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Ontario

BY EMAIL

March 14, 2018

Ontario Energy Board
P.O. Box 2319
27th Floor
2300 Yonge Street
Toronto ON M4P 1E4
Kirsten.Walli@oeb.ca

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Halton Hills Hydro Inc.
2018 IRM Distribution Rate Application
OEB Staff Submission
OEB File No. EB-2017-0045

In accordance with Procedural Order No. 3, please find attached the OEB staff submission in the above proceeding. This document is being forwarded to Halton Hills Hydro Inc. and intervenors in this proceeding.

Halton Hills Hydro Inc. is reminded that its reply submission is due by March 21, 2018, should it choose to file one.

Yours truly,

Original Signed By

Fiona O'Connell
Project Advisor, Major Applications
Encl.

ONTARIO ENERGY BOARD

STAFF SUBMISSION

2018 ELECTRICITY DISTRIBUTION RATES

Halton Hills Hydro Inc.

EB-2017-0045

March 14, 2018

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1 SUMMARY

This is the submission of Ontario Energy Board (OEB) staff on the applications filed by Halton Hills Hydro Inc. (Halton Hills Hydro) on September 25, 2017, October 23, 2017 and December 1, 2017. Halton Hills Hydro's applications are for, respectively, rates pursuant to the OEB's Price Cap Incentive Rate-setting (Price Cap IR) framework, the establishment and disposition of a variance account to account for and remedy an error related to depreciation expense, and recovery of costs incurred as a result of a pay equity settlement agreement (Z factor).

The applications were heard together by the OEB in the current proceeding.[1]

The applications were filed under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B) and under the OEB's *Filing Requirements For Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications - Chapter 3 Incentive Rate-Setting Applications*, issued July 20, 2017 (the Filing Requirements), seeking approval for changes to Halton Hills Hydro's electricity distribution rates to be effective May 1, 2018.

Upon review of the evidence in this proceeding, OEB staff's conclusions are as follows (and are explained in greater detail in the following sections):

1. Halton Hills Hydro's request for approval of the Z-factor should be denied.

2. Halton Hills Hydro's request for approval of the Depreciation DVA should be denied.

3. A price cap adjustment of 1.20% should be approved.

4. Halton Hills Hydro's proposed Retail Transmission Service Rates should be approved, subject to the updating of Uniform Transmission Rates that were made effective January 1, 2018.

5. Halton Hills Hydro's proposed continued transitioning of Residential Rate Design should be approved.

[1] EB-2017-0045

6. Halton Hills Hydro's proposal to clear its Group 1 deferral and variance accounts should be approved.

2 ISSUES

2.1 Z-factor Application for Pay Equity

Background

In the application filed on December 1, 2017, Halton Hills Hydro requested Z-factor treatment and cost recovery related to Pay Equity costs. Halton Hills Hydro had previously advised the OEB of its intention to file such an application by way of letter dated June 29, 2017.[2]

Halton Hills Hydro is requesting recovery of $261,251 related to a pay equity settlement for the period from 2012 and forecasted to April 30, 2021 (which latter date is just before the effective date for Halton Hills Hydro's next scheduled cost of service (CoS or rebasing) application.

Submission

The following is a summary of the factors upon which OEB staff submits that Halton Hills Hydro's request for approval of the Z-factor be denied. These factors are explained in greater detail below.

1) Pay equity is a matter that is part of the normal course of business of any LDC, including Halton Hills Hydro.

2) Halton Hills Hydro was aware of this particular issue since 2012, and has experience with pay equity as an issue generally for much longer (at as far back as 1990).

3) The Pay Equity issue is not one for which "… the management of the distributor could not have been able to plan and budget for the event and that the harm caused by extraordinary events is genuinely incremental to their experience or reasonable expectations."[3]

4) Halton Hills Hydro's claim that the impact is material is due to its aggregation of the costs, including forecasted costs from January 1, 2018 to March 31, 2021 as

[2] Filed in response to OEB Staff Question # as IRR – Appendix C
[3] Filing Requirements For Electricity Distribution Rate Applications – 2017 Edition for 2018 Rate Applications - Chapter 3: Incentive Rate-Setting Applications, July 20, 2017, p. 17

one lump sum. On an annual basis for the period of nearly 10 years, no amount would approach the annual materiality threshold of $50,000 appropriate for Halton Hills Hydro based on its approved 2016 revenue requirement.

5) For the forecast period from January 1, 2018 to March 31, 2021, the requested amounts are forecasts, and not audited actuals. The amounts are well below the materiality threshold on an annual basis, and Halton Hills Hydro should be able to manage its costs, including Pay Equity settlements, for that period under the envelope of existing rates as adjusted by the annual Price Cap IR formula.

OEB staff discusses each of these in turn.

1. Pay equity is a matter that is part of the normal course of business

Pay equity is a matter that is common to any incorporated business. For business incorporated under the Ontario *Business Corporations Act*, the current applicable legislation is the *Pay Equity Act*.[4] This would apply to Halton Hills Hydro. Further, Halton Hills Hydro noted that its predecessor municipal electricity utility was subject to this legislation as well, and that pay equity had been an issue back in 1990. A Pay Equity Committee was established with both management and union representation since 1991.[5]

All (or nearly all) Ontario LDCs, including Halton Hills Hydro have an organized workforce comprised of unionized employees as well as non-unionized employees, mostly management. There is an established management-union team to discuss, and attempt to resolve work-related matters on an ongoing basis.

While the outcome of any disputed matter is not predetermined or pre-determinable, pay equity is a matter within the “normal course of business”, and clearly has been so at Halton Hills Hydro and its predecessor MEU since 1991. This is not “extraordinary”.

2. Halton Hills Hydro has been aware of this specific issue since 2012

In its Z-factor application, Halton Hills Hydro notes that the Pay Equity Committee established Terms of Reference, which were formally signed on February 13, 2013. The

[4] For federally regulated firms such a telephone companies, railways and cable companies, Federal legislation will apply. Businesses incorporated and operating in other provinces would be subject to similar provincial legislation.
[5] Z-factor Application, December 1, 2017, p. 4.

Pay Equity Committee met from then until a settlement was reached through an agreement reached through an arbitration settlement agreement in February 2017.[6]

However, Halton Hills Hydro has not raised it in filings with the OEB prior to filing the Letter of Intent on June 29, 2017.[7] The matter was not raised in Halton Hills Hydro's 2016 cost of service application, and the only identification was an expensed amount in 2014 under Account 5630 – Outside Services Employed.[8] While this has been ongoing since late 2012, this has never been on the radar for the OEB or other stakeholders, as Halton Hills Hydro has never brought it to light. This is a matter that they were managing internally as part of their business.

3. Halton Hills Hydro should have been able to plan and budget for the impact of the Pay Equity matter from 2012 to early 2017

As noted above, Halton Hills Hydro has had a Pay Equity Committee since 1991. The current pay equity issue arose in 2012, and Terms of Reference were signed in February 2013. Therefore, the matter was known and was ongoing until resolution with the arbitrated settlement agreement reached in early 2017.

Halton Hills Hydro rebased its rates for 2012. It was under annual price cap adjustments to distribution rates for the next three years (2013, 2014 and 2015), before rebasing again in 2016. For 2017 to 2020 (to April 30, 2021, since Halton Hills Hydro's rate year currently runs from May 1 to April 30), Halton Hills Hydro's distribution rates again are being adjusted annually under the Price Cap IR methodology.

