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Our File No. 173431

August 9, 2018

VIA RESS, EMAIL AND COURIER

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attention: Kirsten Walli,
Board Secretary

Dear Ms. Walli:

Re: EB-2017-0049: Hydro One Networks Inc., 2018-2022 Distribution Custom IR Application

Please find enclosed herewith BOMA's Final Argument.

Yours truly,

FOGLER, RUBINOFF LLP

Thomas Brett

Thomas Brett
TB/dd
Encls.
cc: All Parties *(via email)*

EB-2017-0049

ONTARIO ENERGY BOARD

Hydro One Networks Inc.

Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022

FINAL ARGUMENT OF

BUILDING OWNERS AND MANAGERS ASSOCIATION, GREATER TORONTO ("BOMA")

August 9, 2018

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Introduction

BOMA is of the view that the Board should not approve Hydro One Networks Inc.'s ("HONI") application as filed. BOMA's Argument will deal with each of Sections A through J of the Final Issues List, though not in the order set out in the Final Issues List.

Custom Application

HONI describes its custom IR application as a "revenue cap application", which is not an option offered by the Board for electricity distributors. Neither the Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012 ("RRF Report"), nor the Rate Handbook for Utility Rate Applications for electricity distributors (the "Handbook"), issued October 13, 2016 offer electricity distributors the option of a revenue cap application. The available options are a fourth generation IR (price cap), an annual IR index, and a custom IR (Handbook, p24). The company cannot conjure approval for an application by calling it both a custom IR and a revenue cap application.

The RRF Report establishes three types of applications electricity distributors may make. The Board says this about the 4th generation IR method:

> *"The Board is establishing three rate-setting methods. Each distributor will select the method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. 4th Generation Incentive Rate-setting ("4th Generation IR"), which builds on 3rd Generation IR, is most appropriate for distributors that anticipate some incremental investment needs will arise during the plan term. The Board expects that this method will be appropriate for most distributors.*
>
> *Building on the current 3rd Generation IR, the 4th Generation IR method includes certain enhancements to better align indexing of rates with the inflation faced by distributors in Ontario and to strengthen the efficiency incentives inherent in the rate-adjustment mechanism. The 4th Generation IR method will be appropriate for distributors that*

anticipate that some incremental investment needs may arise during the term of the rate method.

Under this method, rates are set on a single forward test-year cost of service basis and subsequently indexed by the 4^{th} generation price cap index formula. The Board will retain a comprehensive price cap form of adjustment mechanism. The Board believes that the price cap approach, like that used in the Board's earlier IR plans, continues to be appropriate for most distributors." (RRF Report, p4)

The Board repeats this point at p13 of the RRF Report, in Table 1, in which the Board explains the characteristics and applicability of each of the three methods. .

The Handbook for Utility Rate Applications, issued on October 13, 2016, adopts the rate-setting options set out in the RRF Report. Under the heading Rate-Setting Options, it states:

"To support the move to an outcomes based approach, the OEB recognized the need to provide flexibility in rate setting options to give utilities the necessary tools to develop business plans that meet their needs. The RRFE established three incentive rate-setting (IR) methodologies for electricity distributors: Price Cap IR (previously known as 4^{th} Generation IR), Custom IR, and the Annual IR Index.

- *Price Cap IR: Under this methodology, base rates are set through a cost of service process for the first year and the rates for the following four years are adjusted using a formula specific to each year. For electricity distributors, the formula includes an industry-specific inflation factor and two factors for productivity. One productivity factor is a fixed amount for industry-wide productivity and the other is a stretch factor, which is set each year based on the level of productivity the electricity distributor has achieved.*

- *Custom IR: Under this methodology, rates are set for five years considering a five-year forecast of the utility's costs and sales volumes. This method is intended to be customized to fit the specific utility's circumstances, but expected productivity gains will be explicitly included in the rate adjustment mechanism. Utilities adopting this approach will need to demonstrate a high level of competence related to planning and operations. Additional guidance on Custom IR applications is set out below.*

- *Annual IR Index: Under this methodology, rates are subject to the same annual adjustment formula as those under Price Cap IR. Utilities under the Annual IR Index are not required to periodically set base rates using a cost of service process, but they are required to apply the highest stretch factor. This approach is the most mechanistic of all rate applications. These utilities are required to provide five-year distribution system plans as a reporting requirement every five*

> > *years, and like all other distributors will continue to report their performance using the OEB's Performance Scorecard. This will allow the OEB to determine whether the planning process and level of investment is adequate and whether service levels remain appropriate.*
>
> *Electricity distributors may choose from any of these three methodologies. There are no eligibility requirements for any of these methods, but the rate application must meet the requirements of the rate-setting option. Those requirements are set out in the OEB's RRFE Report, in the filing requirements and in this Handbook."*

The Handbook is the most recent statement of the Board's rate-setting alternatives for electricity distributors, prepared four years after the RRF Report and after the Board's Toronto Hydro decision (EB-2014-0116).

In summary, the Board has been very clear from the RRF onward that the revenue cap option is not available to electricity distributors.

HONI's contention that the Board's RRFE and Rate Handbook provide distribution utilities with a revenue cap rate-setting option is clearly wrong. The company makes two references in the Handbook to justify its use of a revenue cap proposal. The first was a sentence at p6, which describes the topics to be covered in the Handbook. It states:

> *"This Handbook applies specifically to rate applications, under any of the legislative sections identified above, which are intended to set rates for a multi-year period (custom IR) or for the first year of a multi-year period (Price Cap IR or Revenue Cap IR). Under the RRF, there are a variety of incentive rate-setting IR options which are discussed further in section 6."*

This section is part of the introduction to the Handbook. It is not the part of the Handbook that specifically deals with the ratemaking option open to electricity distributors and electricity transmitters. Those options are set out in section 6. Revenue Cap is mentioned in the section quoted above for completeness, as the revenue cap IR is an option for electricity transmitters, one of the categories of utility covered by the Handbook. As noted above, section 6 of the

Handbook sets out three options for electricity distributors, price cap IR, custom IR, and annual IR index. Price cap IR and annual IR both use the same annual adjustment formula. Custom IR does not use a price cap annual adjustment formula. Instead, it sets rates for five years on the basis of a five year forecast of the utility's cost and sales volumes. However, some of the expected productivity gains will be explicitly included in the annual rate adjustment mechanism, by introducing an I-X formula to adjust rates, where X includes a productivity factor and a stretch factor. That does not mean the custom IR becomes a revenue cap plan. There is no other significance to the fact that the description of a custom IR on p6 does not talk about price caps, contrary to Mr. André's erroneous inference.

HONI may be confusing the Board's rate-setting options for electricity distributors with its rate-setting options for electricity transmitters. The Board offers a revenue cap option (rather than a price cap option), along with a custom IR option, to electricity transmitters, given the fact that Ontario does have a uniform transmission rate that applies throughout the province. At p24 of the Handbook, under the heading Electricity Transmitters, the Board states:

> *"Electricity transmitters may choose either Custom IR or a Revenue Cap IR. The Revenue Cap IR methodology is similar to the Price Cap IR option discussed previously for distributors. Individual rates are not set for each transmitter. The revenue requirement for each transmitter is approved by the OEB and this is used to set uniform transmission rates that apply throughout the province. Therefore, instead of a Price Cap IR option, a transmitter can propose an incentive mechanism for adjusting its revenue requirement in a similar manner."*

After erroneously conducting that it has the option of adopting a revenue cap, HONI attempts to show why a revenue cap is superior to a price cap. HONI suggests that it is necessary to the integration of the three acquired utilities in 2021. BOMA does not believe the argument has much merit. First, HONI has already decided to create six new rate classes, for the three acquired utilities for the years 2021 and 2022, two for each of the three utilities, and has also provided cost allocation data and rate data for those three new utilities, pursuant to directions from the Board to allocate only those costs that ensure that the revenue-to-cost ratio for the six rate classes are within Board policy limits. Moreover, the Board stipulated that the costs allocated to the three acquired utilities be no greater than their current allocated costs, so it is not clear what role an index of HONI's revenue requirement has to do with the creation of the six rate classes for the three companies.

C-Factor

However, the index HONI proposes to use, in addition to the traditional I-X term used in price cap applications, includes a third component, a Capital Custom Factor ("C-Factor"), the amount of which is "determined to recover the incremental revenue in each test year necessary to support HONI's proposed Distribution System Plan beyond the amount of revenue recovered in rates" (Exhibit A, Tab 3, Schedule 1, p2). "In rates", in this context means the rates determined by the I-X formula applied to the previous year's revenue requirement.

The company's evidence also describes the C-Factor in this manner:

> *"The Capital Custom Factor proposed in this Application and used in the RCI (Revenue Cap Index) is designed to ensure that the total revenue resulting from the Custom IR is able to meet Hydro One's specific circumstances arising from the proposed capital investments set out in Hydro One's DSP* (Ibid, p5)",

and further that:

> *"The Custom Capital Factor is the percentage change in the Total Revenue Requirement (line 11 of Table 1 below) attributable to the <u>capital investment that is not otherwise recovered</u> from customers"* (Ibid, p5) (our emphasis).

BOMA has serious concerns with the proposed C-Factor. First, the C-Factor lessens the Applicant's incentive to impose discipline on its capital expenditures, as it is explicitly designed to ensure that the plan's proposed capital expenditures over the plan term, which are substantially increased over the term, are recoverable in the revenue requirement for each of the plan years. The impact of the C-Factor on the revenue requirement is very substantial. It underpins increases in revenue requirement of an average of $45.2 million in each of 2019, 2020, 2021, and 2022 of the plan, which in turn underpins an average annual increase of rate base of $420 million (Exhibit Q, p7) from $7,666.4 million in 2018 to $9.326.5 million in 2022, an increase of $1.660 billion (Exhibit Q, p9).

