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February 18, 2020

Delivered by Email, RESS & Courier

Ms. Christine Long
Registrar and Board Secretary
Ontario Energy Board
2300 Yonge Street
27th Floor, Box 2319
Toronto, ON M4P 1E4

Dear Ms. Long:

Re: Application for leave to upgrade existing transmission line facilities in the Barrie-Innisfil area
Board File No. EB-2018-0117
InnPower Responses to Technical Conference Undertakings

In connection with the subject proceeding, please find enclosed InnPower Corporation's technical conference undertaking responses. Paper copies of this letter and the accompanying documents will be delivered to you by courier.

Should you have any questions or require further information in this regard, please do not hesitate to contact me.

Yours very truly,

BORDEN LADNER GERVAIS LLP

Per:

Original signed by Gian Minichini

Gian Minichini

cc: Glen McAllister, InnPower Corporation
Danny Persaud, InnPower Corporation
Linda Gibbons, Hydro One Networks Inc.
Michael Engelberg, Hydro One Networks Inc.

EB-2018-0117

APPLICATION FOR LEAVE TO UPGRADE EXISTING TRANSMISSION LINE FACILITIES IN THE BARRIE-INNISFIL AREA

InnPower Corporation

Response to Technical Conference Undertakings

Filed: February 18, 2020

Table of Contents

UNDERTAKING JT1.1

Reference:

EB-2018-0117 – InnPower Corporation Technical Conference Evidence (Exhibit K.T1.2) – Tab B – Slide 4: Power Supply and Demand

Undertaking:

To provide a historical look back, breaking down essentially the table back five years from present and then a 15-year projection forecast for each of the stations.

Response:

Table JT1.1-1 below provides InnPower's historical and forecasted system peak loading by supply point. The forecasted load figures for years 2020 to 2031 were derived using the forecasted subdivision draft approval figures from Table JT1.2-1, which is provided in the response to JT1.2, below. The forecasted load figures for years 2032 to 2035 are based on an annual average forecasted demand growth of 1.1%.

As described in InnPower's slide deck (Tab B of Exhibit KT.1.2), which was presented at the Technical Conference on Feb. 11th 2020, InnPower applied an empirically-derived per unit demand of 2.88 kW in deriving load forecasts for residential developments. Load forecasts for schools, recreational centres and small commercial developments also use empirically-derived per unit demands based on similar facilities in InnPower's service territory. For large commercial and industrial load forecasts, InnPower used industry-accepted per unit demands based on land area as there is no information on how these lands are to be specifically used. These numbers are 0.073 kW/m^2 (77 VA/m^2) for commercial lands, and 0.058 kW/m^2 (61 VA/m^2) for industrial lands. InnPower further assumed a power factor of 0.95, reflective of its current system conditions.

For 2020 to 2031, InnPower multiplied the number of forecasted occupancies/energizations with the per-unit demands outlined above and totalled them. This was used to provide an incremental peak demand on a year by year basis. Starting in 2032, InnPower forecasted the increase in demand growth per supply point using the following methodology. InnPower used the average annual historical demand growth excluding major developments of 2.27 MVA (2.16 MW at 0.95 power factor) and multiplied this number by the 2019 proportionate peak at every supply point (21% for Barrie, 76% for Alliston and 2% for Everett of the total system peak in 2019). This resulted in an annual MVA increase for every supply point. Overall, this represents a 1.1% growth in the total system peak year over year.

As can be seen, the 2032 forecasted total system peak is approximately 203 MVA (192 MW at 95% pf). Additionally, the 2032 forecasted large commercial and industrial peak is about 54 MVA (51 MW at 95% pf). This is consistent with the information presented in the InnPower slide deck in Tab B of Exhibit KT.1.2.

Table JT1.1-1: InnPower Corporation's historical and forecasted system peak loading by transformer station.