Like any utility under a PBR/IRM form of regulation, where the linkage between costs and revenues is loosened relative to that under traditional cost of service, the utility has more flexibility to manage projects and costs to meet customers' needs and expectations, while also striving to meet shareholders' earnings expectations. Further, the OEB highlighted in the 2012 cost of service decision its expectation that Halton Hills Hydro would manage its costs under the approved OM&A envelope. While the decision was with respect to the 2012 application that resulted in rebased rates, this would also extend to the subsequent IRM period (i.e., 2013 to 2015). Its favourable financial performance in 2012 to 2014 shows that the utility attempted to do this – and largely succeeded, but with one exception; the utility does not appear to have made any

[6] Z-factor Application, December 1, 2017, page 5, para. 2.7
[7] Appendix IRR-C, requested in OEB Staff Question #8 a)
[8] See OEB Staff Question # 10 and SEC-8

attempt to plan or budget for the known and ongoing pay equity matter, even though it was well-positioned to plan for that possible “rainy day”.

This was not an exogenous “event”; Halton Hills Hydro’s management knew about this issue, was involved in it and could, and should, have done some planning and budgeting for the eventual resolution; it was certainly in a financial position to easily do so. On an annual revenue requirement basis, none of the amounts are material.

The following is an excerpt from the OEB decision on Halton Hills Hydro’s 2012 cost of service application in which the company was explicitly informed by the OEB of the OEB’s expectations that Halton Hills Hydro would manage under the envelope of OM&A costs approved in that decision:

> **Board Findings**
>
> Intervenors have submitted that HHH should be allowed (based on CGAAP valuation) an OM&A figure for the test year in the range of $5,124,500 to $5,309,510, based either on comparisons with other proceedings or taking into account decrements to the 4 main cost drivers. The Board considers the comparisons to other proceedings to be useful to consider as a general approach. However, the Board must base its determinations on the record before it in this proceeding. The Board finds that HHH has provided adequate rationale for most of its spending requirements. However, the Board also notes that HHH’s actual OM&A spending in 2008 to 2010 was significantly lower than 2008 Board approved spending. Such a pattern followed by a significant increase in the test year is a potential cause for concern.
>
> The Board will approve OM&A spending using an envelope approach.
>
> The Board accepts that tree trimming has been under funded and notes that HHH will amortize the program and costs over 4 years. The Board accepts the need and the costs that have been validated by a 3rd party whose findings have not been disputed by intervenors. However, the Board agrees with intervenors that ratepayers should not be required to pay for the entire deferred incremental tree trimming costs necessary to remedy the under-funded budget during the IRM term, particularly when overall OM&A spending during the IRM period has been lower than the 2008 Board approved level.

> HHH submitted that its wages and benefits have also been under funded for the past few years and must be increased. The Board notes that HHH held off on hiring additional staff however, the evidence indicates that some of the 2008 approved budget could have funded those additions.
>
> Given the adjustments outlined above and accounting for growth in the customer forecast, the Board has determined that the forecast OM&A envelope will be $5.9 M.
>
> This is based on a sharing of 2.5% year over year escalation of 2008 approved levels notwithstanding the lower actual expenditures levels during the IRM period. This figure also includes the provision for $286k in MIFRS transition costs which the Board finds is beyond HHH's control and was uncontested.
>
> *The Board will not direct specific spending cuts, as these are matters for HHH to manage within the spending envelope approved by the Board. The Board expects that HHH will be able to prioritize its business activities and implement planned spending within the envelope approved.*[9]
> [Emphasis added]

Therefore, the utility knew what was expected of it by the OEB.

Was the utility under any pressure that would challenge its ability to manage its operations and associated costs, including planning for and budgeting for the pay equity matter being discussed through the Pay Equity Matter?

[9] Decision and Order EB-2011-0271, pp. 17-18, also quoted in OEB Staff Question #11.

OEB staff submits that no such situation existed from 2012 to at least 2016 (2017 audited actuals are not currently available). OEB staff queried Halton Hills Hydro about certain key financial statistics for the period. The following table is Halton Hills Hydro's response to OEB Staff Question # 11 a) and b):[10]

Year		**2012**	**2013**	**2014**	**2015**	**2016**
Regulatory Return on Equity (1)	Approved (in Rates)	8.82%	8.82%	8.82%	8.82%	9.19%
	Achieved	13.30%	14.97%	12.91%	6.70%	6.76%
Net Income, net movement in regulatory balances, total comprehensive income (2)	Actual	$2,490,960	$3,623,607	$3,419,317	$3,067,551	$1,350,087
Dividends (2)	Actual	$1,077,592	$1,295,344	$1,296,560	$1,297,000	$1,297,000

(1) Source: 2016 Scorecard
(2) Source: Audited Financial Statements

There are several points to be made with respect to this table.

[10] On a tangential matter, OEB staff submits that Halton Hills Hydro is incorrect in stating that its approved ROE from 2012 to 2015 is 8.82%, despite its explanation of dealing with OEB staff about the utilities RRR filings, as documented in OEB Staff Question # 8 b). The Partial Settlement Agreement (February 29, 2012) in EB-2011-0271 states, under Issue 5.1:

> This Partial Settlement Agreement reflects the Board's Cost of Capital Parameters for ROE and short term debt for cost of service applications for rates effective January 1, 2012 (see Appendix A). The Parties have agreed that the final revenue requirement for rate-making purposes will be subject to the Board's Cost of Capital Parameters for ROE and short term debt for cost of service applications for rates effective May 1, 2012, to be issued by the Board in early 2012. The updated parameters will be incorporated into the Draft Rate Order to be prepared following the final disposition of this application.

The OEB's issued ROE for May 1, 2012 was 9.12%, as documented in in the letter issued on March 2, 2012 and available on the OEB's website. The OEB accepted the Partial Settlement Agreement. Halton Hills Hydro documented that it used the 9.12% ROE in its Draft Rate Order filing (June 20, 2012), and no party took issue with this. This does not alter consideration of the pay equity matter, or of which years the utility achieved earnings above, below or within the deadband of 300 basis points around its approved ROE. However, OEB staff submits this in order to clarify the utility's historical information.

First, even with a (corrected) deemed 9.12% ROE for 2012 to 2015, Halton Hills Hydro over-earned (on a regulated basis) by more than 300 basis points in each of 2012, 2013 and 2014. While it did not achieve the approved ROE in 2015 and 2016 (again on a regulated basis), its performance was within the deadband.

The net income has been healthy for all years, although it declined for 2016. The utility has also paid similar level of dividends to its shareholder each year despite varying net income levels. The dividend was over $1 million for 2012, and has been nearly $1.3 million in every subsequent year. Net income after tax not paid out in dividends has been re-invested as retained earnings. Re-investment is beneficial to customers to maintain or improve assets and operations to service them, but it also benefits the shareholder by increasing its equity interest on which it expects to earn a return.

There is nothing wrong with Halton Hills Hydro's actions in this regard. Shareholders expect to be compensated for the time value of money and the risk they undertake with their investment. There is no guarantee of this, but they should have a reasonable opportunity to earn a reasonable, market-based return on their investments. There has been no extraction of equity (the annual dividends do not exceed net income after tax in any year).

However, given its healthy financial position over this period during which the Pay Equity Committee was discussing the pay equity issue, OEB staff submits that the utility could easily have – and should have – budgeted for any potential outcome. Not establishing a contingency fund (or "rainy day fund") given its financial health and the known matter does not seem rational. The annual amounts involved are minimal compared to the utility's net income after tax in every year, and the utility could easily have planned for final resolution of this issue, rather than seeking further recovery from ratepayers at this time.

