Hydro One Networks Inc.
7th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5393
Fax: (416) 345-6833
Joanne.Richardson@HydroOne.com

Joanne Richardson
Director, Major Projects and Partnerships
Regulatory Affairs

BY COURIER

January 09, 2020

Ms. Christine E. Long
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Long:

EB-2018-0117- Hydro One Networks Inc.'s Section 92 – Barrie Area Transmission Upgrade Project – Interrogatory Responses

Please find attached Hydro One Networks Inc.'s responses to interrogatories received in the above-noted proceeding as part of Procedural Order No.1 dated December 6, 2019.

An electronic copy of this has been filed through the Ontario Energy Board's Regulatory Electronic Submission System (RESS).

Sincerely,

ORIGINAL SIGNED BY JOANNE RICHARDSON

Joanne Richardson

OEB STAFF INTERROGATORY #1

Reference:

Exhibit B/Tab 1/Schedule 1/Attachment 1/p. 1
Exhibit B/Tab 3/Schedule 1/Attachment 2/Integrated Regional Resource Plan/pp. 14, 35, 53
Exhibit B/Tab 3/Schedule 1/Attachment 2/Integrated Regional Resource Plan/Appendix A, p. 70, Table A-10; Appendix B, p. 89, Table B-2
Exhibit B/Tab 3/Schedule 1/Attachment 3/Regional Infrastructure Plan/p. 39, Appendix C and D

Interrogatory:

The application indicates that the Barrie Transformer Station (TS) limited time rating (LTR) will be exceeded in 2022. The load forecasts in the Integrated Regional Resource Plan (IRRP) have been revised in the Regional Infrastructure Plan (RIP). The RIP indicates lower actual 2014 load demand and lower forecast 2015 to 2034 load demand than the IRRP.

Currently, six feeders in the Barrie TS are used to supply Alectra Utilities Corporation (Alectra) and one feeder supplies InnPower Corporation (InnPower). Based on the forecasts provided in the IRRP, the IRRP concluded that InnPower will exceed its existing feeder load capacity of 25 MW by 2020. It recommended that Hydro One Distribution and InnPower develop a plan to uprate Barrie TS, build new 44 kV feeders to support InnPower's forecast growth and enable the existing 13M3 feeder to be relocated out of the Hydro One Transmission corridor.

Load forecasts for InnPower's service area indicate that the power demand in Innisfil and South Barrie will grow by approximately 48 MVA in the next five years. The Barrie Area Transmission Upgrade (BATU) Project will provide an estimated additional 36 MVA of supply to InnPower.

Questions:

a) Please provide the following information for the Barrie TS:
   i. An updated demand forecast for the Barrie TS that shows both 5 year historical and 20 year forecast demand.

ii. Please confirm that the Barrie TS remains a summer peaking station.

iii. When will the Barrie TS LTR be exceeded based on the most recent load forecasts?

iv. Are these forecasts consistent with the IRRP and RIP? If they differ, please explain.

b) Please confirm that the Alectra Load Transfer from Barrie TS to Midhurst TS has occurred. If so, please confirm the date in which it occurred.

c) Please confirm that there was no option to transfer InnPower's load growth to another station, which would avoid the need to upgrade Barrie TS.

d) Please explain the impact of Alectra not needing capacity on the project, including the need date.

e) Please provide a five year historical load plus 20 year forecast of load for Barrie TS. For each year, please provide a breakdown of each utilities' load supplied by Barrie TS. Please explain any significant year-to-year changes in the forecast.

f) Please provide the load forecast for InnPower on the existing and new feeder positions at the Barrie TS.

g) Please provide any updates to the planning information provided in the pre-filed evidence including the impact of the latest provincial conservation targets.

h) Please provide any updates on the progress of the 13M3 feeder relocation out of the Hydro One Transmission corridor.

<u>Response:</u>

a)

i. The most recent Barrie TS forecast is the same one that was used to run the Economic Evaluation in this Section 92 application. The forecast is provided in the Table 1 below.

Table 1 – Historical and Forecast Barrie TS Load

	Historical						**Forecast -->**						
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
Load (MW)	112	95*	98*	90*	120	115	112	119	128	137	140	140	140

	---> Forecast												
Year	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
Load (MW)	140	140	140	140	140	140	140	140	140	140	140	140	140

**Load transfers and cooler than normal summers resulted in historical load values in 2015-2017 that were lower than normally expected.*

ii. Confirmed. The Barrie TS remains a summer peaking station.

iii. Based on the most recent historical data, the Barrie TS summer Limited Time Rating ("LTR") 103.5 MW based on a 0.9 power factor has already been exceeded and the forecast values, in response Part (a) (i) above show that the station LTR will continue to be exceeded.

iv. The forecast provided in response to Part (a) (i) above differs from those used in the IRRP and RIP because Alectra revised its load forecast at Barrie TS resulting in Alectra not exceeding their assigned capacity at Barrie TS. Any additional Alectra load growth will be supplied by Midhurst TS, where Alectra has spare capacity available at that station. Additionally, during this time, InnPower also provided an updated forecast (in March 2019) to Hydro One as they received more information on development in the South Barre/Innifil area. As a result, InnPower's forecast increased from that provided in the IRRP and RIP.

b) Alectra provided the following update to Hydro One, via email, on December 17, 2019. The below is an extract from that communication;

> *"The planned transfer by the legacy PowerStream (now Alectra Utilities) of 27MW of load from Barrie TS to Midhurst TS has not yet occurred. As described in the December 16, 2016 Barrie/Innisfil Sub-Region IRRP (Ex B-3-1 Attachment 2 Page 13), legacy PowerStream planned to transfer load from Barrie TS to Midhurst TS by 2020 should full data centre load growth materialize. As of December 2019, the load growth of the data centres has not fully materialized and thus, the need to transfer load has not yet materialized. Alectra Utilities has installed the necessary tie-in switches in December 2017*

> *and October 2018 to enable the transfer and will continue to monitor the load growth of data centres to determine the need to transfer load from Barrie TS to Midhurst TS as required."*

c) InnPower has confirmed there is no other viable option to transfer InnPower's load growth to another station without incurring significant voltage issues along other feeders, and\or capacity issues at the closest alternate transformer stations (i.e. Everett TS and Alliston TS). The BATU Project is necessary to meet the mid-term needs of InnPower by increasing its supply out of Barrie TS. The Project will be pivotal for the future extension of 230 kV transmission line into Innisfil to address future load growth. This upgrade and associated mid to long-term plans are consistent with the recommendations of the Barrie/Innisfil sub-region regional planning process.

d) Although Alectra has indicated it does not need additional capacity at Barrie TS, the immediate capacity need at the station still exists since the Barrie TS LTR has already been exceeded several times. The forecast, provided in response to part (a) (i) above still supports the immediate need for additional capacity. The long-term capacity need at the upgraded Barrie TS (indicated in IRRP to occur in 2026, and in RIP to occur in 2031) will likely be delayed due to Alectra's lack of capacity needs, and there will likely be spare capacity available at Barrie TS for new customers seeking to connect in the area.

e) Historical and forecast Barrie TS peak load, split by utility, is provided in the Table below. The abnormally high historical loading on the InnPower feeder at Barrie TS in 2018 was due to temporary load transfers that were required to facilitate distribution work on feeders normally supplied by neighbouring stations. The slightly higher-than-normal historical loading for InnPower in 2017 and 2018 was also due to similar temporary load transfers. InnPower's actual peak at Barrie TS in 2019 was 11 MW, however its load was 9 MW at the time when Barrie TS hit its peak of 115 MW. Based on development plans in the South Barrie and Innisfil area, InnPower load is expected to grow significantly over the next 5 to 10 years.

The load forecast portion of Table 2 shows the non-coincident peaks that each LDC is expecting to reach without load transfers.

Table 2 – Historical and Forecast Barrie TS Load – Split by Utility

	Historical						Forecast -->						
Year	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
InnPower Load (MW)	11	5	18	18	32	9	22	29	38	46	50	50	50
Alectra Load (MW)	101	90	80	72	88	106	90	90	90	90	90	90	90
Barrie TS Load (MW)	112	95	98	90	120	115	112	119	128	137	140	140	140
	---> Forecast												
Year	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**
InnPower Load (MW)	50	50	50	50	50	50	50	50	50	50	50	50	50
Alectra Load (MW)	90	90	90	90	90	90	90	90	90	90	90	90	90
Barrie TS Load (MW)	140	140	140	140	140	140	140	140	140	140	140	140	140

f) The most recent InnPower forecast for Barrie TS (updated in March 2019), as shown in Table 2 above is the same forecast load Hydro One used to run the Economic Evaluation in this Application. Up to mid-2022, the forecast InnPower load will be supplied by the one existing Barrie TS feeder, and any over-loading up to this point will be addressed through temporary load transfers. Following the in-servicing of the BATU Project in June 2022, the forecast InnPower load will be able to be supplied by two Barrie TS feeders. Typically, 44kV feeders have a capacity of 25 MW and once the second Barrie TS feeder is available for InnPower, exact feeder loading will be an InnPower exercise done at a later date.

g) The planning information provided in the pre-filed evidence is up-to-date and reflects the most recent information from all stakeholders involved.

With respect to provincial conservation targets, in March 2019, the Minister of Energy, Northern Development and Mines directed the IESO to immediately discontinue the 2015-2020 Conservation First Framework and implement a new Interim Framework with a centrally delivered program offering until December 31, 2020. As a result, the long-term province-wide conservation target of 30 TWh by 2032 described in the 2015 IRRP is no longer in effect.

