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January 24, 2020

RESS, EMAIL & COURIER

Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Attention: Ms. Christine E. Long, Registrar and Board Secretary

Dear Ms. Long:

Re: Hydro One Networks Inc. ("Hydro One")
MAAD s. 86 Applications for Orillia Power Distribution Corporation (OEB File No. EB-2018-0270) and for Peterborough Distribution Inc. (OEB File No. EB-2018-0242)
Applicant Reply Argument

We are legal counsel to Hydro One Networks Inc. ("Hydro One') in proceeding EB-2018-0270. Osler, Hoskin and Harcourt LLP are legal counsel to Hydro One Inc. in proceeding EB-2018-0242. Please find enclosed Hydro One's Reply Argument for both the above-referenced proceedings. Copies have been filed on RESS and served on each party in the proceedings.

Yours truly,

Charles Keizer

Enclosure

cc: Hydro One
All Parties

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ONTARIO ENERGY BOARD

EB-2018-0242/0270

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c.15, Schedule B;

AND IN THE MATTER OF an application (EB-2018-0242) by Hydro One Networks Inc., 1937680 Ontario Inc., Peterborough Distribution Inc., and AmalCo, under sections 86(1)(a), 86(1)(c), 78, 18, 77(5) and 74 of the *Ontario Energy Board Act*, *1998*, as the case may be, for the relief necessary to effect Hydro One Networks Inc.'s purchase of the electricity distribution system assets of Peterborough Distribution Inc.;

AND IN THE MATTER OF an application (EB-2018-0270) by Hydro One Inc., Hydro One Networks Inc. and Orillia Power Distribution Corporation under sections 86(2)(b), 86(1)(a), 78, 18, 77(5), and 74 of the *Ontario Energy Board Act*, *1998*, as the case may be, for the relief necessary to effect Hydro One Inc.'s purchase of all issued and outstanding shares of Orillia Power Distribution Corporation, the disposition of Orillia Power Distribution Corporation's distribution system to Hydro One Networks Inc. and the transfer by Hydro One Inc. of that distribution system to Hydro One Networks Inc.

REPLY ARGUMENT OF

HYDRO ONE NETWORKS INC.

JANUARY 24, 2020

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1. INTRODUCTION

These are the reply submissions of Hydro One Inc. ("HOI"), Hydro One Networks Inc. (together referred to as "Hydro One" or "Applicants") made in respect of both of its applications (the "Applications") for leave to acquire Peterborough Distribution Inc. ("PDI") (EB-2018-0242) and for leave to acquire Orillia Power Distribution Corporation ("OPDC") (EB-2018-0270) (the "Transactions").

The Transactions are forecast to generate annual ongoing OM&A and capital savings of $7.8 million and $1.3 million for PDI and $4.7 million and $0.2 million for OPDC, resulting in $9.3 million (for PDI) and $6.5 million (for OPDC) in cost to serve savings after the deferred rebasing period. These savings will be shared by Hydro One legacy ("legacy customers") and the respective acquired customers. With respect to OPDC, legacy customers will see a $1.7 million reduction in the costs to be collected from them and OPDC customers will see a $4.8 million reduction in the costs that would otherwise be collected from them if the transaction is not approved. For PDI, legacy customers will see a $3.6 million reduction in the costs to be collected from them and PDI customers will see a $5.7 million reduction in the costs that would otherwise be collected from them if the transaction is not approved.

The evidence shows that both PDI and OPDC customers will have both lower cost structures and lower rates beyond the deferral period, together with lower rates for Hydro One legacy customers. Furthermore, as articulated throughout these proceedings, and elaborated further in this reply, Hydro One is committed to ensuring that the reliability and quality of service to the current PDI and OPDC customers will be maintained or improved. Hydro One therefore submits that the evidentiary record demonstrates clearly that the "no harm" test is satisfied and that the submissions of the intervenors in these proceedings have not provided any reasonable basis to suggest otherwise. Based on the record in these proceedings, the leave sought should be granted.

2. NO HARM TEST

The "no harm" test has been clearly articulated by the OEB in the *Handbook to Electricity Distributor and Transmitter Consolidations* (the "*Consolidation Handbook*") as follows:

> "The OEB will consider whether the 'no harm' test is satisfied based on an assessment of <u>the cumulative effect</u> of the transaction on the attainment of its statutory objectives. If the proposed transaction has a positive or neutral effect on the attainment of these objectives, the OEB will approve the application."[1] (emphasis added)

Not surprisingly, there is general agreement among OEB Staff and intervenors that this is the test to be applied. However, what is surprising is the interpretation of the test by SEC and Energy Probe. These interpretations (as discussed below) are wholly inconsistent with the test as written and also with how the test has been applied by the OEB.

The key phrase in the test as stated in the *Consolidation Handbook* is that the test is satisfied based on the "assessment of the cumulative effect" on the attainment of the statutory objectives. This means that the OEB looks at the effect of a consolidation transaction as a whole, recognizing that some aspects affect the statutory objectives more or less than others (potentially positively or negatively), but in the entirety the effect must be either positive or neutral on the attainment of the objectives. Rather than taking a holistic approach, SEC has espoused a view that the test is binary. SEC has identified a series of factors and has concluded that if Hydro One is off side on any one of those factors, then Hydro One's Applications should be denied, even if the transactions taken as a whole would have a positive or neutral effect on the OEB's statutory objectives.[2] SEC's interpretation is inconsistent with the OEB's established test and should be disregarded.

With respect to the pricing component of the "no harm test", the *Consolidation Handbook* provides:

> "To demonstrate 'no harm', applicants must show that there is a reasonable expectation based on underlying cost structures that the

[1] OEB, *Handbook to Electricity Distributor and Transmitter Consolidations* (January 19, 2016) ["*Consolidation Handbook*"], p.4.

[2] SEC Submission, para. 2.2.1.

costs to serve acquired customers following a consolidation will be no higher than they otherwise would have been."[3]

In Hydro One's previous application for leave to acquire OPDC (EB-2016-0276), the OEB was of the view that "it would have been reasonable to see a forecast of costs to service Orillia customers beyond the ten year period and an explanation of the general methodology of how costs would be allocated to Orillia ratepayers after the deferral period".[4] The OEB indicated that such information would assist the OEB in determining if there was a reasonable expectation that the underlying cost structures would be no higher than they would have been without consolidation. This is exactly what Hydro One has done in the current proceedings, i.e., providing for both the PDI and OPDC Transactions a forecast of costs beyond the 10-year period and an explanation of how costs would be allocated to the relevant customers. The evidence is that both PDI and OPDC customers will have both lower cost structures and lower rates beyond the deferral period.[5] Additionally, Hydro One legacy customers will see lower cost structures and rates.[6] Based on this evidence, the OEB should grant the leave sought.

The fact that the Transactions result in lower cost structures and lower rates for all customers is not satisfactory for Energy Probe, which attempts to further distort the "no harm" test by stating Hydro One still has not met the test – notwithstanding the fact that Hydro One has produced rates that meet the price element of the "no harm" test, and quality of service will be maintained after consolidation. Energy Probe believes that the Transactions would have an adverse effect on economic efficiency and the viability of the electricity distribution sector. There is absolutely no adverse effect on economic efficiency and the financial viability of the distribution sector as a result of this consolidation and there is no evidence on the record to suggest that there are such adverse effects. The Applications to purchase PDI and OPDC are clear – costs will be removed

[3] *Consolidation Handbook*, p. 7.
[4] EB-2016-0276 Decision and Order (April 12, 2018), p. 13.
[5] Exhibit I-1-11 (OPDC); Exhibit I-2-43 (PDI), which updated the response in I-1-1.
[6] *Ibid*.

from the electricity sector[7] to the benefit of Hydro One's legacy customers and the acquired customers in the form of lower revenue requirement relative to the status quo.[8]

As articulated throughout these proceedings, and elaborated further in this reply, Hydro One is committed to maintaining or improving the reliability and quality of service to the current PDI and OPDC customers. There will be no harm relative to these criteria and customers will also be protected through the OEB's codes and licence requirements with respect to service quality and reliability. Hydro One therefore submits that the evidentiary record continues to demonstrate clearly that the "no harm" test is satisfied and that the submissions of the intervenors in this proceeding have not provided any reasonable basis to suggest otherwise.

In fact, it is very difficult to imagine how the Transactions are not in the public interest, given the benefits of reduced cost structures, lower customer rates and Hydro One's commitments with respect to reliability and service quality.

For all of these reasons, and others as discussed in the proceedings, Hydro One has demonstrated that the Transactions meet the "no harm" test.

3. PRICE

As stated in the submissions that follow, the rates charged to the acquired and legacy customers during the deferred rebasing period are appropriate and consistent with OEB's MAADs policies. The cost structures (and the resultant rates) following the deferred rebasing period are less than they would be in the absence of the Transactions, with benefits being shared between acquired and legacy customers. OEB staff and intervenors have raised various issues with the foregoing which are addressed below. The concerns raised are not supportable based on the evidence in this proceeding and the OEB should conclude that there is no harm to either acquired or legacy customers from a pricing perspective.

[7] Such as Board of Directors, Audit Costs, Regulatory Assessment costs of addition regulatory filings, IESO settlement costs and certain administrative functions within the LDC (e.g. finance, HR, IT systems).

[8] As described in Exhibit J2.2.

3.1 Rates during the Deferred Rebasing Period

3.1.1 *Acquired Customers*

For the first five years after the closing of the Transactions, PDI's and OPDC's current Base Distribution Delivery Rates will be reduced by 1% (for residential, general service and large use customers) and frozen at that level. The 1% reduction will be implemented via a rate rider from Years 1 to 5. This rate reduction provides approximately $3.5 million worth of benefits to PDI customers and $2.0 million worth of benefits to OPDC customers over the five-year period.[9]

For Years 6 to 10 of the deferred rebasing period, rates for the PDI and OPDC service areas will be set using the OEB's Price Cap adjustment mechanism applied to each utility's last OEB-approved rates[10] as provided for in the OEB's *Report on Rate-Making Associated with Distributor Consolidation* (the "*Consolidation Policy*")[11]. In addition, PDI's and OPDC's customers will be guaranteed a cumulative $1.8 million and $3.2 million, respectively, in ESM benefits earned from Year 6 to Year 10.[12]

No party to these proceedings objects to the Applicants' rate proposal for the deferral period as it applies to PDI's and OPDC's customers. CCC agrees that the proposal will leave the acquired customers better off than under the Status Quo (non-consolidation) scenario, and OEB Staff states that the proposal is consistent with OEB policies.[13] However, OEB Staff has asked Hydro One to comment on whether an equivalent fixed (as opposed to volumetric) rate rider could be established for the residential class.[14] Hydro One has no concerns with utilizing a fixed rate rider, as suggested

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[9] See Exhibit I-1-24 (PDI and OPDC). Based on an assumed IRM increase of 1.7% and based on load forecasts provided in Exhibit I-5-18.

[10] See Exhibits A-1-1 (both PDI and OPDC) and I-1-20 (PDI).

[11] OEB, *Report on Rate-Making Associated with Distributor Consolidation* (March 26, 2015).

[12] See Exhibit A-1-1 (PDI p. 10; OPDC p. 8)

[13] CCC Submission, p.7; OEB Staff Submission, p.22.

[14] OEB Staff Submission, p. 22.

by OEB Staff. It is consistent with what Hydro One has done in its prior acquisitions (Norfolk, Haldimand and Woodstock).[15]

3.1.2 *Legacy Customers*

VECC and CCC raise a similar concern about the impact of the Applicants' rate proposals on Hydro One legacy customers during the rebasing deferral period. Essentially, their concern is that it is unfair that PDI and OPDC customers will get the benefit of services provided by Hydro One during the deferral period but those Hydro One services will be "fully funded" by legacy customers.[16]

The OEB's consolidation policies allow the acquirer in a consolidation transaction to recover their acquisition costs by deferring rebasing:

> "In general, consolidation costs may include out-of-pocket/transaction costs, acquisition premiums, and restructuring costs. Regardless of the nature, timing, or certainty of expected benefits of consolidation, the ability to retain any achieved savings for a sufficient amount of time to provide a reasonable opportunity to at least offset the costs of a transaction will be an important factor in a distributor's consideration of the merits of consolidation."[17]

The achieved savings that occur in the deferral period result from the reduction of costs (e.g. elimination of duplicate functions) in the acquired utilities. If the Transactions are approved, Hydro One will be able to retain these savings as both PDI and OPDC customers will be charged their existing rates over the deferral period (subject to price cap adjustments). Any reductions in the cost to serve these customers are allowed to be kept by Hydro One shareholders to offset the costs of the Transactions, per the OEB's policies. Until the end of the deferral period, Hydro One's legacy customers will continue to pay their rates as if the Transactions had not occurred. Hydro One will continue to provide all the services to its legacy customers that it currently does, at their current service level and cost. They will not be harmed. At the end of the deferral period, Hydro

[15] As the residential rates for these prior acquisitions transition to fully-fixed rates, Hydro One proposed a change in the original 1% rate rider to align with the new fixed-variable split, which was approved by the OEB. See evidence filed in EB-2019-0044 and the OEB Decision in that proceeding dated December 12, 2019.

[16] CCC Submission, p. 10; VECC Submission, p. 7.

[17] OEB, *Rate-making Associated with Distributor Consolidation* (July 23, 2007), p. 4.

One legacy customers will benefit by having Hydro One's fixed costs spread over a larger customer base.

Intervenors attempt to argue that legacy customers will be harmed because Hydro One staff who are currently 100% dedicated to serving these customers will, as a result of the Transactions, only be providing them 96%[18] of their efforts. This is not correct for two reasons. First, the *non-incremental* services that Hydro One staff will be providing to the acquired customers are functions that would be required regardless of whether these Transactions occurred (e.g., the preparation of financial statements, support for IT systems, etc.). These activities will require no additional effort to serve the new customers;[19] therefore, there is no impact on Hydro One's legacy customers. Second, the *incremental* costs Hydro One will incur to serve the acquired customers will be covered by the revenues collected from acquired customers at the rates that will apply to them over the deferred rebasing period (i.e., frozen rates for the first 5 years and IRM-adjusted rates for the next 5 years). To the extent that revenues collected from acquired customers over the deferred rebasing period do not cover Hydro One's incremental costs, the risk of under-recovery rests with Hydro One shareholders.

The fact that there is not a perfect match between the revenues collected from current PDI and OPDC customers and the incremental cost to serve those same customers during the deferred rebasing period is understood and deliberate. The inherent intent of the deferred rebasing period in the OEB's *Consolidation Handbook* is to incent consolidations by allowing the consolidator a period of time to recover consolidation costs.

Legacy customers will not be harmed during the deferral period. Where appropriate, the impact of serving the additional customers has been reflected in the incremental costs to serve them. All other services provided by Hydro One staff will not result in less service to legacy customers.

3.2 Rates After the Deferred Rebasing Period

Following the deferred rebasing period (i.e., commencing in Year 11), Hydro One will introduce new rate classes for PDI's and OPDC's residential and general service customers. This is to ensure

[18] SEC Submission, para. 3.2.6.
[19] Technical Hearing Transcript, Vol. 1, p. 187, and Oral Hearing Transcript, Vol. 2, pp. 183-184.

that Hydro One is able to charge the acquired customers rates based on the most accurate assessment of the cost to serve them.

In order to accurately assess the cost to serve PDI and OPDC customers, Hydro One will track the incremental capital costs of serving those customers and will maintain this tracking after the deferred rebasing period to inform ratemaking on an ongoing basis. Hydro One will also track the incremental operating costs used to serve PDI and OPDC customers during the deferred rebasing period. These tracked costs will be used to: (i) report on the costs and savings associated with serving PDI and OPDC customers; and (ii) derive Hydro One's Residual Cost-to-Serve,[20] which will inform the Year 11 rate applications for PDI and OPDC customers.

The cost allocation approach proposed by Hydro One for Year 11 uses the OEB's cost allocation model ("CAM"), and the principles embedded therein, to allocate all OM&A and asset-related costs (including all shared OM&A and asset costs) to both the acquired and legacy rate classes. The rates for all customer classes will then be set in accordance with the OEB's normal rate design process that includes moving all customer classes to within the OEB's approved revenue-to-cost ("R/C") ratio ranges.[21]

A key element of Hydro One's cost allocation proposal is the use of adjustment factors to directly allocate the costs of the local fixed assets used to serve acquired customers to the proposed new acquired rate classes.[22] A direct allocation approach is possible because PDI and OPDC customers are located in defined service areas for which Hydro One can precisely identify the cost of the fixed assets that serve these customers.[23]

In addition to collecting the residual cost to serve the acquired customers, Hydro One's proposed Year 11 cost allocation and rate design approach also sets rates for the acquired rate classes that

[20] As described in Exhibits A-4-1 of both Applications.

[21] Exhibit A-5-1, pp. 5-8; and Oral Hearing Transcript, Vol. 1, pp. 23-24.

[22] Local fixed assets refer to the assets in USofAs 1815 to 1860, which include poles, wires, transformers and distribution stations.

[23] Hydro One will know the precise amount of assets used to serve the acquired utilities at the time of integration and will track the capital additions specifically associated with serving PDI and OPDC customers over the deferred rebasing period Hydro One further proposes to continue tracking the capital additions specifically associated with PDI and OPDC in order to update the direct allocation adjustment factors at subsequent rebasing, as necessary.

will collect a portion of Hydro One's shared costs.[24] This ensures that once the deferred rebasing period ends, PDI and OPDC customers pay their share of the cost of the functions, resources and assets that are carried out or held centrally by Hydro One. The methodology used to allocate shared costs applies equally (i.e., in the exact same manner) to both the acquired and legacy rate classes and is entirely consistent with the current OEB-approved methodology for allocating such costs.[25] This was explicitly confirmed during cross-examination by OEB counsel, who asked whether the allocation of assets that were not being directly allocated (i.e., shared assets) would be "consistent" with the cost allocation methodology. Hydro One's witness confirmed that: "I would say more than consistent. It uses the exact same methodology."[26]

As shown in the responses to interrogatories I-2-43 (PDI) and I-1-11 (OPDC), and summarized below, all the rates that Hydro One forecasts it will charge the acquired customers in Year 11 are lower than what they otherwise would be if the Transactions are not approved.

Table 3-1: Forecasted Rates to be Charged for the Acquired Utilities in Year 11

	OPDC Year 11 Base Distribution Charges (per Exhibit I-1-11 for OPDC)		**PDI Year 11 Base Distribution Charges** (per Exhibit I-2-43 for PDI)	
	With consolidation	**Without consolidation**	**With consolidation**	**Without consolidation**
Residential (750 kWh)	$29.36	$50.25	$27.16	$37.67
GS< 50 kW (2000 kWh)	$73.94	$127.00	$61.55	$82.14
GS > 50 kW (250 kW)	$734.51	$1,316.50	$1,027.66	$1,508.51

Likewise, the rates to Hydro One legacy customers in Year 11 will also be lower than what they otherwise would be if the Transactions are not approved.[27]

[24] 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, 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 LV charges) (see Exhibit A-4-1, p. 6).

[25] Exhibit A-5-1, p. 7; Oral Hearing Transcript, Vol. 2, pp. 69 and 178.

[26] Oral Hearing Transcript, Vol. 2, p. 69.

[27] Hydro One legacy class rates were determined based on looking at each transaction individually. The impact on legacy class rates of integrating PDI and OPDC at the same time is not expected to materially change the combined reduction in legacy rates shown.

Table 3-2: Forecasted Rates to be Charged to Hydro One Legacy Customers in Year 11

	Hydro One Year 11 Base Distribution Charges (OPDC Transaction) (per Exhibit I-1-11 for OPDC)		**Hydro One Year 11 Base Distribution Charges (PDI Transaction)** (per Exhibit I-2-43 for PDI)	
	With consolidation	**Without consolidation**	**With consolidation**	**Without consolidation**
Residential UR (UR 750 kWh)	$42.25	$44.87	$41.44	$44.87
GS< 50 kW (UGe 2000 kWh)	$102.25	$108.84	$102.26	$108.84
GS > 50 kW (UGd 250 kW)	$3,237.03	$3,440.78	$3,238.09	$3,440.78

For the Year 11 rebasing applications, in addition to following the OEB’s cost allocation and rate design principles and practices as discussed above, Hydro One commits to ensure that the total costs to be collected in rates from the former PDI and OPDC customers would remain between: (i) the Year 11 Residual Cost-to-Serve scenario; and (ii) the Year 11 revenue requirement forecasted by PDI and OPDC under the Status Quo (i.e. non-consolidation) scenario.[28] This concept has been referred to throughout this proceeding as the “goal posts” – with the Residual Cost-to-Serve revenue requirement being the “lower” goal post, and the Status Quo revenue requirement being the “upper” goal post.[29]

The delta between the two goal posts is equivalent to the cost savings of each Transaction.

