January 14, 2022

Ontario Energy Board
2300 Yonge Street, 27th Floor
P.O. Box 2319
Toronto, ON M4P 1E4
Attention: Registrar

Dear Registrar:

Re: Reliability and Power Quality Review Comments
Board File no. EB-2021-0307

Halton Hills Hydro Inc. ("HHHI") thanks the Ontario Energy Board ("OEB") for the opportunity to comment on the Reliability and Power Quality Review ("RPQR") and in particular, the questions put forth by the OEB in the November 30, 2021 letter.

HHHI is in a unique position to comment on the RPQR proceeding as HHHI was involved in the working group for the initial proceeding (EB-2010-0249). Many of the topics raised in Appendix A of the November 30, 2021 letter had been discussed before at the original review.

HHHI has responded to the general questions and provided feedback on the potential issues and the questions identified in the letter in Appendix A.

In the event of any additional information, questions or concerns, please contact David Smelsky, Chief Financial Officer, at dsmelsky@haltonhillshydro.com or (519) 853-3700 extension 208, or Tracy Rehberg-Rawlingson, Regulatory Affairs Officer, at tracyr@haltonhillshydro.com or (519) 853-3700 extension 257.

Sincerely,

Tracy Rehberg-Rawlingson

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Regulatory Affairs Officer, HHHI

Cc: Scott Knapman, President & CEO, HHHI
David J. Smelsky, CFO, HHHI
Matthew Wright, Operations Manager, HHHI

Appendix A – Questions for Stakeholders' Consideration

General Questions

- **Do stakeholders have a view on the approach, including prioritization, to addressing the identified issues? What is the best approach to develop solutions to the issues identified? What issues or concerns can be addressed in parallel and what issues or concerns shall be tackled in sequence?**

  While HHHI feels that the identified issues have merit, HHHI wonders if the OEB has considered a cost benefit analysis to determine whether investigating these issues provides value to all ratepayers. The question becomes one of diminishing returns. How much money should LDCs expend to reach a possibly, unattainable goal of perfect reliability? LDCs in the province design their distribution and transmission systems to optimize benefits to the grid, minimize operational risks and provide a safe, cost effective and reliable network for staff and customers. There will always be a worst performing feeder, worst performing circuit and customer with more outages and longer outages. Additionally, given the distinctiveness of each LDC, how would the OEB purport to determine a provincial level of reliability that would be fair to the uniqueness of each LDC? Currently, some LDCs could provide the information requested immediately, while others would require additional investments in infrastructure and software to provide the information, let alone detail how to improve the metric.

- **Do stakeholders have any specific concerns or issues that have not been identified?**

  HHHI believes that the possible cost to ratepayers to provide the reporting and improvement to metrics identified may be cost prohibitive and should be considered at all levels of discussions. Additionally, there should be consideration to the idea that customers themselves have the ability to access technology in order to mitigate reliability and power quality concerns.

Utility Accountability

- **OEB staff's assessment of distributors' reported data suggests that there may be a significant gap in reporting between transmitters, host distributors and embedded distributors in terms of delivery point/loss of supply outages. Outages reported under loss of supply and major events account for more than 50% of the total number of outages in the province. What type of improvements to transmission and/or distribution reporting and/or performance expectations should be considered to increase utilities' responsibilities for loss of supply events? What are stakeholders' views on the appropriate form of incentives to drive reliability performance?**

The removal of Major Events and Loss of Supply from outage metrics is intended to normalize the outage information for controllable actions by the LDC. Major Events and Loss of Supply are generally out of the LDC's control.

Perhaps the OEB should focus more on the causes of Loss of Supply to determine where more focus would be warranted.