Compared to the 2016 Barrie/Innisfil IRRP, the update to the long-term provincial conservation target is expected to only affect the energy efficiency programs portion of the conservation savings forecast beyond 2020. The estimated impact of the update as mentioned above is an increase in the Barrie TS planning forecast of nearly 12 MW by the end of 2034 (which represents the end of the IRRP forecast period). The need for the Project remains and this additional load will be assessed in future cycles of Regional Planning.

h) Hydro One Distribution has requested an estimate for the 13M3 feeder relocation. The design is expected to be completed by November 2020. Once completed, Hydro One Distribution will work through the agreement with InnPower based on the cost estimate and release the work for construction in 2021. The expectation is that the feeder will be relocated by end of 2021 to be ready for the targeted in-service date of the BATU Project, which is June 2022.

OEB STAFF INTERROGATORY #2

Reference:
Exhibit B/Tab 3/Schedule 1/Attachment 1/pp. 3-4
Exhibit B/Tab 3/Schedule 1/Attachment 2/p. 39
Exhibit B/Tab 9/Schedule 1/p. 6

Interrogatory:
The application states that the existing 115/44 kV transformation facilities at Barrie TS are nearing end-of-life and have reached capacity. Likewise, circuits E3B and E4B, which supply Barrie TS, are nearing end-of-life and are expected to exceed their load meeting capability in the near-term. Furthermore, the 115 kV switchyard and the T1 230/115 kV auto-transformer at Essa TS that supply circuits E3B and E4B have already exceeded their expected life.

The application asserts that development of the annexed lands in South Barrie, the continued development of data centres in the City of Barrie and forecast growth in the Town of Innisfil, including the proposed industrial and commercial development of Innisfil Heights, contribute to the forecast growth.
Due to changing load growth in the area since the RIP, Alectra indicated that it no longer required incremental capacity.

Questions:
a) Please describe the impact on reliability for Barrie TS and for the feeders supplied from it in the event that the new 230 kV circuits, E28 and E29, are not available.

b) Please provide information on any plans that Hydro One has for connecting additional stations to E28 and E29 or otherwise utilizing the 230 kV capacity of the line.

c) Please comment on the status of the anticipated developments in the South Barrie and Innisfil areas, and discuss implications with regard to the BATU Project.

Response:
a) In the extremely rare event that both new 230kV circuits are not available, supply to Barrie TS will be lost. Barrie TS has low voltage load transfer capability with Midhurst TS and Alliston TS and thus load transfers will occur to temporarily restore

power to the affected loads until at least one of the 230kV circuits is restored into service.

b) To the best of Hydro One's knowledge, Metrolinx is planning on building an electrification station (which will be known as the 'Allandale Traction Power Station') in the near future that will be supplied directly from this Project's new 230kV line and utilize capacity of the line.

To the best of Hydro One's knowledge, InnPower is considering to build a new transformer station in the next 5-10 years that will also be supplied from this Project's new 230kV line and utilize capacity of the line.

c) Hydro One confirmed with InnPower that commercial and industrial development has occurred in both South Barrie and Innisfil and is expected to continue in 2020. As per the most recent forecast, InnPower will start exceeding its single feeder capacity of 25MW at the existing Barrie TS in 2021, therefore the need for additional supply must be addressed as soon as possible. Regardless of any new development in the area, the need for additional capacity at Barrie TS is urgent. The station has already peaked above its Limited Time Rating on several occasions over the past two years and is anticipated to continue to do so in the future. Should the BATU project not proceed, InnPower will have major issues in supplying its forecast load past the year 2022.

OEB STAFF INTERROGATORY #3

Reference:
Exhibit B/Tab 3/Schedule 1/Attachment 1/pp. 16, 43, 97
Exhibit B/Tab 3/Schedule 1/Attachment 2/p. 39

Interrogatory:
Metrolinx is planning to electrify the Barrie GO train lines and has approached Hydro One, requesting 40-50 MW of capacity. The new 230 kV circuits from Essa TS to Barrie TS would provide adequate capacity and tapping positions for Metrolinx's substation, however, the supply capacity at Essa TS may present some limitations.

Question:
a) Please comment on the status of the Metrolinx Electrification Plans for the Barrie Area and discuss implications with regard to the BATU Project.

Response:
a) The Metrolinx electrification is part of the Government of Ontario Regional Express Rail ("RER") expansion program. The scope and timing of these Traction Power Station projects will be determined by the successful bidder that Metrolinx will select to undertake the RER project. Metrolinx issued a Request for Qualifications on April 3, 2018, and prequalified teams were selected on May 30, 2019 (see links below). To Hydro One's knowledge the selection process remains ongoing.

Whether or not Metrolinx's electrification plans materialize the need for the BATU project still exists. On the other hand, if the BATU project does not proceed, there will not be sufficient capacity available to supply Metrolinx, or to address the additional non-Metrolinx related capacity needs in the Barrie/Innsfil area.

More information please refer to the following:
https://www.infrastructureontario.ca/Request-for-Qualifications-Issued-RER-GO-Regional-Express-Rail-Corridor/

Information regarding the status can be found at the following link;
https://www.infrastructureontario.ca/RER-GO-Regional-Express-Rail-Corridor/#pDetailStatus

OEB STAFF INTERROGATORY #4

Reference:
Exhibit B/Tab 3/Schedule 1/Attachment 1/p. 1
Exhibit B/Tab 5/Schedule 1/pp. 1-4

Interrogatory:
The IESO letter states that based on the timeline and magnitude of the urgent need to replace infrastructure nearing its end-of-life and to provide supply capacity for the Barrie/Innisfil area, it will not be feasible to address the transmission line supply need and transformation capacity need through additional conservation and local generation. A wires option has been determined to be the only feasible option. The IESO recommended replacing the existing Barrie TS and the E3B/E4B transmission line with new 230 kV infrastructure.
The application states that three transmission alternatives were considered for the project. Alternative 3, which recommends rebuilding Barrie TS to 230 kV supply, is the preferred alternative. This option addresses the near-term and medium-term capacity needs, removes an aging 115 kV switchyard at Essa TS, allows for future expansion capability to supply the region's long-term capacity needs, and satisfies the IESO's Ontario Resource and Transmission Assessment Criteria.

Questions:
a) The evidence indicates that the IESO recommends an integrated solution, comprising conservation and additional transmission and distribution facilities to meet the growing demand. Please comment on or provide any information which demonstrates the IESO's support for Hydro One's specific proposed solution since Alectra has withdrawn from the project.

b) Please explain the methodology to determine that facilities are at end-of-life and provide the information that was used to determine end-of-life for this project.

c) Please explain how and when facilities transition from near end-of-life status to end-of-life status, including Barrie TS transformers and E3B circuit.

d) In the evaluation of Alternative 1, was distributed generation considered to increase capacity? What is the impact of distributed generation and conservation on the viability of Alternative 1?

e) Please provide the cost of the line losses for Alternative 2.

f) Please provide an updated cost estimate for Alternative 3, if the estimate has changed from that provided in the application.

g) Was replacing only the end-of-life E4B circuit with a 230 kV line to provide a dual 115/230 kV supply to Barrie TS considered? If not, please explain.

h) Please provide information on any other alternatives that were considered for meeting the forecast growth in the Barrie/Innisfil area, but were rejected.

Response:

a) The following response was provided to Hydro One by the IESO to assist with answering this part (a) of the interrogatory.

The 2016 Barrie/Innisfil Sub-region IRRP provides recommendations to address the sub-region's forecast electricity needs over the next 20 years, based on the application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC"). Electricity needs come in different forms such as: equipment capacity, load restoration, and equipment end-of-life. The proposed solution primarily addresses the end-of-life ("EOL") needs at Barrie TS and components of its 115 kV supply infrastructure. In addition, the net demand growth in the southern portion of the City of Barrie and in the Town of Innisfil is forecast to exceed the supply capacity of both Barrie TS and the 115 kV supply circuits to the station in the near term. While Alectra's departure from the project has released additional capacity which is of value in the future (since load in the area is growing), the EOL and capacity needs identified remain and must still be addressed. Given that the EOL and capacity needs remain, IESO is in support of the proposed solution consistent with the recommendations from the 2016 Barrie/Innisfil Sub-region IRRP.

b) Hydro One performs a continuous asset risk assessment ("ARA") process to determine individual asset needs, which includes the determination of end-of-life, and relies on asset condition data, engineering analysis and other information including the input of experienced electrical system planning professionals. The methodology and inputs into this process are explained in detail as part of Hydro One's 2020-2022 Transmission Rate Application, Case EB-2019-0082, Exhibit B, Tab 1, Schedule 1, Transmission System Plan Section 2.1.2.3. Specific asset condition assessment information used for determining Essa TS and Barrie TS transformer end-of-life is provided below in part (c).

c) Consistent with the response in part (b) above, the determination of an asset as end-of-life is through verified condition information as obtained through Hydro One's preventive and corrective maintenance programs. Hydro One uses the Expected Service Life ("ESL") of assets as a general guideline to inform investment decisions. The ESL is defined as the average time duration in years that an asset can be expected to operate under normal system conditions and is determined by considering manufacturer guidelines and Hydro One's historical asset retirement data. The ESL is used as a fleet-wide parameter to inform investment decisions. Assets operating beyond ESL generally have a higher likelihood of failing and/or are in poor condition and therefore, generally, incur higher maintenance costs. The term End of Life is also used and is defined as the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences. Therefore, while assets may be operating beyond ESL they may not be at EOL.

Asset assessment information (current as of December 2019) used to determine end-of life for the transformers at Barrie TS and Essa TS that relate to this project, is shown below:

Table 1 - Barrie TS: T1&T2 Transformer Asset Risk Assessment Information

		Asset Risk Index (ARI)					
Risk	**Asset**	**Age**	**Demographics**	**Condition**	**Composite**	**Asset Risk Assessment (ARA)**	**Comments**
Equipment: Transformers	T1	57	100	75	40	High	• Assessment concludes the T1 has been approaching its expected service life, experiencing insulating material degradation per Dissolved Gas Analysis. • Oil leaks were reported from the transformer. • Tap changer is old model, showing operation defects. • Insulation oil quality is in an acceptable range. • T1 is a non-standard unit. • Recommend to replace the T1 in next 5 years to mitigate reliability risk, environmental risk, and lower lifecycle cost.