Second, ironically enough, the C-Factor is much more permissive than the price cap and ICM regime ratemaking alternative. The Board made clear in the RRFE and the Handbook that the ICM regime could not be utilized in tandem with a custom IR because this would be contrary to the nature and rationale for the custom IR, would amount to double dipping, and seriously inflate capital expenditures. The ICM policy contains several checks and balances that are not present in the capital index, such as a general materiality threshold, a project specific materiality threshold, a deadband, and separate identification of the projects (and ISDS for each of them), and differentiation of the projects proposed for ICM funding from the capital projects (programs), which would be funded by the I-X index applied to the previous year's rates, the base capital budget. The corollary of the Board's policy on "no ICM with custom IR" is that the capital index cannot be used in tandem with a custom IR to justify the capital expenditures in the years 2 to 5 of the custom IR plan, or cannot be used unless it is substantially modified.

Third, unlike the ICM facility, which can be used in some circumstances to fund a utility's proposed capital expenditures not supported by rates under the I-X price cap formula, the C-Factor is formulaic, and operates to automatically justify/reflect the rising capital expenditures without either a materiality threshold or a deadband or other constraints. It applies to all the capital driven elements of the revenue requirements (Exhibit A, Tab 3, Schedule 2, p6). It deprives the Board of the opportunity to consider each proposed capital expenditure, in excess of that funded by the I-X formula, on its own merits, to determine which projects or programs are material and important enough to warrant incremental funding. The Board utilized that opportunity in the recent Alectra rate case (EB-2017-0024). In that case, the Board was able to make a detailed project by project analysis which led to about one-half of the proposed projects not being approved for ICM funding, either because they did not meet a project specific materiality factor, or they were deemed not to be of significant importance to the operation of the utility. Moreover, use of the C-Factor formula means that the escalation in capital expenditures the projects funded through the incremental funding are treated no differently than the projects funded by the I-X index.

The C-Factor is especially problematic when applied to the increase in capital expenditures in the last three years of the five year plan. The company's evidence is that today's estimates of these costs are high level estimates, or planners' estimates with a margin of error of +/-50% (Tr 9, p97). These estimates should not be codified into an index at the outset. Rather, the Board should review the projects as they mature over the term of the plan to ensure they do not result in excessive increases over the previous years' capital budget, taking into account, inter alia, the degree to which the company was able to execute the prior years' forecast plans, and to avoid over budget spending in the subsequent years, as a result of unfinished projects carried forward from previous years. There should be no automatic recovery of over budget capital in any year, otherwise the integrity of the custom IR "model" will be destroyed. The Board has made it clear on several occasions, including in the Handbook, that the applicant for a custom IR must demonstrate to the Board that it is capable of managing the utility's growth with annual budgets (Handbook, p27).

Dr. Lowry, the Board staff's expert witness, was also critical of the custom capital factor. He made the following comments on the C-Factor:

> *"The proposed ratemaking treatment of capital cost is problematic. The C-Factor would incent Hydro One to exaggerate its need for supplemental revenue, and substantially raises regulatory cost for the OEB and stakeholders. The Company is perversely incented to spend excessive amounts on capital to contain OM&A expenses. The kinds of capex accorded C-Factor treatment are similar to those incurred by distributors in the productivity studies. The RCI would effectively apply chiefly to revenue for OM&A expenses and provide only a floor for revenue growth even though it is designed to play neither of these roles. We discuss several possible upgrades to the capital cost treatment and conclude that a materiality threshold and dead zone should be added to the C-Factor mechanism."* (Exhibit M1, p3) (our emphasis)

> *"The proposed ratemaking treatment of capital cost is similar to that which the Board approved for Toronto Hydro but nonetheless raises several concerns. The C-Factor ensures that the Company recovers its proposed capital cost less a perfunctory X factor markdown. Hence, capital revenue is chiefly determined on a cost of service basis. Incentives to contain capex and OM&A expenses are imbalanced, creating perverse incentives to incur excessive capex to reduce OM&A costs. Notwithstanding the proposed claw back of some capex underspends, Hydro One still has some incentive to exaggerate capex needs since this strengthens the case for a C-Factor and reduces pressure for capex containment."* (Exhibit M1, p37) (our emphasis)

> *"Distributors are also incentivized to "bunch" their deferrable capex in ways that increase supplemental revenue. The data in Table 7 suggests that Hydro One may be pursuing this strategy now. The table shows that capital additions are forecasted to be higher than the norm for the 2013-2015 period after a three-year lull from 2016 to 2018. Hydro One proposes to build an Integrated System Operating Center right in the middle of the plan term when the impact on the C-Factor would be close to the greatest possible. The impact on the C-Factor would be much less if the center were finished in 2019 or 2022."* (Exhibit M1, p37)

> *"Another problem with the proposal is that customers must fully compensate Hydro One for expected capital revenue shortfalls when capex is high, even though most of the capex in question is likely to be similar in kind to that incurred by distributors in the productivity research sample used to calibrate X. Utilities can then be compensated twice for the same capex: once via the C-Factor and then again by a low X factor in this and future IRMs."* (Exhibit M1, p38)

> *"Given the inherent unfairness to customers of asymmetrically funding capital revenue shortfalls, and Hydro One's incentives to exaggerate capex requirements, stakeholders and the Board must be especially vigilant about the Company's capex proposal. This raises regulatory cost. The need for the OEB to sign off on multiyear total capex proposals complicates Custom IR proceedings and is one of the reasons why the Board now requires and reviews distribution system plans --- a major expansion of its workload and that of stakeholders. The regulatory cost of Hydro One's C-Factor proposal is further raised by the provision that it be permitted to keep legitimate capex productivity gains. The Company will be incentivized to pursue its claims under this provision energetically."* (Exhibit M1, pp38-39)

> *"If the OEB is prepared to deviate from Hydro One's proposed C-Factor treatment, we note that the establishment of a materiality threshold and dead zone for supplemental capital revenue in Custom IR plans is most in keeping with its current policies. This could be done in such a manner that the first 10% of unfunded capex (after the X factor markdown) is ineligible for C-Factoring. However, the materiality threshold and dead zones need not be modelled on those in the incremental capital modules used in 4th GIRM. For example, if proposed capex exceeded the materiality threshold, a set percentage of all unfunded capex could be declared ineligible for C-Factoring. This would strengthen the Company's incentive to contain capex at the margin. A similar idea is for a set number of basis points (e.g., 50) of the otherwise appropriate C-Factor to be disallowed. The OEB disallowed a 10% share of Toronto Hydro's proposed capex in a recent proceeding.54 Any of these dead zone approaches can make customers whole for the addition of a growth escalator to Hydro One's RCI."* (Exhibit M1, pp40-41)

BOMA is of the view that the C-Factor should either be eliminated altogether, or subject to a number of restraints to make it more akin to the Board's ICM policy. As Dr. Lowry recommends (Ibid 66), subject the C-Factor to a materiality threshold and a deadband, to reduce the degree to which it can be used to exaggerate the revenue requirement. Additionally, the C-Factor could be reduced as in the later years of the plan, as rebasing draws nearer.

The C-Factor is redundant, confusing, and dangerous for ratepayers.

HONI has, in effect, and as it has recognized throughout its application, a custom IR plan, in which it has estimated its costs and rates over the period 2018 through 2022. It has stated that the 2018 budget has been based on a cost of service approach. The Board should calculate the amount of capital expenditures which is supported by the rates set using the I-X formula, plus a reasonable growth factor, and further capital requests should be treated as ICM requests pursuant to the Board's established policy.

The features of the ICM constraints should be applied to the forecast capital costs.

BOMA endorses Dr. Lowry's critique of the C-Factor, and urges the Board not to be overly influenced by an earlier Toronto Hydro decision. That decision was made some time ago, and the Board has since learned a great deal about the custom IR model. Moreover, HONI's basic approach (before introduction of a C-Factor) was a price cap, not a revenue cap.

BOMA agrees with Dr. Lowry's comment on the company's proposed Capital Service Variance Accounts (Exhibit A, Tab 3, Schedule 2, p10).

The company proposes that revenue requirement variances (decreases) associated with decreases in in-service additions, due to verifiable productivity gains, be excluded from the refund (credit) calculation at the end of the term for return to ratepayers. BOMA disagrees. HONI will already benefit from a reduction in OM&A over the term, and the provision will lead to a great deal of debate, given the manner that HONI appears to wish to verify and report productivity-driven savings. At the very least, such savings should be calculated for each productivity initiative that results in a lower capital cost for a specific project(s) or a reduction in OM&A expenditures, and be part of a report filed with the Board and stakeholders as part of the company's annual updates. BOMA prefers that the exception not be made.

RRFE/Distribution System Plan ("DSP") - Engagement with Customers

One of the four pillars of RRFE is customer focus, to enable the utility to provide customers outcomes which the customers value.

The Applicant did engage with its customers and stakeholders over the DSP and its rates application. It hired IPSOS REID to manage a substantial engagement. However, the application as proposed did not reflect ratepayers' needs and preferences, as required by the RRFE.

Ratepayers made it clear that rates were too high and further rate increases were its dominant concern. Maintenance of reliability was their second priority, but not increasing rates further was their first priority by a substantial margin. Not raising rates and maintaining reliability were not equal priorities. No further rate increases were the number one priority.