In response to OEB staff Question # 13 a) and b), Halton Hills Hydro filed a document from its external Pay Equity Consultant, Gallagher McDowall Associates.[11] In the document, the consultant states:

> Given the myriad number of "moving parts" in the Pay Equity negotiations, and the number of possible outcome scenarios, management's control over the

[11] Appendix IRR – F

> Pay Equity process was necessarily limited, and precise planning / budgeting for possible outcomes was not possible.

OEB staff concurs that "**precise** planning / budgeting for possible outcomes was not possible". However, that is not what is required, or what the OEB specifically signaled as its expectations for Halton Hills Hydro to manage its operations and costs generally in the 2012 decision.[12] The pay equity issue was an ongoing matter that management was aware of and even actively engaged in, and its financial position was such that it could and should have had some plan for, and money set aside to deal with, an outcome that was realized.

OEB staff notes that Gallagher McDowall Associates did not address Halton Hills Hydro's financial outlook nor its rate regulatory situation; it was asked to provide its opinion within the context of its expertise on pay equity. However, for the purposes of determining whether the pay equity matter should be recovered from ratepayers, OEB staff submits that consideration of what the utility was expected to do and capable of doing, given its circumstances overall, is pertinent. The utility could and should have been capable of planning and budgeting for final resolution in some manner, even if precise forecasts could not be identified.

4. On an annual revenue requirement basis, the pay equity amounts are immaterial

In the Z-factor application, Halton Hills Hydro provided the following table (Table PE1) showing the Pay Equity Claim, by year, with 2012 to 2014 aggregated:

Table PE1 - Summary of Pay Equity Agreement Costs

Year	Pay Equity Adjustments	OMERs Adjustments	Pay Equity Advisory Expense	Carrying Charges	Total
2012-2014	64,003	9,586			73,589
2015	24,125	3,128			27,254
2016	19,585	2,826	26,109		48,520
Sub-total	107,713	15,540	26,109	-	149,362
2017	18,415	2,689	9,848	1,987	32,939
Sub-total end of 2017	126,129	18,229	35,957	1,987	182,301
2018*	19,756	2,884		916	23,556
2019*	21,320	3,113			24,433
2020*	21,613	3,155			24,768
2021*^	5,403	789			6,192
Total	**194,221**	**28,170**	**35,957**	**2,902**	**261,251**

* Forecasted
^ January 1, 2021 to April 30, 2021 only

[12] EB-2011-0271

Table IRR-7 filed in response to SEC-7 shows the Pay Equity Adjustments for all years. Individually for each of 2012, 2013 and 2014, these are:

Year	Pay Equity Adjustment
2012	$19,548
2013	$21,497
2014	$22,958

No breakout of the OMERS Adjustment of $9,586 (from Table PE1) is provided, but any disaggregation should be close proportionately to the pay equity adjustments. Regardless, none of the annual amounts come close to the materiality threshold of $50,000 applicable to Halton Hills Hydro based on its approved revenue requirement, either from the 2012 or 2016 cost of service applications.

Z-factor applications are with respect to an “event”. The OEB has noted some flexibility in what can be acceptable as an “event”. An “event” can occur over more than one single year, as was the case for the 2013 Ice Storm in late December, where restoration occurred that month and into January. However, while there was an “event” whereby settlement was reached in early 2017, the proposed Z-factor costs relate to an extended period of time of over 9 years.

The materiality threshold of the maximum of $50,000 or 0.5% for base revenue requirement, up to $1,000,000 is based on an annual concept. OEB staff submits that it is inappropriate to aggregate all costs for over 9 years and claim that it is material relative to an annual threshold. If that was the case, then all that an applicant would have to do would be to aggregate costs over a long enough period; that is clearly not the intention of the materiality threshold.

In addition, OEB staff has considered the matter of materiality in the context of defining what portion of the requested relief could be defined as an event and to therefore be in a position to assess materiality. The OEB has addressed this in relation to a Z factor “event” as opposed to a “cause” in a decision regarding Enbridge Gas Distribution Inc.:

> The two primary areas of dispute are the change from "event" to "cause" in the criteria, and the maintenance of the threshold at $1.5 million.
>
> …
>
> … the Board will not adopt Enbridge's proposal to use "cause" as the reference. The Board will retain the reference to "event". In reply, Enbridge submitted that if the Board does not adopt its proposal, then the approach proposed by Board staff is the most appropriate of the alternative positions. The Board will adopt Board's staff's proposed wording as it is sufficiently similar to the criteria for Union Gas and for electricity distributors and transmitters. The criteria will be as follows:
>
> > (i) Causation: The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event.

On an annual basis, the pay equity adjustments are below the annual threshold of $50,000 that would apply to Halton Hills Hydro. OEB staff submits that the "payment adjustments" for the period 2012 up to 2017 and paid out in 2017 could be defined as stemming from an "event" and would exceed the materiality threshold in relation to how it affects the 2017 revenue requirement. However, as noted earlier, OEB staff submits that the "exogeneity" (Management Control) criterion is not satisfied. Further, as OEB staff documents below, due to the price cap IR adjustment and growth in customers and demand, since 2017, the $50,000 materiality threshold based on the approved 2016 revenue requirement understates Halton Hills Hydro's actual threshold.

5. Future forecast period from January 1, 2018 to April 30, 2021

Halton Hills Hydro is seeking approval for Z-factor treatment, and recovery via rate riders for forecasted amounts as shown in Table PE1, copied above.

On an annual basis, each of the forecasted period amounts are less than $25,000 – which is only 50% of the materiality threshold of the $50,000 currently applicable to Halton Hill Hydro. Further, from its final RRWF from the 2016 cost of service application, Halton Hills Hydro had a "distribution" (base) revenue requirement of $9,953,991. This is just below the $10,000,000 rate base threshold, beyond which the materiality threshold is 0.5% of the base revenue requirement. Halton Hills Hydro is a growing

utility, as shown by growth in customers in rate applications and RRR and Yearbook data. With current customer growth patterns, and the impact of annual Price Cap IR adjustments since 2016 and forecasted to 2020, the base revenue requirement would exceed $10,000,000. Thus, the $50,000 materiality threshold understates the actual materiality threshold of 0.5% of the annual base revenue requirement, as shown in the following tables. The requested pay equity costs for the forecasted period are immaterial on an annual basis, as noted above.

Halton Hills Hydro - Estimated Materiality adjusted for growth and Inflation less Productivity

Year	Inflation (IPI)		Base X-factor	Stretch-factor for Halton Hills Hydro		Price Cap Index		Average Annual Growth (from Yearbook data)	"Distribution" (Base) Revenue Requirement		Materiality Threshold
2016									$ 9,953,991.28	RRWF reflecting Decision and DRO	$ 50,000.00
2017	1.90%		0.00%	0.00%		1.90%		0.7%	$ 10,217,708.66		$ 51,088.54
2018	1.20%		0.00%	0.00%		1.20%		0.7%	$ 10,416,362.93		$ 52,081.81
2019	1.80%	(est.)	0.00%	0.00%	(est.)	1.80%	(est.)	0.7%	$ 10,681,837.25		$ 53,409.19
2020	1.80%	(est.)	0.00%	0.00%	(est.)	1.80%	(est.)	0.7%	$ 10,954,077.52		$ 54,770.39

Note: Average Annual growth rate is a simple estimate, averaging change in customers and change in kWh (overall and per customer), as the main components of "demand" common to all customer classes. The period used has been from 2012 to 2016, corresponding to most recent Yearbook data for Halton Hills Hydro. It is an approximation of actual growth in demand that the utility must service.