	T2	57	100	71	38	Very High	• Assessment concludes the faulty gases were detected in the T2 main tank, indicating electrical discharge activities have been occurring. • Tap changer was old model, and multifold issues were reported including dysfunction, burning contacts and high moisture contents. • T2 is a non-standard unit. • Oil leaks were reported on the transformer. • Recommend to replace the unit within next 5 years to mitigate reliability risk, environmental risk, and lower lifecycle cost.

Table 2 - Essa TS: T1&T2 Transformer - Asset Risk Assessment Information

			Asset Risk Index (ARI)				
Risk	**Asset**	**Age**	**Demographics**	**Condition**	**Composite**	**Asset Risk Assessment (ARA)**	**Comments**
Equipment: Transformers	T1	66	100	78	45	Very High	• Assessment concludes the T1 has exceeded its expected service life, experienced insulating material degradation and has significantly aged. • There is a history of oil leaks from the transformer. • Subcomponents are obsolete and their operational integrities are deteriorating • T1 is a non-standard unit. • Recommend to replace the T1 within next 5 years to mitigate reliability risk, environmental risk, and lower lifecycle cost.
	T2	27	8	12	10	low	• Assessment concludes the T2 is currently in a good operational condition, and will be maintained as normal.

Regarding E3B: the conductor is 70 years old and in decent condition; the insulators range from 69-71 years old; and the poles range from 69-71 years old and were last assessed in 2015 as being in decent condition. Based on ESL statistics, the E3B assets are expected to reach EOL within the next 10 years.

Regarding E4B: the conductor is 58 years old and in good condition; 65% of the insulators are 58 years old; and 65% of the poles are 58 years old, most of which were assessed as being in poor condition. Based on ESL statistics, most E4B assets are expected to reach EOL with the next 10 to 20 years, however, the wood poles that are in poor condition will likely need to be replaced in the next 2-5 years.

The remaining assets at Essa TS and Barrie TS, are due for replacement based on Hydro One methodology; specifically Barrie 44 kV breakers due to performance & utilization, and Essa 115 kV breakers due to relative age, maintenance costs, and performance.

d) As indicated in the IRRP, large transmission-connected generation and small-scale distribution-connected DG options were considered, however, they were ruled out as viable alternatives for meeting both asset end-of-life and capacity needs in the Barrie/Innisfil Sub-region. According to the IESO[1], while Alternative 1 meets the end-of-life asset needs for the area, it would not result in incremental supply capacity at Barrie TS or the 115 kV supply circuits from Essa TS needed to accommodate the near term demand forecast at Barrie TS. The incremental cost of additional distributed generation and conservation required to provide the required supply capacity to accommodate the medium term demand forecast is estimated to be four times higher in comparison to the incremental cost of Alternative 3.

e) Hydro One did not specifically calculate line losses for Alternative 2, given this alternative's solution does not satisfy any long-term supply need criteria. However, for perspective, a simple illustrative example is provided below which is indicative of the magnitude of the results that could be expected:

[1] The IESO provided information to Hydro One to assist with the response to this part of the interrogatory

Line losses are calculated as:

Equation (1): Losses in MW = $I^2 \times R$

Where:
I = current in amperes
R = resistance of conductor in ohms
MW = Power (P)*

Equation (2): *Power (P) is calculated as: $P = V \times I$

Where:
V = voltage and,
I = current

With respect to equation (1): for a set amount of load (P), the higher the voltage (V) the lower the current (I). Specifically V and I are inversely proportional. To supply the same load (P) at different voltages, 44 kV or 230 kV for example, five times the current on a 44 kV system is required, compared to that on a 230kV system (assuming the same conductor size). At 44 kV voltage, the same amount of load would require five times the amperes required to supply, as compared to that under a 230 kV voltage system. Assuming the same conductor is used for both systems, the losses on a 44kV circuit system would be 25 times higher than losses on a 230 kV circuit system. The loss calculations for both voltage level systems are shown below, using the line loss equation (1):

This scenario is represented formulaically below:
On the 230 kV system: 230 kV Losses = $I^2 \times R = I^2R$
On the 44 kV system: 44 kV Losses = $(5I)^2 \times R = 25\ I^2 \times R = 25I^2R$

Therefore, the total additional loss on the 44kV system, compared to the 230kV system with all other factors assumed to be equal, is a multiple of 25 times.

f) The BATU Project cost estimate has not changed from that provided in the prefiled evidence to this Application.

g) Replacing and/or converting only the E4B circuit with a 230 kV line while keeping E3B operating at 115 kV will result in not meeting the capacity need as the two circuits would not be able to back each other up during contingencies as per ORTAC criteria. Furthermore, replacing and/or converting only E4B to 230 kV does not address the other end-of-life asset needs at Barrie TS and Essa TS, which is critical to maintaining the reliability of supply to the load. Therefore, this option is not considered a viable option.

h) All alternatives considered were included and identified in the IRRP.

OEB STAFF INTERROGATORY #5

Reference:
Exhibit B/Tab 3/Schedule 1/Attachment 2/p. 70

Interrogatory:
InnPower provides service to the Town of Innisfil, as well as lands annexed by the City of Barrie in 2010. InnPower's distribution loads are supplied via ten distribution stations which are supplied by five 44 kV feeders and four distribution feeders from Hydro One owned distribution stations (i.e., Cookstown DS and Thornton DS); and three feeders originating from Alliston TS, one from Barrie TS, and one from Everett TS. InnPower's distribution voltages include 27.6 kV and 8.32 kV.

InnPower is currently a winter peaking utility. When accounting for diversity with the other local distribution companies at the substation level, however, the stations supplying InnPower are summer peaking. With anticipated growth from new developments and changing demographics, InnPower expects to transition to summer peaking. As such, InnPower has provided a summer peak forecast in-line with the sub-region's peak demand needs.

Questions:
a) What proportion of the InnPower load is supplied from Barrie TS?

b) Please explain whether the load growth could be supplied from other Hydro One feeders and distribution stations that currently supply InnPower instead of upgrading Barrie TS.

c) When is InnPower expected to become a summer peaking utility?

Response:
a) Approximately 50% of InnPower's load is supplied from Barrie TS.

b) See response to Exhibit I, Tab 1, Schedule 1, Part (c).

c) InnPower has been a summer peaking utility since 2016, reaching a 2019 peak of 60 MW in the month of July. The last time InnPower peaked in the winter was in 2015, reaching a peak of 51 MW in February.

OEB STAFF INTERROGATORY #6

Reference:
Exhibit B/Tab 9/Schedule 1/p. 1

Interrogatory:
The cost of the upgraded circuits will be included in the Line Connection Pool since these circuits are radially supplying Barrie TS. The cost of the new Barrie TS will be included in the Transformation Connection Pool since it is a step down transformer station that will supply existing and new load, and the cost of the additional line connections at Essa TS will be included in the Network Pool for cost classification purposes.

Hydro One will be responsible for the avoided cost of the sustainment work and InnPower will be responsible for the remainder of the project cost which will be paid through load revenue and capital contribution.

Questions:
a) Please confirm whether the BATU Project costs are included in Hydro One's application for its 2020-2022 transmission revenue requirement. If so, please confirm that the project costs included in this application are the same as those provided in Hydro One's 2020-2022 transmission revenue requirement.

b) Please comment on InnPower's plans for the inclusion of its portion of the line and station costs of this project in its rate base, including whether InnPower expects to recover these costs in its next cost of service application.

Response:
a) The BATU Project is included in Hydro One's application for its 2020-2022 transmission revenue requirement with in-service additions totaling $80.9M[1].

As per this Application, Hydro One expects that $84.9M[2] will be included in its rate base in 2022[3].

[1] Consisting of $58.6M in 2020 and $22.3M in 2021, totaling $80.9M.
[2] Equal to the total capitalized cost of $86.4M (per sum of the cost tables 1, 2 and 3 in Exhibit B, Tab 7, Schedule 1), less $1.5M which represents the first-year capital contribution in 2022 from InnPower, as provided in Exhibit B, Tab 9, Schedule 1, Table = total of $84.9M.
[3] As per Exhibit B, Tab 11, Schedule 1.

b) The following was provided by InnPower:

> Related to the BATU Project, InnPower plans to seek approval at its next Cost of Service distribution rates application, for
>
> i. the inclusion of the annual capital contribution principal payment of the line and station costs in its rate base, and
>
> ii. the annual interest payment associated with funding the project.

As per the Accounting Procedures Handbook Article 410, InnPower will be recording the capital contribution paid to Hydro One Networks Inc. in Uniform System of Accounts, account 1609 – Intangible Assets – Capital Contribution Paid. Therefore the capital contribution to Hydro One will come into InnPower's rate base, equally, over the 15 year payment period.

OEB STAFF INTERROGATORY #7

Reference:
Exhibit B/Tab 9/Schedule 1/p. 5

Interrogatory:
Table 7 indicates a pool cost responsibility for transformation facilities of $25.5 M. Table 10, however, indicates a pool cost responsibility for transformation facilities of $25.2 M.

Question:
a) Please confirm the correct pool cost responsibility for transformation facilities and update the tables accordingly.

