F-12 K2.2

EB-2018-0242/0270

HYDRO ONE NETWORKS

ORILLIA POWER DISTRIBUTION CORPORATION
MAADs EB-2018-0270

PETERBOROUGH DISTRIBUTION INC.
MAADs EB-2018-0242

VECC COMPENDIUM

December 3, 2019

TAB 1

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0242**	**Hydro One Networks Inc. / Peterborough Utilities Inc.**
	EB-2018-0270	**Hydro One Networks Inc. / Orillia Power Distribution Corporation**

VOLUME: **Technical Conference**

DATE: **October 4, 2019**

Peterborough ratepayers, yes.

MS. GIRVAN: When do you intend to clear those accounts?

MR. FLANNERY: So we would take a look at those. So generally, we would get to where we thought it would be a material balance. So if it wasn't written anywhere, in terms of the SPA or the asset purchase agreement, the APA. If it wasn't outlined there, we would take a look at it and when it got to sort of a material balance in terms of that utility, we would then look to dispose of those amounts.

MS. GIRVAN: Okay. So you don't know at this stage?

MR. FLANNERY: We haven't made a determination yet.

MS. GIRVAN: Okay. Thank you.

MR. FLANNERY: I guess, just in following on from that, as you can see from Peterborough's attachment 1, a lot of these accounts are commodity-based. So if you have a look at the second -- or actually the first item on attachment 1, the wholesale market service charge, it seems to have -- some of these items take some swings in debits and credits, depending on what those global adjustments are from period to period.

So a material balance that is negative might go back, as it is done in the 2017 numbers, from a debit to a credit.

So from year to year, there is definitely some movements there.

MS. GIRVAN: Okay. I guess my concern, again, this is sort of like the ICM discussion we were having earlier

TAB 2

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0242**	**Hydro One Networks Inc. / Peterborough Utilities Inc.**
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page 11 is the net movement? Ah.

MR. HURLEY: Yes.

MR. SHEPHERD: Okay. So you're getting net movement of 694 or something each year?

MR. HURLEY: In that range.

MR. SHEPHERD: Give or take. Which means that you already now owe the customers 2.6 million, and by the time this case is over it will be another -- it will be like 3.3 or more? Is that right?

MR. HURLEY: That's correct.

MR. SHEPHERD: Okay. You haven't applied to have that cleared, have you?

MR. HURLEY: No. We did one such application a few years ago, and we did reduce the liability by about 1.3 million. However, we haven't done one since.

MR. SHEPHERD: Are you planning to do another one?

MR. HURLEY: Not at this time, no. We are awaiting the decision --

MR. SHEPHERD: Okay. So I will ask Hydro One. If the sale is approved are you planning to clear this? And if so, when?

MS. RICHARDSON: My understanding from a conversation I had yesterday -- and I did mean to check that last night, so I'm sorry -- is that the addendum to the share purchase agreement requires us to clear this account at the time that the purchase is completed. So it will be refunded to the ratepayers of Orillia at that point in time, once the OEB approves it, of course.

TAB 3

OEB STAFF INTERROGATORY # 19

Reference:

Exhibit A-2-1, Table 1 Projected Costs Savings; Page 19 Incremental Transaction and Integration Costs

Interrogatory:

Questions:

a) Please provide a more detailed breakdown for how the Status Quo Forecast and Hydro One Forecast was quantified in Table 1 of Exhibit A-2-1, showing the supporting calculations for the differences in OM&A and capital under both scenarios, as well as any key assumptions or figures used in those calculations.

   i. Please ensure that the more detailed Exhibit A-2-1 Table 1 requested in part a) above also separately presents the timeline and any underlying calculations supporting the incremental transaction costs ($0.2M) and integration costs ($9.0M).

Response:

a) Exhibit A, Tab 2, Schedule 1 Table 1 provides a comparison of OPDC's operations as a stand-alone distribution company relative to the costs of operating OPDC's service territory once it is integrated within Hydro One. Please refer to Attachments 1 and 2 of this response for the detailed calculation of Projected Savings summarized in Exhibit A, Tab 2, Schedule 1, Table 1.

   Hydro One's projections regarding the integrated service territory are based on its overall, provincial distribution operations which utilize an Asset Risk Assessment (ARA) process. The Hydro One ARA process encompasses the assessment of a multitude of applicable asset categories. In the OPDC integration case, Hydro One examined the functions outlined below:

   - Vegetation Management
   - Lines Maintenance and Refurbishment
   - Demand Work
   - Wood Pole Replacement
   - Stations

OPDC - EB-2018-0270	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	YR 1	**YR 2**	**YR 3**	**YR 4**	**YR 5**	**YR 6**	**YR 7**	**YR 8**	**YR 9**	**YR 10**
CAPITAL EXPENDITURES BREAKDOWN - STATUS QUO										
Service centre	10,000	10,000	10,000	10,000					8,000,000	
Substations		2,800,000		100,000						
Poles & wires	2,177,000	1,295,000	1,391,000	1,646,000						
Meters	383,000	163,000	33,000	33,000						
Heavy Vehicles	690,000									
Light vehicles	80,000	80,000	75,000	40,000						
Other capital assets	91,000	91,000	91,000	91,000						
To be determined					2,900,000	3,000,000	3,100,000	3,200,000	3,300,000	3,400,000
GROSS CAPITAL EXPEI	3,431,000	4,439,000	1,600,000	1,920,000	2,900,000	3,000,000	3,100,000	3,200,000	11,300,000	3,400,000
Contributed capital (defer	**218,000**	**130,000**	**139,000**	**165,000**	**150,000**	**160,000**	**170,000**	**180,000**	**190,000**	**200,000**
NET CAPITAL EXPENDI	3,213,000	4,309,000	1,461,000	1,755,000	2,750,000	2,840,000	2,930,000	3,020,000	11,110,000	3,200,000
Percentage increase (c	-36.2%	34.1%	-66.1%	20.1%	56.7%	3.3%	3.2%	3.1%	267.9%	-71.2%

