

EB-2018-0242/0270

HYDRO ONE/PETERBOROUGH/ORILLIA MAADS

COMPENDIUM OF MATERIALS

SCHOOL ENERGY COALITION

SEC INTERROGATORY # 44

Reference:

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

Interrogatory:

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

Response:

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

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

¹ Total revenue collected from rates is derived by applying approved IRM increases between 2013 and 2019 to the approved revenue collected from rates in 2013.

² External revenues are held constant at 2013 approved values.

³ Estimated values for revenues related to LV charges have been added to the total distribution revenue collected as described in Exhibit A-4-1, pg 3.

⁴ Total revenue collected from rates for Year 10 (with consolidation) is derived by holding 2019 rates revenue requirement constant for 2020-2024 and then applying IRM factor of 1.55% for 2025-2029.

⁵ Total revenue collected (including external revenues) per Exhibit I, Tab 1, Schedule 10, part (d).

⁶ Total revenue collected (including external revenues) from the acquired rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (plus \$1.5M in estimated revenue collected from the "combined classes").

⁷ Total revenue collected (including external revenues) per Table 2, Exhibit A, Tab 4, Schedule 1, pg 4.

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

¹ Total revenue collected per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

² Total revenue collected is derived using the compound annual growth in total revenue requirement between 2017 and 2022.

³ External revenues are held constant at 2022 values per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

⁴ Total revenue collected for Hydro One legacy rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (minus \$1.5M in estimated revenue collected from the "combined classes").

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

OEB STAFF INTERROGATORY # 12

Reference:

Exhibit A-4-1

Interrogatory:

Questions:

a) Please provide a table which estimates Hydro One and OPDC revenue requirements and revenue requirements per customer:

- i. Today (e.g. 2019)
- ii. In Year 10 with the proposed consolidation
- iii. In Year 10 without the proposed consolidation
- iv. In Year 11 with the proposed consolidation, including all costs that are expected to be allocated to OPDC
- v. In Year 11 without the proposed consolidation

Please develop the comparison for each of the following customer types: Residential, General Service less than 50 kW, General Service greater than 50 kW and total of all customer types (i.e. total revenue requirement).

b) Please confirm that the values provided in response to part a) iv) above include OPDC rebasing following the end of the deferred rebasing period. If they do not, please ensure that they do.

Response:

a) The tables below provide the requested information for Hydro One's Urban rate classes and OPDC.

OPDC	Today (2019) ^{1,2,3}	Year 10 (2029) with consolidation ^{2,3,4}	Year 10 (2029) without consolidation ^{2,3,5}	Year 11 (2030) with consolidation ⁶	Year 11 (2030) without consolidation ^{2,3,7}
Revenue Requirement					
Residential	\$4,471,729	\$4,886,300	\$7,110,967	\$5,073,009	\$7,281,348
GS < 50kW	\$1,623,718	\$1,779,756	\$2,602,179	\$1,538,976	\$2,665,364
GS 50-4,999 kW	\$2,400,644	\$2,676,069	\$3,798,964	\$2,385,875	\$3,889,680
Other	\$363,045	\$395,662	\$596,908	\$588,293	\$611,972
Total	\$8,859,135	\$9,737,786	\$14,109,018	\$9,586,153	\$14,448,364
Revenue Requirement per Customer					
Residential	\$357	\$356	\$518	\$366	\$526
GS < 50kW	\$1,155	\$1,162	\$1,699	\$997	\$1,726
GS 50-4,999 kW	\$14,430	\$14,958	\$21,234	\$13,241	\$21,587
Other	\$90	\$95	\$143	\$140	\$146
Total	\$489	\$496	\$719	\$485	\$731

¹ Total revenue collected from rates is derived by applying approved IRM increases between 2010 and 2019 to the approved revenue collected from rates in 2010.

² External revenues are held constant at 2010 approved values.

³ Estimated values for revenues related to LV charges have been added to the total distribution revenue collected (refer to Exhibit I, Tab 3, Schedule 9).

⁴ Total revenue collected from rates for Year 10 (with consolidation) is derived by holding 2019 rates revenue requirement constant for 2020-2024 and then applying IRM factor of 1.7% for 2025-2029.

⁵ Total revenue collected (including external revenues) per Exhibit I, Tab 2, Schedule 17.

⁶ Total revenue collected (including external revenues) from the acquired rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (plus \$0.6M in estimated revenue collected from the "combined classes").

⁷ Total revenue collected (including external revenues) per Table 2, Exhibit A, Tab 4, Schedule 1, pg 4.

Hydro One	Today (2019) ¹	Year 10 (2029) with consolidation ^{2,3}	Year 10 (2029) without consolidation ^{2,3}	Year 11 (2030) with consolidation ⁴	Year 11 (2030) without consolidation ^{2,3}
Revenue Requirement					
Residential (UR)	\$97,456,815	\$121,420,723	\$121,420,723	\$137,202,655	\$137,390,232
GS<50kW (UGe)	\$23,037,678	\$28,770,504	\$28,770,504	\$28,015,108	\$28,054,505
GS>50kW (UGd)	\$28,548,646	\$35,752,868	\$35,752,868	\$31,919,505	\$31,966,604
Other	\$1,348,816,751	\$1,685,459,484	\$1,685,459,484	\$1,709,828,767	\$1,712,281,421
Total	\$1,497,859,890	\$1,871,403,579	\$1,871,403,579	\$1,906,966,036	\$1,909,692,763
Revenue Requirement per Customer					
Residential (UR)	\$424	\$469	\$469	\$525	\$526
GS<50kW (UGe)	\$1,276	\$1,520	\$1,520	\$1,471	\$1,473
GS>50kW (UGd)	\$16,413	\$19,665	\$19,665	\$17,452	\$17,478
Other	\$1,275	\$1,504	\$1,504	\$1,519	\$1,521
Total	\$1,146	\$1,337	\$1,337	\$1,354	\$1,356

¹ Total revenue collected per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

² Total revenue collected is derived using the compound annual growth in total revenue requirement between 2017 and 2022.

³ External revenues are held constant at 2022 values per Hydro One's Draft Rate Order in EB-2017-0049, Exhibit 1.0, filed April 5, 2019.

⁴ Total revenue collected for Hydro One legacy rate classes per Exhibit I, Tab 1, Schedule 49, Attachment 2 (minus \$0.6M in estimated revenue collected from the "combined classes").

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b) Confirmed.

Comparison of Assumed Cost Per Customer Increases

<i>Rate Class</i>	<i>2019</i>	<i>2030</i>	<i>Increase</i>	<i>CAGR</i>
<u>Hydro One</u>				
UR	\$424.00	\$517.00	21.93%	1.82%
UGe	\$1,276.00	\$1,475.00	15.60%	1.33%
UGd	\$16,413.00	\$17,506.00	6.66%	0.58%
<u>Orillia (no deal)</u>				
Residential	\$357.00	\$526.00	47.34%	3.58%
GS<50	\$1,155.00	\$1,726.00	49.44%	3.72%
GS>50	\$14,430.00	\$21,587.00	49.60%	3.73%
<u>Peterborough (no deal)</u>				
Residential	\$300.00	\$433.00	44.33%	3.46%
GS<50	\$749.00	\$1,044.00	39.39%	3.07%
GS>50	\$9,567.00	\$13,525.00	41.37%	3.20%

Sources:

EB-2018-0242 SEC #44

EB-2018-0270 Staff #12

1 MR. HARPER: Okay.

2 MR. ANDRE: Then in terms of the second part of your
3 question, so the number there, the equivalent number there
4 is the \$20,550,000, and that is the revenue that would be
5 collected from those PDI customers.

6 MR. HARPER: Right. Then when you go down, I think
7 there is a comparable part for the Hydro One part, and
8 that's with consolidation and that would show the revenue
9 to be collected from the, you know, the revenue
10 collected --

11 MR. ANDRE: That's correct.

12 MR. HARPER: -- it's the same -- okay, no, that's
13 fine.

14 MR. ANDRE: So it's the revenue collected. So it's
15 got some of the revenue that has been -- that's being
16 collected from the PDI customers, to the extent that
17 there's been some shared costs that are now being
18 collected. The combination of those two is the -- aligns
19 with the cost allocation model.

20 MR. HARPER: It also has the fact that for most
21 classes, the revenue-to-cost is one sort of thing. So it
22 isn't the allocated costs; it is the costs that will be
23 collected.

24 MR. ANDRE: Collected, that's correct.

25 MR. HARPER: I have to figure out where I am now, now
26 that you have managed to --

27 MR. ANDRE: Skip through a few questions?

28 MR. HARPER: Exactly. That's great. So if we could

1 to staffing where we might have part-time or contract or
2 temporary workers that are allowing us, in this period of
3 uncertainty, to keep the utility running as we should run
4 it.

5 However, if the regulatory decision is to decline this
6 approval, we've got to look at it as if -- essentially
7 regroup. We're doing a distribution system plan. We're
8 filing a cost of service. There's a couple of years' worth
9 of work there, as you well know.

10 But we've got to essentially reset the utility going
11 forward and say, you know, okay we brought back a retiree
12 on a part time contract basis to help us out in this time
13 of uncertainty. Going forward, if we're running this
14 utility, we would probably make a different decision. We
15 would go out and hire a full time person. They would be
16 on, you know, our pension and benefits plan.

17 So those costs are essentially worked into these
18 numbers going forward and then from 2020 to 2030, as Mr.
19 Hurley said, we'd essentially use an inflationary factor of
20 2 percent a year.

21 MR. SHEPHERD: So, Mr. Hurley, how much is -- that
22 five million 542 for 2020, how much is that more than 2018
23 actual?

24 MR. HURLEY: It is about \$500,000 more.

25 MR. SHEPHERD: So your status quo is about
26 five million more over the ten years than what you're
27 spending right now?

28 MR. HURLEY: How much did you say?

1 MR. SHEPHERD: Five million, \$500,000 a year for ten
2 years.

3 MR. HURLEY: Oh, okay. That's fair. Inflated by 2
4 percent.

5 MR. SHEPHERD: I am going to stop there. Thank you
6 very much.

7 MR. MILLAR: Thank you, Mr. Shepherd. I would like to
8 go a few minutes more before our break.

9 Mr. Kehoe, I know you travelled here from out of town
10 and would probably prefer to get done today. Are you
11 prepared to ask your questions?

12 MR. KEHOE: Yes.

13 MR. MILLAR: Are you prepared to go?

14 MR. KEHOE: I've got it here.

15 **EXAMINATION BY MR. KEHOE:**

16 MR. KEHOE: Now, in the discussion, we're in a
17 scenario that Ontario Power, at least Orillia Power
18 Distribution here is under pressure from the municipality
19 not to sell at any cost to supplement their agenda.

20 There isn't a situation anywhere that you could say
21 would run a comparison between the debt that Hydro One has
22 to assume and the record refurbishing of Darlington and the
23 power lines that were built in the 1950s, that they could
24 even remotely compete with Orillia's distribution.

25 Orillia's distribution has held a long-time record as
26 being in the lowest 5 percent of all the collective
27 municipal utilities. And they did so with the work ethic
28 that their employees had, and a goal to work totally in the

1 status quo?

2 MR. SHEPHERD: Yes.

3 MR. HURLEY: Yes, we did that.

4 MR. SHEPHERD: You did that. Okay. So what's the
5 assumed long-term debt rate in your status quo?

6 MR. HURLEY: We used the latest available Board-
7 approved rates that we had at the time, and I believe it
8 was 4.16.

9 MR. SHEPHERD: So you did not use the 6.25 on the
10 note?

11 MR. HURLEY: No, we did not.

12 MR. SHEPHERD: But that's --

13 MR. HURLEY: That is looking out to 2030. We went all
14 the way out using 4.16.

15 MR. SHEPHERD: But Hydro One, when you did the ESM
16 calculation, you used 6.25, right?

17 MR. FLANNERY: That's correct, for the ESM it uses the
18 rates embedded in Orillia's last approved cost of service.

19 MR. SHEPHERD: So if we looked at the difference
20 between the interest in the status quo calculation and the
21 ESM calculation, that's that difference of 6.25 to 4.16?
22 You didn't make any other adjustments?

23 MR. FLANNERY: No.

24 MR. SHEPHERD: Okay. And Hydro One's long-term debt
25 rate, is it lower than 4.16 or higher?

26 MR. FLANNERY: The recently approved Hydro One
27 Distribution debt grade in its last application was higher
28 than the Board's 2019 approved cost of capital, I believe.

1 MR. SHEPHERD: It is like 4.3 or 4.25 or something,
2 right?

3 MR. FLANNERY: It is higher. I think it is in, it is
4 in A-3-1 and I can -- let's check. It may not be in A-03-
5 01. It may be in attachment 20 to either application. I
6 believe the number is -- so this is attachment 20,
7 page 2 -- 4.47.

8 MR. SHEPHERD: All right. And then also on number 3,
9 SEC number 3, you talk about the increase in capital
10 expenditures for the new OPDC operation centre.

11 Now, first I want to ask the question of OPDC. You
12 have a plan that if you are not acquired, you are going to
13 have to build a new op centre, right?

14 MR. HIPGRAVE: That's correct.

15 MR. SHEPHERD: And that's in roughly 2027, 2028?

16 MR. HIPGRAVE: I believe in the schedules it falls in
17 2028, assuming that year one is 2020.

18 MR. SHEPHERD: Now, you actually have a sort of a
19 fairly urgent need for that, don't you?

20 MR. HIPGRAVE: Urgent is a relative term. We began a
21 process in 2013 of having a full-scale building assessment
22 done by professionals. And as a result of that, there was
23 obviously, you know, options to repair, refurbish or
24 replace.

25 And at that time the decision was that we would begin
26 the process of looking to design a new building, as that
27 was the most -- the best fit really going forward for the
28 organization, the best business decision.

1 willing to show us how you calculated that 9-million-880?

2 MR. HURLEY: It's a very big model. I mean, it is not
3 that I am -- I am not trying to be uncooperative. I just
4 don't understand why you need it.

5 MR. SHEPHERD: Okay, so I will explain. So your
6 existing rates have in them a ROE which is about 100 basis
7 points higher than the current rate, right?

8 MR. HURLEY: A hundred basis points -- we're at 9.85,
9 yes.

10 MR. SHEPHERD: Right. Your existing rates have a
11 working capital allowance of 15 percent, right?

12 MR. HURLEY: Correct.

13 MR. SHEPHERD: Your existing rates have your old
14 depreciation rates, right?

15 MR. HURLEY: Sorry?

16 MR. SHEPHERD: They have your old depreciation rates.

17 MR. HURLEY: Yes.

18 MR. SHEPHERD: Not the new ones.

19 MR. HURLEY: Correct.

20 MR. SHEPHERD: There's a bunch of changes like that
21 that are quite significant. Is that true?

22 MR. HURLEY: Yes. To go forward, yes, there are.

23 MR. SHEPHERD: And so what I would like to see is how
24 did you take those into account to get to an increase in
25 revenue requirement when you are already making lots of
26 money.

27 We can see -- you have reported already what you're
28 making.

1 line 2, the one thing I would point out is you can see in
2 the historical, just out of interest, 2015 is where we
3 actually did the one substation that I referred to. Not
4 all of the cost is in that distribution station line. I
5 referred to it being 2.1, but you can also see the run rate
6 on the actual capital spend and distribution stations has
7 been by band-aid. There hasn't been any money spent.