IPC Load Forecast (CUMULATIVE)
(Based on 2019 DS peak and 44kV Customers Peak Demand)

SUPPLY POINT	INNPOWER ASSIGNED STATION CAPACITY BY HONI (MVA)	INNPOWER HISTORIAL SYSTEM PEAK (MVA)					INNPOWER FOREASTED SYSTEM PEAK (MVA)															
							Based on Forecasted Subdivision Draft Apporval												Based on Forecasted Growth of average of 1.1% per year			
		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
ALLISTON TS	50.00	38.11	39.79	46.43	50.60	49.09	56.02	58.39	61.27	63.92	65.85	70.32	73.47	76.71	79.16	81.10	81.71	82.66	84.40	86.13	87.87	89.60
BARRIE TS - TOTAL	14.00	11.47	12.50	13.68	14.32	13.82	18.41	23.70	31.15	39.06	47.94	57.47	68.19	77.53	86.69	94.90	103.16	116.42	116.90	117.39	117.88	118.36
res., schools, rec. centres, small commercial		11.47	12.50	13.68	14.32	13.82	16.78	22.07	26.96	32.30	36.05	40.45	46.04	50.25	54.28	57.36	60.49	62.49	62.97	63.46	63.94	64.43
large commercial & industrial (40% Conservative Factor)		0.00	0.00	0.00	0.00	0.00	1.63	1.63	4.19	6.76	11.89	17.02	22.15	27.28	32.41	37.54	42.67	53.93	53.93	53.93	53.93	53.93
EVERETT TS	3.00	2.11	2.11	1.05	1.37	1.37	1.42	1.42	1.51	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.58	1.63	1.68	1.73	1.77
TOTAL SYSTEM	**67.00**	**51.68**	**54.39**	**61.17**	**66.29**	**64.28**	**75.85**	**83.51**	**93.93**	**104.56**	**115.37**	**129.37**	**143.24**	**155.82**	**167.43**	**177.58**	**186.45**	**200.66**	**202.93**	**205.20**	**207.47**	**209.74**

As a measure of prudency and due diligence, InnPower has undertaken a sensitivity analysis on the forecasted data (shown in the Table JT1.1-2 below) in order to achieve a more conservative estimate of its forecasted total system peak. To achieve this, the forecasted incremental total system peak in each year was discounted by 35% ([2019 System Peak] + ([20xx System Peak]-[2019 System Peak]) x 0.65). 35% was empirically derived as a ratio of occupancy permits issued to total occupancy permits forecasted on average. Note that this 35% is applied to the total system, which includes the already discounted (40%) large commercial and industrial loads. This results in a higher conservative estimate for the large commercial and industrial loads.

Table JT1.1-2: InnPower Corporation's forecasted total system peak loading after applying sensitivity analysis.

INNPOWER FOREASTED SYSTEM PEAK (MVA)																
	Based on Forecasted Subdivision Draft Apporval												Based on Forecasted Growth of average of 1.1% per year			
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
TOTAL SYSTEM (35% Conservative Factor)	71.80	76.78	83.55	90.46	97.49	106.59	115.60	123.78	131.33	137.93	143.69	152.92	154.40	155.88	157.35	158.83

UNDERTAKING JT1.2

Reference:

EB-2018-0117 – InnPower Corporation Technical Conference Evidence (Exhibit K.T1.2) – Tab B – Slides 6-10

Undertaking:

To provide current construction developments in progress or in the process of permitting, with a projection within the next 15 years, including units planned and under construction.

Response:

Figure JT1.2-1 below is a revised version of the map provided in the InnPower slide deck in Exhibit KT.1.2. Figure JT1.2-1 shows major subdivision developments currently underway in InnPower's service area, and Figure JT1.2-2 provides recent close-up photographs of the various developments. Note Figures JT1.2-1 and JT1.2-2 are meant to provide a snapshot of the largest and most significant developments currently underway in InnPower's service area. They are not intended to represent an exhaustive list of all development and construction activity occurring in the area. Additionally, Figures JT1.2-1 and JT1.2-2 do not show the many subdivisions that have already been completed and energized, which are reflected in the forecast figures provided in Table JT1.1-1 above. InnPower expects that developments will start and continue as the weather becomes warmer in 2020. Note also that although some sites are partially energized, as indicated in Figure JT1.2-1, construction of those developments is ongoing.

