1

EB-2019-0082

Hydro One Transmission

Energy Probe Compendium for Panel 4

Vol.1

Table 2: Average Bill Impacts on Transmission and Distribution-connected Customers

	2019*	2020	2021	2022
Rates Revenue Requirement ($ millions)	$1,550.2	$1,623.3	$1,706.2	$1,791.6
% Increase in Rates Revenue Requirement over prior year		4.7%	5.1%	5.0%
% Impact of load forecast change		3.8%	0.6%	0.7%
Net Impact on Average Transmission Rates		**8.5%**	**5.7%**	**5.7%**
Transmission as a % of Tx - connected customer's Total Bill		*7.4%*	*7.4%*	*7.4%*
Estimated Average Bill Impact		**0.6%**	**0.4%**	**0.4%**
Transmission as a % of Dx - connected customer's Total Bill		*6.2%*	*6.2%*	*6.2%*
Estimated Average Bill Impact		**0.5%**	**0.4%**	**0.4%**

** 2019 revenue requirement is as proposed in Hydro One's 2019 Transmission Application (EB-2018-0130).*

The total bill impact for a typical Hydro One medium density residential (R1) customer consuming 400 kWh, 750 kWh and 1,800 kWh monthly is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR") as detailed below in Table 3.

Table 3: Typical Medium Density (R1) Residential Customer Bill Impacts

	Typical R1 Residential Customer		
	400 kWh	**750 kWh**	**1,800 kWh**
Total Bill as of May 1, 2018[1]	$84.33	$123.51	$241.03
RTSR included in 2017 R1 Customer's Bill *(based on 2016 UTR)*	$4.78	$8.96	$21.50
Estimated 2019 Monthly RTSR[2]	$5.09	$9.55	$22.92
2019 increase in Monthly Bill	**$0.12**	**$0.23**	**$0.55**
2019 increase as a % of total bill	*0.1%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	$5.50	$10.32	$24.77
2020 increase in Monthly Bill	**$0.41**	**$0.77**	**$1.85**
2020 increase as a % of total bill	*0.5%*	*0.6%*	*0.8%*
Estimated 2021 Monthly RTSR[3]	$5.80	$10.88	$26.10
2021 increase in Monthly Bill	**$0.30**	**$0.56**	**$1.34**
2021 increase as a % of total bill	*0.3%*	*0.4%*	*0.5%*

Witness: Clement Li

	Typical R1 Residential Customer		
	400 kWh	**750 kWh**	**1,800 kWh**
Estimated 2022 Monthly RTSR[3]	$6.11	$11.46	$27.51
2022 increase in Monthly Bill	**$0.31**	**$0.59**	**$1.41**
2022 increase as a % of total bill	*0.4%*	*0.5%*	*0.6%*

[1] *Total bill including HST, based on time-of-use commodity pricing effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).*
[2] *2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and Hydro One's rates revenue requirement proposed in 2019 Transmission Rate Application (EB-2018-0130).*
[3] *The impact on RTSR is assumed to be the net impact on average Transmission rates, as per Table 2, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).*

The total bill impact for a typical Hydro One General Service Energy less than 50 kW ("GSe < 50 kW") customer consuming 1,000 kWh, 2,000 kWh and 15,000 kWh monthly is determined based on the forecast increase in the customer's RTSR as detailed below in Table 4.

Table 4: Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

	GSe Customer Monthly Bill		
	1,000 kWh	**2,000 kWh**	**15,000 kWh**
Total Bill as of May 1, 2018[1]	$201.89	$373.66	$2,606.65
RTSR included in 2017 GSe Customer's Bill *(based on 2016 UTR)*	$10.63	$21.26	$159.47
Estimated 2019 Monthly RTSR[2]	$11.33	$22.67	$169.99
2019 increase in Monthly Bill	**$0.27**	**$0.55**	**$4.10**
2019 increase as a % of total bill	*0.1%*	*0.1%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	$12.25	$24.49	$183.70
2020 increase in Monthly Bill	**$0.91**	**$1.83**	**$13.71**
2020 increase as a % of total bill	*0.5%*	*0.5%*	*0.5%*
Estimated 2021 Monthly RTSR[3]	$12.91	$25.82	$193.62
2021 increase in Monthly Bill	**$0.66**	**$1.32**	**$9.92**
2021 increase as a % of total bill	*0.3%*	*0.4%*	*0.4%*
Estimated 2022 Monthly RTSR[3]	$13.61	$27.21	$204.08
2022 increase in Monthly Bill	**$0.70**	**$1.39**	**$10.46**
2022 increase as a % of total bill	*0.3%*	*0.4%*	*0.4%*

[1] *Total bill including HST, based on time-of-use commodity pricing effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).*
[2] *2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and rates revenue requirement proposed in 2019 Transmission Rate Application (EB-2018-0130).*
[3] *The impact on RTSR is assumed to be the net impact on average Transmission rates, as per Table 2, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).*

Table 3: Revenue Requirement ($ Millions)

Components	2018[1]	2019[2]	2020	Reference
OM&A	394.3	-	375.9	Exhibit F, Tab 1, Schedule1
Depreciation and Amortization	468.6	-	471.5	Exhibit F, Tab 6, Schedule 1
Income Taxes	57.2	-	52.7	Exhibit F, Tab 7, Schedule 2, Attachment 1
Return on Capital	703.6	-	773.2	Exhibit G, Tab 1, Schedule 1
Total Revenue Requirement	**1,623.8**	**1,642.3**	**1,673.4**	
Deduct External Revenues and Other [3]	(54.7)	(54.5)	(55.0)	
Rates Revenue Requirement	**1,569.1**	**1,587.8**	**1,618.4**	
Regulatory Deferral and Variance Accounts Disposition / Foregone Revenue	(58.4)	(37.6)	4.8	Exhibit H, Tab 1, Schedule 3
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,510.7**	**1,550.2**	**1,623.3**	
Year Over Year %		2.6%	4.7%	

Note 1: Represents OEB approved 2018 revenue requirement from Hydro One Transmission's 2017 to 2018 rate application in EB-2016-0160
Note 2: The 2019 revenue requirement is based on proposed revenue requirement in EB-2018-0130
Note 3: External Revenue and Other includes External Revenue, MSP Revenue, Export Tx Service Revenue and Low Voltage Switch Gear Credit

Exhibit Reference: E-1-1, Table 1.