8 And then forecasting going forward, I think that we're
9 looking probably at one a year over the next nine years.

10 MR. SHEPHERD: So then I want to ask the same --

11 MR. JOHN STEPHENSON: I could get more detail for you
12 for -- roughly.

13 MR. SHEPHERD: That's good. So how many distribution
14 stations, substations are in the Hydro One plan?

15 MR. FALTOUS: So this plan has been developed to be
16 able to address the risks associated with six substations
17 for Peterborough over the ten years.

18 MR. SHEPHERD: So whereas they were going to replace
19 nine, based on their very close knowledge of the situation,
20 you are only going to replace six?

21 MR. FALTOUS: I think, to clarify -- so the approach
22 that we take to asset investments is based on condition.
23 It may not be based on age and it may be a little bit
24 different than Peterborough's.

25 So, you know, what we deemed was a prudent number to
26 address over the ten years was six in this particular case.

27 MR. SHEPHERD: Thank you.

28 MS. GIRVAN: Can I just follow up? Is there any way

1 for Hydro One to provide more detailed assumptions
2 regarding how they derived their forecast? Because we have
3 two numbers that are significantly different based on the
4 same service territory, and I think what everybody is
5 trying to understand is how do we test -- how do we test
6 that evidence?

7 How do we look at what Peterborough says they are
8 required to do, which we see in front of us on the screen,
9 versus what Hydro One is saying that's required, which is
10 considerably less than this?

11 MR. SHEPHERD: Could you prepare something like
12 attachment 1 to SEC 23?

13 [Hydro One witness panel confers]

14 MR. FALTOUS: Yes, so I would like to clarify that the
15 investment is actually not materially different.

16 As I mentioned, if you look at the total numbers over
17 the ten years, Hydro One's numbers are \$60 million, and
18 Peterborough's are 65.

19 So I would not say that is a significant difference.
20 It is less than 10 percent of a difference in terms of
21 investment.

22 MR. SHEPHERD: Let me just stop you there. If your
23 unit costs are much higher and clearly your rate base is
24 much higher, so they probably are, then you are actually
25 doing a lot less work for the same money.

26 MR. FALTOUS: No, that is not the case. Don't forget
27 that Hydro One has -- there are savings as a result of the
28 economic efficiencies that we have talked about that are

1 MS. RICHARDSON: It is for the shareholders to cover
2 their acquisition premium costs as per the Board's
3 policies.

4 After the deferral period, then all customers, as we
5 show in evidence, both legacy and acquired customers, will
6 benefit from the transaction.

7 MR. SHEPHERD: Now, in SEC number 8 -- I am
8 specifically looking at B, so B, we said, do you have any
9 studies showing that on all of these other acquisitions the
10 costs to serve those acquired customers went down because
11 of your acquisition?

12 And in B you have refused to answer the question. So
13 -- because you say the past acquisitions are not relevant.
14 And the reason I am saying it is relevant is because you
15 have claimed that there is going to be savings. If you
16 never had savings before, then your claim is probably
17 wrong.

18 MS. RICHARDSON: So...

19 [Witness panel confers]

20 MS. RICHARDSON: So you're talking about the
21 transactions that occurred ten, 20 years ago, and those
22 costs weren't tracked. But what we have tracked is the
23 costs for our recently-acquired utilities, Norfolk,
24 Woodstock, and Haldimand, and the evidence in the rate
25 filing, the distribution rate filing, which you are
26 familiar with, Mr. Shepherd -- was that in 2021, we had
27 planned to increase the revenue requirement for Hydro One
28 Networks by 10.7 million, which was the incremental cost to

1 serve those customers.

2 Our legacies' revenue requirement would still only be
3 increased by the inflation factor which was allowed for
4 Hydro One.

5 Our evidence is also that the status quo of those
6 utilities would have been, on a OM&A basis, 20.2 million
7 and we have reduced it to 10.7.

8 So we do have evidence of our recent acquisitions. We
9 just did not track it back in 2010.

10 MR. SHEPHERD: So my question was going to be --
11 you've refused because my question was irrelevant. And
12 that is what it says.

13 And my question is: Do you have any studies about --
14 of the costs to serve previous acquisitions, prior to
15 Norfolk. Do you have any studies like that?

16 MS. RICHARDSON: No, we do not.

17 MR. SHEPHERD: Why not?

18 MR. KEIZER: Well, first of all, it continues to be
19 irrelevant. Given the fact that the Board in considering
20 the no-harm test should be considering it in the context of
21 the evidence related to the particular transaction, and a
22 review of previous transactions isn't relevant to this
23 transaction. And that's Hydro One's position.

24 MR. SHEPHERD: Well, of course, what the Board has
25 said in the distribution case is you told us there would be
26 no harm and now we find out that these guys have rate
27 increases, that's not okay. Isn't that what the Board
28 said?

1 MR. KEIZER: Well, I am not going to interpret the
2 Board's decision here today for that purpose.

3 But I think certainly a distinguishing factor is that
4 was at the end of a deferral period -- and I don't want to
5 get into a debate or submissions as to what the Board said
6 or didn't say in that case.

7 What the Board is to do in this case is to consider
8 what it believes to be the consequence of the transaction
9 going forward for this particular transaction, based upon
10 these particular forecasts of status quo and otherwise.

11 MR. SHEPHERD: And so, Mr. Keizer, I am inviting you
12 to provide whatever evidence you have that your past
13 acquisitions have resulted in lower costs to serve those
14 customers.

15 If you have no evidence of that, that's great, but I
16 am inviting you to file it.

17 MR. KEIZER: And my response to it is whether there is
18 or there isn't is irrelevant, and that is the position of
19 Hydro One.

20 MR. SHEPHERD: All right. Remember where the onus is.
21 Okay. My next question is on SEC 10.

22 I am not sure I understand why in the ESM model Hydro
23 One used a 6.25 debt rate, when clearly that isn't what
24 would normally happen and it isn't what you are going to in
25 fact pay in debt costs, and it isn't what would happen if
26 there was no transaction.

27 It's not one of the possible futures. So I am not
28 sure I understand why 6.25 makes sense.

Comparison of Distribution Rate Increases 2005 to 2013 to 2019 - Hydro One Acquired Distributors - Residential

Monthly Consumption

750 kwhr

Acquired Distributor	Rate Class	2005 Dx. Rates			2013 Dx. Rates			Inc. 2005 to 2013	2019 Dx. Rates			Inc. 2013 to 2019	Inc. 2005 to 2019
		Fixed	Variable	Annual	Fixed	Variable	Annual		Fixed	Variable	Annual		
Hydro One (Ailsa Craig)	R1	\$7.67	0.00660	\$151.44	\$23.85	0.03353	\$587.97	288.25%	\$27.89	0.03227	\$625.11	6.32%	312.78%
Hydro One (Arkona)	R1	\$3.93	0.00210	\$66.06	\$23.85	0.03353	\$587.97	790.05%	\$27.89	0.03227	\$625.11	6.32%	846.28%
Hydro One (Arnprior)	R1	\$8.49	0.01170	\$207.18	\$23.85	0.03353	\$587.97	183.80%	\$27.89	0.03227	\$625.11	6.32%	201.72%
Hydro One (Arran-Elderside)	R1	\$6.47	0.00760	\$146.04	\$23.85	0.03353	\$587.97	302.61%	\$27.89	0.03227	\$625.11	6.32%	328.04%
Hydro One (Artemesia)	R1	\$9.44	0.00590	\$166.38	\$23.85	0.03353	\$587.97	253.39%	\$27.89	0.03227	\$625.11	6.32%	275.71%
Hydro One (Bancroft)	R1	\$10.04	0.00760	\$188.88	\$23.85	0.03353	\$587.97	211.29%	\$27.89	0.03227	\$625.11	6.32%	230.96%
Hydro One (Bath)	R1	\$9.96	0.00690	\$181.62	\$23.85	0.03353	\$587.97	223.74%	\$27.89	0.03227	\$625.11	6.32%	244.19%
Hydro One (Blandford-Blenheim)	R1	\$8.56	0.00720	\$167.52	\$23.85	0.03353	\$587.97	250.98%	\$27.89	0.03227	\$625.11	6.32%	273.16%
Hydro One (Blyth)	R1	\$5.01	0.00730	\$125.82	\$23.85	0.03353	\$587.97	367.31%	\$27.89	0.03227	\$625.11	6.32%	396.83%
Hydro One (Bobcaygeon)	R1	\$10.83	0.00780	\$200.16	\$23.85	0.03353	\$587.97	193.75%	\$27.89	0.03227	\$625.11	6.32%	212.31%
Hydro One (Brighton)	R1	\$8.54	0.00860	\$179.88	\$23.85	0.03353	\$587.97	226.87%	\$27.89	0.03227	\$625.11	6.32%	247.52%
Hydro One (Caledon CH 02)	R1	\$11.41	0.00820	\$210.72	\$23.85	0.03353	\$587.97	179.03%	\$27.89	0.03227	\$625.11	6.32%	196.65%
Hydro One (Campbellford/Seymour)	R1	\$9.10	0.00860	\$186.60	\$23.85	0.03353	\$587.97	215.10%	\$27.89	0.03227	\$625.11	6.32%	235.00%
Hydro One (Cavan-Millbrook-N. Monaghan)	R1	\$11.27	0.01070	\$231.54	\$23.85	0.03353	\$587.97	153.94%	\$27.89	0.03227	\$625.11	6.32%	169.98%
Hydro One (Centre Hastings)	R1	\$8.59	0.00770	\$172.38	\$23.85	0.03353	\$587.97	241.09%	\$27.89	0.03227	\$625.11	6.32%	262.63%
Hydro One (Chalk River)	R1	\$10.48	0.01090	\$223.86	\$23.85	0.03353	\$587.97	162.65%	\$27.89	0.03227	\$625.11	6.32%	179.24%
Hydro One (Champlain Twp.)	R1	\$7.55	0.00710	\$154.50	\$23.85	0.03353	\$587.97	280.56%	\$27.89	0.03227	\$625.11	6.32%	304.60%
Hydro One (Clarence-Rockland)	R1	\$6.78	0.00740	\$147.96	\$23.85	0.03353	\$587.97	297.38%	\$27.89	0.03227	\$625.11	6.32%	322.49%
Hydro One (Cobden)	R1	\$9.86	0.01410	\$245.22	\$23.85	0.03353	\$587.97	139.77%	\$27.89	0.03227	\$625.11	6.32%	154.92%
Hydro One (Deep River)	R1	\$12.55	0.01830	\$315.30	\$23.85	0.03353	\$587.97	86.48%	\$27.89	0.03227	\$625.11	6.32%	98.26%
Hydro One (Deseronto)	R1	\$9.57	0.00890	\$194.94	\$23.85	0.03353	\$587.97	201.62%	\$27.89	0.03227	\$625.11	6.32%	220.67%
Hydro One (Dundalk)	R1	\$10.83	0.00870	\$208.26	\$23.85	0.03353	\$587.97	182.32%	\$27.89	0.03227	\$625.11	6.32%	200.16%
Hydro One (Durham)	R1	\$12.34	0.00990	\$237.18	\$23.85	0.03353	\$587.97	147.90%	\$27.89	0.03227	\$625.11	6.32%	163.56%
Hydro One (Eganville)	R1	\$10.34	0.01220	\$233.88	\$23.85	0.03353	\$587.97	151.40%	\$27.89	0.03227	\$625.11	6.32%	167.28%
Hydro One (Erin)	R1	\$9.76	0.01520	\$253.92	\$23.85	0.03353	\$587.97	131.56%	\$27.89	0.03227	\$625.11	6.32%	146.18%
Hydro One (Exeter)	R1	\$11.34	0.00770	\$205.38	\$23.85	0.03353	\$587.97	186.28%	\$27.89	0.03227	\$625.11	6.32%	204.37%
Hydro One (Fenelon Falls)	R1	\$4.13	0.00770	\$118.86	\$23.85	0.03353	\$587.97	394.67%	\$27.89	0.03227	\$625.11	6.32%	425.92%
Hydro One (Forest)	R1	\$11.46	0.00760	\$205.92	\$23.85	0.03353	\$587.97	185.53%	\$27.89	0.03227	\$625.11	6.32%	203.57%
Hydro One (Georgian Bay Energy - Chatsworth)	R1	\$7.00	0.00760	\$152.40	\$23.85	0.03353	\$587.97	285.81%	\$27.89	0.03227	\$625.11	6.32%	310.18%
Hydro One (Georgina)	R1	\$8.63	0.00790	\$174.66	\$23.85	0.03353	\$587.97	236.64%	\$27.89	0.03227	\$625.11	6.32%	257.90%
Hydro One (Glencoe)	R1	\$9.58	0.00620	\$170.76	\$23.85	0.03353	\$587.97	244.33%	\$27.89	0.03227	\$625.11	6.32%	266.08%
Hydro One (Grand Bend)	R1	\$10.12	0.00700	\$184.44	\$23.85	0.03353	\$587.97	218.79%	\$27.89	0.03227	\$625.11	6.32%	238.92%
Hydro One (Hastings)	R1	\$12.41	0.01080	\$246.12	\$23.85	0.03353	\$587.97	138.90%	\$27.89	0.03227	\$625.11	6.32%	153.99%
Hydro One (Havelock-Belmont-Methuen)	R1	\$11.40	0.00910	\$218.70	\$23.85	0.03353	\$587.97	168.85%	\$27.89	0.03227	\$625.11	6.32%	185.83%
Hydro One (Kirkfield)	R1	\$3.53	0.00800	\$114.36	\$23.85	0.03353	\$587.97	414.14%	\$27.89	0.03227	\$625.11	6.32%	446.62%
Hydro One (Lanark Highlands)	R1	\$8.30	0.00820	\$173.40	\$23.85	0.03353	\$587.97	239.08%	\$27.89	0.03227	\$625.11	6.32%	260.50%
Hydro One (Larder Lake)	R1	\$11.93	0.00810	\$216.06	\$23.85	0.03353	\$587.97	172.13%	\$27.89	0.03227	\$625.11	6.32%	189.32%
Hydro One (Latchford)	R1	\$9.90	0.00710	\$182.70	\$23.85	0.03353	\$587.97	221.82%	\$27.89	0.03227	\$625.11	6.32%	242.15%

