OSHAWA PUC NETWORKS

2015-2019 CUSTOM INCENTIVE REGULATION RATE PLAN

MID-TERM UPDATE

INTRODUCTION & OVERVIEW

Introduction

1. Oshawa PUC Networks Inc. (OPUCN) owns and operates an electricity distribution system in Ontario, serving approximately 57,200 customers in the City of Oshawa and the Region of Durham.

2. In January, 2015 OPUCN filed an Application (CIR Application) with the Ontario Energy Board (OEB or Board) to approve proposed electricity distribution rates for the years 2015 through 2019. OPUCN proposed that its rates be set in advance for each year of the 5 year period pursuant to a Custom Incentive Rate Plan (CIR Plan) submission as contemplated under the Board's *Renewed Regulatory Framework for Electricity* (RRFE).

3. In its CIR Application as filed OPUCN proposed a number of annual updates or adjustments which would be applied in advance of each of the years 2016 through 2019 to adjust its proposed rates in a manner intended to address the risks that, in OPUCN's view of its particular circumstances, were inherent in forecasting its revenues and costs over the proposed 5 year CIR Plan period.

4. In November, 2015 the OEB issued its decision (2015 Decision) on OPUCN's CIR Application.[1] In its 2015 Decision the Board found that *"the number and frequency of the proposed adjustments over the plan term is inconsistent with the*

[1] EB-2014-0101, Decision and Order, November 12, 2015.

risk management principles under the Custom IR model – to manage within rates set, given that actual costs and revenues will vary from forecast”.[2]

5. In place of the annual adjustments initially proposed by OPUCN in its CIR Application, the Board found that a mid-term review would be a reasonable alternative for OPUCN, to allow for rate adjustments in 2018 and 2019, if warranted, based on *“a limited number of 2016 actual and forecast updates”*.[3]

6. Accordingly, in its 2015 Decision the Board set OPUCN's distribution rates on a final basis for 2015, 2016 and 2017. The Board also approved rates for 2018 and 2019 on an interim basis. The Board directed OPUCN to file an application for finalization of 2018 and 2019 revenue requirement and rates through consideration and adjustment, as warranted, of the following elements of its 2018 and 2019 interim rates:

   (a) Its forecast of new customer connections (currently approved for 2018 and 2019 at 3%[4]) and the impact of this update on its forecast of rate base and revenue.

   (b) The amount and timing of its capital expenditures, and attendant changes in rate base, resulting from:

      (i) The proposed MS9 substation.[5]

      (ii) “Regional planning”; i.e. the cost and schedule of the proposed Hydro One Enfield TS and associated OPUCN contributions and other related capital expenditures.[6]

      (iii) Third party requests for relocation of OPUCN plant.[7]

   (c) It's cost of capital, updating for the OEB's 2017 cost of capital parameters.[8]

---

[2] 2015 Decision, p.9.
[3] 2015 Decision, p.9.
[4] 2015 Decision, p.30.
[5] 2015 Decision, p.20.
[6] 2015 Decision, pp.20 and 23.
[7] 2015 Decision, p.9.
[8] 2015 Decision, pp.32-33.

(d) It's cost of power, and attendant changes to its working capital allowance.[9]

7. In its 2015 Decision the OEB also directed that OPUCN report annually on the metrics which it proposed for its CIR Plan[10];

(a) Its OEB scorecard.

(b) Its OEB service quality levels (which OPUCN undertook to maintain at 2014 levels).

(c) Outage reductions achieved as a result of its program to replace porcelain insulators and reduce foreign interference (animal contact).

8. Included with this Application is OPUCN's first CIR Plan annual report, as directed in the 2015 Decision. Hereafter OPUCN plans to file its CIR Plan annual reports on April 30th of each year through 2019.

9. In this application OPUCN also requests:

(a) A rate rider to effect disposition of OPUCN's Group 1 Deferral and Variance Accounts; and

(b) An adjustment to implement approved Retail Transmission Service and Connection costs.