TAB 4

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0242**	**Hydro One Networks Inc. / Peterborough Utilities Inc.**
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VOLUME: **Technical Conference**

DATE: **October 4, 2019**

how many existing substations do you have?

MR. HIPGRAVE: Sure. So we have nine in our system. I think I may have mentioned this yesterday, but no problem. It's -- we've got one that is actually coming online this year. We have one that we built in 2016. I think it came online just early in '17.

Looking at the remaining seven, five of those are in the 1970s vintage. So, you know, currently they're at 40 to 50 years of age. So our intention over the period '24 to '30 would likely be to build two, possibly three, although we've smoothed that cost over those five years, not knowing at this point exactly what year we would build those substations in.

MR. HARPER: Fine, thank you. I was just trying to sort of understand the reason -- you have been helpful in that regard. Thank you very much.

MR. HIPGRAVE: You're welcome.

MR. HARPER: Those are all of my questions.

MR. MILLAR: Okay, anyone else? Okay. Very good. With respect to undertakings, do we have a guesstimate on the timeline for those?

MR. KEIZER: I think it was in the Board order, was it not?

MR. MILLAR: Oh, yes, it is. You're right. I'm sorry. I have it right here. So why don't I just read that. The date for that is October 18th. So do you think we will be on-track for that?

MR. KEIZER: I think we just have to assess --

TAB 5

UNDERTAKING - JT1.9

Reference:

Undertaking:

To provide the calculations for capital spend for OPDC and for PDI.

Response:

When deriving the Hydro One forecast for an LDC territory Hydro One's investment plan is used as a starting point for establishing an expenditure plan to ensure the prudent management of its distribution system. From there the plan is scaled to the LDC's demographics and further adjusted to account for specifics related to the LDC (e.g., asset condition, age, characteristics, etc. as compared to Hydro One's system). This is illustrated in Figure 1 below.

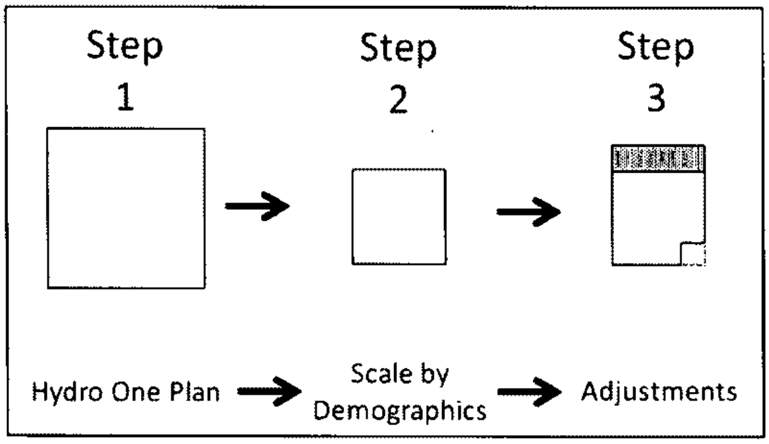

Figure 1

Hydro One's plan utilizes an Asset Risk Assessment (ARA) process. The Hydro One ARA process encompasses the assessment of a multitude of applicable asset categories. In both the OPDC and PDI integration cases, Hydro One examined the functions outlined below:

- Vegetation Management
- Lines Maintenance and Refurbishment
- Demand Work
- Wood Pole Replacement
- Stations

- Environment
- Other Sustainment
- Customer Connections / Upgrades
- System Reinforcement
- Distributed Generation
- Other Development.

As part of the due diligence process supporting the transactions, Hydro One conducted field assessments, visual inspections and evaluations in Peterborough and Orillia to collect asset information on existing PDI and OPDC assets. This information feeds directly into the capital expenditure forecasts (as explained above) and itemized in the attachments to JT1.8.

There are three main steps in the calculation of the Hydro One forecasts.

1. Hydro One's investment plan is used as a starting point representing a prudent plan needed to manage a distribution system.

2. Key system demographics are used to scale the Hydro One investment plan dollars to account for the size of the acquired LDC, effectively scaling Hydro One system costs down to the size of the LDC. These key system demographics are listed below:

   - Number of Customers
   - Total Circuit Length (km)
   - Overhead Circuit Length (km)
   - Underground Circuit Length (km)
   - Right of Way Length (km)
   - Number of Stations.

3. The scaled system costs are further adjusted to account for specifics related to the LDC being acquired (e.g., asset condition, asset age, unique system characteristics, etc.). As noted above, the information used to make such adjustments is obtained through Hydro One's due diligence via site visits, filed assessments, etc.). Some specific examples that were taken into account in deriving Hydro One's forecasts for the Peterborough and Orillia service areas include:

   - Station condition

- Urban vs rural service territory
- Pole density per km of line
- Proportion of overhead vs underground circuits
- PCB compliance status
- Local vegetation density.