Hydro One (Lucan/Granton)	R1	\$8.63	0.01130	\$205.26	\$23.85	0.03353	\$587.97	186.45%	\$27.89	0.03227	\$625.11	6.32%	204.55%
Hydro One (Malahide Twp.)	R1	\$8.19	0.00700	\$161.28	\$23.85	0.03353	\$587.97	264.56%	\$27.89	0.03227	\$625.11	6.32%	287.59%
Hydro One (Mapleton Twp.)	R1	\$10.03	0.00740	\$186.96	\$23.85	0.03353	\$587.97	214.49%	\$27.89	0.03227	\$625.11	6.32%	234.35%
Hydro One (Markdale)	R1	\$10.70	0.00690	\$190.50	\$23.85	0.03353	\$587.97	208.65%	\$27.89	0.03227	\$625.11	6.32%	228.14%
Hydro One (Marmora)	R1	\$8.53	0.00740	\$168.96	\$23.85	0.03353	\$587.97	247.99%	\$27.89	0.03227	\$625.11	6.32%	269.98%
Hydro One (McGarry Twp.)	R1	\$9.54	0.00750	\$181.98	\$23.85	0.03353	\$587.97	223.10%	\$27.89	0.03227	\$625.11	6.32%	243.50%
Hydro One (Meaford)	R1	\$9.46	0.00780	\$183.72	\$23.85	0.03353	\$587.97	220.04%	\$27.89	0.03227	\$625.11	6.32%	240.25%
Hydro One (Middlesex Centre)	R1	\$10.61	0.00630	\$184.02	\$23.85	0.03353	\$587.97	219.51%	\$27.89	0.03227	\$625.11	6.32%	239.70%
Hydro One (Napanee)	R1	\$11.02	0.00820	\$206.04	\$23.85	0.03353	\$587.97	185.37%	\$27.89	0.03227	\$625.11	6.32%	203.39%
Hydro One (Nipigon Twp.)	R1	\$11.33	0.01310	\$253.86	\$23.85	0.03353	\$587.97	131.61%	\$27.89	0.03227	\$625.11	6.32%	146.24%
Hydro One (North Dorchester Twp.)	R1	\$6.43	0.00690	\$139.26	\$23.85	0.03353	\$587.97	322.21%	\$27.89	0.03227	\$625.11	6.32%	348.88%
Hydro One (North Dundas Twp.)	R1	\$8.19	0.00780	\$168.48	\$23.85	0.03353	\$587.97	248.99%	\$27.89	0.03227	\$625.11	6.32%	271.03%
Hydro One (North Glengarry Twp.)	R1	\$5.45	0.00820	\$139.20	\$23.85	0.03353	\$587.97	322.39%	\$27.89	0.03227	\$625.11	6.32%	349.07%
Hydro One (North Grenville - Kemptville)	R1	\$10.78	0.01320	\$248.16	\$23.85	0.03353	\$587.97	136.93%	\$27.89	0.03227	\$625.11	6.32%	151.90%
Hydro One (North Perth - Listowel)	R1	\$11.04	0.00840	\$208.08	\$23.85	0.03353	\$587.97	182.57%	\$27.89	0.03227	\$625.11	6.32%	200.42%
Hydro One (North Stormont)	R1	\$3.59	0.00740	\$109.68	\$23.85	0.03353	\$587.97	436.08%	\$27.89	0.03227	\$625.11	6.32%	469.94%
Hydro One (Omensee)	R1	\$11.25	0.01200	\$243.00	\$23.85	0.03353	\$587.97	141.96%	\$27.89	0.03227	\$625.11	6.32%	157.25%
Hydro One (Perth East Twp.)	R1	\$4.02	0.00630	\$104.94	\$23.85	0.03353	\$587.97	460.29%	\$27.89	0.03227	\$625.11	6.32%	495.68%
Hydro One (Prince Edward County)	R1	\$10.66	0.00840	\$203.52	\$23.85	0.03353	\$587.97	188.90%	\$27.89	0.03227	\$625.11	6.32%	207.15%
Hydro One (Quinte West - Frankford)	R1	\$4.52	0.00740	\$120.84	\$23.85	0.03353	\$587.97	386.57%	\$27.89	0.03227	\$625.11	6.32%	417.30%
Hydro One (Rainy River)	R1	\$11.41	0.00840	\$212.52	\$23.85	0.03353	\$587.97	176.67%	\$27.89	0.03227	\$625.11	6.32%	194.14%
Hydro One (Ramara Twp.)	R1	\$4.47	0.00760	\$122.04	\$23.85	0.03353	\$587.97	381.78%	\$27.89	0.03227	\$625.11	6.32%	412.22%
Hydro One (Red Rock Twp.)	R1	\$12.04	0.01800	\$306.48	\$23.85	0.03353	\$587.97	91.85%	\$27.89	0.03227	\$625.11	6.32%	103.96%
Hydro One (Russell)	R1	\$9.74	0.01150	\$220.38	\$23.85	0.03353	\$587.97	166.80%	\$27.89	0.03227	\$625.11	6.32%	183.65%
Hydro One (Schreiber Twp.)	R1	\$12.31	0.01470	\$280.02	\$23.85	0.03353	\$587.97	109.97%	\$27.89	0.03227	\$625.11	6.32%	123.24%
Hydro One (Severn Twp)	R1	\$7.74	0.00720	\$157.68	\$23.85	0.03353	\$587.97	272.89%	\$27.89	0.03227	\$625.11	6.32%	296.44%
Hydro One (Shelburne)	R1	\$10.57	0.01060	\$222.24	\$23.85	0.03353	\$587.97	164.57%	\$27.89	0.03227	\$625.11	6.32%	181.28%
Hydro One (South Bruce Peninsula - Wiarton)	R1	\$11.92	0.01240	\$254.64	\$23.85	0.03353	\$587.97	130.90%	\$27.89	0.03227	\$625.11	6.32%	145.49%
Hydro One (South Glengarry)	R1	\$6.82	0.00600	\$135.84	\$23.85	0.03353	\$587.97	332.84%	\$27.89	0.03227	\$625.11	6.32%	360.18%
Hydro One (South River)	R1	\$10.63	0.01000	\$217.56	\$23.85	0.03353	\$587.97	170.26%	\$27.89	0.03227	\$625.11	6.32%	187.33%
Hydro One (Springwater Twp.)	R1	\$8.69	0.00660	\$163.68	\$23.85	0.03353	\$587.97	259.22%	\$27.89	0.03227	\$625.11	6.32%	281.91%
Hydro One (Stirling-Rawdon Twp.)	R1	\$9.30	0.00830	\$186.30	\$23.85	0.03353	\$587.97	215.60%	\$27.89	0.03227	\$625.11	6.32%	235.54%
Hydro One (Thedford)	R1	\$9.46	0.00650	\$172.02	\$23.85	0.03353	\$587.97	241.80%	\$27.89	0.03227	\$625.11	6.32%	263.39%
Hydro One (Thessalon)	R1	\$11.70	0.00840	\$216.00	\$23.85	0.03353	\$587.97	172.21%	\$27.89	0.03227	\$625.11	6.32%	189.40%
Hydro One (Thorndale)	R1	\$2.71	0.00710	\$96.42	\$23.85	0.03353	\$587.97	509.80%	\$27.89	0.03227	\$625.11	6.32%	548.32%
Hydro One (Tweed)	R1	\$2.84	0.00760	\$102.48	\$23.85	0.03353	\$587.97	473.74%	\$27.89	0.03227	\$625.11	6.32%	509.98%
Hydro One (Wardville)	R1	\$6.97	0.00780	\$153.84	\$23.85	0.03353	\$587.97	282.20%	\$27.89	0.03227	\$625.11	6.32%	306.34%
Hydro One (Warkworth)	R1	\$11.45	0.00940	\$222.00	\$23.85	0.03353	\$587.97	164.85%	\$27.89	0.03227	\$625.11	6.32%	181.58%
Hydro One (West Elgin)	R1	\$9.89	0.01130	\$220.38	\$23.85	0.03353	\$587.97	166.80%	\$27.89	0.03227	\$625.11	6.32%	183.65%
Hydro One (Woodville)	R1	\$2.28	0.00760	\$95.76	\$23.85	0.03353	\$587.97	514.00%	\$27.89	0.03227	\$625.11	6.32%	552.79%
Hydro One (Wyoming)	R1	\$8.47	0.00650	\$160.14	\$23.85	0.03353	\$587.97	267.16%	\$27.89	0.03227	\$625.11	6.32%	290.35%
Averages - Hydro One Medium Density Acquireds		\$8.92	0.00877	\$185.91	\$23.85	0.03353	\$587.97	216.26%	\$27.89	0.03227	\$625.11	6.32%	236.24%

Hydro One (Brockville)	UR	\$9.12	0.00750	\$176.94	\$16.50	0.02529	\$425.61	140.54%	\$19.57	0.01779	\$394.95	-7.20%	123.21%
Hydro One (Caledon OH 01)	UR	\$14.07	0.00460	\$210.24	\$16.50	0.02529	\$425.61	102.44%	\$19.57	0.01779	\$394.95	-7.20%	87.86%
Hydro One (Carleton Place)	UR	\$10.59	0.01430	\$255.78	\$16.50	0.02529	\$425.61	66.40%	\$19.57	0.01779	\$394.95	-7.20%	54.41%
Hydro One (Dryden)	UR	\$10.68	0.01320	\$246.96	\$16.50	0.02529	\$425.61	72.34%	\$19.57	0.01779	\$394.95	-7.20%	59.92%
Hydro One (Georgian Bay Energy - Owen Sound)	UR	\$7.00	0.00860	\$161.40	\$16.50	0.02529	\$425.61	163.70%	\$19.57	0.01779	\$394.95	-7.20%	144.70%
Hydro One (Lindsay)	UR	\$11.90	0.00810	\$215.70	\$16.50	0.02529	\$425.61	97.32%	\$19.57	0.01779	\$394.95	-7.20%	83.10%
Hydro One (Perth)	UR	\$10.83	0.00970	\$217.26	\$16.50	0.02529	\$425.61	95.90%	\$19.57	0.01779	\$394.95	-7.20%	81.79%
Hydro One (Quinte West - Trenton)	UR	\$4.52	0.00740	\$120.84	\$16.50	0.02529	\$425.61	252.21%	\$19.57	0.01779	\$394.95	-7.20%	226.84%
Hydro One (Smiths Falls)	UR	\$9.36	0.01130	\$214.02	\$16.50	0.02529	\$425.61	98.86%	\$19.57	0.01779	\$394.95	-7.20%	84.54%
Hydro One (Thorold)	UR	\$10.20	0.01170	\$227.70	\$16.50	0.02529	\$425.61	86.92%	\$19.57	0.01779	\$394.95	-7.20%	73.45%
Hydro One (Whitchurch-Stouffville)	UR	\$7.69	0.00820	\$166.08	\$16.50	0.02529	\$425.61	156.27%	\$19.57	0.01779	\$394.95	-7.20%	137.81%
Averages - Hydro One Urban Acquireds		\$9.63	0.00951	\$201.17	\$16.50	0.02529	\$425.61	111.56%	\$19.57	0.01779	\$394.95	-7.20%	96.32%
Hydro One Legacy	R1	\$15.99	0.02100	\$380.88	\$23.85	0.03353	\$587.97	54.37%	\$27.89	0.03227	\$625.11	6.32%	64.12%
Hydro One Legacy	UR	\$11.82	0.01610	\$286.74	\$16.50	0.02529	\$425.61	48.43%	\$19.57	0.01779	\$394.95	-7.20%	37.74%

Comparison of Distribution Rate Increases 2005 to 2019 - Hydro One Acquired Distributors - General Service

100 kW

Monthly Consumption

Acquired Distributor	Rate Class	2005 Dx. Rates			2013 Dx. Rates			Inc. 2005 to 2013	2019 Dx. Rates		Inc. 2013 to 2019	Inc. 2005 to 2019
		Fixed	Variable	Annual	Fixed	Variable	Annual		Fixed	Variable		
Hydro One (Alisa Craig)	Gsd	\$13.11	3.35000	\$4,177.32	\$55.62	11.37000	\$14,311.44	242.60%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Arkona)	Gsd	\$1.82	1.58000	\$1,917.84	\$55.62	11.37000	\$14,311.44	646.23%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Arnprior)	Gsd	\$16.36	2.96000	\$3,748.32	\$55.62	11.37000	\$14,311.44	281.81%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Arran-Elderside)	Gsd	\$6.32	2.63000	\$3,231.84	\$55.62	11.37000	\$14,311.44	342.83%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Attemesia)	Gsd	\$14.95	4.40000	\$5,459.40	\$55.62	11.37000	\$14,311.44	162.14%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Bancroft)	Gsd	\$18.78	2.96000	\$3,777.36	\$55.62	11.37000	\$14,311.44	278.87%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Bath)	Gsd	\$7.78	3.01000	\$3,705.36	\$55.62	11.37000	\$14,311.44	286.24%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Blandford-Blenheim)	Gsd	\$18.34	2.90000	\$3,700.08	\$55.62	11.37000	\$14,311.44	286.79%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Blyth)	Gsd	\$16.56	2.69000	\$3,426.72	\$55.62	11.37000	\$14,311.44	317.64%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Bobcaygeon)	Gsd	\$17.82	3.48000	\$4,389.84	\$55.62	11.37000	\$14,311.44	226.01%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Brighton)	Gsd	\$17.58	3.39000	\$4,278.96	\$55.62	11.37000	\$14,311.44	234.46%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Caledon CH 02)	Gsd	\$18.62	4.58000	\$5,719.44	\$55.62	11.37000	\$14,311.44	150.22%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Campbellford/Seymour)	Gsd	\$12.21	3.01000	\$3,758.52	\$55.62	11.37000	\$14,311.44	280.77%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Cavan-Millbrook-N. Monaghan)	Gsd	\$17.08	3.74000	\$4,692.96	\$55.62	11.37000	\$14,311.44	204.96%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Centre Hastings)	Gsd	\$13.96	2.46000	\$3,119.52	\$55.62	11.37000	\$14,311.44	358.77%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Chalk River)	Gsd	\$16.32	4.56000	\$5,667.84	\$55.62	11.37000	\$14,311.44	152.50%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Champlain Twp.)	Gsd	\$15.73	2.31000	\$2,960.76	\$55.62	11.37000	\$14,311.44	383.37%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Clarence-Rockland)	Gsd	\$5.07	2.07000	\$2,544.84	\$55.62	11.37000	\$14,311.44	462.37%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Cobden)	Gsd	\$16.80	5.19000	\$6,429.60	\$55.62	11.37000	\$14,311.44	122.59%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Deep River)	Gsd	\$18.41	5.75000	\$7,120.92	\$55.62	11.37000	\$14,311.44	100.98%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Deseronto)	Gsd	\$7.37	3.08000	\$3,784.44	\$55.62	11.37000	\$14,311.44	278.17%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Dundalk)	Gsd	\$18.11	4.14000	\$5,185.32	\$55.62	11.37000	\$14,311.44	176.00%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Durham)	Gsd	\$18.55	3.45000	\$4,362.60	\$55.62	11.37000	\$14,311.44	228.05%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Eganville)	Gsd	\$16.34	5.88000	\$7,252.08	\$55.62	11.37000	\$14,311.44	97.34%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Erin)	Gsd	\$31.56	1.89000	\$2,646.72	\$55.62	11.37000	\$14,311.44	440.72%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Exeter)	Gsd	\$8.34	3.29000	\$4,048.08	\$55.62	11.37000	\$14,311.44	253.54%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Fenelon Falls)	Gsd	\$15.10	2.42000	\$3,085.20	\$55.62	11.37000	\$14,311.44	363.87%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Forest)	Gsd	\$19.18	2.99000	\$3,818.16	\$55.62	11.37000	\$14,311.44	274.83%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Georgian Bay Energy - Chatsworth)	Gsd	\$7.88	2.91000	\$3,586.56	\$55.62	11.37000	\$14,311.44	299.03%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Georgina)	Gsd	\$13.18	4.08000	\$5,054.16	\$55.62	11.37000	\$14,311.44	183.16%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Glencoe)	Gsd	\$8.35	2.04000	\$2,548.20	\$55.62	11.37000	\$14,311.44	461.63%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Grand Bend)	Gsd	\$17.01	3.12000	\$3,948.12	\$55.62	11.37000	\$14,311.44	262.49%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Hastings)	Gsd	\$17.57	4.26000	\$5,322.84	\$55.62	11.37000	\$14,311.44	168.87%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Havelock-Belmont-Methuen)	Gsd	\$17.00	3.86000	\$4,836.00	\$55.62	11.37000	\$14,311.44	195.94%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Kirkfield)	Gsd	\$11.01	4.73000	\$5,808.12	\$55.62	11.37000	\$14,311.44	146.40%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Lanark Highlands)	Gsd	\$14.00	4.21000	\$5,220.00	\$55.62	11.37000	\$14,311.44	174.17%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Larder Lake)	Gsd	\$15.40	3.44000	\$4,312.80	\$55.62	11.37000	\$14,311.44	231.84%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Latchford)	Gsd	\$1.56	1.95000	\$2,358.72	\$55.62	11.37000	\$14,311.44	506.75%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Lucan/Granton)	Gsd	\$12.85	3.69000	\$4,582.20	\$55.62	11.37000	\$14,311.44	212.33%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Malahide Twp.)	Gsd	\$12.05	4.34000	\$5,352.60	\$55.62	11.37000	\$14,311.44	167.37%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Mapleton Twp.)	Gsd	\$16.50	4.34000	\$5,406.00	\$55.62	11.37000	\$14,311.44	164.73%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Markdale)	Gsd	\$17.66	2.03000	\$2,647.92	\$55.62	11.37000	\$14,311.44	440.48%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (Marmora)	Gsd	\$7.27	2.66000	\$3,279.24	\$55.62	11.37000	\$14,311.44	336.43%	\$106.94	20.25300	\$25,586.88	78.79%
Hydro One (McGarry Twp.)	Gsd	\$15.40	4.54000	\$5,632.80	\$55.62	11.37000	\$14,311.44	154.07%	\$106.94	20.25300	\$25,586.88	78.79%