Overview

10. Adjusting the revenue requirement underlying OPUCN's approved interim 2018 and 2019 rates for the updates to OPUCN's forecast cost of service contemplated by the 2015 Decision, OPUCN's final revenue requirement and rates for 2018 and 2019 would decrease relative to interim rates as follows:

---

[9] 2015 Decision, p.22.
[10] 2015 Decision, p.11.

Table 1

Year	Interim Base Revenue Requirement ($000s)	Updated Base Revenue Requirement ($000s)	Interim Residential Rate	Final Residential Rate
2018	$24,975	$23,741	$17.93 Fixed/Month $0.0078 per kWh	$17.35 Fixed/Month $0.0078 per kWh
2019	$26,406	$24,974	$21.55 Fixed/Month $0.0041 per kWh	$20.97 Fixed/Month $0.0041 per kWh

11. For a typical residential customer consuming 800 kWh/month the monthly bill impact of OPUCN's proposed rate adjustment would be a decrease, compared to interim rates, of $0.58 in 2018 and $0.58 in 2019.

12. The main drivers of these rate changes are:

(a) Cost of capital:

A decrease in OEB mandated ROE and a decrease in OPUCN's forecast long term interest rate, offset somewhat by an increase in the OEB's mandated short term interest rate, resulting in:

(i) A decrease in forecast base revenue requirement of $652,000 in 2018 and $746,000 in 2019; and

(ii) A decrease in forecast regulated return on capital of $579,000 in 2018 and $664,000 in 2019.

Table 2

Year	Interim Cost of Capital Parameters			Update Cost of Capital Parameters		
	ROE	*L/T Interest*	*S/T Interest*	*ROE*	*L/T Interest*	*S/T Interest*
2018	9.19%	4.54%	1.65%	8.78%	3.72%	1.76%
2019	9.19%	4.54%	1.65%	8.78%	3.72%	1.76%

(b) Customer growth:

An updated forecast customer growth rate for each of 2018 and 2019 of 1.82%, compared to the 3.00% included in interim rates, resulting in:

(i) A decrease in forecast base revenue requirement of $42,000 in each of the years 2018 and 2019 ; and

(ii) A decrease in forecast regulated return on capital of $39,000 in 2018 and $49,000 in 2019.

(c) Cost of power:

Forecast cost of power was updated based upon the Board's *Regulated Price Plan Report – April 20, 2017* (2017 RPP Report). OPUCN estimated 2017 cost of power based upon the *Ontario Electricity Market Price Forecast* included in the 2017 RPP Report and reduced the rates by 25% to reflect the Provincial Fair Hydro Plan. The 2017 estimate was then increased 2%, year over year, in each of the years 2018 and 2019 to reflect inflation. The updated cost of power resulted in a consequent adjustment to OPUCN's working capital requirements, in turn resulting in:

(i) A decrease in forecast base revenue requirement of $19,000 and $2,000 in 2018 and 2019 respectively relative to forecast; and

(ii) A decrease in forecast regulated return on capital of $15,000 in 2018 and $2,000 in 2019.

(d) Capital expenditures:

(i) Forecast capital contributions to Hydro One in respect of the Enfield TS have been reduced from $13.5 million to $4.0 million and the expected in-service date has been deferred from 2018 to 2019;

(ii) Capital expenditures associated with regional planning load transfers to Enfield TS of $6.5 million have been included in OPUCN's updated forecast for 2019;

(iii) Forecast for MS9 remains unchanged;

(iv) Forecast plant relocations resulting from third-party requests have not been updated; and

(v) Forecast net new customer connection costs have not been changed;

All resulting in:

(A) Base revenue requirement being $522,000 and $642,000 lower in 2018 and 2019 respectively; and

(B) Regulated return on capital decreasing by $401,000 in 2018 and $473,000 in 2019.