Response:
a) Hydro One confirms the correct pool cost responsibility for transformation is $25.5M and has updated Table 10 accordingly per the below;

Table 10: Transformation Connection Pool Project Cost Responsibility and Capital Contribution

$M	Cost of Work (per B-7-1)	Cost Responsibility		Customer Capital Contribution
		Customer	Pool	
Station Facilities (230k/44V DESN at Barrie TS)	36.7	11.2	25.5	2.6
Total	**36.7**	**11.2**	**25.5**	**2.6**

OEB STAFF INTERROGATORY #8

Reference:
Exhibit B/Tab 6/Schedule 1/p. 1

Interrogatory:
The Qualitative Benefits of the project are listed in Exhibit B, Tab 6, Schedule 1.

The Filing Requirements for Electricity Transmission Applications (Chapter 4) states that when an applicant attributes market efficiency benefits to a proposed project, such as lower energy market prices, congestion reduction, or transmission loss reduction, the evidence submitted must include quantification of each of the market efficiency benefits listed for that proposed project.

Question:
a) Has Hydro One quantified any benefits of the BATU Project? If so, please provide them.

Response:
a) Hydro One has identified the line losses savings of the BATU project to be about 0.6 MW at peak load, and an annual energy savings of 2,238 MWh (please see Table 5-1 Impact of Network Upgrades, in EB-2019-0082 at Exhibit B, Tab 1, Schedule 1, TSP Section 1.8.

   Based on an average 2018 Hourly Ontario Energy Price (“HOEP”) of $24.30/MWh, the annual cost savings would be approximately $54k.

OEB STAFF INTERROGATORY #9

Reference:
Exhibit B/Tab 7/Schedule 1/pp. 1, 3, 6, and 7

Interrogatory:
A budgetary estimate was included with the leave to construct application. Hydro One estimated line work cost to be $23.4 million and the avoided sustainment cost to be $7 million with a pool contribution of $3.4 million.

Questions:

a) Please explain the significant variance in cost of the proposed line work compared to the like-for-like sustainment line work and the customer allocation.

b) Given the current stage of the development work, please comment on the AACE classification of the cost estimates provided in the application and whether any revision of these estimates is anticipated or required.

c) Please confirm whether the budgeted contingency costs are sufficient to cover the identified risks. Hydro One has estimated the contingency cost to be $7.4 million which is 8.1% of the total cost of the project.

d) How did Hydro One establish that $7.4 million is an appropriate contingency cost?

Response:

a) Comparison of major aspects driving the cost difference between the proposed BATU line work and the like-for-like sustainment line work are listed below:

115kV like-for-like line work	230kV development line work
This work involves replacing individual components of the circuit that have been classified as end-of-life. Components are typically replaced on an as-required basis.	This work involves building a new 230 kV double circuit steel lattice transmission line.
Replacement of wood poles is significantly cheaper: • Wood poles typically do not require foundations • Equipment costs to install wood poles are comparatively cheaper, than the 230kV infrastructure requirements	Construction of new lattice towers is significantly more expensive: • New lattice towers require concrete foundations which become even more complex when dealing with wetland and swampy conditions • Heavier equipment required compared to that of 115kV infrastructure, and the added complexity of getting the equipment to site through poor soil conditions at this Project's location results in increased cost
Under a like-for-like replacement, no new capacity would be added and as such no capital contribution would be triggered from the existing connected customers using their existing contracted capacity	The Transmission System Code requires a cost allocation calculation (which in turn would drive a potential capital contribution) to determine the assignment of the incremental cost of supplying increased supply capacity requests/ connections to triggering customer(s).

b) The cost estimate for the BATU Project is an Association for the Advancement of Cost Engineering ("AACE") Class 3 (which has an expected accuracy range of +30%/-20%). No revision of the Project estimate is anticipated at this time.

c) Confirmed. Hydro One anticipates that the budgeted contingency costs are sufficient to cover the identified risks.

d) For major projects Hydro One reviews the risks of those projects during the project development and estimation phase. A risk workshop was undertaken to identify major risks for this Project. The risk of any unplanned outage requirements at Essa TS and Barrie TS due to age and condition of equipment, the risk of an escalation of the price of materials/major components (such as the Transformers) and the risk of schedule delays due to availability of outages to the existing 230 kV circuits at Essa TS were identified and assessed, and cost provisions for those items were included in the cost estimate.

OEB STAFF INTERROGATORY #10

Reference:
Exhibit C/Tab 1/Schedule 1/pp. 3-5

Interrogatory:
The new 230 kV lines will be equipped with an appropriate conductor size that will meet current and future load requirements and an optical ground wire (OPGW) located at one of the two shield wire positions on the towers. Conductor size will be 1443.8 kcmil ACSR/TW (56/19) Superior, shield wire will be 7 No. 5 Alumoweld, and OPGW will be 7 No. 5 Equivalent (short-circuit capacity and rated tensile strength).

The application states Barrie TS is currently supplied by two single circuit 115 kV transmission lines from Essa TS spanning between the two stations associated with circuit E3B constructed on 60 foot high wood structures and circuit E4B constructed on 80 foot high wood structures. The double circuit that will be constructed is to be built using steel lattice towers ranging in height from 130 to 150 feet.

The Barrie TS footprint requires expansion to accommodate the new 230/44 kV switch yard. The expansion will occur on property owned by Hydro One adjacent to the existing station fence.

Questions:

a) What is the difference in capacity provided by the BATU Project by changing from 115 kV to 230 kV?

b) Does the proposed BATU Project provide sufficient capacity for any future increases in load that may be required to meet the supply for any new customer connections, such as the proposed Metrolinx Station?

c) Is Hydro One aware of any proposed customer connections along the new 230 kV circuit or on the ROW south of Barrie TS?

d) Please explain any reliability and/or back-up supply concerns for Barrie TS with both circuits now proposed to be on a single tower structure instead of on two separate tower lines.

e) What has been Hydro One's experience with scheduled outages during construction of similar projects in this area of the province? If there have been delays or cancellations of scheduled outages, what were the impacts on both schedule and final costs?

f) Please confirm what will be done with the existing 115 kV facilities at Barrie TS.

Response:

a) The capacity of the existing 115 kV E3B/E4B circuits is approximately 120 MW and the capacity of the new 230kV circuits will be between 400 MW to 450 MW.

b) Yes, the BATU project circuits will provide sufficient capacity to meet the long-term growth needs in the Barrie/Innisfil area, including those load connections related to new customer connections, such as the proposed Metrolinx Station.

c) See response to Exhibit I, Tab 1, Schedule 2, part c.

d) See response to Exhibit I, Tab 1, Schedule 2, part a.

e) Outages are an ongoing risk for all construction projects, however there have not been any identified elevated risk within the project plan. The impact of any outage delays or cancellations will be determined by the significance of those events, however the current project plan includes consideration for minor impacts in the form of project contingency.

   Scheduled outages are required in order to perform the Project work at both Essa TS and Barrie TS. The risk to executing scheduled/planned outages is dependent on prevailing system conditions, including unplanned outages that are beyond the control of Hydro One.

   A recent experience with scheduled outage delays during the construction of a project in this area of the province occurred in 2019 when both AL6 breaker and a T4 transformer failures at Essa TS caused several outage cancellations during installation of new 230 kV in-line switches at Orillia TS. This was due to system conditions (power flow limitations on a major Ontario interface) that would not accommodate an outage for this project at that time. The impact of the cancelled outage on the schedule is estimated to result in a delay to the in-service date of approximately 10-12 months. The additional cost to that project is not yet know and will not be available until the project's post-in-service.

The impact to cost and schedule due to outage delays or cancellations is highly variable. The impact of a specific delay to a project schedule is dependent on whether the outage is part of the critical path and whether float-time (a period of time allowed for unexpected outage delays) was allotted for these types of project related delays. Delayed or cancelled outages can range from several hours to many months.

Ultimately the granting of a planned outage is provided by the IESO and is beyond the control of Hydro One. Hydro One and the IESO work closely together, maintaining frequent communication, to manage the impacts of any constraints to planned outages they may impact a specific Hydro One project. The cost impact of outage delays can range from hourly standby charges for resourcing & equipment to significant costs that include demobilization and remobilizing of those resources and equipment.

f) The existing 115kV end-of-life facilities at Barrie TS will be decommissioned and removed/scrapped.

OEB STAFF INTERROGATORY #11

Reference:
Exhibit B/Tab 1/Schedule 2/p. 6
Exhibit B/Tab 6/Schedule 1
Exhibit E/Tab 1/Schedule 1/pp. 2-3 and Attachment 1

Interrogatory:
The evidence states that the Barrie TS footprint will be expanded 100 feet by 40 feet and that the ROW associated with the BATU Project will require new land rights. The application provides information on directly impacted properties. The application states that the new 230 kV E28/E29 double circuit will follow the existing E3B ROW corridor.

Approximately 7.5 km of the transmission line easement, shared by both E3B and E4B, will be reduced from the current width of 165 feet to 110 feet. Additionally, Hydro One will no longer require the 1.5 km easement section currently occupied solely by the E4B line, which runs east from Essa TS and joins at a point with the E3B line ROW. Easement rights along the proposed corridor route are being renegotiated for the new double circuit 230 kV transmission line.

