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January 25, 2021
Our File: EB20200133

Attn: Christine Long, Registrar

Dear Ms. Long:

Re: EB-2020-0133 – COVID-19 Deferral Account Consultation – SEC Comments

We are counsel to the School Energy Coalition ("SEC"). These are SEC's comments on the OEB Staff Proposal ("Staff Proposal") as part of the *Consultation on the Deferral Account – Impacts Arising from the COVID-19 Emergency*.

Overview

The Staff Proposal correctly notes that the COVID-19 pandemic is a "once-in-a-century crisis that has inflicted far-reaching economic and social impacts across Ontario and globally".[1] When the Government of Ontario declared the first emergency in March 2020, the Board responded quickly by creating Account 1509 (and the various Sub-Accounts) to allow utilities to track the financial impacts of the pandemic. Ten months later, the COVID-19 pandemic continues to cause a significant impact on almost all aspects of society. Recently, the Government of Ontario issued a second emergency declaration because of the alarming growth in new cases. Individuals and businesses in Ontario continue to suffer due to the economic restrictions that are in place, and those effects are likely to be felt even after sufficiently widespread vaccinations of the population allow daily activity to return to normal.

SEC conceptually agrees with the principled approach that is taken in the Staff Proposal, but would put the choices facing the Board in starker terms. SEC submits there are three broad perspectives the Board may be confronted with regarding COVID-19 impacts on the utilities it regulates:

1. ***Z-Factor Approach.*** Under this approach the emphasis is on the fact that utility management could not have been expected to plan for a pandemic like this, and therefore any impacts should be a Z-factor that flows through to customers in their rates. The utility is fully protected

[1] OEB Staff Proposal, Consulting on the Deferral Account – Impacts Arising from the COVID-19 Emergency (EB-2020-0133), December 16, 2020, ["Staff Proposal"], p.7

from increases in costs (although traditionally not lost revenues) using this approach, as this category of risk is presumed to be allocated, in part, to customers.

SEC agrees with OEB Staff that this situation does not have the hallmarks of a Z-Factor. First, the bulk of the utility impacts are caused by a general economic downturn (of which the pandemic was the proximate cause). The Board has never to our knowledge insulated utilities from an economy-wide economic downturn. That has always been assumed to be included in the business risks for which the Return on Equity ("ROE") compensates the utility. Second, and perhaps related, Z-factors are typically events that affect utilities in some unique way (e.g. a storm), different from the customers.

2. ***Business Risk Approach.*** Since most of the impacts arise out of a general economic downturn, and economy-wide restrictions, it is reasonable to consider that utilities are expected to bear this category of risks. Under this approach, utilities would get no extra recovery from customers for pandemic related incremental costs or lost revenues. This is particularly appropriate given the data provided that utilities had a negative impact of 1.3% in Q2 2020, while the general Ontario economy was impacted negative 12.4%.[2] This suggests that already hurting customers should not have to reach into their pockets further to fund utilities that, for the most part, are weathering the pandemic better than their customers are.

   This approach is consistent with a strict application of the Board's role as a market proxy. The market generally does not allow competitive companies to shift the cost of the pandemic to customers that cannot afford it. A good example is landlords, who are not protected from bad debt associated with cash-strapped tenants, and cannot raise rents on everyone else to cover those bad debts. In most of Ontario, rents are actually going down, as potential tenants' reduced ability to pay depresses demand.

3. ***Financial Viability Approach.*** The approach starts from the Board's mandate to ensure the financial viability of the sector and individual utilities. Instead of assigning the risk associated with the pandemic to the customers (#1 above) or the utilities (#2 above), this approach essentially bifurcates the risk. If the utility is or should be able to manage the pandemic impacts, it should do so. On the other hand, if the risk is high enough to put the utility's ability to serve its customers at risk, it is no longer a business risk but an existential risk. Both customers and shareholders are concerned about that higher risk, and the Board can look to both to bear the cost.

It was SEC's expectation from the initial part of the Staff Proposal that OEB Staff was taking the third approach, and we agree in principle that it is the most appropriate one. However, the details of the Staff Proposal do not completely adhere to the principled approach of financial viability. Under the Staff Proposal, there is an unstated assumption that the customers should reimburse even financially healthy utilities for some of the incremental costs associated with the pandemic. SEC does not agree that customers should bear incremental costs for utilities that would otherwise remain financially viable.

[2] Staff Proposal, p.7

Principle of Financial Viability/Necessity Must Guide Any Recovery

SEC agrees with OEB Staff's recognition that the pandemic impact is of a fundamentally different character than other unexpected and extraordinary events that a utility may face. The event has not only caused impacts on utility operations, costs and revenues, but the customers have also been harmed by the pandemic.[3] The pandemic has led to customer-driven impacts as individuals, businesses and institutions are dealing with their own increased costs, changes in operations, and/or lost revenue.[4] In most cases, they will be unable to pass on the increased costs and revenue losses through higher future prices, because their customers are also financially hurting.