13. Overall, the updates summarized above result in forecast decreases as follows ($000's):

Table 3

Year	Regulated Return	Rate Base	Working Capital	Working Capital Allowance	Operating Expense	Other Service Revenue	Base Revenue Requirement
2018	$1,034	$8,238	$10,475	$982	$206	$6	$1,234
2019	$1,187	$9,453	$9 671	$906	$263	$18	$1,432

<u>Structure of the Evidence</u>

14. In the 2015 Decision the OEB directed OPUCN to file with its application for final 2018 and 2019 rates *"information, including information on financial performance, sufficient for the OEB to determine whether rate adjustments are warranted"*.[11]

15. The following information is provided in this Exhibit A in support of this Application:

[11] 2015 Decision, p.10.

16. OPUCN’s CIR Plan report for the period October 1, 2015 through December 31, 2016 is filed as Exhibit B.

UPDATED 2015-2017

17. The following is a comparison of OEB-Approved to actual costs, revenues and resulting earnings in 2015 and 2016, and updated forecast results for 2017 results ($000's):

Table 4

Metric	OEB-Approved			OPUCN Results		
	2015	*2016*	*2017*	*2015*	*2016*	*2017 (Est)*
Regulated net income	$3,665	$3,850	$3,990	***$2,994***	***$4,410***	***$3,990***
Rate Base	$98,510	$104,742	$108,537	***$98,582***	***$106,567***	***$109,000***
ROE	9.30%	9.19%	9.19%	***7.59%***	***10.35%***	***9.15%***
Distribution revenue	$20,975	$22,439	$23,079	***$19,313***	***$22,364***	***$22,788***
Other service revenue	$1,319	$1,472	$1,579	***$1,638***	***$1,705***	***$1,759***
Operating expenses	$16,080	$17,468	$17,840	***$15,648***	***$17,001***	***$17,675***
PILS	$196	$307	$424	***$37***	***$240***	***$139***

2015

18. Actual results for 2015 were impacted by the effective date for 2015 rates directed in the 2015 Decision. OPUCN applied for rates effective January 1, 2015 and was the 2015 Decision directed OPUCN's new rates for 2015 be effective October 1, 2015. As a result, distribution revenue was less than plan. OPUCN was able to partially offset this revenue shortfall by containing operating expenses in the year. In the result, OPUCN's regulated return on equity (ROE) for 2015 was 7.59% compared with the applicable OEB rate for 2015 of 9.30%.

2016

19. In 2016, OPUCN outperformed the OEB-Approved regulated net income by $560,000 and ROE by 1.16%. Income in 2016 was $4,410,000 and ROE was

10.35%. OPUCN benefited from higher than planned other service revenue of $233,000, and lower operating expenses (lower by $467,000) and PILS (lower by $67,000).

20. OM&A in 2016 was under plan by $190,000, and depreciation expense was lower by $277,000. OM&A was lower than forecast in 2016 by 1.5% as a result of merger discussions during 2016 and consequent deferral of certain planned labour expenses. Depreciation expense was lower than forecast in 2016 as a result of the difference in actual componentization of expenditures and the relative depreciation rate compared to plan. Cumulative capital expenditures were $20 million compared to the planned $22 million, which also contributed to the lower depreciation expense.

2017

21. Regulated net income and ROE results for 2017 are forecast in line with plan. While there are moderate differences in the components contributing to earnings, they are expected to offset each other.

UPDATED CUSTOMER GROWTH FORECAST

22. Interim rates for 2018 and 2019 were set in the 2015 Decision based on OPUCN's initial customer growth forecast of 3% for each of these years. In its decision the Board approved an annual 1.5% growth rate for 2015, 2016 and 2017 and a 3.0% growth rate for 2018 and 2019, and provided OPUCN an *"opportunity to update the forecast growth rate for 2018 and 2019 based on actual results to date at the mid-term review."*[12]

23. The following table summarizes the actual customer connections up to and including 2016, and updated forecast connections for 2017 through 2019:

Table 5

Description	Residential	GS<50 kW	GS 50 to 999 kW	Large User	GS>1,000 kW	Streetlight	Sentinel Light	USL	Total
Average Annual Customer Connection Count									
2008 Board Approved	47,243	3,845	522	2	9	11,650	77	305	63,653
2012 Board Approved	49,920	3,961	518	1	10	12,762	22	313	67,507
2015 Board Approved	50,977	4,002	507	1	12	12,710	23	296	68,529
2016 Board Approved	51,742	4,062	515	1	12	12,960	22	296	69,611
2017 Board Approved	52,518	4,123	522	1	12	13,215	22	296	70,710
2008	47,058	3,794	534	3	9	11,622	26	301	63,345
2009	47,603	3,860	525	2	10	11,801	26	303	64,128
2010	48,115	3,929	513	1	10	11,996	25	307	64,894
2011	48,651	3,889	521	1	10	12,128	24	303	65,525
2012	49,021	3,851	512	1	11	12,213	24	296	65,927
2013	49,516	3,905	500	1	11	12,333	24	295	66,584
2014	50,203	3,953	503	1	11	12,465	24	296	67,454
2015	51,153	4,028	509	1	12	12,714	24	285	68,724
2016	52,115	4,112	517	1	13	12,958	24	274	70,013
2017 Bridge Year (YTD Actual)	52,861	4,146	517	1	13	13,212	23	272	71,046
2018 Test Year (Regression)	53,813	4,221	526	1	13	13,472	23	271	72,340
2019 Test Year (Regression)	54,782	4,297	535	1	14	13,737	22	269	73,658

[12] 2015 Decision, p. 30.

24. Percentage growth rates by customer class are:

Table 6

Description	Residential	GS<50 kW	GS 50 to 999 kW	Large User	GS>1,000 kW	Streetlight	Sentinel Light	USL	Total
Average Annual Customer Connection Count									
2014	1.4%	1.2%	0.5%	0.0%	0.0%	1.1%	0.0%	0.2%	1.3%
2015	1.9%	1.9%	1.2%	0.0%	9.1%	2.0%	0.0%	-3.7%	1.9%
2016	1.9%	2.1%	1.6%	0.0%	8.3%	1.9%	0.0%	-3.9%	1.9%
2017 Bridge Year (YTD Actual)	1.4%	0.8%	0.0%	0.0%	0.0%	2.0%	-2.8%	-0.5%	1.5%
2018 Test Year (Regression)	1.8%	1.8%	1.8%	0.0%	1.5%	2.0%	-2.8%	-0.5%	1.8%
2019 Test Year (Regression)	1.8%	1.8%	1.8%	0.0%	7.6%	2.0%	-2.8%	-0.5%	1.8%

25. Actual customer growth rates for 2015 and 2016 were 1.9%. Updated forecast customer growth for 2017 is 1.5%.

26. In discussions with representatives of the City of Oshawa and consistent with a report issued by the Region of Durham on June 26, 2015 – *Durham Regional Official Plan*, OPUCN is revising its forecast customer growth for 2018 and 2019 to 1.8% for each of the years. The Region of Durham's report included estimates for growth in households of 1.8% for the five years ending in 2016 and for the five years ending in 2021.[13] Representatives of the City of Oshawa have revised their forecast in line with the Region of Durham through 2021.

27. While infrastructure expansion continues to occur in Oshawa as a result of the 407 ETR extension and other City and Region initiatives, OPUCN has reset the timing of expected growth in customer connections for 2018 and 2019 to be consistent with current City and Region forecast growth in households. Both the City and the Region continue to predict that growth rates will be higher than historical levels but also agree that the pace for such growth is likely to be more gradual than anticipated prior to issuance of the most recent report.

[13] Durham Regional Official Report, p. 38
https://www.durham.ca/departments/planed/planning/op_documents/officialplan/dropoc.pdf

28. For these reasons, OPUCN is revising its estimates for customer connections growth to 1.8% for each of the years 2018 and 2019.

29. In addition to updating customer connection growth expectations, OPUCN is adjusting its forecast demand and consumption for 2018 and 2019 to reflect the observed trend for softening demand and consumption by its customers.