Questions:
a) Please explain why the E3B ROW will be used instead of the E4B ROW for the new circuits.

b) Please clarify why new property rights are needed since the new route is on the existing E3B ROW.

c) Please confirm that the 1.5 km section of E4B ROW that is not required for the BATU Project will be abandoned. If not, please clarify what will be done with this section of the ROW.

d) Please confirm that the E3B ROW will remain at a width of 165 feet for the first 1.5 km from Essa TS towards Barrie TS.

e) The ROW requires 16.01 hectares of land rights on lands owned by private landowners. Please provide additional information on the ownership of the privately-owned properties, identifying the number of residential properties and the number of commercial properties.

f) Please provide an update on the negotiations for the new permanent land rights required for the BATU Project with private landowners, including any concerns that have been expressed by landowners with respect to the BATU Project.

g) Please provide an update on the status of permits related to the use of federal, provincial and municipal lands, municipal roads allowances and highways, as well as rail and water crossings.

h) Please discuss any concerns that Hydro One has with respect to obtaining any of the required new land rights and/or permits for the BATU Project.

i) Has Hydro One approached any landowners that will be impacted by temporary access rights to be used for construction staging, access, flagging and permitting? Have any of these landowners expressed any concerns with the temporary access rights? Will the temporary access rights require any environmental approvals? If so, please explain.

j) Please explain whether it is possible for the Barrie TS to be rebuilt within the existing footprint, and if so, why this option was not selected. Also, please clarify the increase in size of the Barrie TS footprint as in the application it is listed as 100 feet by 40 feet, and in other places as an expansion of 90 feet.

<u>Response:</u>

a) During the 230 kV project construction phase, Hydro One is required to maintain 115kV supply to the existing Barrie TS. This can only be accomplished by utilizing either circuit E3B or E4B as a temporary bypass. The new project construction could occur on either the E3B or E4B ROW. Hydro One selected to construct the new 230 kV line on the E3B ROW because, of the two existing 115 kV circuits, E4B is in better condition compared to E3B and is considered a more reliable option to maintain supply to Barrie TS during Project construction. Additionally E4B has a higher capacity, than E3B, and will better accommodate recent historical summer peak loading at Barrie TS. Once the new 230 kV circuits are built and in-serviced, the E4B circuit will be disconnected and removed.

b) Where Hydro One's existing E3B ROW is sited, Hydro One relies upon various land rights for its current occupation. These land rights include:

- Hydro One-owned property;
- Statutory easement right on Infrastructure Ontario Bill 58 lands;
- Existing easement rights on municipal and privately-owned properties;
- Municipal road allowance

In the instances where Hydro One relies on existing easement rights on privately-owned properties, due to the restrictive nature of the existing easement rights, it was determined that Hydro One was not able to site the new 230 kV E28/E29 double circuit on the majority of those directly impacted properties. These easements are specific to structure type (i.e. wood pole structures), number of structures per property and centerline location. Hydro One would be restricted to the construction of a like-for-like line if no new property rights were acquired, which is not the preferred option.

Hydro One has acquired new, less restrictive easement rights to allow for the planned 230 kV double circuit BATU project. Hydro One will release all existing registered easement agreements on third party lands impacted by this section where Hydro One will no longer require associated land rights (as referred to in Exhibit E, Tab 1, Schedule 1). These releases will be completed at the conclusion of the BATU project construction phase and/or when all E4B infrastructure has been removed from the existing E4B ROW in this section.

c) Confirmed.

d) Not confirmed. The first 1.5 km of the E3B ROW, from Essa TS towards Barrie TS, is currently not 165 feet, and Hydro One will not require the ROW for the new 230 kV E28/E29 double circuit line in this section to be 165 feet. Hydro One requires a 100 foot width ROW in this section, using its proposed engineering design. This is consistent with the existing ROW and the existing associated easement agreements that Hydro One is relying upon.

e) The below table identifies the number of residential properties and the number of commercial properties:

Property Ownership Type	**Number of Properties**
Residential Includes land use types: rural recreational, rural residential, vacant agricultural, improved agricultural	11
Commercial Includes land use types: institutional lands, industrial resource, commercial	4
Total	**15**

f) Hydro One has initiated land acquisition activities with all impacted private landowners. Hydro One has been successful in negotiating all of the required fifteen permanent land right agreements with private landowners.

To date, no substantial concerns have been raised by private landowners with respect to the proposed Project and Hydro One has not received any substantial concerns regarding the Project's tower locations, line clearances or continued operations in proximity to the proposed transmission line.

g) The status of permits related to the use of federal and municipal lands, municipal road allowances and highways, as well as rail and water crossings are as follows:

- Hydro One has identified all municipal road allowance occupations and shared the location of the occupations to the local municipality. Hydro One does not require any permits and/or approval to occupy municipal road allowances as Hydro One enjoys legislated occupation rights pursuant to Section 41 of the *Electricity Act, 1998*;
- The new 230 kV E28/E29 double circuit ROW does not impact federal or provincial lands which require permitting and does not cross highway, rail, or permanent water crossings.

h) Since presenting formal offers to impacted landowners, (beginning in Q2 2017) Hydro One has not received any significant concerns from those land owners with respect to obtaining any of the land rights. Hydro One has acquired all permanent land right requirements for this Project. All construction-related permits will be acquired in 2020 prior to the start of construction.

i) Hydro One has identified and will utilize fee simple owned land adjacent to Essa TS for the majority of the construction staging and material storage for the BATU Project.

Hydro One has identified three temporary off-corridor access road requirements and will be engaging these third-party property owners in Q1 2020. Any additional required temporary access rights, construction staging, flagging and permitting required for project construction on third-party owned properties if any, will be identified in Q1 2020 and any impacted landowners will be approached at that time. Hydro One does not anticipate any issues with acquiring temporary access rights if determined they are necessary.

The temporary real estate access rights do not require environmental approvals.

j) It is not possible to construct the new 230kV Barrie TS station project within the current Barrie TS yard footprint due to insufficient space. The current Barrie TS facility will need to remain energized and maintain existing load supply. The existing Barrie TS 115kV station equipment cannot not be de-energized, decommissioned and removed until the new 230kV station has been constructed and placed in-service. Expanding the existing Barrie TS yard will utilize existing land already owned by Hydro One and avoid any additional real estate acquisition costs for land or land rights for this Project.

In Exhibit B, Tab 2, Schedule 1, of the Application's prefiled evidence it states that the, "Station's footprint will be expanded by an additional area measuring approximately 100 feet by 400 feet". The 90 feet that was indicated in Exhibit C, Tab 2, Schedule 1, is a typo and should read as, "the fenced yard facility will be expanded approximately 100 feet to the west".

OEB STAFF INTERROGATORY #12

Reference:
Exhibit E/Tab 1/Schedule 1/p. 6 and Attachments 2 to 7

Interrogatory:
Hydro One has provided the forms of land rights agreements that will be used to obtain the required land rights for the project.

Questions:
a) Please confirm that all of the affected property owners had the option to receive, or will receive the option of, independent legal advice regarding the land agreements.

b) Please confirm that the forms of agreements are consistent with agreements previously approved by the OEB in Hydro One leave to construct decisions. If so, please reference the EB number of the Decision and Order in which they were approved.

Response:
a) Confirmed. Hydro One provided all affected property owners the option to receive independent legal advice regarding the land agreements. Hydro One committed to reimbursing these owners for reasonably incurred legal fees associated with the review and completion of the necessary land rights.

b) Confirmed. The Hydro One form agreements included in this application have been previously approved by the OEB in Hydro One's leave to construct application EB-2019-0077, the Power South Nepean Project.

OEB STAFF INTERROGATORY #13

Reference:
Exhibit B/Tab 1/Schedule 1/p. 5
Exhibit B/Tab 11/Schedule 1

Interrogatory:
Hydro One provided a project schedule, setting out the construction and in-service timelines.

Questions:

a) Please update the project schedule at the above reference, if the schedule has changed.

b) Hydro One has indicated that it hopes to receive a decision granting leave to construct by February 28, 2020. Please comment on the impact to the proposed in-service date of June 2022, if the OEB's decision is issued after February 28, 2020.

Response:

a) The Project schedule as per Exhibit B, Tab 11, Schedule 1, is accurate and remains unchanged. Hydro One's request for an OEB approval in February 2020 per Exhibit B, Tab 1, Schedule 1, page 5 was incorrect. Please refer to Part (b) below for more information.

b) As per Exhibit B, Tab 11, Schedule 1, construction related activities for station and line work are scheduled to start in May and July 2020 respectively. Hydro One requests OEB approval of this Application prior to May 2020, specifically by April 15, 2020, to facilitate an effective execution of the BATU Project. Approval by April 15, 2020 will allow crews to be mobilized for the intended start of station construction in May 2020.

OEB STAFF INTERROGATORY #14

Reference:

Exhibit B/Tab 7/Schedule 1/p. 12
Exhibit B/Tab 3/Schedule 1/Attachment 2/p. 13

Interrogatory:

Hydro One has indicated that the BATU Project requires the following environmental approvals - Environmental Certificate of Approval and Environmental Screen Out/Class EA.

Question:

a) Please comment on the current status of these approvals.

Response:

a) The BATU project was subject to the Class Environmental Assessment ("EA") for Minor Transmission Facilities (2016) under the *Ontario Environmental Assessment Act*. The Class EA was completed on March 23, 2018.

   An Environmental Compliance Approval ("ECA") is required under the *Environmental Protection Act and Ontario Water Resources Act* for regulated systems and processes. An Environmental Activity and Sector Registry ("EASR") approval is required for significant noise or air emissions sources. Hydro One facilities associated with the BATU Project, in this case Barrie TS and Essa TS, both require an ECA for Industrial Sewage (Drainage) and an EASR approval. The applications for the Barrie TS and Essa TS ECAs and EASRs have not yet been submitted.

   These approvals will be submitted within the next six months once detailed engineering has been finalized. The EASRs are effective upon submission of the application, while the ECAs require up to 12 months for the Ministry of the Environment, Conservation, and Parks to review and issue the approval. All approvals will be obtained prior to the installation or construction of the station components they relate to, while unrelated Project work can proceed as scheduled. The schedule presented at Exhibit B, Tab 11, Schedule 1 includes these environmental related approval timelines. Hydro One does not anticipate any adverse impacts to that schedule due to these approvals.