Hydro One (Meaford)	Gsd	\$18.49	3.12000	\$3,965.88	\$55.62	11.37000	\$14,311.44	260.86%	\$106.94	20.25300	\$25,586.88	78.79%	545.18%
Hydro One (Middlesex Centre)	Gsd	\$13.14	2.64000	\$3,325.68	\$55.62	11.37000	\$14,311.44	330.33%	\$106.94	20.25300	\$25,586.88	78.79%	669.37%
Hydro One (Napanee)	Gsd	\$16.99	3.23000	\$4,079.88	\$55.62	11.37000	\$14,311.44	250.78%	\$106.94	20.25300	\$25,586.88	78.79%	527.15%
Hydro One (Nipigon Twp.)	Gsd	\$17.91	2.70000	\$3,454.92	\$55.62	11.37000	\$14,311.44	314.23%	\$106.94	20.25300	\$25,586.88	78.79%	640.59%
Hydro One (North Dorchester Twp.)	Gsd	\$11.96	2.28000	\$2,879.52	\$55.62	11.37000	\$14,311.44	397.01%	\$106.94	20.25300	\$25,586.88	78.79%	788.58%
Hydro One (North Dundas Twp.)	Gsd	\$10.07	1.94000	\$2,448.84	\$55.62	11.37000	\$14,311.44	484.42%	\$106.94	20.25300	\$25,586.88	78.79%	944.86%
Hydro One (North Glenora Twp.)	Gsd	\$13.43	2.60000	\$2,873.16	\$55.62	11.37000	\$14,311.44	398.11%	\$106.94	20.25300	\$25,586.88	78.79%	790.55%
Hydro One (North Grenville - Kemptville)	Gsd	\$15.59	4.33000	\$5,383.08	\$55.62	11.37000	\$14,311.44	165.86%	\$106.94	20.25300	\$25,586.88	78.79%	375.32%
Hydro One (North Perth - Listowel)	Gsd	\$22.87	2.53000	\$3,310.44	\$55.62	11.37000	\$14,311.44	332.31%	\$106.94	20.25300	\$25,586.88	78.79%	672.91%
Hydro One (North Stormont)	Gsd	\$3.55	2.02000	\$2,466.60	\$55.62	11.37000	\$14,311.44	480.21%	\$106.94	20.25300	\$25,586.88	78.79%	937.33%
Hydro One (Omenee)	Gsd	\$16.28	3.71000	\$4,647.36	\$55.62	11.37000	\$14,311.44	207.95%	\$106.94	20.25300	\$25,586.88	78.79%	450.57%
Hydro One (Perth East Twp.)	Gsd	\$10.98	3.26000	\$4,043.76	\$55.62	11.37000	\$14,311.44	253.91%	\$106.94	20.25300	\$25,586.88	78.79%	532.75%
Hydro One (Prince Edward County)	Gsd	\$17.54	3.56000	\$4,482.48	\$55.62	11.37000	\$14,311.44	219.28%	\$106.94	20.25300	\$25,586.88	78.79%	470.82%
Hydro One (Quinte West - Frankford)	Gsd	\$2.25	2.65000	\$3,207.00	\$55.62	11.37000	\$14,311.44	346.26%	\$106.94	20.25300	\$25,586.88	78.79%	697.84%
Hydro One (Rainy River)	Gsd	\$14.69	4.47000	\$5,540.28	\$55.62	11.37000	\$14,311.44	158.32%	\$106.94	20.25300	\$25,586.88	78.79%	361.83%
Hydro One (Ramara Twp.)	Gsd	\$16.03	2.68000	\$3,408.36	\$55.62	11.37000	\$14,311.44	319.89%	\$106.94	20.25300	\$25,586.88	78.79%	650.71%
Hydro One (Red Rock Twp.)	Gsd	\$16.57	4.92000	\$6,102.84	\$55.62	11.37000	\$14,311.44	134.50%	\$106.94	20.25300	\$25,586.88	78.79%	319.26%
Hydro One (Russell)	Gsd	\$14.67	5.68000	\$6,992.04	\$55.62	11.37000	\$14,311.44	104.68%	\$106.94	20.25300	\$25,586.88	78.79%	265.94%
Hydro One (Schreiber Twp.)	Gsd	\$15.82	5.89000	\$7,257.84	\$55.62	11.37000	\$14,311.44	97.19%	\$106.94	20.25300	\$25,586.88	78.79%	252.54%
Hydro One (Severn Twp)	Gsd	\$16.99	2.68000	\$3,419.88	\$55.62	11.37000	\$14,311.44	318.48%	\$106.94	20.25300	\$25,586.88	78.79%	648.18%
Hydro One (Shelburne)	Gsd	\$15.26	2.23000	\$2,859.12	\$55.62	11.37000	\$14,311.44	400.55%	\$106.94	20.25300	\$25,586.88	78.79%	794.92%
Hydro One (South Bruce Peninsula - Wiarton)	Gsd	\$18.28	4.79000	\$5,967.36	\$55.62	11.37000	\$14,311.44	139.83%	\$106.94	20.25300	\$25,586.88	78.79%	328.78%
Hydro One (South Glengarry)	Gsd	\$13.19	1.90000	\$2,438.28	\$55.62	11.37000	\$14,311.44	486.95%	\$106.94	20.25300	\$25,586.88	78.79%	949.38%
Hydro One (South River)	Gsd	\$16.94	3.90000	\$4,883.28	\$55.62	11.37000	\$14,311.44	193.07%	\$106.94	20.25300	\$25,586.88	78.79%	423.97%
Hydro One (Springwater Twp.)	Gsd	\$15.68	2.73000	\$3,464.16	\$55.62	11.37000	\$14,311.44	313.13%	\$106.94	20.25300	\$25,586.88	78.79%	638.62%
Hydro One (Stirling-Rawdon Twp.)	Gsd	\$18.55	3.29000	\$4,170.60	\$55.62	11.37000	\$14,311.44	243.15%	\$106.94	20.25300	\$25,586.88	78.79%	513.51%
Hydro One (Thedford)	Gsd	\$13.52	2.70000	\$3,402.24	\$55.62	11.37000	\$14,311.44	320.65%	\$106.94	20.25300	\$25,586.88	78.79%	652.06%
Hydro One (Thessalon)	Gsd	\$14.38	2.58000	\$3,268.56	\$55.62	11.37000	\$14,311.44	337.85%	\$106.94	20.25300	\$25,586.88	78.79%	682.82%
Hydro One (Thorndale)	Gsd	\$10.87	2.60000	\$3,250.44	\$55.62	11.37000	\$14,311.44	340.29%	\$106.94	20.25300	\$25,586.88	78.79%	687.18%
Hydro One (Tweed)	Gsd	\$5.87	2.49000	\$3,058.44	\$55.62	11.37000	\$14,311.44	367.93%	\$106.94	20.25300	\$25,586.88	78.79%	736.60%
Hydro One (Wardsville)	Gsd	\$9.11	2.53000	\$3,145.32	\$55.62	11.37000	\$14,311.44	355.01%	\$106.94	20.25300	\$25,586.88	78.79%	713.49%
Hydro One (Warkworth)	Gsd	\$16.31	3.58000	\$4,491.72	\$55.62	11.37000	\$14,311.44	218.62%	\$106.94	20.25300	\$25,586.88	78.79%	469.65%
Hydro One (West Elgin)	Gsd	\$11.57	1.77000	\$2,262.84	\$55.62	11.37000	\$14,311.44	532.45%	\$106.94	20.25300	\$25,586.88	78.79%	1030.74%
Hydro One (Woodville)	Gsd	\$12.77	3.47000	\$4,317.24	\$55.62	11.37000	\$14,311.44	231.50%	\$106.94	20.25300	\$25,586.88	78.79%	492.67%
Hydro One (Wyoming)	Gsd	\$13.15	3.66000	\$4,549.80	\$55.62	11.37000	\$14,311.44	214.55%	\$106.94	20.25300	\$25,586.88	78.79%	462.37%
Averages - Hydro One Medium Density Acquireds		\$14.10	3.30544	\$4,135.77	\$55.62	11.37000	\$14,311.44	246.04%	\$106.94	20.25300	\$25,586.88	78.79%	518.67%
Hydro One (Brockville)	Ugd	\$16.58	1.99000	\$2,586.96	\$32.32	6.91400	\$8,684.64	235.71%	\$111.74	11.54800	\$15,198.48	75.00%	487.50%
Hydro One (Caledon OH 01)	Ugd	\$19.71	4.28000	\$5,372.52	\$32.32	6.91400	\$8,684.64	61.65%	\$111.74	11.54800	\$15,198.48	75.00%	182.89%
Hydro One (Carleton Place)	Ugd	\$18.18	4.25000	\$5,318.16	\$32.32	6.91400	\$8,684.64	63.30%	\$111.74	11.54800	\$15,198.48	75.00%	185.78%
Hydro One (Dryden)	Ugd	\$14.55	2.64000	\$3,342.60	\$32.32	6.91400	\$8,684.64	159.82%	\$111.74	11.54800	\$15,198.48	75.00%	354.69%
Hydro One (Georgian Bay Energy - Owen Sound)	Ugd	\$7.88	2.91000	\$3,586.56	\$32.32	6.91400	\$8,684.64	142.14%	\$111.74	11.54800	\$15,198.48	75.00%	323.76%
Hydro One (Lindsay)	Ugd	\$18.41	3.49000	\$4,408.92	\$32.32	6.91400	\$8,684.64	96.98%	\$111.74	11.54800	\$15,198.48	75.00%	244.72%
Hydro One (Perth)	Ugd	\$15.19	2.30000	\$2,942.28	\$32.32	6.91400	\$8,684.64	195.17%	\$111.74	11.54800	\$15,198.48	75.00%	376.55%
Hydro One (Quinte West - Trenton)	Ugd	\$2.25	2.65000	\$3,207.00	\$32.32	6.91400	\$8,684.64	170.80%	\$111.74	11.54800	\$15,198.48	75.00%	373.92%
Hydro One (Smiths Falls)	Ugd	\$7.13	2.66000	\$3,277.56	\$32.32	6.91400	\$8,684.64	164.97%	\$111.74	11.54800	\$15,198.48	75.00%	363.71%
Hydro One (Thorold)	Ugd	\$17.36	3.81000	\$4,780.32	\$32.32	6.91400	\$8,684.64	81.67%	\$111.74	11.54800	\$15,198.48	75.00%	217.94%
Hydro One (Whitchurch-Stouffville)	Ugd	\$16.73	2.35000	\$3,020.76	\$32.32	6.91400	\$8,684.64	187.50%	\$111.74	11.54800	\$15,198.48	75.00%	403.13%
Averages - Hydro One Urban Acquireds		\$14.00	3.03000	\$3,803.97	\$32.32	6.91400	\$8,684.64	128.30%	\$111.74	11.54800	\$15,198.48	75.00%	299.54%

1 86 percent, but, yes, it is below one.

2 MR. SHEPHERD: And when you forecast the savings for
3 these customers at the time of the MAADs applications, did
4 you tell them what their rates were going to be when they
5 were brought into Hydro One?

6 MR. ANDRE: No, as I recollect the discussion about
7 rates was we laid out several options in terms of how their
8 rates might be set at the time of rate harmonization. That
9 was a matter that was not discussed as part of the MAADs
10 application, per the rules, my understanding, anyway, of
11 how MAAD applications are intended to work, but there was
12 just -- there was no discussion of the rates specifically,
13 there was only a discussion of the process that would be
14 used for setting the rates.

15 MR. SHEPHERD: And at that time you expected to use
16 the old method, didn't you, that your original plan was
17 that you would simply fold these acquired utilities into
18 your legacy rate classes and harmonize, right, as you did
19 with the other 92 you've acquired?

20 MR. ANDRE: I believe that was one of the options. I
21 think we laid that as one option. We could create new rate
22 classes to serve them was the other option, and I think the
23 third one was, you know -- I can't recall, but I do recall
24 there was a third, more generic option, so the potential to
25 create new classes was discussed at the time of the MAADs,
26 as far as I can recollect. I don't know if it was for all
27 three, but I know that was discussed.

28 MR. SHEPHERD: So during the -- for these three

1 acquired utilities, you have had savings, right? You have
2 had savings over the last seven, eight years that you've
3 owned them, or the total seven, eight years until you
4 integrated, right?

5 MR. ANDRE: That's my understanding, yes.

6 MR. SHEPHERD: But you said -- and if you go to page
7 54 of K10.7, you said at the technical conference -- and
8 I'm quoting you on line 23, "The savings are to Hydro One
9 as a whole." Right? It's not savings to the acquired
10 customers, it's savings to the enterprise, and then you
11 have to figure out who gets them, right?

12 MR. ANDRE: Yes, so as an example, if the utilities
13 had stayed on their own I think they would have been
14 spending 19.7 million on OM&A costs and when they are
15 integrated into Hydro One there is only a ten point -- I
16 can't remember -- 10.1 or 10.7 in incremental OM&A, 10.7,
17 my colleague confirms -- so that's the incremental OM&A
18 that Hydro One has to spend to serve those same acquireds,
19 as opposed to the 19.7 in OM&A that they would have served
20 had they remained independent.

21 MR. SHEPHERD: Well, that's not their savings, though,
22 right? That is total savings, because you are actually
23 allocating 17 million to acquired customers; right?

24 MR. ANDRE: That is the savings to Hydro One to serve
25 both its existing customers and the acquired customers.

26 MR. SHEPHERD: So here's where I'm going with this:
27 I'm right, am I not, that for the 92 acquisitions you did
28 before these three, you simply folded them all in, and they

1 went into the -- your existing rate classes; it took a
2 while, because some of them had big rate increases, right?

