assurance does the Board and PDI customers have that the no-harm test (per PDI customers) will continue to be met in future rebasing applications?

Response:

a) In pages 8-9 of Exhibit A, Tab 5, Schedule 1, Hydro One describes its rate design proposal for the acquired customer classes. The first paragraph is Hydro One's standard process in determining rates for any of its customer classes, therefore if there is no change to OEB policies and procedures in rate design, Hydro One would expect that the principles articulated in this paragraph would be ongoing for subsequent rebasing applications.

   In the second paragraph, Hydro One confirms that the treatment with respect to the goal posts refers to the setting of rates at the time of the first rebasing.

b) The no-harm test applies at the time of the evaluation of the acquisition and it is premised upon the status quo. It is not realistic to continue to apply the no-harm test as a rate-setting feature 15-20 years into the future. There is also no basis for reliably establishing what the PDI status quo costs would have been 16 years into the future and beyond. See Exhibit I, Tab 2, Schedule 30.

VECC INTERROGATORY # 33

Reference:
Exhibit A/T5/S1, pages 10-11

Preamble:
The Supplemental Evidence states: "In the Table 2 illustration, the cost allocation model has allocated $45M to the acquired utility ($30M in residual costs to serve plus $15M in Shared Costs)".

Interrogatory:

a) In the illustrative example set out in Table 2, for those activities captured under Residual Costs, the cost allocation model is assumed to allocate costs equivalent to the Residual Costs (i.e., $30 M). Please confirm that this is simply an assumption made for purposes of the illustrative example and that, for those activities captured by the Residual Costs, the dollars allocated to the Acquired Utility by the cost allocation model could be more or less than the calculated Residual Costs. If not confirmed please explain why.

b) If confirmed, would it be reasonable to also include in the third row of Table 2 the impact of the cost allocation model treatment of Residual Costs and re-label the row – "Impact of Cost Allocation Model Treatment of Shared Costs and Residual Costs"?

c) Please confirm that the fourth row in Table 2 (Post-Consolidation Cost Allocation) is meant to reflect the cost allocation model results when applied to the consolidated utility. If not confirmed, please explain why.

d) Please confirm that the sixth row in Table 2 (Post-Consolidation Rates Revenue Requirement) is meant to reflect the results after the Status Quo Revenue Requirements for the Hydro One Legacy customers (collectively) and the Acquired Utility have been adjusted such that the R/C ratios for each class fall within the Board approved ranges. If not confirmed, please explain why.

e) Please confirm that the adjustment referred to part (d) is not an adjustment to the allocated costs as suggested by rows 4-6 in Table 2. Rather row 5 is really just the difference between the allocated costs and the revenue requirement after the adjustment referred in part (d) has been made. If not confirmed please explain why.

Response:

a) Confirmed, for illustrative purposes, the $30M cost assumption shown as Post-Consolidation Cost to Serve assumes that the Acquired Utility's residual cost to serve is equal to the dollars allocated in the cost allocation model. The dollars allocated to the Acquired Utility by the cost allocation model could be more or less than the $30M shown.

b) Confirmed, the third row does capture the combined impact of the cost allocation model treatment on Shared Costs and Residual Costs.

c) Confirmed.

d) Confirmed.

e) Confirmed. The adjustment referred to in row 5 is associated with setting the revenue to cost ratios for the rate classes and would impact the rates revenue requirement to be collected from customers.

VECC INTERROGATORY # 34

Reference:
Exhibit A/T5/S1, pages 9-12

Preamble:
Assume the following cost allocation results at the time of rebasing:

Illustrative Cost Allocation Exercise ($M)			
	Hydro One Legacy	Acquired Utility	Combined
Status Quo Revenue Requirement to be Collected from Customers	$1,000	$40	$1,040
Post Consolidation Cost to Serve	$1,000	$30	$1,030
Impact of Cost Allocation Model Treatment of Shared Costs	($15)	$15	-
Post-Consolidation Cost Allocation	$985	$45	$1,030
Impact of Setting R/C Ratio Within Board Approved Range on Rates Revenue Requirement	$3	($3)	-
Post-Consolidation Rates Revenue Requirement based on Board Approved Ranges	$988	$42	$1,030
Adjustment to Ensure No-Harm to Acquired Utility/Legacy Customers	$2	($2)	-
Post Consolidation Rates Revenue Requirement	$990	$40	$1,030
Consolidation Benefits	($10)	-	($10)