OEB STAFF INTERROGATORY #15

Reference:
Exhibit B/Tab 7/Schedule 1/Tables 1 and 8

Interrogatory:
The real estate cost for the project is $2.5 million. There is no real estate cost listed for the comparable station projects. The most recent comparable project for the Essa TS work is Detweiler TS, which has an in-service date of November 2011.

Questions:

a) Please confirm the real estate costs for all alternatives provided in the application. Please update alternative project costs, if required, to reflect the inclusion of real estate costs.

b) Please confirm that, although not listed, comparable station project costs include real estate costs. If not, please adjust for real estate costs.

c) Are there any projects more current than 2011 for cost comparison of the Essa TS work? If so, please provide their costs.

d) Please clarify the use of a 2% escalation cost for comparable projects versus actual CPI rates. What would be the impact(s) if actual CPI rates were used instead of a 2% escalation cost?

Response:

a) Real estate costs for the BATU line Project have been included and updated in Table 8, as provided below. Hydro One confirms the station project's comparative Tables, (Table 9 and Table 10) do not include any real estate costs as the land on which the project work was undertaken was already owned by Hydro One prior to the project work being undertaken.

1 **Table 8: Costs of Comparable Line Projects**[1]

Project	**BATU Project**	**WATR Project**	**GATR Project**	**SGTR Project**
Technical	230 kV double circuits on single structures All steel lattice towers	230 kV double circuits on single structures Predominantly steel lattice tower structures with some steel poles	230 kV double circuits on single structures Predominantly steel lattice tower structures with some steel poles	230 kV double circuits on single structures Predominantly steel lattice tower structures with some steel poles
Length (circuit km)	9.0	13.6	5.0	27.0
Project Surroundings	Mostly rural	Urban-Rural Parallel to Karn Rd Multiple road crossings	Urban Parallel to Hwy 6 Multiple crossings –highway, roads	Mostly rural
Environmental Issues	Wetland and swamp conditions, are requiring increased foundation sizing, helical piles and more complex access requirements	None	None	Poor soil conditions required some tower foundations to be changed to pad and pier or piled type foundations
In-Service Date	Jun - 2022	Mar - 2012	Nov - 2016	Oct - 2008
Total Lines Work Cost	$22.9 M	$35.6 M	$23.1 M	$43.0 M
Less: Non-Comparable Costs Real Estate Line Bypass	 $2.5 -	 $0.5 M $4.3 M	 $1.4 M -	 - -
Total Comparable Project Costs	$20.4 M	$30.8 M	$21.7 M	$43.0 M
Add: Escalation Adjustment (2%/year)	-	$6.9 M	$2.5 M	$13.4 M
Total Comparable Project Costs	$20.4 M	$37.7 M	$24.2 M	$56.4 M
Total Cost per Km ($M's / km)	$2.3 M	$2.8 M	$4.8 M	$2.1 M

[1] Updated for real estate costs from the original Table 8 filed in Exhibit B, Tab 7, Schedule 1

b) See response a), above, with respect to real estate costs for station projects.

c) No there are no projects more current than 2011 to which Hydro One can reasonably compare the BATU related Essa TS work. Selection of projects with comparable work, to that proposed at Essa TS, focused on the expansion of the 230 kV diameters/bus-work that provide new 230 kV termination points, because that is the primary goal at Essa TS for this part of the BATU Project.

d) A 2% CPI cost escalation rate was chosen for use in the comparable project costs for consistency and simplicity purposes. The Bank of Canada's target CPI rate has historically been around 2% and continues to be so. (Please refer to the Bank of Canada's recent October 2019 Monetary Policy report[2]).

The below table provides actual historical Ontario CPI rates back as far as 2008 (2008 is the in-service date of the oldest Project comparable used in the BATU evidence). The average CPI rate is 1.95% over the 15 year period, excluding 2009 (this is considered an outlier data-year) which is approximately the same as that used in Tables 8, 9 and 10 of Exhibit B, Tab 7, Schedule 1.

Table 1: Ontario CPI

Year	CPI Rate (%)[3]
2008	2.27
2009	0.38
2010	2.43
2011	3.08
2012	1.41
2013	1.05
2014	2.31
2015	1.22
2016	1.79
2017	1.68

[2] https://www.bankofcanada.ca/wp-content/uploads/2019/10/mpr-2019-10-30.pdf
[3] Data source: IHS Global November 2019. Data from 2008 to 2018 are actual and beyond 2018 forecast.

2018	2.35
2019	1.98
2020	1.80
2021	1.90
2022	2.00

Notwithstanding the above, and to be responsive to OEB Staff's question, Hydro One calculated comparative project cost results using the Table 1 Annual Ontario CPI rate values above and compared these to the totals provided in evidence at Table 8 and 9 of Exhibit B, Tab 7, Schedule 1. Table 2 below provides comparative project totals with CPI escalation using both methods and shows the results are not materially different.

Table 2: Cost of Comparable Projects Using Annual Ontario CPI rates
(Using information in Tables 8, 9 & 10 filed Exhibit B, Tab 7, Schedule 1)

Table 8 Comparison - Costs of Comparable Line Projects	**WATR Project**	**GATR Project**	**SGTR Project**
Costs Sub-total*	30.8 M	21.7 M	43.0 M
Escalation Adjustment (2%/year)*	6.9 M	2.5 M	13.4 M
Total Comparable Project Costs (using 2% per annum)*	37.7 M	24.2 M	56.4 M
Total Cost per Km ($M's / km)*	2.8 M	4.8 M	2.1 M
Escalation Adjustment (using actual Ontario CPI/year)	6.0 M	2.5 M	12.0 M
Total Comparable Project Costs (using actual Ontario CPI/year)	36.8 M	24.2 M	55.0 M
Total Cost per Km ($M's / km)	2.7 M	4.8 M	2.0 M

* Per the Prefiled evidence in Exhibit B, Tab 7, Schedule 1

Table 9 Comparison - Costs of Comparable Station Projects for Barrie TS	**Detweiler 230kV, 350 MVAr SVC**	**Hydro Quebec: 1250 MVA Interconnection**	**Detour Lake – 230kV Line Connection at Pinard TS**
Costs Sub-total*	26.0 M	21.5 M	23.7 M
Escalation Adjustment (2%/year)*	6.1 M	6.6 M	5.0 M
Total Comparable Project Costs (using 2% per annum)*	32.1 M	28.1 M	28.7 M
Escalation Adjustment (using actual Ontario CPI/year)	5.3 M	5.9 M	4.4 M
Total Comparable Project Costs (using actual Ontario CPI/year)	31.3 M	27.4 M	28.1 M

* Per the Prefiled evidence in Exhibit B, Tab 7, Schedule 1

Table 10 Comparison - Costs of Comparable Station Projects for Essa TS	**St. Isidore TS T3/T4 Replacement**	**Palmerston TS Station Refurbishment**	**Enfield TS New Station Build**
Costs Sub-total*	35,369k	33,934k	31,088k
Escalation Adjustment (2%/year)*	1,797 k	1,797 k	1,961 k
Total Comparable Project Costs (using 2% per annum)*	**37,166 k**	**37,166 k**	**33,049 k**
Escalation Adjustment (using actual Ontario CPI/year)	1,724 k	2,090 k	1,861 k
Total Comparable Project Costs (using actual Ontario CPI/year)	**37,093 k**	**36,024 k**	**32,949 k**

* Per the Prefiled evidence in Exhibit B, Tab 7, Schedule 1

OEB STAFF INTERROGATORY #16

Reference:
Transmission System Code 6.3.19

Interrogatory:
Under section 6.3.19 of the Transmission System Code (TSC), the approval is being sought for an extension from five years to 15 years for InnPower to provide $15.7 million in capital contributions. The Board in its decision to permit extensions in the capital contribution installments beyond five years foresaw only one justification for an extended period. That is, where the consumer bill impacts are still too high and continue to present a barrier to the implementation of a regional plan.

Questions:

a) Please confirm that the consumer bill impacts would be too high for InnPower over a five year capital contribution period, and thus, the need for a 15 year capital contribution period.

b) Please explain and clarify any difference between the interest rate that InnPower will be charged versus the amount to be shown in the proposed variance account.

c) Please confirm if the proposed variance account balance will be recovered from Hydro One customers.

d) If Metrolinx (or any other large customer) will be connecting to the line, please confirm if they will be providing a portion of capital contribution towards the cost of the BATU Project. If possible, please provide the capital contribution that will be made by Metrolinx (or any other large customer).

e) Please explain how InnPower's capital contribution could change if additional customers are supplied from Barrie TS.

Response:

a) Confirmed. The following response was provided to Hydro One by InnPower to assist in answering this part of the interrogatory.

InnPower confirms that by including the capital contribution of $15.7 million over 5 years in its rate base, as opposed to over 15 years as recommended by Hydro One and InnPower, will create a significant rate impact[1] to InnPower's customers. InnPower estimates that the $15.7 million capital contribution will ultimately account for an increase in excess of 20% to InnPower's rate base. If the capital contribution is payable over five years, the full $15.7 million will included in InnPower's next cost of service application, anticipated to be for rates effective January 1, 2022, which coincides with the BATU Project in service date of 2022. The BATU project is required for InnPower to service load growth which is anticipated to increase at a more or less even annual stream over the next 10 to 15 years, as opposed to a sudden step change at a particular point in time. By extending the capital contribution payment term from 5 years to 15 years, the capital contribution payment stream will more closely coincide with the forecast additional customers and the associated load increases. This will allow for the new customer base to fund, through their distribution rate charges, the capital contribution relating to the new load they are utilizing, as opposed to InnPower's current customer base, who do not require the expansion of the system.

Further InnPower rate impact information is provided at Exhibit I, Tab 1, Schedule 21.

b) InnPower is only being charged the prescribed CWIP rate on the deferred capital contribution in accordance with the TSC.