3 MR. ANDRE: That's right, it took -- the integration
4 period for some of the classes was four years.

5 MR. SHEPHERD: And it's true that some of them had
6 two, three, four hundred percent rate increases, right?

7 MR. ANDRE: I recall there was one utility -- it was
8 Ailsa Craig -- that did have a significant increase. I
9 can't remember the exact amount, Mr. Shepherd.

10 MR. SHEPHERD: Well, lots of them had very significant
11 increases, right? Lots of them had more than 100 percent
12 increases, right?

13 MR. ANDRE: Well, and I think it was that experience,
14 in terms of attempting to fold acquired utilities into
15 Hydro One's existing rate structure that drove the Board in
16 the decisions for these three acquired utilities to say,
17 no, you have to make sure that you charge them their cost
18 to serve, because by being folded into either our R2 or R1
19 class, yes, it did generate those kinds of large impacts,
20 and I think it drove the thinking with respect to the
21 new -- the three acquired utilities.

22 MR. SHEPHERD: So issue 56 in this proceeding says --
23 and I can read it:

24 "Due to costs allocated to acquired utilities
25 appropriately reflect the OEB's decisions in
26 related Hydro One acquisition proceedings."

27 And you've tried to do that by taking a new approach
28 to both cost allocation and rate design for acquired;

1 Hydro One anticipates this new approach will achieve similar benefits but on an
2 accelerated pace due to the increased system coverage enabled by a shorter cycle and a
3 refined scope. The new strategy will quickly reduce the maintenance backlog and enable
4 program optimization. The shorter cycles will improve public safety, reliability, and
5 asset condition providing a more detailed understanding of current and future workloads.
6 Shorter cycles will also reduce customer and environmental impacts due to more
7 frequent, less impactful maintenance.

8

9 **2.2 UPDATE OF COST ALLOCATION TO NEW ACQUIRED CUSTOMER**

10 **CLASSES AND COMPARISON OF BILL IMPACTS**

11

12 As discussed in Section 2.2.3 of Exhibit G1, Tab 3, Schedule 1, Hydro One developed
13 adjustment factors for use in the 2021 Cost Allocation Model (“CAM”) to ensure that the
14 costs allocated to the six new acquired residential and general service rate classes (AUR,
15 AUGe, AUGd, AR, AGSe and AGSd) appropriately reflect the cost of serving the
16 customers in these rate classes. Hydro One continues to believe the overall methodology
17 used to develop the adjustment factors is appropriate. However, upon further
18 consideration, Hydro One submits that it is appropriate to also include the cost of
19 distribution stations in its adjustment factor calculations. The proposed change, rationale
20 and results of making this change are described in the following sections.

21

22 The updated cost allocation, rates and bill impacts evidence provided below was prepared
23 with reference to Hydro One’s 2021 and 2022 revenue requirement as proposed in the
24 Application as of June 2017. The changes to the 2021 and 2022 revenue requirement that
25 will result from the updates discussed in Section 1 of this Exhibit are not captured by the
26 updated evidence provided below. Hydro One notes that the 2021 revenue requirement
27 of \$1,684 million shown in Table 2 of this Exhibit is only \$4 million (0.2%) higher than
28 the revenue requirement underpinning the revised cost allocation, rates and bill impacts

1 that are presented in the sections that follow. As such, the difference in revenue
2 requirement will not materially impact the analysis and conclusions that are presented
3 below.

4
5 **2.2.1 Including Distribution Station Equipment in the Calculation of Adjustment**
6 **Factors**

7
8 In Exhibit G1, Tab 3, Schedule 1, section 2.2.3, Hydro One stated that adjustment factors
9 were developed to align the amount of gross fixed assets (“GFA”) in USofA accounts
10 1830 to 1860 (i.e. poles, towers, fixtures, overhead/underground conductors and devices,
11 line transformers and meters) allocated by the CAM for these locally used assets with the
12 amount of GFA specifically required to serve the new acquired rate classes. Upon further
13 consideration since filing its Application, Hydro One has added distribution station
14 equipment (USofA accounts 1815 to 1820) to the assets that should be included in the
15 adjustment factor calculations. Similar to the assets covered by USofA accounts 1830 to
16 1860, distribution stations can be considered “local” assets that are essentially used to
17 serve just the new acquired rate classes. As such, it is appropriate and necessary that
18 USofA accounts 1815 and 1820 also be included in the GFA adjustment factor
19 calculations.

20
21 The change in the GFA adjustment factor in turn impacts the calculation of the NFA and
22 NFA ECC allocators in the CAM’s “E2 Allocator” tab, which are adjusted using the
23 same methodology as described in the Application.

24
25 Similarly, the depreciation adjustment factor has also been revised to include the
26 depreciation assigned by the CAM to USofA accounts 1815 to 1820 for the new acquired
27 rate classes using the same methodology as described in the Application.

In addition, Hydro One has also made a correction to two items: i) a correction to the 2015 year-end GFA values used for Haldimand and Norfolk in determining the GFA adjustment factor, and ii) including USofA 1830-5 Secondary poles in the calculation of the depreciation adjustment factor. The impact of these corrections is minor and is noted for the sake of transparency. The changes to the allocation of overall costs, shown below, are mainly driven by the proposed change to the allocation of distribution station equipment.

2.2.2 Costs Allocated to the Acquired Classes

The 2021 CAM has been updated with the revised adjustment factors as described above. Adding distribution station equipment costs to the adjustment factor calculations has reduced the costs allocated to the new acquired rate classes by about \$5.5 million, or 12%, when compared to the 2021 CAM included in the Application as of June 2017. The revised costs allocated to each of the acquired rate classes are shown in the “O1 Revenue to Cost Output Sheet” provided in Attachment 3. The revised CAM has also been provided in MS Excel format as Q-01-01-03.xlsx. As a result of this change, the updated revenue-to-cost ratios of the six new acquired rate classes are much closer to the OEB-approved range, as shown in Table 11 below.

Table 11: Impact of Updated Cost Allocation on Revenue-to-Cost Ratios

Rate Class	2021 R/C Ratio from the CAM	
	Evidence (June 2017)	Updated Cost Allocation
UR	1.10	1.10
R1	1.10	1.10
R2	0.97	0.97
Seasonal	1.11	1.10
GSe	1.00	1.00
GSd	0.93	0.92
UGe	1.01	1.00
UGd	0.91	0.90

UNDERTAKING – JT 3.21

Undertaking

To provide an explanation that shows for 1815 and 1820, or for all of them, what was allocated in March and how and what was allocated in June and how.

Response

The table below summarizes the values for USofAs 1815 and 1820 that were initially allocated to the new acquired rate classes in the 2021 CAM, compared to the adjusted values allocated to the acquired classes using the cost allocation approach described in Exhibit G1, Tab 3, Schedule 1 (March 2017 and June 2017), and Exhibit Q, Tab 1, Schedule 1 Section 2.2 (December 2017).

		Application (March 2017)		Blue Page Update (June 2017) (Note 1)		Exhibit Q Update (December 2017) (Note 2)	
USofA	USofA Description	Allocated by CAM	After Adjustment to CAM Allocation	Allocated by CAM	After Adjustment to CAM Allocation	Allocated by CAM	After Adjustment to CAM Allocation
1815	Transformer station equip - above 50kV	\$7,335,788	\$7,335,788	\$7,788,401	\$ 7,788,401	\$7,788,401	\$9,212,494
1820	Distribution station equip - below 50kV	\$41,646,316	\$41,646,316	\$40,639,443	\$40,639,443	\$40,639,443	\$8,223,341

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S
13																		
14																		
15	ID and Factors	Total	UR	R1	R2	Seasonal	GSe	GSD	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	AUR	AUGe	AUGd
151	Density		1,000	1,900	4,800	3,600	2,400	2,200	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
152	Factors																	
162	DCP1	6,243,791	426,417	1,124,090	971,897	117,469	317,774	296,363	94,027	107,301	120,546	2,713	3,878	10,880	2,594,035	25,276	9,071	22,055
164	DCP4	23,810,775	1,753,984	4,165,467	3,417,006	384,270	1,216,713	1,245,467	362,208	486,164	46,182	5,844	15,586	26,479	10,461,621	93,332	33,492	96,963
165	DCP12	65,104,491	4,676,562	10,730,684	8,775,129	987,462	3,371,522	3,649,203	997,896	1,440,425	120,546	14,777	47,127	66,807	29,633,994	201,255	102,794	288,308
166																		
257																		
258	DCP1-DA	6,243,791	147,145	736,997	1,609,803	145,927	366,602	346,620	45,198	57,044	120,546	2,713	3,878	10,880	2,594,035	25,276	9,071	22,055
259	DCP4-DA	23,810,775	621,053	2,802,337	5,807,511	489,826	1,404,685	1,470,686	174,236	260,944	46,182	5,844	15,586	26,479	10,461,621	93,332	33,492	96,963
260	DCP12-DA	65,104,491	1,663,949	7,254,279	14,986,768	1,264,842	3,889,721	4,315,366	479,696	774,261	120,546	14,777	47,127	66,807	29,633,994	201,255	102,794	288,308

sume no density adjustment on acquir

1 As long as that split is in between those goalposts, that's
2 going to be what we say is a fair allocation.

3 It might be more to legacy customers; it might be more
4 to the acquired customers. But it's the output of the cost
5 allocation and rate design process.

6 MR. SHEPHERD: And you don't have a plan for what
7 happens if it's not within the goalposts, right?

8 MR. ANDRE: No, we do. There's a number of IR
9 responses that have dealt with what would happen if you
10 fall outside those goalposts.

11 Like if the results of the model would say collect
12 more from the acquired customers than their status quo
13 costs would have been, our proposal is we back off the
14 revenue-to-cost ratios to ensure that only the maximum
15 savings that was generated by the acquisition flows to
16 legacy customers.

17 We are not going to allocate more than the savings
18 generated by the acquisition to legacy customers. We are
19 going to cap it at that value.

20 Then at the other end, we do the same. If we -- you
21 know, if we were proposing to actually allocate less than
22 the residual costs --

23 MR. SHEPHERD: Which would be surprising.

24 MR. ANDRE: -- which would be surprising, but in that
25 case we would bump up the revenue-to-cost ratios to make
26 sure we had at a minimum collect that residual cost.

27 MR. SHEPHERD: Isn't that exactly the same methodology
28 you put to the Board in 2017-0049, the allocation with

1 adjusting factors and play with the revenue-to-cost ratios?

2 MR. ANDRE: Yeah, we didn't -- as I said earlier, I
3 don't think we did as good a job as we could have in terms
4 of explaining those goalposts. That was our argument, that
5 those costs fell in between.

6 But I don't know that we did a good enough job.
7 Obviously, we didn't do a good enough job explaining it to
8 the Board so they understood that principle and understood
9 the inherent fairness in that principle.

10 MR. SHEPHERD: So aside from refinements to the
11 adjustment factors -- because I understand you have
12 improved the adjustment factors, right, in that process?

13 MR. ANDRE: Yes.

14 MR. SHEPHERD: But aside from that, you are basically
15 saying to the Board we want you to approve what you refused
16 to approve in 0049, but this time we're giving you better
17 information so that you will understand it better.

18 MR. ANDRE: I think we've done a much better job of
19 explaining our proposals around the goalposts in the
20 evidence that is part of this application.

21 MR. SHEPHERD: Thank you.

22 MR. PIETREWICZ: I will leave it with one more
23 question from me, and leave it to others to determine where
24 we go next.

25 I would like to turn our attention to on PDI again,
26 SEC 43. That's Exhibit I, tab 2, schedule 11 -- I'm sorry,
27 schedule 43, page 1 of 1 of SEC 43.

28 And what this table shows is some estimates of monthly

1 factors from the model.

2 MR. SHEPHERD: It would certainly be 10- or 20- or
3 \$30 million higher, right?

4 MR. ANDRE: I don't know about the exact quantum, but,
5 yes, it would be notably higher.

6 MR. SHEPHERD: All right. So here's why I am asking
7 the question. So you have got these 92 acquireds that you
8 have already got in the fold, and then you have got these
9 three new ones. Is it 92? Is that right? Niagara-on-the-
10 Lake said 92, but you said 80 plus --

11 MR. ANDRE: 89 -- I thought it was 89, and then there
12 was another one -- it's around 90, Mr. Shepherd. I don't
13 know the exact number.

14 MR. SHEPHERD: Let's say 90 and we will pretend it's
15 right. If -- so those -- the customers in those acquired
16 utilities are paying -- they have a different deal than
17 these ones. This is what you said on Tuesday. They have a
18 different approach to their rates being set. They go into
19 the regular classes, and so the costs that they are bearing
20 are significantly higher than these acquireds; right? It
21 was not just the 46 million, as you say, it's higher than
22 that.

23 MR. ANDRE: You're correct. The costs are higher, Mr.
24 Shepherd. The proposal around the integration of those 90
25 acquired utilities was fully explored as part of the 2006
26 application, and there would have been different
27 circumstances around those 90. I mean, some of those 90
28 utilities included utilities that had 300 customers, 400

1 assets required and the number of customers. That's
2 obviously a factor as well for a number of the US of As.

3 But the asset-related costs will be tied to the
4 specific assets required to serve it.

5 MR. SHEPHERD: And part of the reason why you are
6 doing that is because you can't actually allocate the
7 shared costs because in order to allocate the shared costs,
8 you'd have to know what they were.

9 MR. ANDRE: I mean, we know that they are everything
10 over and above the incremental costs, that's how we've...

11 MR. SHEPHERD: But you don't know what the total cost
12 is to serve the OPDC or PDI customers without any
13 adjustment factors. You don't know that number.

14 MR. ANDRE: It's a cost -- I mean, you can't know that
15 number. I mean, we certainly know the incremental costs
16 that are required, OM&A and capital. We know the
17 incremental costs that are required to serve the acquired
18 utilities.

19 But in terms of the total costs, the only way to get
20 that is to go through the cost allocation process.

21 MR. SHEPHERD: Okay. So can you provide for the Board
22 -- you have already provided the CAM for 2030 with the
23 adjustment factors, right.

24 Can you provide the CAM for 2030 without the
25 adjustment factors, treating those customers in PDI and
26 OPDC just as if they were the same as any other customers
27 in any other city; density, everything else. Can you do
28 that run?

1 MR. ANDRE: No. I mean, the density factor we don't
2 have. We haven't run a study to look at what that density
3 -- you know, what that density factor should be for each of
4 those communities, like PDI and Orillia.

5 MR. SHEPHERD: I am pretty sure you answered that
6 question already. I am pretty sure you told us they're
7 both in the urban class.

8 MR. ANDRE: They're in the urban class, but the
9 specific -- that density factor construct that we use for
10 some of our other classes couldn't easily be applied. I
11 don't know how I would apply that to the -- right now, how
12 I would apply that to the acquired utilities.

13 MR. SHEPHERD: I thought it was binary. You either
14 met the test or you don't.

15 MR. ANDRE: What is binary?

16 MR. SHEPHERD: The density factor. You are either in
17 the class that has the higher density or you are not.
18 Right?

19 MR. ANDRE: Yes. But what you were saying is run it
20 without the adjustment factors, and you're saying put them
21 into your urban classes?

22 MR. SHEPHERD: Yes.

23 MR. ANDRE: So that will get you closer to what the
24 Board had asked us to do, which was make sure that you
25 charge them their costs to serve.