The drivers of the increase in the 2020 revenue requirement compared the 2018 OEB approved revenue requirement are summarized by component in Table 4. The increase is predominantly driven by two years' worth of rate base growth and an increase in the regulatory deferral account balance being disposed of, which is partially offset by lower OM&A costs. The 2020 total revenue requirement is $49.6 million greater than the 2018 OEB amounts; however, the 2020 total revenue requirement is $16 million lower than

5

what it would have been had the 2018 OEB approved revenue requirement been adjusted for inflation in 2019 and 2020[3].

Table 4: Changes to Individual Components of Rates Revenue Requirement Since Most Recent Rebasing

Description	2020 vs. 2018 ($ millions)	2020 vs. 2018 (%)
Increase in OM&A	-18.4	-1.2%
Rate Base Growth	80.1	5.3%
Lower cost of debt	-7.5	-0.5%
Tax	-4.6	-0.3%
Impact on Revenue Requirement	**49.7**	**3.3%**
External Revenue	-0.3	0.0%
Regulatory Deferral and Variance Accounts Disposition	63.2	4.2%
Total Change	**112.6**	**7.5%**

Exhibit Reference: E-1-1, Table 6

6.2 BUDGETING ASSUMPTIONS

In developing its Investment Plan, Hydro One utilized the Ontario Consumer Price Index ("CPI") for its assumptions about inflation. A CPI of 2% was assumed over the planning period. The Global Insight exchange rate forecast was used for other variables such as fleet vehicle related costs, which are typically obtained in US dollars. The exchange rate was forecast to range between 0.793 and 0.803 over the planning period. Further details

[3] The 2019 and 2020 total revenue requirements would be $1,656.3 and $1,689.4, respectively. This assumes that the 2018 OEB approved total revenue requirement is adjusted by an annual inflation rate of 2%.

regarding the economic assumptions underpinning the Investment Plan can be found in Section 2.1 of the TSP.

6.3 LOAD FORECAST SUMMARY

Hydro One uses econometric (top-down) and end-use (bottom-up) models to forecast the transmission system load. For the top-down approach, both monthly and annual econometric models are used. For the bottom-up approach, end-use models are used to analyse the transmission system load by sector (i.e. residential, commercial and industrial customers). Key information used in the analysis includes economic data, demographics, industrial production and commercial floor space forecast provided in the economic forecast. The purpose of using both the econometric and end-use forecast models is to arrive at a balanced forecast that represents a consistent set when looked at from macro (econometric) and micro (end-use) perspectives. This forecasting methodology was reviewed and approved by the OEB in previous Hydro One transmission rate cases and is detailed in Exhibit E, Tab 3, Schedule 1.

The proposed test period billing determinants arising from Hydro One's load forecast are summarized in Table 5.

Table 5: Hydro One's 2020-2022 Load Forecast (12-Month Average Peak in MW)

		Hydro One Rate Categories (Charge Determinants)		
	Ontario Demand	**Network Connection**	**Line Connection**	**Transformation Connection**
2020	19,586	19,604	19,071	16,252
2021	19,451	19,469	18,941	16,142
2022	19,304	19,322	18,800	16,021

Exhibit Reference: E-3-1, Table 1

Table 6 summarizes the change in billing determinants as compared to 2018 OEB-approved amounts from the Prior Proceeding.

Table 6: 2018 vs. 2020 Changes in Billing Determinants

Year		Hydro One Rate Categories (Charge Determinants) (MW)		
	Ontario Demand	Network	Line Connection	Transformation Connection
2018 (OEB-approved)	20,378	20,410	19,746	16,876
2020	19,586	19,604	19,071	16,252
% Change	(3.9)%	(3.9)%	(3.4)%	(3.7)%

The proposed decrease in the 2020 charge determinant load forecast relative to the currently approved 2018 load forecast (per EB-2016-0160) results in an estimated 3.8% impact on rates due to load. The key drivers of the reduction in the 2020 load forecast are (i) the actual Ontario demand in 2018 was 3.5% lower than the forecast approved in the Prior Proceeding for the year 2018, and (ii) the Ontario demand is expected to further decline by 0.4% between 2018 and 2020 due to a combination of slow economic growth and conservation initiatives during this period.

The reduction in the actual load relative to the previously approved load forecast is primarily driven by the impact from the expanded Industrial Conservation Initiative (ICI) program on Ontario demand. In September 2016, the Government of Ontario expanded the ICI program to include more than one thousand newly eligible Class A customers with monthly peak demand greater than one megawatt, down from the previous eligibility threshold of three megawatts. Sector restrictions were also removed so that institutional

8

CUSTOM IR APPLICATION SUMMARY

1. APPLICATION STRUCTURE

Hydro One's application is based on a Custom Incentive Rate-Setting ("IR") approach for a 3 year period. The methodology utilized is a Revenue Cap IR in which the revenue requirement for the test year t+1 is equal to the revenue requirement in year t inflated by the Revenue Cap Index ("RCI") set out below.

Hydro One's revenue requirement in the first year of the 3 year period (2020) is determined using a cost of service, forward test year approach, consistent with the OEB's Renewed Regulatory Framework ("RRF") as most recently set out in the *Handbook for Utility Rate Applications* (the "Handbook"), released by the OEB in October 2016. The revenue requirement in the following years, 2021 and 2022, is determined using an RCI that is calculated for each year.