In fact, ratepayers themselves are now less likely to be able to absorb any utility price increase, just as customers of those ratepayers are less able to absorb price increases from them. This makes the request for the collection of additional amounts from customers fundamentally different from a Z-Factor or ICM/ACM application.

The evidence is that the impact of the pandemic on utilities has been relatively insignificant compared to the other sectors. As the Staff Proposal correctly notes, "at a time when the impact of the pandemic resulted in the largest quarterly GDP decline on record, the impact in the utilities industry was not particularly severe."[5] The evidence shows that in Q2 2020, the entire Ontario utility industry saw a reduction in GDP of 1.3%, whereas total production (i.e. output across all industries) declined by 12.4%, and many specific industries had declines that were much more precipitous.[6] Those sectors, which are competitive, have limited ability to make up the cost increases and revenue declines by charging their customers more money.

In fact, if anything, London Economics International LLC ("LEI") understates the relative financial health of utilities compared to the economy as a whole. A good example is the LEI report on cost of capital. It shows declining costs of debt, which is of particular benefit to capital intensive industries like utilities.[7] It shows that the allowed ROE for Ontario utilities has increased from 95.8% of S&P Return to 120.3% of the S&P level. It also shows that independent assessments of credit strength of utilities remain very positive in 2020.[8] All of this should ground a conclusion that, from a cost of capital point of view, Ontario utilities will be significantly better off as a result of the pandemic compared to the economy as a whole, and in absolute terms, over the medium to long-term instead, LEI concludes that "Ontario utilities are being fairly compensated for risk based on current calculations."[9]

The Staff Proposal is also correct to recognize that ultimately any disposition of Account 1509 is an exercise of the Board's rate-setting authority, and that the Board is required in setting just and reasonable rates to be guided by its statutory objectives for electricity and natural gas.[10] These objectives include, most importantly, protecting the interest of consumers with respect to price, and ensuring the maintenance of a financially viable industry.

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[3] Staff Proposal, p.10
[4] Staff Proposal, p.10
[5] Staff Proposal, p.7
[6] Staff Proposal, p.7
[7] LEI, A Report on the OEB's Cost of Capital Parameters and the Impacts of COVID-19, p.1,3,8
[8] LEI, A Report on the OEB's Cost of Capital Parameters and the Impacts of COVID-19, p.7-8
[9] LEI, A Report on the OEB's Cost of Capital Parameters and the Impacts of COVID-19, p.1
[10] Staff Proposal, p.10, 11; *Ontario Energy Board Act, 1998*, s.1(1)(1),2 and 2(2)(5.1)

In exercising this jurisdiction, it is fundamental that the Board as an economic regulator must act as market proxy.[11] While utilities are essential services, they are still monopolies who are regulated as for-profit businesses. They are given an opportunity to earn a regulatory ROE, but like any other business, it is not guaranteed. Even though the COVID-19 pandemic has negatively impacted Ontario utilities, ratepayers should not be required to subsidize them.

What is consistent with the Board's statutory mandate is that the Board should only consider recovery of any balances in Account 1509 be limited to situations where it is required to ensure an individual utility, or the sector as a whole, remain financially viable. The Staff Proposal has come to a similar conclusion. It recommends that in addition to the principles of prudence, causation and materiality, any recovery must meet the principle of necessity. Necessity is defined as "[r]ecovery of any balances recorded in the Account should be subject to evidence that the costs are not only reasonable, but also necessary to the maintenance of the utility's financial viability."[emphasis added][12] SEC agrees, but as discussed in these submissions, the Staff Proposal would allow recovery far above what would be required to adhere to that principle.

Means Test

Central to the Staff Proposal is inclusion of a pair of Means Tests to put the "necessity principle into quantifiable terms".[13] SEC believes that this attempt to make financial viability mechanistic is fundamentally incorrect. Financial viability is not by its nature formulaic. If the financial viability of a utility is in fact at risk, SEC believes that the Board should be looking at all aspects of that issue, and should not attempt to short circuit that review by applying a formula. Both the customers, and the shareholders, deserve a more thorough review of financial viability by the regulator than the mechanistic application of a generic threshold or test.

The tests actually proposed in the Staff Proposal are also somewhat surprising.

For "mandated costs" (costs related to complying with government or OEB actions aimed at providing customer relief), 100% of the prudently incurred costs would be recoverable, but only up to the point in which the resulting ROE[14] reached 300 basis points above the ROE embedded in the utility's base rates.[15] For all other costs (net of savings) and lost revenues, utilities would be able to recover from customers only 50% of prudently incurred amounts, but only up to the point in which the revised ROE reached 300 basis points below the ROE embedded in the utility's base rates.[16] Thus, the Staff Proposal says that recovery of mandated costs cannot take a utility above the upper end of the deadband, and recovery of 50% of other impacts cannot take a utility above the lower end of the deadband.

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[11] Staff Proposal, p.18; Also see *Ontario (Energy Board) v. Ontario Power Generation Inc., 2015 SCC 44*, paras.11, 120

[12] Staff Proposal, p.11

[13] Staff Proposal, p.13

[14] Revised ROE is actual ROE plus any amounts included in Account 1509 that would be recovered.