Interrogatory:

a) Hydro One Legacy is made up of a number of customer classes. Please explain how the initial adjustment to address the Impact of Setting R/C Ratio Within Board Approved Range on Rates Revenue Requirement would be allocated amongst Hydro One's Legacy customer classes (e.g., would it be allocated to just those Legacy customer classes with R./C ratios of less than 100%?).

b) How would Hydro One assign the subsequent adjustment required to Ensure No-Harm to Acquired Utility/Legacy Customers would be allocated amongst Hydro One's Legacy customer classes (i.e., would it be assigned to all Legacy customer classes or just to those with R/C ratios of less than 100%)?

c) If the response to part (b) is just those classes with R/C ratios below 100%, how can Hydro One ensure that all Legacy classes are actually benefitting from the acquisition?

d) If the response to part (b) is all customer classes, how can Hydro One ensure that the final R/C ratios will continue to all be within the Board's approved ranges?

<u>Response:</u>

a) Consistent with the approach previously approved by the Board for Hydro One when R/C ratio adjustments were required, Hydro One would propose that any R/C ratio adjustments would either shift costs to those rate classes whose R/C ratios are furthest below 100% or shift costs away from those classes whose R/C ratios are furthest above 100%.

b) See a).

c) Hydro One proposes to adjust R/C ratios as described in a), but is open to making any required R/C ratio adjustments in a manner that the Board deems most appropriate. Given that PDI's rates harmonization will happen concurrent with the rebasing of all Hydro One rate classes, the resulting R/C ratios for all classes reflect both the allocation of Hydro One legacy costs plus the PDI residual costs. As such, Hydro One believes that adjusting R/C ratios as described in part a) will minimize the cross subsidization between rate classes that is implicit in having a range of approved R/C ratios. The benefit to all Hydro One legacy classes is derived from the allocation of a portion of shared costs to the PDI acquired rate classes a part of the cost allocation model.

d) As described in part a), to the extent that R/C ratios adjustments are required, none of the adjustments to legacy class R/C ratios will result in R/C ratios outside the Board approved range. Given the relatively small amount of revenues collected from PDI acquired classes versus legacy classes, any adjustments required to the legacy R/C ratios to accommodate a shift in PDI acquired class revenues would be small.

CCC INTERROGATORY # 14

Reference:
Ex. A/T5/S1/p. 2

Interrogatory:
Please fully explain how the $9.3 million of "Savings Resulting From Hydro One's Acquisition of PDI" was derived. Is Hydro One prepared, at this time, to commit to setting rates for the PDI zone customers based on the "Total Residual Cost to Serve" upon rebasing? How will the $9.3 million of savings flow through to customers?

Response:
For a summary explaining the derivation of how the savings from the PDI acquisition were derived please refer to Exhibit I, Tab 2, Schedule 29.

As Hydro One indicated in Exhibit A, Tab 5, Schedule 1, page 11, Hydro One believes that the savings from consolidation should benefit both legacy and acquired customers. If Hydro One was to set rates for PDI customers based on the "Total Residual Cost to Serve" then Hydro One's legacy customers would not see any of the benefits of consolidation. Hydro One is not proposing this outcome; however, if the Board did decide that PDI customers should only be charged their residual cost to serve, Hydro One's legacy customers would not be harmed (i.e., 100% of the benefits of the transaction would accrue to PDI customers), as they would not incur any additional costs as a result of the transaction.

When Hydro One sets rates for customers (both legacy and PDI) after the deferral period, those rates will be determined on the *Total Residual Cost to Serve* reduced revenue requirement ($9.3M savings). The methodology for how savings can be expected to flow through to customers is provided at Exhibit A, Tab 5, Schedule 1 sections 4.0 and 5.0.

CCC INTERROGATORY # 15

Reference:
Ex. A/T5/S1/p. 2

Interrogatory:
Please describe, in detail, how Hydro One will track and report on the actual incremental, OM&A and capital costs to service PDI customers until the end of the ten-year deferral period. Please specifically define what is meant by "incremental" OM&A and capital costs? Please describe, in detail, the format in which these costs will be reported to the OEB.

Response:
Please see Exhibit I, Tab 1, Schedule 46a) for how Hydro One will track actual incremental OM&A and capital costs to serve PDI during the deferral period.

Please see Exhibit I, Tab 1, Schedule 46 for a definition of "incremental" costs.

Hydro One plans to report the actual incremental OM&A and capital costs to serve PDI by work program at the time of the next rebasing. This would be similar to that provided in EB-2017-0049 Exhibit I, Tab 53, Schedule CCC-70.