The RCI includes an industry-specific inflation factor and two custom productivity factors. Consistent with the RRF, these productivity factors are explicitly included in the rate adjustment mechanism and provide an incentive for Hydro One to achieve capital and OM&A productivity improvements that are in addition to those imbedded in the Hydro One Transmission Business Plan in Exhibit A, Tab 3, Schedule 1, Attachment 1.

The RCI also includes a Custom Capital Factor ("C") that is designed to recover revenue related to new capital investments that are placed in-service in each test year, as further described in this Exhibit.

9

OEB Staff Interrogatory # 21

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02 Page: 1-2 – Revenue Cap Proposal
Hydro One describes its Custom IR proposal as:

> *"Hydro One's application is based on a Custom Incentive Rate-Setting approach for a 5- year period. The methodology utilized is a Revenue Cap IR in which revenue for the test year t+1 is equal to the revenue in year t inflated by the Revenue Cap Index ("RCI") set out below."*

On page 2, Hydro one gives the formula as:

The Custom Revenue Cap Index (RCI) is expressed as:
RCI = I – X + C

Where:

- "I" is the Inflation Factor, as determined annually by the OEB.
- "X" is the Productivity Factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.
- "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Distribution System Plan, beyond the amount of revenue recovered in rates.

Typically, a revenue cap formula is of the form:

$$Rev_t = Rev_{t-1} \times (1 + (I - X + g))$$

where the I and X are as described above, and g (growth) is based on growth in demand (customers, consumption, energy demand). Revenues are capped by the formula, with rates set to recover the annual revenue requirement updated by this formula.

In Hydro One's proposal, the updated revenue requirement will be converted into rates each year based on the demand forecasted (where forecasted numbers of customers, kWh and kW, as

10

applicable) are used as the billing determinants for the revenue requirement as allocated between customer classes and between fixed and variable charges.

Interrogatory:

a) Growth in operating scale is an important driver of cost growth. What is the rationale for a revenue cap index that does not include a scale escalator?

b) Please confirm that, under Hydro One's proposal, it has an opportunity, under certain conditions, of earning more revenues than the revenue requirement adjusted by the annual RCI. For example, if actual demand (as a combination of number of customers, kWh and kW) exceeds Hydro One's forecasted demand, Hydro One would receive more revenues as it would be the lower forecasted demand which would be the billing determinants for establishing rates in the year. In the alternative, please explain.

c) Why does Hydro One characterize its proposal as a revenue cap, even though it is little different than Toronto Hydro-Electric System Limited's Custom IR approved in EB-2014-0016, which was characterized there as a Price Cap?

Response:

a) Under Hydro One's RCI, any additional capital requirements required to serve any load/demand growth would be captured in the formula through the Custom Capital Factor. The expected growth in billing determinants would be captured in rates through the rate design process outlined in Exhibit H1, Tab 1, Schedule 2, wherein billing determinants are updated annually in line with the expectation of the load forecast. As a result of these two factors, Hydro One does not believe that a growth factor is required in the RCI.

b) The potential to over-recover revenue, as described by OEB staff's question, exists in all instances where rates are set based on forecast billing determinants. Likewise there is potential that Hydro One could under earn revenue if the actual number of customers, kWh and kW is lower than forecasted billing determinants. This risk is not driven by Hydro One's proposed RCI but by the fact that actual load will not exactly match the load forecast underpinning rates. A utility that was under a multi-year cost of service rate setting framework would have the same opportunity to over/under earn revenue as a utility subject to an incentive rate-setting structure such as Hydro One's proposed RCI.

c) Hydro One's proposal is appropriately characterized as a Revenue Cap Index (RCI) because the index is used to escalate the prior year's revenue requirement. Toronto Hydro's Custom IR Price Cap Index is used to directly adjust the prior year's base distribution rates.

OEB INTERROGATORY #5

Reference:

A-04-01 p.1-3

Handbook for Utility Rate Applications, October 13, 2016

Interrogatory:

Hydro One's 3-year Custom IR plan consists of rebasing the revenue requirement for 2020 through a cost of service approach, based on forecasted 2020 test year capital and operating costs. After rebasing the revenue in 2020 on a Cost of Service basis, Hydro One proposes a Custom Incentive Rate-Setting approach based on a Revenue Cap IR for the following two years (2021 and 2022). The revenue requirement for the rate year t is equal to the revenue requirement in year t-1 adjusted annually by the revenue cap index (RCI):

$$RR_t = RR_{t-1} \times (1 + RCI_t)$$

where:

$$RCI_t = I_t - (X + stretch) + C_t \pm Z_t$$

- I_t is the Inflation (i.e., Input Price Inflation or IPI), as determined annually by the OEB for the following rate year. Hydro One proposes an electricity transmission sector-specific inflation factor based on an analysis documented in PSE's evidence
- X is the base productivity factor representing the historical sector annual productivity trend.
- $stretch$ is a stretch factor to ensure a sharing of benefits of improved productivity and cost performance between shareholders and ratepayers over the plan term.
- C_t is Hydro One's Custom Capital Factor, determined to recover the incremental capital-related revenue requirement in each rate year necessary to support Hydro One's proposed Transmission System Plan, beyond the amount already recovered in the revenue cap-adjusted revenue requirement for that year
- Z is for any qualifying adjustment(s) for recovery of (capital and/or operating expense) for exogenous factors (e.g., major storm damage recovery, policy changes) that meet the OEB's requirement for Z-factors.

Hydro One has not included a growth ("g") factor in its revenue cap proposal, on the basis that there is little change in the transmission load forecast (and hence on the cost allocation of the charge determinants to be used for determining the Uniform

Transmission Rates (UTRs) to recover the aggregate revenue requirements of all transmitters for each year.