- If revenue resulting from the proposed cost allocation and rate design methodology comes in at the lower goal post, all savings from the Transactions would accrue to PDI and OPDC customers. They would pay the Residual Cost-to-Serve, so Hydro One’s legacy customers would be held harmless, but would not see any benefit from the Transaction.

- If revenue comes in at the upper goal post, all savings from the Transactions would accrue to Hydro One’s legacy customers. PDI and OPDC customers would be held harmless (since they would be paying what they would have paid anyways under a non-consolidation scenario) but would not see any benefits from the Transaction.

[28] The cost of low voltage (LV) charges would be added to both the Residual Cost-to-Serve and Status Quo revenue requirements.

[29] As described in Exhibit A-4-1, pp. 7-8.

Any amount of revenue collected from customers that falls between the goal posts results in a sharing of the benefits between Hydro One legacy customers and PDI and OPDC customers. Based on the evidence in these proceedings, Hydro One has prepared the table below. Hydro One's forecast of the revenues to be collected from the acquired customers (including an allocation of shared costs) using the OEB-approved CAM and the normal rate design process achieves exactly that outcome (Column B).

Table 3-3: Net Savings for Legacy and Acquired Customers per Hydro One's Proposed Cost Allocation and Rate Design

	A	B	C	B-A	C-B
	Residual Cost-to-Serve Acquired Customers (lower goal post)	Forecast Costs to be Collected from Acquired Customers post-rebasing	Status Quo costs that would otherwise be collected from Acquired Customers post-rebasing if Transaction is not approved (upper goal post)	Net Benefits to Legacy Customers	Net Benefits to Acquired Customers
PDI	$17.0M	$20.6M	$26.3M	$3.6M	$5.7M
OPDC	$7.9M	$9.6M	$14.4M	$1.7M	$4.8M

Notes:
1. Data in Column A from Exhibit A-4-1, Table 4 and Attachment 18 in each of the PDI and OPDC Applications.
2. Data in Column B from Exhibit I-1-49 (p. 6) for PDI and I-1-9 (p.6) for OPDC.
3. Data in Column C from Exhibit A-4-1, Table 4 and Attachment 18 in each of the PDI and OPDC Applications.

OEB Staff and intervenors have raised a number of concerns with Hydro One's proposed cost allocation and rate design approach for the post-rebasing deferral period (Year 11), each of which is discussed below.

3.2.1 *Creation of New Rate Classes*

In order to ensure that the PDI and OPDC acquired customers are charged rates that most closely reflect the cost to serve them, Hydro One is proposing to put the residential and general service PDI and OPDC customers in their own discrete rate classes. This will ensure that these customers are not overallocated costs to serve them.

SEC, and only SEC, objects to the addition of new rate classes on the basis that this would reduce administrative efficiency.[30] VECC and OEB Staff disagree.[31]

As noted by Mr. Andre during the oral hearing and affirmed by OEB Staff, this option is specifically provided for by the OEB in the *Consolidation Handbook*.[32] Further, the creation of new acquired customer rate classes will allow Hydro One to allocate to those customers the cost of fixed assets used only to serve them given the specific characteristics and available information for PDI's and OPDC's service areas (e.g. customer density, distribution system configuration, historic capital investments).

As discussed in evidence and at both the technical conference and oral hearing, creating new acquired rate classes allows Hydro One to allocate the costs to serve the acquired residential and general service customers more precisely than if they were simply put into an existing legacy rate class.[33] As shown in Table 3-4 below, putting the acquired PDI and OPDC customers into either separate rate classes that are allocated average Hydro One costs or into Hydro One's existing urban rate classes results in an over-allocation of the amount of local fixed assets required to serve them, which in turn drives an over-allocation of most OM&A and all asset-related costs. In either of these situations, acquired customers would end up inappropriately paying for the costs associated with local fixed assets (e.g. poles, wires, transformers) that are being used to serve legacy customers, and whose function does not change as a result of the integration of PDI and OPDC. The result is that the acquired customers would not be charged their cost to serve and in fact would be cross-subsidizing legacy customers.

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[30] SEC Submission, paras. 2.5.31 and 2.5.32.

[31] VECC Submission, p. 18, and OEB Staff Submission, p. 11.

[32] Oral Hearing Transcript, Vol. 1, p. 91, and *Consolidation Handbook*, p. 18.

[33] Exhibit A-5-1, p. 4; I-1-47, I-5-17 (PDI); I-1-8, I-6-10 (OPDC); Technical Conference Vol.1, pp. 190-191; and Oral Hearing Vol.1, p.92.

Table 3-4: Comparison of Known Cost-to-serve with Allocated Costs

	Total Local Fixed Assets in USofA 1815-1860 in Year 11 (2030) (in million $)		
	Assets known to be required to serve acquired customers based on data from financial reporting systems (A)	**Assets allocated by CAM if acquired customers are put into separate rate classes and allocated average Hydro One asset costs (B)**	**Assets allocated by CAM if acquired customers are merged into urban legacy classes and allocated average urban asset costs (C)**
PDI	148.8	691.0	341.1
OPDC	64.3	255.6	135.6

References:
Column (A) PDI: I-1-48, Attachment 2, Worksheet Tab 5, Cell K7
OPDC: I-1-9, Attachment 2, Worksheet Tab 5, Cell K7
Column (B) PDI: I-1-48, Attachment 2, Worksheet Tab 5, Cell O7
OPDC: I-1-9, Attachment 2, Worksheet Tab 5, Cell O7
Column (C) PDI: Undertaking J1.3 Table 3, Row C
OPDC: Undertaking J1.3 Table 1, Row C

For this reason, Hydro One believes that the need to ensure that acquired customers are only charged Hydro One's specific costs to serve them (consistent with the OEB's direction in previous acquisitions[34]) justifies establishing new acquired rate classes.

3.2.2 *Use of Direct Allocation Methodology*

SEC, CCC and VECC assert that direct allocation of costs is not typically allowed by the OEB in these types of circumstances and is not an objective way to assign costs.[35] Importantly, OEB Staff in these proceedings disagree entirely with the intervenors, stating that they accept that where costs associated with specific rate classes are known, direct allocation is appropriate.[36] Further, OEB Staff agrees that Hydro One's proposal to use adjustment factors as a proxy for direct allocation is reasonable.[37] Hydro One also disagrees with the positions of intervenors regarding the use and appropriateness of direct allocation being proposed in the Applications.

[34] Page 14 of the OEB Decision and Order dated July 3, 2014 in the Norfolk MAAD Application (EB-2013-0187) states: "Concerning the setting of future rates, it is the Board's expectation that at the time of rate rebasing HONI will propose rate classes for NPDI customers that reflect costs to serve the NPDI service area, as impacted by the productivity gains due to the consolidation." Similar statements were made in the OEB's Decision and Order of March 12, 2015 in the Haldimand MAAD Application (EB-2014-0244) and the Decision and Order of September 11, 2015 in the Woodstock MAAD Application (EB-2014-0213).

[35] SEC Submission, paras. 2.5.19 to 2.2.24, and 2.5.29; CCC Submission, pp. 4 and 10; and VECC Submission, pp. 18 and 19.

[36] OEB Staff Submission, p. 12.

[37] OEB Staff Submission, p. 12.

Surprisingly, intervenors view the proposed direct allocation of local fixed asset costs to PDI and OPDC customers as extraordinary. SEC in particular states that "what Hydro One is asking the Board to approve in this case is the use of a cost allocation approach – direct allocation – that has never been approved by the Board for any similar use".[38] As support for its extraordinarily definitive assertion, SEC relies on a submission by OEB Staff in a 2005 cost allocation consultation, which apparently "warned that distributors should exercise a high degree of caution in considering direct allocation."[39] SEC also claims that "no distributors use direct allocation to allocate fixed assets to one or more rate class, except street lighting or sentinel lighting."[40] CCC appears to agree with SEC.[41]

VECC attempts to give SEC's argument some substance, arguing that the direct allocation methodology being proposed will not directly assign costs to a specific Hydro One rate class but rather a subset of Hydro One's classes (the acquired customer classes). According to VECC, this does not meet the requirements of the OEB's 2005 Cost Allocation Methodology Report (the "2005 CA Report") which states that:

> "Direct allocation must be applied if and only if one hundred percent of the use of a clearly identifiable and significant distribution facility can be tracked directly to a single rate classification."[42]

With respect to PDI and OPDC as discrete utilities serving all of their respective customer classes as a group, 100% of the actual asset costs required to serve each acquired utility are either known or will be specifically tracked.[43] As a result, Hydro One's proposal to directly allocate those known asset costs to the acquired rate classes that cover the entire PDI and OPDC service areas is consistent with the intent of the OEB's policy in the 2005 CA Report.

As summed up by Mr. Andre at the oral hearing,

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[38] SEC Submission, para. 2.5.29.

[39] SEC Submission, para. 2.5.19.

[40] SEC Submission, para. 2.5.23.

[41] CCC Submission, pp. 4 and 10.

[42] Cost Allocation Review under EB-2005-0317, Report on "Board Directions on Cost Allocation Methodology for Electricity Distributors" (September 29, 2006), p. 31.

[43] Exhibit A-5-1, pp. 6-7 and Oral Hearing Transcript, Vol.1, p. 142.

> "when you are bringing in three new acquired classes into the mix and you know the costs associated with serving or the assets associated with serving those utilities, to me it is no longer appropriate or not the optimal solution to continue to rely on coincident peak as the allocator, particularly, as I say, since this notion of direct allocation is something that is a principle that, you know, that is recognized as a good basis for allocating costs."[44]

Furthermore, as VECC recognizes: "specifically tracking and assigning the costs to serve customers (in a number of classes) in a specific area is not without merit."[45] In this circumstance, Hydro One submits that splitting the directly allocated fixed assets for an acquired utility across the proposed acquired rate classes is appropriate because it allows Hydro One to most accurately identify the cost to serve the proposed acquired classes. The outcome is a more precise allocation of costs to serve the acquired classes, which in turn results in a more precise allocation of the costs required to serve the legacy customers.

Hydro One further submits that its proposal for direct allocation is consistent with what the OEB has previously approved for both Hydro One and other distributors in practice. In the case of Hydro One, the OEB has previously approved the direct allocation of costs for sentinel lights and settlement costs for interval meter customers, which are directly allocated to a group of four rate classes (i.e., GSd >50, UGd >50, ST and DGen).[46] Based on a review of the publicly available CAMs for a number of recently rebased distributors, the use of direct allocation has also been approved by the OEB on a number of occasions for establishing the rates of the Large User and Embedded Distributor rate classes, as well as some other rate classes.[47]

Moreover, the OEB Staff report prepared for the 2005 Cost Allocation Review consultation states:

> "Direct allocations may not prove common in practice, as more than one customer classification may make some use of the facilities in

[44] Oral Hearing Transcript, Vol. 1, p. 127.

[45] VECC Submission, p. 19.

[46] Direct allocation has been approved for Hydro One since at least 2008 when rates were set in cost-of-service proceeding EB-2007-0681, per Exhibit G2-1-1.

[47] Direct allocation to the Large User and/or Embedded Distributor classes was approved for Energy+ (EB-2018-0028), Essex Powerlines (EB-2017-0039), ELK (EB-2016-0066), Powerstream (EB-2015-0003), Entegrus (EB-2015-0061) and Toronto Hydro (EB-2014-0116). The proceedings referenced for Toronto Hydro and Entegrus also include direct allocation to a number of other rate classes, including residential and general service classes.

> question. ... To prepare and review direct allocations will take time and effort and therefore is not encouraged for items that a distributor considers insignificant."[48] (emphasis added)

In Hydro One's experience, it normally would take considerable time and effort to directly allocate costs – and in most cases, is not even possible. That is not the case for PDI and OPDC. This is because the process of integrating them into Hydro One's financial reporting systems separately tracks their fixed asset costs at the time of integration. Also, Hydro One has committed to track capital (i.e., fixed asset) additions related to the acquired utilities going forward. Consistent with the 2005 Staff Report, the issue of correctly allocating the cost to serve the acquired utilities is a significant item that merits the time and effort required to develop the adjustment factors that directly allocate costs to the proposed acquired customer rate classes.

It is Hydro One's position (and also Navigant's[49] and OEB Staff's[50]) that the direct allocation of costs to the acquired customers of PDI and OPDC is an appropriate way to allocate costs in these circumstances, because the information is available and it allows for rates to those customers to more accurately reflect the costs to serve them. As noted in the supplemental evidence from Navigant:

> "Direct assignment is always the preferred approach for attributing costs to customer classes and should be used where a direct link can be made between costs and the service provided to specific customers. However, usually only a small percentage of a utility's costs can be directly assigned because most costs are incurred by a utility to jointly serve many classes of customers. Costs that cannot be directly assigned, such as joint or common costs, are allocated."[51]

Hydro One's proposed direct allocation approach produces a more accurate result, and it is only appropriate that it be done.

[48] Cost Allocation Review under EB-2005-0317, Staff Report dated June 28, 2006, p. 27.
[49] Supplemental Evidence Exhibit A-5-1, Appendix A, p. 3.
[50] OEB Staff Submission, p.12.
[51] Supplemental Evidence Exhibit A-5-1, Appendix A, p. 3.

3.2.3 *Cost Causality in Hydro One's Cost Allocation Proposal*

SEC argues that the cost allocation approach (and utilization of the goal posts) violates the primary rate-setting principle of cost causality, because it gives Hydro One discretion to allocate the cost savings of the Transactions between acquired customers and Hydro One legacy customers.[52]

This is not what is happening, or what Hydro One has proposed. At no point will Hydro One "allocate" any savings from the Transactions. Past the deferred rebasing period, Hydro One will allocate all costs (including shared costs) across both legacy and acquired customers and will do so in accordance with the OEB's cost allocation principles. The rates will then be set following the OEB's normal rate design practice. The cost allocation and rate design approach proposed affords Hydro One zero discretion to allocate the savings.

When SEC suggested at the oral hearing that Hydro One was giving preferred treatment to PDI and OPDC customers, Mr. Andre's response was clear:

> "MR. ANDRE: I wouldn't characterize it as a preferred position. In all cases we're using the Board's cost allocation model that allocates shared costs, common costs, direct OM&A costs, all of the costs are allocated across all rate classes on the same basis.
>
> The only distinction is that for those acquired utilities we're able to identify the specific assets associated with serving them, and therefore we're building that into the model and then letting the model flow the way it would normally flow in terms of allocating costs across all rate classes.
>
> So I don't know if I would characterize them as preferred. I mean, the acquired customers are unique to some extent. We've been given specific direction that to make sure that the costs that we charge them reflect their costs to serve in the MAADs decisions -- in the previous MAADs decisions, rather, and we're trying, you know, as best as possible to do that, to accurately reflect the costs to serve."[53]
> (emphasis added)

The amount of savings that will accrue to legacy and acquired customers will be driven entirely by the output of the OEB-approved CAM and the normal rate design process. It is not a matter of

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[52] SEC Submission, paras. 1.4.2(b), 2.2.1(b) and 2.4.1 to 2.4.3.

[53] Oral Hearing Transcript, Vol.1, p. 137.

Hydro One exercising any discretion and picking a revenue requirement to be collected, or savings amount, between the goalposts.

If anything, utilizing a direct allocation methodology for the fixed assets required to serve PDI and OPDC customers will enhance the principle of cost causality – by ensuring that the cost of the local fixed assets used by PDI and OPDC customers are recouped specifically, and only, from those same customers. As noted during the oral hearing:

> "MR. ANDRE: Direct allocation is not a socializing of costs, it is the exact opposite. It is identifying the specific assets associated with serving OPDC and PDI, so it is the antithesis of socializing. It is saying, no, we specifically know the assets required to serve you. We're going to identify those assets and then use the Board's cost allocation principles that say, given an amount of assets, <u>how much OM&A should you be paying associated with those assets, how much shared costs should you be paying associated with those assets, how much net income and interest costs should you be paying associated with those assets</u>, and it is doing that, <u>as it does for all other classes</u> within the model.
>
> MR. SHEPHERD: So then you are not going to socialize any costs to the PDI and OPDC customers.
>
> MR. ANDRE: We're socializing all of the <u>shared costs</u> and all of the <u>upstream distribution costs</u>, so <u>all of the costs that are not directly allocated will be socialized, just like it is for all classes within the model</u>."[54] (emphasis added)

In summary, contrary to SEC's assertions: (i) Hydro One has no discretion in the cost allocation methodology being proposed in these Applications; and (ii) a direct allocation approach results in greater (not less) cost causality for <u>both</u> acquired and legacy customers.

3.2.4 ***Purpose-Driven Approach to Cost Allocation***

SEC, CCC and to some extent OEB Staff, suggest that the specific cost allocation and rate design approach being proposed is purpose-driven – i.e., that the methodology is being proposed to keep rates to the acquired customers low in order to get the Transactions approved.[55] SEC alleges that

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[54] Oral Hearing Transcript, Vol. 1, p. 151.

[55] SEC Submission, paras 2.1.4, 2.4.5, 2.4.8, 2.4.13 and 2.5.29; and CCC Submission, pp. 4 and 10.

Hydro One is proposing this "special" cost allocation approach in order to get the Transactions approved, and that Hydro One is "in effect putting their thumb on the scale to ensure that cost allocation gets between the goal posts".[56]

The foregoing is a mischaracterization of the approach proposed and a serious allegation that is plainly not true. There is nothing special about Hydro One's approach to cost allocation in these Applications – as noted above, it is meant to be responsive to previous OEB direction and enhance the principle of cost causation in the acquired customer rates. Normally, only a small percent of a utility's costs can be directly assigned because most utility assets jointly serve many classes of customers. While direct allocation, as discussed in Section 3.2.2 of this reply, is not frequently used, that has more to do with the practicalities of actually being able to do it.

SEC alleges that Hydro One has intentionally expanded the types of assets to be directly allocated to the acquired customers in an effort to make the cost allocation proposal purpose-driven:

> So, first Hydro One said they would directly allocate poles and wires and things in that general category. They ran into a problem with that, because the rates for acquired customers were still too high relative to status quo. Then, they added distribution stations and related assets, which they think brings the costs allocated to the acquired customers down below status quo. Just to be on the safe side, they have now changed the allocation of upstream assets to further reduce the costs allocated to the acquired customers.[57]

This is a serious allegation, and also untrue. As SEC knows from its participation in the EB-2017-0049 proceeding, the rationale for the inclusion of stations was fully explored in Hydro One's last distribution rate proceeding, and no principled concerns were raised with the underlying rationale for directly allocating the cost of stations used to serve customers within the acquired service areas.[58] The direction allocation of stations also came up at the oral hearing, when Panel Chair Spoel questioned Mr. Andre about the rationale for directly allocating station costs in the Norfolk, Haldimand and Woodstock cases. In response, Mr. Andre explained that without direct allocation,

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[56] SEC Submission, para. 2.4.5.

[57] SEC Submission, para. 2.4.9.

[58] As evidenced by the summary of intervenor arguments provided in the OEB Decision and Order in EB-2017-0049, pp. 151-159.

the acquired customers in those three service areas would have been allocated $48.4 million in station costs, as opposed to the $17.4 million in costs for the stations actually required to serve them.[59] This would have meant that $31.0 million in stations being used to serve legacy customers would have actually been cross-subsidized by the acquired utility customers if stations were not directly allocated.[60]

The rationale for refining the methodology to determine the upstream distribution assets included in the direct allocation adjustment factors was discussed in the pre-filed evidence, at the technical conference, at the oral hearing, and in an undertaking in this proceeding.[61] Undertaking J1.2 showed that the refinement made to the allocation of upstream distribution assets had no impact on the allocation of costs to OPDC, since 100% of their load is supplied through upstream distribution assets. However, for PDI, this refinement appropriately reduces the upstream distribution assets allocated to PDI to account for the fact that only 49% of PDI's customer load flows through upstream distribution facilities, with the balance of the load being supplied from transmission stations located within their service area, to which PDI's distribution facilities are directly connected (i.e., upstream distribution assets are not required to supply 51% of PDI's load).