30. The following tables present updated forecast demand and consumption:

Table 7

Description	GS 50 to 999 kW	Large User	GS>1,000 kW	Streetlight	Sentinel Light	Total
Billed Demand (kW)						
2008	876,464	124,131	204,487	26,489	109	1,231,680
2009	861,503	89,007	190,299	27,041	102	1,167,952
2010	871,715	70,585	195,141	27,634	99	1,165,174
2011	867,070	83,704	192,700	27,830	100	1,171,404
2012	846,459	89,554	182,189	27,720	100	1,146,022
2013	843,160	92,753	184,241	25,276	100	1,145,530
2014	831,789	93,203	186,714	25,520	100	1,137,326
2015	847,479	95,584	190,580	26,032	100	1,159,775
2016	850,825	99,526	202,815	26,568	100	1,179,834
2017	832,942	92,630	176,491	19,559	101	1,121,723
2018	834,069	90,488	167,714	13,345	97	1,105,714
2019	835,118	88,370	169,068	13,902	93	1,106,551

Table 8

Description	Residential	GS<50 kW	GS 50 to 999 kW	Large User	GS>1,000 kW	Streetlight	Sentinel Light	USL	Total
kWh Billed									
2008 Board Approved	487,192,399	140,097,188	358,858,375	60,139,982	80,956,601	10,072,853	40,813	3,841,944	1,141,200,155
2012 Board Approved	496,447,375	132,319,612	359,363,080	33,402,763	78,175,306	11,044,796	38,567	3,208,501	1,114,000,000
2015 Board Approved	488,310,442	134,064,266	337,307,809	42,639,586	88,420,452	8,578,852	34,297	2,686,537	1,102,042,241
2016 Board Approved	491,380,161	134,854,492	340,651,148	42,660,606	88,120,102	5,237,834	32,910	2,667,193	1,105,604,445
2017 Board Approved	492,297,001	135,063,742	342,688,526	42,752,494	87,493,647	4,853,625	31,630	2,652,385	1,107,833,051
2008	470,718,851	131,868,017	352,632,150	46,461,021	102,433,272	9,725,840	39,233	3,372,873	1,117,251,257
2009	467,977,819	128,019,505	349,784,301	36,580,289	87,237,589	10,202,758	36,792	2,825,455	1,082,664,508
2010	476,941,035	131,282,103	355,234,224	33,402,763	80,783,141	10,427,904	35,812	2,831,501	1,090,938,483
2011	484,582,022	135,695,878	359,534,375	37,740,699	79,908,016	10,253,017	35,812	2,769,028	1,110,518,847
2012	473,288,468	131,590,801	338,342,507	40,812,737	76,828,137	10,139,708	35,812	2,745,701	1,073,783,871
2013	475,282,449	132,382,128	337,123,668	42,326,219	79,176,233	9,082,284	35,812	2,752,416	1,078,161,209
2014	485,503,507	133,729,082	336,406,114	42,700,435	81,400,346	9,155,875	35,812	2,711,219	1,091,642,390
2015	479,177,852	132,197,810	333,350,818	41,948,976	81,234,207	9,302,763	35,813	2,512,230	1,079,760,469
2016	477,455,153	130,049,530	330,168,199	41,438,246	83,295,745	9,490,651	35,814	2,500,582	1,074,433,920
2017 Bridge Year (YTD Actual)	481,242,441	130,109,123	329,149,932	40,749,634	78,965,335	7,199,509	34,672	2,564,505	1,070,015,151
2018 Test Year (Regression)	480,011,939	129,585,178	329,595,262	39,807,307	75,038,332	4,912,438	33,345	2,612,659	1,061,596,461
2019 Test Year (Regression)	478,548,339	129,015,226	330,009,795	38,875,446	75,644,065	5,117,254	32,059	2,660,941	1,059,903,127

31. In addition to reflecting the updated customer connections growth, OPUCN's load forecast model takes into account latest CDM activity as well as demand and consumption trends which have been steadily decreasing over the last several years.

32. In its Report of the Ontario Energy Board - *Defining Ontario's Typical Electricity Customer* released on April 14, 2016, the Board states that *"a recent review indicates that average residential consumption has declined significantly since the standard was last established. As a result, the OEB has determined that the standard used for illustrative purposes should now be 750 kWh per month"*[14], a reduction from the previous standard of 800 kWh per month.