Based on the Total Factor Productivity and total cost benchmarking analyses in the evidence of Power Systems Engineering Inc. (PSE), Hydro One has proposed base X and stretch factors of 0% and 0%. Thus, as proposed, Hydro One's Custom IR revenue requirement adjustment would be:

$$RevReqt_t = RevReqt_{t-1} \times (1 + (IPI_t^{Tx} - (0\% + 0\%) + C_t \pm Z_t))$$

a) Please confirm that, as proposed with a 0% base X and stretch factors, there are no productivity gain expectations in the 3-year Custom IR plan except for any that might be factored into the rebased revenue requirement for 2020. In the alternative, please explain.

b) In the OEB's Handbook for Utility Rate Applications (Rate Handbook), the OEB states the following:

- Custom IR: Under this methodology, rates are set for five years considering a five-year forecast of the utility's costs and sales volumes. This method is intended to be customized to fit the specific utility's circumstances, but expected productivity gains will be explicitly included in the rate adjustment mechanism. Utilities adopting this approach will need to demonstrate a high level of competence related to planning and operations. Additional guidance on Custom IR applications is set out below.[1]

With the proposed X and stretch factors set at 0%, please explain how the revenue cap adjustment satisfies the OEB's expectation in the Rate Handbook that "expected productivity gains will be explicitly included in the rate adjustment mechanism."

c) As proposed, the revenue requirement adjustment formula escalates OM&A by inflation, while the capital-related revenue requirement is adjusted by inflation and by the C-factor accounting for all forecasted capital additions per the Transmission System Plan beyond the inflation adjustment. Isn't Hydro One's Custom IR plan, as proposed, equivalent to a 3-year cost of service plan (i.e., with the revenue requirement rebased through a cost of service approach for 2020, with formulaic

[1] Handbook for Utility Rate Applications, October 13, 2016, p. 24

adjustments for inflation on OM&A and inflation and capex growth on the capital-related revenue requirement for 2021 and 2022). Please explain your response.

d) The OEB provides further discussion on the Custom IR plan expectations in the Rate Handbook:

- Index for the Annual Rate Adjustment: The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. *Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).*[2] **[Italics added]**

Please explain how Hydro One's proposed revenue cap formula satisfies the emphasized section of the OEB's policy.

Response:

a) As indicated in Exhibit A, Tab 4, Schedule 1, Hydro One's proposal is based on a Productivity Factor (X) that is equal to the sum of Hydro One's Custom Industry Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor. Based on PSE's study, Hydro One's proposed Productivity Factor of 0% reflects the sum of the Custom Industry Total Factor Productivity (TFP) measure of 0% and a Custom Productivity Stretch Factor specific to Hydro One of 0%.

Although PSE determined that the electricity transmission industry TFP is -1.45%, a proposed Custom Industry Factor Productivity measure of 0% was proposed consistent with the OEB's findings in 4th generation IRM for electricity distributors. The decision to utilize a 0% Custom Industry Factor Productivity instead of a -1.45% as calculated, imposes a 1.45% implicit stretch factor on Hydro One as outlined in PSE's report. The proposed stretch factor of 0% is assigned based on the results of PSE's total cost benchmarking study and reflects appropriate productivity gains expectations as established by the OEB under 4th generation IRM for utilities that have demonstrated total cost performance similar to that of Hydro One.

[2] Ibid., p. 25

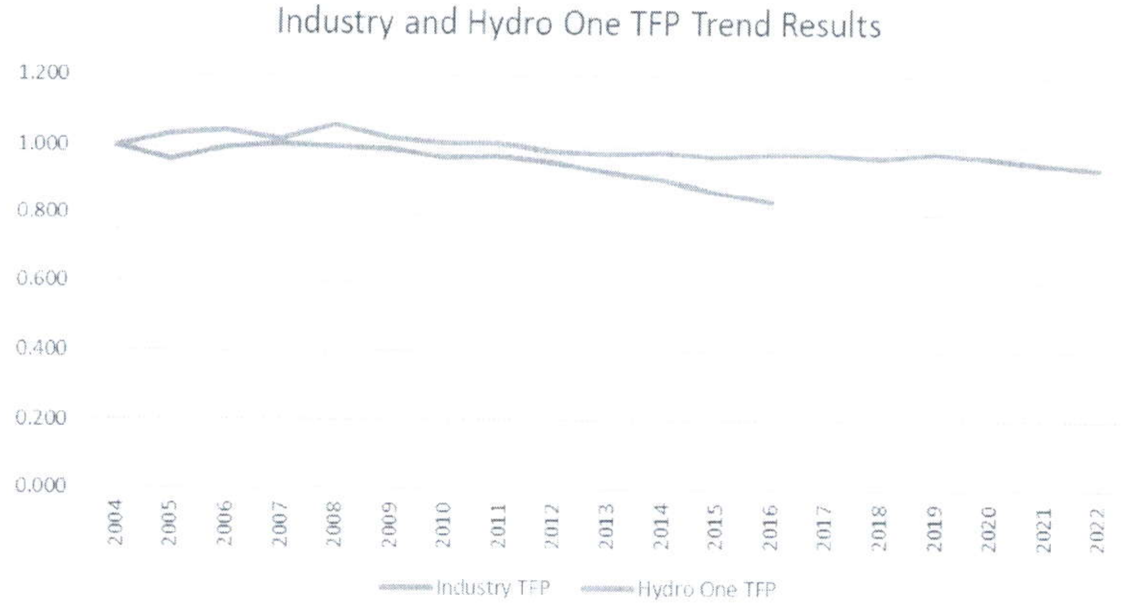
Additionally, significant productivity savings have been embedded in the 2020 OM&A forecast and 2020-2022 Capital Plan. Hydro One has challenged itself to find further productivity gains and included in this application additional progressive productivity savings as discussed further in Exhibit A, Tab 3, Schedule 1 and Section 1.6 of the TSP. Hydro One's commitment to these savings in the Application is to the benefit of ratepayers because the capital expenses underpinning the proposed revenue requirements are reduced by these amounts.