The 2.88% interest rate that InnPower will be charged by Hydro One shown in the calculations outlining the proposed variance account is the interest on the unpaid balance at the Board's prescribed construction work in progress (CWIP) rate which is updated quarterly and published on the Ontario Energy Board's website as per 6.3.19 of the Transmission System Code. Any difference in the amount shown in the calculation contained in this application versus actuals would be a result of updates published on the Ontario Energy Board's website at https://www.oeb.ca/industry/rules-codes-and-requirements/prescribed-interest-rates. For the calculation provided to the Ontario Energy Board as part of this application,

[1] InnPower estimate the impact to their residential customer's base distribution charges, by Year-5, to be an increase greater than 10%, compared to that under the 15 year scenario, which would only be an increase of approximately an incremental 3% in the fifth year.

Hydro One did not forecast future updates to the rate but held the rate constant at 2.88% as per the Q4 2019 update (which has remained unchanged for the Q1 2020 update). The CWIP rate used can be seen in the list of assumptions on page 2 of Attachment 1 to Exhibit B, Tab 9, Schedule 9. The amount being booked to the variance account is the difference between what InnPower is being charged (CWIP rate) and the revenue requirement applicable for the in-serviced assets (dependent on NBV vs. Load methodology). Any unrecovered balance, credit or debit, on the variance account would be subject to the OEB's prescribed interest rate for approved deferral and variance Accounts

c) Confirmed. Any approved balances would be recovered through Uniform Transmission Rates from all Ontario Transmission customers. The proposed variance account balance will be subject to review by the OEB when brought forward for disposition in a future Hydro One transmission revenue requirement application.

d) Yes, if Metrolinx (or any other large customer) will be connecting, or require additional capacity from the line, they will be providing a portion of capital contribution towards the cost of the BATU Project as per the Transmission System Code 6.3.17. At this time it is not possible to forecast the amount of capital contribution that Metrolinx, or any other large customer, may be required to make. In fact at this time no other customers, including Metrolinx, have indicated they are prepared to contract for any capacity on the line.

e) If an additional customer(s) are supplied from Barrie TS, it is expected that this could have a material impact upon InnPower's capital contribution as forecast in this Application. As per the TSC, section 6.3.17, the actual cost reconciliation for InnPower would be recalculated in proportion to the revised incremental capital that InnPower is cost accountable for. This cost accountability split is directly related to the portion of contracted capacity that InnPower and any other connecting customer(s) require.

To demonstrate the potential impact to InnPower's capital contribution if other customer(s) were to connect at (or before) the project is placed into service, Hydro One has analyzed two hypothetical scenarios in which two customers require capacity: *Scenario 1*, where one additional customer requires an equal increase in capacity to that of InnPower and *Scenario 2*, where one additional customer requires only a fraction (10%) of the increase in the new line's capacity compared to that of InnPower's increased capacity request.

Scenario 1

Where another customer requires additional capacity in an amount equal to that of InnPower's incremental capacity requirements, the incremental Project costs would be allocated 50/50 between those two customers for the purposes of calculating their capital contributions. If no other factors change (i.e. load forecast), this would effectively eliminate the requirement of InnPower paying a capital contribution towards the Transformation Pool investments (currently amounting to $2.6M), and it would reduce InnPower's current forecast capital contribution towards the Line Pool investments from the current $13.1M to $2.6M.

Scenario 2

To demonstrate the impacts of calculating the capital contribution based on a scenario where two customers may contract for different proportions of the additional supply, Hydro One have assumed a scenario where InnPower's incremental capacity requirements at 90% and an additional customer is only 10%. Again, assuming no other factors change, this would reduce InnPower capital contribution towards the Transformation Pool investments to $1.5M (from the current $2.6M) and reduce the capital contribution towards the Line Pool investments from the current $13.1M to $11.0M, for a total capital contribution from InnPower of $12.5M instead of the current $15.7M.

The above examples provide an indication of how InnPower's current capital contribution calculations could be impacted. If the OEB provides leave to construct approval for the BATU Project and a new customer(s) contracts for significant capacity prior to the completion and in-servicing of the Project or during the 15 year rebate period outlined in the TSC post in-service, effectively triggering 6.3.17 of the TSC, Hydro One would inform the OEB of the impact of the new customer connection upon the capital contribution of InnPower and enter into discussions with InnPower regarding the necessity of InnPower continuing a 15-year deferred capital contribution payment schedule requested in this Application and make appropriate revisions to protect the rate payer.

0OEB STAFF INTERROGATORY #17

Reference:
Exhibit B/Tab 9/Schedule 1/pp. 12-17, Attachment 1

Interrogatory:
Hydro One has provided discounted cash flow analysis tables in the application.

Question:
a) Please explain how the discount rate of 5.59% used in discounted cash flow tables was determined.

Response:
a) As outlined on Exhibit B, Tab 9, Schedule 1, page 24, the 5.59% discount rate was determined by utilizing the OEB-approved return on equity of 9.00%[1] on common equity, 2.29%[2] on short-term debt, and 4.68%[3] on long-term debt with the OEB-approved deemed equity to debt ratio (40%/60%) and takes into consideration the current enacted income tax rate of 26.5%.

	Deemed Capital Structure	**Cost (%)**	**Weighted Average**	**Tax Affected**
Debt				
Short-Term	4%	2.29%	0.09%	0.07%
Long-Term	56%	4.68%	2.62%	1.93%
Equity	40%	9.00%	3.60%	3.60%
Cost of Capital			**6.31%**	**5.59%**[4]

[1] OEB-approved ROE from Hydro One's most recent transmission rate application EB-2016-0160
[2] OEB-approved short-term debt rate from Hydro One's most recent transmission rate application EB-2016-0160
[3] Hydro One's actual long-term debt rate as approved by the OEB in Hydro One's current transmission rate application EB-2016-0160
[4] Due to displaying the rounding of line items in the table to two decimal places, the above values add to 5.60%, however, the actual tax effected Cost of Capital is 5.59% - as shown.

OEB STAFF INTERROGATORY #18

Reference:
Exhibit B/Tab 9/Schedule 1/pp. 4-5, Tables 8-10

Interrogatory:
Hydro One has provided tables outlining the cost responsibility and capital contribution.

Questions:

a) In calculating the Pool allocation as discussed in Tab 7, avoided costs that occur in the first three years are not discounted. Please explain why.

b) Please show/explain how the customer capital contributions in Tables 8 to 10 are calculated.

Response:

a) Avoided costs that occur in the first three years were not discounted as the current assets are at end-of-life and would have been replaced at the same time as the other assets being replaced as part of a consolidated sustainment project to maximize cost savings by bundling work as well as reducing the impacts on downstream customers by reducing the number of planned outages.

b) These calculations were provided on page 12 to 24 of Exhibit B, Tab 9, Schedule 1. The calculations are performed in accordance with the Transmission System Code section 6.5 Economic Evaluations of New and Modified Connections and Appendix 5 Methodology and assumptions for economic evaluations.

OEB STAFF INTERROGATORY #19

Reference:
Exhibit B/Tab 9/Schedule 1/pp. 2 and 7, Attachment 1

Interrogatory:
Page 2 states that the need for the requested deferral and variance account is to ensure that: (1) Hydro One is able to recover the appropriate cost of capital over the loan term as Hydro One would be charging InnPower interest at the OEB's CWIP rate, which does not equate to Hydro One's full cost of capital; and (2) to ensure that Hydro One is able to recover the cost of its investment during the capital contribution deferral period.
Hydro One proposed to record costs associated with the BATU Project using the Loan Methodology as opposed to the "standard capital contribution methodology" (i.e., the NBV Reduction Methodology).

Questions:

a) Please confirm that both the Loan Methodology and the NBV Reduction Methodology would allow Hydro One to recover the revenue requirement on the unpaid capital contribution over the loan period instead of recovering the CWIP rate on the unpaid capital contribution. If not, please explain what is being recovered under both methodologies.

b) Please confirm that the revenue requirement difference between the Loan Methodology and the NBV Reduction Methodology is due to the tax calculation as a result of the way the capital contribution is recorded (i.e., as a capital contribution or in a deferral and variance account). If not, please explain the reason for the revenue requirement difference.

c) Please confirm that the tax treatments shown in Tables A to D reflect actual tax treatments. If not, please explain the actual tax treatment.

d) Under the NBV Reduction Methodology in Tables C and D, please explain why taxes on capital contribution are applied during the period that the capital contribution is received and not the period that the capital contribution is amortized into income over the life of the asset.

e) Please explain whether the revenue requirement difference between the two methodologies is a permanent difference or a timing difference that will reverse in the future. If it will reverse, please explain when it will reverse and whether it will be reflected in the proposed account.

<u>Response:</u>

a) Confirmed. Both the Loan Methodology and the NBV Reduction Methodology would allow Hydro One to recover the revenue requirement on the unpaid capital contribution as per the OEB's Notice of Revised Proposal to Amend a Code[1]. However, the Loan Methodology option would result in a smaller impact on Hydro One Transmission's rate payers versus the NBV Reduction Methodology.

b) The majority of the revenue requirement difference between the Loan Methodology and the NBV Reduction Methodology is due to the tax calculation as a result of the way the capital contribution is recorded; the remainder is due to the impact on depreciation.

c) Confirmed. Table A to Table D of Exhibit B, Tab 9, Schedule 1, reflect actual tax treatments.

d) As per section 12(1)(x) of the *Income Tax Act*, any additional capital contributions from the customer after the initial in-service are treated as revenue for corporate taxation purposes and subject to the full 26.5% corporate tax rate.