The end result is a forecast that represents the Hydro One funding needed to prudently manage the acquired OPDC and PDI service territories once integrated into Hydro One Networks. A more specific capital plan will be prepared by Hydro One post-closing of any PDI and OPDC transaction.

The foregoing provides the basis for the assessment of the LDC's assets and the methodology, including scaling variables, that was used to establish the more granular forecasts set out in Undertaking JT1.8. Consistent with the OEB's typical review of capital forecasts, the provision of the mathematical calculations underpinning the forecasts are not relevant to the Board's consideration of the issues in this proceeding.

TAB 6

UNDERTAKING - JT1.8

Reference:

Undertaking:

To provide more granularity for the capital plan, similar to attachment at SEC 23.

Response:

Please find on Attachment 1 and 2, more granularity for the Hydro One capital plan for the Peterborough and Orillia service territories, respectively. Hydro One has provided more granularity for the capital plan in key categories of spend. A best effort attempt was made to utilize the categories found in PDI's and OPDC's capital plan which is provided in EB-2018-0242 Exhibit I, Tab 2, Schedule 23, Attachment 1 and EB-2018-0270 Exhibit I, Tab 1, Schedule 19, Attachment 4 respectively. Where spend could not be placed into one of the existing categories, we utilized the categories aligning with the functions detailed in EB-2018-0242 Exhibit I, Tab 1, Schedule 17 part a) and EB-2018-0270 Exhibit I, Tab 1, Schedule 19 for Peterborough and Orillia respectively.

Hydro One cautions against simple total dollar comparison between status quo and Hydro One's capital spending forecast in any specific category due to differences in investment and system planning approaches. For example, Hydro One has various options to address station risk for the PDI service territory such as load transfers, voltage conversion, station refurbishment, and full station replacement. Hydro One also has the ability to mitigate risk of failures with methods unavailable to PDI such as a more than adequate level of spare transformers and a fleet of Mobile Unit Substations.

Hydro One's capital envelope for PDI sufficiently addresses station needs as required. For example, the Hydro One station capital expenditure envelope over the 10 year period is sufficient to complete 6 station rebuilds/major refurbishments as well as 10 transformer replacements that could address 7 or more additional stations. Additionally, funding is also sufficient for station decommissioning as deemed appropriate. Hydro One has identified a number of specific stations to be addressed and anticipates additional station needs will arise in the forecast period. The specific plans for each station will be developed post integration.

Attachment 1

Hydro One Forecast (Peterborough)

($'s in thousands)

		2020 Year 1	2021 Year 2	2022 Year 3	2023 Year 4	2024 Year 5	2025 Year 6	2026 Year 7	2027 Year 8	2028 Year 9	2029 Year 10
Land	*Note 1*										
Buildings	*Note 2*										
Distribution Stations		986	3,696	1,617	1,259	1,791	3,124	1,358	1,393	1,429	1,465
Poles and Fixtures	*Note 3*										
Overhead Conductor	*Note 4*										
Underground Conduit	*Note 4*										
Underground Conductor	*Note 4*										
Transformers	*Note 4*										
Services	*Note 5*										
Meters		344	641	570	585	600	544	558	572	587	602
Measurement and Test Equipment		0	0	0	0	0	0	0	0	0	0
System Supervisory Equipment	*Note 6*										
Computer Equipment		0	0	0	0	0	0	0	0	0	0
Transportation Equipment	*Note 1*										
Wood Pole Replacements		204	503	516	529	543	557	571	586	601	616
Line Refurbishment		312	768	788	808	829	850	872	894	917	940
System Reinforcement		156	384	393	403	412	422	432	442	453	464
Customer Connections & Upgrades / Distributed Generation		486	1,195	1,224	1,253	1,283	1,314	1,345	1,378	1,411	1,444
Demand Work		107	264	271	278	285	293	300	308	316	324
Stand Alone LDC (7 mths)	*Note 7*	3,411									
Contributed Capital	*Note 8*										
Net Capital Expenditures		**6,007**	**7,452**	**5,379**	**5,115**	**5,744**	**7,103**	**5,437**	**5,573**	**5,713**	**5,856**

Note 1 Costs embedded in other categories as applicable
Note 2 Costs embedded in "Distribution Stations" and "System Reinforcement" categories
Note 3 Costs embedded in "Wood Pole Replacements", "Line Refurbishment", "System Reinforcement", "Customer Connections & Upgrades / Distributed Generation", "Demand Work"
Note 4 Costs embedded in "Line Refurbishment", "System Reinforcement", "Customer Connections & Upgrades / Distributed Generation", "Demand Work"
Note 5 Costs embedded in "Customer Connections & Upgrades / Distributed Generation" and "Demand Work"
Note 6 Costs embedded in "Customer Connections & Upgrades / Distributed Generation", "Distribution Stations", "System Reinforcement"
Note 7 Represents the 7 month period prior to operational integration with Hydro One
Note 8 Contributed capital accounted for in other categories as applicable

Attachment 2

Hydro One Forecast (Orillia)

($'s in thousands)