It should be noted that none of the intervenors, besides SEC, raised concerns with the propriety of directly allocating station assets or the methodology for determining and adjusting the upstream distribution assets to be directly allocated.

The rationale for directly allocating stations and upstream distribution facilities are grounded on well-founded cost allocation principles and intended to ensure that acquired customers only pay costs commensurate with the amount of assets actually being used to serve them. SEC's characterization that Hydro One's proposals are intended to achieve a pre-defined outcome is baseless.

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[59] Oral Hearing Transcript, Vol. 1, pp. 85 to 86.

[60] *Ibid*.

[61] Exhibit A-5-1, p. 8; Technical Conference Transcript, Vol. 1, p. 89; Oral Hearing Transcript, Vol.1, pp. 24-25 and 85-86; and Undertaking J1.2.

3.2.5 *Fairness of Cost Allocation to Legacy Customers*

SEC, CCC and VECC argue that the cost allocation proposals are unfair because they treat "like customers" unequally – specifically, Hydro One legacy customers in urban areas will not benefit from a direct allocation methodology (and resultant lower rates).[62] OEB Staff simply states that this issue will need to be addressed at the first rate application after rebasing.[63]

In apparent support for its position, SEC cites the fact that Hydro One proposes to charge the PDI and OPDC acquired customers lower rates than what it charges its urban rate classes, whose rates were derived on the basis of a Density Study and were recently affirmed in Hydro One's last distribution rates proceeding (EB-2017-0049).[64]

Hydro One firmly believes that its proposed cost allocation and rate design approach is fair to all customers, and the submissions of the intervenors should be rejected.

First, the cost allocation principles being proposed are, in Hydro One's view, fully compliant with OEB policies and practice. As noted above, while direct allocation is the preferred approach for attributing costs to customer classes, it is not possible without information about the specific assets used to serve those customer classes. As Mr. Andre indicated at the technical conference, the information required to directly allocate costs to a subset of Hydro One's legacy customers (e.g., to create a "Smith Falls" rate class) is simply not available.[65] Any attempt to identify the "specific" asset costs associated with serving a subset of Hydro One's legacy classes would be an *allocation* process, not a direct assignment, and would therefore not meet the requirement of the OEB's 2005 CA Report which states that direct allocation should only be used when "clearly identifiable and significant distribution facility can be tracked directly".[66] This is simply not possible for any sub-region within Hydro One's existing service territory. However, as noted above, the acquired customers are in a different circumstance that permits direct allocation. It is also important to note

[62] SEC Submission, paras 2.5.1 to 2.5.16; CCC Submission, pp. 4 and 10; and VECC Submission, p. 19.
[63] OEB Staff Submission, p.12.
[64] SEC Submission, paras. 2.5.6 to 2.5.9.
[65] See Technical Conference Transcript, Vol. 1, pp. 85-86, and the responses to interrogatories I-2-11 and I-2-33 (PDI) and I-2-27 (OPDC).
[66] Cost Allocation Review under EB-2005-0317, Report on "Board Directions on Cost Allocation Methodology for Electricity Distributors" (September 29, 2006), p. 31.

that by ensuring that the amount of local fixed assets known to be required to serve the acquired utilities are appropriately allocated to them, by definition, the remaining fixed assets are exactly the amount of fixed assets required to serve all legacy customers as a group (i.e. effectively, the legacy classes as a group are being "directly allocated" their fixed assets).

Second, SEC's understanding and characterization of the Density Study are incorrect. SEC's mischaracterization of the Density Study is discussed in detail in Section 4.3.3 of this reply, but some points relative to the issue of fairness will be covered here. The Density Study, which underpins the density factors used to set Hydro One's urban rates, did not review actual costs to serve urban areas relative to non-urban areas, nor did it test the results using a form of direct allocation, as SEC suggests.[67] As such, Hydro One's approved urban rates are based on an allocation process that includes density factors that improve the allocation of costs across all of Hydro One's density-based classes, but the urban rates still do not reflect the actual direct cost of serving the wide range of urban areas in Hydro One's service territory.[68] The simple fact that Hydro One's urban class rates are different than the proposed rates for the acquired classes does not mean that legacy customers are being treated unfairly or "unequally". Both sets of rates are based on using the OEB's cost allocation principles and rate design policies, the only difference being that density factors are used to reflect the cost of serving the wide range of urban areas included in Hydro One's legacy class, whereas the PDI and OPDC acquired class rates reflect the fact that the amount of local fixed assets required to serve them are known and can be directly allocated. If, as SEC believes, the allocation of costs to legacy customers should be modified, the proper forum to address that issue is at Hydro One's next rebasing application. This is in line with OEB Staff's submission.

3.2.6 *Fairness of R/C Ratio Adjustments to Legacy Customers*

VECC and OEB Staff take issue with the proposal to adjust R/C ratios, if necessary, to bring the revenues to be recovered from the acquired classes back within the goalposts.[69] Specifically, VECC states that if R/C ratios for the acquired customers are lowered outside the OEB-approved

[67] SEC Submission, para 2.5.9.
[68] Oral Hearing Transcript, Vol.1, pp. 139 and 158-159.
[69] VECC Submission, pp. 20 to 22.

R/C ratio ranges as a result of any goal post-related adjustments, Hydro One has not set out how it proposes to recover those costs (i.e., which customer classes will see an increase in their R/C ratio or by how much). Further, VECC states that if such recovery becomes necessary, Hydro One's shareholders (and not legacy customers) should be responsible for any revenue shortfalls.[70]

As the evidence shows, Hydro One anticipates that it will be able to set the R/C ratios for the PDI and OPDC acquired rate classes within the OEB-approved R/C ratio ranges.[71] The need for a R/C ratio adjustment under the theoretical situation where the proposed revenue requirement to be collected falls outside the goal posts was discussed during the technical conference, at the oral hearing and in interrogatories.[72] Given the fact that the costs Hydro One proposes to collect from the acquired customer classes fall well within the goal posts, as shown in Table 3.3, Hydro One believes it is highly unlikely that the situation raised by VECC would arise. However, if it did, at the oral hearing Hydro One discussed that it would likely adjust the R/C ratios for those classes who are furthest away from a ratio of 1.0[73] in a manner consistent with its past practice for making such adjustments, and which has been approved by the OEB on numerous occasions.[74] Hydro One suggests that the same approach would apply here; however, that would be subject to review and approval by the OEB panel in a future rate proceeding.

With regards to VECC's concern that any reduction made to the acquired classes' R/C ratios in the initial rebasing year to levels below the OEB-approved ranges would be eliminated in subsequent years, Hydro One submits that any subsequent adjustments to R/C ratios for the acquired classes (as with all classes) would be done in accordance with approved OEB policy at the time and in a manner that mitigates customer bill impacts, all of which would be subject to OEB approval in a future rate proceeding.

[70] VECC Submission, pp. 21 to 22.

[71] See Exhibits I-1-49 (PDI) and I-1-10 (OPDC).

[72] Technical Conference Transcript, Vol. 1, pp. 94-95 and pp. 193-195; Oral Hearing Transcript, Vol. 1, pp. 57-58 and 130; and interrogatories I-1-8 (PDI) and I-2-21 (OPDC).

[73] Oral Hearing Transcript, Vol. 2, pp. 133-134.

[74] Most recently in EB-2017-0049 associated with brining the DGen rate class R/C ratio within the OEB-approved range, and also in EB-2013-0416 for adjusting the R/C ratios across a large number of rate classes.

Hydro One notes that it makes further submissions with respect to the recovery of costs associated with needing to move R/C ratios outside the OEB-approved ranges in Section 7 (Conditions) below.

3.2.7 *Cost Allocation Flawed: Outdated Data and a Single Adjustment Factor*

VECC takes the position that the cost allocation approach is flawed because the direct allocation to individual acquired rate classes will rely on outdated data.[75] Further, VECC suggests that the direct cost allocation approach should include specific adjustment factors for each account in the Uniform System of Accounts.[76]

Hydro One submits that the splitting of the directly allocated costs across the acquired customer rate classes on the basis of the existing PDI and OPDC cost allocation results will cause the least disruption to the acquired customers' existing rates. This is because any changes in rates at the Year 11 rebasing will only be driven by Hydro One's rates proposal and not by changes in the relative amount of assets historically used by each of the acquired classes arising from an update of rate class load shapes.

In response to the concern VECC had previously raised in its EB-2017-0049 submission regarding the use of a single direct allocation adjustment factor per rate class instead of an account specific adjustment factor, Hydro One submits, as it did in the EB-2017-0049 case, that its use of a single adjustment factor for the gross fixed assets in USofAs 1815 to 1860 is intended to directly allocate the fixed asset costs in a manner that would be relatively simple to implement within the CAM and readily understandable to the OEB and intervenors. More importantly, the use of a single direct allocation adjustment factor for USofAs 1815 to 1860 eliminates the potential for

[75] On page 19 of the VECC submission they note that the split of directly allocated costs across the acquired rate classes is based on PDI's and OPDC's cost allocation in their last rebasing applications (i.e., 2013 for PDI, and 2010 for OPDC).

[76] VECC Submission, p. 19.

inaccuracies that arise due to differences in how individual utilities report their amount of fixed assets by specific USofA accounts.[77]

3.2.8 *Cost Allocation Proposals Unchanged*

SEC and CCC suggest that the cost allocation and rate design proposals in these Applications are unchanged from the proposals rejected by the OEB in EB-2017-0049.[78] As noted in Hydro One's response to VECC interrogatories,[79] two important changes have been made to the CAM in response to the EB-2017-0049 proceeding:

- 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 is important since it will ensure that PDI and OPDC rate classes are only assigned upstream distribution costs consistent with the extent to which upstream distribution facilities are used to supply the PDI and OPDC service areas.

- 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.

Beyond the concerns raised by the OEB in its EB-2017-0049 Decision and Order related to the use of direct allocation adjustment factors, addressed by the changes referenced above, Hydro One has also in these proceedings responded to other issues raised in the EB-2017-0049 Decision. Hydro One addressed each of the individual concerns raised by the OEB in EB-2017-0049 in the response to VECC interrogatory I-4-24; and one of the key differences is that as part of these proceedings, Hydro One has provided significantly more evidence on its cost allocation and rate setting approach post-deferral, including:

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[77] An example of the differences that can exist in how distributors record amounts in individual USofAs is demonstrated in Exhibit I-1-48 , Attachment 2, Tab 5 (for PDI) and Exhibit I-1-9, Attachment 2, Tab 5 (for OPDC) which illustrate that PDI records significant amounts in USofAs 1830 and 1845, whereas OPDC show no costs associated with those USofA accounts.

[78] SEC Submission, paras. 1.1.5 and 2.4.6; and CCC Submission, p. 4.

[79] Exhibit I-4-24 (PDI).

- the rationale for creating separate rate classes;
- additional detail on the direct allocation adjustment factors, including the principles underlying the proposal to directly allocate fixed asset costs to the acquired customer rate classes and the importance of direct allocation in accurately reflecting the cost to serve the acquired classes; and
- details on the commitment to ensure that costs to be collected from acquired customers, at a minimum recover the Residual Cost-to-Serve (incremental revenue requirement) attributable to the acquired customers, and at a maximum do not recover more than the costs they would have to pay under a Status Quo scenario (i.e., the “goal post” commitment).

While the items noted above do not represent a significant departure from what was proposed in EB-2017-0049, as noted by Hydro One during the oral hearing[80]:

> “MR. ANDRE: So, you know, in developing the evidence for 0049, I think there was a lot that we didn't appreciate in terms of the arguments that would need to be made.
>
> So the fundamentals are largely the same. We have made some improvements to the cost allocation model, to the tracking of the adjustment factors in the future. So we have made those improvements.
>
> In fact, in interrogatory VECC I-4-24, we go through each of the points that the Board raised.
>
> So I would encourage everyone to go and read that IR, because we address each of the points that the Board made. And I concede in there we didn't do as good a job laying out the case for, you know, why we were doing what we were doing.
>
> As an example, for rate classes, we basically said we're creating these rate classes because it is absolutely necessary in order to achieve what the Board told us to do.
>
> We didn't really expand on that, in terms of the reasoning. We didn't expand on the fact that, you know, the Board recognizes that

[80] Oral Hearing Transcript, Vol.1, pp. 108-109.

> creating new rate classes is appropriate. That wasn't in our original evidence. That came up later in Q1-1.
>
> So the fundamentals didn't change, but we didn't -- I will be frank, because it was my evidence. We didn't do a good enough job of explaining the basis for our proposals and the rationale for those proposals.
>
> MR. SHEPHERD: Okay. So it sounds like what you're saying, Mr. Andre -- and we talked about this at the technical conference. In fact, just in case you were denying that, I was -- I had it in here just in case. But you didn't. It sounds like what you are saying is the Board got it wrong in 0049. We were right, they were wrong, but it was our fault because we didn't explain it right. Is that what you are saying?
>
> MR. ANDRE: No, I'm not saying the Board got it wrong. I am saying the Board made its decision based on the evidence that was presented, and the way that evidence was presented somewhat piecemeal in Exhibit Q1, that was filed later in interrogatories, et cetera, didn't provide a sufficient and complete picture of our proposal.
>
> The goalposts, for example, is something that in our final argument we touched on the costs are going to fall between these two numbers, but that notion of ensuring that you have those goalposts to make sure that acquired customers, you know, at least pay their revenue requirement that they incur, that they drive, and at most pay the costs that they would have paid had they not been acquired, that concept, for example, wasn't front and centre in our 0049 application." (emphasis added)

In summary, Hydro One has made two specific changes to the CAM from EB-2017-0049, but more importantly, Hydro One has provided significantly more detail and explanations of how it expects to set rates for PDI and OPDC after the deferral period, which address the other issues raised in the EB-2017-0049 Decision.

4. COST SAVINGS TO CUSTOMERS

4.1 Introduction

The evidence before the OEB in these proceedings clearly demonstrates that the Transactions will lead to operational synergies and lower ongoing cost structures when compared to the Status Quo scenarios.

With respect to the acquisition of PDI, the Applicants have forecast significant reductions to OM&A and capital expenditures attributable to the Transactions. For example, in Year 10 following consolidation (2029), the OM&A and capital expenditure savings are forecast to be $7.8 million and $1.3 million, respectively.[81] With respect to the acquisition of OPDC, the Applicants have forecast OM&A and capital expenditure savings in Year 10 of $4.7 million and $0.2 million, respectively.[82] These savings are for Year 10 alone, and do not include the savings in Years 1 through 9, or the cost savings after Year 10, which are anticipated to persist.

These forecast savings are reflected within the comparison of: (i) PDI's and OPDC's "Status Quo" revenue requirement forecasts to operate their distribution businesses (as stand-alone distributors); versus (ii) Hydro One's revenue requirement forecasts of the incremental costs to operate PDI's and OPDC's distribution systems once integrated within Hydro One (the "Residual Cost-to-Serve" forecasts).

OEB Staff and VECC accept that there are likely to be capital and OM&A cost savings as a result of the Transactions achieved by eliminating duplicated services and the artificial boundaries between the distribution systems of Hydro One and the acquired utilities.[83] SEC fails to concede even the obvious – that reducing duplication of personnel, equipment and functions will inevitably lead to cost savings. CCC is largely supportive of SEC's arguments.

OEB Staff and intervenors question the accuracy of the Status Quo and Residual Cost-to-Serve forecasts and, to varying degrees, suggest that PDI and OPDC's Status Quo forecasts are too high

[81] Exhibit A-2-1, p. 2.
[82] Exhibit A-2-1, pp. 1-2.
[83] See OEB Staff Submission, p. 14, and VECC Submission, pp. 10-11.

and Hydro One's Residual Cost-to-Serve forecasts are too low. They argue that this results in the forecast cost savings of the Transactions being overstated.

Hydro One's response to OEB Staff and intervenor submissions on these points is set out below. PDI and OPDC, in their reply submissions, will also address OEB Staff's and intervenors' arguments that their Status Quo cost forecasts are too high.

4.2 Evidence of Cost Savings

The Applicants have comprehensively outlined the detailed methodology, assumptions and cost breakdowns that underpin the derivation of the relevant capital and OM&A forecasts, which provide a sound basis for comparison and analysis for the purpose of the two Applications.[84]

Hydro One, PDI and OPDC have each provided a 10-year projection of OM&A and capital expenditures, as set out below.[85]

Table 4-1: Projection of Cost Savings – PDI Transaction

	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	9.7	9.9	10.1	10.3	10.6	10.8	11.1	11.4	11.7	12.0
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	**1.0**	**5.4**	**5.8**	**6.5**	**6.7**	**6.9**	**7.1**	**7.3**	**7.5**	**7.8**
Capital										
Status Quo Forecast	6.2	6.4	6.0	6.2	6.4	6.5	6.7	6.9	7.0	7.2
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**	**(1.1)**	**0.6**	**1.1**	**0.7**	**(0.6)**	**1.3**	**1.3**	**1.3**	**1.3**

[84] For example, see Exhibit I-1-17, Attachment 2, p. 2 (PDI), Exhibit I-1-19 (OPDC), and JT1.8, JT1.9, and JT2.11 (PDI and OPDC).

[85] Exhibit A-2-1, Table 1 (PDI and OPDC).

Table 4-2: Projection of Cost Savings – OPDC Transaction

	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	5.5	5.7	5.8	5.9	6.0	6.1	6.2	6.4	6.5	6.6
Hydro One Forecast	4.1	2.0	2.1	1.7	1.7	1.7	1.8	1.8	1.8	1.9
Projected Savings	**1.4**	**3.7**	**3.7**	**4.2**	**4.3**	**4.4**	**4.4**	**4.6**	**4.7**	**4.7**
Capital										
Status Quo Forecast	3.2	4.3	1.5	1.8	2.8	2.8	2.9	3.0	11.1	3.2
Hydro One Forecast	3.4	2.4	2.4	2.5	2.6	2.8	2.8	2.9	2.9	3.0
Projected Savings	**(0.2)**	**1.9**	**(0.9)**	**(0.7)**	**0.2**	**0.0**	**0.1**	**0.1**	**8.2**	**0.2**

The pre-filed evidence of the Applicants was supplemented throughout the proceedings, via responses to interrogatories, undertakings, and at the two-day technical conference and two-day oral hearing, which provided additional evidence from the Applicants to support the forecast revenue requirements and projected cost savings.

On Day 1 of the oral hearing, Hydro One went through its methodology to forecast OM&A and capital costs for PDI and OPDC in detail. Hydro One explained that it derived these forecasts using a similar methodology to that used to forecast costs for its entire distribution system – looking at each investment area, then incorporating distributor-specific characteristics to come up with an average cost per demographic to apply to PDI and OPDC. Both PDI and OPDC explained how they derived their forecast.[86]

4.3 Hydro One Current Cost Levels

In its submission, SEC requests that the OEB not only deny the current Applications, but also that it direct Hydro One to "stop trying to acquire other distributors".[87] Leaving aside the ability of the OEB to grant the latter relief, the true basis of SEC's argument relies on an assumption that Hydro

[86] For OPDC, see Technical Conference Transcript, Vol 1, pp. 26, 126-128; Vol 2, pp; 116, 131,144-146.
For PDI, see Technical Conference Transcript, Vol 1, pp. 2, 3, 29, 116-117, 131; Vol 2, pp. 86-87, 151, 153.

[87] SEC Submission, para. 2.7.2.

One will always be a higher cost utility than any distributor it acquires, and therefore that no Hydro One acquisition will ever yield cost savings. SEC attempts to justify its position by parsing data points in an attempt to show that Hydro One's current costs and rates on a per customer basis (overall and urban) are higher than other distributors.[88] SEC further argues that the most recent PEG benchmarking report confirms SEC's position, as does Hydro One's own Density Study.[89] OEB Staff and other intervenors do not make similar arguments – nor do they appear to support SEC's extraordinary request.