	Customers	% chg	kWh (no losses)	kWh per customer	% chg	
2012	20,893		488,059,514	23,359.95		
2013	21,499	2.9%	500,284,418	23,270.13	-0.4%	
2014	21,534	0.2%	509,742,327	23,671.51	1.7%	
2015	21,929	1.8%	510,232,248	23,267.47	-1.7%	
2016	22,112	0.8%	503,249,244	22,759.10	-2.2%	
		1.4%			**-0.6%**	**0.7%**

Further, the 2018 to April 30, 2021 costs are forecasts – they are not audited actuals. There is no certainty that that costs will occur. If, for example, an affected employee was to cease employment before April 30, 2021, future amounts to April 30, 2021 may not be paid. Halton Hills Hydro is requesting recovery through rate riders where the costs are uncertain, in addition to not being material on an annual basis.

Finally, OEB staff notes that Halton Hills Hydro is under a Price Cap IR form of rate adjustment, for the period from May 1, 2017 to April 30, 2021. Distribution rates are set through the standard I – X (inflation less expected productivity, the latter including the annually updated stretch factor) formula. As the OEB pointed out explicitly in its decision on Hydro Hills Hydro's 2012 cost of service application, and as has been articulated by the OEB in policy documents regarding PBR/IRM forms of regulation, under these

streamlined and formulaic rate regulatory plans, the utility is expected to manage its investments, operations, and associated costs in light of customer demand and other requirements and business environmental factors, such as inflation, interest rates, policy, technology, etc. PBR/IRM forms of regulation loosen revenues from costs; if the plan design and parameters are appropriate, then the utility has an opportunity to recover prudently and reasonably incurred capital and operating costs and an opportunity to earn a return on shareholders' investments that satisfies the Fair Return Standard.[13]

The costs forecasted for 2018 through April 30, 2021 are immaterial on an annual basis, and are not certain, and Halton Hills Hydro should be able to manage these costs along with all other costs for its distribution network investments and operations. In OEB staff's submission, the forecasted future costs for the period January 1, 2018 to April 30, 2021 do not qualify for Z-factor treatment.

Conclusion

On the basis of the evidence and established OEB policies, OEB staff submits that the requested Z-factor treatment for pay equity costs for the period from 2012 to April 30, 2021 should be denied in its entirety. Halton Hills Hydro has not satisfied the requirements for Z-factor treatment; the costs are not "extraordinary", they are immaterial on an annual basis, there is no evidence that Halton Hills Hydro has or will have, since 2012 or forecasted to April 30, 2021, its financial viability affected adversely in a material way, and the utility, particularly given its very favourable achieved returns in 2012 to 2014, even when the Pay Equity Committee was meeting on this matter, should have been able to establish some form of contingency. Finally, as the OEB noted specifically in its decision on Halton Hills Hydro's 2012 cost of service application, and which applies generally to all distributors during terms of formulaic rate adjustments (e.g., Price Cap IR), the utility is expected to manage its investments and costs with consideration to adequately servicing its customers. Halton Hills Hydro should have done so as this was a known issue during this whole period. If it did not do so, this should be borne by the utility and its shareholders, not by Halton Hills Hydro's customers.

[13] As defined in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084)*, December 11, 2009, section 3.1, and established and reaffirmed through court decisions since the 1920s in Canada and the United States.

2.2 Depreciation Deferral and Variance Account

Background

Halton Hills Hydro requested approval from the OEB to establish a depreciation deferral and variance account (the Depreciation DVA). Halton Hills Hydro is proposing to account for and remedy an error made in the calculation of depreciation expense in its most recent CoS proceeding, which established the rates that took effect on May 1, 2016[14] (the 2016 Rate Year Application).

Relating to the proposed Depreciation DVA, Halton Hills Hydro is requesting approval as follows:

(a) An accounting order to authorize Halton Hills Hydro to establish the Depreciation DVA.

(b) The annual allocation of $330,259 for correctly calculated depreciation amounts for the years 2016 to 2021 (or the next cost of service year, whichever comes first).

(c) The clearance of the Depreciation DVA balance in the amount of $660,519 for the years 2016 and 2017 commencing May 1, 2018 for a twelve month period.

(d) The annual clearance of the account from 2019 up to and including the next cost of service year.

Halton Hills Hydro also proposes that the Depreciation DVA have an effective date of May 1, 2016. Halton Hills Hydro provided a table[15] which outlines the periods that the distributor is requesting recovery regarding the Depreciation DVA. This table is shown below.

[14] EB-2015-0074
[15] OEB staff Question #20

Table IRR – 8 Recovery periods for Depreciation Expense

Year of Depreciation	Depreciation Amount	Recovery / DVA Disposition Period	
		Start Date	End Date
2016	330,259	May 1, 2018	April 30, 2019
2017	330,259	May 1, 2018	April 30, 2019
2018	330,259	May 1, 2019	April 30, 2020
2019	330,259	May 1, 2020	April 30, 2021
2020	330,259	May 1, 2021	April 30, 2022

Submission

OEB staff submits that recovery of the Depreciation DVA be denied, based on the following conclusions.

1. The onus is on an applicant to ensure that the evidence it files in support of its application is complete and accurate.

2. Halton Hills Hydro has not demonstrated any financial viability concerns in its application.

3. Halton Hills Hydro should have provided for more rigorous controls, review, and diligence of depreciation numbers reported to the OEB in its 2016 Rate Year Application, in light of a previous OEB-ordered audit.

4. Approval of the full amount of the Depreciation DVA for the requested periods relate to some historic periods, which may constitute retroactive rate-making.

5. There is an incomplete record related to the Depreciation DVA and not enough clarity has been established by the applicant.

OEB staff submits that these conclusions are supported by the following reasons.

1. The onus is on an applicant to ensure that the evidence it files in support of its application is complete and accurate.

Halton Hills Hydro may not have accepted full responsibility for this error as it indicated that it "believes that due diligence was done."[16] However, Halton Hills Hydro did indicate that it is "imperative that the LDC learn from the mistakes and put in place controls that will limit, and hopefully eliminate, such errors in the future."[17] Halton Hills Hydro also articulated that depreciation expenses will be accurately presented to the OEB going forward, with the new ERP system that it has put in place.[18]

That said, the onus is on an applicant to ensure that the evidence it files in support of its application is complete and accurate. This is clearly stated in the *2016 Filing Requirements for Electricity Distribution Rate Applications.*[19] It is therefore Halton Hills Hydro's responsibility to present accurate evidence based upon which the OEB will make its decision.

Halton Hills Hydro incorrectly characterized this error as "administrative in nature"[20], whereas OEB staff notes that this error is substantive and not simply "administrative". Ratepayers should not be harmed by inaccurate evidence presented by the distributor.