26 MR. SHEPHERD: Yes.

27 MR. ANDRE: But as I said, even the urban and general
28 service energy and demand classes, there is still an

1 element of averaging. But something that I haven't
2 mentioned which is even more important is the whole minimum
3 system and PLCC adjustment.

4 For Hydro One, that drives a very different allocation
5 of costs to the residential versus the general service
6 demand class.

7 MR. SHEPHERD: I understand.

8 MR. ANDRE: And right now, by keeping them as separate
9 classes with the adjustment factor applied to assets, we're
10 able to maintain that split so that the existing customers
11 don't see a big jump.

12 If we were to bring them into the Hydro One classes,
13 you would see that big disparity in the general service
14 because we would be applying Hydro One's minimum system and
15 PLCC adjustment.

16 MR. SHEPHERD: Well, you would also be increasing the
17 percentage of your customers that were in the urban
18 classes, which would fundamentally affect your other
19 classes, right?

20 MR. ANDRE: Yes. If you group them together, yeah,
21 you would be changing the complete results of the model.

22 And it's not -- you know, the Board -- something that
23 just sort of dawned on me is that the Board in their
24 consolidation handbook, Mr. Shepherd, makes it very clear.
25 On page 18 of that book, they say a utility has the ability
26 -- when you have an acquisition, you can either put them
27 this into one of your existing classes or create a new rate
28 class to put your acquired customers into.

1 And I think the goal is whatever best reflects the
2 costs to serve.

3 So our view is that creating a new rate class where
4 you accurately identify the assets required to serve them
5 is the best way to achieve that.

6 MR. SHEPHERD: So are you refusing to provide a copy
7 of the -- or a run of the cost allocation model that treats
8 the customers of OPDC and PDI the same as legacy customers
9 with similar characteristics? Are you refusing to provide
10 that?

11 MR. ANDRE: Yes.

12 MR. SHEPHERD: We know you can do it. The question is
13 will you.

14 MR. ANDRE: Yes. They would be similar and they would
15 not accurately reflect the costs to serve those acquired
16 customers as our proposal does.

17 MR. SHEPHERD: So are you refusing to provide it, yes
18 or no?

19 MR. KEIZER: Yes, we are refusing to provide it.

20 MR. SHEPHERD: Okay. And so then I am on SEC 40.
21 page 4, and this is, I think, for OPDC.

22 So in 2018, you paid a million dollars to -- more than
23 a million dollars to Hydro One or its affiliates for
24 operations and maintenance services. Can you tell us about
25 that?

26 MR. HURLEY: I can speak to that. That's a bit
27 misleading. That is actually our total operations and
28 maintenance costs that we incurred in 2018.

Table 3: Meter Reading Weighted Average Costs in 2018 and 2021 CAMs
(Sheet I7.2)

Meter Reading Weighted Average Costs

2018 CAM		from I7.2																	
UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST							TOTAL
0.5%	3.9%	52.8%	13.2%	13.0%	11.9%	1.4%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%							100.0%
2021 CAM		from I7.2																	
UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	Acq_UR	Acq_UGe	Acq_UGd	Acq_Res	Acq_GSe	Acq_GSd	TOTAL
0.5%	3.8%	52.6%	13.1%	12.9%	11.9%	1.3%	3.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.5%	0.1%	0.0%	100.0%

2.2.2 Density Factors (CAM Sheet E2)

No density adjustment is required for the six new acquired rate classes, as these classes are not distinguished based on density. The value “1” has been input in the 2021 CAM sheet E2 for the six acquired rate classes. These factors for all Hydro One existing rate classes remain unchanged from the factors used in the 2017 model.

Table 4: Density Factors in 2021 CAM (CAM Sheet E2)

UR	R1	R2	Seasonal	GSe	GSd	UGe	UGd	St Lgt	Sen Lgt	USL	DGen	ST	Acq_UR	Acq_UGe	Acq_UGd	Acq_Res	Acq_GSe	Acq_GSd
1.000	1.900	4.800	3.600	2.400	2.200	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

2.2.3 New Acquired Rate Class Allocator Adjustments

All costs associated with serving the customers of the Acquired Utilities in 2021 have been added to the 2021 CAM. Six new rate classes have also been added to the 2021 CAM to accommodate the rate harmonization of the acquired utilities in 2021. All inputs to the 2021 CAM have been reviewed to ensure that the model is appropriately assigning costs to the Hydro One existing and the new acquired rate classes. In addition, three adjustment factors were developed and included in the 2021 CAM to ensure that the costs allocated to the six new acquired rate classes appropriately reflect the cost of serving the customers in these rate classes. These adjustment factors are described below.

Witness: Henry Andre

1 ***Fixed Assets Adjustment***

2
3 An adjustment factor has been applied to the amount of gross fixed assets (“GFA”) in
4 USofA accounts 1830 to 1860 to align the costs allocated by the CAM to these USofA
5 accounts with the amount of GFA specifically required to serve the new acquired rate
6 classes. The amount of GFA that should appropriately be allocated to the new acquired
7 rate classes is estimated from the GFA in these USofA accounts for the acquired utilities
8 prior to acquisition plus the in-service additions to these accounts up to 2021. The total
9 GFA that should appropriately be assigned to the new acquired rate classes also takes into
10 consideration that a portion of Hydro One’s bulk distribution assets associated with
11 serving customers in each of the new acquired rate classes should also be allocated to
12 these classes. The amount of bulk distribution assets assigned to the new acquired classes
13 was determined using the same proportion of bulk assets assigned to Hydro One’s other
14 customer classes not directly served by the bulk system.

15
16 Assets in all other USofA fixed asset accounts (e.g. distribution station assets, land,
17 buildings, general plant, etc.) are considered to be commonly shared among all classes
18 served by Hydro One. The amount of these common assets normally allocated to all rate
19 classes using the cost allocation principles underlying the CAM are not adjusted.

20
21 The GFA adjustment factors are shown in Table 5. The adjustment factors are applied to
22 the GFA in USofAs 1830 to 1860 as shown in rows 437-507 of the 2021 CAM’s “E2
23 Allocators” tab. Hydro One proposes to apply these same factors in future runs of the
24 CAM.

Table 5: GFA Adjustment Factor

GFA (USofA 1830-1860)	Acq_URes	Acq_UGSe	Acq_UGSd	Acq_Res	Acq_GSe	Acq_GSd
Adjustment Factor	0.495	0.362	0.190	0.660	0.688	0.378

The amount of GFA not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Given the Board's CAM methodology, the appropriate allocation of GFA to the new acquired rate classes is critical for driving the allocation of the majority of distribution O&M costs, other than customer-related costs (e.g. billing, collections, meter-related expenses). The allocation of O&M costs, in turn, is a key driver of most administration and general costs.

Net Fixed Asset ("NFA") Allocator Adjustment

The NFA and NFA ECC allocators in the CAM's "E2 Allocator" tab are also adjusted to reflect the GFA adjustment for USofA's 1830-1860 as described above. GFA values assigned to the new acquired rate classes are translated to NFA values based on the relationship between total GFA and NFA determined from rows 112 to 116 in the CAM's "O6 Source Data for E2" tab. The NFA adjustment factors that have been applied are shown in Table 6 below.

Table 6: NFA and NFA ECC Adjustment Factor

NFA and NFA ECC	Acq_URes	Acq_UGSe	Acq_UGSd	Acq_Res	Acq_GSe	Acq_GSd
Adjustment Factor	0.531	0.446	0.350	0.689	0.730	0.495

Witness: Henry Andre

The amount of NFA and NFA ECC not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Depreciation Cost Adjustment

A depreciation adjustment factor is applied to the depreciation assigned by the CAM to USofA accounts 1830 to 1860 for the new acquired rate classes. The depreciation amounts assigned to the new acquired rate classes as shown in “Sheet 7 Amortization” of the CAM are reduced by the same GFA adjustment factors discussed above in order to reduce the depreciation amount assigned to the new acquired rate classes consistent with the reduction in the GFA for those USofA accounts.

The depreciation amount not assigned to the new acquired rate classes as a result of applying the adjustment factors shown above is subsequently redistributed to all other rate classes in proportion to the amounts already assigned to those classes.

Table 7 shows the unadjusted depreciation amounts compared to the adjusted amounts for each rate class shown in row 2016 of the “O4 Summary by Class & Accounts” tab of the CAM.

Table 7: Adjusted Depreciation Amounts to Reflect New Acquired Rate Classes

Deprecation USofA 5705	UR	R1	R2	Seas	GSe	GSd	UGe	UGd	St.L	Sen.L	USL	Dgen	ST	AUR	AUGSe	AUGSd	AR	AGSd	AGSe
Unadjusted	22.4	75.0	138.7	27.3	40.8	45.7	6.0	9.7	3.3	1.5	0.6	1.0	14.9	2.5	0.9	1.8	7.0	1.7	3.1
Adjusted	22.7	76.1	140.7	27.7	41.4	46.3	6.1	9.8	3.4	1.6	0.6	1.0	15.1	1.6	0.5	0.9	5.3	1.4	1.8

Witness: Henry Andre

1 MR. SHEPHERD: I am asking why your savings are lower
2 than they were when you got approval. I am asking you to
3 undertake to provide details of what changes caused them to
4 be lower; can you do that?

5 MR. ANDRE: Yes, sure, we will undertake to do that.

6 MR. SIDLOFSKY: JT3.20.

7 **UNDERTAKING NO. JT3.20: TO PROVIDE DETAILS OF THE**
8 **CHANGES THAT CAUSED SAVINGS TO BE LOWER THAN WHEN HONI**
9 **GOT APPROVAL**

10 MR. SHEPHERD: My next question is on the same
11 interrogatory response; this is page 3 of that response
12 in F. So we were looking at the rate base allocated to the
13 six acquired rate classes, and it looks like it totalled
14 361.5 million. And you said yes, it does, but that's not
15 the right number.

16 So maybe you could just explain this answer and why
17 the number that appears to be in the cost allocation model
18 is not the right number for rate-making purposes.

19 MR. ANDRE: Right. So the \$361.5 million figure comes
20 from the 01 sheet of the cost allocation model. And what
21 that represents is the amount of assets that would have
22 been or were allocated to those classes prior to the
23 application of the adjustment factors that Hydro One has
24 adopted.

25 The adjustment factors, in terms of being able to
26 incorporate it into the model, Mr. Shepherd, the easiest
27 place to do that was in the allocators tab. So it's in
28 that tab where we make the adjustments -- I guess it's E 6

1 allocators tab. It's in that tab where we show the
2 adjustments to the gross fixed assets after the application
3 of the adjustment factors. And that doesn't translate into
4 the numbers that come into the 01 sheet. It goes and gets
5 these numbers from another tab where that adjustment wasn't
6 reflected.

7 So in terms of the costs that are allocated by rate
8 base, like net income, interest costs, PILs and all of
9 that, that allocation is based on the 173.6 million in rate
10 base, not the 361.

11 MR. SHEPHERD: Excellent, thank you. And my next
12 question is still in the same interrogatory response. This
13 is in attachment 1, and I have two questions on that.

14 The first is -- we heard the other day that you have
15 zero capital productivity -- Hydro One has zero measured
16 capital productivity. Did you hear that.

17 MR. ANDRE: No. To be honest, Mr. Shepherd, I haven't
18 heard that testimony.

19 MR. SHEPHERD: Will you accept, subject to check, that
20 your witness said that?

21 MR. ANDRE: Okay.

22 MR. SHEPHERD: I am looking at these lower capital
23 spend for the acquired area and I am thinking, well, if
24 this is not because of productivity, then doesn't this mean
25 you're investing less in their systems?

26 And I -- there's probably a good explanation; I am
27 just trying to understand.

28 MR. ANDRE: Well, like I say, you know, if that

1 question had been put to panel 2 -- I expect that yes, if
2 they are spending less, Mr. Shepherd, we now had the
3 utility's integrated for, you know, a year, a year plus,
4 and I would imagine they have better information on the
5 status and the performance and the state of those assets.

6 So I would expect that the capital reflects the latest
7 information they have about the need of the assets in the
8 acquired utilities.

9 MR. SHEPHERD: I was asking more a question, and this
10 is presumably not you -- I am sorry, the information said
11 all the acquired questions were of this panel, so that's
12 why I am asking you.

13 MR. ANDRE: Sure, no problem, Mr. Shepherd.

14 MR. SHEPHERD: Otherwise I would have asked the last
15 panel.

16 What I am trying to understand is whether this means
17 that the emphasis or the prioritization of the customers in
18 the acquired areas has been reduced if you are spending
19 less. Or is that not a fair conclusion?

20 And if that's outside of your area, just tell me.

21 MR. ANDRE: No, like I said, this reflects what our
22 asset management group now believes the assets in these
23 three acquired utilities require to maintain a safe
24 reliable system.

25 But, yes, it does -- it does represent a change, but
26 this is the latest information on what we believe these
27 assets require.

28 MR. SHEPHERD: All right. The next question I have is

1 recent acquireds.

2 MR. SHEPHERD: My question is -- this appears to be
3 unfair to the old ones, the old acquireds, because you are
4 giving this special deal to the new ones. And that may be
5 because the deal for the old acquireds was unfair.

6 MR. QUESNELLE: Mr. Shepherd, now you are definitely
7 going back to what the Board determined. I think if you
8 pose your questions as to the acquireds -- what's the
9 comparison doing for us, as far as understanding whether or
10 not the direction is involved the issue in this case?

11 MR. SHEPHERD: Why don't I go there, and then I think
12 you'll see that the questions I was asking were critical.

13 Right now, you're proposing to allocate \$41.2 million
14 of costs. And the way -- what you did to respond to the
15 Board is you said, okay, first we are going to reduce it
16 from 60 to 46, wait that's not enough because now we've got
17 the Orillia decision. Let's reduce it another 5 million
18 because of the distribution stations, ah, that's still not
19 enough. So now we have to reduce it by having those
20 customers at 80 percent, or I think it's 83 percent,
21 revenue to cost ratio just to keep their rates below what
22 they would have paid otherwise.

23 Isn't that what you ended up doing? Because
24 otherwise, you can't -- Hydro One can't get its costs low
25 enough so that the costs to serve these customers are below
26 what they would have paid. You can't, right?

27 MR. VEGH: Again, Mr. Shepherd is now creating a
28 narrative around how these costs were allocated. If he has

1 questions around how the costs were actually allocated, he
2 can ask those questions.

3 But so far it's been a bit of a speech about how he
4 believes what was motivating Hydro One's activities.

5 MR. SHEPHERD: Well, maybe my friend Mr. Vegh hasn't
6 done as much cross as some other people, because one of the
7 things you do in cross is you put a narrative to the
8 witness and you say isn't that true, and that's what I just
9 did.

10 MR. ANDRE: I am happy to answer the question. And I
11 would start, Mr. Shepherd, by saying, you know, you went
12 through -- you started here and then I think you mentioned,
13 and then the Orillia decision came along and you thought,
14 okay, the costs were too low.

15 I believe during the technical conference we had
16 specific discussion around that, and there's an
17 interrogatory where you asked about that. And I
18 specifically responded that the Orillia decision had
19 nothing to do with the move to eliminate the distribution
20 stations.

21 When we looked closer at the costs that were being
22 allocated to the acquired utilities, what we noticed was
23 that the amount of distribution stations that were being
24 allocated was significantly higher than the actual
25 distribution station asset costs for the acquireds. And we
26 looked at that and said, does that seem right?