The OEB's change to the standard consumption was based on analytical findings described in the report which support the trend for lower consumption for the typical Ontario electricity customer. OPUCN has determined consumption trends for its customers which are in line with the OEB findings.

[14] Defining Ontario's Typical Electricity Customer, p. 1.

The following tables present the updated forecast average billable consumption per customer and the differences compared to OPUCN's load forecast used in its 2015 CIR Application:

Table 9

Description	Residential	GS<50 kW	GS 50 to 999 kW	Large User	GS>1,000 kW	Streetlight	Sentinel Light	USL	Total
Annual Billed Energy per Average Customer Connection									
2008 Board Approved	10,312	36,436	687,468	30,069,991	8,995,178	865	530	12,597	17,928
2012 Board Approved	9,945	33,406	693,751	33,402,763	7,817,531	865	1,729	10,248	16,502
2015 Board Approved	9,579	33,495	665,301	42,639,586	7,368,371	675	1,477	9,082	16,081
2016 Board Approved	9,497	33,195	661,973	42,660,606	7,343,342	404	1,465	9,007	15,883
2017 Board Approved	9,374	32,756	656,114	42,752,494	7,291,137	367	1,455	8,947	15,667
2008	10,003	34,762	660,979	18,584,408	11,381,475	837	1,509	11,206	17,638
2009	9,831	33,170	666,256	18,290,145	9,182,904	865	1,415	9,340	16,883
2010	9,913	33,414	693,140	33,402,763	8,078,314	869	1,432	9,238	16,811
2011	9,960	34,897	690,748	37,740,699	7,990,802	845	1,492	9,154	16,948
2012	9,655	34,175	661,471	40,812,737	7,316,965	830	1,492	9,292	16,287
2013	9,599	33,905	674,247	42,326,219	7,197,839	736	1,492	9,330	16,192
2014	9,671	33,834	669,465	42,700,435	7,400,031	735	1,492	9,175	16,184
2015	9,368	32,824	655,557	41,948,976	6,769,517	732	1,492	8,830	15,712
2016	9,162	31,627	639,241	41,438,246	6,407,365	732	1,492	9,143	15,346
2017 Bridge Year (YTD Actual)	9,104	31,378	637,270	40,749,634	6,074,257	545	1,486	9,424	15,163
2018 Test Year (Regression)	8,920	30,699	626,845	39,807,307	5,684,722	365	1,469	9,649	14,882
2019 Test Year (Regression)	8,736	30,024	616,495	38,875,446	5,327,047	373	1,452	9,877	14,605

Table 10

Description	Residential	GS<50 kW	GS 50 to 999 kW	Large User	GS>1,000 kW	Streetlight	Sentinel Light	USL	Total
Annual Billed Energy per Average Customer Connection									
2015	211	672	9,744	690,610	598,854	-57	-15	251	394
2016	335	1,568	22,731	1,222,360	935,977	-328	-27	-136	665
2017 Bridge Year (YTD Actual)	270	1,377	18,844	2,002,861	1,216,881	-178	-31	-477	667
2018 Test Year (Regression)	309	1,547	22,018	2,911,690	1,552,224	3	-28	-788	768
2019 Test Year (Regression)	361	1,760	25,965	3,656,696	1,847,658	-5	-30	-1,132	924

UPDATED CAPITAL EXPENDITURES

33. Based on current information from Hydro One and OPUCN engineering, the following updates to forecast rate base as directed in the 2015 Decision have been made for 2018 and 2019:

Enfield TS/Regional Planning

34. The forecast for regional planning costs underpinning OPUCN's CIR Application totalled $22.5 million, of which $13.5 million was OPUCN's expected contribution to Hydro One for the costs of the Hydro One Enfield TS, and the balance ($9.0 million) was forecast for OPUCN work for load transfer, egress and access connection with the new Enfield TS.