CCC INTERROGATORY # 16

Reference:
Ex. A/T5/S1/p. 3

Interrogatory:
When does Hydro One propose that PDI is harmonized into Hydro One's rate structure?

Response:
Hydro One is proposing to harmonize PDI into Hydro One's rate structure at the end of the deferral period, Year 11, which is expected to be 2030. Please refer to Exhibit I, Tab 1, Schedule 47.

CCC INTERROGATORY # 17

Reference:
Ex. A/T5/S1/p. 4

Interrogatory:
Is it Hydro One's current proposal that all acquired utilities' customers will have their own rate classes? Does this mean that they will never be harmonized with the other Hydro One rate classes?

Response:
Hydro One anticipates including PDI customers in the following new rate classes:

- Acquired Residential, which will include all customers currently in the PDI residential class
- Acquired General Service < 50, which will include all customers currently in the PDI GS <50 kW class.
- Acquired General Service >50, which will include all customers currently in the PDI GS 50 to 4,999 kW class.

Customers in the PDI Streetlight, Sentinel Light, USL and Large User classes would be merged with the respective Hydro One rate classes.

The new rate classes would come into effect when the deferred rebasing period ends (i.e. for year 11), subject to Board approval, and are anticipated to be ongoing. Hydro One believes that creating new rate classes for the PDI service territory is necessary to ensure that the rates charged to PDI residential and general service customers will appropriately reflect their cost-to-serve.

CCC INTERROGATORY # 18

Reference:
Ex. A/T5/S1/pp. 1 and 7

Interrogatory:
The evidence states that Hydro One proposes to allocate shared costs to PDI's rate classes by apply the same cost allocation principles and allocators normally used in the OEB's cost allocation model to allocate such costs. When shared costs are allocated to PDI's customers upon rebasing, how will Hydro One ensure that it will, "result in rates that collect costs from PDI customers that are less than what those customers would have paid in the absence of the proposed transaction."? How will Hydro One demonstrate this to the OEB?

Response:
Hydro One's proposal for cost allocation and rate design, as described in Exhibit A, Tab 5, Schedule 1, will ensure that costs to be collected from PDI customers are less than what those customers would have paid in the absence of the proposed transaction. This will be demonstrated by comparing the revenue to be collected from PDI customers at proposed year 11 rates, versus PDI's year 11 status quo revenue requirement. Exhibit I, Tab 2, Schedule 43 illustrates how this could translate into PDI customers' total bills.

CCC INTERROGATORY # 19

Reference:
Ex. A/T5

Interrogatory:
If significant capital requirements for the PDI service territory during the deferred rebasing period, how will those be funded?

Response:
If capital expenditure requirements incurred during the deferral period qualified under the OEB's Incremental Capital Module rate-setting mechanism, then Hydro One would apply for an ICM as discussed in the *Handbook to Electricity Distributor and Transmitter Consolidations*, page 17. PDI customers would be responsible for paying the ICM rate rider.

If the expenditures did not quality for an ICM, then those capital requirements would be funded by Hydro One's shareholder up to the time of rebasing of rates and approval of the expenditures in rate base.

CCC INTERROGATORY # 20

Reference:
Ex. A/T5/S1p. 11

Interrogatory:
The evidence discusses savings and consolidation benefits. If those savings do not materialize how will PDI's customers be better off following the deferred rebasing period?

Response:
Hydro One has no reason to believe that the savings and consolidation benefits outlined in the Application will not materialize. However, if the savings are not achieved at the level indicated in the application, Hydro One would still ensure that PDI's customers' rates revenue requirement would fall below the Status Quo goal post as shown in Table 4 of Exhibit A, Tab 4, Schedule 1. This would mean that the benefits from consolidation received by legacy customers would be less than it otherwise would have been, however legacy customers would still not be harmed.

Further, as per Exhibit I, Tab 1, Schedule 18 page 2, Hydro One is guaranteeing an ESM payment to customers of $1.8M for results expected to occur between years 6 to 10 of the deferred rebasing period. Hydro One is absorbing all of the risk of attaining the savings as provided in Exhibit A, Tab 3, Schedule 1. As a result Hydro One is highly incented to maximize these synergy savings which ultimately will form the cost levels at which PDI's service territory future rates will be set on.

Additionally, PDI customers will have other Hydro One customer centric benefits such as: extended call centre hours; Hydro One initiatives to help customers manage their bills; multi-channel outage notifications and related outage information; service guarantees; and website tools and information including e-billing and MyAccount web portal access to assist customers with bill management. For further elaboration on these benefits to PDI customers please refer to Exhibit A, Tab 1, Schedule 2.