Taxes have been applied during the period the capital contribution is received in accordance with the Income Tax Act. In accordance with paragraph 12(1)(x) amounts received as reimbursements/inducements (i.e. capital contributions) are treated as income for tax. However, there are exceptions where amounts are received in respect of a depreciable property that was; i) Acquired in the current year, ii) acquired three years preceding the current year, and iii) acquired the year immediately following the current year. Under these exemptions the taxpayer can elect to reduce the capital cost of the property (rather than take the amounts into income). Since, the capital contributions received fall outside the time frames noted in i) to iii) above they do not qualify for an exception and are treated as income.

[1] EB-2016-0003 dated August 23, 2018

e) The revenue requirement difference between the two methodologies is a permanent difference due to the tax implications between both methodologies.

OEB STAFF INTERROGATORY #20

Reference:

Exhibit B/Tab 10/Schedule 1/p. 3, Appendix A

Interrogatory:

Hydro One is requesting approval of an accounting order to establish a new variance account, the "Capital Contribution Differential Account".

Questions:

Regarding the requested establishment of the deferral and variance account:

a) In the application, Hydro One is unclear on the specific section of the *Ontario Energy Board Act, 1998* (OEB Act) in which it is requesting approval of an accounting order to establish a new variance account. Please identify the specific section of the OEB Act in which Hydro One is requesting approval of an accounting order.

b) Please confirm that the account is requested regardless of if the Loan Methodology or NBV Reduction Methodology is used in determining the revenue requirement difference.

c) Hydro One indicated that the expected shortfall in revenue requirement to be recorded in the account is $5.2 million over the loan period, which exceeds the $3 million materiality threshold of Hydro One Transmission. Typically, the materiality threshold is an annual amount. Please confirm that the annual amount expected to be recorded in the account would not meet an annual materiality threshold of $3 million.

    i. The NBV Reduction Methodology expects $7.5 million to be recorded in the account over 15 years or $4.6 million to be recorded in the account over five years. This equates to an average of $500,000 annually for 15 years or $920,000 annually for five years. Please explain why Hydro One Transmission is requesting the account given the immaterial annual amounts.

d) In the draft accounting order, it states that Hydro One is proposing the establishment of this account for any other customer in the future that utilizes the provision in TSC section 6.3.19 to delay full capital contribution payment.

i. Please explain whether this account is to be used only if the payment period exceeds a five year period or for all capital contributions regardless of payment period.
ii. Please confirm that Hydro One is requesting this account to be used for any future projects where there is a delay in the capital contribution payment and not specifically for the BATU Project.

e) In the Notice of Revised Proposal to Amend a Code (EB-2016-0003), dated August 23, 2018, page 17 indicates a transmitter expressed the view that distributors should pay interest to the transmitter at the transmitter's OEB approved cost of capital on the unpaid capital contribution balance, rather than the OEB's prescribed CWIP rate. The OEB disagreed. Please provide additional rationale on Hydro One's position to deviate from the OEB's policy on using the CWIP rate.

Response:

a) Hydro One is requesting approval to establish a new variance account under section 78 of the OEB Act.

b) Confirmed. However, utilizing the NBV methodology over the loan methodology would result in a higher deferral account balance to be recovered from Hydro One Transmission rate payers.

c) Hydro One confirms that the annual amount expected to be recorded in the account relating to this specific BATU Project would **not** meet an *annual* materiality threshold of $3 million. However, Hydro One is requesting this to be a generic variance account which would be available to use for future transmission projects where similar circumstances may occur, e.g. if other customers elect to avail themselves to the recent amendments to the Transmission System Code ("TSC") allowing a delay in their capital contribution payment beyond Day One of a project's in-service date. Section 6.3.19 of the TSC states:

> *"Where a distributor is required under this Code to provide a capital contribution to a transmitter, the*

> *transmitter shall permit the capital contribution to be provided in equal installments over a period of time not to exceed five years unless a longer period is approved by the Board. Where a distributor provides the capital contribution in installments, the transmitter shall charge interest on the unpaid balance at the Board's prescribed construction work in progress (CWIP) rate which is updated quarterly and published on the Board's website. The interest charges shall accrue monthly commencing on the date the connection asset goes into service and be paid annually, as part of each installment payment." [emphasis added]*

Due to the updated amendments to the TSC, Hydro One points out that it has effectively **<u>no</u>** control over the timing of when it will receive the customer's capital contributions (e.g. the customer may choose to pay their capital contribution all upfront or over an extended period). This will create a cash shortfall to Hydro One, as the CWIP rate is insufficient to cover the long-term debt rate of Hydro One, much less the WACC to maintain the asset in rate base. Hydro One anticipates the annual cumulative impact of shortfalls will grow as other distributors become aware, and then avail themselves, of the new opportunity these TSC provisions allowed on other Hydro One constructed projects. This will likely result in entries that will satisfy the deferral account eligibility threshold criteria.

d)
   i. Hydro One proposes that the account will be used for all capital projects in which a distributor elects to defer the capital contribution, regardless of the elected payment period.

   ii. Confirmed.

e) Under the proposal, the distributor will only be paying the OEB prescribed CWIP rate (currently 2.88%) for the outstanding capital contribution balance as per the TSC 6.3.19 (as quoted in part c above). As per the OEB Notice of Revised Proposal to Amend a Code EB-2016-0003 August 23, 2018 ("the Amendments"), the "OEB intent was to hold the transmitter harmless". As the asset will be fully in-service, the transmitter, per OEB standard rate-making principles, should be allowed to recover all costs associated with the approved asset. Hydro One current third party long term debt rate is 4.68% and return on equity is even higher, which results in Hydro One cross-subsidizing the distributor.

Additionally, as Hydro One will not be able to forecast if customers will elect to defer capital contribution payments, Hydro One's business plan assumes that any customer capital contributions are received on Day 1, thus lowering its rate base and revenue requirement. This also results in Hydro One cross-subsidizing the distributor.

The regulatory account is designed to calculate the impact of the delayed receipt of capital contributions on the transmitter and allow the transmitter to recover its prudently incurred costs (as shown in Exhibit B, Tab 9, Schedule 1, Attachment 1).

Hydro One believes requesting the account for approval at this time is prudent, due to the uncertainty of these risks and their potential size. If the OEB does not approve the account in this Application, Hydro One will be required to amend the transmission rate application to forecast delays in capital contribution payments and their resulting impact on revenue requirement for all transmission projects for distributors within Ontario (not just the current investment) to ensuring Hydro One is held whole.

Hydro One believes it is more prudent and less impactful to rate payers to manage this risk through a regulatory account instead of forecasting the potential impact in revenue requirement. Hydro One understands that the OEB's approval to establish the account is not a guarantee of cost recovery. The Board will have the opportunity, during a future transmission revenue requirement application, to review the prudency of any amounts recorded in the deferral account prior to approving for disposition.

OEB STAFF INTERROGATORY #21

Reference:

Exhibit B/Tab 1/Schedule 1/Attachment 1 – InnPower May 23, 2019 letter
InnPower October 16, 2019 letter

Interrogatory:

As part of the application, Hydro One included a letter from InnPower regarding the capital contribution period and its support for the BATU Project. The following questions are directed to Hydro One as the applicant, but OEB staff requests that Hydro One make all necessary inquiries of InnPower in order to respond to these questions.

Questions:

a) In the October 16, 2019 InnPower letter, InnPower states that if the capital contribution is to be paid within five years, this will impose increased financial pressure on the company as well as on InnPower's ratepayers.

   i. Please quantify the impact of the capital contribution payment over a five year and 15 year period on InnPower's cash flows, ROE and bill impact to rate payers.
   ii. Please further discuss any other pressures or issues that may arise due to the difference in payment terms.

Response:

a) The following responses were provided to Hydro One by InnPower to assist in answering this interrogatory.

   i. Please refer to the response provided in Exhibit I, Tab 1, Schedule 16, Part (a).

   ii. InnPower continues to experience significant growth throughout their service territory, including the Town of Innisfil and the South Barrie lands. In order to supply and support the growth, InnPower is contributing to and supporting the BATU Project.

Consistent with the response provided in Exhibit I, Tab, 1, Schedule 16, InnPower is supporting Hydro One's request for a 15 year capital contribution payment period due to the quantum of the capital contribution payment and its impacts on InnPower customers if it was levied into rate base over a shorter period of time. For example, if InnPower was required to pay the capital contribution over 5 years, this would result in a $3.14 million/year capital expenditure. Based on InnPower's 2016 cost of service, the approved annual capital expenditures, included in rates, were $4.4 million. The BATU Project's capital contribution would represent approximately 71% of InnPower's annual approved capital expenditures. InnPower requires its approved capital expenditure budget for expansion and maintenance of its distribution network. To reduce or defer 70% of its planned investments, to accommodate the BATU rate base portion under its current level of approval, would impact electricity service to InnPower's customers. If the Board was to allow InnPower to increase its capital expenditure portfolio by the capital contribution amount over only five years, this will result in a substantial rate impact to customers[1]. By extending the BATU Project's capital contribution over 15 years, InnPower can effectively manage its annual capital expenditures to include the $1.05 million capital contribution payment.

If the 15 year time horizon is disallowed by the OEB, InnPower will also incur significant borrowing costs, which will be included in revenue requirement, to finance the larger annual $3.14 million payment. These increased interest costs will contribute to rate increases as a result of the significant increase in the rate base for the 5-year scenario, compared to the interest costs under the longer 15-year period.

Extending the capital contribution payment over a 15-year time horizon also coincides with InnPower's preliminary load growth estimates. A 15-year payment term allows for new customers, who require the BATU Project expansion, to contribute (in the form of rates revenues) towards the annual $1.05 million capital contribution payment. This allows for a more measured rate base growth that will be matched more closely to InnPower customer and load growth increases.

[1] Please refer to Exhibit I, Tab, 1, Schedule 16, Part (a), regarding estimated customer impacts.