OEB staff also notes a decision and order, on motion to review (the Motion), regarding Veridian Connections Inc. (Veridian).[21] The Motion sought to vary the a previous OEB decision[22] to permit Veridian to recover an additional $478,224 in revenue requirement related to 2009 amortization expenses associated with smart meter capital expenditures made in 2006, 2007, and 2008. However, the OEB did not allow an adjustment for this error and determined the following regarding the Motion:

[16] OEB staff Question #18
[17] SEC-1
[18] OEB staff Question #19
[19] Filing Requirements For Electricity Distribution Rate Applications - 2015 Edition for 2016 Rate Applications, July 16, 2015, Chapter 1, page 3
[20] OEB staff Question #15
[21] EB-2013-0022, April 25, 2013
[22] EB-2012-0247

- The failure to include the $478,224 for recovery in Veridian's prior proceeding[23] was an error on the part of Veridian;
- Veridian should have been aware of the correct amount of the smart meter expenditures, including amortization expenses;
- It expects a utility to provide the OEB with accurate accounting for rate setting purposes;
- Veridian has control of its books and records;
- Veridian has the responsibility to ensure mistakes do not occur; and
- If the OEB were to allow recovery this would result in retroactive ratemaking.

2. Halton Hills Hydro has not demonstrated any financial viability concerns in its application.

Halton Hills Hydro stated that "to leave the understatement uncorrected would severely impair HHHI's ability to earn a fair return for the distribution of electricity" and "the understatement of depreciation puts HHHI very close to under-earning by 300 basis points."[24] However, OEB staff notes that Halton Hills Hydro has not demonstrated any financial viability concerns in its application, nor is it actually forecasting to under-earn by more than 300 basis points.

3. Halton Hills Hydro should have provided for more rigorous controls, review, and diligence of depreciation numbers reported to the OEB in its 2016 Rate Year Application, in light of a previous OEB-ordered audit.

OEB staff also indicated that the OEB had previously ordered an audit of the Account 1575 IFRS-CGAAP Transitional PP&E Amounts balance in its 2012 cost of service decision.[25] The audit of the Account 1575 balance included a review of Halton Hills Hydro's depreciation values. The OEB voiced concerns that numerous material updates were made to the Account 1575 balance during Halton Hills Hydro's 2012 cost of service proceeding.[26]

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[23] EB-2012-0247
[24] Halton_Application_Depreciation_20171023, page 2; as also indicated in SEC-4, Halton Hills Hydro's 2016 regulatory return on equity (ROE), including the full calculations as provided to the OEB in the RRR filings is shown in Appendix IRR – K, shows an Achieved ROE which is 2.43% below the Deemed Last CoS ROE
[25] EB-2011-0271
[26] For example, one of these updates reflected the results of Halton Hills Hydro finalizing its 2011 capital expenditures and depreciation during its 2011 year-end audit process with KPMG. In particular, this

If enhanced controls were put into place in response to the shortcomings identified as part of the OEB audit, the depreciation error may have been avoided. In this proceeding, OEB staff noted that it was unclear why the distributor had not provided for more rigorous controls, review, and diligence of depreciation numbers reported to the OEB, considering this previous OEB-ordered audit. Halton Hills Hydro did not provide a full explanation as to why these actions regarding the depreciation numbers reported to the OEB were not put in place. However, Halton Hills Hydro indicated that it had embarked on a process after the 2012 cost of service proceeding to replace an aging ERP system to better account for depreciation expense.[27]

OEB staff also notes that the Chapter 2 Appendices[28] specifically alert applicants to incorporate changes impacting remaining useful lives from adopting MIFRS when calculating depreciation amounts.

4. Approval of the full amount of the Depreciation DVA for the requested periods relate to some historic periods which may constitute retroactive rate-making.

Approval of the full amount of the Depreciation DVA for the requested periods relate to some historic periods. As a result, approval of these amounts may constitute retroactive rate-making (e.g. recovery of $330,259 in the Depreciation DVA related to each of the 2016 and 2017 fiscal years). Retroactive rate-making is inconsistent with standard OEB policy and practice.

The requested correction for the 2016 rate year (May 1, 2016 to April 30, 2017) may also constitute a departure from what was agreed to in settlement in the 2016 Rate Year Application, and which settlement was accepted by the OEB in its decision.

There are also other OEB precedents that rule against retroactive rate-making, in response to a distributor requesting corrections to certain balances that were approved on a final basis in a prior proceeding.[29]

update involved Halton Hills Hydro reducing its CGAAP depreciation from an amount of $2,741,106 to an amount of $2,115,000, generating a material difference of $626,106.
[27] OEB staff Question #19
[28] 2016 Chapter 2 Appendices, Tab App.2-CB_NewCGAAP_DepExp_2012, line 62
[29] EB-2017-0056 Kitchener-Wilmot Hydro Inc., March 1, 2018 Decision and Order, page 10

Halton Hills Hydro stated that the depreciation error was discovered in early Q2 of 2017 as it was comparing its 2016 audited depreciation expenses to the amount that was approved in the 2016 Rate Year Application.[30] Halton Hills Hydro stated that it could not have discovered the error until all of the 2016 asset additions were completed and the 2016 depreciation expense was calculated.[31] However, OEB staff notes that Halton Hills Hydro likely would have presented financial statements at least on a quarterly basis to its Board of Directors. As a result the depreciation error should have been discovered earlier than Q2 2017.

5. There is an incomplete record related to the Depreciation DVA and not enough clarity has been established by the applicant.

OEB staff submits that the record is incomplete on a number of items. OEB staff identifies the following deficiencies:

i. OEB staff indicated that the Chapter 2 Appendices[32] specifically alert applicants to incorporate changes impacting remaining useful lives from adopting MIFRS when calculating depreciation amounts. Halton Hills Hydro stated that the "2015 depreciation values that were incorporated into the 2016 OEB approved rate base are correct."[33] However, OEB staff is unclear why Halton Hills Hydro stated that the 2015 depreciation values are correct and does not believe this to be an accurate statement.

   In its application and interrogatory response, Halton Hills Hydro indicated that its depreciation expense Excel model assumed that the opening 2015 undepreciated cost reflected the total revised extended useful lives, rather than the revised extended useful lives that were remaining as at January 1, 2015. As a result, the 2015 depreciation values incorporated into rate base may be incorrect.

ii. Halton Hills Hydro demonstrated that the Depreciation DVA rate rider is being allocated based on metered kWh/ kW[34] instead of 2016 OEB approved revenue requirement, which would be consistent with past OEB practice. OEB staff is unclear why this method of rate design is being proposed by Halton Hills Hydro.

[30] OEB staff question #15
[31] Ibid
[32] 2016 Chapter 2 Appendices, Tab App.2-CB_NewCGAAP_DepExp_2012, line 62
[33] OEB staff Question #22
[34] OEB staff Question #24

iii. OEB staff also notes that Halton Hills Hydro has provided the rate design[35] for the proposed Depreciation DVA rate rider that would be effective May 1, 2018. For the 2018 rate year, $660,519[36] would be recovered from customers, of which $330,259 would relate to each of the 2016 and 2017 years. However, Halton Hills Hydro has not provided the rate design for the proposed rate rider that would be effective May 1, 2019, and would continue until Halton Hills Hydro next rebases, where $330,259 would be recovered from customers for each rate year. If the proposal for the Depreciation DVA is approved, the company would need to provide this in its draft rate order or in a future application.

iv. OEB staff requested[37] that Table B2 – 2018 IRM Revised Bill Impacts be revised to show the impact of all items, including the proposed Depreciation DVA rate rider. Halton Hills Hydro provided its response to this interrogatory via VECC-1. However, the company did not explain the wide-ranging bill impacts.[38] For example, the "Distribution Impact with Depreciation Adjustment"[39] for the following rate classes are as follows:

- Residential 2.59%
- General Service Less Than 50 kW 1.16%
- General Service 50 to 999 kW -26.99%
- General Service 1,000 to 4,999 kW -30.88%
- Unmetered Scattered Load 2.01%
- Sentinel Lighting 0.81%
- Street Lighting 3.57%

v. Halton Hills Hydro provided a revised Table A1 – 2016 Approved Cost of Service vs. 2016 Correctly Calculated[40]. Halton Hills Hydro indicated that the revised depreciation amount shown in the model is the 2016 actual depreciation for

[35] OEB staff Question #24
[36] $330,259 X 2 years (2016 and 2017) = $660,519
[37] OEB staff Question #25
[38] VECC-1
[39] *Ibid.*
[40] Halton_IRR_TableA1Excel_EB-2017-0045_20180220.xls

additions up to 2015, based on its ERP system, plus depreciation for the 2016 capital additions that is reflected in its 2016 Rate Year settlement proposal.[41]

OEB staff has recalculated Table A1 - 2016 Approved Cost of Service vs. 2016 Correctly Calculated, in the attached spreadsheet titled "Halton_IRR_TableA1Excel_EB-2017-0045_20180220_OEB staff.xls", tab "2016 Dep Actual vsRev_CoS_Staff."

Based on OEB staff's recalculation of Table A1 – 2016 Approved Cost of Service vs. 2016 Correctly Calculated, the variance between the "2016 Actual Depreciation as per ERP system" and "Revised 2016 CoS Calc" 2016 actual depreciation is approximately $143,000 lower than the "Revised 2016 CoS Calc." potential depreciation error of $339,393 identified by Halton Hills Hydro in this Application. This difference of approximately $143,000 indicates that Halton Hills Hydro may have overstated its potential depreciation error. Ratepayers should not be harmed if the 2016 actual depreciation is lower than the "Revised 2016 CoS Calc." depreciation.

OEB staff assumes that this difference results from actual 2016 capital additions being used in the 2016 actual depreciation amounts and projected 2016 capital additions, as per the 2016 Rate Year settlement proposal, being used in the "Revised 2016 CoS Calc." depreciation.

Halton Hills Hydro should confirm whether OEB staff's recalculation of Table A1 – 2016 Approved Cost of Service vs. 2016 Correctly Calculated is correct, or if a different number should be used – i.e. Halton Hills Hydro should confirm if the 2016 actual depreciation is approximately $143,000 lower than the "Revised 2016 CoS Calc." depreciation of $339,393 and that a depreciation error of approximately $196,000 (or $339,393 less approximately $143,000) may be more appropriate to be reflected in the Depreciation DVA than $339,393.

[41] OEB staff Question #17

Alternative Options

In the event that the OEB does not deny the complete recovery of the Depreciation DVA, OEB staff submits that the following are reasonable options that may be considered by the OEB:

One option is to approve recovery relating to the 2018 and forward fiscal years, which may avoid retroactive rate-making. OEB staff notes that typically a DVA would normally be effective the same date as the rates in a proceeding (i.e. May 1, 2018). Therefore, the rate riders approved would be prospective in nature. OEB staff is of the view that no true-up should be recorded to any amounts that may be approved in this proceeding, as Halton Hills Hydro's draft accounting order[42] does not involve the use of Account 1595, Disposition and Recovery/Refund of Regulatory Balances.

Halton Hills Hydro stated that it will not charge interest on the Depreciation DVA[43]. If the OEB allows Halton Hills Hydro recovery of some of the Depreciation DVA balance, OEB staff agrees with Halton Hills Hydro that no carrying charges should be applied to this DVA, as depreciation expense is a non-cash item.

A second option is to approve the forward amounts only on an interim basis effective May 1, 2018 in this proceeding. A prudence review of the amounts recorded in this DVA may be examined in a future proceeding before the OEB, when disposition of this DVA is requested by Halton Hills Hydro. As noted above, no carrying charges should be applied to these amounts.

A third option is that the OEB could direct Halton Hills Hydro to revise its base rates to correct this error going forward. There is a precedence for this with respect to the adjustments to base rates made by the OEB for the former Enersource Hydro Mississauga Inc. (Enersource)[44].

[42] OEB staff question #16
[43] Halton_Application_Depreciation_20171023, page 2
[44] EB-2016-0002, December 8, 2016

As noted in this Enersource decision:

- Enersource changed its financial reporting method from Canadian Generally Accepted Accounting Principal to International Financial Reporting Standards (IFRS), effective January 1, 2012. This change led to a credit balance of Account 1575, IFRS-CGAAP Transition PP&E Amounts, refunded to Enersource's customers. In its decision and order in Enersource's cost of service proceeding[45], the OEB directed Enersource to adjust its depreciation expense, the weighted average cost of capital and the revenue requirement over a period of four years, to dispose of the Account 1575 credit balance.

- Enersource was scheduled to file a cost of service application in 2017, at which time the expiry of the adjustment would be addressed through rebasing. As Enersource requested to defer rebasing in 2017, the utility proposed to address the adjustment expiry by increasing its notional 2017 revenue requirement (i.e. in its 2017 IRM application) by $4,108,820, which was the same amount that was removed from the revenue requirement in the prior four year period.

- The OEB approved[46] Enersource's proposal to address the expiration of the IFRS adjustment by increasing its 2017 notional revenue requirement and determined that Enersource's 2017 notional revenue requirement was to be increased by $4,108,820, using 2015 billing determinants to calculate the base rate increase. The OEB stated that the initial IFRS adjustment to rebase and this associated revenue requirement increase should be reviewed at Enersource's next rebasing application.

The OEB revised the base rates in an IRM proceeding when Enersource had essentially "disposed" of the amounts that were captured in Account 1575 in the prior cost of service proceeding[47]. OEB staff cautions that if the OEB chooses this approach, it should do so because it is satisfied that this is a unique circumstance. Utilities should not be encouraged to cherry pick adjustments to base rates during an IRM term.

[45] EB-2012-0033
[46] EB-2016-0002, December 8, 2016
[47] EB-2012-0033

A fourth option is to revise the requested Depreciation DVA, or in its adjustment to base rates, to reflect 2016 actual depreciation expense. The 2016 actual depreciation expense is lower than the proposed amount requested by Halton Hills Hydro in this application and the OEB could direct Halton Hills Hydro to use the 2016 actual depreciation expense in its Depreciation DVA or in its adjustment to base rates.

OEB staff has recalculated Table A1 - 2016 Approved Cost of Service vs. 2016 Correctly Calculated, in the attached spreadsheet titled "Halton_IRR_TableA1Excel_EB-2017-0045_20180220_OEB staff.xls", tab "2016 Dep Actual vsRev_CoS_Staff." Based on OEB staff's recalculation of Table A1, the variance between the "2016 Actual Depreciation as per ERP system" and "Revised 2016 CoS Calc" is approximately $143,000[48] lower than the potential depreciation error of $339,393 identified by Halton Hills Hydro in this Application. This difference of approximately $143,000 indicates that Halton Hills Hydro may have overstated its potential depreciation error of $339,393.

OEB staff is of the view that a depreciation error of $196,000[49] (or $339,393 less approximately $143,000) may be more appropriate to be reflected in the Depreciation DVA or the adjusted base rates, than is the $339,393 amount. Ratepayers should not be harmed if the 2016 actual depreciation is lower than the "Revised 2016 CoS Calc." depreciation.