Table JT1.2-1 provides a list of known residential and commercial development locations planned or underway in InnPower's service area, along with the forecasted number of units expected to come online for each development location in each year between 2020 and 2032.

Figure JT1.2-1: Map of InnPower Corporation's service area showing major subdivision developments currently underway.

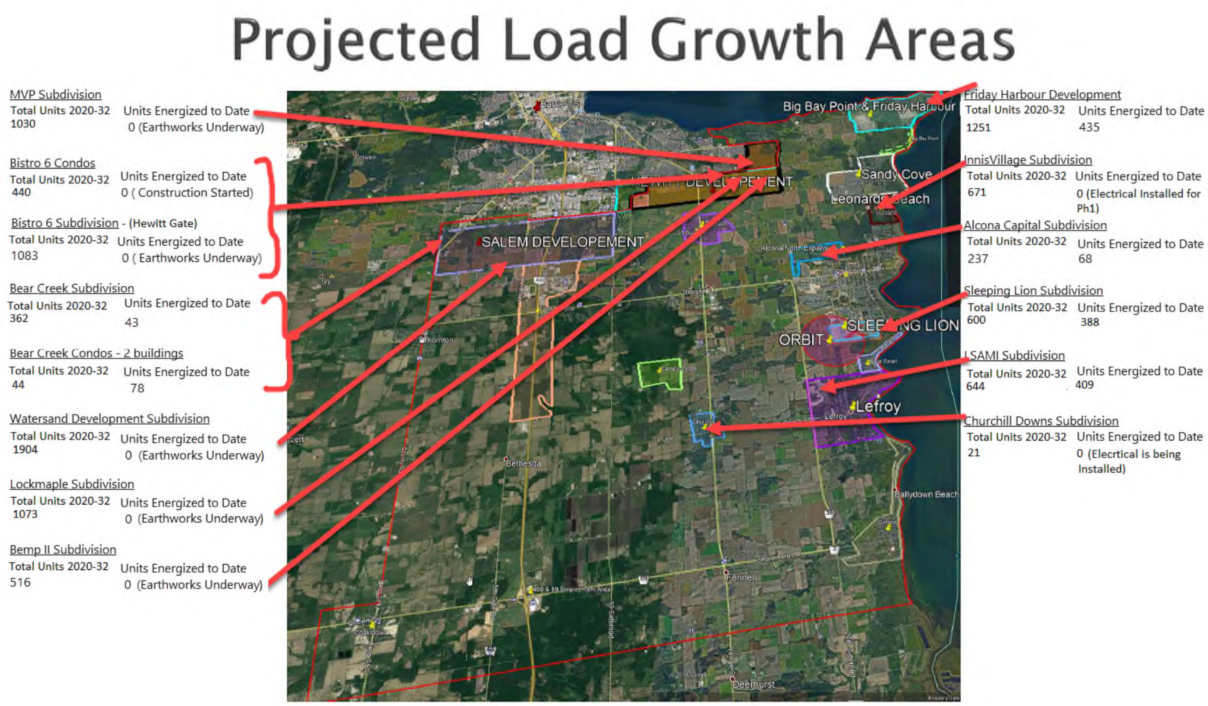
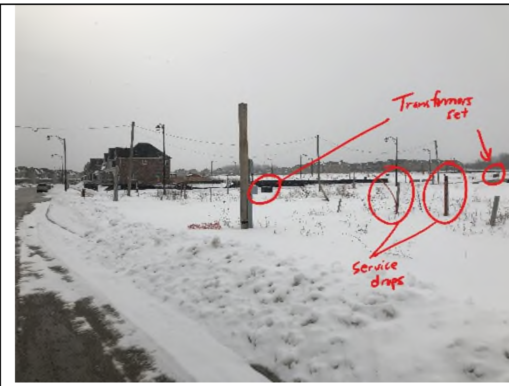


Figure JT1.2-2: Close-up photographs of subdivisions currently in development in InnPower's service area.