Hydro One's reply to these points is set out below, along with a brief discussion of SEC's "diseconomies of scale" submission. However, at the outset Hydro One submits that SEC's above noted conclusions and the accompanying analysis are incorrect and should be disregarded. SEC's sole focus is to attack Hydro One's credibility and its acquisition efforts no matter what and without full regard to the facts related to the particular two transactions in question. The only relevant cost information related to the disposition of these Applications is the forecasted cost to serve the acquired utilities' customers (and legacy customers) based on the rate proposals in these Applications. The arguments of intervenors regarding benchmarking, or how Hydro One's average costs or urban rates compare to other utilities is, in Hydro One's view irrelevant. Nevertheless, in the event the OEB disagrees, we have offered our reply submissions to each.

As the OEB itself acknowledges, the outcomes of past acquisitions are irrelevant for the purposes of determining whether the specifics of these particular Transactions satisfy the "no harm" test. The arguments made by intervenors as to existing cost and rate comparators between Hydro One and other utilities is also not relevant – because they indicate nothing about the impact of the proposed Transactions (and corresponding rate proposals) on PDI, OPDC or legacy customers.

4.3.1 *SEC's Cost per Customer Comparison*

SEC references certain Hydro One-wide rates and revenue information to support its position that Hydro One is a "high cost" utility, before making the leap to suggest that this means Hydro One should never acquire another utility and could never serve it at a lower cost. This, of course, ignores

[88] SEC Submission, paras. 1.3.5(a), 1.3.8(c), 2.3.2(b), 2.3.52, and 2.3.54 to 2.3.59.
[89] SEC Submission, paras. 2.3.2(b), 2.3.58 to 2.3.61, and 2.3.64.

the specifics of the acquired distribution system being purchased and of any particular rate proposal being made as part of the Applications.

As the OEB knows, Hydro One serves a sparsely populated, largely rural territory. Hydro One's distribution system consists of over 123,000 km of distribution lines serving 1.3 million customers, spread out over 950,000 km^2 of service territory.[90] Moreover, a significant proportion of Hydro One's customers are located in parts of the province that present challenging construction and maintenance conditions (e.g., remote locations, Canadian Shield, highly forested areas, areas that are frequented by storms, etc.).

Hydro One's distribution system also serves close to 50 embedded distributors at more than 300 connection points to the distribution system. As a result, a significant portion of Hydro One's costs and revenue requirement are associated with assets that are in fact used to serve the customers of embedded distributors. Thus, in SEC's comparison of revenue per customer, the costs associated with serving embedded distributor's customers actually show up as Hydro One costs of serving their own customers. As such, any revenue comparison, to be fair, should exclude the cost of providing distribution service to other utilities and their customers. Moreover, those costs (of the upstream distribution facilities used by embedded distributors), which SEC currently includes in the distribution revenue per customer figure for Hydro One, should be transferred to the distribution revenue per customer figure for embedded distributors.

Given these factors, it is not surprising that Hydro One's average cost, or revenue, per customer, would appear to be higher than other distributors. That should be expected. But SEC's figures are incorrect – the difference is not what they assert – and is, in any event, irrelevant in the context of the specific rate proposals in these Applications.

With respect to SEC's attempt to restrict the comparison to Hydro One's urban rate classes and the rate classes of other "urban" distributors, SEC again attempts to compare figures that in Hydro One's view, are not directly comparable. There are several reasons for this, but the primary reason is that the comparison is between urban rates established on an allocated cost basis (in Hydro One's case) to rates based on actual costs (in terms of the comparators). As discussed in Sections 3.2.5

[90] 2018 Yearbook of Electricity Distributors.

and 4.3.3 of this reply, while Hydro One's CAM includes density factors which strive to better allocate the costs across its wide range of density-based classes, the resulting cost allocation is still only an approximation of Hydro One's cost of serving its urban classes.

Hydro One has other concerns with the data presented by SEC in the table on page 23 of SEC's submission that compares Hydro One's urban class rates with other utilities, including:

- SEC states that Hydro One's rates are 2018 rates, when in fact they are 2019 rates and include recovery of foregone revenue from 2018 and part of 2019 (which artificially increases the rates in the table relied upon by SEC for comparison purposes).

- Hydro One notes that the selected comparators used by SEC exclude Toronto Hydro and Alectra – urban utilities that would likely have higher costs and drive up the comparator average.

- While Hydro One's rates utilized in SEC's table are based on a 2018 rebasing *plus* a subsequent 2019 Custom IR increase, the utilities against which it is being compared have not been rebased in a number of years (Essex Powerlines, Hydro Hawkesbury and Erie Thames are the only other 2018 rebasings). The others in SEC's table were rebased in 2010 (OPDC), 2013 (PDI and West Coast Huron), 2014 (Orangeville), 2015 (Oshawa and Festival Hydro), 2016 (Kingston, Hydro Ottawa, and Rideau St. Lawrence) and 2017 (Brantford, E.L.K., London Hydro, and Renfrew). SEC's comparisons fail to acknowledge or account for the fact that Hydro One's rates reflect a recent rebasing (and updated cost structure) as compared to the others.

Hydro One also supports the reply submission by PDI and OPDC in these proceedings with respect to this issue.[91] As noted in their submission, SEC's reliance on a utility's customer density as a comparator for performance is misplaced as it does not account for the large variation in the number of customers each utility serves. The size variation among the utilities is considerable and

[91] Reply Argument by PDI and OPDC, pp. 7-8.

results in comparing the costs for utilities that serve 335,320 customers against a utility that has 4,312 customers.[92]

As noted, there are many factors that need to be considered in comparing utilities' rates before any conclusions can be made with respect to the unit cost to serve. Because of the nature of its distribution territory, Hydro One will have higher system-wide costs to serve its customers. However, this does not mean that the Residual Cost-to-Serve forecast for these Transactions is inaccurate. Hydro One stands by its forecast provided in these Applications which are specific to the distribution systems being purchased in the Transactions.

4.3.2 ***SEC's Benchmarking Comparison***

SEC points to the PEG 2018 Benchmarking Update (the "Update") to support its argument that Hydro One is a high cost utility because the Update indicates that: (i) Hydro One was 16.1% above expected costs (with only six distributors worse, and 56 better); (ii) PDI was 5.8% above expected costs; and (iii) OPDC was 5.7% below expected costs. These figures, SEC suggests, further support its argument that the Transactions should be denied.

In Hydro One's view, the Update is of limited or no value to the OEB in making its determination in the current Applications.

First, the data about the relative cost performance of Ontario distributors is unrelated to the cost forecasts and rate proposals for PDI and OPDC presented in the Applications. Second, Hydro One has been recognized by the OEB's own benchmarking consultant (PEG) as being an outlier in Ontario.[93] As a result, the OEB should be cautious in relying on benchmarking results as a measure of Hydro One's cost performance relative to other distributors in Ontario.

Third, while the PEG model does include some density variables (e.g., number of customers and line length), it is not comprehensive – excluding many other variables of relevance to any cost analysis of Hydro One's system.[94] PEG also examined a wide range of other business condition

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[92] *Ibid*, p. 8.

[93] PEG report *Empirical Research in Support Of Incentive Rate Setting In Ontario* (issued May 2013), p. 49.

[94] These variables are shown at Table 16 of the PEG Report (EB-2010-0379).

variables that were not included in its Ontario model because they were not statistically significant or did not have a sensible correlation. Those variables included: % of distribution territory on Canadian shield, share of service territory that is urban, and municipal population per square kilometre of urban territory.[95] While it may make sense that these variables are not statistically significant for the other Ontario distributors, they are significant factors for Hydro One. As such, in Hydro One's view, the PEG model does not fully capture Hydro One's business conditions.

As noted above, Hydro One's service area is significantly different than other Ontario utilities due to its overall size and rural nature. The distribution system contains many radial feeders that serve remote areas that can be difficult to access and are adjacent to a high degree of forestation. The vast size of the service area also means that Hydro One is more likely to be impacted by storms which may not typically impact the entire province. These are just a few of the practical considerations that will place upwards pressure on costs, which are not accounted for in PEG's benchmarking model.

Even leaving all that aside, and accepting the Update as-is for Hydro One, recent benchmarking reports filed by PEG show a trend of cost performance improvement:

Table 4-3: Hydro One Cost Performance

Time Period	3-Year Average Score
2014 to 2016[96]	21.4%
2015 to 2017[97]	17.4%
2016 to 2018[98]	16.2%

[95] PEG Report filed in EB-2010-0379, *Productivity and Benchmarking Research in Support Of Incentive Rate Setting In Ontario: Report To The Ontario Energy Board* (issued November 21, 2013 and revised December 19, 2013 and January 24, 2014), p. 60.

[96] PEG report available from OEB website <https://www.oeb.ca/sites/default/files/PEG-benchmarking-report-20180823-revised.pdf>.

[97] *Ibid*.

[98] PEG report available from OEB website <https://www.oeb.ca/sites/default/files/PEG-Benchmarking-Report_20190815.pdf>.

4.3.3 *SEC's Interpretation of Density Study*

SEC makes much of the Density Study prepared for Hydro One in 2013, suggesting that it was a rigorous effort to directly assign costs to Hydro One's urban rate classes that results in a precise determination of the cost to serve Hydro One's urban rate classes. SEC goes on to further say that if this is not what the Density Study does, then Hydro One should have "fixed" it at its recent distribution rate case. Additionally, SEC says that if the Density Study does accurately produce a precise cost to serve, then Hydro One's higher urban rates (as compared to PDI's and OPDC's rates) is proof that Hydro One's cost to serve PDI and OPDC customers will not be any different than Hydro One's current urban rate classes.

To reach this conclusion, SEC completely mischaracterizes the Density Study before setting up an entirely flawed comparison between how costs are allocated to Hydro One's urban rate classes versus Hydro One's proposal in these Applications to directly assign costs to PDI and OPDC customers.

The Density Study was carried out to better understand Hydro One's cost to serve its customers in its density-based rate classes (including its urban rate classes). It resulted in the introduction of new density factors into Hydro One's CAM that significantly *improved* the allocation of costs to Hydro One's density-based classes. However, the density factors still over-estimated the costs of serving urban customers. As noted by the authors of the Density Study:

> " ... the mean density of the high-density sample areas likely understates the mean density of the UR class and the mean density of the low-density sample areas likely overstates the mean density of the R2 class. As this study has shown, HONI's distribution service costs are inversely related to customer density. Hence, the ratio of the mean assigned costs between the low-, medium- and high-density sample areas is likely a conservative estimate of the difference in the costs to serve the R2, R1 and UR rate classes."[99] (emphasis added)

The inputs to the Density Study used a combination of estimated average asset costs, actual OM&A costs on an operating area or province-wide basis, and largely distance-based allocators to derive

[99] EB-2012-0136, Exhibit D-1-1, Attachment 1, Report on "Customer Density and Distribution Costs", p. 40.

costs for Hydro One's high-, medium- and low-density areas.[100] In other words, contrary to what SEC suggests,[101] the Density Study did not directly assign costs to Hydro One's high density urban areas. Hydro One has been clear that that cannot be done (see Section 3.2.2 in this reply submission). Consequently, it is incorrect and inappropriate to compare Hydro One's urban rates (formed through an allocation of costs) to the PDI and OPDC rates being proposed in these Applications that account for a direct allocation of the local fixed assets used to serve the acquired customers.

Hydro One's rates to existing customers are outside the scope of these proceedings. Whether, as SEC suggests, the density factors resulting from the Density Study should be "fixed" is not for the OEB to resolve here.

4.3.4 ***Diseconomies of Scale***

In its submission, SEC raises a "diseconomies of scale" theory, which is completely of its own making. SEC suggests that the evidence in these proceedings confirms the theory. It is unclear what purpose this part of SEC's submission serves. What is clear is that there is no evidence on the record regarding diseconomies of scale, and what SEC provides is not evidence (much less, expert evidence from a qualified economist). There is no data or analysis done as to whether Hydro One's cost structure, as SEC so confidently states, is reflective of the diseconomies of scale theory. In fact, Hydro One's own economist indicates that while diseconomies of scale may be relevant in the manufacturing sector (which is the example that SEC used), it would not apply in the case of a utility acquisition. In Hydro One's view, the OEB has no option but to give zero weight to any of SEC's submissions on this point. It is entirely without merit, and demonstrative of nothing.

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[100] See pages 15-26 in EB-2012-0136, Exhibit D-1-1, Attachment 1, Report on "Customer Density and Distribution Costs".

[101] In fact, despite repeated assertions by Hydro One witnesses at the Technical Conference and oral hearing that Hydro One does not have information about specific assets used to serve its legacy urban areas (and therefore cannot directly assign costs to customers in those areas in the same was as proposed in these Applications), SEC continues to pretend otherwise. Para. 2.3.80 of the SEC Submission incorrectly states that: "Hydro One has already demonstrated with the Density Study that they can study the costs to serve specific areas." Similarly, at para. 2.3.82, SEC states: "any study of cost savings after those acquisitions would show that costs went up, not down. Hydro One knows the costs, because it did a study already".

4.4 Cost Savings in Past Acquisitions

To support its position that the proposed Transactions will not generate any cost savings, SEC relies heavily on an argument that past acquisitions have shown, without exception, that: "Hydro One has Never Produced Cost Savings from Acquisitions of other LDCs".[102] Despite this definitive statement, SEC also argues that "Hydro One has never studied [past] acquisitions to see if it is actually generating the expected cost savings." Thus, on the one hand SEC appears to indicate that the evidence clearly shows that past acquisitions never resulted in any cost savings but, on the other hand, argues that no cost savings evidence from past acquisitions has ever been prepared. Apart from SEC's argument being internally inconsistent, on both these points SEC is wrong.

SEC appears to rely on increases in the distribution rates of utilities acquired by Hydro One in 1999 and the early 2000s for the proposition that Hydro One's acquisitions never result in cost savings. There are several problems with this argument.

First, the OEB in past MAAD proceedings has stated that what transpired in previous MAAD cases is irrelevant.[103] Nonetheless, SEC persistently resurrects this argument as it has since the argument was first dismissed in the Hydro One/Norfolk Power MAAD proceeding. Hydro One feels compelled to emphasize this fact, so as not to have this line of inappropriate argument and conjecture continue to future MAAD proceedings.

Second, SEC's comparison of the change in rates for past acquisitions from 2005 to 2019 does not say anything about the cost savings associated with the past acquisitions. To quantify cost savings it would be necessary to understand how: (i) Hydro One's revenue requirement associated with serving both its own customers and the customers from past acquisitions (i.e., legacy revenue requirement plus acquired distributors' incremental revenue requirements) compares with (ii) what the total revenue requirement would have been for Hydro One and all past acquired distributors if the acquisitions had never happened (i.e., legacy revenue requirement plus acquired distributors' status quo revenue requirements). Once again, SEC is erroneously comparing customer rates that are based on a cost allocation model versus the actual cost to serve customers.

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[102] SEC Submission, para. 1.3.5, but also see 1.3.5(b) and (c), 2.3.2(d), 2.3.3 to 2.3.16, and 2.6.5.
[103] EB-2013-0196/0187/0198 Decision and Order, p. 17.

Third, the rate-setting approach being proposed in this case is entirely different from the rate proposals in the acquisitions of the early 2000s. Specifically, whereas in those earlier acquisitions acquired customers were brought into Hydro One's existing rate classes, the proposal before the OEB in these Applications is to put PDI and OPDC residential and general service customers in discrete, new acquired customer classes for the long-term, potentially in perpetuity. Hydro One does not plan to integrate PDI or OPDC customers into Hydro One's existing legacy rate classes unless there will be no measurable impacts to PDI or OPDC customers.[104] The rate proposal in these Application, while not driven by past acquisitions, effectively responds to concerns about the long-term rate impacts, by ensuring that: (a) the acquired customers in PDI and OPDC are more precisely allocated the costs to serve them both in Year 11 and in the long-term; (b) rates collected from PDI and OPDC customers are less than what they would have paid in the absence of the proposed Transactions; and (c) Hydro One legacy customers are unharmed or better off than they would have been in the absence of the Transactions. Further, in order to demonstrate the cost savings of the Transactions, Hydro One has also committed to tracking the actual incremental OM&A and capital costs to serve PDI and OPDC customers during the deferral period, and to continue tracking the capital costs to serve PDI and OPDC customers from Year 11 onwards.[105]

Fourth, even if past transactions were relevant to the OEB's determination of these Applications, which they are not, the distribution rates charged to customers acquired by Hydro One approximately 20 years ago tells us nothing about whether those rates actually reflected the costs to serve the utilities and whether there were cost savings resulting from the Transactions. For SEC to support its assertions, it would need substantive details on the asset conditions of the acquired utilities (and whether sales were pursued by the selling distributors because major capital investments were required), service quality the customers had pre-acquisitions, return on equity the acquired distributors were achieving, if there was any cross-subsidization between property tax ratepayers and electricity ratepayers – all of which would have impacted the 2005 rates. We have none of this information to support SEC's arguments.[106]

[104] Oral Hearing Transcript, Vol. 2, pp. 167-168, 179-181.
[105] Exhibit A-5-1, Section 3.0 (PDI and OPDC).
[106] Oral Hearing Transcript, Vol. 1, pp. 74-75.

SEC's broad assertions and conclusions are entirely unsupported – in addition to being entirely irrelevant to the disposition of the current Applications.

Fifth, while cost savings were not tracked on these much older acquisitions,[107] there is empirical cost savings evidence for Hydro One's three most recent acquisitions (i.e., Norfolk, Haldimand and Woodstock). This evidence shows very clearly that cost savings have been achieved for all three acquisitions:[108]

[107] Technical Conference Transcript, Vol. 1, p. 66; Oral Hearing Transcript, Vol. 1, p. 76.

[108] Technical Conference Transcript, Vol. 1, p. 67; EB-2017-0049, Exhibit I-14-Energy Probe-12 (updated for 2018 actuals).

Table 4-4: Cost Savings from Norfolk, Haldimand and Woodstock

NPDI					
$/Million		**2016**	**2017**	**2018**	**Cumulative**
OM&A	Status Quo	5.9	6.0	6.1	18.0
	MAAD	2.7	2.7	2.8	8.2
	Actual	2.7	2.2	2.8	7.7
	Projected Savings	3.2	3.3	3.3	**9.8**
	Actual Savings	3.2	3.8	3.3	**10.3**
Capex	Status Quo	4.6	4.4	4.5	13.5
	MAAD	2.9	3.0	3.1	9.0
	Actual	0.9	1.7	2.0	4.6
	Projected Savings	1.7	1.4	1.4	**4.5**
	Actual Savings	3.7	2.7	2.5	**8.9**
HCHI					
OM&A	Status Quo	-	8.5	8.6	17.1
	MAAD	-	4.5	4.6	9.1
	Actual	-	3.9	3.0	6.9
	Projected Savings	-	4.0	4.0	**8.0**
	Actual Savings	-	4.6	5.6	**10.2**
Capex	Status Quo		5.4	5.6	11.0
	MAAD		3.3	3.4	6.7
	Actual		3.5	3.5	7.0
	Projected Savings		2.1	2.2	**4.3**
	Actual Savings		1.9	2.1	**4.0**
WHSI					
OM&A	Status Quo	-	4.0	4.1	8.1
	MAAD	-	1.6	1.4	3.0
	Actual	-	2.0	1.8	3.8
	Projected Savings	-	2.4	2.7	**5.1**
	Actual Savings		2.0	2.3	**4.3**
Capex	Status Quo		2.5	2.6	5.1
	MAAD		3.2	1.8	5.0
	Actual		1.7	1.8	3.5
	Project Savings		(0.7)	0.8	**0.1**
	Actual Savings		0.8	0.8	**1.6**

*Note: The Norfolk transaction closed in 2015, so the cost impacts were tracked as of 2016. The Haldimand and Woodstock transactions closed in 2016, so the cost impacts were tracked as of 2017.

As demonstrated, significant OM&A and capital cost savings have been achieved in all three of Hydro One’s most recent consolidations in every year, resulting in $24.8 million in OM&A savings and $14.5 million in capital cost savings in a two to three year period. Moreover, the actual cost savings from all three transactions have exceeded the forecasted costs savings (on a cumulative basis) by $7.5 million.