[15] Staff Proposal, p.19,23

[16] Staff Proposal, p.20,23

These +/-300 basis points earnings based deadband Means Tests are based on the Board's +/- 300 basis point ROE deadband embedded in a number of OEB policies, such as an incremental funding (i.e. ACM/ICM and IRM adjustment) or regulatory review (i.e. off-ramps).[17]

SEC agrees with the Staff Proposal that a Means Test is appropriate. A utility should only be allowed to recover any net costs or lost revenue related to the COVID-19 pandemic if it is necessary to the maintenance of a financially viable utility. This is consistent with the Board's statutory objectives both from the point of view of an individual utility and sector, but also from that of electricity or natural gas customers. A utility or sector that is not financially viable threatens this essential service which would harm all customers.

SEC does not agree with the Staff Proposal that there should be two different Means Tests depending on the type of costs. SEC submits that the recovery of any COVID-19 related costs or lost revenue is only appropriate if the utility's financial viability is at risk. There should not be a different Means Test for costs related to complying with government or OEB actions. <u>None</u> of those costs should be recoverable unless the utility's financial viability is threatened. The distinction between cost categories is not entirely clear, nor has Staff provided a rationale for why one set of costs should be favoured over another. SEC does not believe that is appropriate, and in the analysis below we focus solely on the bottom end of the 300 basis point deadband.

The larger concern is with the use of the 300 basis points deadband at all. The Staff Proposal appears to equate a utility ROE below 300 basis points with a threat to the financial viability of either the specific utility or the sector as a whole. No evidence or analysis has been provided by either OEB Staff or LEI that demonstrate this, and it is not likely that it is true.

In fact, SEC submits history demonstrates that only a much lower ROE would actually threaten the viability of a utility in most cases. As shown in Appendix A to these comments, for numerous utilities over the last 5 years their actual ROE has been below the 300 basis points deadband, in some cases for consecutive years. SEC is not aware of a single utility that has brought a request to the Board for an early rebasing, or sought any other relief because their financial performance was threatening their viability. In some cases, those same utilities with low ROE have sought deferrals of their rebasing applications.

It is telling that, when the Board asked stakeholders, as part of the issues list process, if advanced policy direction was required to deal with any critical emergency in terms of financial hardship faced by utilities that required immediate support from the Board, not a single utility requested anything concrete that demonstrated that their financial viability was at issue.[18] In the end, the Board determined that no compelling reasons were provided by stakeholders for any advanced policy direction.[19]

As early as May, the Board instituted monthly reporting requirements not just with respect to the Account 1509 balances, but also on a range of other metrics for the purposes of "monitoring of the

[17] Staff Proposal, p.13
[18] Staff Proposal, p.13
[19] OEB Letter Re: Consultation on the Deferral Account – Impacts Arising from the COVID-19 Emergency – Issues List (August 14, 2020), p.2

financial situation", specifically of electricity distributors.[20] Since the Board has this enhanced information, SEC assumes that if the financial situation of the sector would threaten its viability, that information would have been noted in the Staff Proposal and/or LEI analysis. In fact, both LEI and OEB Staff indicate that, to date, no utilities have been shown to be in financial distress because of the pandemic.

None of this should be surprising. An ROE of approximately 6% is far above a level that would credibly be considered a risk to a utility's financial viability, especially when the dip in ROE of this magnitude should only be expected to last for a year or two. There are many businesses in this province that are struggling to survive, and most would be beyond satisfied in the current economic conditions to have an ROE of anything approaching 6% (or even any return on equity at all).

Another concern is that using a 300 basis point deadband from approved ROE as a cap on recovery could act as a bailout to utilities that, but for COVID-19, would have an ROE already below the approved level built into rates. Over the past 5 years (2015-2019), the average ROE for electricity distributors is 1.41% below the amount built into rates. If the Board is to use a specific ROE deadband of 300 basis points, or some other amount, as the cap on general recovery of COVID-19 costs, it should be the *lower* of the deadband amount from the approved ROE built into rates, and the actual ROE that the utility would have had if the pandemic had not occurred. The latter can be easily calculated, since utilities are reflecting all the costs and lost revenues due to the pandemic in Account 1509. A revised "normalized" ROE can be calculated by removing the costs and including the lost revenues.

SEC wants to be clear that it is not convinced that selecting a specific number is the best approach. A more appropriate method would be to require that, if a utility feels their financial health is in jeopardy because of the COVID-19 pandemic, they can bring an application for recovery and provide individualized evidence demonstrating that recovery of amounts included in Account 1509 is required to maintain their viability.

With that said, if the Board does believe it is preferable to set a specific lower deadband, the amount should not be the 300 basis points number proposed in the Staff Proposal. Unfortunately, SEC is not in a position to propose a specific level of ROE that would generally trigger the financial viability of any specific utility or the sector as a whole to be at risk, as it does not have the required utility specific data. But, what is clear is that an ROE of 300 basis points below the deemed rate built into a utilities rate is not the correct number and the actual ROE level that would meet the definition of requiring additional funding through clearance of an amount in Account 1509, is substantially lower than the figure included in the Staff Proposal.