b) Please refer to part a) above.

c) Hydro One's Custom IR proposal differs from a 3-year cost of service plan in several ways. Firstly, the proposal is based on a mechanistic index that includes the productivity gains expectations outlined in part a) of this response. Unlike multi-year cost of service applications, the cost of capital is not updated annually. Once calculated in this proceeding, the Capital Factors will not change in future years and therefore future revenue will vary due to changes in the inflation factor. Further, as discussed in Exhibit A, Tab 4, Schedule 1 the current application has proposed additional Custom IR features that protect rate payers which include an Earning Sharing Mechanism (ESM) and the Capital In-Service Variance Account (CISVA).

d) As indicated in Exhibit A, Tab 4, Schedule 1 the revenue requirement for 2021 and 2022 are derived using Custom Revenue Cap Index (RCI) RCI = I – X + C. Part a) above provides discussion on what type of productivity measures are built into the proposed revenue requirement as well as the implicit stretch factor which is imposed through the adoption of the proposed 0% Custom Industry Total Factor Productivity (TFP).

Figure 3 Industry TFP and Hydro One TFP



Hydro One's long-term TFP trend compares favorably to the industry trend. Hydro One's annual TFP trend is 1.27% higher than the industry TFP trend from 2004 to 2016. The industry has had a consistent decline in TFP since 2004. In Section 6.1, we address some possible causes for negative TFP growth.

1.4 PSE CIR Parameter Recommendations

PSE recommends the following general custom IR formula to escalate the allowed revenue requirement during the CIR period.

$$Growth\ Revenue = Inflation - X - Stretch\ Factor + Capital\ Factor \quad \text{[Equation 1]}$$

The specific parameter values for each component are as follows:

- PSE recommends a two-factor **inflation factor** comprised of input weights of 14% labour and 86% non-labour. In 4GIR for the electric distribution industry, the inflation factor grows by 30% of the growth in Average Weekly Earnings (AWE) for Ontario, and 70% of the growth in GDP-IPI FDD. The AWE accounts for the labour component of total costs and the GDP-IPI FDD accounts for the non-labour component. However, this 4GIR weighting needs to be updated for transmission operations. With the transmission weighting of 14% and 86%, historically the inflation factor would grow a bit slower than under the distribution 4GIR weights.

- The PSE **X factor** recommendation is 0.0%. This is based on the negative industry TFP finding of -1.45%. While a negative X factor could be considered, the 4GIR Decision made clear the Board did not desire to have a negative X factor embedded within the escalation formula. For this reason, PSE recommends a 0.0% X factor, which is the same X factor that is found in 4GIR. However, the difference between the industry TFP trend and the X factor should be considered as an "implicit stretch factor". In other words, Hydro One will be expected or "stretched" to outpace the industry's historical TFP by 1.45%. This would be an extraordinarily large stretch factor value.

- The PSE **stretch factor** recommendation is 0.0%. There are two reasons for this recommendation. The first is the "implicit stretch factor" of 1.45%, which is due to the X factor being set at 0.0%. The second reason is the total cost benchmarking result that shows Hydro One is 27.1% below its benchmark costs throughout the CIR period. PSE notes that in 4GIR a benchmark finding of -25% or less would imply a 0.0% stretch factor. Hydro One's score of -27.1% meets this standard. Given the strong cost performance and the large implicit stretch factor, PSE believes a stretch factor of 0.0% is warranted.

- PSE recommends not including an **output growth factor** to simplify the revenue cap formula. While mathematically an output growth factor should be included within the formula (as we will show in Section 2), the measured outputs in this study are unlikely to measurably grow during the CIR period. The output factor would be very close to 0.0% for every year. Additionally, the inclusion of the capital factor to the formula should capture the expected capital cost impact of output growth.

- The **capital factor** is based on Hydro One's proposed capital spending needs. PSE is not making any recommendations regarding the magnitude of the capital factor. We do, however, insert the proposed capital spending amounts into the TFP and total cost benchmarking studies, so the Board and stakeholders can ascertain the projected TFP trends and total cost benchmarking scores that result from the proposed level of capital spending. As is seen in those evaluations, the proposed capital spending by Hydro One compares favorably to the industry. The TFP trend during the CIR period continues to exceed the historic TFP trend of the industry, and Hydro One's projected total costs are 27.1% below its benchmark values throughout the CIR period.

The methodology used to arrive at Equation 1 is shown in the following section.

2 The Revenue Escalation Formula

Since so much of this study ultimately relates to the custom IR process, a brief overview of the mathematics underlying the general revenue escalation formula is warranted. This section gives a general equation for a generic revenue escalation formula and explains how this formula was determined. Subsequent sections discuss total cost benchmarking (Sections 3 and 5) and TFP research (Sections 4 and 6), and the results for those sections are used in CIR recommendations.

2.1 Derivation of the Formula

In the previous section, we recommended the following equation as the general custom IR formula to escalate the allowed revenue requirement during the CIR period.

$$Growth\ Revenue = Inflation - X - Stretch\ Factor + Capital\ Factor \quad \text{[Equation 1]}$$

This section shows how Equation 1 was determined.