2.3 Price Cap Adjustment

Background

Halton Hills Hydro seeks to increase its rates, effective May 1, 2018, based on a mechanistic rate adjustment using the OEB-approved ***inflation minus X-factor*** formula applicable to Price Cap IR applications. Halton Hills Hydro included an adjustment of 1.90%, pending the OEB's update to the formula parameters.[50]

[48] Halton_IRR_TableA1Excel_EB-2017-0045_20180220_OEB staff", tab "2016 Dep Actual vsRev_CoS_Staff.", cell M53
[49] Ibid, cell N55
[50] Halton_2018_ IRM_EB-2017-0045_20170925, page 4

Submission

OEB staff submits that the Price Cap IR formula applicable to Halton Hills Hydro should be set as described below. Inserting the components discussed below into the following formula results in a 1.20% increase to Halton Hills Hydro's rates: ***1.20% = 1.20% - (0.00% + 0.00%).***

The inflation factor[51] of 1.20% applies to all Price Cap IR applications for the 2018 rate year.

The X-factor is the sum of the productivity factor[52] and the stretch factor[53]. It is a productivity offset that will vary among different groupings of distributors. Subtracting the X-factor from inflation ensures that rates decline in real, constant-dollar terms, providing distributors with a tangible incentive to improve efficiency or else experience declining net income.

The productivity component of the X-factor is based on industry conditions over a historical study period and applies to all Price Cap IR applications for the 2018 rate year.

The stretch factor component of the X-factor is distributor specific. The OEB has established five stretch factor groupings, each within a range from 0.00% to 0.60%. The stretch factor assigned to any particular distributor is based on the distributor's total cost performance as benchmarked against other distributors in Ontario. The most efficient distributor would be assigned the lowest stretch factor of 0.00%. Conversely, a higher stretch factor would be applied to a less efficient distributor (in accordance with its cost performance relative to expected levels) to reflect the incremental productivity gains that the distributor is expected to achieve. The stretch factor assigned to Halton Hills Hydro is 0.00%.

OEB staff submits that an adjustment of 1.20% should be used and be effective May 1, 2018. The adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes.[54]

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[51] *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors,* (EB-2010-0379), December 4, 2013
[52] *Ibid.*
[53] The stretch factor groupings are based on the Report to the Ontario Energy Board – "Empirical Research in Support of Incentive Rate-Setting: 2016 Benchmarking Update", prepared by Pacific Economics Group LLC., July 15, 2017.
[54] Price Cap IR and Annual IR Index adjustments do not apply to the following rates and charges: rate

2.4 Retail Transmission Service Rates

Background

Distributors charge retail transmission service rates (RTSRs) to their customers to recover the amounts they pay to a transmitter, a host distributor or both for transmission services. All transmitters charge Uniform Transmission Rates (UTRs) approved by the OEB to distributors connected to the transmission system. Host distributors charge RTSRs to distributors embedded within the host's distribution system.

Halton Hills Hydro is partially embedded within Hydro One Networks Inc.'s distribution system, and is requesting approval to adjust the RTSRs that it charges its customers to reflect the rates that it pays for transmission services.

Halton Hills Hydro has updated the RTSR Model with its 2016 billing determinants, non-loss adjusted, as filed in the 2016 RRRs and its 2016 billing detail for wholesale transmission charges. However, no change has been made for the UTRs that were updated effective January 1, 2018.

The differences resulting from the approval of new RTSRs will be captured in Accounts 1584 and 1586 for future disposition.

Submission

OEB staff submits that the UTRs that were updated effective January 1, 2018[55] should be incorporated into the 2018 Rate Generator Model.

2.5 Residential Rate Design

Background

All residential distribution rates currently include a fixed monthly charge and a variable usage charge. The OEB's residential rate design policy stipulates that distributors will

riders, rate adders, low voltage service charges, retail transmission service rates, wholesale market service rate, rural or remote electricity rate protection charge, standard supply service – administrative charge, transformation and primary metering allowances, loss factors, specific service charges, microFIT charge, and retail service charges.

[55] EB-2017-0359

transition residential customers to a fully fixed monthly distribution service charge over a four-year period, beginning in 2016.[56] The OEB requires that distributors filing IRM applications affecting 2018 rates continue with this transition by once again adjusting their distribution rates to increase the fixed monthly service charge and decrease the variable charge consistent with the policy.

The OEB expects an applicant to apply two tests to evaluate whether mitigation of bill impacts for customers is required during the transition period. Mitigation usually takes the form of a lengthening of the transition period. The first test is to calculate the change in the monthly fixed charge, and to consider mitigation if it exceeds $4. The second is to calculate the total bill impact of the proposals in the application for low volume residential customers (defined as those residential RPP customers whose consumption is at the 10th percentile for the class). Mitigation may be required if the bill impact related to the application exceeds 10% for these customers.

Halton Hills Hydro stated that it is transitioning residential customers to a full fixed monthly distribution service charge, as per OEB policy[57]. Halton Hills Hydro indicated that the transition will take place over four years beginning in 2016 and has continued the third year of the transition. Halton Hills Hydro stated that the calculations are shown in the 2018 Rate Generator Model on Tab 16. Rev2Cost_GDPIPI. Halton Hills Hydro indicated that the total bill impact does not exceed $4, therefore, no rate mitigation is required.[58] OEB staff notes that Tab 16 of 2018 Rate Generator Model identifies an impact of $2.92[59].

When the 2018 IRM Rate Generator Model is updated to reflect the required changes in the Price Cap and RTSRs, the impact will result in a decrease of $0.16 or 0.15% on the total monthly bill for the typical residential customer using 750 kWh per month. However, OEB staff notes that this bill impact has not been adjusted for the proposed Z-Factor Application for Pay Equity and proposed Depreciation DVA, as these amounts have not been approved by the OEB, and are outstanding issues.

When the 2018 IRM Rate Generator Model is updated to reflect the required changes in the Price Cap and RTSRs, the proposed total bill impact for a residential customer in the 10th percentile will result in an increase of $1.95 or 4.21% on the total monthly bill.

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[56] OEB Policy – "A New Distribution Rate Design for Residential Electricity Customers" EB-2012-0410, April 2, 2015
[57] *Ibid.*
[58] Halton_2018_ IRM_EB-2017-0045_20170925, page 5 & 6
[59] Tab 16, Cell F27

OEB staff notes that as the total bill impact is less than 10%, no further mitigation measures are required.[60]

Submission

As the total bill impact submitted by Halton Hills Hydro does not exceed $4 nor does the total bill impact exceed 10% for a residential customer in the 10th percentile, OEB staff submits that no rate mitigation is required.

OEB staff submits that the proposed 2018 increase to the monthly fixed charge is calculated in accordance with the OEB's residential rate design policy, as calculated in the 2018 Rate Generator Model. The results of the monthly fixed charge, and total bill impact for low consumption residential consumers show that no mitigation is required.

However, OEB staff is of the view that these amounts have been calculated before the impacts of the proposed Z-Factor Application for Pay Equity and proposed Depreciation DVA. If the proposed Z-Factor Application for Pay Equity and proposed Depreciation DVA are approved by the OEB these bill impacts should be revised.

2.6 Deferral and Variance Accounts

Background

In each year of an IRM term, the OEB will review a distributor's Group 1 deferral and variance accounts in order to determine whether their total balance should be disposed.[61] OEB policy requires that Group 1 accounts be disposed if they exceed (as a debit or credit) a pre-set disposition threshold of $0.001 per kWh, unless a distributor justifies why balances should not be disposed.[62] If the balance does not exceed the threshold, a distributor may elect to request disposition.