SEC does agree strongly with one aspect of the Staff Proposal on the implantation of the Means Test. If a formula is used, it should not only act as a threshold, but also as a cap on recovery.[21] Otherwise, a number of perverse incentives and outcomes exist. As the Staff Proposal points out, all else being equal, a utility who is under the 300 basis points lower end deadband could be put in a better position than a utility who is above it after recovery. Further, it incents utilities to incur additional costs to lower

[20] OEB Letter, Re: Temporary Monthly Reporting Requirement Related to the Impact on Distributors Arising from the COVID-19 Emergency (May 12, 2020)

[21] Staff Proposal, p.23

their ROE to be under the deadband so that they can recover amounts in Account 1509. Neither of these situations is appropriate, nor is consistent with the concept of a necessity based Means Test.

If the Board does implement an ROE based Means Test, it should be a guideline only, but should be neither a necessary, nor a sufficient condition, for recovery of any prudently incurred amounts. It should still be open for the Board to scrutinize other aspects of the utility to determine if financial viability is at stake if no recovery is granted. For example, if a utility is continuing to pay dividends to its shareholders, then it is hard for it to claim that its financial viability is at issue, and that regardless of its actual ROE, additional funding is required from customers.

<u>Costs and Savings</u>

Costs. The Staff Proposal creates two categories of costs, those related to implementing government or OEB actions aimed at providing customer relief, and all other costs and lost revenues related to the COVID-19 pandemic.

Separate and apart from different Means Tests, the Staff Proposal recommends different recovery percentages (100% for the government/OEB actions, and 50% for all other costs).[22] SEC believes that if the Board creates a Means Test that is truly based on allowing recovery up until the point a utility's financial viability is at risk (which as discussed in detail the current proposal clearly does not do), then the division into 50% recovery as opposed to 100% becomes less important. Recovery would be based on ensuring financial viability, not adhering to a sharing formula.

If the Board is going to create a Means Test that allows for recovery of amounts above the true point in which a financial viability is at risk, then SEC submits that sharing does become a relevant issue. In that case, sharing fairly requires that 50% of all costs (net of savings), regardless of categories should be allowed. SEC does not believe that there is a sufficient basis to differentiate between the categories of costs, which at some level all are caused directly or indirectly by government response to the pandemic.

SEC notes that we do not believe sharing should be the operative principle for these costs in the absence of a true risk to financial viability, but in the event that a formulaic approach is adopted by the Board, it is submitted that all incremental costs should be shared up to the appropriate cap, with no distinction between the two proposed categories of costs.

Savings. The Staff Proposal recommends that Account 1509 should include not just increases in costs attributable to the pandemic, but also savings, whether caused by the pandemic or implemented as mitigation measures to contain the impacts of pandemic cost increases or lost revenues. These are offsets to the incremental costs or lost revenues.

It is not enough for only actual savings to be included in Account 1509. The utility should also be required to record or report as offsets the savings that should have been achieved. SEC agrees, for example, with the Staff Proposal's view that "[u]tilities should be expected to establish that incremental financing costs have been minimized <u>and savings maximized, as a result of reprioritization of business activities</u>."[emphasis added][23]

[22] Staff Proposal, p.23
[23] Staff Proposal, p.28

When the COVID-19 pandemic began it was clear that utilities might incur additional costs and receive lower revenues. Like all other businesses who were in a similar situation, they should have taken actions to mitigate the financial impact by reducing costs where appropriate. SEC notes that some utilities have clearly done this. For example, it was reported in June that Enbridge Gas had offered early retirement to over 800 employees "to manage the impacts of COVID-19".[24] Similarly, Oshawa PUC Networks temporarily laid off 11 employees "as part of an effort to mitigate the impacts of Covid-19."[25]

Broad Definition of Savings Required. The Board should mandate that any utility seeking disposition of any balances included in Account 1509, be required to provide evidence that demonstrates that it took all reasonable actions to reduce its costs to mitigate the financial impact of increased costs and reduced revenue caused by the pandemic. If utility does not meet its burden of demonstrating that it has done so, then the Board should impute a reasonable level of savings that should have been expected, and that will act to offset any amounts that are sought to be recovered.

The Board should also clarify the definition of savings to include not just *proactive* measures taken to reduce costs in a certain area, but where reductions are achieved because certain spending did not occur as there was a reprioritization of resources within the utility (i.e. filling a vacancy or redirecting funding to incremental pandemic related costs).

Capital-Related Costs and Savings. The Staff Proposal recommends that only permanent capital-related incremental impacts (costs or savings) should be eligible for recovery, subject to the Means Test, but that temporal shifts in the timing and execution of existing or planned capital projects should not be eligible.[26]

SEC disagrees with this aspect of the Staff Proposal, as it would eliminate a substantial amount of utility savings that would offset their increased costs/reduced revenue. Based on SEC's involvement in a number of 2021 distribution rate cases in the past 6 months, deferral of capital work, either by design or by circumstances, has been common in 2021.[27] There is no reason that these savings should not be included as an offset to a utility who is seeking recovery of their increased costs and lost revenue. The revenue requirement related to deferred capital work is no different than deferred OM&A work reflected in reduced costs that the Staff Proposal agrees should be included.