HHHI would also like to note that Loss of Supply could apply to upstream distribution/transmission maintenance. For example, if the upstream distributor/transmitter needs to do maintenance on a feeder, the downstream LDC has the option to 1) face lack of supply resulting from the maintenance to the detriment of the downstream LDC's customers, or to 2) transfer load to another feeder. In option 1, customers may be without power for an extended duration, but it will not affect the final outage metrics as it would be classified as loss of supply. In option 2, the customer may still have power, however, the LDC may be forced to pay for double peak billing as the load is shifted to another feeder; this option will also, ultimately, negatively affect the customer as the customers will be required to pay for any variances resulting through rate riders. Perhaps the OEB could consider any charges due to loss of supply that may normally result in double peak billing, to be borne by the upstream distributor/transmitter to ensure that downstream LDCs and their customers not be penalized in any way. HHHI would also like clarification of whether all LDCs classify upstream maintenance outages as loss of supply and if so, what sources they use to determine if there is a loss of supply. The scenario above could also apply to emergency outages caused by Loss of Supply where a downstream LDC shifts load to ensure a shorter outage time, but would still be billed for double peak billing. The upstream distributor/transmitter could be held responsible for any increment double peak billing charges.

HHHI's comments on Major Events is included in the response to the question below.

- **OEB staff's assessment of reported Major Events suggests that distributors have very different interpretations of what constitutes a "Major Event", which affects overall reliability performance scores. Should the OEB revise its Major Event reporting requirements to achieve a common understanding among distributors regarding the type of outages and events that should be reported under the Major Event category? Should the OEB review the effectiveness of outage restorations?**

HHHI is confused by the statement "distributors have very different interpretations of what constitutes a "Major Event", which affects overall reliability performance scores". In the previous reliability proceeding, the working group determined that IEEE Standard 1366 or a fixed percentage of customers affected would determine whether outages constituted a Major Event. Either of the aforementioned options is formula based with little chance of misinterpretation. When a Major Event occurs, LDCs are required to file a report that indicates which method was used to categorize the outage as a Major Event.

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Additionally, it is the responsibility of the LDC to effectively, quickly and safely restore power to their customers. In cases of severe events, customers understand that there is the possibility of outages. If the customer is not satisfied with the response of the LDC, they have the ability to submit a complaint to the OEB. At that time, the OEB may choose to review the effectiveness of the outage restoration using the LDC Major Event report filed. It is not the responsibility, nor the expertise, of the OEB to evaluate and dictate how restorations should occur as each situation is different and the LDC is in the best position to determine how restoration should happen in the area. Should the OEB find inconsistency or irregular responses in the Major Event report, then the OEB is able to contact the LDC for further details and clarification.

- **OEB staff's assessment of historical outage data has also suggested that there are inconsistent approaches between distributors in terms of reporting outages (e.g., different interpretations between "Adverse Weather" and "Tree Contacts" defined in RRR). What is the best approach to ensure consistent outage cause reporting across the sector?**

  HHHI believes that there may be inconsistent approaches to *classifying* outages between LDCs, as opposed to inconsistent reporting. HHHI would suggest that more detailed examples and definitions, along with a priority chart, would be beneficial for ensuring more consistent reporting. For example, if a vehicle accident caused an outage but it was due to freezing rain, then a priority chart would determine if the cause was adverse weather or foreign interference.

  Additionally, the OEB and stakeholders may benefit from a joint training/discussion session that covers the causes and how they should be reported. HHHI would recommend the session be recorded so that any new staff could receive the exact same understanding.

  HHHI would like to note that the cause "Unknown" should remain a valid cause as many unknown causes can be related to animal contact, but without the evidence of the animal in question, it is difficult to determine conclusively.

<u>**Monitor Utility Performance**</u>

- **The current performance evaluation (i.e., service area level SAIFI & SAIDI) does not support benchmarking across the industry due to the different characteristic of each utility (such as size and locations). What would be required to ensure successful distributor reliability benchmarking across the sector**?

  As pointed out in the above paragraph, each LDC is unique with very different system challenges and architectures. HHHI would not suggest assigning LDCs to cohorts as the nature and number of the differences in architectures may lead to misleading comparisons. Areas of differences can relate to the obvious, including customer density, terrain, geographic location, feeders that service both urban and rural areas, weather trends and embeddedness, to the less obvious such as the municipal use of salt brine versus sand, pole heights, flora/fauna (tree and animal contacts) and local by-laws, to the utterly obscure such as intersection configurations and bad drivers.