The 2016 actual year-end total balance for Halton Hills Hydro's Group 1 accounts including interest projected to April 30, 2018 is a credit balance of $1,148,898. This

[60] Ibid
[61] Group 1 accounts track the differences between the costs that a distributor is billed for certain IESO and host distributor services (including the cost of power) and the associated revenues that the distributor receives from its customers for these services. The total net difference between these costs and revenues is disposed to customers through a temporary charge or credit known as a rate rider.
[62] Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR), EB-2008-0046, July 31, 2009

amount represents a total credit claim of $0.0023 per kWh, which exceeds the disposition threshold. Halton Hills Hydro is proposing to dispose this credit amount over a one-year period, beginning in the 2018 rate year.

Included in the balance of the Group 1 accounts is the Global Adjustment (GA) credit account balance of $227,590. A customer's costs for the commodity portion of its electricity service reflects the sum of two charges: the price of electricity established by the operation of the Independent Electricity System Operator (IESO) administered wholesale market, and the GA.[63]

The GA is paid by consumers in several different ways:

- For Regulated Price Plan (RPP) customers, the GA is incorporated into the standard commodity rates, therefore there is no variance account for the GA.

- Customers who participate in the Ontario Industrial Conservation Initiative program are referred to as "Class A" customers. These customers are assessed GA costs through a peak demand factor that is based on the percentage their demand contributes to the top five Ontario system peaks. This factor determines a Class A customer's allocation for a year-long billing period that starts in July every year. As distributors settle with Class A customers based on the actual GA costs there is no resulting variance.

- "Class B" non-RPP customers pay the GA charge based on the amount of electricity they consume in a month (kWh). Class B non-RPP customers are billed GA based on an IESO published GA price. For Class B non-RPP customers, distributors track any difference between the billed amounts and actual costs in the GA Variance Account for disposal, once audited.

Halton Hills Hydro had one customer that transitioned to Class A during the period of disposition.[64] Accordingly, the utility applied to have the balance of this account disposed through a separate kWh rate rider for Class B customers in order to ensure proper allocation between Class A and Class B customers.

[63] The GA is established monthly, by the IESO, and varies in accordance with market conditions. It is the difference between the market price and the sum of the rates paid to regulated and contracted generators and conservation and demand management (demand response) program costs.
[64] Halton_2018_ IRM_EB-2017-0045_20170925, page 7

Halton Hills Hydro proposes a refund of its GA variance account credit balance of $227,590, as at December 31, 2016, including interest to April 30, 2018. As per Table 1 below, a credit balance of $225,036 is allocated to Class B customers. A credit balance of $2,554 is allocated to the customer that transitioned to Class A, which will be settled directly with this customer.

Table 1: Refund of GA Variance

Proposed Amounts	Proposed Method for Refund
A credit balance of $225,036 refunded to customers who were Class B for the entire period from January 2015 to December 2016	per kWh rate rider

The balance of the Group 1 accounts includes a credit balance of $38,933 for the refund of Capacity Based Recovery (CBR) charges for Class B customers related to the IESO's wholesale energy market Demand Response 3 program. Distributors paid CBR charges to the IESO in 2015 and 2016 and recorded these to a dedicated sub-account. The disposition of this sub-account is impacted by whether or not a distributor had any customers who were part of Class A during the period from January 2015 to December 2016.

Halton Hills Hydro had a Class A customer during the period of disposition. The distributor applied to have the balance of this account disposed through a separate kWh rate rider for Class B customers, in order to ensure proper allocation between Class A and Class B customers.

As a customer was reclassified between Class A and Class B during the period of disposition, Halton Hills Hydro requested refunding of a portion of CBR Class B costs by way of 12 equal installments to the customer that transitioned to Class A.

Regarding the CBR balance, a credit balance of $38,725 is allocated to Class B customers and a credit balance of $209 is allocated to the customer that transitioned to Class A, which will be settled directly with this customer.

The remaining Group 1 accounts being sought for disposition, through the general Deferral and Variance Account rate rider and the non-Wholesale Market Participant

(non-WMP) rate rider allocated to the GS 1,000 to 4,999 kW service rate class, include the following flow through variance accounts: Low Voltage Charges, Smart Meter Entity Charges, Wholesale Market Service Charges, Retail Transmission Service Charges, Commodity Power Charges, and Account 1595 residual balances. The Group 1 accounts have a credit balance of $882,375, which results in a refund to customers.

The balances proposed for disposition reconcile with the amounts reported as part of the OEB's *Electricity Reporting and Record-Keeping Requirements*.[65] Halton Hills Hydro further notes that its proposal for a one-year disposition period is in accordance with the OEB's policy.[66]

Submission

OEB staff supports the disposition of a credit balance of $1,148,898 as of December 31, 2016, including interest projected to April 30, 2018 for Group 1 accounts. This amount represents the clearance of both 2015 and 2016 balances, as no DVA balances were cleared in Halton Hills Hydro's 2017 IRM application[67], as the disposition threshold was not exceeded.

The following table identifies the principal and interest amounts which OEB staff supports for disposition.

[65] Electricity Reporting and Record Keeping Requirements, Version dated May 3, 2016
[66] As outlined in the EDDVAR Report cited at an above footnote.
[67] EB-2016-0076

Table 2: Group 1 Deferral and Variance Account Balances

Account Name	Account Number	Principal Balance ($) A	Interest Balance ($) B	Total Claim ($) C=A+B
LV Variance Account	1550	834,834	21,393	856,227
Smart Meter Entity Variance Charge	1551	-12,889	-413	-13,302
RSVA - Wholesale Market Service Charge	1580	-1,502,604	16,228	-1,486,376
Variance WMS - Sub-account CBR Class B	1580	-37,972	-961	-38,933
RSVA - Retail Transmission Network Charge	1584	65,366	39,940	105,306
RSVA - Retail Transmission Connection Charge	1586	187,776	49,158	236,934
RSVA – Power	1588	-264,639	3,062	-261,577
RSVA - Global Adjustment	1589	-223,413	-4,177	-227,590
Disposition and Recovery of Regulatory Balances (2014)	1595	-292,615	25,578	-267,037
Disposition and Recovery of Regulatory Balances (2015)	1595	-124,067	71,517	-52,550
Totals for all Group 1 accounts		-1,370,223	221,325	-1,148,898

OEB staff submits that if approved by the OEB, the balance of each of the Group 1 accounts approved for disposition shall be transferred to the applicable principal and

interest carrying charge sub-accounts of Account 1595. Such transfer shall be pursuant to the requirements specified in Article 220, Account Descriptions, of the *Accounting Procedures Handbook for Electricity Distributors*.[68] OEB staff submits that the date of the transfer must be the same as the effective date for the associated rates, which is, generally, the start of the rate year. OEB staff is of the view that Halton Hills Hydro shall ensure these adjustments are included in the reporting period ending June 30, 2018 (Quarter 2).

OEB staff submits that these balances should be disposed through rate riders as calculated in the Rate Generator Model. The rate riders will be in effect over a one-year period from May 1, 2018 to April 30, 2019.[69]

All of which is respectfully submitted

[68] Accounting Procedures Handbook for Electricity Distributors, effective January 1, 2012
[69] 2018 IRM Rate Generator Model Tab 6.1 GA, Tab 6.1a "GA Allocation", Tab 6.2 "CBR B", Tab 6.2a "CBR_Allocation" and Tab 7 "Calculation of Def-Var RR"