On the other hand, SEC is not aware of many situations where capital work was accelerated in time due to the COVID-19 pandemic, except projects that were offset by reductions in other areas. Though, it is possible, for example, a utility could have accelerated capital work related to providing additional connections to a hospital, or other essential services. In a situation like that, the utility should be given the opportunity to recover the revenue requirement related to those incremental amounts, subject to the means. SEC sees no reason why these expenditures should be treated differently than any other incremental expenditures.

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[24] *Chatham Daily News, Enbridge offers early retirement, severance to 800 employees,* June 22, 2020

[25] EB-2020-0048, Interrogatory Response 4-SEC-35

[26] Staff Proposal, p.29

[27] For example in Niagara Peninsula Energy Inc. (NPEI) 2021 cost of service application (EB-2020-0040), NPEI reduced its bridge year (2020) capital expenditures forecast, in part, due to delays in certain projects caused by COVID-19 (see Interrogatory Response 2-Staff-8).

Lost Revenue. SEC has had an opportunity to review in draft the submissions of the Vulnerable Energy Consumers Coalition ("VECC") with respect to the proposed methodology for calculating lost revenue. SEC shares VECC's concerns that the LEI methodology[28], even if it is able to be implemented, will act more as a load forecast true up account (albeit one that only captures reductions in load) as opposed to only recovering the lost revenue from reduced load caused only by COVID-19. As presently constructed, it will capture reductions in load caused by all non-weather impacts, which is not appropriate. Load variations are a risk for which utilities are already compensated in ROE.

Baseline. The Staff Proposal correctly recognizes that it is important to properly determine the baseline for any incremental cost or savings. It proposes a methodology that considers what is embedded in rates and what costs a utility has actually incurred in previous non-pandemic years. For costs, the Staff Proposal recommends a baseline that would be the greater of amounts in excess of, a) embedded in base rates (adjusted for inflation less productivity), and b) highest actual annual amount over the last 5 years (2015-2019).[29] For savings, the Staff Proposal recommends a baseline for measuring incremental savings as the lower of amounts, a) embedded in base rates (adjusted for inflation less productivity), and b) lowest actual annual amount over the last 5 years (2015-2019).[30]

The use of the "greater of" or "lower of" approaches creates obvious problems, especially as it relates to the savings baseline. For example, for a utility rebased in 2018, it would almost be a certainty that the *lowes*t actual amount spent in any year between 2015 and 2019, will be lower than the 2018 amount included in base rates (adjusted to 2020). This will have the effect of greatly diminishing any savings offset that customers would have.

SEC submits that the amount embedded in rates, subject to the appropriate annual adjustments, should be the default baseline. In most cases, the use of historic actuals should only be used if the cost item is a type that does not occur every year or is inherently variable, so that it can be reasonably assumed that the amount built into the rates is not reflective of the amounts that would be included in an overall budget. While SEC agrees with OEB Staff that the amount embedded in rates must be adjusted[31], the Staff Proposal is incomplete. Not only should there be adjustments to account for the annual IRM and the annual inflationary increase less the stretch factor, but also an amount must be included to reflect that over time utilities' revenues are increasing due to customer and load growth. This is similar to what is done through the growth factor in an ACM/ICM, and what is proposed by LEI for the purposes of creating a 2020 normalized load forecast.[32] In fact, a version of the same methodology could be used for the purpose of determining the growth factor for the purposes of setting the baseline amounts for incremental cost/savings.

SEC emphasizes that we are proposing this as a default baseline, not a formulaic approach. In keeping with our view that this should be about financial viability, the Board in considering the pandemic impacts in the context of a utility in financial distress and should look closely at those impacts, including whether the default baseline is appropriate.

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[28] LEI, Report on Gains and Losses From Differences in Load and Production, p.5-11

[29] Staff Proposal, p.17

[30] Staff Proposal, p.17

[31] *New Policy Options for the Funding of Capital Investments: Supplemental Report* (EB-2014-0219). January 22, 2016, See Appendix B.

[32] LEI, Report on Gains and Losses From Differences in Load and Production, p.7

Disposition Allocation

The Staff Proposal recommends that utilities should propose that any disposition should minimize what it considers cross-subsidization upon disposition by tracking incremental impacts by rate class and rate zone, where applicable.[33] With respect to lost load, the Staff Proposal specifically recommends that "recovery of amounts associated with net load impacts should be from the customer class in which it occurred, unless it is not practical or reasonable to do so."[34] In Staff's view, this will minimize any cross-subsidization.

SEC disagrees with this proposed default approach. If anything, it is counter to good cost allocation principles. Costs or lost revenues that arise from customers not paying their bills or reducing their demand (i.e. bad debt or lost revenue) are a different character than traditional incremental direct costs that a utility may collect from a specific rate class.