The Distribution Customer's Engagement Report dated August 16, 2017 (the "Report") stated, under the Summary of Findings, that:

> *"Keeping costs as low as possible is customers' top priority. This was evident across most of Hydro One's distribution customers segments, with the exemption of local distribution companies ("LDCs")"* (p7).

BOMA would note that LDCs pass through HONI's charges to their own customers, so their responses do not reflect <u>end use customers' needs and preferences</u> (our emphasis). As the Board noted in the recent HONI Transmission decision, HONI should seek to have their LDC customers provide <u>their</u> customers preferences.

The Report stated further (p7) that:

> *"The preference for keeping costs low, for some customers is influenced by a desire to see Hydro One demonstrate greater fiscal management and operational efficiency <u>before considering rate increases</u>..."* (p7) (our emphasis), and, *"The final factor is that for some customers, electricity costs represent a financial challenge and are approaching being unaffordable"* (p8).

These latter customers feel that they simply cannot afford an increase in rates.

IPSOS REID also reported that:

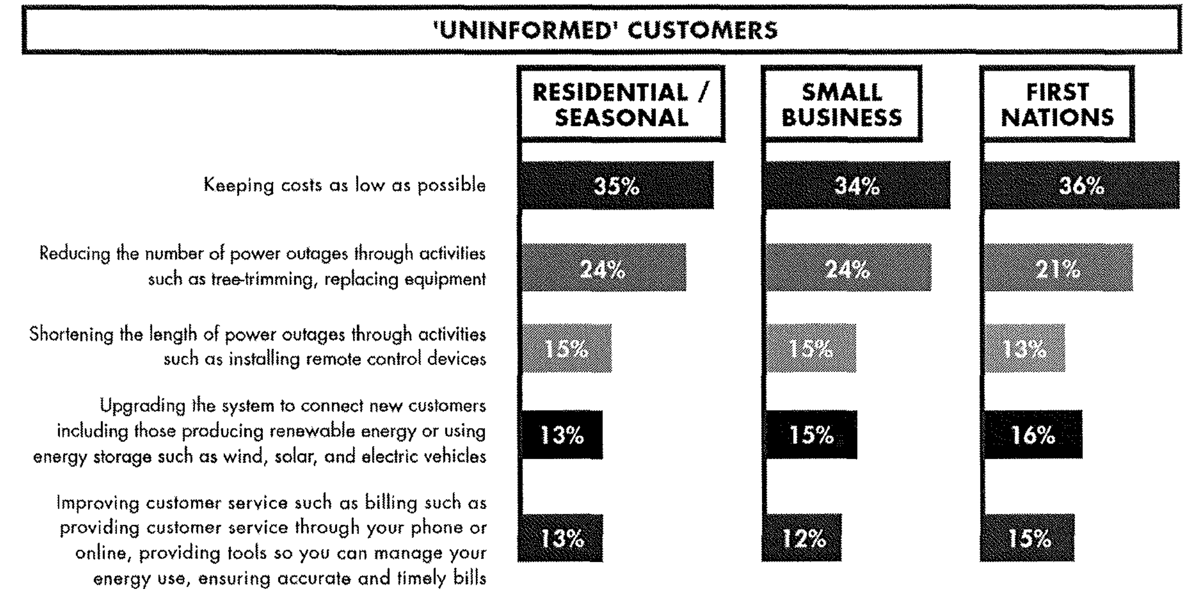
> *"Negative experience with and poor perception of HONI have bled into their (customers) view of the company's ability to make prudent, cost-effective investment decisions. They question HONI's current operational effectiveness and believe that maintaining the system can be achieved by managing costs more effectively rather than increasing rates."* (Ibid, p11)

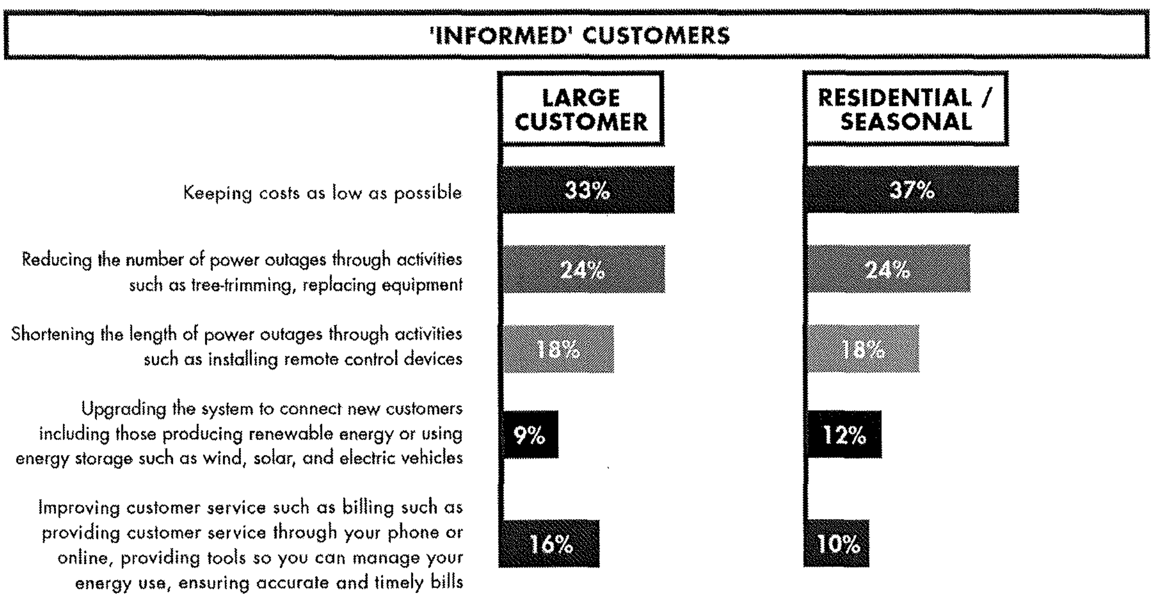
HONI continues to fail to recognize that customers do not accept that further rate increases are necessary. This is not surprising, given the history of HONI distribution's recent rate increases.

The following table reproduces p16 of the IPSOS REID report. It shows clearly the preference of all customers for lower rates, which is consistently forty percent more important to customers than "reducing the length of power outages" (improving reliability) and three times more important than "improving customer service". The table demonstrates that large customers were no different from other customer groups in this respect as 33% of the large customers' top priority was keep costs low, while only 24% said reducing the number of power outages was their top priority.

ALL CUSTOMER SEGMENTS

CUSTOMER PRIORITIES





Q5. Hydro One would like to better understand what is important to you as a [insert] customer. [Below is /I am going to read] Hydro One's major expenditures in pairs and for each pair please tell me which one is more important to you. Paired choice preferences relative to other options. Base: Uninformed - Residential/ Seasonal (n=499). One respondent opted not to answer, Small Business (n=199). One respondent opted not to answer Q5., First Nations (n=300). Informed - Large Customers (n=87). Base: Residential/Seasonal (n=1604).

The customers' priorities were also clearly stated by the Board staff Summary of Community Meetings, EB-2017-0049 dated September 7, 2017 ("Staff Meetings"). In its summary of what was said at the Community Meetings, the staff stated:

> *"The OEB should not approve the request by Hydro One to increase its rates. Reasons given included:*
>
> - *Hydro One should find efficiencies instead*
> - *CEO and executive compensation should be reduced*
> - *Replacement of assets should have already been paid for with revenues in the past (replacement reserve) and new funds are not necessary*
> - *Rates in Ontario are the highest in the country, creating hardship for customers, forcing business to close or relocate".*

As for the Fair Hydro Plan, the Board staff's summary noted that customers were confused about its impact, and concerned that it was short-term relief, which simply shuffled some of the burden of higher rates from ratepayers to taxpayers, and would result in significant increase after the expiry of the plan in four years.

In its DSP, HONI confirmed that the customers' primary concern was costs. For example, the evidence is that:

> *"Cost is definitely the top priority for Residential and Small Business customers, and is one of the top priorities for Large Customers. This preference is influenced by a desire to see Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases"* (Exhibit B1, Tab 1, Schedule 1, DSP 1.3, p16).

BOMA disagrees that large customers rated "maintain reliability" as an equal priority to keeping rates down. The Table on p14 of BOMA's Argument shows that reliability was a second priority for large customers as well.

Second, ratepayers made it clear that they did not want to pay higher rates for improvements in customer service. The majority of customers indicate that the current level of reliability and service they receive from HONI is in line with their expectations, and therefore, there is not a strong desire for improved service, particularly if it means raising rates.

> *"Customer service levels beyond existing levels are not something for which customers are willing to pay higher rates"* (Ibid).

However, HONI ignored this caution and proceeded to propose an array of new or expanded customer service initiatives which, while having some merit, contributed to the proposed substantial rate increases.

Moreover, the timing of the customer engagement was such that HONI's planners had already made their initial statement of priorities or selection of themes for projects and programs prior to the receipt of the final IPSOS report. This fact also calls into question the extent to which HONI actually was influenced by the engagement findings.

HONI should have later engaged customers on its various rate plans. It did not.

HONI's discussion in the application of how its DSP reflected customer needs and preferences was brief and skeletal.

Plan Options

HONI states that its proposal (plan B-modified) will maintain the reliability of its system, but reliability is customers' second priority. Maintenance of reliability, which is promised in plan B-modified, will be done at the cost of a substantial increase in rates, which clashes with most customers' first priority. It is not clear what specific changes in this area were made to accommodate customer needs and preferences.

BOMA agrees with HONI's decision to increase its power quality program from $1.5 million to $3.5 million in 2018, which is a modest cost increase for a program requested by many larger users. That was one area where HONI responded to customers' expressed needs and preferences.