		2020 Year 1	2021 Year 2	2022 Year 3	2023 Year 4	2024 Year 5	2025 Year 6	2026 Year 7	2027 Year 8	2028 Year 9	2029 Year 10
Service Centre		0	0	0	0	0	0	0	0	0	0
Substations		215	531	546	562	579	596	614	632	650	669
Poles & Wires	*Note 1*										
Meters		422	187	193	198	204	210	217	223	230	236
Heavy Vehicles	*Note 2*										
Light Vehicles	*Note 2*										
Other Capital Assets	*Note 2*										
Wood Pole Replacements		68	168	173	178	183	188	194	200	206	212
Line Refurbishment		27	68	70	72	74	76	78	81	83	86
System Reinforcement		233	576	593	610	627	710	690	704	717	732
Customer Connections & Upgrades / Distributed Generation		290	716	737	758	779	879	856	873	891	909
Demand Work		49	122	125	129	133	136	141	145	149	153
Stand Alone LDC (7 mths)	*Note 3*	2,070									
Contributed Capital	*Note 4*										
Net Capital Expenditures		**3,375**	**2,368**	**2,436**	**2,507**	**2,579**	**2,796**	**2,790**	**2,857**	**2,926**	**2,997**

Note 1 Costs embedded in "Wood Pole Replacements", "Line Refurbishment", "System Reinforcement", "Customer Connections & Upgrades / Distributed Generation", "Demand Work"

Note 2 Costs embedded in other categories as applicable

Note 3 Represents the 7 month period prior to operational integration with Hydro One

Note 4 Contributed capital accounted for in other categories as applicable

TAB 7

SEC INTERROGATORY # 23

Reference:
[A/4/1, p. 2]

Interrogatory:
Please confirm that, taking into account depreciation each year, PDI currently expects to spend more than $115 million on capital (plus customer contributions) over the 17 year period 2013 to 2030, a compound annual growth rate of 3.5% per year. Please provide the Distribution System Plan or similar document of PDI supporting that level of capital spending. If there is no DSP or multi-year plan, please provide "PDI's 2019 Rate Base forecast" referred to in Attachment 20, with all supporting documents and all assumptions explained.

Response:
PDI's capital spend (before contributed capital) over the 17 year period (from 2013 to 2029) is forecast to be $126 million which is greater than the $115 million suggested in the above statement. Taking the gross expenditures of $5.2M in 2013 and the gross expenditures of $9.2M in 2029 represents a compound growth rate of 3.6%, not 3.5%.

Please see the Attachment to this Exhibit for further detail.

For PDI's forecast referred to in Attachment 20, please refer to Exhibit I, Tab 1, Schedule 17 Attachment 3.

PETERBOROUGH DISTRIBUTION INC.
STATEMENT OF CAPITAL EXPENDITURES

Note: the total for years 2013 to 2017 agree to the audited financial statements, 2018 numbers are interim numbers and prior to audit, 2020 to 2030 are projections.

($'s in thousands)

	Actuals						Budget	Forecast										
	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Land				6														
Buildings		134	138	94		2	60	62	63	62	62	62	62	62	62	62	62	62
Distribution Stations		56	1,356	217	15	55	877	2,142	2,143	2,344	1,545	1,546	1,648	1,649	1,748	1,745	1,842	1,644
Poles and Fixtures	996	606	1,230	1,847	1,384	681	1,121	883	893	1,138	1,135	1,258	1,084	1,081	1,294	1,286	1,422	1,458
Overhead Conductors	900	1,264	1,439	593	933	1,151	1,127	857	889	1,140	1,002	1,259	989	946	1,230	1,217	1,361	1,395
Underground Conduit	777	982	958	330	704	575	614	664	637	476	545	625	741	805	836	831	917	940
Underground Conductors	513	491	623	292	626	380	700	899	919	608	849	713	929	980	1,010	1,020	1,100	1,140
Transformers	1,082	2,033	1,041	836	1,394	1,181	1,529	1,285	1,273	1,256	1,759	1,643	1,643	1,694	1,824	1,846	1,957	1,995
Services	764	667	451	1,204	453	329	252	308	276	176	113	167	246	261	269	271	291	298
Meters	177	162	286	338	310	453	400	200	200	100	100	103	105	400	410	150	154	158
Measurement and Test Equipment			82	9	16													
System Supervisory Equipment			101		12	317												
Computer Equipment								250	671	45	50	50	50	100	50	500	50	50
Transportation Equipment							352	400	102	34	501	455	680	505	62	32	0	245
Gross Capital Expenditures	**5,209**	**6,395**	**7,704**	**5,766**	**5,847**	**5,124**	**7,033**	**7,948**	**8,066**	**7,378**	**7,660**	**7,881**	**8,176**	**8,481**	**8,794**	**8,960**	**9,156**	**9,384**
Contributed Capital	1,416	1,313	2,203	1,838	1,745	648	1,433	1,705	1,676	1,338	1,465	1,529	1,661	1,800	1,942	1,933	1,950	1,997
Net Capital Expenditures	**3,793**	**5,082**	**5,501**	**3,928**	**4,102**	**4,476**	**5,600**	**6,243**	**6,390**	**6,040**	**6,195**	**6,352**	**6,515**	**6,681**	**6,852**	**7,027**	**7,206**	**7,387**

TAB 8

OEB STAFF INTERROGATORY # 15

Reference:

Exhibit A-2-1, page 2 Table 1, pages 22-23
Exhibit A-3-1, page 8 Table 2

Interrogatory:

Preamble:

Hydro One is requesting approval to utilize US GAAP for accounting purposes in relation to the ongoing business of the former PDI. PDI currently uses IFRS for financial accounting purposes. The current distribution rates for the PDI service territory are underpinned by Modified IFRS (MIFRS) for regulatory accounting purposes and will continue to be during the deferred rebasing period.