While these costs and lost revenues are capable of being tracked to a specific rate class, any disposed of amounts should not then be allocated back only to those classes. Direct allocation is only appropriate if those costs can be identified and only benefit the specific rate class from which they arise.

The entire premise behind the disposition of Account 1509 in the Staff Proposal is the impacts of the pandemic may be so great on the utility that, if the Means Test is met, a certain level of additional revenue is required because it is necessary to ensure the financial viability of the utility/sector. A fundamental principle of rate regulation is that benefits follow costs (and costs follow benefits). All customers of an individual utility benefit from maintaining its financial viability, and so they should all be responsible for the costs of doing so.

A more appropriate approach would be to allocate costs in the same way the Board disposes amounts in an ICM/ACM of Z-Factor, through a rate rider that is calculated on a per customer, KWh or KW basis. This ensures all customers bear these costs in a fair but proportionate manner.

Other Issues

Period of the Account. The Staff Proposal notes that the initial Accounting Orders creating the initial Account 1509 were made effective March 24, 2020. OEB Staff proposes that amounts incurred prior to that be recorded separately, and if a utility seeks recovery, it should bring forward arguments demonstrating why they seek disposition.[35]

SEC does not understand OEB Staff's legal basis for the position that any amounts can be recorded prior to the effective date of March 24, 2020. On its face, this would seem to be impermissible retroactive ratemaking.

The Staff Proposal also recommends that a utility should have the ability to record amounts in the Account 1509 until its rebasing application, assuming that it is able to support costs in future years (post 2020) that are directly attributable to the pandemic.[36] SEC generally agrees, but recommends the Board clarify that it should be the subsequent rebasing application after/or the year it expects to

[33] Staff Proposal, p.33
[34] Staff Proposal, p.26
[35] Staff Proposal, p.30
[36] Staff Proposal, p.30

reach a new normal. As the Board is aware, a number of 2021 cost of service applications have been settled on the basis that the impacts of the COVID-19 are to be addressed through Account 1509 and this consultation. It is expected that this approach will likely continue for at least some 2022 cost of service applicants because the longer-term impacts may not be known in 2021, as the pandemic is not over.

Greenfield Utilities. At the January 14th Stakeholder Conference, representatives from both Nextbridge and EPCOR South Bruce raised the question of how the Staff Proposal would apply to new greenfield utilities. SEC believes that, as much as possible, the principles behind the Staff Proposal should apply to these utilities even if, practically speaking, the detailed implementation may need to be different. For example, Nextbridge's construction of its transmission line has not been completed and so it does not have any revenue (or approved rates). In Nexbridge's case, the Means Test for determining financial viability would occur at the time it seeks to clear the balance in Account 1509. At that time, the Board will assess the financial impact (including its ROE) if recovery of the balances in the account were not allowed.

Ontario Power Generation. SEC believes that any final Board policy should not apply fully to Ontario Power Generation ("OPG") because of unique circumstances that warrant a different approach. Unlike distribution and transmission utilities, the impacts of the pandemic on OPG and how that translates to costs and savings over-time are much more complicated, and because the pandemic comes at the end of its current Custom IR term (2017-2021) it may find itself in a financially better position vis-à-vis ratepayers.

As LEI notes, as a result of the pandemic, OPG postponed the start of the Darlington Unit 3 refurbishment from May to September.[37] This has led to an increase in revenue by approximately $137M as Unit 3 remained in service for those additional months in 2020.[38] Under the Staff Proposal, this $137M increase in revenue caused by increased production can only be used as an offset to any pandemic related cost increases (at a value of 50%). It is very possible that even without these increased revenues, OPG will not meet the Means Test and customers would not get any credit for this increased revenue.

The problem, as LEI correctly points out, is that the delay means there will be a period of time in 2023/2024 when Unit 3, which had been anticipated to being back in-service, will remain off-line and still undergoing refurbishment. OPG has included this time in its production forecast for its next Custom IR term (2022-2026).[39] Customers "will pay" 100% of the cost of the reduced production forecast in 2023/2024 through higher payment amounts. A similar problem would occur if OPG delays any other planned maintenance outages in 2020 or 2021 but are then also included in the production forecast and capital/OM&A costs included in its 2022-2026 Custom IR application.

SEC submits a more appropriate approach is for OPG to record all costs/savings in Account 1509, but that rules regarding what amounts and on what basis can be recovered (including potentially net credits) to be dealt with in the current rate proceeding before the Board. For example, if the extra

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[37] LEI, Report on Gains and Losses from Differences in Load and Production, p.13; See also EB-2020-0290, Exhibit E2-1-2, p.7

[38] LEI, Report on Gains and Losses from Differences in Load and Production, p.14

[39] LEI, Report on Gains and Losses from Differences in Load and Production, p.14; See also EB-2020-0290, Exhibit E2-1-1, p.5

revenue from 2020 is included in Account 1509, and is directly related to the lost revenue in 2023, then the Board may elect in the rate proceeding to offset the two.