Plan B-modified proposed a 2018 increase over 2017 of 6.1% with an average annual increase of 3.4% over the term.

HONI's executives initially proposed two plans to its board, plan A and plan B. Both involved substantial rate increases.

HONI's response to pressure from its board to reduce rate impacts was to propose a third plan (B-modified), which included 2018 rates 6.1% higher than the existing (2017) rates, with average annual rate increases over the remaining four years of the IRM plan from 2019 to 2022, of 3.4%, for a total increase (arithmetic) of over 20% in the next four and one-half years (Q, 1, 1, p3). The compounded rate increase over five years would be somewhat higher.

The company initially produced three candidate investment plans, A, B, and C, all of which resulted in the rate increases. HONI claimed plans A and B would result in increases in reliability relative to the status quo, a 6% increase in reliability for plan A, 3% for plan B, while plan B-modified would maintain current reliability. Plan B-modified actually increased the reliability of the network, insofar as it was driven by fewer poles in poor condition. HONI claimed that plan C would result in a 2% decrease in reliability (Exhibit A, Tab 3, Schedule 1, pp18-19). However, HONI did not examine in any detail, nor did it present to its Board plan C, which would result in lower rate increases than option B modified. HONI only briefly investigated plan C, which produced lower, but still substantial, rate increases, and which resulted in a small decrease in reliability. However, unlike plans A, B, and B-modified, plan C was not a fully developed plan, or carefully costed because HONI dismissed it as unacceptable out of hand, because it would likely result in a decrease in reliability of about 2%. How they estimated the decline without a detailed analysis is not clear (see Tr 9, p44 for HONI's view of factors which determine reliability).

Moreover, HONI did not analyze and consider, either at the senior management level or at its Board, any IRM plans that would result in an annual rate increase based on the forecast inflation rate over the next five years, or included a rate freeze for one or two years followed by rate increases at forecast inflation for the next three years. BOMA believes that HONI should have done that to be responsive to the stakeholders' needs and preferences, as reflected in the consultation.

In BOMA's view, HONI's application was driven by its internal (bureaucratic) requirements to pursue each of its internal corporate priorities without much regard to its customers' needs and preferences.

Reliability

BOMA is concerned that HONI did not seriously analyze the impact on reliability, including SAIDI and SAIFI. The company agreed that the estimates contained at Exhibit A, Tab 3, Schedule 1, pp 18-19 were high level estimates of reliability impacts of different levels of investment in poles, lines, stations, and vegetation management expenses (I-29-Staff-164, p4). Second, the company stated that many factors influenced reliability in addition to SAIDI and SAIFI, some of which are not in the control of the company (Tr 9, p44).

It was clear from the IPSOS Report (see, for example, the footnote to p12, below) that HONI had already decided that, in order to maintain current level of reliability of service, it would propose a five year capex and OM&A plans that would require a 1% annual bill increase for residential and small business customers.

> *"Q17. Hydro One has determined that in order to at least maintain the level of reliability and customer service it currently provides, a typical [residential or seasonal / small business] customer's total monthly bill will need to increase by [IF residential or seasonal 1.1% or the equivalent of $2.00 / IF small business 1% of the equivalent of $5.20]. The increase will be applied each year for the next 5 years. By the fifth year, a typical monthly bill will be roughly [IF residential or seasonal $10.00 / IF small business $26.00] higher than it is now. Please note that this increase reflects the cost to maintain the current level of reliability and service to customers. The monthly bill could still increase for other reasons which are outside the control of Hydro One. Would you be willing to accept this increase to maintain the current level reliability and customer service across the electricity system? Note that for the Telephone Survey, this question was posed as Which of the following is closest to your point of view? Base: Uniformed - Residential (n=400), Seasonal (n=100), Small Business (n=200), First Nations (n=300). Informed – Residential (n=1502), Seasonal (n=102)"*

The bill increase translates into monthly HONI rate increases of between 3% and 4%, due to HONI Distribution's percentage of the customers' bills.

Distribution System Plan and Capital Budget

In dealing with this topic, BOMA will address several elements of the Distribution System Plan (the "plan" or the "DSP") and the ensuing capital projects. The previous chapter discussed the fact that the plan, the capital budget, and ensuing rates, do not reflect customers' needs and preferences. This section will deal with other aspects of the plan and the capital budget. BOMA will address:

- Whether the level of proposed capital expenditures over the plan period has been sufficiently supported.

- Whether the plan and the related capital budget are supported by an arm's length independent third party review.
- Does the plan and the application include productivity gains? The Board requires that all custom IR projects reflect productivity gains over the term of the plan.
- Is the planning process adequate, transparent, and does it encourage better outcomes over the plan term?
- The RRFE is designed to achieve customer focus, operational effectiveness, public policy responsiveness, and financial performance? Does the plan and the capital budget promote these goals?
- Are the forecast capital expenditures over the last three years of the plan properly supported?
- Does the plan and capital budget demonstrate that HONI is able to manage its work program within the budget restraints in the application? The Board has stated in the RRF that demonstration of the company's ability to manage within the budget is a key element of a successful custom IR application (RRF, p19).
- Does the plan and capital budget address the OM&A savings that will result from the increased capital expenditures?
- Does the plan properly prioritize and pace capital expenditures? Does the optimization process advance the prioritization of projects?
- Are the plan and ensuing capital budget executable, and is the company advancing credible proposals improve its execution of the plan and budget?

- What is the significance of the debate between the company's internal auditor and the planning department, over the extent to which the company has dealt with the criticisms initially made by Ontario's Auditor General in its 2015 Report.

Capital Budget

The December 21, 2017 version of the Application (Exhibit Q, Tab 1, Schedule 1, p 7 of 25, Tables 4 and 5) includes capital expenditures over the plan term of $3.570 billion, compared to capital expenditures of $3.279 billion over the previous five years, 2013 to 2017, an increase of $290 million, or 9%. The plan period "in-service capital additions" are forecast at $3.6 billion, resulting in an increase in rate base in 2022 of $9.326 billion, an increase over the 2017 rate base of $1.71 billion. Almost half of the total capital budget in 2018-2022 is for system renewal, primarily poles, stations, and lines. The $1.71 million system renewal budget over the term is $340 million higher than the system renewal budget for the previous five year historical period (2014-2017) of $1.375 million, an increase of approximately 26%. The system renewal capital expenditures also accelerated sharply over the plan term from $248.6 million in 2018 to $451.1 million in 2022, an increase of $210 million, or approximately $80%. These increases are excessive, in particular, the increase in system renewal projects and programs, the timing of which is at the company's discretion. That is true whether the projects are discrete one-off projects or annual tranches of ongoing renewal programs. The company listed most renewal projects as medium priority.

First, in BOMA's view, these increases in capital expenditures, which are, through the consequent large increases in rate base, depreciation, and return, the principal driver of rate increases of over 20% over the plan term, which BOMA views as excessive. Moreover, one would expect reduction in OM&A expenditures, especially in corrective maintenance and trouble calls, would decline as a result of the increased capital expenditures, but OM&A expenses are forecast to increase, not decline, over the term of the plan.

Second, the Board has suggested on many occasions that the custom IR plans should be supported by third party expert assessment. However, the AESI Report, which was the third party support, mostly addressed the format of the DSP, and whether it technically complied with the Rate Handbook, in other words, whether it ticked all the boxes. It contained little or no detailed analysis, commentary, or conclusions on the quality and substance of the plan.

Third, the plan and capital budget did not reflect the fact that, in previous years, the company underspent capital relative to what it had planned, in the major renewal asset categories of poles, stations, and lines. The company admitted that its past practices, in estimating slowness in redirecting funds, and data gaps needed to be improved and promised that it was working on improvements. However, it seems wrong to simultaneously push for a relatively large increase in capital expenditures before making the improvements. Why not demonstrate the improved execution and link between planning and execution first?

Fourth, the company also agreed that its estimate for projects in the out years of the plan (years 3, 4, and 5) were simply planners' estimates, which have an accuracy of +/-50%, and that fully engineered accurate estimates exist only for projects to be completed over the next 18 to 24 months, and moreover, that it did not make sense to attempt to make more detailed estimates for projects which would not be built for several years. However, as a result of the company's approach, and given that planners would err on the high side on the estimate for projects three, four, and five years in the future, the capital budgets for those years are very rough approximations of what the projects will actually cost. The Board should not approve such estimates as a basis for rates until estimating practices and accuracy improves.

Fifth, the Board expects applicants for custom IR projects to demonstrate that they can manage the company's affairs within the budget established in the application. This is one of the key differences between a custom IR, which is meant to be incentive rate-making, and a multi-year cost of service application, which HONI is currently on. They have to manage within their forecasts by, inter alia, finding productivity improvements over the IRM program term. In a custom IR plan, true-ups or overspends are not permitted over the plan term, except in truly exceptional circumstances. Moreover, the applicants for custom IR plans are expected to make allowances in their budget for storms. However, HONI seems to think that it will be able to seek rate relief from the Board for overspend during the term of the IRM plan. Such relief, consistently afforded, would turn the custom IR plan into a multi-year cost of service arrangement (which HONI Distribution has enjoyed in 2015, 2016, and 2017), but which is not consistent with the RRFE. The Board should make it clear to HONI that it will not entertain such proposal over the plan term.

Sixth, another contributing factor to excessively high forecasts are the relatively high level of contingency that HONI builds into its projects. The current level is 19%, which inflates the forecasts on which rates are based.