What the evidence clearly shows is that for the most recent Hydro One acquisitions (and indeed, the only ones for which cost savings were specifically tracked), there have been significant cost savings – at levels greater than forecast.

Finally, at para. 1.3.8(d) of its submission,[109] SEC states, under the heading "No Merger Savings" that "Since 2005, Hydro One, the most prolific acquiror of other LDCs in the industry, has seen its distribution revenue per customer (a proxy for cost per customer) increase by 45.77%. The rest of the industry has increased by 23.44%. There is no evidence of cost savings from Hydro One mergers." Hydro One has made no acquisitions between the period of 2005 and today (i.e., the period over which SEC claims our revenue requirement has increased by 45.77%).[110] By 2005, all of the 1999/2000 acquisitions would have been fully integrated into Hydro One (realizing cost efficiencies before that point in time) and therefore would not contribute to new revenue cost savings starting in 2005. With respect to the Norfolk, Haldimand and Woodstock acquisitions SEC is willfully ignoring the Decision in EB-2017-0049, which required Hydro One to continue treating Norfolk, Haldimand and Woodstock as separate entities from a revenue requirement and rates perspective. As a result, these three acquisitions would also not have contributed to any distribution revenue per customer efficiencies over the 2005-2018 period. To claim that Hydro One's "prolific acquisitions" should have reduced our revenue per customer values since 2005 demonstrates a complete disregard for the facts.

4.5 Revenue Requirement Forecasts (Status Quo and Residual Cost-to-Serve)

The Applicants are projecting significant revenue requirement savings, based on the forecast cost savings[111] associated with the Transactions (i.e., Hydro One's Residual Cost-to-Serve forecasts as compared to PDI's and OPDC's Status Quo forecasts).

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[109] Also see paras. 2.3.4(d)(iii) and 2.3.85 of SEC Submission.

[110] In para. 2.3.85 of its submission, SEC actually suggest that over the period from 2005 to 2018, Hydro One customer numbers increase by 20% as a result of acquisitions. This is untrue. In paras. 2.3.86 to 2.3.88, SEC claims that this increase in customers due to acquisitions should have translated to lower costs for Hydro One. Again, this is untrue.

[111] See Tables 4-1 and 4-2, above.

As noted above, in order to forecast the revenue requirement savings, PDI and OPDC each prepared a Status Quo forecast of their respective revenue requirements (as if the Transactions did not proceed), and Hydro One prepared a "Residual Cost-to Serve" forecast of the revenue requirement for each of PDI's and OPDC's service areas (as if the Transactions did proceed).

OEB Staff and intervenors have, to varying degrees, expressed concern with the forecast revenue requirements – suggesting that the Status Quo forecasts prepared by PDI and OPDC are too high, and the Residual Cost-to-Serve forecasts are too low. Hydro One's response to the criticisms of the Status Quo and Residual Cost-to-Serve forecasts are set out below. Given that the Status Quo forecasts were prepared by PDI and OPDC, the reply submissions of PDI and OPDC will also address the Status Quo forecasts.

Before addressing the arguments of OEB Staff and intervenors, some perspective is warranted. While any forecast (given the nature of forecasts) can be subject to scrutiny and criticism, all of the forecast cost savings (and more) would have to disappear for the Transactions to run afoul of the "no harm" test. As noted above, OEB Staff and VECC accept that some cost savings can be achieved but take issue with the quantum. If the Transactions are permitted to proceed, the actual cost savings that transpire will not perfectly match the forecast savings in the evidence – but Hydro One submits that it would be impossible for the cost savings to fall to zero.

As noted above, the actual cost savings associated with Hydro One's most recent acquisitions (Norfolk, Haldimand and Woodstock) were reasonably close to (and indeed greater than) the forecasted savings in their MAAD applications. There will be cost savings associated with the Transactions – and the evidence of the Applicants on the record in these proceedings is the best information as to the quantum of those savings. The Applicants stand by their revenue requirement forecasts.

4.5.1 *PDI and OPDC Forecasts: Status Quo*

OEB Staff's and intervenors' concerns that the Status Quo forecasts are too high rely on the following two arguments: (i) the revenue requirement forecasts of PDI and OPDC are projected to increase at a rate above the industry average; and (ii) because PDI's and OPDC's current ROEs are at an acceptable level, if they were to rebase today, their revenue requirements should be roughly the same as they were in 2013 (PDI) and 2010 (OPDC).

4.5.1.1 *Above Industry Average Growth Rate*

OEB Staff, at Table 7 in their submission, calculated the average compound annual growth rate ("CAGR") utilized in the PDI and OPDC Status Quo revenue requirement forecasts and compared those figures to the CAGR of revenue requirements for other cohort distributors.[112]

In doing so, OEB Staff calculated that PDI's forecast CAGR from 2013 (the year of PDI's last rebasing) to 2030 was 3.2%. However, in calculating this average, OEB Staff used PDI's 2010 OEB-approved revenue requirement of $15.4 million (a number that does not include LV charges) and compared it to PDI's 2030 revenue forecast of $26.3 million (a number that does include LV charges). Similarly, Staff calculated that OPDC's forecast for CAGR from 2010 (the year of OPDC's last rebasing to 2030) was also 3.2%. For OPDC, OEB Staff used OPDC's 2010 OEB-approved revenue requirement of $7.6 million (which does not include LV charges) and compared it to OPDC's 2030 revenue requirement forecast of $14.5 million (which includes LV charges).

If OEB Staff had done an "apples to apples" comparison, using both PDI's and OPDC's 2030 revenue requirement[113] ($24.9 million[114] and $13.4 million[115]) excluding LV charges, the resultant CAGR for both would be 2.9%, and not the 3.2% that OEB Staff states. This shows that the Status Quo revenue requirement forecasts included in Hydro One's Applications, which had a CAGR of 2.9%, are reasonable in terms of being aligned with industry averages.

Also, given the wide range of CAGRs among cohorts, it seems inappropriate to consider industry averages to be more accurate a forecast than the specific projections made by the actual asset owners (i.e., PDI and OPDC) that know the needs of the actual assets and system being transferred.

[112] The cohort utilities' CAGR calculations came from Attachment 19 in the original pre-filed evidence (both Applications) and Undertaking J2.2 (both Applications). This data uses revenue requirement and rate base data from 2017 and 2018 rebasing applications before the Board.

[113] The escalation of these revenue requirements from their last rebasing levels (i.e., $15.288 million for PDI and $7.656 million for OPDC) was illustrated in Attachment 18 of the pre-filed evidence in each respective Application.

[114] Exhibit A-4-1, Table 1 (PDI).

[115]Exhibit A-4-1, Table 1 (OPDC).

In addition to the Status Quo revenue requirement forecasts being in line with industry averages, the rate base additions built into the Status Quo revenue requirement forecasts are also in line with industry averages. Table 4-5 below shows the CAGR of rate base data informed from Attachment 19.

Table 4-5: Adjusted Rate Base Data from Attachment 19

Source: Adapted from EB-2018-0242, Attachment 19, page 1 of 1						*OEB Staff Calculations*	
Utility (2018 Approvals)	**Application**	**Rate Base, 2018 Approval ($)**	**Rate Base, Last Approval ($)**	**Change ($)**	**Change (%)**	**Average Annual Change (%)**	**Compound Annual Growth Rate (%)**
Centre Wellington	EB-2017-0032	17,046,778	11,778,959	5,267,819	44.7%	8.9%	7.67%
Cooperative Hydro Embrun Inc.	EB-2017-0035	4,680,408	2,907,927	1,772,481	61.0%	15.2%	12.64%
Essex	EB-2017-0039	58,033,511	41,119,714	16,913,797	41.1%	5.1%	4.40%
Hydro Hawkesbury	EB-2017-0048	8,528,333	6,386,201	2,142,132	33.5%	8.4%	7.50%
Westario	EB-2017-0084	50,358,448	41,870,815	8,487,633	20.3%	4.1%	3.76%
				Average	**40.1%**	**8.4%**	**7.2%**

Source: Adapted from EB-2018-0242, Attachment 19, page 1 of 1						*OEB Staff Calculations*	
Atikokan	EB-2016-0055	3,435,243	2,799,500	635,743	22.7%	4.5%	4.18%
Brantford	EB-2016-0058	88,429,953	75,737,921	12,692,032	16.8%	4.2%	3.95%
CNP	EB-2016-0061	89,608,015	73,497,788	16,110,227	21.9%	5.5%	5.08%
InnPower	EB-2016-0085	52,584,820	32,279,524	20,305,296	62.9%	15.7%	12.98%
Lakefront	EB-2016-0089	19,540,253	17,660,020	1,880,233	10.6%	2.1%	2.04%
London	EB-2016-0091	299,568,786	268,985,256	30,583,530	11.4%	2.8%	2.73%
Northern Ontario	EB-2016-0096	7,767,615	7,273,107	494,508	6.8%	1.7%	1.66%
Renfrew	EB-2016-0166	6,684,775	6,016,657	668,118	11.1%	1.6%	1.52%
Thunder Bay	EB-2016-0105	109,772,927	93,339,122	16,433,805	17.6%	4.4%	4.14%
Welland	EB-2016-0110	33,665,167	31,435,867	2,229,300	7.1%	1.8%	1.73%
				Average:	**18.9%**	**4.4%**	**4.0%**

Source: Adapted from EB-2018-0242, Attachment 19, page 1 of 1		*OEB Staff Calculation*	
	Change (%)	**Average Annual Change (%)**	**Average Compound Annual Growth Rate (%)**
Average of 2017 and 2018 Approvals:	**26.0%**	**5.7%**	**5.1%**

Based on these calculations, the cohort average CAGR in recent years for rate base is 5.1%. However, the Status Quo rate base CAGR for PDI is 2.3%, and for OPDC is 4.9% - both of which are below the cohort average. Taking a closer look at the numbers, Table 4-6 below demonstrates that the majority of the growth in rate base for both PDI and OPDC has already occurred (since the last rebasing), with the forecast CAGR *under Hydro One ownership* at 1.86% and 3.25%.

Table 4-6: Rate Base Additions Since Last Rebasing vs. Forecasted Rate Base Additions

$000s	OEB Approved Rate Base	2018 Actual	2019 Bridge	CAGR (Approved to Bridge)	2030 SQ Forecast	CAGR (2019 to 2030)	CAGR (since rebasing)
OPDC (last rebased 2010)	20,806	35,241	37,742	6.84%	53,678	3.25%	4.9%
PDI (last rebased 2013)	65,407	76,776	79,212	2.77%	97,046	1.86%	2.4%

Simply put, there is no evidence that the Status Quo forecasts for rate base or revenue requirement are overstated.

4.5.1.2 *PDI and OPDC Have Adequate Current ROEs*

Notwithstanding that the evidence demonstrates the reasonableness of the forecast revenue requirements and rate base increases for PDI and OPDC, the Applicants note the significant time that has passed since PDI's and OPDC's last rebasing. This is relevant to the fact that PDI's and OPDC's current revenue requirements are understated. By the time PDI and OPDC next rebase, PDI will not have had a cost-of-service rate case in 17 years, and OPDC will not have had one for 20 years. Consideration of any revenue requirement increases must take this into account.

OEB Staff and VECC seek to downplay this fact. They take the position that because PDI and OPDC are not currently underearning (at least based on their current ROEs), perhaps 17 and 20 years between rebasings is not all that significant in terms of revenue requirements. They suggest that given the current ROEs for PDI and OPDC, their distribution rates would not be higher if they rebased today.

This notion, though, was clearly explained and refuted by the PDI and OPDC witnesses at the hearing. Both witnesses indicated that their ROEs over the last couple of years were artificially inflated due to various facts, largely tied to being in limbo pending the final disposition of these Applications (e.g., not replacing employees that have left, not undertaking regulatory filings, not preparing Distribution System Plans, etc.):

> MR. SHEPHERD: … What was your -- what do you anticipate your ROE, your regulatory ROE to be in 2019, Mr. Stephenson? Are we in the seven and a half range? Is that right?

> MR. JOHN STEPHENSON: I would think that it would be similar to the experience that we saw in 2018, which was in the 7 percent range, which would be caveated of course for the fact that we're not running a full flight of resources, right. So it is a bit of an artificial number.
>
> MR. SHEPHERD: Understood. All right. Just one other thing I want to ask about this, Mr. Andre.[116] …
>
> MS. GIRVAN: … Just again a couple of questions for Orillia and Peterborough, first with Orillia.
>
> Why did you stay out so long and not apply to rebase your rates?
>
> MR. HURLEY: So back in 2010, we were a bit lucky in our timing as to when we applied for rebasing. We managed to get the very best cost of capital parameters that I think we've ever had, before or since. That's helped us kind of main taken a reasonable revenue level, along with the IRMs that we have added each year.
>
> We felt we could run our business -- basically we've managed to do that over the last 7 or 8 years and remain reasonably profitable.
>
> What's been going on in the last couple of years, though, maybe Grant can talk to a bit more. But we have been a bit on hold with the potential purchase by Hydro One. We've lost staff because of that. We're certainly going to have to -- if we were to have to continue on status quo, we would certainly have to add those staff back, plus some, because the regulatory requirements are certainly increasing and there's other areas as well.
>
> So I mean, if you look at our results up to now, we're doing okay. Part of that is because we've got artificially low costs the last couple of years, and again we know going forward that's not going to be the case. We are going to have to rebase going forward to restore our revenue structure up against our cost structure.[117]

These were (and are) prudent actions for utilities expecting to be sold. Under normal operational circumstances, the current ROEs for both PDI and OPDC would be significantly less, absent an immediate rate rebasing. Moreover, the downward trend in their respective ROE's illustrates their inability to earn the OEB's approved return under their current revenue requirement.

[116] Oral Hearing Transcript, Vol. 1, p. 40.
[117] Oral Hearing Transcript, Vol. 2, pp. 168-69.

Both PDI and OPDC have provided reasonable status quo forecasts that reflect the capital and operating needs that they believe will be required to serve their customers in the next 10 years.

4.5.2 ***Hydro One Forecasts: Residual Cost-to-Serve***

OEB Staff and intervenors raise various concerns about Hydro One potentially underestimating the costs to operate the PDI and OPDC distribution businesses. These concerns include:

- no forecast incremental costs for common activities (e.g., customer care, human resources, finance, etc.)[118]
- no forecast incremental costs for general plant and low incremental capital costs
- the absence of forecast capitalized overheads[119]
- the CAGR used to forecast Residual Cost-to-Serve revenue requirements is too low
- the forecast of no new incremental corporate costs and legacy customer impact.

Hydro One responds to these concerns below.

4.5.2.1 *No (or Low) Incremental Costs for Common Activities*

SEC's broad assertion that Hydro One is forecasting no incremental costs for common activities is untrue. It is a mischaracterization of what is clearly on the record in these proceedings. What Hydro One has said in these proceedings is as follows:

- Common corporate costs (such as finance/audit, regulatory, human resources, etc.) will not increase as a result of the Transactions. The costs of these business functions are not driven by customer numbers.
- Certain other shared common costs (e.g., customer care) will result in some incremental costs being incurred by Hydro One, and have been accounted for in Hydro One's forecast

[118] SEC Submission, paras. 2.3.26 and 2.3.44; See OEB Staff Submission, p. 14, and VECC Submission, pp. 7-9.
[119] Energy Probe Submission, p. 4; VECC Submission, p. 11.

incremental costs. This was illustrated in interrogatory responses[120] and clearly articulated in the following exchange:

> MS. RICHARDSON: … [I]f we needed an extra person or an extra activity in our shared cost that was included in our Table 2 of [Exhibit] A-2-1.
>
> So for example our customer care facility. So customer care we generally consider is a shared services. But there's certain aspects of customer care that are on a per unit basis, like an extra postage stamp, an extra envelope, a bill presentment. All of those incremental costs are included in our Table 2 costs within --
>
> MR. SHEPHERD: The residual costs.
>
> MS. RICHARDSON: Yes, residual.
>
> MR. SHEPHERD: That's what I'm saying --
>
> MR. ANDRE: Customer billing is a good example. Like, customer-care type costs are a good example. They're both incremental and they go into the shared bucket of costs that then get shared across all classes.[121]

On this point, SEC also argues that Hydro One has failed to incorporate into its forecast incremental costs to serve PDI and OPDC, asserting that the transfer of certain employees from PDI and OPDC into Hydro One may not replace a departing Hydro One existing employee – and therefore would be incremental to Hydro One's existing complement of employees.[122] This is incorrect – there has been no failure to include the incremental costs of PDI and OPDC employees from being incorporated into Hydro One.

An explanation of how PDI and OPDC employees would be integrated into Hydro One was clearly laid out in Hydro One's pre-filed evidence at Exhibit A-2-1 in both Applications. For example, for PDI, Hydro One plans to expand its local complement of direct positions by 13 employees in order to address the needs of its expanded service area, while only four staff will be absorbed into vacancies within Hydro One. As noted: "Therefore, the result is a net reduction of 4 local trades

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[120] Exhibits I-1-17 and I-4-25 (PDI); Exhibits I-1-19 and I-5-9 (OPDC).

[121] Technical Hearing Transcript, Vol. 1, p. 187.

[122] SEC Submission, para 2.3.44.

and technical positions to serve the same territory."[123] The evidence also shows that Hydro One is forecasting increased costs in its non-local indirect operations and back office functions (e.g., call centres).[124]

Therefore, to suggest that Hydro One's forecasts of incremental costs to serve PDI and OPDC ignore transferred employees needed (over and above Hydro One's existing staff) to serve the additional customers in PDI and OPDC is wrong based on the evidence. The incremental staff needed to serve PDI and OPDC customers have been included in the Hydro One Residual Cost-to-Serve forecasts.

4.5.2.2 *Low Capital Forecasts within PDI and OPDC Service Areas*

The concern about the long-term asset replacement costs of Hydro One being higher than those of PDI or OPDC is grounded in the (incorrect and unsubstantiated) assumption that Hydro One is a utility with higher unit costs. At the technical conference and oral hearing, this issue "crystallized" in the discussion about how to address the aging distribution stations in PDI's service territory. Despite Hydro One's extensive explanation of how it would approach capital investments on the stations in PDI's service area, OEB Staff and intervenors have chosen to ignore that explanation – preferring instead to assert that PDI had planned to replace or refurbish nine stations during the deferred rebasing period at a cost of $18.4 million, but Hydro One will only replace or refurbish six stations during that period at a cost of $18.1 million. Of course, that is not true. However, based on that flawed and inaccurate comparison, OEB Staff and intervenors conclude that Hydro One cannot carry out capital replacement work at the same cost as PDI, which means there will be no capital cost savings associated with the Transactions – and even worse, higher capital costs to PDI and OPDC customers in the long-term. This is untrue.

How Hydro One plans to address the aging distribution stations in PDI's and OPDC's service areas is addressed extensively in the evidentiary record of this proceeding.[125] Hydro One's forecast

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[123] Exhibit A-2-1 (PDI), pp. 11-12.

[124] Exhibit I-1-17 (PDI); Exhibit I-1-19 (OPDC).

[125] See Exhibit A-2-1, Table 1 (both Applications), interrogatory responses I-1-17, I-1-30, I-4-7 and I-4-25 (PDI) and I-1-3, I-1-19 and I-5-9 (OPDC), undertaking responses JT1.08, JT1.09, JT2.11) various questions at the Technical Conference and Oral Hearing, plus Exhibit K1.2 (presentation at Oral Hearing).

expenditures on PDI's distribution stations is set out in Attachment 1 of JT1.8[126], and amounts to $18.1 million. As noted in JT1.8, this amount "is sufficient to complete 6 station rebuilds/major refurbishments as well as 10 transformer replacements that could address 7 or more additional stations." In addition, Hydro One's forecast capital expenditures would cover station decommissioning as appropriate, and additional station work anticipated to arise during the deferred rebasing period. This is contrasted with PDI's capital expenditure plan incorporated into its Status Quo forecast, which simply sought to replace or refurbish one station a year over the deferred rebasing period.[127]

The two approaches (Hydro One's and PDI's) are different – and the capital expenditure forecasts were arrived at independently of one another. As explained in Hydro One's presentation (under direct examination) at Day 1 of the oral hearing, the Hydro One approach is a multi-step process that involves: (i) taking the Hydro One system-wide capital investment plan/budget and adjusting it for the incremental capital costs associated with maintaining PDI's or OPDC's system (based on the information gathered about PDI's or OPDC's distribution system including asset condition); (ii) converting that adjusted capital investment plan into a capital cost figure per customer and then multiplying that "per customer" amount by the forecast for PDI and OPDC for each year (and adjusting for inflation) to arrive at an annual capital expenditure budget; and (iii) a further manual adjustment is made by Hydro One, based on its judgment as to the adequacy and reasonableness of the annual capital expenditure amounts, based on Hydro One's understanding of the assets.