Interplay With Existing Ratepayer Protection Mechanisms. As the Board is aware, there are a number of existing generic or utility specific ratepayer protection mechanisms such as Earnings Sharing Mechanisms or Capital In-Service Variance Accounts. The Board should clarify that those mechanisms should be applied in a way that ensure that there is no double counting of costs or savings, and that provisions of these accounts should take precedent to Account 1509.

Comment on Underlying Data. SEC cautions the Board against reaching any definite conclusions regarding the impact of COVID-19 based on the survey information that was undertaken by LEI.[40] The data inherently based on inconsistent assumptions as to what should be included, and how it should be valued. Furthermore, only 13 utilities responded to the survey.[41] In addition, much of the causal aspect of that data (i.e. what is pandemic related) is based on utility judgements. The forecast component of the input is a survey of utilities carried out by LEI, in which utilities were asked to guess at future impacts of COVID-19.[42] LEI does not provide any basis for thinking that the utility guesses are any better than guesses by the Board or other stakeholders, nor does the Board know the basis, if any, on which utilities have developed the information/forecasts they have provided. A similar concern exists with respect to the balances in Account 1509. As this consultation has not concluded, utilities do not know exactly what they should or should not record. There is likely significant inconsistencies amongst utilities in what they are or are not including in the account.

Conclusion

SEC submits that the Board should adopt as its underlying principle that incremental costs or lost revenues related to the pandemic should be recoverable from customers if the utility's financial viability would otherwise be threatened. In each case in which financial viability is in question, the Board should conduct a thorough review, and fashion a recovery solution tailored to that specific situation.

The guidelines with respect to calculation of incremental costs or lost revenues, and any Means Test, should be indicative only, and should not be applied in a mechanistic manner. When financial viability is an issue, both utilities and their customers deserve a thorough and specific review, and a solution that solves the problems in the most appropriate manner.

All of which is respectfully submitted.

Yours very truly,
Shepherd Rubenstein P.C.

Mark
Rubenstein
2021-01-25
15:33:56

Mark Rubenstein

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[40] LEI, COVID-19 Impact Study, p.7-8

[41] LEI, COVID-19 Impact Study, p.8

[42] LEI, COVID-19 Impact Study, p.8

cc: Wayne McNally, SEC (by email)
Interested Stakeholders (by email)

Appendix A

Return on Equity (Actuals v. Embeded In Rates)					
Electricity Distributor	**2015**	**2016**	**2017**	**2018**	**2019**
Alectra Utilities Corporation		-1.15%	-0.42%	-1.26%	-1.74%
Algoma Power Inc.	1.77%	0.59%	-1.19%	-1.08%	-0.86%
Atikokan Hydro Inc.	4.02%	-6.39%	0.68%	2.43%	-1.16%
Bluewater Power Distribution Corporation	2.85%	2.88%	1.33%	2.88%	1.95%
Brant County Power Inc.	-5.94%				
Brantford Power Inc.	2.08%	-2.45%	2.60%	-0.88%	-1.61%
Burlington Hydro Inc.	0.35%	-1.38%	-2.67%	-2.93%	-2.20%
Cambridge and North Dumfries Hydro Inc.	0.64%				
Canadian Niagara Power Inc.	1.07%	0.04%	1.92%	-2.20%	-2.94%
Centre Wellington Hydro Ltd.	-0.85%	-4.97%	-5.44%	-1.86%	-3.81%
Chapleau Public Utilities Corporation	-8.72%	-12.94%	-11.11%	-18.31%	-0.54%
Cooperative Hydro Embrun Inc.	-7.83%	-5.68%	-8.64%	-0.88%	1.03%
E.L.K. Energy Inc.	1.60%	-0.73%	2.37%	7.39%	0.88%
Elexicon Energy Inc.		0.01%	-0.34%	0.41%	-5.11%
Energy Plus Inc.		0.13%	-1.61%	-0.68%	0.08%
Enersource Hydro Mississauga Inc.	-1.39%				
Entegrus Powerlines Inc.	0.07%	-1.73%	-1.55%	-0.99%	1.39%
EnWin Utilities Ltd.	-1.13%	-4.88%	-5.46%	-3.66%	-4.29%
EPCOR Electricity Distribution Ontario Inc.	1.88%	1.05%	11.65%	2.96%	-6.21%
Erie Thames Powerlines Corporation	0.27%				
ERTH Power Corporation		-0.75%	-0.51%	1.38%	3.05%
Espanola Regional Hydro Distribution Corporation	6.79%	-2.83%	-6.67%	-5.00%	-18.58%
Essex Powerlines Corporation	1.85%	-2.60%	-6.48%	-0.89%	-1.70%
Festival Hydro Inc.	4.94%	-1.93%	-0.87%	-1.00%	-0.20%
Fort Frances Power Corporation	1.88%	-2.52%	-2.42%	-1.78%	-1.73%
Greater Sudbury Hydro Inc.	-0.62%	1.19%	0.32%	-1.26%	-0.36%
Grimsby Power Incorporated	-7.41%	-6.80%	1.73%	-0.74%	1.20%
Guelph Hydro Electric Systems Inc.	-0.76%				
Haldmand County Hydro Inc.	-1.86%				
Halton Hills Hydro Inc.	-2.12%	-2.43%	-2.21%	-2.12%	-4.95%
Hearst Power Distribution Company Limited	-33.21%	-0.86%	-1.00%	-2.42%	4.72%
Horizon Utilities Corporation	0.70%				
Hydro 2000 Inc.	2.10%	-3.87%	-15.64%	-16.28%	2.41%
Hydro Hawkesbury Inc.	10.36%	8.27%	-1.91%	-13.10%	7.54%
Hydro One Brampton Networks Inc.	-1.64%				
Hydro One Networks Inc.	-0.53%	-0.78%	-0.84%	-0.93%	1.90%
Hydro One Remote Communities Inc.	0.00%	0.00%	0.00%	0.00%	0.00%
Hydro Ottawa Limited	-1.50%	0.61%	0.91%	-0.05%	-0.16%
Innpower Corporation	-1.37%	-5.08%	-7.84%	2.69%	1.31%
Kenora Hydro Electric Corporation Ltd.	-8.87%				
Kingston Hydro Corporation	-5.86%	-2.76%	-1.37%	-1.71%	0.31%
Kitchener-Wilmot Hydro Inc.	2.11%	0.82%	0.23%	-0.30%	-0.63%
Lakefront Utilities Inc.	-1.43%	-1.40%	-2.21%	-1.02%	-1.20%