a) Has Hydro One or 1937680 undertaken any studies or reviews of the types of transactions that will be impacted by the accounting standard transition from IFRS to US GAAP in the former PDI?

b) Please quantify the estimated impact on PDI's revenue requirement during the deferred rebasing period as a result of PDI changing its accounting standards. Specifically, please separate the components of revenue requirement that are expected to be impacted and show how these calculations are derived.

c) Please explain Hydro One's intentions with respect to how it plans to account for these differences with respect to distribution rates.

d) If Hydro One's intention in part d) above is to request to have an Accounting Order established to track the revenue requirement differences between MIFRS and US GAAP in the former PDI service territory as part of this proceeding, please prepare a Draft Accounting Order as an appendix for approval.

e) Please explain and quantify what impact, if any, the change from IFRS to US GAAP has on the amounts forecasted in Table 1: Projected Cost Savings - $M of Exhibit A-2-1.

f) Please prepare the amounts in Table 1: Projected Cost Savings - $M of Exhibit A-2-1 on the basis that PDI remains on IFRS (and continues with its existing accounting policies with respect to capitalization, depreciation, etc.) for financial reporting and MIFRS for ratemaking purposes.

g) Please explain and quantify what impact, if any, the change from IFRS to US GAAP has on the amounts forecasted in the proposed ESM calculation under Table 2: Earnings Sharing Mechanism of Exhibit A-3-1 (particularly, on OM&A, depreciation, financing costs, and taxes).

h) Please prepare the amounts in Table 2: Earnings Sharing Mechanism of Exhibit A-3-1 on the basis that PDI remains on IFRS (and continues with its existing accounting policies with respect to capitalization, depreciation, etc.) for financial reporting and MIFRS for ratemaking purposes.

Response:

a) Hydro One assessed areas of USGAAP and IFRS differences, and determined that the only area that could impact revenue requirement is the potential difference in capitalization policies of the two companies, particularly with respect to capitalization of certain overhead costs. In the Hydro One forecast capital costs noted in Exhibit A, Tab 2, Schedule 1, Table 1, there are no overhead costs as based on Hydro One's assessment they were deemed to be non-incremental. PDI's capitalization policy allows allocation of overheads to fixed assets. As such the difference between the Hydro One forecast capital costs and the Status Quo Peterborough capital costs in Exhibit A, Tab 2, Schedule 1, Table 1 is that the Peterborough costs include capitalization of overheads whereas in the Hydro One forecast no overhead costs are included.

b) Please see part a).

c) Please see part a).

d) Based on the response to part a) above Hydro One believes this is not applicable.

e) Please see part a).

f) Please see part a).

g) There is no impact.

h) See part g) above.

TAB 9

SEC INTERROGATORY # 47

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

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

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

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

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

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

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

TAB 10

UNDERTAKING - JT2.11

Reference:

Undertaking:

With respect to VECC 7c, to provide the forecast for Hydro One residual OM&A and Peterborough's status quo OM&A broken down to the level of detail shown in table 2, such that the differences reconcile with the amounts shown in the response.

Response:

Attachment 1 provides PDI Status Quo OM&A and Hydro One Forecast OM&A presented at the level of detail shown in EB-2018-0242, Exhibit I, Tab 4, Schedule 7 (VECC 7), Part c), Table 1.

Attachment 2 provides OPDC Status Quo OM&A and Hydro One Forecast OM&A presented at the level of detail shown in EB-2018-0270, Exhibit I, Tab 1, Schedule 3 (Staff 3), Part b), Table 1.

Attachment 1
PDI Savings / Synergy Category
($ thousands)

	Status Quo Forecast		Hydro One Forecast		Projected Savings	
	Year 2	Year 10	Year 2	Year 10	Year 2	Year 10
Administration						
Mgmt / Corporate Governance	975	1,182	-	-	975	1,182
Financial / Regulatory	723	876	-	-	723	876
Other	1,232	1,494	793	72	439	1,422
	2,930	**3,552**	**793**	**72**	**2,137**	**3,480**
Back Office						
Customer Service	1,836	2,226	2,033	2,215	(197)	11
Information Technology / Other	1,380	1,673	-	-	1,380	1,673
	3,215	**3,899**	**2,033**	**2,215**	**1,182**	**1,684**
Distribution Operations	**3,727**	**4,519**	**1,641**	**1,941**	**2,086**	**2,578**
Total OM&A	**9,872**	**11,970**	**4,467**	**4,228**	**5,405**	**7,742**

Attachment 2
OPDC Savings / Synergy Category
($ thousands)

	Status Quo Forecast		Hydro One Forecast		Projected Savings	
	Year 2	Year 10	Year 2	Year 10	Year 2	Year 10
Administration						
Mgmt / Corporate Governance	795	931	-	-	795	931
Financial / Regulatory	413	484	-	-	413	484
Other	634	742	498	88	135	654
	1,842	**2,157**	**498**	**88**	**1,344**	**2,069**
Back Office						
Customer Service	1,357	1,589	782	876	575	713
Information Technology / Other	574	673	-	-	574	673
	1,931	**2,262**	**782**	**876**	**1,149**	**1,386**
Distribution Operations	**1,881**	**2,202**	**729**	**919**	**1,152**	**1,283**
Total OM&A	**5,654**	**6,621**	**2,009**	**1,883**	**3,645**	**4,738**

TAB 11

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	**EB-2018-0242**	**Hydro One Networks Inc. / Peterborough Utilities Inc.**
	EB-2018-0270	**Hydro One Networks Inc. / Orillia Power Distribution Corporation**

VOLUME: **Technical Conference**

DATE: **October 3, 2019**

MS. RICHARDSON: Yes, that is correct.