The fact that Hydro One's approach is different from PDI's and OPDC's is precisely what should be expected – and desired – in the context of a consolidation. With respect to the station replacements/refurbishments in PDI's service area, whereas PDI plans to replace or refurbish nine stations for $18.4 million, Hydro One's investment plan and capital forecasting process suggests that capital spending on the stations (at this stage) should be spent on replacing or refurbishing 6 stations, and leaving adequate funding to deal with 7 or more other stations in a manner to be determined once Hydro One has an opportunity to operate these stations. Perhaps this will mean replacing or refurbishing 3 additional stations for a total of 9 stations (i.e., the exact same plan as

[126] Hydro One's forecasted expenditures on OPDC's distribution stations is set out in Attachment 2 of the same undertaking and amounts to $5.6 million.

[127] Oral Hearing Transcript, Vol. 2, pp. 81-82.

PDI) or perhaps Hydro One will address 13 or more stations while staying within its capital expenditure forecast. Additionally, eliminating the artificial boundary between PDI and Hydro One may allow opportunities to develop more integrated solutions that take advantage of Hydro One's surrounding assets. This is an example of the benefit of consolidation. Determinations by Hydro One will be driven by its initial experience operating the PDI stations, reliability metrics, safety considerations and potential cost and engineering efficiencies – as it is for all current Hydro One investment decisions.

The evidence about station replacement in PDI's service territory, then, does not stand for the proposition that OEB Staff and intervenors suggest – namely, that Hydro One's asset replacement costs are higher than PDI's. It is not indicative of PDI's or OPDC's customers getting less capital infrastructure for the same expenditures going forward, as suggested in SEC's submission at para. 1.4.2(f), nor does it justify OEB Staff's concern at page 15 of its submission that Hydro One has not appropriately accounted for the asset replacement needs of PDI and OPDC over the coming decade. As demonstrated very clearly by Hydro One, the "nine versus six" stations debate could just as easily have been viewed as the "nine versus thirteen" stations debate and is not indicative of "less for more" outcome.

The capital budget expenditure forecasts in the Applications were developed differently by PDI and OPDC on the one hand, and Hydro One on the other, but all were developed to prudently and appropriately maintain the distribution systems through to 2030. The fact that the plans are different in these circumstances should not concern or surprise the OEB.

In addition to the discussion about PDI's distribution stations, OEB Staff and SEC cite Hydro One's higher cost-based specific service charges ("SSCs") as evidence that Hydro One's unit costs are generally higher than PDI's or OPDC's. Hydro One notes that the SSCs in the PDI and OPDC tariff schedules are in fact amounts prescribed by the OEB for use by all distributors (in the absence of a specific study to assess a distributor's cost of providing the service) in the 2006 Distribution Rate Handbook issued on May 11, 2005 (the "2006 Rate Handbook"). Specifically, the PDI and OPDC $15 charge for easement letters and the $30 charge for special meter readings (cited at p. 16 of the OEB Staff Submission) are contained in Schedule 11-1 of the 2006 Rate Handbook. These SSCs were established on a uniform basis for all distributors. While they may have been reflective of an "average" cost (across all distributors) to provide that service in 2006 (i.e., 14 years ago), they have not been updated since then and are not reflective of the PDI and OPDC cost to serve.

Hydro One informed OEB Staff in earlier interrogatory responses[128], that it is important to note that many of the SSCs defined in the rate orders of both PDI and OPDC are set per Section 11 of the 2006 Rate Handbook. The 2006 charges no longer reflect the true costs to render these services and on November 5, 2015, the OEB announced that it would be initiating a comprehensive policy review of miscellaneous rates and charges applied by electricity distributors for specific activities or services they provide to their customers (EB-2015-0304). The resulting charge that is effective today for this one and only miscellaneous service charge that has been updated, has almost doubled relative to the previous 2006 Rate Handbook charge ($22.35 to $43.64). Given this information, the charges outlined by the 2006 Rate Handbook cannot be used as a basis for comparison to Hydro One's cost of providing those same services, which reflect the actual 2018 cost of providing those services based on a study that was completed as part of Hydro One's most recent distribution rate application (EB-2017-0049). The fact that Hydro One's SSC are higher than other utilities has no correlation to unit costs or to the cost it has forecast to serve PDI and OPDC.

Finally, SEC makes the broad and unsupported assertion that Hydro One's forecasts provide for <u>no</u> incremental general plant costs. SEC cites Hydro One's plans for new operating centres in each of the Orillia and Peterborough regions. In fact, these new facilities are required regardless of the PDI and OPDC acquisitions and any incremental cost impacts for the facilities to accommodate the acquisitions are anticipated to be minimal.[129]

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[128] EB-2016-0276 – Exhibit I-1-4 (January 20, 2017).

[129] For the consolidated requirements of the regions servicing Orillia and Peterborough, there are nine incremental staff being added to the Orillia area (Exhibit A-2-1, p. 13) and 13 incremental staff being added to the Peterborough area (Exhibit A-2-1, p. 12). Most of the employees being added from PDI and OPDC are trade staff who (unlike administrative staff) would not require desk space for example. Relative to the operating centre space and staff requirements, the addition of these trade staff will have very minimal impact to the facility and cost.

4.5.2.3 *CAGR Used by Hydro One to Forecast its 2030 Revenue Requirement is Too Low*

VECC and SEC argue that the CAGR used by Hydro One to forecast revenue requirement for its legacy customers is too low. VECC states that Hydro One is using 2.2% instead of the industry average of 2.9%, while SEC states that Hydro One is using 1.24% instead of the industry average of 2.95%.[130]

Hydro One submits that the Year 11 revenue requirement forecast for serving legacy customers does not materially impact the determination of the cost to serve the PDI and OPDC acquired customers, and is therefore not relevant to a determination of the no harm test. Nevertheless, if the OEB disagrees, Hydro One has provided its reply to this issue below.

The detailed assumptions made by Hydro One that underpin its revenue requirement and customer count forecasts in these Applications for the period from 2022 and 2030[131] are based on the most current data from its approved revenue requirement for 2017 to 2022 (as per the OEB's decision in EB-2017-0049). For instance, the assumed growth in the Residual Cost-to-Serve forecast revenue requirement is based on the average annual growth rate from 2017 to 2022 (as approved by the OEB in EB-2017-0049) and includes the increase associated with rebasing plus four years of IRM increases. This was clarified in an exchange with Panel Chair Spoel:

> "CHAIR SPOEL: And then you've assumed that the increases from 2022 and on will continue to be at the same average percentage increase as in that five-year for which you have an IRM right now?
>
> MR. ANDRE: Yes.
>
> CHAIR SPOEL: You're not expecting that you will increase your -- when you rebase the next time, all things being equal. If you didn't acquire anything new or things just ticked along, that when you come back in 2022 or in 2021 for 2023 rates, whenever it is you come back in, that you actually wouldn't be asking for any additional cost increase and you would just continue on getting the same percentage increase as you had from 2017 to 2022?

[130] See VECC Submission, p. 20, and SEC Submission, para. 2.3.30.

[131] As noted at Exhibit I-1-48 (PDI) and Exhibit I-1-9 (OPDC).

MR. ANDRE: So I understand the question.

CHAIR SPOEL: That's the assumption you have built into this?

MR. ANDRE: Well, yes. But, Madame Spoel, the assumption or the 2018 -- in 2018, those five years up to 2022, that first year of that five years includes a rebasing.

CHAIR SPOEL: Right.

MR. ANDRE: So the application had a rebasing and then four years of IRM. So we averaged the increase of one year of rebasing plus 4 years of IRM, turned that into an average annual increase, and applied that going forward.

So there is that rebasing is built into the average, because it is included in the first year.

CHAIR SPOEL: Thank you. I didn't understand that. That is helpful, thanks very much."[132] (emphasis added)

Given the specific information available to Hydro One that reflects the most current rate increases approved by the OEB, the use of an industry average to reflect cost increases is, in Hydro One's view, not appropriate.

With respect to the values cited by SEC in its submission (i.e., the 1.24% and 2.95% figures), there are a number of problems – specifically:

- For both the 1.24% and 2.95% figures, SEC is comparing cost per customer, and not revenue requirement (as VECC does). Cost per customer can be distorted by the changes in number of customers. While number of customers can influence revenue requirement, it is not the only or most significant contributor.

- With respect to the 1.24% cited, SEC's figures utilize a "simple" average of the cost per customer for urban residential and general service customer classes. Given the significantly large number of residential customers in comparison to GS customers, a simple average understates the increases.

[132] Oral Hearing Transcript, Vol. 1, pp. 49-51.

- Finally, SEC is comparing a CAGR of 1.24%, for costs allocated to just the urban classes (in 2019 to 2030), to a CAGR of 2.95% for all classes in the period from 2005 to 2019. Given the different groups of customers being compared over those two periods, this results in an "apples to oranges" comparison.

The appropriate CAGR on cost per customer assumed in Hydro One's proposal from 2017 to 2030 is 1.5%.[133] Hydro One submits that the CAGR over the 2017 to 2030 period is lower than the value quoted by SEC for the 2005 to 2019 period, and slightly lower than the CAGR in revenue requirement noted by VECC, as a result of the efforts Hydro One has been undertaking to improve its productivity and efficiency as discussed by the Hydro One witnesses at the oral hearing.

4.5.2.4 *VECC's Critique of OM&A Costs*

VECC devotes a considerable portion of its submission to challenge Hydro One's evidence that its current OM&A cost per customer ($176) is less than the OM&A cost per customer for PDI ($245) or OPDC ($359). In VECC's view, Hydro One's calculations to arrive at these figures are flawed. After making certain adjustments that it believes provide a more appropriate apples-to-apples comparison of current OM&A costs per customer, VECC concludes that PDI's current OM&A cost per customer is actually lower than Hydro One's (by $17) but that OPDC's remains higher than Hydro One's (by $74). On the basis of its "re-worked" numbers, VECC comes to the surprising conclusion that "the 'no harm' test is not met for PDI's legacy customers."[134]

Regardless of the difference in Hydro One's and VECC's calculations, this conclusion is surprising because it is based on a single point of comparison which exists completely outside the Transactions (i.e., 2018 rates in the absence of the Transactions being completed, versus the rates that are forecast in Year 11, at the end of the deferral period). Also, VECC's submission only addresses OM&A costs, not the total cost to serve (i.e., it excludes capital). Hydro One notes that the "no harm" test is applied to the impacts of the consolidation Transactions, not to some current rate comparison. VECC's adjustments to the OM&A cost per customer calculations are not

[133] This is calculated as the CAGR between a 2017 value of $1119/customer, calculated as the approved 2017 revenue requirement of $1,467.6M divided by the 2017 forecast number of customers of 1,311,594 as filed in Draft Rate Order in EB-2016-0081, and the 2030 value of $1.356/customer shown in Exhibit I-2-44.

[134] See VECC Submission, pp. 5 to 6.

relevant to the “no harm” test. What VECC seeks to conclude from these figures demonstrates a lack of understanding of what the OEB is to determine in these proceedings.

With respect to OM&A forecasts in the evidence (i.e., the relevant evidence), VECC simply raises some of the same concerns addressed earlier in this reply submission, namely: (i) Hydro One using different escalation factors than PDI or OPDC; (ii) Hydro One’s assumed customer care costs increasing at a materially lower rate due to reliance on digital service channels; and (iii) Hydro One not adequately addressing the decrease in distribution operations costs. Hydro One believes that it has adequately addressed these items elsewhere in this reply submission (see Sections 4.5 and 5.2) as well as the evidence in these proceedings.

5. RELIABILITY & QUALITY OF SERVICE

According to the *Consolidation Handbook*[135], in applying the “no harm” test the OEB is guided by the reliability and service delivery metrics of the distributor and the expectation of continuous improvement in delivering reliability and service quality. Notwithstanding the submissions of OEB Staff and the intervenors, both of the PDI and OPDC Transactions enable the OEB to conclude no harm with respect to reliability and service quality.

5.1 Reliability

SAIDI and SAIFI results were provided by Hydro One and each of PDI and OPDC. As a proxy, Hydro One’s data reflected reliability statistics for feeders in the vicinity of the two acquired utilities.[136] With respect to frequency of interruption (SAIFI), Hydro One’s statistics were better than those of both PDI and OPDC. With respect to duration (SAIDI), PDI and OPDC had lower duration statistics relative to Hydro One’s proxy area.

While PWU submitted that Hydro One has provided sufficient evidence to illustrate that the transfer of PDI or OPDC’s distribution system to Hydro One would maintain or improve the adequacy, reliability and quality of electricity service, OEB Staff and all other intervenors

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[135] *Consolidation Handbook*, p. 7.
[136] Exhibit A-2-1, p. 9.

expressed concerns regarding service quality and reliability or suggested that the evidence was inconclusive on whether acquired customers would experience harm in this regard.[137]

Contrary to the positions of OEB Staff and intervenors, the reliability statistics presented by Hydro One, PDI and OPDC can be reconciled. OEB Staff's and intervenors' treatment of the reliability statistics was superficial at best and, at worst, they either ignored evidence on the record or did not accurately articulate the evidence on which they relied. The evidence clearly demonstrates that reliability will be maintained and that there are plans in place for its continuous improvement.

In referencing reliability, OEB Staff and intervenors address frequency and duration together, thereby ignoring the essential difference between what SAIFI and SAIDI measure and the drivers of each. Hydro One has better SAIFI statistics than both PDI and OPDC. OEB Staff and intervenors attempted to manufacture an argument that, because of Hydro One's capital plan over the deferred rebasing period, the SAIFI statistics for PDI would diminish. However, this argument is not based on a complete or correct representation of the evidence as discussed below. No similar argument was made with respect to SAIFI for OPDC.

OEB Staff and intervenors highlighted that the PDI status quo forecast plans to replace/refurbish nine stations during the course of the ten year deferred rebasing period, and incorrectly characterize Hydro One's intention as only identifying six stations to replace or refurbish. Based on this difference in approach, intervenors wrongly infer that there will be harm to existing PDI customers.

Hydro One clarified at the technical conference that Hydro One's station plans included six explicitly identified stations plus a capital envelope to address more stations.

> "MR. FALTAOUS: So the details of exactly what we're going to do for every one of those stations have not yet been confirmed, but we do have dollars to be able to address that station. Whether the appropriate is to replace it or whether it's to refurbish it, that will be worked out upon closing of the transaction, upon developing a detailed plan.
>
> MR. SHEPHERD: But there is six of them?

[137] OEB Staff Submission, pp. 18-19.

> MR. FALTAOUS: There are six that we have clearly identified, but there is a capital envelope that could be used to address more if needed."[138]

Furthermore, Hydro One provided Undertaking JT 1.8, which provided further detail that the approximately $18 million capital envelope is sufficient to complete the identified six PDI stations plus address 7 or more additional stations. Therefore, Hydro One's capital envelope is better described as providing sufficient funding to address 13 or more stations rather than the 6 referenced by the intervenors. Contrary to the uncertainty expressed by OEB Staff and intervenors, not only will the relative difference in SAIFI between Hydro One and PDI not diminish, Hydro One has in place plans to sustain and continuously improve reliability for the PDI territory.

As for SAIDI, it relates to timing for restoration of service – driven by relative geographic proximity of interruptions within the service area. In other words, differences in the SAIDI results that currently exist between the proxy Hydro One service territory and the results of the individual acquired utilities can be attributed to differences in geography (rural vs. urban).[139] By delving into these aspects and not a cursory view as taken by OEB Staff and intervenors, the SAIDI statistics can be reconciled based upon the evidence to show no harm to acquired customers.

SEC acknowledged that Hydro One is a rural utility and its SAIDI would not be as good as SAIFI. [140] However, with respect to SAIDI, no party has acknowledged the key fact, which is that when operating in either the PDI or OPDC territory, Hydro One will be operating within an urban environment with the current advantages enjoyed by PDI and OPDC. Hydro One will retain local knowledge from existing PDI and OPDC staff. PDI and OPDC will have access to Hydro One's larger pool of direct trades and technical staff in their respective geographic regions, resulting in the regional operations centres having a considerably higher number of trades and technical staff to serve the consolidated region's needs. This retained local knowledge, in coordination with Hydro One's regional operations and staff, will allow Hydro One to maintain or improve reliability.[141] Additionally, with the consolidation and integration of the territories there is an

[138] Technical Conference Transcript, Vol. 2, p. 3.
[139] Exhibit I-1-28 (PDI).
[140] SEC Submission, para. 4.1.1.
[141] Exhibit A-2-1, p. 9 (PDI) / p. 11 (OPDC).

opportunity to further improve the reliability for OPDC and PDI customers through new tools and technologies Hydro One currently utilizes on its distribution system, such as the use of smart meters to confirm outage locations.[142]

OEB Staff has requested a specific condition of approval with respect to reliability. Hydro One submits that based on the foregoing such a condition is not required. Hydro One's further submissions on the proposed condition are set out in Section 7 below.

5.2 Service Quality

All parties acknowledge that all of Hydro One, PDI and OPDC exceed the OEB's target scorecard metric for key service quality metrics. As a result, all are performing above expectations. The primary issue raised was with respect to the "Telephone Answered on Time" metric (the "Telephone Metric") where Hydro One was below that of PDI and OPDC. Without accurate consideration of the broader evidence, OEB Staff and intervenors asserted that acquired customers would either be worse off or see no improvement. However, for the reasons below, these submissions should not be accepted.

It is important to place the Telephone Metric in the appropriate context. This metric reflects the percentage of calls that are answered within 30 seconds. The metric does not reflect the percentage of calls unanswered, but rather calls answered in a specific and short time limit. Hydro One's metric significantly exceeds the OEB target of 65%.

> "MR. FALTAOUS: I think to clarify, the measure is not that people are not getting an answer. It's basically the percentage of calls that are answered within 30 seconds.
>
> MR. SHEPHERD: Yes.
>
> MR. FALTAOUS: So it doesn't mean that the calls are not answered. It's that they're -- you know, Hydro One 78 percent of the time is answering their calls within 30 seconds, and some of the calls are taking a little bit longer than that to answer. So it's not that customers are not getting a response."[143]

[142] Exhibit A-2-1, Section 2.2.
[143] Technical Conference Transcript, Vol. 2, p. 59.

SEC also argued that with the addition of 51,000 more customers, Hydro One has provided no evidence that it has a plan to handle an additional 50,000 calls a year with no more personnel.[144] The evidence contradicts SEC's assertion that there is no evidence of a plan or increased expenditure on customer service. In fact, Hydro One intends to add more customer care personnel and costs. As indicated at the technical conference:

> "MR. FALTAOUS: Okay. Yeah. And so customer care, you know, we would generally refer to this as shared costs, but there is incremental customer-care costs with taking on a lot more customers, so that would be representing the incremental portion of customer-care costs.
>
> MR. HARPER: I understand. I was just trying to categorize them, because yesterday we were talking about what were shared costs and what were not shared costs. And I just wanted to clarify, because I appreciate -- and I think we clarified yesterday, customer care was in the shared-cost category.
>
> MR. FALTAOUS: It is shared, but there is also an incremental element of cost.
>
> MR. HARPER: I fully understand that."[145]

In EB-2018-0270, Hydro One has shown the incremental customer care costs in interrogatory response I-1-19 Attachment 1 and I-5-9 (in EB-2018-0242, I-1-17 and I-4-25) and discussed the costs in I-5-8 (in EB-2018-0242, I-4-26).