27 And when we looked at the operation of the acquireds,
28 we thought, okay, the distribution stations really do

1 provide more of a local service. I mean, in the future
2 there may be some feeders that go outside the -- outside
3 the acquired utility service territory. But right now,
4 they provide a local service, very similar to the poles and
5 the wires and the transformers that are within those
6 acquired utilities.

7 So that's the driver for making that change. It had
8 nothing to do with the Orillia decision. And what we
9 arrive at, the 41 million, is a cost that we believe fairly
10 captures two things: It captures the incremental costs.
11 So if you go back to JT3.18-19 and you reference the 25.6
12 figure, I think you correctly pointed out that figure
13 represents the only the incremental costs associated with
14 acquiring the utilities.

15 The 41.2 that we end up allocating to them captures
16 not only the incremental cost, it captures the fact that
17 there's upstream distribution facilities that are now being
18 used to serve the acquired utilities. There are common
19 shared facilities, things like operating centres, service
20 centres, call centres, the meter services shop, our head
21 office building, our IT and billing systems, those are all
22 shared facilities that now we are allocating a share of
23 those costs to the acquired customers per the Board's
24 methodology, and we believe it's appropriate that they
25 share in those costs and that's where you end up with the
26 41.2 million.

27 MR. SHEPHERD: And so the bottom line ends up being
28 that your costs go up by 25.6 to serve these people, but

1 you think that they should pay another 15.7 -- 15.6, sorry,
2 as their share of the common costs, which basically reduces
3 the rates for everybody else, right?

4 MR. ANDRE: Yes, that's right.

5 MR. SHEPHERD: Because otherwise, everybody else would
6 have to pay.

7 MR. ANDRE: That's correct. To the extent we don't
8 recover a share of those costs from the acquired customers,
9 we'd be recovering from the other rate classes, that's
10 right.

11 MR. SHEPHERD: And the thing that happened between
12 March and December is -- aside from the Orillia decision
13 which you say has no bearing -- is that somebody had the
14 bright idea to go look and see whether this was right?

15 MR. ANDRE: Yes. I mean, we were looking at those, you
16 know, in preparation for the upcoming interrogatories, in
17 preparation for the hearing. I mean, like we were looking
18 at, you know, are these numbers correct.

19 MR. SHEPHERD: And so the people in Smiths Falls, for
20 example, they pay the full amount of all these things.
21 There's no adjustment for them, right?

22 MR. ANDRE: Yes, that's correct.

23 MR. SHEPHERD: And the people in Trenton, and the
24 people in Thorold, they all pay the full -- I am trying to
25 understand why, aside from the fact that the Board is
26 getting tougher with you about acquisitions, I am trying to
27 understand why the cost allocation to these acquisitions is
28 fair and the cost allocation markedly different for the old

1 acquireds is also fair. Which one is no longer fair?

2 MR. QUESNELLE: Mr. Shepherd, I think Mr. Vegh made an
3 objection to that line as to whether or not the original
4 acquired costs are fair. Those are acquired entities now.
5 They are customers of Hydro One, and have been for twelve
6 years.

7 I recognize -- I think it's valid to have the
8 comparison of the methodology and point to the differences.
9 But at this juncture, I think the evidence that has been
10 given is that there was a conversation and there were Board
11 decisions back in 2006.

12 MR. SHEPHERD: Mr. Chairman, if Mr. Andre answers my
13 question that the current cost allocation is fair, then
14 that's the end of it. By implication, the old one is
15 unfair, but you're right, there's nothing we can do about
16 it.

17 But if his answer is neither of them is fair, or
18 there's a balance, or they're fair in different ways, then
19 I think this Board should hear it because that relates to
20 these acquireds.

21 MR. QUESNELLE: In that context, Mr. Andre.

22 MR. ANDRE: I think the allocation to the three
23 acquireds that we have now follows the Board's underlying
24 principles that are in the cost allocation model. There
25 are certain costs that are allocated based on number of
26 customers and weighted number of bills, and that is the
27 same as it always has been.

28 And then on top of that, we've adjusted -- we have

1 made an adjustment to what the model would normally
2 allocate to be consistent with the direction that the Board
3 has provided with respect to setting rates for these three
4 acquired classes as part of their MAAD decision.

5 MR. SHEPHERD: I wonder if you could turn to Exhibit
6 K10.8, which is the materials from the Orillia motion. And
7 I am looking at page 31, which is part of the Niagara-on-
8 the-Lake analysis.

9 I am not going to ask you to agree with the analysis;
10 I know there's lots of things you disagree with in it. But
11 I am going to ask you about one statement in here. It's
12 the last two bullets on page 31 -- does do you want to wait
13 to get it up on the screen?

14 MR. ANDRE: I have it. It's not up on the screen; I
15 don't know if we want to wait to bring it up on the screen.

16 MR. SHEPHERD: You can read those two bullets while we
17 are waiting for it to get up on the screen, page 31 of
18 K10.8. Sorry, page 31 of K10.8. There you go. And right
19 at the bottom of the page, you see those last two bullets?
20 So basically they have stated two sort of basic underlying
21 rate principles, and I am going to ask you whether you
22 agree with them. The first is, if ownership changes but
23 the acquired service territory is merged with a lower-cost
24 service territory then rates in the acquired territory
25 should fall.

26 And then the second -- the last bullet is, if
27 ownership changes but the acquired service territory is
28 merged with a higher cost service territory, then the rates

1 to continue into the future.

2 MR. ANDRE: Yes, that's the assumption we've made, and
3 we have indicated that we would potentially revisit those
4 allocation factors, but, you know, in the long-term there
5 may be a need to revisit that, but right now that is the
6 assumption that is built into the process that we've
7 adopted.

8 MR. SHEPHERD: Well, you just said that going forward
9 you are not going to have the information. How are you
10 going to revisit it if you don't have the information?

11 MR. ANDRE: I think people raise the point that in 40
12 years after all of the assets have been replaced, you know,
13 is it still appropriate to use those adjustment factors,
14 and we concede that once all of the assets have been
15 replaced, and that happens over a very long period of time,
16 that it may be necessary to revisit it. I can't tell you
17 right now what we would do. Certainly in the near-term,
18 you know, in the next five, ten years, we believe the
19 adjustment factors as proposed in our application would be
20 appropriate.

21 MR. SHEPHERD: So what you are proposing to this Board
22 is that, going forward, if you add distribution stations --
23 or indeed any of those assets, anywhere in the province --
24 these acquired customers are going to bear some of the
25 cost?

26 MR. ANDRE: That's exactly right. And, sorry, just
27 let me finish -- and in the same way, if we happen to need
28 a distribution station within Woodstock because their load

1 is growing or a new auto plant sets up or -- then that cost
2 would be shared among all of the other Hydro One customers,
3 so it works both ways.

4 MR. SHEPHERD: So these costs -- this whole category
5 of costs is going to be socialized going forward between
6 all of your customers across the province?

7 MR. ANDRE: Yes, that's correct.

8 MR. SHEPHERD: All right, except that these customers
9 pay a lesser share than your legacy customers?

10 MR. ANDRE: They would pay the -- so the adjustment
11 factors would apply to whatever rate base exists in the
12 future; that's correct.

13 MR. SHEPHERD: So -- and this -- this adjustment
14 doesn't apply to any other customer, so, for example, the
15 92 utilities you've applied so far -- you've acquired prior
16 to this time, they all had the same issue, but you didn't
17 adjust for that and you're not going to; you're not
18 proposing to.

19 MR. ANDRE: That's correct.

20 MR. SHEPHERD: And so if you spend a million dollars
21 on a station in Ancaster, then they'll all pay, except
22 these three utilities, the customers of these three
23 utilities, which will pay about half or so?

24 MR. ANDRE: The -- yes, that is an outcome of the
25 adjustment factor approach, would be that they -- the
26 acquired utilities would get a share of whatever growth
27 happens, you know. I would state again that if there was a
28 station that was built specifically for Woodstock or

1 Norfolk or Haldimand, they would too only get a 60 percent
2 share of that cost of the station.

3 MR. SHEPHERD: And this problem, this problem is an
4 artifact of postage-stamp rates, right? It only exists
5 because of postage-stamp rates?

6 MR. ANDRE: Yes, I mean, the socializing across a
7 utility like Hydro One that serves the whole province, and
8 so we have one rate for a particular class regardless of
9 where in the province you are, if that's what you are
10 referring to postage-stamp rates, then I would say, yes,
11 that is an outcome of postage-stamp rates.

12 MR. SHEPHERD: And the difference between these
13 acquireds and the previous acquireds or your legacy
14 customers for that matter, the difference between them in
15 terms of treatment, which sounds -- you will agree it
16 sounds on the face of it it isn't very fair -- is the
17 result of the Board saying, no, these guys -- these three
18 at least, you can't ask them to pay more than their fair
19 share of the cost to serve them, right? Which is the first
20 time you've heard that.

21 MR. ANDRE: That is the direction we were given in the
22 MAADs decision and that's the direction we're following.

23 MR. SHEPHERD: Mr. Chairman, that's probably a good
24 time to take a break.

25 MR. QUESNELLE: Yep. Thank you, Mr. Shepherd.

26 Ms. Anderson has a question.

27 **QUESTIONS BY THE BOARD:**

28 MS. ANDERSON: Sorry, I just have one clarification.

1 rebasing period. And the Board in EB-2017-0049 says that
2 you are required to apply the same cost causation analysis
3 to both legacy or acquired customers, right? That's what
4 it says?

5 MR. ANDRE: Yes, they set an expectation in terms of
6 distinguishable cost causation analysis, yes.

7 MR. SHEPHERD: You are not proposing to do that in the
8 case of OPDC or PDI, right?

9 MR. ANDRE: No, I disagree. I think what we are
10 proposing does have -- does recognize the distinguished
11 cost causation associated with both OPDC and PDI, in that
12 for those two service areas, we know specifically the
13 amount of assets, local assets required to serve those
14 utilities.

15 So we have that piece of information. Our proposal
16 with respect to the adjustment factors is akin to a direct
17 allocation of those fixed asset costs to those -- to the
18 acquired classes, which is certainly permitted by the
19 Board. Navigant had indicated that that is an appropriate
20 way to allocate costs.

21 And then every other cost, so all of the OM&A
22 including shared OM&A is then allocated you know, using the
23 Board's model which follows the cost allocation cost
24 causation principles embedded in the cost allocation model.

25 MR. SHEPHERD: So what you are attempting to do, your
26 allocation of principle for PDI and for Orillia is local
27 assets serving that area are directly allocated, right?

28 MR. ANDRE: Correct.

1 MR. SHEPHERD: And then everything else that flows
2 from that allocation is also adjusted, right?

3 MR. ANDRE: No. So once you identify the local
4 assets, then everything else -- so the allocation of, you
5 know, all of the A&M costs and all of the costs that are
6 outside the 1850 to 1820, so all of the OM&A costs,
7 including shared costs -- would then be allocated per the
8 Board's cost causation principles --

9 MR. SHEPHERD: Yes, aren't some of those costs
10 allocated based on rate base?

11 MR. ANDRE: Yes. And so rate base would have been --
12 to the extent that rate base would have been impacted by
13 the adjustments you make to the allocation of assets
14 required to serve that area, then, yes, that -- so
15 identifying the assets required to serve an area has an
16 impact on gross fixed assets, it has an impact on net fixed
17 assets, it has an impact on depreciation.

18 So those factors are there. But then A&G costs and
19 net income costs and interest costs, all of those are
20 driven by either the gross book value of assets or the net
21 book value of assets, and that's done using the Board's
22 cost allocation principles.

23 MR. SHEPHERD: But they will be lower if your direct
24 allocation is lower than your standard allocation, right?

25 MR. ANDRE: I think we've been very clear to say the
26 standard allocation in this case, what it would do is it
27 would allocate to those service areas Hydro One's average
28 costs based on the relative peak of that service area,

1 relative to the rest of Hydro One.

2 MR. SHEPHERD: Yes.

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

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

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

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

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

25 MR. SHEPHERD: You have a GIS, right?

26 MR. ANDRE: We do.

27 MR. SHEPHERD: And your GIS will tell you how many
28 poles and what wires and what transformers and everything,

1 even in some cases the vintage of those things, right?

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

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

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

16 So I think we are following the cost causation
17 principles.

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

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

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

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

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

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

9 MR. SHEPHERD: Yes.

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

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

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

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

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

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

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

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

Comparison of 2030 Costs Allocated in EB-2018-0270

<i>Class</i>	<i>Allocated Costs</i>	<i># Customers</i>	<i>Cost/Customer</i>
UR	\$121,580,909	261,362	\$465.18
AUR	\$5,370,979	13,850	\$387.80
UGe	\$29,973,096	19,046	\$1,573.72
AUGe	\$1,744,685	1,544	\$1,129.98
UGd	\$39,265,034	1,772	\$22,158.60
AUGd	\$2,462,920	180	\$13,682.89

Source: Ex. I-1-9 Attach 3

Allocation - Sheet O1, line 40

Customers - Sheet I6.2, line 23

Comparison of 2030 Costs Allocated in EB-2018-0242

<i>Class</i>	<i>Allocated Costs</i>	<i># Customers</i>	<i>Cost/Customer</i>
UR	\$121,452,732	261,362	\$464.69
AUR	\$14,111,869	35,211	\$400.78
UGe	\$29,642,792	19,046	\$1,556.38
AUGe	\$4,077,833	3,925	\$1,038.94
UGd	\$38,589,389	1,829	\$21,098.63
AUGd	\$4,806,102	403	\$11,925.81

Source: Ex. I-1-48 Attach 3

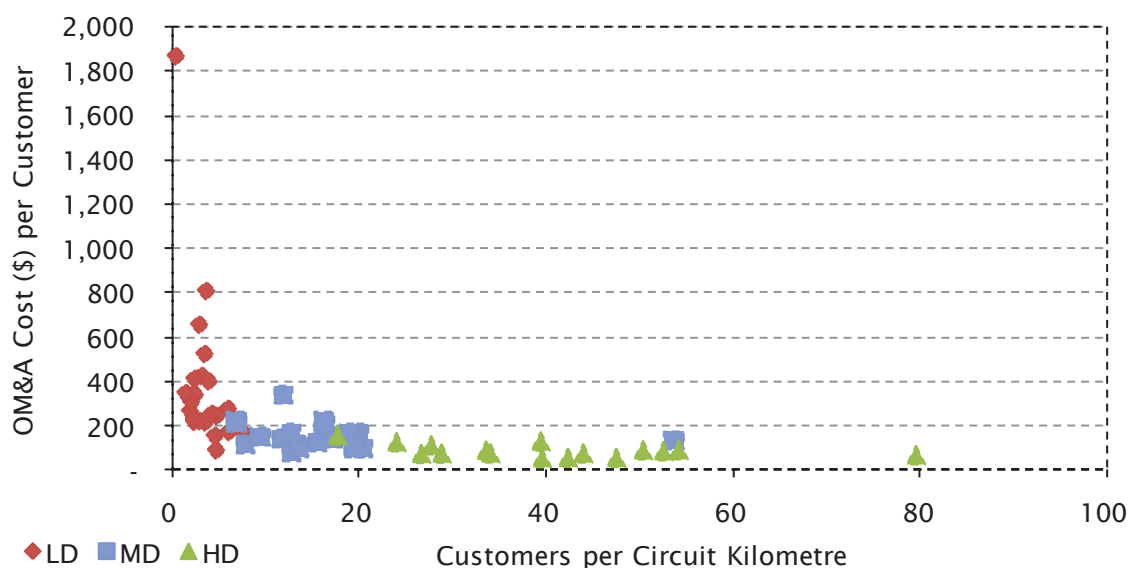
Allocation - Sheet O1, line 40

Customers - Sheet I6.2, line 23

Figure 59: High-Density Sample Area Results

Operating Area	Sample Area	OM&A	Asset Intensity
Dryden	HD1	77	8,323
Essex	HD1	126	5,076
Kingston	HD1	57	2,882
Newmarket	HD1	130	9,037
Owen Sound	HD1	58	4,700
Perth	HD1	76	7,740
Sudbury	HD1	77	4,631
Timmins	HD1	69	2,709
Essex	HD2	157	4,451
Newmarket	HD2	87	3,773
Perth	HD2	113	7,136
Sudbury	HD2	90	4,946
Timmins	HD2	91	4,905
Newmarket	HD3	91	2,265
Sudbury	HD3	56	6,176
Newmarket	HD4	75	5,151
Average		89	5,244

Source: LEI and PNXA analysis

Additional Scatter Plots**Figure 60: Relationship between OM&A Costs and Customer Density (per circuit kilometre)**

Source: LEI and PNXA analysis

1 as it is, Mr. Shepherd, there are no plans and there have
2 been no discussions about reducing the number of classes.
3 These six classes have been created. We hope to use them
4 in the future potentially to merge others as there's
5 another response that says they may go into that, we may
6 need to create new classes, so that part of it is as it is.