MR. SHEPHERD: And on the second page here, it says if there is a change in union wage rates or if there's minor changes in interest or inflation rates, those would not be adjusted. Right?

MS. RICHARDSON: Correct.

MR. SHEPHERD: Major changes in interest rates or inflation rates would be adjusted, right?

MS. RICHARDSON: What we've said, if it is changes that would have occurred or impacted Orillia as a status quo forecast, they would be included in the adjustments.

MR. SHEPHERD: So all of these things like union wage rates and interest and inflation rates, no matter how big or small they are, you are going to treat them as a wash because they apply to status quo and to Hydro One?

MS. RICHARDSON: So the purpose here is to try to find out what the rates for Orillia would have been after the rebasing period in year 11, right?

MR. SHEPHERD: Hmm-hmm.

MS. RICHARDSON: So we've put -- Orillia has provided a forecast of what their costs will be. At this point in time we would expect those to be the costs of what will occur.

When it comes to setting rates in year 11, if we need to change the goalpost because cf some unforeseen cost changes, we would bring that forward in evidence and request approval for that change of the goalpost. And what we anticipate that would be is ones that would have occurred to Orillia if they had been a status quo or to their customers if they're operating under Hydro One.

MR. SHEPHERD: Sorry, if the same change applied to Hydro One and Orillia, then you wouldn't adjust or you would adjust? I don't understand.

MS. RICHARDSON: So for example, if there is a change in the Board's return on equity, we will adjust it for that. If there is a storm that goes through Orillia and all of their poles are torn down, they would have had to incur the costs to replace all of those assets regardless if we purchase or not. So those are the types of things that would impact the goalposts in year 11.

MR. SHEPHERD: Okay, I understand.

Can you go to number 26. What we were trying to get at is whether Hydro One replaces assets at higher costs than OPDC. And the same question applies to PDI as well.

And I am wondering if you can help the Board to understand what are the Hydro One replacement costs for particular categories of assets -- you certainly have that data -- and how does that compare to the current replacement costs for OPDC and PDI for similar assets? Again, this is data that you all have, right?

[Hydro One witness panel confer]

MS. RICHARDSON: So we would expect that information may be available for Hydro One for rates applications, but none of us here have that information, or some of the assets, not all of them. We don't have that information.

MR. SHEPHERD: Okay. But -- and you would not have

TAB 12

Ontario

ONTARIO ENERGY BOARD

FILE NO.:	EB-2018-0242	Hydro One Networks Inc. / Peterborough Utilities Inc.
	EB-2018-0270	Hydro One Networks Inc. / Orillia Power Distribution Corporation

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VOLUME:	Technical Conference
DATE:	October 4, 2019

acquisitions dependent on the customers of the current PDI and Orillia service territories being placed into new -- newly formed acquired rate classes?

So is it dependent? Certainly the consolidation handbook allows for that, the creation of new rate classes, and we believe that the creation of new rate classes is necessary to ensure that we're identifying the specific costs to serve.

So yes, I would say that the creation of new rate classes will best achieve the Board's goal of ensuring that we charge just the cost to serve to those customers.

MR. SHEPHERD: You don't have a rate class for any of the customers where you could put them directly into an existing rate class and the no-harm test would be met, right? Because in each case, if you put them into an existing rate class, their rates would go up. Is that right?

MR. ANDRE: So we haven't -- we haven't done the -- we haven't looked at what it would look like putting them in the UR residential and the UR general service classes. But as I indicated yesterday, even the -- you know, there's things with respect to the minimum system and the PLCC adjustments that would drive differences between the allocation to residential and general service.

And our minimum system and PLCC adjustments are different than for the acquired, so that would be one contributor. And I think I also mentioned yesterday that even though the density factors that are used for those

TAB 13

NAVIGANT

Independent review of proposed cost allocation and rate design approach

Prepared in the context of the Hydro One and PDI and Hydro One and OPDC MAAD applications

Prepared for

hydro one

Prepared by

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April 26, 2019

Basic principles of rate design

Likely the most widely cited work on utility ratemaking is the 1961 publication "Principles of Public Utility Rates" by Professor James C. Bonbright in which he identified guiding principles for rate design. To paraphrase, rates should be designed:

1. To yield enough revenue to recover costs;
2. Based on a fair apportionment of costs among different customers and avoiding 'undue discrimination' in rate relationships;
3. To provide efficient price signals and discourage wasteful usage; and
4. To be relatively stable, predictable, simple, and easy to understand.

The cost allocation study provides the basis for ensuring costs and revenue are apportioned fairly among customer classes. While great effort is expended to identify cost drivers and appropriate allocation factors to spread costs among customer classes, allocation factors are naturally subject to judgment and imprecision.

The theoretical ideal of cost-of-service-based rate design is to develop rates that precisely recover the costs allocated to a respective customer class. When revenue equals allocated costs, the class has a revenue-to-cost ratio of one. In practice, this outcome is rarely achieved. Consequently, it is generally accepted that an appropriate outcome is a revenue-to-cost ratio that falls within a range around one. Determining the appropriate level of tolerance that can be allowed and still result in rates that are just and reasonable is the subject of much debate.