Hydro One's forecast considers all incremental OM&A costs which by definition include applicable incremental administration or support services costs (e.g. customer care). Customer care (e.g. billing, call center) represents a significant incremental cost that has been provided for in the Hydro One Forecast. Exhibits I-1-19 and I-1-17 in EB-2018-0270 and EB-2018-0242, respectively, provide the forecast approach and annual dollar amounts forecast. Overhead costs, such as finance and human resources, are expected to experience no incremental costs.

Hydro One has also introduced, and will continue to introduce, technological options to enhance customer experience and interaction that neither PDI nor OPDC has the customer base to provide.

[144] SEC Submission, para. 3.2.6.

[145] Technical Conference Transcript, Vol. 2, p. 117.

Hydro One's customer service area is going through and is anticipated to continue to go through significant transformation/evolution over the 10-year planning period which forms this application. Many of these transformations relate to a customer shift to greater reliance and use of digital service channels which typically can be delivered at a lower cost than traditional channels.[146]

The Hydro One Call Centre is open longer and is supported by an award-winning 24/7 Interactive Voice Response ("IVR") system in addition to customer service staff.[147] When an outage occurs, Hydro One customers can use other channels, such as online access via smart-phone or other battery-charged laptops and devices, for receiving information about outage details, including estimated restoration time. Customers have the option to sign up for e-mail or text outage notifications. Hydro One has a redesigned website and *myAccount* self-service portal, providing an array of information and tools, such as *Predict My Bill*.

OEB Staff and intervenors downplayed these important aspects of customer service that Hydro One can provide even though they are for the most part beyond the current reach of PDI and OPDC. As PDI stated at the technical conference:

> "MR. WHITEHOUSE: We have the capabilities of gathering that material at this time, but the cost for a smaller utility like that to have outage management and automated services like that that Hydro One has, it is just not within our realm to be able to afford to be able to do that.
>
> MR. SHEPHERD: Because it costs too much?
>
> MR. WHITEHOUSE: Because it costs too much.
>
> MR. SHEPHERD: Thank you."[148]

SEC dismissed Mr. Whitehouse's view in its submissions and speculated that all distributors will have the above capabilities in the future. However, SEC has no evidence in this regard and it is purely conjecture. Its submissions should be disregarded.

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[146] Undertaking JT2.10

[147] This IVR provides customers the ability to self-serve, for many of their most common account and service needs, such as reporting a power outage and obtaining their current account balance.

[148] Technical Conference Transcript, Vol. 2, pp. 61-62.

Hydro One is able to offer customers a high level of service quality and the ability to take advantage of technological changes that neither PDI or OPDC can provide. The proposed Transactions, in this regard, not only do no harm, but are to the benefit of PDI and OPDC customers.

6. OTHER ISSUES

6.1 Earning Sharing Mechanism (ESM)

Hydro One will implement an ESM for Years 6 to 10 of the deferred rebasing period that protects PDI and OPDC customers and ensures that they share in the excess earnings[149] resulting from the consolidations. Hydro One's ESM will guarantee a cumulative $3.2 million of over-earnings to be shared with former OPDC customers and $1.8 million to be shared with the former PDI customers. Hydro One also submits that its proposed ESM better protects the acquired customers than the ESM set out in the OEB's *Consolidation Policy,* which contemplates using the consolidated entity's audited financial statements. Due to the relative size of PDI and OPDC compared to Hydro One, any savings resulting from the transactions would have limited impact on the overall earnings shown in Hydro One's financial statements.[150] As such, Hydro One proposes to calculate the excess earnings on the operations of the acquired entities as opposed to the consolidated new entity's earnings.[151]

For this calculation, Hydro One plans to use forecast OM&A and capital costs in which the OM&A forecast includes a 20% risk factor.[152] Hydro One proposes to record the guaranteed refund due to ratepayers in a deferral account, accruing interest as prescribed by the OEB. Hydro One has also

[149] "Excess earnings", as discussed in Exhibit A-3-1, means the LDC's share (50%) of net income (earnings) in Years 6 to 10 that is more than 300 basis points above the LDC's approved ROE.

[150] The OEB recognized this concern in the 2016 Handbook, commenting that the "ESM as set out in the 2015 Report may not achieve the intended objective of customer protection for all types of consolidation proposals" and inviting applicants "to propose an ESM that better achieves the objective of protecting customer interests during the deferred rebasing period".

[151] Exhibit A-3-1, p. 3.

[152] As set out in Exhibit A-3-1, Table 1, p. 5 (PDI and OPDC).

requested to apply to dispose of the balance in the deferral account in Year 10 but is not opposed to refunding the ESM earnings on an annual basis.[153]

Given the significant level of forecast savings, 65% to 70% of OM&A[154], and reductions in capital costs when compared to the Status Quo, Hydro One submits that the savings levels incorporated in its proposed ESM, along with the guarantee which shifts all the risks to Hydro One, is reasonable and should be approved as filed.

VECC appears to imply that an actual annual ESM calculation using Hydro One's ESM methodology (and the live excel ESM model provided in evidence) would produce a better result.[155] However, in the circumstance where actual results are used, it is important to note that the ESM will only provide additional payments to ratepayers if Hydro One achieves a level of savings greater than that forecast in the evidence. VECC's position, together with that of SEC which also rejects Hydro One's proposal, is peculiar since both regard Hydro One's forecast savings as flawed, but at the same time expect Hydro One to exceed those savings for purposes of ESM. Neither VECC or any other intervener proposed that Hydro One's savings could be a level that would drive a higher ESM than that proposed. Under Hydro One's proposal ratepayers receive the guaranteed payment regardless of the timing and actual total level of savings achieved.

If Hydro One were to be forced to adopt a different version of the ESM, one that is calculated on actuals, the risk of not achieving the cost forecast is then shared between Hydro One shareholders and acquired LDC ratepayers. Hydro One submits, an ESM calculation based on actual results for periods 6 to 10 years into the uncertain future does not protect ratepayers better than the guaranteed ESM Hydro One is proposing in the application. Hydro One, as mentioned elsewhere in this argument, stands by its residual cost forecast and believes it is a reasonable expectation of where both OM&A and capital costs will land. The ESM guarantee is a real and significant benefit to customers and would be lost if the ESM is not approved as filed.

VECC takes issue with the 20% risk factor applied to the ESM in Hydro One's proposal. Hydro One submits that the 20% is reasonable based on the fact that Hydro One's shareholder is accepting

[153] Exhibit A-3-1, p. 8.
[154] Exhibit A-2-1, Table 1.
[155] VECC Submission, p. 14.

the risk that the OM&A forecast is not achieved, the risk that assets are not in the condition anticipated and the risk that the anticipated load and customer load profiles do not materialize. The application of the risk factor is in exchange for a guaranteed amount which is to the benefit of acquired customers under the ESM. All of the risks of attaining the synergy savings as outlined in the application as well as all other economic risks (inflation, tax changes, union salary adjustments) are being assumed by Hydro One's shareholders.[156] The customers of PDI and OPDC hold absolutely no risk under Hydro One's proposed ESM, if approved as filed. Notwithstanding the foregoing, VECC proposes a reduction in the OM&A Risk Premium but provides no basis or rationale for the proposed decrease to 10%. Hydro One submits that given the risks associated with the transactions under its proposal, the 20% risk factor is reasonable and appropriate.

The OEB is being asked to approve the Transactions as proposed by Hydro One. If the OEB does not find the ESM as proposed based upon its underlying assumptions fully acceptable, then the OEB's alternative is to establish an ESM as provided for by the *Consolidation Handbook.*

In that circumstance, Hydro one would use the actual costs to serve PDI and OPDC to calculate an ESM, in a form that more closely aligns with that described in the *Consolidation Handbook.* This calculation would also include the actual depreciation charged on the assets associated with serving each as well as the then-current debt and tax rates. Any over-earnings (in Years 6 to 10) 300 basis points over the current OEB-approved ROE for PDI or OPDC would be shared with customers. There would be no guaranteed amount. Hydro One would not be able to provide audited statements but would provide working papers to show how the over-earning calculations were derived.

6.2 Accounting Matters

OEB Staff[157] and SEC[158] both submit that Hydro One's request to use US Generally Accepted Accounting Principles ("GAAP") in respect of PDI's and OPDC's financial accounting and reporting should be granted. Hydro One identified two areas where its use of US GAAP versus

[156] Exhibit I-1-20.
[157] OEB Staff Submission, p. 24.
[158] SEC Submission, para. 5.5.1.

modified IFRS could impact revenue requirement – capitalization policies and the level of PP&E componentization.

6.2.1 *Capitalization of Overhead Costs*

Energy Probe's submission with respect to PDI asserts that excluding overheads from the PDI forecast would reduce the Hydro One forecast by $400,000.[159] This is incorrect.

As shown in evidence,[160] if PDI were to capitalize indirect overheads (in addition to its direct overheads) in the same manner as Hydro One, it would decrease the PDI Status Quo revenue requirement forecast in Year 11 by $400,000 (from $24.9 million to $24.5 million), and decrease the OPDC Status Quo revenue requirement forecast by $60,000 (from $13.44 million to $13.39 million).[161] This was the only identified difference between OPDC's and PDI's GAAP under IFRS, and Hydro One's US GAAP policies. OPDC, PDI and Hydro One's accounting policies all allow capitalization of overheads, the only difference being that Hydro One capitalizes indirect overheads, whereas OPDC and PDI do not. Hydro One's Residual Cost-to-Serve revenue requirement is based on *incremental* costs and therefore does not include overhead costs.

As such, Hydro One submits that the Status Quo and Residual Cost-to-Serve forecast revenue requirements are comparable. Hydro One's request to adopt US GAAP for the PDI and OPDC service territories for financial and regulatory reporting will not have a material impact on the reported results of either utility starting after the close of the Transactions.

6.2.2 *Depreciation*

OEB Staff propose in their submission that the OEB establish a deferral account to capture any material transition impact that is favourable to acquired customers.[162] Hydro One takes no issue with a deferral account to the extent that it is symmetrical in the treatment of ratepayers and Hydro One. However, if the OEB is contemplating the approval of an account that is asymmetrical in nature, as suggested by OEB Staff, Hydro One does not believe this would reflect a measured or

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[159] Energy Probe Submission, p. 4.

[160] Undertaking JT2.2.

[161] Energy Probe Submission, p. 4, and VECC Submission, p. 11. Technical Conference Transcript, Vol. 2, p. 137.

[162] OEB Staff Submission, p. 25.

balanced approach to setting conditions for these Applications or encourage further consolidations. Additionally, Hydro One does not believe that OEB Staff have provided sufficient rationale or evidentiary basis that would justify the imposition of such a one-sided asymmetrical account.

With respect to Hydro One's plan to restate the depreciation rates for PDI and OPDC assets, SEC submits "there is some information on the record as to the impact of this, but that information has not really been tested".[163] SEC's statement is incorrect. Extensive information has been provided during these proceedings in the form of interrogatory responses[164], undertakings[165] and evidence provided by witnesses at the technical conference in response to questions SEC and other interveners raised regarding the comparability of depreciation forecasts and the drivers of the comparative depreciation cost and rates. Hydro One confirmed that any potential change in depreciation cost is <u>not</u> a function of a change in accounting policy (as a result of changing from MIFRS to US GAAP). The differences in depreciation rates reflect the fact that blended rates were used in the status quo and residual forecasts that reflect each of the utilities' region-specific asset mix. The actual depreciation rates by asset category (unblended) reflect each utility's asset life expectancy, which is reflective of the applicable maintenance and operating polices[166] under their respective asset stewardship.

Hydro One's assessment is that the overall remaining lives of the acquired assets are approximately equal to the remaining life of Hydro One's assets and that the pooled depreciation methodology and rates will be reflective of these assets under Hydro One's ownership[167] and not give rise to material depreciation differences.

SEC and other interveners had ample opportunity to review the evidence regarding this issue and cross-examine witnesses at the oral hearing, but failed to do so. This is hardly a reason to declare the evidence on this issue as not having been tested. In fact, on Day 2 of the technical conference

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[163] SEC Submission, para. 5.6.4.
[164] For example, Exhibit I-4-19 (PDI).
[165] JT1.5.
[166] *Ibid*.
[167] *Ibid*.

VECC offered a summary of the position of Hydro One and appeared to understand it very clearly.[168]

The blended depreciation rates forecast for the type of asset categories Hydro One expects to invest in for the acquired service territories are effectively equal. As provided in evidence and during the technical conference, the comparable depreciation rates for the blended asset category distribution plant are 2.39% for PDI and 2.30% for Hydro One.[169] OPDC's blended depreciation rate for this category is also comparable to Hydro One's.[170] Distribution plant is the asset category where more than 92%[171] of each utility's respective total asset acquisitions will be included (under both a status quo scenario and a post-transaction scenario). Hydro One maintains that once the acquired assets (approximately $35 million of OPDC's assets and approximately $75 million of PDI's assets) are pooled with Hydro One's distribution system assets of approximately $7.5 billion,[172] these acquired assets are not of sufficient size or weighting to move Hydro One's pooled asset useful lives by USofA asset, and as such will not have a material impact on the pooled depreciation rates or depreciation cost results on a go-forward basis. The impact of the change in depreciation expense of the acquired assets is not a result of the change in depreciation rates or the adoption of a difference accounting standard. As such, Hydro One submits the proposed condition for a deferral account is not appropriate; and if such an account is created, Hydro One maintains that based on its assessment, no entries are expected to be recorded in it over the 10 year deferral period.

6.3 Tax

SEC submits that because of the structure of each transaction, the value of assets or goodwill for tax purposes will increase. Because the issue of whether the benefit of the FMV bump for tax purposes is shared between customers and shareholders is currently before the Courts, SEC submits that Hydro One should be required to calculate that benefit and hold it in a deferral account for future consideration by the OEB.

[168] Technical Conference Transcript, Vol. 2, pp. 90-91.
[169] Exhibit 1-4-19 (PDI).
[170] Technical Conference Transcript, Vol. 1, p. 78.
[171] Technical Conference Transcript, Vol. 1, p. 139
[172] Technical Conference Transcript, Vol. 1, p. 20.

SEC's submission should not be accepted. First, SEC fails to acknowledge the distinction between the matter currently under appeal and the facts of these applications. The matter before the courts is unique to those circumstances and should not be seen as a rule of general application. The current transactions deal with the acquisition of shares/assets where a purchase price has been paid as opposed to an Initial Public Offering.

SEC's notion is based on an incorrect statement of OEB policy. SEC wrongly believes that the "Board's policy requires that some portion of that bump go to rate payers."[173] This is incorrect as evidence by the 2006 EDR OEB report which states "the Board rejects the proposal by Schools, and concludes that tax savings arising from disallowed expenses, including purchased goodwill and charitable donations, will not be allocated to ratepayers. Ratepayers have not paid for the expense through rates, and therefore are not entitled to the tax benefit."[174] The OEB's position above supports the cost follows benefits principle. As the purchase price premium is a true cost to the shareholder (not passed on to ratepayers); it follows that the tax benefits arising from it should also belong to the shareholder. It would be inappropriate to have Hydro One calculate and track the FMV bump to be shared with rate-payers in a deferral account for these two transactions.

6.4 Specific Service Charges (SSCs)

With respect to Hydro One's proposal to alter the SSCs of PDI and OPDC to align with those of Hydro One following consolidation, Hydro One notes that OEB Staff support this proposal, correctly observing that the revenue differences arising between Hydro One's and the acquired utilities SSCs are not significant.

SEC does not support Hydro One's proposal with respect to SSCs and states that Hydro One has not demonstrated that its generic service charges are more appropriate for PDI and OPDC customers. It is important to note that the majority of SSCs are in fact either the same amount or less for Hydro One as compared to PDI and OPDC.[175] Additionally, for OPDC, the difference in miscellaneous service revenue between applying OPDC versus Hydro One service charges is less

[173] SEC Submission, para. 1.4.4(f).
[174] RP-2004-0188 - 2006 EDA Handbook – Report of the Board (May 11, 2005), p. 55.
[175] JT2.5; Exhibit I-1-13 (OPDC).

than $14,000.[176] A similar analysis provided for PDI, shows that the difference in miscellaneous service revenue between applying PDI versus Hydro One service charges based on 2018 service volumes shows that PDI customers would have paid $295,000 less if Hydro One's charges had been applied.[177] This is largely because Hydro One no longer levies the $15 Notification Charge on Overdue Accounts that PDI applies. Based on the foregoing, the SSC for PDI and OPDC should be aligned with Hydro One following consolidation.

Further information on SSCs and the OEB's initiative to update those costs on an industry-wide bases is found in section 4.5.2.2 above.

7. CONDITIONS

OEB Staff have proposed five conditions that they believe should be imposed on the approval of both the PDI and OPDC Transactions. However, as set out below, the conditions as proposed by OEB Staff are misplaced in the current circumstances for three main reasons: (i) the Transactions clearly create no harm; (ii) even if the risk alleged by OEB Staff was material, the OEB has the inherent jurisdiction to protect ratepayers in the absence of the proposed conditions; and (iii) some conditions as proposed are unworkable. To the extent that the OEB considers it necessary to impose one or more of the conditions proposed by OEB Staff, Hydro One has proposed alternative approaches which, when combined with the OEB's inherent powers, provide ratepayers with the protections intended by OEB Staff.

The stated purpose of OEB Staff's conditions is to shift the risks associated with the proposed consolidations from ratepayers to Hydro One. However, this view of risk transfer is inaccurate. Hydro One as the consolidating utility always bears the risk of any consolidation transaction; the ratepayer will not bear the risk in the normal course. Since the OEB will assess the resulting rates after the deferred rebasing period, the consolidating entity, having made and relied on its forecasts as the basis for entering into the Transactions, bears the risk of achieving those forecasts.[178]

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[176] Exhibit I-2-6 (OPDC).
[177] JT2.6.
[178] *Consolidation Handbook*, pp. 11 and 17.

A decision of "no harm" in these proceedings will not transfer risk to ratepayers and will in no way diminish the OEB's statutory authority and obligation to set just and reasonable rates at the end of the deferral period. Further, the establishment of just and reasonable rates requires that ratepayers pay "no more than what is necessary for the service they receive."[179] This ensures that ratepayers are protected from the transfer of risk. The OEB's responsibility – and particularly a future OEB panel's responsibility – to protect the interests of ratepayers is not lost with a decision of "no harm" regarding the current Applications.

The foregoing was evident in the OEB's decision in EB-2017-0049 where Hydro One proposed rates for its recently acquired utilities: Norfolk Power, Haldimand County Hydro and Woodstock Hydro. In that decision, the OEB indicated that if the outcome of the acquisition was contrary to the public interest objective that was clearly articulated in the OEB's MAADs decisions approving the proposed acquisitions, it was appropriate for the OEB to consider the consequences.[180]

Because of the OEB's ongoing authority and obligation to set just and reasonable rates, SEC's proposition that there is some unalterable permanence to the transaction that leaves ratepayers unprotected is a fallacy. Although shares and physical assets will be exchanged, the cost consequences arising from the Transactions will not be fully materialized until after the deferred rebasing period. The OEB retains the power to evaluate those costs at the end of the deferred rebasing period and determine how they will affect rates. This impact on rates is what matters to customers, and because the OEB retains ongoing jurisdiction to set just and reasonable rates, the rate consequences of the Transactions are in no way permanent, unalterable or foreordained as SEC suggests.

Therefore, a key principle that should guide the OEB in deciding to set any condition is as follows: if the OEB has the inherent jurisdiction to deal with the circumstance that the condition is attempting to control, then the condition should not be imposed.

This is an appropriate guiding principle for two reasons. First, if the OEB has the inherent power to deal with the issue in question in a future proceeding, then the condition will be unnecessary.

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[179] *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44 at para. 20.
[180] EB-2017-0049 Decision and Order, p. 164.

The ratepayer will be protected from the perceived risk by the OEB, which must exercise its statutory powers reasonably and, in some cases, according to a standard of correctness.[181]

Second, imposing conditions over circumstances that the OEB has inherent jurisdiction to address in future proceedings would fetter the discretion of a future panel, preventing it from dealing with those issues differently based on changed circumstances or new/better evidence. Indeed, some of the conditions proposed by OEB Staff include a predetermined disallowance. This would directly pre-empt a future panel's determination of just and reasonable rates in accordance with the OEB's statutory mandate. It would also preclude the consideration of relevant evidence or circumstances that are not currently contemplated or which may only arise at the time of rebasing.