 Bear Creek Ridge Condos Construction	 Bear Creek Ridge Subdivision Construction	 Bistro 6 Condos Construction
 Bistro 6 Subdivision Construction	 Friday Harbour Resort Condos Construction	 Friday Harbour Resort Condos


Friday Harbour Resort Construction


Secondary School Construction



LSAMI Subdivision Construction

Sleeping Lion Subdivision Construction


Innisvillage Subdivision Construction

EMG Barrie GT Inc. Subdivision Construction

 EMG Barrie GT Inc. Subdivision Construction	 MVP Subdivision Construction	 Watersand Subdivision Construction
 Watersand Subdivision Construction		

Table JT1.2-1: List of known residential and commercial developments in InnPower's service area and forecasted number of units associated with each development in 2020-32.

Location	Unit Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Alcona	Residential	467	319	276	295	225	195	22	0	0	0	0	0	0	1,799
Alcona South	Residential	100	100	100	100	100	100	0	0	0	0	0	0	0	600
Bigbaypoint	Residential	225	275	250	301	100	100	0	0	0	0	0	0	0	1,251
Bigbaypoint	Commercial	0	0	1	1	1	1	1	1	1	1	1	1	3	13
Churchill	Residential	6	0	0	0	0	0	0	0	0	0	0	0	0	6
Cookstown	Residential	0	0	30	23	0	0	0	0	0	0	0	0	0	53
Hewitt	Residential	467	1,397	1,133	1,227	925	1,144	1,826	1,360	1,371	1,043	1,063	445	132	13,533
Hewitt	Commercial	1	2	0	0	0	0	0	0	0	0	0	7	0	10
Lefroy	Residential	101	140	175	167	65	65	0	0	0	0	0	0	0	713
Salem	Residential	264	239	400	318	250	1,121	1,013	1,074	809	645	200	257	0	6,590
Salem	Commercial	4	0	0	0	0	0	0	0	0	0	0	13	0	17
Total (Residential)		**1,630**	**2,470**	**2,364**	**2,431**	**1,665**	**2,725**	**2,861**	**2,434**	**2,180**	**1,688**	**1,263**	**702**	**132**	**24,545**
Total (Commercial)		**5**	**2**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**21**	**3**	**40**
Total		**1,635**	**2,472**	**2,365**	**2,432**	**1,666**	**2,726**	**2,862**	**2,435**	**2,181**	**1,689**	**1,264**	**723**	**135**	**24,585**

UNDERTAKING JT1.3

Reference:
EB-2018-0117- Hydro One Networks Inc.'s Section 92 – Barrie Area Transmission Upgrade Project – Interrogatory Responses – Exhibit I, Tab 1, Schedule 1 – Response to OEB Staff Interrogatory No. 1(e), Page 4 of 6, Table 2

Undertaking:
To provide demand forecast narratives explaining changes between years broken down between residential, industrial/commercial.

Response:

Please refer to the responses of JT 1.1 and JT 1.2, above, which provide residential and industrial/commercial peak demand and unit counts are provided.

Over the next five years, the growth in peak demand at Barrie TS is as follows:

1. 2019-2020 projected increase of 4 MW, primarily attributable to residential growth.
2. 2020-2021 projected increase of 5 MW, primarily attributable to residential growth with 6% large commercial & industrial growth.
3. 2021-2022 projected increase of 7 MW, primarily attributable to residential growth with 13% large commercial & industrial growth.
4. 2022-2023 projected increase of 8 MW, primarily attributable to residential growth with 17% large commercial & industrial growth.
5. 2023-2024 projected increase of 8 MW, primarily attributable to residential growth with 25% large commercial & industrial growth.
6. 2024-2025 projected increase of 9 MW, primarily attributable to with 30% large commercial & industrial growth.

Please note that Hydro One's response to Interrogatory #1(e), Exhibit 1, Tab 1, Schedule 1, page 5 of 6 contained the following errors:

1. The 2019 peak demand of 11 MW stated in IRR #1(e) should be 13 MW (14 MVA); and
2. Hydro One, in copying the load data into Table 2, inadvertently shifted InnPower's forecast behind by one year in error (for instance, the 2021 estimates were used in 2020, and the 2022 estimates were used in 2021). The true 2020 forecast for Barrie TS is 18 MW (19 MVA), and not 22 MW as indicated in Table 2 of IRR #1(e).