Rather than comparing LDC to other LDCs, it would be more appropriate to ensure that each LDC can support the metrics they file. The Scorecard currently assigns a "trend" arrow. This could be used to determine the amount of information required in the Scorecard Management Discussion and Analysis. The OEB can review each LDC on a case by case basis to ensure they are managing outages appropriately.

Another option for the OEB would be to move the SAIDI and SAIFI benchmarking to an econometric calculation that takes into account all the differences.

Ultimately, as stated above, it is the responsibility of the LDC to effectively, quickly and safely restore power. If a customer is not satisfied with the response of the LDC, they have the option to complain to the OEB. At that time, the OEB may choose to request and review the cause of the outage and determine the effectiveness of the outage restoration and whether the LDC has taken necessary measures to limit future occurrences. It is not the responsibility of the OEB to evaluate and dictate how restorations should occur as each situation is different and the LDC is in the best position to determine how restoration should happen.

- **Power quality and momentary outages can have a significant impact on customers. The OEB has seen an increase in customer concerns regarding these issues. Should the OEB establish reporting requirements to monitor utility performance in relation to momentary outages and power quality issues? What type of power quality issues should be and can be reported and monitored?**

Many distribution systems are designed with redundancy to ensure customers do not suffer prolonged outages. These systems are designed to "switch" from one circuit, or one feeder, to another in the case of an outage. This switching reduces the number of prolonged outages. However, with this design, there are momentary outages as the system switches. While momentary outages can be a nuisance to some customers, a momentary outage is actually evidence that the system is working as designed. HHHI understands that some customers require a constant source of power to avoid losses in product and/or productive time. In such cases, customers have the option of designing their systems by implementing readily available technology (for example DERs) to ride through outages and mitigate any losses. It can be noted that many of these customers have looked into infrastructure that can ensure a constant supply of power, however, many have decided against such action as the cost/benefit analysis does not show a favourable return. Nonetheless, HHHI is pleased to work with customers that choose to implement these types of solutions.

Similar to customers, LDCs have the ability to design systems or consider non-wire agreements (NWA) that would limit momentary outages, however, the cost to do so is currently prohibitive.

Fully automated systems would aid with both momentary outages and power quality, however, as stated above, the cost can be prohibitive. While many LDCs are attempting to add automation in their systems as they update, upgrade and expand their systems, they are still limited by the rate approval process for capital and maintenance.

In many cases, a lack of power quality is determined by customers contacting the LDC. In some cases, LDCs have the automation in place to monitor power quality and can determine, proactively, when there may be issue. However, as stated before, these abilities come with investment costs and may include potential oversight personnel and ongoing maintenance.

Customer Specific Reliability

- **Given customers' expectations are changing because of an increasing reliance on a reliable system, should the OEB develop customer-focused reliability measures that can provide greater transparency on the level of service individual customers are receiving? Along with creating customer-focused reliability standards, should the OEB consider consequences when reliability performance expectations are not met (e.g., customer compensation when reliability falls below acceptable level)?**

  HHHI recognizes that each distribution system will have varying degrees of reliability. Additionally, different customers have different expectations of reliability. In some cases, the reliability may be a direct result of ineffective systems. However, some of the cases are related to specific feeders and/or customers with many applicable factors that could contribute to reliability. Take, for example, a rural customer at the end of a radial line with a half mile laneway that includes a customer owned overhead private line to the house. This customer may face numerous reliability issues related to the length of the radial line, foliage, animals, and even tree contacts on the customer owned portion of the line. Alternatively, a customer that lives in a new subdivision with underground infrastructure in an urban setting supplied by multiple feeder points would historically face fewer reliability issues. It is possible to build a distribution system that would provide the rural customer with the same reliability as the urban customer, however, the cost would be significant. It is unlikely that the urban customer would be delighted to face increased rates so that the rural customer could have identical reliability. Additionally, there comes a point of diminishing returns whereby it no longer makes sense to invest more cost in reliability improvements. HHHI would like to understand if the OEB expects that every customer in the province should meet a minimum reliability standard and if so, 1) what would be the expected standard; and 2) how would LDCs recover the funds to ensure the standard is met? It should also be noted that some LDCs may not have the current ability to report on individual reliability and power quality without incurring significant capital asset upgrade cost to their current systems.