Seventh, BOMA supports the idea that underspends in a given year should be returned to ratepayers via a deferral account. Given the fact that HONI is proposing more rapid redirection of funds, the money should be returned via a rate rider immediately at the next annual rate adjustment proceeding, rather than at the end of the term. Capital trackers are not consistent with the Board's clear expectation that the custom IR applicants must demonstrate that they can manage with the constraints of the approved budget. Wildly fluctuating capital expenditure levels, over budget one year and under budget the next are not acceptable, and not consistent with the custom IR concept, which as the Board notes in the Rate Handbook, assumes a high level of competence in both planning and execution.

Eighth, BOMA does, therefore, support giving the company discretion to promptly redirect funds in the event a project is stalled for reasons beyond the company's control, or to deal with a suddenly emerging urgent need, subject to complete documentation being retained and made available to the Board and stakeholders in the following annual rate adjustment proceedings.

Ninth, the 2018 capital budget includes a $122.6 million over spend from the three years 2015, 2016, and 2017. HONI overspent on both relocations, and unanticipated storms in those three years. The company seemed to adopt the view that they had no choice but to make the expenditures and the full amount should be recoverable in rates in 2018. BOMA would support funding the storm overspend, but not the relocations. Relocation expenditures are expenditures required by law, and they should, therefore, always be the last amount to be removed from an annual capital budget. They must be assigned the highest priority, and must be done first. The company should have known in advance of the relocation requirement for the following year, over the 2015, 2016, and 2017 period, and should have removed more discretionary items, like system renewal and general plant projects, in order to make room for the required relocations. They did not do that, and ought not be allowed to put those amounts into rate base in 2018. While BOMA would approve the addition of the storm repair capital to rate base, the company should re-examine its storm repair budget levels in light of the apparent continuous increase in serious storms along with other extreme weather events.

Planning Process

BOMA is not convinced that HONI's planning process and planning decision-making result in a fully supportable capital budget.

HONI is concerned about:

- the timing of the planning process in relation to other aspects of the preparation of the DSP and the application to the Board;
- how HONI prioritizes its projects, especially the apparent lack of a financial framework for the planners;
- the availability of complete data on asset condition, in particular the lack of data on defects discovered in the lines and related equipment, and information about the repairs that were made;
- the lack of a direct link between planned investments and reliability results on the one hand, and the company's use of high level estimates of reliability outputs to justify particular capital investment levels on the other;
- the fact that most general plant investments are ranked high priority, while most system renewal and system service projects are ranked medium priority
- the relative isolation of the planners from the operation of the company and the overly defensive posture of the planning executives during cross-examinations.

The company's evidence is that the main themes for the DSP were decided by the planning group before the final report of the customer engagement was available. That sequence seems wrong and is evidence that the results of the IPSOS study was treated casually rather than seriously.

As a related matter, BOMA does not understand why the top level financial guidance from the senior executives is not made available to planners. the evidence was that the company targeted a 4.2% annual growth in capital expenditures in order to realize its allowed ROE over the plan term. Surely, it would assist the planners to prioritize these proposed projects in their planning sector at the outset, and make the later stages of the selection process easier. Generally, BOMA would encourage closer collaboration between the planners and the executors, and with other elements in the company, including financial. The planning staff still seems to exist in an "ivory tower" within the company.

BOMA is concerned about the strong disagreement between HONI's internal auditors and the planning executives over the company's internal auditor's assessment of the degree to which the company had addressed HONI's data shortcomings, pointed out by Ontario's Auditor General in its 2015 report. The company, in these circumstances, should have provided a witness from its internal audit group. Intervenors heard only "one side of the story" during the hearing.

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HONI's unique vocabulary does not help. HONI seems to have its own vocabulary. <u>Assets do not have needs</u>; customers do. <u>Projects do not have risks</u>; projects are done to alleviate risks identified and quantified (our emphasis). Projects that must be done to comply with legislation, regulations or codes were not "demand"; they are non-discretionary, as the Chair noted, or required by law. System renewal projects should not be subdivided into sustaining or "development", and so on. HONI, or at least the rest of us, could benefit by HONI standardizing its vocabulary to the rest of the electricity distribution industry.

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The plan does not seem to address modernization and automation of the grid in a significant way, other than through enlargement of a power quality program, which BOMA supports.

HONI does not commit to a specific improvement in reliability in the plan, as an output of the increased capital budget. While BOMA understands that factors other than equipment conditions affect reliability, HONI does not try to quantify other than in a very simplistic manner, what the reliability impacts of the different plan capex options are (I-29-Staff-164, p3).

Benchmarking

The Rate Handbook contains Specific Consideration for Custom Incentive Rate setting for applicants. At pp25-26, it states:

> *"Benchmarking: Benchmarking is a fundamental requirement of a Custom IR application, both internal benchmarking to demonstrate continuous improvement and external benchmarking as identified in Section 5. A Custom IR application without benchmarking will be considered incomplete."*

Section 5 requires that utilities seeking approval for custom IR plans submit both external and internal benchmarking, the latter to assess continuous improvement by the utility over time (Rate Handbook, p18).

The Board made it clear that:

> *"...the OEB will place greater reliance on benchmarking evidence for a Custom IR application to assess proposals over the five year term."* (Ibid)

The Board also emphasized:

> *"What is important is that the utility explains how it has interpreted the benchmarking and what actions it has taken as a result of it." (p18), and " In reviewing benchmarking, the OEB will consider: ... The linkages between the results of the benchmarking and the proposals in the rate application".* (p19)

In this case, HONI has provided a benchmarking study by Navigant/First Quartile for poles and stations, and a benchmarking study for vegetation management. However, the latter was superseded by a study by Clear Path, based on the author's experience with the Clear Path's vegetation management methodology at Pacific Gas and Electric. The Navigant/First Quartile cost benchmarking study used a peer group, not an econometric approach.

The Navigant/First Quartile study had a very small number of respondents against which to compare HONI's costs of pole and station refurbishments, eleven for poles replacement costs, and four for stations.

The data, such as it was, showed that for the eleven comparable peers, HONI's unit cost was 16% higher than the average of the group, $8.266 million vs. $7.105 million. After the removal of one very low cost outlier, the differential declined to 6%. However, the report failed to remove a very high cost outlier, when such removal would have negatively impacted HONI's position relative to its peers.

In BOMA's view, the Navigant study was not a useful benchmarking exercise. It looked at only three years of data (for the internal benchmarking), and the samples were too small to be statistically valid. It did not explain why it only used three years of data. The authors appeared to make only a modest effort to obtain data from more sources. As a result, HONI did not meet the Board's requirements for benchmarking to support its application.

That said, the report did make a number of interesting "best practice" recommendations for both poles and station remediation, including a poles refurbishment program, more intensive pole testing, centralized rather than district decision making on pole replacements, the need for a more formal change order process at HONI, earlier detailed engineering estimates on station remediation projects up to one year before construction is due to begin, a formal data governance process, and better information on maintenance results.

HONI did indicate that it was looking into a refurbishment program, but it was not a high priority during the proposed five year plan period. HONI stated that if they had extra funds to spend on poles, they would spend them to replace more poles in poor condition, regardless of the substantial cost advantages (one-seventh the cost, according to the study) of refurbishment over replacement, and the fact that HONI estimated that (10,000) 14% to 15% of the 72,000 poles HONI proposes to replace over the five year period, would be candidates for refurbishment. HONI also noted that refurbishment used up OM&A dollars, while replacement was capital. To summarize, HONI did not take the refurbishment recommendation seriously, notwithstanding that their expert recommended it. HONI appeared to try to discredit and diminish the refurbishment idea during cross-examinations. BOMA could not determine to what extent HONI intends to adopt the other best practice recommendation of Navigant. HONI did not appear to explicitly address them, although Mr. Bowness did state that they were re-examining their estimating practices, and the need for centralized equipment replacement decisions.

Vegetation Management

The Board retained Clear Path and Arbour Metrics to conduct a Forestry Survey Assessment. It was completed on November 10, 2017 and filed as part of the December 17, 2017 update of HONI's evidence (Exhibit Q, Tab 1, Schedule 1, Attachment 2).

The vegetation management study was done at the Board's request. The vegetation management program is a very large program, with a current budget of $140 million, and forecast to be in the $140 million to $150 million range, through the five year plan term, a total of approximately $750 million (Tr 5, p168). $150 million per year is approximately 25% of HONI's annual OM&A budget.

Vegetation intrusion is the largest cause of outages and has a major impact on reliability. The Clear Path report was critical of HONI's traditional approach to vegetation management, and stated that up to 50% of the historic spending on vegetation management did not improve the safety or reliability of the distribution network. It was also gold-plated. Based on this study, HONI has developed a new vegetation management strategy that maintains corridors on a three year cycle, focusing on defects removal including defects from "off-corridor" hazard trees, rather than clearing all vegetation within the corridor as the current program does, together with supporting quality assurance and quality control programs.

HONI stated the new program is not likely to reduce overall costs of vegetation management until 2023 (Exhibit Q, Tab 1, Schedule 1, p14). However, Clear Path estimated that the minimum amount to implement the program would be $325 million over three years, or approximately $108 million per year. That cost (Tr 5, pp171-172) depended on productivity forecasts of HONI's workers, on which Clear Path had only partial information. Yet HONI had estimated $145 million per year for each year of the plan. BOMA would suggest the cost, in the later years 2021, 2022, be reduced to $120 million, assuming that HONI would, and should, maintain the productivity of the utilities, reports of which Clear Path had used to derive the cost estimate. That would also be a productivity improvement over the term, as required by custom IR applicants. It may not affect the costs over the next few years, because of the backlog. However, the study's authors stated that reliability should be substantially improved, as the study's authors claim that outages due to vegetation interference are to decline 20% to 40% from current levels by 2020.