Approaches for tying rate design to cost allocation studies vary widely across Canada and the United States. Navigant has not performed an exhaustive study of standards applied by regulators and public service commissions in each province or state, but we are aware that various policies are followed. Examples range from requiring all classes to be within one percent of cost of service, to simply viewing the cost allocation study as one of many factors to be considered when setting rates. Navigant believes it is generally recognised that allowing a utility flexibility to deviate from a revenue-to-cost ratio of one is an appropriate response to the imprecise cost allocation process and a reasonable approach to balance competing rate design objectives.

OEB principles of rate design for electricity distribution

Like the cost allocation protocols employed in the CAM, the OEB has established standardised classes and a standardised rate structure for each class.

TAB 14

ONTARIO ENERGY BOARD

FILE NO.:	EB-2018-0242	Hydro One Networks Inc. / Peterborough Utilities Inc.
	EB-2018-0270	Hydro One Networks Inc. / Orillia Power Distribution Corporation

VOLUME: Technical Conference

DATE: October 3, 2019

relative to the rest of Hydro One.

MR. SHEPHERD: Yes.

MR. ANDRE: And it would allocate Hydro One's average costs, and Hydro One is a largely rural utility, so the allocation of Hydro One's average costs without any adjustment is -- wouldn't result in the appropriate or -- it wouldn't accurately reflect -- which the Board tell us they want us to do -- it wouldn't accurately reflect the costs to serve those specific service areas.

MR. SHEPHERD: Right. So where I am going with this is the Board was very clear if you are going to apply it to the acquireds you have to apply the same rules to the legacy, so why are you not directly allocating the capital costs to serve the people in Brockville and in Smiths Falls and in Ancaster?

MR. ANDRE: Because for those areas, Mr. Shepherd, we don't know the specific amount of fixed assets associated with serving just those areas.

MR. SHEPHERD: And why don't you know that?

MR. ANDRE: Because we track all assets. Our financial system tracks all poles used within the distribution system, all transformers used within the distribution system. It doesn't have a geographic breakout, you know, for a particular community.

MR. SHEPHERD: You have a GIS, right?

MR. ANDRE: We do.

MR. SHEPHERD: And your GIS will tell you how many poles and what wires and what transformers and everything, even in some cases the vintage of those things, right?

MR. ANDRE: It will tell us numbers, but it won't tell us how much of the costs that are associated with -- you know, that are from our financial database are actually associated with those specific assets.

MR. SHEPHERD: So then when the Board said you have to apply the same rules to legacy as to acquired, you are basically saying, we can't, so we are not going to. Is that right? Because we just don't have the information.

MR. ANDRE: I think I have been very clear that we are applying the same rules. So the Board permits direct allocation where that is possible, and all of the allocation of OM&A costs and shared costs follow the exact principles that are underlying the Board's cost allocation model.

So I think we are following the cost causation principles.

MR. SHEPHERD: But you are not directly allocating to legacy customers. You are only directly allocating to acquired customers, right?

MR. ANDRE: Because we have the information that will let us accurately identify the costs of serving that service area within which the acquired customers are located.

MR. SHEPHERD: I am not saying that you are ignoring what the Board is telling you. What I am saying is the Board told you to do something and you're saying, we won't do that because we can't. Isn't that right?

MR. ANDRE: No. I disagree. I think the cost causation principle that we're applying for the acquired classes is not applicable to those specific communities that you referenced.

MR. SHEPHERD: All right. If you are willing to take an early lunch, I think that might be helpful.

MR. MILLAR: Okay. Why don't we do that. Let's come back in one hour.

MR. SHEPHERD: Yes.

--- Luncheon recess taken at 12:22 p.m.

--- On resuming at 1:29 p.m.

MR. MILLAR: Good afternoon, everyone. I would like to get us started again.

Mr. Keizer, has there been any progress with respect to the issues you were going to have a look at over lunch? These were with relation to some of the undertakings Mr. Shepherd was encouraging.

MR. KEIZER: I don't believe that I had specific ones that I was considering over lunch. Mr. Rodger may have --

MR. MILLAR: I'm sorry, I think that's right. It was Mr. Rodger.

MR. KEIZER: We did with respect to the update we did orally this morning -- sorry, with respect to the update that I did this morning, we did do a paper update. So we have distributed that to parties as well. But I don't think I had any particular...

MR. MILLAR: You're right. Mr. Rodger, were there any discussions?

TAB 15

UNDERTAKING - JT1.5

Reference:

Undertaking:
To provide a 1575 or 1576 calculation; if refused, to provide a reason.

Response:
Hydro One has completed the calculations of the Year 10 rate base value for both OPDC and PDI, if each utility kept their own depreciation rate and the capital additions were as provided in Table 1 of Exhibit A, Tab 2, Schedule 1, "Hydro One Forecast". For capital additions made in Years 1- 10, Hydro One maintained its own depreciation rate as these new assets will be purchased and/or constructed by Hydro One and then operated and maintained under Hydro One's ownership throughout the life of the asset.