The correct figures represents a 4 MW (5 MVA) increase from 2019 to 2020, and not the 11 MW (12 MVA) increase stated in the interrogatory response.

UNDERTAKING JT1.4

Reference:

EB-2018-0117- Hydro One Networks Inc.'s Section 92 – Barrie Area Transmission Upgrade Project – Interrogatory Responses – Exhibit I, Tab 1, Schedule 1 – Response to OEB Staff Interrogatory No. 1(e), Page 5 of 6, Table 2; and Exhibit I, Tab 1, Schedule 16 – Response to OEB Staff Interrogatory Number 16(a), Page 2 of 4.

Undertaking:

To clarify the discrepancy between the statement and the table quoted in reference to OEB Staff Interrogatory Number 16(a), Exhibit I, Tab 1, Schedule 16, Page 2 of 4.

Response:

As explained in the response to JT1.3 above, Table 2 in Hydro One's response Interrogatory #1(e) contained errors resulting in InnPower's 2019 peak demand being reduced by 2 MW, and the forecasted values in Table 2 in the response to IRR#1(e) being shifted by one year. JT 1.3, above, provides InnPower's forecasted year over year incremental demand growth for Barrie TS, which shows an expected rate of load growth starting at 4 MW per year from 2019 to 2020, increasing to 9 MW per year from 2024 to 2025.

Table 2 in the response to Interrogatory #1(e) shows that InnPower's load growth is forecasted to reach 50 MW in 2024 (which should be 2025 after adjusting for error described in the response to JT1.3 above) and plateauing at this value until 2039. This number does not represent InnPower's forecasted total system load growth, which is expected to grow beyond 50 MW from 2025 onwards. Rather, 50 MW is a forecast of the maximum capacity expected to be allocated to InnPower at Barrie TS (assuming the BATU project is completed). InnPower's additional load growth beyond 50MW that cannot be serviced by Barrie TS will need to be serviced by an alternative supply solution as the need arises.

UNDERTAKING JT1.7

Reference:

EB-2018-0117- Hydro One Networks Inc.'s Section 92 – Barrie Area Transmission Upgrade Project – Interrogatory Responses – Exhibit I, Tab 1, Schedule 16 – Response to OEB Staff Interrogatory Number 16(a), Page 2 of 4, Footnote 1.

Undertaking:

To provide the exact percentage calculated by the model.

Response:

The model used to calculate the base distribution rate increase in the response to IRR #16 did not take into account the proposed customer growth, which has been corrected in the revised model used in the responses for JT1.8 and JT1.9, below. In the original model, the actual incremental percentage rate increase calculated for the capital contribution paid over 5 years was 11.09% versus the incremental rate increase of the capital contribution being brought in over 15 years of 3.69%. In the original model, the Residential customer growth number used was equal to the Residential customer growth experienced between the 2013 COS and the 2017 COS, which was growth of 9.6% from 2013 to 2017, as further detailed in Table JT1.7-1 below.

Table JT1.7-1: Number of InnPower customers in 2013, 2017, and 2022.

Residential	2013	2017	2022	% =/- 2013 to 2017
Customers	14,189	15,555	17,048	9.6%
kWh	146,329,877	145,847,424	159,848,777	-0.3%
kWh per Customer	10313	9376		
GS<50				
Customers	910	1,034	1,175	13.6%
kWh	29,061,346	31,828,340	36,156,994	9.5%
kWh per Customer	31,935.55	30,781.76		
GS>50				
Customers	66	88	117	33.3%
kWh	51,921,263	63,763,903	84,997,282.70	22.8%
KW	149,368	176,744	235,599.75	18.3%
kWh per Customer	786,685.80	724,589.81		
kW per Customer	2,263.15	2,008.45		
Sentinels				
Customers	237	161	161	-32.1%
kWh	104,109	103,052	103,052	-1.0%
KW	289	286	286	-1.0%
kWh per Customer	439	640		
kW per Customer	1.22	1.78		
Streetlights				
Customers	2,889	2,995	3,107	3.7%
kWh	1,504,796	561,223	582,268.86	-62.7%
KW	4,398	1,599	1,658.96	-63.6%
kWh per Customer	520.87	187.39		
kW per Customer	1.52	0.53		
USL				
Customers	78	74	76	-5.1%
kWh	591,925	461,015	473,474.86	
kWh per Customer	7,589	6,230		
Total Customer/Connections	18,369	19,907	21,685	8.4%
Total kWh	228,921,391	242,103,942	281,688,375	5.8%
Total kW	154,055	178,629	237,545	