The allowed revenue escalation within the revenue escalation formula should mimic the expected growth in costs. Production theory postulates that there should be three main components within the escalation formula. These three components are: input price inflation (I), a productivity expectation (X), and output growth (O).

$$Growth\ Revenue = I - X + O \qquad \text{[Equation 2]}$$

The mathematical derivation of Equation 2 is provided below. It begins with the assumption that the allowed growth in revenue should be equal to the expected growth in costs.

$$Growth\ Revenue = Growth\ Cost \qquad \text{[Equation 3]}$$

Basic production theory states that costs equal the product of input prices and input quantities (Q). In turn, the growth in costs will equal the growth in input prices (I) plus the growth in input quantities.

$$Growth\ Cost = I + Growth\ \mathrm{Q} \qquad \text{[Equation 4]}$$

If we add and subtract the same term to the right-hand side of the equation, that is the same as adding zero, and the equation remains unchanged. We will both add and subtract output growth (O) to Equation 4 to develop Equation 5 below.

$$Growth\ Cost = I + Growth\ Q + O - O \qquad \text{[Equation 5]}$$

As we will further discuss in Section 4 on the TFP methodology, the TFP trend is defined as the change in output quantity minus the change in input quantity. In equation form:

$$TFP\ trend = O - Growth\ Q \qquad \text{[Equation 6]}$$

We can rearrange the terms in Equation 5 to the following equation.

$$Growth\ Cost = I - (O - Growth\ Q) + O \quad \text{[Equation 7]}$$

And then insert Equation 6 into Equation 7.

$$Growth\ Cost = I - TFP\ trend + O \qquad \text{[Equation 8]}$$

The last step in getting to Equation 2 is to insert Equation 3, redefine the TFP trend and call it X.

$$Growth\ Revenue = I - X + O \qquad \text{[Equation 9]}$$

A "stretch factor" is sometimes added to the escalation formula to challenge (or stretch) the utility to achieve TFP gains above and beyond the industry TFP expectation. A positive stretch factor slows allowed revenue growth in a manner that shares with customers the financial benefits of the utility exceeding the industry TFP trend. Within 4GIR, the stretch factor is informed by econometric total cost benchmarking evidence, because an inefficient firm can more easily cut costs and ramp up TFP trends than an efficient utility can.

Once we insert the stretch factor (SF) term, we have the following equation.

$$Growth\ Revenue = I - X - SF + O \qquad \text{[Equation 10]}$$

As stated in Section 1.4 the output growth factor (*Growth O*) will be close to zero every year (see Table 8). For example, average annual growth rates from 2020 to 2022 of KM of Line, Maximum Peak Demand, and Output Quantity Index are 0.02%, 0.00%, and 0.01%, respectively. Furthermore, the existence of a Capital Factor should capture the anticipated capital cost impacts of output growth. Thus, if we drop the output term from the equation we get:

$$Growth\ Revenue = I - X - SF \qquad \text{[Equation 11]}$$

Hydro One is proposing to add a Capital Factor term that accounts for additional capital spending. When this term is added, we arrive at the following equation, which was the recommendation in Section 1.4 .

$$Growth\ Revenue = I - X - SF + Capital\ Factor \quad \text{[Equation 12]}$$

The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service. An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.

It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.

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

- Performance Metrics: The OEB has established a scorecard for electricity distributors, however, additional performance metrics should also be proposed so that expected outcomes can be monitored. All other utilities must propose a comprehensive scorecard that is informed by the scorecard for electricity distributors, but specifically includes other performance metrics aligned to the outcomes identified in the application. This is required for both Custom IR and cost of service rate applications.

- Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application.

The adjudication of an application under the Custom IR method requires the expenditure of significant resources by both the OEB and the utility. The OEB therefore expects that a utility that applies under Custom IR will be committed to

OEB INTERROGATORY #6

Reference:

A-04-01

Decision with Reasons EB-2017-0049, March 7, 2019, pp. 31-33

Decision and Order EB-2018-0218, June 20, 2019, pp. 19-21

Interrogatory:

OEB staff notes that the proposed Custom IR plan, with respect to the adjustment formula for Hydro One's revenue requirement for the years 2021 and 2022, is similar in many respects, to Hydro One's current distribution Custom IR plan approved in EB-2017-0049, including the inclusion of a C-factor, and to Hydro One SSM's revenue cap plan for 2019-2026 recently considered and decided upon in EB-2018-0218.

a) Hydro One proposed a similar "revenue cap" adjustment formula, including a Custom Capital Factor (C-Factor) for its 5-year Custom IR plan (2018-2022) for distribution rate-setting in an earlier application (EB-2017-0049). The plan had distribution specific inflation, base X and stretch factors, and also differed in that the plan adjusted distribution rates rather than the aggregate revenue requirement.

   In its Decision with Reasons EB-2017-0049, the OEB determined that the stretch factor of 0.45% proposed should apply to the revenue cap index for adjusting Hydro One's distribution rates during the plan term, from 2018 to 2022. The OEB also determined that an incremental stretch factor of 0.15% should be included into the C-factor calculation, to incentivize further capital-related efficiencies for the capital program as forecasted in the Distribution System Plan (analogous to the Transmission System Plan filed in this application). This incremental 0.15% stretch factor was in addition to the 0.45% stretch factor approved for the rate adjustment formula and applied to both capital and OM&A.

   Please provide Hydro One's views, with its reasons, on whether on an additional (incremental) stretch factor would be appropriate to provide an incentive for Hydro One to seek further efficiencies in its transmission capital program during the term of this Custom IR plan, similar to what the OEB approved for Hydro One's distribution operations.

b) On June 20, 2019, the OEB issued its Decision and Order pertaining to a multi-year revenue cap plan for the period 2019 to 2026 for Hydro One Sault Ste. Marie LP (Hydro One SSM). Hydro One SSM is an affiliated electricity transmission utility operating around Sault Ste. Marie, formed following the acquisition of Great Lakes Power Limited. In this decision the OEB determined that:

The OEB approves the proposed productivity factor of 0%, a factor indicative of the change in productivity expected for the transmission sector as a whole. No party argued for a negative productivity factor even though both PSE and PEG calculated a negative TFP.

...

The OEB approves a stretch factor of 0.3% to provide an incentive to Hydro One SSM beyond the rate of inflation and balance the needs of its customers and shareholders during the term of the revenue cap framework.
This stretch factor finding was made independent of the acquisition by Hydro One Inc. and the existence of a deferred rebasing period. Clearly, capital and OM&A savings are expected to result from the integration of Hydro One SSM into Hydro One Networks that is underway in 2019. The OEB finds that a stretch factor of 0.3% provides incentives to find further efficiency improvement beyond those proposed by the acquisition.