BOMA suggests the new program as a worthwhile, promising initiative, with potential for significant improvements in reliability for which management should be commended. BOMA assumes that the program would maintain its high priority in the OM&A budget, and notes that the program was presented by HONI mostly as a way to increase reliability and safety, not a cost reduction measure. It may have some second order impact on costs of other activities. However, the "proof of the pudding will be in the eating" for this initiative, and results will need to be carefully monitored, and all the necessary data collected over the plan term. BOMA wonders why it took HONI so long, and the arrival of a senior manager from PGE to the company, to move the company off its traditional approach, which clearly was not working.

Productivity and Continuous Improvement

The Board made clear that annual productivity improvements due to specifically defined productivity initiatives over and above the productivity enhancements due to the productivity factor and stretch factors are required as part of a custom IR application, and that it is not enough for productivity to be embedded in the plan. The productivity and stretch factor HONI proposes for the annual adjustment factor are modest, zero for the productivity factor and 0.45% for the "stretch factor".

The 2018-2023 business plan provides the most recent forecast of expenditures on productivity initiatives over the period 2018-2023. HONI's forecast savings, capital, OM&A and corporate common expenditures (updated) are $398 million over the DSP plan period 2018-2022. (These numbers do not quite match the numbers provided at I-25-Staff-123, p21). HONI describes the savings estimate as "stretch target", for which BOMA takes them to be somewhat aspirational (Exhibit A, Tab 2, Schedule 1, pp21-22). While a few details of each of the productivity initiatives are provided at I-25-Staff-123, p2, the costs of each of the initiatives are not provided, so the cost benefit analysis is not available. The capital and OM&A costs of the measures are simply embedded in the annual capital and OM&A budgets.

BOMA notes that savings projected for the forestry initiative, on the Table in I-25-Staff-123, p2, of approximately $27 million, is at odds with HONI's evidence on vegetation management, which does not predict any cost savings for the new vegetation management program until 2023.

HONI says that it has included the savings and presumably the capital and OM&A costs in the business plan, and the internal management corporate scorecard, used to incent employees to focus on company priorities, but does not intend to report the savings from the various productivity initiatives to the Board or stakeholders on an initiative by initiative basis. The company intends to put on the public record only the total annual savings from productivity measures in the aggregate as part of its Annual Report (J8.4). However, given the costs of generating the savings are included in the company's capital budget and OM&A budget, it is important that ratepayers and the Board obtain reports on at least an annual basis, to determine if the productivity initiatives are generating the intended forecast savings. In other words, is productivity of the company actually increasing, and which initiatives are working and which are not. BOMA recommends that the company be required to file, as part of the annual adjustment process, reports on each productivity initiative listed in Staff-123, including actual savings, with a discussion of any deviation from the savings targets or the capital and OM&A's pending forecasts. The company states that the information is now being generated for the purpose of determining its contribution to annual income.

The Board has previously stated that it is not sufficient for a utility to state that the capital and OM&A expenditures and the savings are embedded in the DSP or the business plan. The information filed should be filed once it has been accepted by the Finance Department of the company, which has the role of verifying the savings. The calculation on which the forecast savings are based should also be part of the report.

With respect to the proposed savings from the "move to mobile", the company did not explain how it developed the forecast savings of 5% of its total distribution budget, or what was included in that budget. It seemed like an "educated guess".

It is important to have more transparency on such an important matter.

The Acquired Utilities

HONI proposes to integrate the three recently acquired utilities (Haldimand, Norfolk, and Woodstock) (the "three acquired LDCs") into its revenue requirement for the 2021 and 2022 rate years. For the years 2018, 2019, and 2020, HONI's revenue requirement will not include the rate base and OM&A and revenue for the three acquired LDCs. HONI has crated six new rate classes; two for each of the three acquired LDCs. The ratepayers of the three acquired LDCs will not inherit HONI's existing rates as hoped with many of HONI's earlier acquisitions, because to do so, would have meant large rate increases for Haldimand, Norfolk, and Woodstock. It also set the revenue/cost ratios of the ratepayers.

The Board had directed HONI, at the time of its acquisition of the three acquired LDCs, to ensure that upon the integration with HONI, allocate to the three acquired LDCs only the costs actually incurred to serve them. Pursuant to the direction, HONI did not allocate costs to the three acquired LDCs on the basis of HONI's existing cost allocation model. Had it done so, it would have allocated $571 million of costs to them. Instead, HONI made a series of adjustments which HONI's cost to serve to reduce the costs to $281 million, about 50% of $571 million. The difference in the two amounts of $250 million will be recovered from HONI's remaining customers.

HONI used a series of adjustment factors which were different for each of the six new rate classes. These factors were not explained in any detail. HONI also, as noted above, set the revenues and cost ratios for the six rate classes at 0.8, the least permissible ratio under Board policy.

The gap between the unadjusted and adjusted costs allocated to the six rate classes for the three acquired LDCs is very large, as HONI's cost base which is much higher than that of the three acquired LDCs. This difference in cost effectiveness results in HONI's existing ratepayers subsidizing the ratepayers in the six new rate classes.

This is the opposite result of the earlier 2000/2001 acquisition by HONI, which saw rates of the acquired utilities increase by very large double digit and triple digit amounts, as they were simply charged HONI's rates once the five year "rate holiday" expired.

BOMA agrees with Schools that HONI does not have a viable policy to integrate acquisitions into the HONI rate structure. It is making it up as it goes along with short-term fixes and arbitrary changes to its cost allocation framework. BOMA believes that the Board should not approve the six new rate classes at this time. It should direct HONI to have an independent expert review its acquisition and harmonization strategies with respect to other Ontario utilities, and develop policy which is fair to existing customers and customers of the companies to be acquired, is sustainable, and practical, and which should be used for future acquisitions by HONI or other Ontario distributors who wish to make acquisitions. The Board should then hold a generic hearing on the issue, and promulgate policy guidelines. In the meantime, BOMA suggests the Board adopt Schools' suggestion that starting in 2021, the three acquired companies pay rates increase equivalent to the weighted average increase, for those years of all existing HONI customers.

II.

In this section of the Argument, BOMA will provide its position on the issues on the Issues List that have not been discussed. Reference will be made to earlier sections that discuss the issue in question.

Planning Process

BOMA is not convinced that HONI's planning process and planning decision-making result in a fully supportable capital budget.

HONI is concerned about:

- the timing of the planning process in relation to other aspects of the preparation of the DSP and the application to the Board;
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- the availability of complete data on asset condition, in particular the lack of data on defects discovered in the lines and related equipment, and information about the repairs that were made;
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- the fact that most general plant investments are ranked high priority, while most system renewal and system service projects are ranked medium priority
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The company's evidence is that the main themes for the DSP were decided by the planning group before the final report of the customer engagement was available. That sequence seems wrong and is evidence that the results of the IPSOS study was treated casually rather than seriously.

As a related matter, BOMA does not understand why the top level financial guidance from the senior executives is not made available to planners. the evidence was that the company targeted a 4.2% annual growth in capital expenditures in order to realize its allowed ROE over the plan term. Surely, it would assist the planners to prioritize these proposed projects in their planning sector at the outset, and make the later stages of the selection process easier. Generally, BOMA would encourage closer collaboration between the planners and the executors, and with other elements in the company, including financial. The planning staff still seems to exist in an "ivory tower" within the company.

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In this case, HONI has provided a benchmarking study by Navigant/First Quartile for poles and stations, and a benchmarking study for vegetation management. However, the latter was superseded by a study by Clear Path, based on the author's experience with the Clear Path's vegetation management methodology at Pacific Gas and Electric. The Navigant/First Quartile cost benchmarking study used a peer group, not an econometric approach.

The Navigant/First Quartile study had a very small number of respondents against which to compare HONI's costs of pole and station refurbishments, eleven for poles replacement costs, and four for stations.

The data, such as it was, showed that for the eleven comparable peers, HONI's unit cost was 16% higher than the average of the group, \$8.266 million vs. \$7.105 million. After the removal of one very low cost outlier, the differential declined to 6%. However, the report failed to remove a very high cost outlier, when such removal would have negatively impacted HONI's position relative to its peers.

In BOMA's view, the Navigant study was not a useful benchmarking exercise. It looked at only three years of data (for the internal benchmarking), and the samples were too small to be statistically valid. It did not explain why it only used three years of data. The authors appeared to make only a modest effort to obtain data from more sources. As a result, HONI did not meet the Board's requirements for benchmarking to support its application.

That said, the report did make a number of interesting "best practice" recommendations for both poles and station remediation, including a poles refurbishment program, more intensive pole testing, centralized rather than district decision making on pole replacements, the need for a more formal change order process at HONI, earlier detailed engineering estimates on station remediation projects up to one year before construction is due to begin, a formal data governance process, and better information on maintenance results.

HONI did indicate that it was looking into a refurbishment program, but it was not a high priority during the proposed five year plan period. HONI stated that if they had extra funds to spend on poles, they would spend them to replace more poles in poor condition, regardless of the substantial cost advantages (one-seventh the cost, according to the study) of refurbishment over replacement, and the fact that HONI estimated that (10,000) 14% to 15% of the 72,000 poles HONI proposes to replace over the five year period, would be candidates for refurbishment. HONI also noted that refurbishment used up OM&A dollars, while replacement was capital. To summarize, HONI did not take the refurbishment recommendation seriously, notwithstanding that their expert recommended it. HONI appeared to try to discredit and diminish the refurbishment idea during cross-examinations. BOMA could not determine to what extent HONI intends to adopt the other best practice recommendation of Navigant. HONI did not appear to explicitly address them, although Mr. Bowness did state that they were re-examining their estimating practices, and the need for centralized equipment replacement decisions.