7 The reference to part D was simply, you know -- yeah,
8 I am not sure why we even referred you to part D, because I
9 think that first sentence gives you the full response,
10 doesn't it?

11 MR. SHEPHERD: All right. You could read it as, well,
12 we didn't look because we didn't have to. Or you could
13 read it as, we know there were no discussions, but even if
14 there were we wouldn't give them to you.

15 MR. ANDRE: Yes. So I can confirm that for this
16 response it's the former.

17 MR. SHEPHERD: Okay, thanks.

18 And then the second question on that response is that
19 you have said, and you have said this in other places too,
20 in other proceedings too, that -- and indeed, other
21 utilities have said this about harmonization, that you are
22 going to keep these six classes separate until there's no
23 material difference in the costs to serve those classes.
24 And I am trying to understand, if they are integrated into
25 your system, how is the cost to serve ever going to
26 converge? Can you just explain how that happens?

27 MR. ANDRE: The -- I understand -- I understand the
28 point that you are making, and I would agree that, you

1 know, given the use of the adjustment factors they will
2 always get less of a share than -- of certain costs than
3 other classes.

4 So the convergence is not likely. But I guess, I
5 mean, you know, the Board could make decisions about --
6 about, you know, for example, the move to all fixed rates.

7 If it turns out that the all fixed residential rate
8 for one of these new acquired classes, you know, is within
9 a dollar or \$2 of one of our other classes, is there a need
10 to maintain two separate classes.

11 So it's really more of a, we don't know what policy
12 changes may come and what they might do to the classes, so
13 it's a catch-all to say it could happen, but I agree that I
14 wouldn't see that happening in the foreseeable future, and
15 I can't see what would drive -- I can't give you an example
16 of something that would drive us to end up with the same
17 rates.

18 MR. SHEPHERD: There's not a natural thing that
19 happens that converges costs; right? This would have to be
20 something unusual for the costs to converge?

21 MR. ANDRE: The only thing I can think of, I mean, you
22 know, if all of the assets -- in 40 years, when all of the
23 assets -- when there's been a turnover, complete turnover,
24 of the assets that are associated with serving these
25 acquired utilities, presumably all of these brand-new
26 assets would have been put in at the Hydro One cost, as
27 opposed to the cost that the acquired utilities spent in
28 putting in those assets.

UNDERTAKING - JT2.1

Reference:

Undertaking:

To provide an explanation of the nature of the difference between the board's model and Hydro One's cost allocation model, and the impact applied to this process; if in evidence, to provide the reference.

Response:

As clarified on page 12 of the transcript, the undertaking was to clarify the impact on the results from the cost allocation model due to differences in the Peak Load Carrying Capacity ("PLCC") assumptions within the model.

Hydro One's cost allocation model applies PLCC values that are specific to Hydro One's conductors and transformers. These values are based on a Minimum System Study originally approved by the OEB in EB-2008-0187, with further updates approved by the OEB in EB-2013-0416. Hydro One's specific PLCC values are 1,154 watts for conductors and 2,939 watts for transformers.

The PLCC values used in PDI and OPDC's cost allocation models (as filed in EB-2012-0160 and EB-2009-0273, respectively) are the default values established by the OEB in 2006. The OEB cost allocation model's default PLCC values are 400 watts for both conductors and transformers.

Exhibit Q, Tab 1, Schedule 1, page 23 of Hydro One's last distribution rate application (EB-2017-0049) included a discussion on the impact of using different PLCC values in Hydro One versus Acquired Utility cost allocation models. As noted in Exhibit Q, Tab 1, Schedule 1, use of higher PLCC values results in a shifting of allocated costs from residential to general service classes.

The table provided below shows the impact on the 2018 Hydro One cost allocation model¹ as a result of applying different PLCC values (Hydro One specific PLCC values and default OEB PLCC values.)

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

HONI Rate Class	Using HONI's PLCC Values		Using OEB Default PLCC Values	
	Allocated Costs (\$M)	Revenue to Cost Ratio	Allocated Costs (\$M)	Revenue to Cost Ratio
UR	\$ 87.1	1.08	\$ 94.3	0.99
R1	\$ 285.0	1.09	\$ 310.4	1.00
R2	\$ 530.1	0.97	\$ 570.1	0.90
Seasonal	\$ 100.0	1.09	\$ 114.1	0.96
GSe	\$ 166.3	0.99	\$ 147.5	1.11
GSd	\$ 156.0	0.89	\$ 101.2	1.37
UGe	\$ 22.5	1.01	\$ 18.5	1.22
UGd	\$ 31.0	0.91	\$ 20.7	1.36
St Lgt	\$ 11.0	0.93	\$ 12.6	0.81
Sen Lgt	\$ 5.7	0.97	\$ 5.7	0.96
USL	\$ 2.8	1.23	\$ 3.0	1.15
DGen	\$ 6.3	0.58	\$ 6.4	0.58
ST	\$ 54.8	0.96	\$ 54.0	0.97
Total	\$ 1,458.5	1.00	\$ 1,458.5	1.00

1 Tell me whether my math is right. If I just is divide
2 1.057 by 1.0431, I get the impact, right?

3 MR. ANDRE: You get which?

4 MR. SHEPHERD: I get the impact on the --

5 MR. ANDRE: Yes, you are right. Yes, that percentage
6 change is how much the commodity would change, yes.

7 MR. SHEPHERD: All right. So then I want to go to
8 Exhibit I56-SEC -- let's use 99, and I am going to the
9 spreadsheet which is 02, okay?

10 MR. ANDRE: Okay. I think these were provided as
11 spreadsheets, so you might not necessarily have it. It
12 depends on the question Mr. Shepherd has. Should Erin pull
13 that up?

14 MR. SHEPHERD: Yes, yes, 99-02. You will be happy to
15 know that I am rapidly reaching the end.

16 And when it comes up, I am looking at the GS 50 to 99
17 tab.

18 MS. McKINNON: Nothing seems to be working on my
19 computer at the moment, so I will bring it up momentarily.

20 MR. ANDRE: I have a hard copy of that, so I can
21 certainly follow along with the question if no one else may
22 be able to.

23 MR. SHEPHERD: I will ask the question and you may be
24 able to answer off the top of your head anyway, if I know
25 you.

26 I am looking at the Woodstock bill comparison and the
27 distribution has gone way up, but then the transmission
28 costs go way down. And so, for example in this customer

1 with 177 kilowatts of demand, the sample customer you are
2 using, their transmission charges go down from \$892 a month
3 to \$596 a month, a 33 percent reduction. And it appears to
4 be all entirely driven by a reduction in the unit cost.

5 And that's true for all three of them, although the
6 difference in the case of one of them is quite small. I
7 wonder if you could just explain why this happens and why
8 this is -- I looked for an explanation and couldn't find
9 one.

10 MR. ANDRE: Yes, I don't know if there is an IR
11 response that has an explanation to that, but I can
12 certainly help you, Mr. Shepherd.

13 The RTSR rates that the acquired utilities were
14 charging their customers, the last time they were sort of
15 rebased would have been at their last cost allocation
16 model. So Woodstock, when would that have been? 2012 or
17 '13, somewhere around there.

18 MR. SHEPHERD: Yes, '11 or '12.

19 MR. ANDRE: And then from then on under the IRM, they
20 just used the Board's RR, revenue requirement work form,
21 which all it does is it looks at the change in transmission
22 charges and then bumps up everyone's RTSR rates as
23 necessary to recover what the forecast transmission charges
24 are going to be in the future.

25 When we do it in 2021, we are now looking at and we
26 are using data that comes from Mr. Alagheband's shop in
27 terms of meter data for the actual customers, either smart
28 meter data or interval meter data, and looking at the

1 contribution of this class to the peaks. And what we are
2 finding with the more current data is that these general
3 service customers are contributing less to the peak -- and
4 remember the peak is what transmission charges are based on
5 -- than what was assumed they were contributing to the peak
6 back when the utilities were calculating those rates.

7 So I think the explanation is something as simple as
8 they were using data from 2012, 2013, on that relative
9 contribution to the peak. In 2021, we are now using the
10 latest data available to us on the contribution of this
11 class to the peak. And the reality is -- and to that I
12 can't speak. I don't know if general service customers
13 either had been better at implementing efficiencies, or
14 better at avoiding the peaks for other reasons, ICI reasons
15 for example. But for whatever the reason is, the latest
16 data shows that they are contributing less to the peak, and
17 therefore by contributing less to the peak they are
18 attracting a smaller amount of the share of transmission
19 charges.

20 MR. SHEPHERD: So that's what I thought. And -- but
21 this comparison appears to imply that the rates, if they
22 had not been acquired, would be that much higher. But what
23 your explanation is, is in fact that the transmission costs
24 would have gone down anyway no matter who owned them;
25 right?

26 MR. ANDRE: I don't know what the approach is for
27 these acquired utilities in terms of updating their load
28 shapes. I mean, they seem -- you know, if they continue to

1 use the revenue-requirement work-form approach then it
2 wouldn't have changed.

3 All we can comment on is the rates that they were
4 paying at the time of acquisition, and if those rates were
5 escalated, then -- and actually, in the case of Woodstock
6 here you can see that the escalated rates for Woodstock
7 actually dropped. We said back in 2014 they were \$902, and
8 now in 2021 the escalated rate is actually only 892, so we
9 did show a bit of a drop, but it's not related to them
10 having adopted different load shapes, but I can't comment
11 on what the utility would have done with respect to the
12 transmission charges that it applied to its customers.

13 MR. SHEPHERD: Would it be correct to understand this
14 difference is as Hydro One -- I guess because you have more
15 resources and you have more expertise in the area of rates,
16 you took a more thorough approach to figuring out what they
17 should pay for transmission and in effect corrected what
18 the acquireds had been charging to a more appropriate
19 level; is that fair?

20 MR. ANDRE: It's the same approach, yeah, that we use
21 for all of our rate classes. Whenever we file a cost-of-
22 service application we revisit the contribution to the
23 peaks and therefore the amount that should be paid for
24 transmission for all of our rate classes, in this case the
25 acquireds included.

26 MR. SHEPHERD: All right. That's all my questions,
27 thank you.

28 MR. SIDLOFSKY: Thanks, Mr. Shepherd.

UNDERTAKING - JT1.2

Reference:

Undertaking:

To provide the T2 SIS for 2017 and 2018 for OPDC.

Response:

Please see attached OPDC T2 Schedule 1's for 2017 and 2018.

Canada Revenue Agency
Agence du revenu
du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2017-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation – Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125 1,215,676 A

Add:

Provision for income taxes – current	101	59,000
Provision for income taxes – deferred	102	239,000
Amortization of tangible assets	104	1,187,017
Charitable donations and gifts from Schedule 2	112	12,500
Non-deductible meals and entertainment expenses	121	8,250
Other reserves on lines 270 and 275 from Schedule 13	125	691,777
Reserves from financial statements – balance at the end of the year	126	1,028,618
Subtotal of additions		3,226,162 ►
		3,226,162

Other additions:

Miscellaneous other additions:

1 Description	2 Amount		
605	295		
1 Deferred debit CGAAP adjustment - liability increased for de	694,000		
Total of column 2	694,000	► 296	694,000
Subtotal of other additions		199	694,000 ►
			694,000
Total additions		500	3,920,162 ►
			3,920,162 B

Amount A plus amount B 5,135,838 C

Deduct:

Gain on disposal of assets per financial statements	401	92,985
Capital cost allowance from Schedule 8	403	3,119,665
Other reserves on line 280 from Schedule 13	413	927,473
Reserves from financial statements – balance at the beginning of the year	414	693,922
Subtotal of deductions		4,834,045 ►
		4,834,045

Other deductions:

Miscellaneous other deductions:

1 Description	2 Amount		
705	395		
1 Actual Repayments C GAAP Liability	4,000		
Total of column 2	4,000	► 396	4,000
Subtotal of other deductions		499	4,000 ►
			4,000
Total deductions		510	4,838,045 ►
			4,838,045 D

Net income (loss) for income tax purposes (amount C minus amount D) 297,793 E

Enter amount E on line 300 of the T2 return.



Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
Orillia Power Distribution Corporation	86512 0596 RC0001	2018-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation – Income Tax Guide*.
- All legislative references are to the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125 1,178,041 A

Add:

Provision for income taxes – current	101	169,000
Provision for income taxes – deferred	102	-140,000
Amortization of tangible assets	104	1,222,768
Loss on disposal of assets	111	59,399
Charitable donations and gifts from Schedule 2	112	12,200
Non-deductible meals and entertainment expenses	121	10,000
Other reserves on lines 270 and 275 from Schedule 13	125	927,473
Reserves from financial statements – balance at the end of the year	126	2,056,618
Subtotal of additions		4,317,458 ▶

4,317,458

Other additions:

Miscellaneous other additions:

1 Description	2 Amount			
605	295			
1 Deferred debit CGAAP adjustment - liability increased for de	693,000			
Total of column 2	693,000	▶	296	693,000
Subtotal of other additions			199	693,000 ▶
Total additions			500	5,010,458 ▶

693,000

5,010,458 B

Amount A plus amount B 6,188,499 C

Deduct:

Capital cost allowance from Schedule 8	403	3,089,640
Other reserves on line 280 from Schedule 13	413	1,828,473
Reserves from financial statements – balance at the beginning of the year	414	1,028,618
Subtotal of deductions		5,946,731 ▶

5,946,731

Other deductions:

Miscellaneous other deductions:

1 Description	2 Amount			
705	395			
Total of column 2		▶	396	
Subtotal of other deductions			499	0 ▶
Total deductions			510	5,946,731 ▶

0

5,946,731 D

Net income (loss) for income tax purposes (amount C minus amount D) 241,768 E

Enter amount E on line 300 of the T2 return.