OEB staff acknowledge that the OEB's findings with respect to Hydro One SSM's revenue cap plan specifically pertain solely to that utility and that plan. However, Hydro One's proposed Custom IR is similar to the Hydro One SSM revenue cap plan, except for the inclusion of the C-factor in place of any ICMs, and is largely supported by PSE's slightly updated report. Please provide Hydro One's views on why a positive, non-zero stretch factor to incentivize further efficiency improvements would not be preferable to its proposed 0% stretch factor.

Response:

a) As stated in Exhibit I, Tab 01, Schedule OEB-5 part a), the current Transmission Application includes an implicit stretch factor which is significant in nature (1.45%) unlike the Distribution application. The implicit stretch factor is as a result of the transmission industry displaying significant negative productivity. Although PSE determined that an electricity transmission industry TFP is -1.45%, the proposed Custom Industry Factor Productivity measure of 0% was proposed consistent with the OEB's findings for distributors in 4th generation IRM.

Moreover, unlike the Hydro One Distribution application which only included productivity savings based on defined initiatives, the current Transmission Application includes in savings in addition to those based on defined initiatives, in the form of progressive productivity savings. Progressive productivity savings represent a commitment from Hydro One to find further efficiencies over the planning period when executing the necessary planned investments in its transmission system without reducing work volumes. Progressive productivity savings are further described in Section 1.6 of the TSP.

b) Given that the PSE study in the HOSSM application was conducted for the purpose of Hydro One Transmission, Hydro One Transmission believes that implementing the findings of the PSE study is appropriate (specifically the Custom Productivity Factor of 0%).

As stated in the HOSSM decision on page 20:

The PSE and PEG evidence for electricity transmission utilities provided in this proceeding was based primarily on 43 U.S. utilities with the only Canadian utility being Hydro One Networks. Given the absence of sufficient Canadian data and utilities the size of Hydro One SSM, the OEB finds neither study appropriate to determine the stretch factor for Hydro One SSM, a small Canadian transmission utility. In the absence of applicable evidence, regardless of the reason, the OEB must rely upon its judgement and experience in incentive regulation to establish a stretch factor.

Additionally, on page 20 of the decision is stated further that:

The OEB has applied a 0% stretch factor to certain electricity distributors based on their total cost performance as benchmarked against other distributors in Ontario. The most efficient distributor is assigned the lowest stretch factor of 0%. Conversely, a higher stretch factor, up to 0.60%, is applied to a less efficient distributor to reflect the incremental productivity gains that the distributor is expected to achieve. The OEB finds no evidence to justify a 0% stretch factor for Hydro One SSM, implying it is the most efficient transmitter.

Based on the sections above, it is evident that the reasons a stretch factor of 0.3% was imposed in the HOSSM proceeding are not applicable to Hydro One Transmission.

In the HOSSM case, PSE's and PEG's results did not directly pertain to SSM but instead were evaluations of Hydro One Network's total cost performance. The dataset does include utilities the size of Hydro One Networks and there is substantial evidence to justify a 0% stretch factor for Hydro One Networks in this application. PSE's total cost benchmarking results reveal that Hydro One Networks costs are 27.1% below the benchmark expectations implying a 0% stretch factor. PEG's recent results for Hydro One Networks in the SSM application implied a 0.15% stretch factor.

CME INTERROGATORY #4

Reference:

A-04-01 p. 1 of 13

Interrogatory:

At Exhibit A, Tab 4, Schedule 1, page 1, Hydro One States: "The RCI also includes a Custom Capital Factor ("C") that is designed to recover revenue related to new capital investments that are placed in-service in each test year, as further described in this Exhibit."

a) Please confirm whether the capital factor will be applied to Hydro One's working cash amounts.

Response:

a) The capital factor has been applied to the revenue requirement components derived from rate base which includes working capital. Please see Exhibit I, Tab 04, Schedule LPMA-2 for a recast of table 2 which excludes working capital from the Capital Factor.

Witness: Stephen Vetsis, Joel Jodoin

LPMA INTERROGATORY #2

Reference:
A-04-01

Interrogatory:

a) Please confirm that the rate base and associated capital costs shown in Table 2 do not include the working capital component of rate base.

b) If (a) is not confirmed, please provide a version of Table 2 that removes the working capital component of rate base and the associated capital costs, consistent with the Board's EB-2017-0049 Decision and Order dated March 7, 2019.

c) Please provide a version of Table 2 that excludes working capital, but reflects an inflation factor of 1.8% in place of the 1.4% used.

Response:

a) The rate base and associated capital costs shown in Table 2 in Exhibit A, Tab 4, Schedule 1 include the working capital component of rate base. The rate base is further discussed in Exhibit C, Tab 1, Schedule 1.

b) Please note that the OEB decision in EB-2017-0049 directed Hydro One Distribution to exclude the working capital component from the calculation of the Capital Factor only. Hydro One was not directed to remove working capital from rate base and the associated revenue requirement as stated in this interrogatory.

The table below removes the working capital component of rate base and the associated capital cost components for illustrative purposes only. The working capital component is identified as a separate row in the following table in which the 2021 and 2022 figure have been escalated by the inflation less productivity factor to be consistent with EB-2017-0049. The change in working capital methodology for 2021 and 2022 compared to what was filed in evidence is immaterial, about $0.1 million and $0.2 million respectively.