Vegetation Management

The Board retained Clear Path and Arbour Metrics to conduct a Forestry Survey Assessment. It was completed on November 10, 2017 and filed as part of the December 17, 2017 update of HONI's evidence (Exhibit Q, Tab 1, Schedule 1, Attachment 2).

The vegetation management study was done at the Board's request. The vegetation management program is a very large program, with a current budget of $140 million, and forecast to be in the $140 million to $150 million range, through the five year plan term, a total of approximately $750 million (Tr 5, p168). $150 million per year is approximately 25% of HONI's annual OM&A budget.

Vegetation intrusion is the largest cause of outages and has a major impact on reliability. The Clear Path report was critical of HONI's traditional approach to vegetation management, and stated that up to 50% of the historic spending on vegetation management did not improve the safety or reliability of the distribution network. It was also gold-plated. Based on this study, HONI has developed a new vegetation management strategy that maintains corridors on a three year cycle, focusing on defects removal including defects from "off-corridor" hazard trees, rather than clearing all vegetation within the corridor as the current program does, together with supporting quality assurance and quality control programs.

HONI stated the new program is not likely to reduce overall costs of vegetation management until 2023 (Exhibit Q, Tab 1, Schedule 1, p14). However, Clear Path estimated that the minimum amount to implement the program would be $325 million over three years, or approximately $108 million per year. That cost (Tr 5, pp171-172) depended on productivity forecasts of HONI's workers, on which Clear Path had only partial information. Yet HONI had estimated $145 million per year for each year of the plan. BOMA would suggest the cost, in the later years 2021, 2022, be reduced to $120 million, assuming that HONI would, and should, maintain the productivity of the utilities, reports of which Clear Path had used to derive the cost estimate. That would also be a productivity improvement over the term, as required by custom IR applicants. It may not affect the costs over the next few years, because of the backlog. However, the study's authors stated that reliability should be substantially improved, as the study's authors claim that outages due to vegetation interference are to decline 20% to 40% from current levels by 2020.

BOMA suggests the new program as a worthwhile, promising initiative, with potential for significant improvements in reliability for which management should be commended. BOMA assumes that the program would maintain its high priority in the OM&A budget, and notes that the program was presented by HONI mostly as a way to increase reliability and safety, not a cost reduction measure. It may have some second order impact on costs of other activities. However, the "proof of the pudding will be in the eating" for this initiative, and results will need to be carefully monitored, and all the necessary data collected over the plan term. BOMA wonders why it took HONI so long, and the arrival of a senior manager from PGE to the company, to move the company off its traditional approach, which clearly was not working.

Productivity and Continuous Improvement

The Board made clear that annual productivity improvements due to specifically defined productivity initiatives over and above the productivity enhancements due to the productivity factor and stretch factors are required as part of a custom IR application, and that it is not enough for productivity to be embedded in the plan. The productivity and stretch factor HONI proposes for the annual adjustment factor are modest, zero for the productivity factor and 0.45% for the "stretch factor".

The 2018-2023 business plan provides the most recent forecast of expenditures on productivity initiatives over the period 2018-2023. HONI's forecast savings, capital, OM&A and corporate common expenditures (updated) are $398 million over the DSP plan period 2018-2022. (These numbers do not quite match the numbers provided at I-25-Staff-123, p21). HONI describes the savings estimate as "stretch target", for which BOMA takes them to be somewhat aspirational (Exhibit A, Tab 2, Schedule 1, pp21-22). While a few details of each of the productivity initiatives are provided at I-25-Staff-123, p2, the costs of each of the initiatives are not provided, so the cost benefit analysis is not available. The capital and OM&A costs of the measures are simply embedded in the annual capital and OM&A budgets.

BOMA notes that savings projected for the forestry initiative, on the Table in I-25-Staff-123, p2, of approximately $27 million, is at odds with HONI's evidence on vegetation management, which does not predict any cost savings for the new vegetation management program until 2023.

HONI says that it has included the savings and presumably the capital and OM&A costs in the business plan, and the internal management corporate scorecard, used to incent employees to focus on company priorities, but does not intend to report the savings from the various productivity initiatives to the Board or stakeholders on an initiative by initiative basis. The company intends to put on the public record only the total annual savings from productivity measures in the aggregate as part of its Annual Report (J8.4). However, given the costs of generating the savings are included in the company's capital budget and OM&A budget, it is important that ratepayers and the Board obtain reports on at least an annual basis, to determine if the productivity initiatives are generating the intended forecast savings. In other words, is productivity of the company actually increasing, and which initiatives are working and which are not. BOMA recommends that the company be required to file, as part of the annual adjustment process, reports on each productivity initiative listed in Staff-123, including actual savings, with a discussion of any deviation from the savings targets or the capital and OM&A's pending forecasts. The company states that the information is now being generated for the purpose of determining its contribution to annual income.

The Board has previously stated that it is not sufficient for a utility to state that the capital and OM&A expenditures and the savings are embedded in the DSP or the business plan. The information filed should be filed once it has been accepted by the Finance Department of the company, which has the role of verifying the savings. The calculation on which the forecast savings are based should also be part of the report.

With respect to the proposed savings from the "move to mobile", the company did not explain how it developed the forecast savings of 5% of its total distribution budget, or what was included in that budget. It seemed like an "educated guess".

It is important to have more transparency on such an important matter.

The Acquired Utilities

HONI proposes to integrate the three recently acquired utilities (Haldimand, Norfolk, and Woodstock) (the "three acquired LDCs") into its revenue requirement for the 2021 and 2022 rate years. For the years 2018, 2019, and 2020, HONI's revenue requirement will not include the rate base and OM&A and revenue for the three acquired LDCs. HONI has crated six new rate classes; two for each of the three acquired LDCs. The ratepayers of the three acquired LDCs will not inherit HONI's existing rates as hoped with many of HONI's earlier acquisitions, because to do so, would have meant large rate increases for Haldimand, Norfolk, and Woodstock. It also set the revenue/cost ratios of the ratepayers.

The Board had directed HONI, at the time of its acquisition of the three acquired LDCs, to ensure that upon the integration with HONI, allocate to the three acquired LDCs only the costs actually incurred to serve them. Pursuant to the direction, HONI did not allocate costs to the three acquired LDCs on the basis of HONI's existing cost allocation model. Had it done so, it would have allocated $571 million of costs to them. Instead, HONI made a series of adjustments which HONI's cost to serve to reduce the costs to $281 million, about 50% of $571 million. The difference in the two amounts of $250 million will be recovered from HONI's remaining customers.

HONI used a series of adjustment factors which were different for each of the six new rate classes. These factors were not explained in any detail. HONI also, as noted above, set the revenues and cost ratios for the six rate classes at 0.8, the least permissible ratio under Board policy.

The gap between the unadjusted and adjusted costs allocated to the six rate classes for the three acquired LDCs is very large, as HONI's cost base which is much higher than that of the three acquired LDCs. This difference in cost effectiveness results in HONI's existing ratepayers subsidizing the ratepayers in the six new rate classes.

This is the opposite result of the earlier 2000/2001 acquisition by HONI, which saw rates of the acquired utilities increase by very large double digit and triple digit amounts, as they were simply charged HONI's rates once the five year "rate holiday" expired.

BOMA agrees with Schools that HONI does not have a viable policy to integrate acquisitions into the HONI rate structure. It is making it up as it goes along with short-term fixes and arbitrary changes to its cost allocation framework. BOMA believes that the Board should not approve the six new rate classes at this time. It should direct HONI to have an independent expert review its acquisition and harmonization strategies with respect to other Ontario utilities, and develop policy which is fair to existing customers and customers of the companies to be acquired, is sustainable, and practical, and which should be used for future acquisitions by HONI or other Ontario distributors who wish to make acquisitions. The Board should then hold a generic hearing on the issue, and promulgate policy guidelines. In the meantime, BOMA suggests the Board adopt Schools' suggestion that starting in 2021, the three acquired companies pay rates increase equivalent to the weighted average increase, for those years of all existing HONI customers.

<u>II.</u>

In this section of the Argument, BOMA will provide its position on the issues on the Issues List that have not been discussed. Reference will be made to earlier sections that discuss the issue in question.

A. General

1. *Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?*

HONI has responded appropriately, except that the Navigant study did not respond to the internal benchmarking requirement as the report covered only three years.

2. *Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?*

No, it has not. See DSP/Customer Engagement.

3. *Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?*

No, it is not. See DSP/Capital Budget section.

4. *Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?*

No, they are not. See as in 3. above.

5. *Are Hydro One's proposed rate impact mitigation measures appropriate and do any of the proposed rate increases require rate smoothing or mitigation beyond what Hydro One has proposed?*

No, they have not. HONI has proposed no such measures, except for distributed generation customers. BOMA supports those mitigation measures.

6. *Does Hydro One's First Nation and Métis Strategy sufficiently address the unique rights and concerns of Indigenous customers with respect to Hydro One's distribution service?*

BOMA supports HONI's efforts to engage with First Nations and in general, its First Nations strategy, and the Settlement Agreement between HONI, First Nations, and Métis.

B. Custom Application

7. *Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?*

See section on Custom IR/RRFE.

8. *Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?*

BOMA supports the 0% productivity factor, the 0.45% stretch factor, and the 2% inflation factor.

9. *Are the values for the proposed custom capital factor appropriate?*

The values are not appropriate. See discussion at Section 1.