HHHI would also like clarification on how upstream outages that regularly affect the same customers would be treated. Would the OEB consider a normalized data set that excluded loss of supply for the purposes of determining reliability and consequences?

HHHI proposes that many customers would benefit from learning more about distribution systems, demarcation points and how they are designed to better understand the costs and potential cost limitations to better reliability.

In the case of the rural customer, it is not cost effective to build a redundancy line for a small percentage of customers and impart those costs on all ratepayers. An alternative could include a recoverable fund that provides subsidies for the purchase of individual generators, self-generation and/or energy storage. In addition, these customers would be an excellent subset of customers that could engage in embedded community generation projects.

HHHI does not feel that providing compensation to customers that fall below a set level of reliability is in the best interest of all ratepayers. It has been observed that when there is refunds or compensation available, there are "market advisors" who take advantage of the programs for their own benefit. This situation would be no different. Furthermore, as indicated above, it is possible that outages to customers may be a result of customer owned infrastructure or past the demarcation point and before the meter. These situations are outside the control of the LDC and would be difficult to identify for reporting purposes.

The alternative to consequences is incentives. The OEB could incentivize greater adoption of distributed energy resource, community net metering and storage in addition to possibly subsidizing generators and battery storage, as discussed above.

<u>Utility Planning</u>

- **How should reliability data be enhanced to support effective utility planning and rate setting? Are there any established methodologies to quantify the value, from a reliability perspective, added by transmission and/or distribution investments?**

  Reliability data could be enhanced with additional automation, however, there is an upfront cost to capital investments when installing new assets and ongoing operating and maintenance expenses for network access and remote operations (i.e. wireless/cell communication and control room costs). As part of customer engagement with a Cost of Service application, LDCs request rate payer feedback on whether, and if so, how much, ratepayers would be willing to pay for greater reliability. These responses feed into the utility planning and rate setting process. One benefit of the customer engagement is educating the customer on added benefits and the costs associated with those benefits.

There are obvious quantifiable activities that can improve reliability like vegetation management. Other activities, like the replacement of poletrans may not have any specific reliability data associated with the work but proactive work will still result in greater reliability in the longer term as any poletrans failure would result in extended outages due to lack of available replacement assets. In general, it is difficult to quantify the value of added investments as it relates to reliability as there are a significant number of variables that can not be controlled.

Conclusion

Many of the ideas above focus on cost and benefit. While LDCs have the ability to address the issues the OEB has raised, it unfortunately, like most things, comes down to cost and whether the benefit that is derived is cost effective for the ratepayer. It is a balancing act between best reliability at the least amount of cost to ratepayers.

When prioritizing asset investments, LDCs weigh multiple factors including customer and community benefit, reliability, environmental stewardship, public and employee safety. With the continuing effects of climate change, LDCs should be investing in ways to make their distribution systems more resilient and "harder", able to withstand extreme weather events. Allowing LDCs to spend on capital projects and innovations instead of always seeking to reduce capex and OM&A with rate applications would allow LDCs more opportunities to upgrade their systems to provide more granular data and the potential to increase reliability.

Customers always have the ability to invest in technology that will provide the improved reliability they require. In such cases, the benefiter pays for the increased reliability and not the entire pool of ratepayers.

Ultimately, all customers, whether residential or commercial, would prefer the most reliability at the lowest prices. While this scenario is unlikely, it is the responsibility of the LDC and the OEB to work together to determine the ideal balance between reliability and rates.