35. OPUCN's updated forecast for regional planning costs total $19.5 million, of which $4 million is now confirmed as OPUCN's contribution to Hydro One for the Enfield TS. Of the balance ($15.5 million), there is still a $9 million cost forecast for OPUCN work for load transfer, egress and access connection with the new Enfield TS. The balance - $6.5 million – is the forecast cost for OPUCN's feeder arrays to integrate the Enfield TS connection to OPUCN's system.

36. In the result:

    (a) OPUCN's Hydro One contributions for Enfield TS have decreased by $9 million.

    (b) OPUCN has confirmed additional investment in OPUCN owned feeder arrays forecast at $6.5 million.

    (c) The net reduction in Enfield TS/Regional Planning costs is forecast at $3.0 million.

37. In addition, the expected in-service date for Enfield and the related assets has been deferred from 2018 to 2019.

38. Hydro One and OPUCN have executed a Connection and Cost Recovery Agreement (CCRA) – Load, a copy of which is included as Attachment 1.

MS9

39. OPUCN's forecast for the MS9 substation remains unchanged from the time of its CIR Application at $7.0 million with an expected in-service date of 2018 as initially planned.

Plant Relocations

40. Forecast plant relocations remain the same as at the time of OPUCN's CIR Application.

41. Cumulative total capital expenditures related to plant relocations is expected to be approximately $2.4 million below plan at the end of 2017 due mainly to the pace of construction being slower than anticipated. However, based on City and Regional planning and the completion of infrastructure for the 407 ETR extension, OPUCN expects the total planned capital for third-party requested plant relocations for the five year period to be spent.

42. In 2018 and 2019, OPUCN expects to spend the planned capital for these years, plus the cumulative shortfall from the years 2015 through 2017.

Connection Costs

43. In accordance with the 2015 Decision, OPUCN reduced annual net expansion and connection costs by $400,000 for the years 2015 through 2017 to compensate for a decrease in forecast customer connections from 3% per year to 1.5% over the same period. Actual 2015 through 2017 expansion and connection costs are expected to be $1.2 million, exceeding the Board-Approved amount by approximately $0.7 million.

44. OPUCN, City and Regional planners estimate the pace of expansion to continue at recent levels, and OPUCN has thus increased its growth forecast from 1.5% for the 2015-2017 period to 1.8% for the 2018-2019 period. Given that;

(a) OPUCN's expansion and connection costs have exceeded OEB approved amounts during the 2015-2017 period by approximately $0.7 million;

(b) OPUCN's forecast growth rate for 2018 and 2019 is 1.8% as compared to the 1.5% embedded OPUCN's 2015-2017 rates;

(c) any further adjustment of net expansion and connection costs embedded in interim 2018 and 2019 rates for the change in growth forecast from 3% to 1.8% would have a *de minimus* impact on rates;

OPUCN has not proposed to update its forecast net expansion and connection costs for 2018 and 2019 (which remain $575,000 and $610,000, respectively).

UPDATED COST OF POWER

45. OPUCN updated its forecast cost of power based on the OEB's *Regulated Price Plan Report – April 20, 2017* (RPP Report). OPUCN estimated 2017 cost of power based upon the *Ontario Electricity Market Price Forecast* included in the RPP Report and reduced the rates by 25% to reflect the Provincial Fair Hydro Plan. A 2% inflation adjustment was then applied to the reforecast 2017 cost of power to derive 2018 cost of power, and an additional 2% inflation adjustment was applied to derive 2019 cost of power.