It is well established that a statutory body may not predetermine issues or fetter the discretion of a future panel in a way that prevents that panel from fulfilling its statutory mandate.[182] Nor can an administrative decision-maker fetter its discretion "by excluding from consideration evidence bearing on [its] statutory mandate."[183] Consistent with these principles, energy regulators across Canada have consistently stressed the need not to fetter the discretion of future panels in setting rates, particularly where, as here, the evidence is insufficient for a final determination of rates.[184] This flexibility is especially important to preserve with respect to the OEB, as unlike some other utility regulators, the OEB has "broad latitude to determine the methodology it uses in assessing

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[181] *Canada (Minister of Citizenship and Immigration) v. Vavilov*, 2019 SCC 65 at paras. 17, 52. The Supreme Court held that although there is a presumption that reasonableness is the applicable standard of review for administrative decisions, decisions that are subject to a statutory appeal mechanism must be reviewed according to appellate standards. Subsection 33(1) of the *Ontario Energy Board Act, 1998*, provides that "an order of the Board" may be appealed to the Divisional Court "upon a question of law." Questions of law are subject to correctness review on appeal: *Housen v. Nikolaisen*, 2002 SCC 33 at para. 9.

[182] Sara Blake, *Administrative Law in Canada*, 6th ed. (Toronto: LexisNexis Canada, 2017), ¶3.14; *Wauzhushk Onigum Nation v. Minister of Finance (Ontario)*, 2019 ONSC 3491 at para. 136; *Parsons Pond Foundation Ltd. v. Corner Brook School District No. 3*, 2003 NLSCTD 126 at para. 18; *Yorkdale Group Inc. v. Ontario (Registrar, New Home Warranties Plan Act)*, 2015 ONSC 2238 at para. 3.

[183] *Max Realty Solutions v. Canada (Attorney General)*, 2016 FC 620 at para. 9.

[184] See, e.g., *Canadian Utilities Ltd., Re*, 1999 CarswellAlta 1765 at para. 69 (Alta. E.U.B.) ("…the Board will not fetter the future discretion of the Board in setting rates for the entities resulting from the reorganization. The level of detail examined in this proceeding was sufficient for the questions at hand, but not for final determination of rates for the resulting entities."); *TransCanada PipeLines Ltd.*, Re, 2014 CarswellNat 9807 (N.E.B.) ("…approval in this proceeding of the requested segmentation tolling parameter would not constrain in any way the Board's future determinations as to whether Mainline tolls for a given period are just and reasonable and not unjustly discriminatory."); *FortisBC Energy Inc., Re*, [2016] B.C.W.L.D. 4576 at para. 74 (B.C. Utilities Comm.) ("These criteria are being added for greater regulatory efficiency and in no way are intended to bind future panels by fettering their discretion.").

utility costs, subject to the Board's ultimate duty to ensure that payment amounts it orders be just and reasonable to both the utility and consumers."[185] It is therefore inappropriate to impose conditions in respect of circumstances that a future OEB panel has the power and duty to address.

The more appropriate basis for imposing a condition on an applicant is to affect or control activities that the regulator cannot directly perform or otherwise control because they are within the day-to-day management of the applicant. These could include, for example, reporting, the tracking of data, or the use of a particular accounting standard. There are aspects of the OEB Staff conditions that appropriately fall within this category. However, there are mechanical and other issues with fulfilling the actions contemplated in the OEB Staff conditions.

Each of the OEB Staff's conditions are considered below:

7.1 Condition 1 – Cost Limit

According to OEB Staff, the intent of Condition 1 is that costs to serve (Hydro One takes "cost to serve" to mean revenue requirement to be collected through rates after the deferral period) the current PDI and OPDC service territories that exceed the status quo forecast are not recoverable through rates. For the purposes of this condition, OEB Staff propose reducing the PDI and OPDC status quo forecasts to reflect a CAGR of no more than 2.9% from the time the utility last rebased. OEB Staff propose that any costs to serve PDI and OPDC customers above the revised status quo forecasts should not be recoverable by Hydro One through rates. As set out in Section 4.5.1 of this reply, there is an error in OEB Staff's calculation of CAGR; the correct CAGR values for PDI and OPDC are both 2.9%, which are in fact appropriate per OEB Staff's own measure. Therefore, no adjustments to the status quo forecasts are required.

At page 27 of their submissions, OEB Staff draw a parallel between Condition 1 and the OEB's rate decision in EB-2017-0049, where Hydro One was obliged to absorb the revenue shortfalls associated with its costs to operate. The fact that this parallel is drawn reinforces that Condition 1 is something that the OEB has the power to impose as part of its consideration of Hydro One's rate proposal at the end of the deferred rebasing period.

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[185] *Ontario (Energy Board) v. Ontario Power Generation Inc.*, 2015 SCC 44 at paras. 7, 105.

OEB Staff have proposed two options for Condition 1. The first is that the rebasing plan to be filed at the end of the deferred rebasing period plan must enable the OEB to determine the costs to serve PDI and OPDC customers in order to assess what costs are above the status quo forecast and not recoverable (the "Cost to Serve Option"). In the event the OEB felt it necessary to impose the condition (which Hydro One believes is not necessary for the reasons above) through the Cost to Serve Option, Hydro One submits that the status quo "Total Cost to Serve" forecasts filed in the Applications[186] would be used as the not-to-exceed costs, since the forecasts are reflective of the Transactions and the best available status quo revenue requirement forecast of both PDI and OPDC. If the OEB deems this condition necessary, Hydro One would be willing to accept the condition that Hydro One shareholders absorb any costs, that would otherwise be collected through customer rates, that are in excess of the status quo cost to serve forecast of each of PDI and OPDC, have been updated for current economic parameters,[187] and include any expenditures that qualify for an ICM as described in the *Consolidation Handbook*.[188]

The second option caps the rates Hydro One can charge to acquired customers going forward (the "Rates Option"). OEB Staff appear to be uncertain as to how the Rates Option would work, as they provide only an example of this option's mechanics. Hydro One submits that if a condition is to be imposed, its mechanics should be clear in order to enable Hydro One to appropriately evaluate the impact of the condition on the Transactions. In any event, Hydro One believes that the proposed Rates Option is not workable. In effect, it results in the OEB making a rate decision under section 78 of the *Ontario Energy Board Act, 1998* (the "OEB Act") as a part of a decision of "no harm" under section 86 of the OEB Act. This is well outside the scope of the "no harm" test and is clearly contrary to the MAADs policy to decide rates at the time of rebasing and not before the deferred rebasing period has even begun. Further, the OEB would be making this rate decision without any evidence on the actual costs to serve and whether just and reasonable rates would exist at the time of rebasing. Hydro One believes making a rate decision 10 years in advance of the implementation of the rates in question, and without the necessary evidence, would be

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[186] Exhibit A-4-1, Table 2.

[187] Oral Hearing Transcript, Vol. 2, p. 70.

[188] *Consolidation Handbook*, p. 17 "Materiality thresholds for the ICM will be calculated based on the **individual distributors' accounts** and not that of the consolidated entity."

unreasonable, premature, and contrary to the OEB policies and the Consolidation Handbook. A future OEB panel is best placed to make this rate decision.

7.2 Condition 2 – Capital Budgets and Accountability

Condition 2 restricts Hydro One's actual capital expenditures for the acquired utilities to its capital expenditure forecasts in each of the Applications for the deferred rebasing period. If these expenditures are exceeded, the additional costs would not be recoverable.

Condition 2, as stated by OEB Staff, is not appropriate. The condition imposes on Hydro One a more restrictive and onerous standard than what typically applies to all other OEB-regulated utilities. In the normal course, to the extent capital forecasts are exceeded, a utility must show that the expenditure was prudently incurred. It is unfair and punitive to subject Hydro One to a higher standard than other utilities. The condition effectively means that even if an expenditure is prudent, it is automatically denied. This is not an appropriate condition, as the OEB has the full authority to decide the issue at the end of the deferred rebasing period, in the absence of the condition. The ratepayer is not exposed to any risk, incremental or otherwise, in the absence of this condition because of the OEB's authority to assess the capital expenditure in question.

Moreover, the condition is excessive as there may be any number of circumstances where prudent and reasonable expenditures need to be made, such as province-wide mandated expenditures on capital assets (e.g. storage solutions, electric vehicles), major storm damage asset replacement, manufacturer recall of assets installed previously or during the deferral period, and assets required due to unexpected forecast load growth in the areas (which would be offset by higher revenues, thus having no or minimal impact on rates).[189] Yet these expenditures would be denied according to the wording of the condition.

Given the fact that the proposed Condition 2 is not appropriate, if the OEB nevertheless deems it necessary to impose a condition, Hydro One would propose the following:

[189] Technical Conference Transcript, Vol. 2, pp. 112-113.

1. Hydro One will report on capital expenditures in its 2023 and 2028 rate applications for the period after the Transaction close and after integration has occurred.

2. Hydro One will report on any differences between its actual and forecast capital expenditure levels over the 10 year deferral period at the time of the first rebasing.

7.3 Condition 3 – Reliability and Service Quality

Condition 3 requires Hydro One to separately track reliability and service quality performance metrics of acquired and legacy customers and to demonstrate that neither has deteriorated because of consolidation. As set out in Section 5 above, Hydro One has shown that reliability and service quality for each acquired utility will not be affected and may improve with the Transactions, such that there is no harm. Hydro One believes that Condition 3 is not required. In any event, the condition as stated by OEB Staff is contrary to the MAADs policy, is administratively onerous for both Hydro One and the OEB, and is unworkable.

According to the OEB's *Consolidation Policy*, "The OEB believes that it is in the best interest of consumers to have consolidating entities operate as one entity as soon as possible after the MAADs transaction."[190] In this regard, Condition 3 proposed by OEB Staff is directly contrary to the intent of the Consolidation Policy. The proposed condition provides as follows:

> "To fulfill this requirement, <u>Hydro One must separately report the measures</u> within the Service Quality, Customer Satisfaction, and System Reliability performance categories <u>included in the OEB's scorecard for former PDI and former Orillia Power</u> from the overall Hydro One service territory reporting at the same time as it reports on its capital costs discussed earlier (i.e. as part of its future cost based rate applications during the deferred rebasing period). For clarity, <u>this reporting requirement is not intended to replace Hydro One's consolidated annual scorecard</u>." (emphasis added)

In order to comply with this condition, service and reliability must be measured and reported not as a consolidated entity but rather as three separate entities even though the systems will be operated and services will be provided on a consolidated basis.

With respect to system reliability, as an example, Condition 3 could inhibit Hydro One's ability to optimize system configuration, as an artificial service territory border would have to be maintained

[190] OEB, *Report on Rate-Making Associated with Distributor Consolidation* (March 26, 2015), p. 7.

to track the necessary information. With consolidated operations there is no artificial boundary, such that comparative reliability data could not be tracked on a standalone basis.[191] Maintaining an artificial boundary would not be appropriate as it will not be reflective of actual consolidated operations. It would also require more manual (and costly) processes to track information outside of Hydro One's consolidated systems, which would be inefficient.[192] Hydro One also notes that such a condition would not be consistent with the overall policy intent to promote consolidation and long-standing direction from the OEB to eliminate artificial electrical borders and promote contiguity,[193] so as to achieve operating and capital savings and provide long term benefits to ratepayers relative to the status quo.

With respect to service quality, for example, OEB Staff and intervenors raised questions about telephone response time (as discussed in Section 5 above). This would require Hydro One to track not only response times on an integrated company-wide basis, but also response times for each of the acquired utilities to provide a scorecard metric for each of the acquired service territories.

Condition 3 requires the ongoing maintenance of acquired distributor specific processes, losing the efficiency of consolidation. This will increase costs, thereby altering the Hydro One forecasts provided in the Applications to account for new incremental costs. If OEB Staff intended for Condition 3 to support no harm and consolidation, which is intended to promote efficiency, it is hard to see how Condition 3 in any way contributes to an efficient result.

Condition 3 as proposed also includes mandatory provisions that if metrics decline for reasons related to consolidation, Hydro One must make investments to return performance to pre-construction levels. With respect, this is not workable. How and the basis on which the three utilities are calculating and recording the metrics varies so there is likely no appropriate baseline metric with adjustments to existing data to provide alignment. In addition, there could be any number of reasons why metrics could change. The OEB would need to make a finding of fact through a proceeding to determine the root cause. The OEB also has limits to its jurisdiction, and it is questionable as to whether the OEB can compel a utility to undertake a specific investment.

[191] Oral Hearing Transcript, Vol. 2, pp. 107-108.
[192] *Ibid*.
[193] RP-2003-0044 Decision and Order, para. 84.

No such direct statutory authority exists. Enforcement of the condition is likely unworkable and, in any event, would create an additional regulatory burden on Hydro One and the OEB.

Nonetheless, Hydro One is cognizant of the OEB's language in the previous OPDC decision with respect to reliability, specifically that:

> "The OEB is satisfied based on the evidence before it, that it can be reasonably expected that Orillia Power's quality and reliability of service would be maintained following a consolidation. The fact that the consolidated entity is required to report on reliability and quality of service metrics in its annual filings confirms to the OEB that any reduction in service quality would become apparent and would be addressed therefore reducing any risk of harm."[194]

Hydro One believes that the language above is the best basis on which to track reliability and service quality.

Nonetheless, if the OEB deems it necessary to impose segregated utility reporting conditions on system reliability, service quality and customer satisfaction, Hydro One would be willing to report, on a best efforts basis leveraging its existing processes, the following:

- New residential/small business services connected on time
- Scheduled appointments met on time
- Telephone calls answered on time
- First contact resolution
- Billing accuracy
- Customer satisfaction survey results
- SAIDI
- SAIFI

However, as noted this information may not be comparable to the historical LDC scorecard reporting. Hydro One has already discovered a number of areas where the three LDCs report these

[194] EB-2016-0276 Decision and Order, p. 16

numbers in a different manner.[195] As a result, alignment of data would have to occur to establish an appropriate baseline. In any event, the measures above should not be used as a basis for capital expenditures as described in Condition 2, and Hydro One does not accept the condition to increase capital expenditures.

7.4 Condition 4 – Tracking Costs During the Deferred Rebasing Period

Under Condition 4, OEB Staff propose that Hydro One should be required to track all costs (capital and OM&A) to serve the acquired customers, including shared costs during the deferred rebasing period. Within its shared costs definition, Hydro One has both incremental and non-incremental shared costs. These are discussed in Section 4 of this submission.

Hydro One has already committed to tracking all incremental shared costs during the deferred rebasing period for both PDI and OPDC.[196]

The tracking of non-incremental shared costs, however, is not possible. This is not because Hydro One does not want to track these costs, but because it is virtually impossible to identify and record them to a specific customer group. Unlike incremental shared costs, which can be uniquely and wholly identified (e.g., cost to print and email a customer bill), non-incremental shared costs cannot be separated and uniquely identified. They can only be allocated. For example, what part of a desk in the accounting department or part of a person in human resources is attributable to PDI or OPDC acquired customers? This is why in the post deferred rebasing period the OEB and Hydro One employ the OEB CAM, which appropriately allocates the costs. This is customary for all utilities (gas and electric) whose rate-setting is regulated by the OEB.

Furthermore, Hydro One neither sees nor understands the value in the request by OEB Staff to want to know, *during the deferral period*, what those costs would be. Any allocation of Hydro One's shared costs will only impact customers upon their rebasing of rates. During the deferral period, Hydro One's legacy customers will continue to pay their OEB approved rates, as will the

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[195] For example, for First Contact Resolution, Hydro One reports based on a customer perception if they received resolution on first contact using a follow-up survey, OPDC reports first contact resolution only if the call needed to be escalated beyond the customer service representative, and PDI's reporting only tracks escalations to senior management.

[196] Beyond the deferred rebasing period, Hydro One will also continue to track capital expenditures for both acquired utilities.

customers of PDI and OPDC (adjusted by a PCI in Years 6 to 10). An allocation of shared costs, will not impact any of these customers.

However, to assist the OEB, Hydro One is willing in its 2023 rates application to provide an example of how shared costs would be allocated to PDI and OPDC customers based on the CAM as if the deferral period had expired at that time. This would include all the incremental costs associated with serving those customers, plus an illustration of how the CAM would allocate shared costs to them. Hydro One believes this is a better portrayal of how the rates for these customers (versus some ineffective tracking of costs) will be formed after the deferral period.

7.5 Condition 5 – Assignment of Shared Costs

Condition 5 is that Hydro One must demonstrate how much of the shared costs have been allocated to the acquired customers in the first rate rebasing application following the deferred rebasing period. Condition 5 is effectively the same as Condition 1, such that if it is determined that it is not possible to appropriately allocate shared costs to acquired customers and still maintain rates below the limit established in Condition 1, any incremental amount of shared costs beyond the established limit would not be recoverable by Hydro One through future rates. OEB Staff further submits that Hydro One should not be allowed to reduce the R/C ratios for either PDI or OPDC outside of the OEB-approved ranges. Hydro One submits that the need to reduce the R/C ratios outside the OEB-approved ranges would only occur if the costs to be collected from the acquired customers exceeded the limit established in Condition 1, and therefore adopting the requirements in Condition 1 will also cover this aspect of Condition 5. As such, Hydro One submits that Condition 5 is fully addressed by Condition 1 and therefore not needed.

Hydro One's submissions with respect to the need for Condition 1 also apply to Condition 5. However, if the OEB deems it necessary to establish Condition 5, Hydro One would accept that condition subject to its being based on the OEB R/C ratio ranges that are currently approved. It is not appropriate for Hydro One to commit to establishing rates for customers at this time if the R/C ratios are unknown.

7.6 Other OEB Staff Conditions

OEB Staff also set out certain other conditions of an administrative nature as follows:

1. *Hydro One should be required to provide a draft accounting order related to its proposed ESM deferral account*

Hydro One will commit to filing such a draft order upon approval of one or both applications or prior to any entries into such an account.

2. *A deferral account should be established to capture any material impact resulting from the proposed transition to US GAAP that is favourable to acquired customers and Hydro One should be required to provide a draft accounting order.*

OEB staff submits that Hydro One's request to use US GAAP in respect of PDI's and OPDC's financial reporting should be granted. As part of OEB staff's submissions, OEB Staff proposed that the OEB establish a deferral account to capture any material transition impact that is favourable to acquired customers. Hydro One takes no issue with a deferral account to the extent that it is symmetrical in its treatment of ratepayers and Hydro One (see Section 6 above).

3. *Hydro One should be required to provide DSPs in its next cost-based application (due in 2022 for 2023 rates) for the PDI and Orillia Power service territories. The DSPs should include information on currently planned investments in the status quo forecasts developed by PDI and Orillia Power. In the event that Hydro One wishes to seek an ICM in advance of 2023 rates, then it should file the associated DSP as part of the ICM application.*

Hydro One will provide DSPs for PDI and OPDC service territories. However, the timing of the filing of the DSP with Hydro One's 2023 rates application may be problematic. This is because approval of the purchase is required to begin the integration process, and time is also required to prepare the information as part of the 2023 application (likely made in 2021). At this time, and prior to transaction close, Hydro One neither owns the assets nor has full access to them, making it impossible for Hydro One to carry out such a major undertaking (i.e., the development of a DSP). As a result, it may be of greater assistance for Hydro One to commit to filing DSPs within 18 months of integration, which would allow Hydro One time to assess the condition of the purchased assets and how they align with the customers' needs.

7.7 SEC – Deferral and Variance Account Conditions

SEC submits that, if the OEB approves either of these Transactions, a condition of approval should be that amounts to the credit of customers in 1575 and 1576 be cleared to customers within the 12-month period after closing. This condition is acceptable to Hydro One.

8. CONCLUSION

Based on the foregoing, Hydro One submits that that the evidence clearly demonstrates that the "no harm" test is satisfied and that the submissions of OEB Staff and intervenors in these proceedings have not provided any reasonable basis to suggest otherwise. Therefore, the leave sought by the Applicants should be granted.

All of which is respectfully submitted this 24th day of January 2020.

HYDRO ONE NETWORKS INC. and HYDRO ONE INC.

By its Counsel:

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