Lakeland Power Distribution Ltd.	0.82%	1.78%	3.61%	3.51%	2.53%
London Hydro Inc.	-1.46%	-2.99%	0.28%	1.30%	0.04%
Midland Power Utility Corporation	-0.06%				
Milton Hydro Distribution Inc.	-1.90%	0.68%	0.26%	1.26%	-2.45%
Newmarket-Tay Power Distribution Ltd.	-1.15%	-1.65%	-7.25%	1.53%	-2.72%
Niagara Peninsula Energy Inc.	-0.34%	-2.44%	-5.73%	-4.27%	-4.57%
Niagara-on-the-Lake Hydro Inc.	-0.46%	-1.92%	0.45%	0.76%	5.40%
North Bay Hydro Distribution Limited	1.35%	-0.29%	-0.74%	0.87%	-3.16%
Northern Ontario Wires Inc.	-2.78%	-5.54%	-2.54%	1.19%	2.14%
Oakville Hydro Electricity Distribution Inc.	-0.01%	1.35%	0.33%	1.29%	-0.05%
Orangeville Hydro Limited	-2.96%	-0.68%	1.24%	2.56%	1.00%
Orillia Power Distribution Corporation	-0.86%	-11.44%	1.18%	-2.30%	-3.83%
Oshawa PUC Networks Inc.	-1.71%	0.67%	-1.57%	-1.07%	0.14%
Ottawa River Power Corporation	-5.58%	-2.87%	2.63%	8.82%	5.29%
Peterborough Distribution Incorporated	-1.44%	-1.96%	-3.93%	-1.67%	-2.70%
PowerStream Inc.	-2.28%				
PUC Distribution Inc.	-4.52%	-8.00%	-7.20%	-4.75%	-0.13%
Renfrew Hydro Inc.	-10.77%	-11.38%	-0.39%	2.03%	0.12%
Rideau St. Lawrence Distribution Inc.	-5.11%	-8.09%	-7.94%	-3.67%	-3.06%
Sioux Lookout Hydro Inc.	-1.60%	-3.82%	-3.29%	0.43%	-0.59%
St. Thomas Energy Inc.	2.34%				
Synergy North Corporation		-5.46%	-5.83%	-0.73%	0.86%
Thunder Bay Hydro Electricity Distribution Inc.	-1.31%				
Tillsonburg Hydro Inc.	2.04%	-3.23%	0.75%	-3.88%	-4.24%
Toronto Hydro-Electric System Limited	1.41%	2.88%	-0.22%	0.03%	-0.86%
Veridian Connections Inc.	-0.05%				
Wasaga Distribution Inc.	-3.74%	-0.76%	-0.31%	0.19%	-2.05%
Waterloo North Hydro Inc.	-2.93%	0.94%	-0.82%	-0.99%	-2.06%
Welland Hydro-Electric System Corp.	-0.21%	-2.30%	-0.27%	2.63%	1.66%
Wellington North Power Inc.	-1.82%	1.49%	-2.07%	-1.42%	-2.72%
West Coast Huron Energy Inc.	-2.07%				
Westario Power Inc.	-0.96%	-2.32%	-6.43%	1.10%	1.99%
Whitby Hydro Electric Corporation	0.77%				
Woodstock Hydro Services Inc.	-0.46%				
Average	**-1.35%**	**-2.14%**	**-1.84%**	**-0.97%**	**-0.77%**

Source: OEB Electricity Distributor Scorecards