UNDERTAKING JT1.8

Reference:

EB-2018-0117- Hydro One Networks Inc.'s Section 92 – Barrie Area Transmission Upgrade Project – Interrogatory Responses – Exhibit I, Tab 1, Schedule 16 – Response to OEB Staff Interrogatory Number 16(a), Page 2 of 4.

Undertaking:

To provide revised bill impact calculations.

Response:

A detailed rate model was developed in order to respond to undertakings JT1.8 and JT1.9. Table JT1.8-1 below contains the total bill impacts in years 2022 to 2036 resulting from InnPower's Capital Contribution for the BATU project, as well as the year over year percentage differences in bill impacts. Three cases are considered:

1. Case 1: the full Capital Contribution of $15.7M is paid in one year (2022, the year BATU is expected to be in service), and the full amount of $15.7M is borrowed in 2022.
2. Case 2: the Capital Contribution is paid over five years, starting in 2022. The borrowing is spread over the five years, such that $3.14M is borrowed in each of the five years.
3. Case 3: the Capital Contribution is paid over fifteen years, starting in 2022. Under this scenario, InnPower does not expect to borrow any money to cover the Capital Contribution.

Table JT1.8-2 provides the percentage differences for each year 2022 to 2036 comparing each of the three cases detailed above and in Table JT1.8-1. The analysis assumes the InnPower will not carryout any other major capital improvements over the 15 year period.

In addition, Table JT1.8-3 below provides the impact on InnPower debt covenants of the 1-year, 5-year, and 15-year funding of the Capital Contribution. These include InnPower's the Debt to Capital covenant from Toronto-Dominion Bank ("TD"), as well as the Debt Service Coverage ratio obligations for both its TD and Infrastructure Ontario ("IO") debt.

The DSC calculation takes into account the Free Cash Flow (FCF), which is the EBITDA less 35% of Net Capex. The 35% of Net Capex assumes that 65% of the cost of capital assets is borrowed from the bank, while the remaining 35% is funded directly by the borrower. For Case

1, with $15.7M in gross capital, 35% of Net Capex is $7.5M, which reduces the FCF down to $1.3M.

For Cases 2 and 3, there is no violation in the DSC covenants due to the reduction of the annual Capital Contribution to $3.14M over 5 years, and $1.046M over 15 years. This allows for the FCF to remain in excess of EBITDA by 1.20 or 1.30 for TD and IO, respectively, thereby not violating the DSC.

Note the original model used to produce the debt covenant table that was included at Tab C of Exhibit KT.1.2 considered only Case 1 (i.e. applying the entire Capital Contribution of $15.7M in one year). However, in that original model, although the entire $15.7M was applied in 2022, the borrowing was assumed to be spread over five years (at a rate of $3.14M per year) starting in 2022. As a result, the values provided for Case 1 in Table JT1.8-3 do not align with those provided in Tab C of Exhibit KT.1.2.

Table JT1.8-1: Residential total bill impacts (excluding Distribution Rate Protection) for years 2022 to 2036 for three cases.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Case 1 - Cap Cont in 1 Year (2022)	$135.48	$130.17	$130.71	$131.25	$131.80	$132.37	$126.80	$127.28	$127.77	$128.26	$128.76	$126.52	$126.99	$127.47	$127.96	$128.46
% change YoY	-	-3.92%	0.41%	0.42%	0.42%	0.43%	-4.20%	0.38%	0.38%	0.39%	0.39%	-1.74%	0.37%	0.38%	0.38%	0.39%
Case 2 – Cap Cont over 5 Years (starting in 2022)	$135.48	$129.10	$129.61	$130.14	$130.67	$131.21	$127.00	$127.48	$127.97	$128.46	$128.97	$126.68	$127.15	$127.64	$128.13	$128.63
% change YoY	-	-4.71%	0.40%	0.40%	0.41%	0.42%	-3.21%	0.38%	0.38%	0.39%	0.39%	-1.78%	0.37%	0.38%	0.38%	0.39%
Case 3 – Cap Cont over 15 Years (starting in 2022)	$135.48	$128.91	$129.43	$129.95	$130.48	$131.02	$125.91	$126.37	$126.84	$127.32	$127.80	$126.47	$126.94	$127.42	$127.91	$128.40
% change YoY	-	-4.85%	0.40%	0.40%	0.41%	0.41%	-3.90%	0.37%	0.37%	0.38%	0.38%	-1.04%	0.37%	0.38%	0.38%	0.39%