Line		Ref.	2020	2021	2022
1	Rate Base	C-1-1	12,338.1	13,054.5	13,876.5
2	Return on Debt	E1-1-1	329.6	348.7	370.7
3	Return on Equity	E1-1-1	443.2	468.9	498.4
4	Depreciation	F-6-1	474.6	505.2	530.9
5	Income Taxes	F-7-2	47.8	58.9	64.3
6	Capital Related Revenue Requirement		**1,295.2**	**1,381.7**	**1,464.3**
7	Less Productivity Factor (0.0%)			0.0	0.0
8	**Total Capital Related Revenue Requirement**		**1,295.2**	**1,381.7**	**1,464.3**
9	OM&A	F-1-1	375.8	381.1	386.4
10	Working Capital		2.7	2.8	2.8
11	**Total Revenue Requirement**		**1,673.8**	**1,765.6**	**1,853.6**
12	Increase in Capital Related Revenue Requirement			86.5	82.6
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			5.17%	4.68%
14	Less Capital Related Revenue Requirement in I-X			1.09%	1.10%
15	**Capital Factor**			**4.09%**	**3.58%**

c) The table below is consistent with part b) above and has been updated to reflect an inflation factor of 1.8% in place of the 1.4%.

Line		Ref.	2020	2021	2022
1	Rate Base	C-1-1	12,338.1	13,054.5	13,876.5
2	Return on Debt	E1-1-1	329.6	348.7	370.7
3	Return on Equity	E1-1-1	443.2	468.9	498.4
4	Depreciation	F-6-1	474.6	505.2	530.9
5	Income Taxes	F-7-2	47.8	58.9	64.3
6	Capital Related Revenue Requirement		**1,295.2**	**1,381.7**	**1,464.3**
7	Less Productivity Factor (0.0%)			0.0	0.0
8	**Total Capital Related Revenue Requirement**		**1,295.2**	**1,381.7**	**1,464.3**
9	OM&A	F-1-1	375.8	382.6	389.5
10	Working Capital		2.7	2.8	2.8
11	**Total Revenue Requirement**		**1,673.8**	**1,767.1**	**1,856.7**
12	Increase in Capital Related Revenue Requirement			86.6	82.7
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			5.17%	4.68%
14	Less Capital Related Revenue Requirement in I-X			1.40%	1.41%
15	**Capital Factor**			**3.78%**	**3.27%**

represents forecasted balances for 2018. Hydro One Transmission will be submitting a Blue Page Update that will reflect the 2018 actual audited balances being requested for disposition.

Table 2: Transmission Regulatory Accounts Requested for Approval ($ Millions)

Description	US of A Account Ref.	Balance as at Dec 31, 2016	Balance as at Dec 31, 2017	Balance as at Dec 31, 2018 (Forecast)	Balance as at Dec 31, 2019 (Forecast)
Excess Export Service Revenue	2405	(28.3)	(15.6)	(0.9)	5.7
External Secondary Land Use Revenue	2405	(37.2)	(29.0)	(16.0)	(0.2)
External Station Maintenance, E&CS and Other External Revenue	2405	1.2	(1.7)	(2.1)	(0.0)
Tax Rate Changes	1592	0.1	0.5	0.4	0.0
Rights Payments	2405	(3.6)	0.1	1.6	0.0
Pension Costs Differential	2405	(3.9)	(9.8)	(18.0)	(5.3)
Long-Term Transmission Future Corridor Acquisition and Development	1508	0.6	0.3	0.0	0.0
LDC CDM and Demand Response Variance Account	1508	(54.1)	(27.5)	12.5	13.6
External Revenue – Partnership Transmission Projects Account	2405	(0.9)	(0.5)	(0.0)	(0.0)
OEB Cost Differential Account	1508	(1.1)	(1.2)	(1.3)	(0.0)
North West Bulk Transmission Deferral	1508	0.6	0.7	0.7	0.8
Total Regulatory Accounts Seeking Disposition		**(126.5)**	**(83.6)**	**(23.0)**	**14.5**
East West Tie Deferral	1508	2.8	7.2	7.2	7.2
SECTR Deferral	1508	13.0	52.0	52.0	52.0
Transmission Forgone Revenue Deferral	1508	0.0	22.3	0.0	0.0
In-Service Capital Additions Variance	2405	0.0	0.0	0.0	0.0
OPEB Cost Deferral	1508	0.0	0.0	14.6	14.9
OPEB Asymmetrical Carrying Charge Account	1522	0.0	0.0	0.0	0.0
Total Regulatory Accounts Not Seeking Disposition		**15.9**	**81.5**	**73.8**	**74.1**
Total		**(110.7)**	**(2.2)**	**50.8**	**88.6**

Table 2: Productivity Savings Forecast Summary ($Millions)

$mm	2020	2021	2022	2023	2024	Total
Operations	47	52	53	53	54	259
Operations Progressive (Defined)	6	12	12	10	10	49
Corporate	12	11	9	7	6	45
Capital Total	**$65**	**$74**	**$73**	**$70**	**$70**	**$353**
Operations	9	10	9	9	9	45
Information Technology	6	9	10	10	10	44
Corporate	7	6	5	4	3	25
OM&A Total	**$22**	**$25**	**$23**	**$23**	**$22**	**$114**
Total Defined	**$87**	**$99**	**$97**	**$93**	**$92**	**$468**
Operations Progressive (Undefined)	11	27	49	68	81	237
Grand Total	**$98**	**$126**	**$146**	**$161**	**$173**	**$704**
Progressive (Defined)	6	12	12	10	10	49
Progressive (Undefined)	11	27	49	68	81	237
Progressive Placeholder	17	39	61	78	91	286

Exhibit Reference: B-1-1, Section 1.6

The Operations, Information Technology and Corporate savings above reflect the expected quantifiable productivity savings for initiatives that have been identified by each group and verified through Hydro One's productivity governance framework. In addition, the Operations group has committed to identifying additional productivity savings over the planning period in the form of Progressive Productivity. Progressive Productivity is a further reduction in cost that Hydro One has included in the final Transmission Business Plan in response to concerns that were raised in the OEB's decision in the Prior Proceeding regarding the level of investment. It represents a commitment from Hydro One to find further efficiencies over the planning period when