10. *Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?*

The productivity study is broadly appropriate. The Navigant benchmarking study on poles and stations is not appropriate. See discussion under "Benchmarking".

11. *Are the results of the studies sufficient to guide Hydro One's plans to achieve the desired outcomes to the benefit of ratepayers?*

See section on Benchmarking.

12. *Do these studies align with each other and with Hydro One's overall custom IR Plan?*

The studies are very different, are program specific, and do not align one with another.

13. *Are the annual updates proposed by Hydro One appropriate?*

BOMA supports, in part, the annual adjustment, but would add an update on productivity initiatives and the savings so created, as discussed in the Productivity and Continuous Improvement section. BOMA does not support an update to the cost of capital as part of the

2021 rates. The Board should maintain its existing policy. In general, due to the fact that the first HONI Distribution custom IR since the RRFE was established, the annual review should be a little more substantive than proposed by HONI.

14. *Is Hydro One's proposed integration of the Acquired Utilities in 2021 appropriate?*

Please see section on Acquired Utilities for comments. BOMA notes that the three acquired utilities will, in total, add only $25.6 million to the 2021 HONI revenue requirement (J2.2).

15. *Is the proposed Earnings/Sharing mechanism appropriate?*

BOMA believes that the earnings sharing proposal should have no deadband. Any refunds should be returned to customers as part of the annual rate adjustment proceeding, on an annual basis, not at the time of rebasing.

16. *Are the proposed Z-factors and Off-Ramps appropriate?*

BOMA proposes that the materiality factor of $3.0 million, on a revenue requirement basis. The scope of the Z-factor should be as defined in the Enbridge case (EB-2012-0459). The Board's existing off-ramp policy is appropriate, except that earnings above or below a 300 basis deadband should <u>require</u> a review of the revenue requirement and related issues (our emphasis).

C. Outcomes, Scorecard and Incentives

17. *Does the application adequately incorporate and reflect the four outcomes identified in the Rate Handbook: customer focus, operational effectiveness, public policy responsiveness, and financial performance?*

BOMA believes that HONI's application does not reflect some of the outcomes identified in the RRFE and Rate Handbook, including customer focus and operational effectiveness. Please see the sections on the Customer Focus and Productivity Initiatives.

18. *Are the metrics in the proposed additional scorecard measures appropriate and do they adequately reflect appropriate outcomes?*

19. *Are the proposals for performance monitoring and reporting adequate and do the outcomes adequately reflect customer expectations?*

20. *Does the application promote and incent appropriate outcomes for existing and future customers including factors such as cost control, system reliability, service quality, and bill impacts?*

Both the Board's Electricity Distributor Scorecard and HONI's Distribution OEB Scorecard are seriously deficient in that they will not incent progress towards meeting customer expectations. For example:

- several elements in the two scorecards lack targets
- the targets that do exist are not challenging enough; some set achievement levels worse than levels already achieved in earlier years, for example, outages and unit cost targets.

BOMA also believes that the Team Scorecard should be made public in order to confirm the linkage between the goals which employees are incented to meet, and the regulatory scorecard. Perhaps the corporate income target could remain redacted.

21. *Does the application adequately account for productivity gains in its forecasts and adequately include expectations for gains relative to external benchmarks?*

See discussion of productivity gain in that section of the Report.

22. *Has the applicant adequately demonstrated its ability and commitment to manage within the revenue requirement proposed over the course of the custom incentive rate plan term?*

See discussion in the DSP/Capital Budget section of BOMA's Argument.

D. Distribution System Plan

23. *Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?*

It was not, and it does not. See the discussion in the RRFE/Customer Engagement section of BOMA's Argument.

24. *Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?*

See the discussion in the DSP/Capital Budget part of BOMA's Argument.

25. *Does the Distribution System Plan adequately reflect productivity gains, benefit sharing and benchmarking?*

See the sections of the report on Productivity, Benchmarking and the RRFE.

26. *Does the Distribution System Plan address the trade-offs between capital and OM&A spending over the course of the plan period?*

BOMA believes HONI did not evaluate the maintenance cost savings resulting from its proposed capital expenditures. Its comments were mostly defensive in nature.

27. *Has the distribution System Plan adequately addressed government mandated obligations over the planning period?*

HONI did not address the distributed generation in any serious manner in its application.

28. *Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?*

BOMA has no issue with the DSP and regional planning.

29. *Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?*

See the DSP/Capital Budget part of BOMA's Argument.

30. *Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?*

See the DSP/Capital Budget part of BOMA's Argument.

31. *Are the methodologies used to allocate Common Corporate capital expenditures to the distribution business appropriate?*

BOMA does not object to HONI's methods used to allocate common corporate capital expenditures.

32. *Are the methodologies used to determine the distribution Overhead Capitalization Rate for 2018 and onward appropriate?*

BOMA suggests the continued use of US GAAP as a basis for capitalizing overhead.

E. Rate Base & Cost of Capital

33. *Are the amounts proposed for the rate base from 2018 to 2022 appropriate?*

Please see the DSP/Capital Budget part of BOMA's Argument.

34. *Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?*

BOMA supports the 7.7% level for working capital.

35. *Is the proposed capital structure appropriate?*

BOMA supports HONI's proposed capital structure. It complies with Board policy.

36. *Are the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rate implementation appropriate?*

BOMA accepts the approach outlined by HONI, except for the proposal to update cost of capital in 2020 for 2021 rates.

37. *Is the forecast of long term debt for 2018 and further years appropriate?*

BOMA would support HONI's approach generally, but does not support the proposed "update".

F. Operations Maintenance & Administration Costs

38. *Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?*

BOMA supports Board staff's submission on OM&A expenses, in particular HONI's too high compensation relative to peers, uncertain and opaque productivity savings, and the failure to recognize likely OM&A reductions from the proposed defect-driven vegetation management program – savings which are predicted by the Clean Path study.

39. *Do the proposed OM&A expenditures include the consideration of factors such as system reliability, service quality, asset condition, cost benchmarking, bill impact and customer preferences?*

BOMA believes that the OM&A does not take into account customer preferences (no increase in customer service if it results in rate increases). The author of Clear Path has forecasted substantial impacts on vegetation intrusion driven outages and reliability, but they are not realized as yet. This data should be monitored quarterly and reported annually to the Board and stakeholders. Clear Path stated that initial improvements should be apparent by the second half of 2018.

40. *Are the proposed 2018 human resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate?*

BOMA supports Board staff submission on compensation.

41. *Has Hydro One demonstrated improvements in presenting its compensation costs and showing efficiency and value for dollar associated with its compensation costs?*

BOMA believes that HONI's evidence was overly complicated, in too many separate submissions. HONI should fully comply with the Board's directions in its September 28, 2017 Decision and Order.

42. *Is the updated executive compensation information filed by Hydro One in the distribution proceeding on December 21, 2017 consistent with the OEB's findings on executive compensation in the EB-2016-0160 Transmission Decision?*

No submission, pursuant to the Board's August 3, 2018 letter.

43. *Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the distribution business for 2018 and further years appropriate?*

BOMA agrees the methodologies are appropriate.

G. Revenue Requirement

44. *Is Hydro One's proposed depreciation expense for 2018 and further years appropriate?*

BOMA supports HONI's proposed depreciation and amortization expense.

45. *Are the proposed other revenues for 2018 – 2022 appropriate?*

BOMA's believes that the service charges for which HONI is requesting substantial revenues should not be approved at this time. HONI should be directed to consult with customers on their proposed substantial increases.

H. Load and Revenue Forecast

46. *Is the load forecast methodology including the forecast of CDM savings appropriate?*

BOMA supports the load forecast but suggests that the Board direct HONI to divide the province into weather regions rather than continue to use only Toronto airport.

47. *Are the customer and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?*

BOMA agrees that the customer and load forecasts are a reasonable reflection of the energy and demand requirements for the plan period.

48. *Has the load forecast appropriately accounted for the addition of the Acquired Utilities' customers in 2021?*

BOMA agrees the load forecast has appropriately accounted for the addition of the acquired utilities' customers in 2021.

I. Cost Allocation and Rate Design

49. *Are the inputs to the cost allocation model appropriate and are costs appropriately allocated?*

BOMA is of the view that the impacts to the cost allocation model are appropriate and that costs are appropriately allocated, except for the acquired utilities, where a generic study is required. See BOMA's argument in the Acquired Utilities part of its submission.

50. *Are the proposed billing determinants appropriate?*

BOMA agrees with the proposed billing determinants.

51. *Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?*

BOMA supports the revenue-to-cost ratios, save for the acquired utilities.

52. *Are the proposed fixed and variable charges for all rate classes over the 2018 – 2022 period, appropriate, including implementation of the OEB's residential rate design?*

BOMA urges the Board to direct HONI to adopt the method outlined in RRFW.

53. *Are the proposed Retail Transmission Service Rates appropriate?*

BOMA supports the proposed Retail Transmission Service Rates.

54. *Are the proposed specific service charges for miscellaneous services over the 2018 – 2022 period reasonable?*

See Issue 45.

56. *Do the costs allocated to acquired utilities appropriately reflect the OEB's decisions in related Hydro One acquisition proceedings?*

BOMA does not agree that the allocation should be made at this time, pending a more general study.

J. Deferral/Variance Accounts

57. *Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?*

58. *Are the proposed new deferral and variance accounts appropriate?*

59. *Is the proposal to discontinue several deferral and variance accounts appropriate?*

BOMA supports Board staff's proposals on these issues.

All of which is respectfully submitted, August 9, 2018.

Tom Brett

Tom Brett
Counsel for BOMA