In summary, for each year the model determines the estimated revenue requirement assuming a cost of service application. The Residential rate calculations assumes the rebasing years are 2022, 2027 and 2032. All other years are assumed to be an IRM year. Residential distribution rates are determined for each year based on the estimated revenue requirement. If it is a rebasing year, the Residential rate will be based on the estimated revenue requirement for that year. If it is an IRM year, the Residential rate will be the rate from the previous year adjusted by the IRM factor for the year. The IRM factor of 1.7% assumes the OEB's inflation factor which is 2.0% for 2020. This is offset by the stretch factor for InnPower of 0.3%. The resulting Residential rates for each year are included in the annual total bill calculations. All other components of the total bill calculations are held constant at the 2020 level as InnPower was not aware of a good method to forecast the other components.

The total bill excludes the Distribution Rate Protection ("DRP") since including it would not provide the correct bill comparison as it would limit the net monthly service charge to $36.86 which is the threshold value for 2020. For InnPower, the net monthly service charge is the gross monthly service charge minus the DRP which is an adjustment to bring the monthly service charge to $36.86. If the DRP was included there would not be any change in the bills when different assumptions are used since the monthly service charge would be limited to $36.86.

Additional assumptions underpinning the model used to produce Table JT1.8-1 are discussed below.

Table JT1.8-2: Percentage differences comparing the three cases detailed in Table JT1.8-1.

% **Differences**	**Case 1 vs Case 2**	**Case 1 vs Case 3**	**Case 2 vs Case 3**
2022	-0.83%	-0.97%	-0.14%
2023	-0.84%	-0.98%	-0.14%
2024	-0.85%	-0.99%	-0.15%
2025	-0.86%	-1.01%	-0.15%
2026	-0.87%	-1.02%	-0.15%
2027	0.15%	-0.71%	-0.86%
2028	0.15%	-0.72%	-0.87%
2029	0.16%	-0.72%	-0.88%
2030	0.16%	-0.73%	-0.89%
2031	0.16%	-0.74%	-0.90%
2032	0.13%	-0.04%	-0.17%
2033	0.13%	-0.04%	-0.17%
2034	0.13%	-0.04%	-0.17%
2035	0.13%	-0.04%	-0.17%
2036	0.13%	-0.04%	-0.17%

Table JT1.8-3: Debt Covenant Tables for Cases 1 to 3.

Year	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Case 1														
Debt: Cap TD	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
Calculated	0.58	0.54	0.51	0.56	0.52	0.49	0.45	0.42	0.39	0.35	0.33	0.30	0.27	0.25
Covenant met	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
DSC TD	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Calculated	2.36	2.28	2.34	0.47	2.26	2.08	1.94	1.84	1.80	1.80	1.84	1.82	1.87	1.87
Covenant met	YES	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
DSC IO	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Calculated	2.36	2.28	2.34	0.47	2.26	2.08	1.94	1.84	1.80	1.80	1.84	1.82	1.87	1.87
Covenant met	YES	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Case 2														
Debt: Cap TD	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
Calculated	0.58	0.54	0.51	0.51	0.52	0.52	0.51	0.51	0.49	0.48	0.46	0.45	0.43	0.42
Covenant met	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
DSC TD	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Calculated	2.36	2.27	2.36	1.85	1.87	1.89	1.90	1.90	2.22	2.26	2.30	2.25	2.31	2.30