The calculation, in the form of the 1575 calculation is provided in Attachment 1 for OPDC and Attachment 2 for PDI. The results are summarized below:

$000	2029			
	OPDC		PDI	
	HONI's Depreciation Rates	OPDC's Depreciation Rates	HONI's Depreciation Rates	PDI's Depreciation Rates
Net PPE	48,369	46,367	93,409	97,146
Avg. PPE	47,575	45,673	92,458	96,013
Working Capital	3,640	3,640	8,727	8,727
Rate Base	51,215	49,313	101,185	104,740
Difference	$1,902		($3,555)	

The above analysis shows that OPDC's rate base would have been lower in 2029 (year 10 of the deferred rebasing period) by $1.9M if OPDC's depreciation rates were used on the purchased assets; whereas PDI's rate base would have been $3.6M higher in 2029 if PDI's depreciation rates were used.

Hydro One reaffirms that the change in depreciation rates is not a function of a change in accounting policies (e.g. it is not related to the change from MIFRS to USGAAP). The depreciation rates used for forecasting purposes (Years 1 to 11 of the analysis) are blended averages and are impacted by each utilities' individual region-specific asset mix and for each utility are reflective of the maintenance and operating policies of the utility owning the assets (i.e. on a stand-alone basis each LDC will have slightly different asset weightings depending on the territory-specific needs of that LDC). Hydro One's depreciation rates are determined through an independent study by Dr. White at Fosters Associates, and underpin the depreciation rates by USofA as approved by the OEB. Once Hydro One integrates the assets of both OPDC and PDI into its distribution system, Hydro One's assessment is that the overall remaining useful life of the acquired LDC's assets is approximately equal to the remaining useful life of Hydro One's assets and therefore the use of Hydro One's depreciation rates will be reflective of the assets useful lives under its stewardship.

TAB 16

UNDERTAKING - JT2.8

Reference:

EB-2018-0242 Exhibit I, Tab 4, Schedule 9 (VECC 9)
EB-2018-0242 Exhibit I, Tab 4, Schedule 10 (VECC 10)
EB-2018-0242 Exhibit I, Tab 4, Schedule 12 (VECC 12)

Undertaking:

To update the numbers in the EB-2017-0049 draft rate order and cost allocation; to provide an updated to Hydro One responses VECC 9, 10, 12 based on the 2018 draft rate order and underlying cost allocation.

Response:

Hydro One is providing updates to the following EB-2018-0242 responses to reflect the results from Hydro One's 2018 cost allocation model as filed in its draft rate order in proceeding EB-2017-0049[1] ("2018 DRO"):

1. VECC 9 part b
2. VECC 10 part e
3. VECC 10 part f
4. VECC 12 part a
5. VECC 12 part b

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

1. VECC 9 part b). The table below provides the requested information.

	Forecast (as filed in 2018 DRO)
OM&A	$544,408,355
Total Number of Customers	1,303,822
UR	227,025
R1	447,465
R2	328,479
Seasonal	147,679
GSe	87,902
GSd	5,239
UGe	18,000
UGd	1,735
St Lgt*	21,581
Sen Lgt*	11,301
USL	5,490
Dgen	1,119
ST	807

Number of connections used for cost allocation purposes.

2. VECC 10 part e): Hydro One's average 2018 OM&A cost per customer is $176/customer for its UR rate class.

3. VECC 10 part f): Hydro One's average 2018 OM&A cost per customer for the UGe, UGd, and ST rate classes are shown in the table below:

Rate Class	OMA per Customer
UGe	$ 447
UGd	$ 5,028
ST	$ 23,904

4. VECC 12 part a): Hydro One's average depreciation per customer for UR, UGe, UGd and ST customer classes (based on the 2018 DRO) are provided below.

	Hydro One			
	UR	**UGe**	**UGd**	**ST**
Depreciation/Customer	$96	$351	$5,699	$18,737

5. VECC 12 part b): Hydro One's average NBV per customer for UR, UGe, UGd and ST customer classes (based on the 2018 DRO) are provided below.

	Hydro One			
	UR	**UGe**	**UGd**	**ST**
NBV/Customer	$1,552	$6,139	$98,771	$341,662

TAB 17

VECC INTERROGATORY # 9

Reference:

Exhibit A/T2/S1, page 3 (lines 1-7)
Attachments 2 & 4
OEB 2017 Yearbook

Interrogatory:

a) Please confirm that the 2017 HONI OM&A costs and customer counts used to derive the $179/customer cost for high density (UR) residential class are forecast values whereas the 2017 OM&A costs and customer counts for PDI are actual values.

b) Please provide a schedule that compares the HONI's total forecast versus actual 2017 OM&A costs and that also compares the customer/connection counts as used in the Cost Allocation Model submitted with the 2017 Draft Rate Order (EB-2016-0081) with the actual 2017 customer counts. (Note: Please include the forecast and actual customer/connection counts for each of HONI's customer classes).

Response:

a) Confirmed.

b) Table below provides the requested information.

	Forecast (as filed in 2017 DRO)	Actuals (2017)
OM&A	$592,962,820	$558,711,095
Total Number of Customers	1,312,485	1,295,709
UR	213,918	215,844
R1	445,243	447,647
R2	334,551	330,514
Seasonal	155,033	147,253
GSe	94,081	88,523
GSd	6,282	5,231
UGe	17,851	17,747
UGd	1,913	1,711
St Lgt*	20,700	22,595
Sen Lgt*	14,836	11,381
USL	5,734	5,455
Dgen	1,523	1,004
ST	822	805

1 *Number of connections used for cost allocation purposes.