Covenant met	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
DSC IO	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Calculated	2.36	2.27	2.36	1.85	1.87	1.89	1.90	1.90	2.22	2.26	2.30	2.25	2.31	2.30
Covenant met	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
Case 3														
Debt: Cap TD	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68	0.68
Calculated	0.58	0.54	0.51	0.49	0.48	0.47	0.46	0.44	0.43	0.42	0.41	0.40	0.39	0.38
Covenant met	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
DSC TD	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
Calculated	2.36	2.27	2.36	1.79	1.83	1.87	1.90	1.93	2.33	2.42	2.50	2.47	2.58	2.59
Covenant met	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES
DSC IO	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Calculated	2.36	2.27	2.36	1.79	1.83	1.87	1.90	1.93	2.33	2.42	2.50	2.47	2.58	2.59
Covenant met	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES	YES

<u>Assumptions Pertaining to Table JT1.8-1</u>

The following outlines the detailed assumptions used in the model.

1. The starting point for the model is the information that supports the approved 2017 cost of service application.
2. Up to 2021 the standard capital reflects information from the DSP filed as part of InnPower's 2017 cost of service application. After 2021, a flat $6 million of standard capital is assumed for each year.
3. Capital associated with the capital contribution to HONI of $15.7 million is included for three cases: included in rate base in one year; included in rate base over 5 years and included in rate base over 15 years.
4. For the 5 and 15 year cases, any CWIP amount paid to HONI is assumed to be capitalized and included in the InnPower rate base.
5. All capital is assumed to have a useful life of 50 years.
6. Rate base is determined each year assuming the average of the opening and closing net book value plus a working capital allowance.
7. Net book value is gross assets minus accumulated depreciation.
8. Gross assets are adjusted each year by the capital in each year.
9. Accumulated depreciated is the previous year amount plus depreciation in the year.
10. Depreciation reflects the useful life assumption plus the half year rule for new capital.
11. Working capital includes a forecast of cost of power plus OM&A expenses
12. Cost of power is the 2017 amount increased by 2% per year.
13. OM&A is the previous year amount increase by the IRM factor plus 44% of customer growth. This formula has been recently used by the OEB to approved OM&A levels in cost of service applications. The 44% represents a factor determined by the Pacific Economic Group (PEG) in their bench-marking work for the OEB which suggest that for every 1% increase in customers OM&A costs will increase by 0.44%.
14. Return on rate base is assumed to be 5.58% over the forecast period which is the rate of return approved in 2017 for InnPower.
15. PILs are calculated for each year but result in value of zero since the CCA amount under the current Bill 97 C brings the PILs to zero. CCA is determined each year based on the capital program and assumes a 12% in the first year on a full year basis and 8% thereafter.
16. Property taxes are the 2017 level increased by 2% each year.
17. Based on the above calculations the total revenue requirement is determined
18. The revenue requirement is offset by other operating revenuewhich is the 2017 amount increased by 2%. This determines the base revenue requirement to be collected with standard distribution rates.
19. A portion of the base revenue requirement is assigned to the Residential class based on the how much of the 2017 approved base revenue requirement was assigned to the

Residential class. The proportion is adjusted each year reflecting how residential customer forecast impacts the total number of customers.

20. The 100% fixed monthly Residential service charge is then determined by taking the assigned revenue requirement and dividing by the Residential customers for the year divided by 12. This produces the monthly Residential rate under a cost of service methodology.
21. Then the user can choose whether the Residential rate will be based on a rebasing year or an IRM year as explained above.

UNDERTAKING JT1.9

Reference:

EB-2018-0117- Hydro One Networks Inc.'s Section 92 – Barrie Area Transmission Upgrade Project – Interrogatory Responses – Exhibit I, Tab 1, Schedule 16 – Response to OEB Staff Interrogatory Number 16(a), Page 2 of 4.

Undertaking:

To provide the total bill impacts on an annual basis for the 5-year and 15-year capital contribution period.

Response:

Please see Table JT1.8-1 in the response to JT1.8, above, which provides total bill impacts on an annual basis for the1-year, 5-year, and 15-year Capital Contribution period.