46. The table below outlines the calculation used to develop the price for cost of power in 2017:

Table 11

	Months	20-Apr-17
Average - Jan 17 - April 17	4	$ 20.41
May 17 - July 17	3	$ 18.45
Aug 17 - Oct 17	3	$ 23.26
Nov 17 - Jan 18	2	$ 26.89
Weighted Average		$ 21.71
Global Adjustment		$ 87.67
2017 Base Non-RPP Price		$ 109.38
Load Weighted Price for RPP Consumers		$ 24.83
Forecast Wholesale Electricity Price		$ 22.81
Ratio		$ 1.09
Weighted Average		$ 21.71
Load Weighted Price for RPP Consumers		$ 23.63
Global Adjustment		$ 87.67
Adjustment to Address Bias		$ 1.00
Adjustment to Clear Existing Variance		$ 1.40
2017 Base RPP Price		$ 113.70

47. The following adjustment was then made to reflect the Provincial Fair Hydro Plan:

Table 12

2017 Base Non-RPP Price		$ 109.38
Adjust for Fair Hydro	25%	$ 27.35
Adjusted Non-RPP Price		$ 82.04

Table 13

2017 Base RPP Price		$ 113.70
Adjust for Fair Hydro	25%	$ 28.43
Adjusted RPP Price		$ 85.28

48. An inflation rate of 2% was applied each year for 2018 and 2019.

49. Current pricing for other cost of power components was used for; Network Service Charge, Line and Connection Charge, Wholesale Market Service Charge and Smart Meter Entity Charge.

50. The updated cost of power resulting from the price adjustments and updated load forecast, including the estimated impact of the Fair Hydro Plan, are summarized in the following table ($000s):

Table 14

Year	OEB-Approved	Updated
2018	$123,228	$112,753
2019	$124,412	$114,740

51. The updated costs of power in Table 14 include (i.e. are net of) the adjustment (reduction) of approximately $30 million per year on account of the anticipated impact of the Fair Hydro Plan, which when flowed through the working capital allowance calculation has reduced OPUCN's forecast revenue requirement by approximately $160,000 per year.

52. OPUCN seeks the Board's direction on whether to include in its cost of power related working capital adjustment for finalizing 2018 and 2019 rates the forecast of the impact of the Fair Hydro Plan. Alternatively, OPUCN's final 2018 and 2019 rates can be set without forecasting this impact, and then adjusted, as warranted, in the manner which the OEB determines to apply to other distributors on Custom IR Plan rate plans.

INTERIM/FINAL RATE COMPARISON

53. The following is a comparison of OEB approved interim distribution rates for 2018 and 2019 and the final rates requested by OPUCN in this application:

Table 15

	Proposed Final Rates 2018	Interim Rates 2018	Increase/ (Decrease)		Proposed Final Rates 2019	Interim Rates 2019	Increase/ (Decrease)	
Residential								
Fixed Charge / Mth	17.35	17.93	(0.58)	(3.2)%	20.97	21.55	(0.58)	(2.7)%
Volumetric Rate / kWh	0.0078	0.0078	0.0000	0.0%	0.0041	0.0041	0.0000	0.0%
Typical Monthly Bill ($'s)	$23.59	$24.17	$(0.58)	(2.4)%	$24.25	$24.83	$(0.58)	(2.3)%
GS Less Than 50 KW								
Fixed Charge / Mth	16.07	17.00	(0.93)	(5.5)%	16.47	17.37	(0.90)	(5.2)%
Volumetric Rate / kWh	0.0170	0.0171	(0.0001)	(0.6)%	0.0178	0.0177	0.0001	0.6%
Typical Monthly Bill ($'s)	$50.07	$51.20	$(1.13)	(2.2)%	$52.07	$52.77	$(0.70)	(1.3)%
GS 50 To 999 KW								
Fixed Charge / Mth	55.28	56.43	(1.15)	(2.0)%	57.54	58.29	(0.75)	(1.3)%
Volumetric Rate / kW	4.7330	4.8301	(0.0971)	(2.0)%	4.9233	4.9867	(0.0634)	(1.3)%
Typical Monthly Bill ($'s)	$2,327.12	$2,374.88	$(47.76)	(2.0)%	$2,420.72	$2,451.91	$(31.18)	(1.3)%
GS Intermediate 1,000 To 4,999 KW								
Fixed Charge / Mth	1,161.65	1,185.86	(24.21)	(2.0)%	1,209.14	1,224.94	(15.80)	(1.3)%
Volumetric Rate / kW	2.4926	2.5329	(0.0403)	(1.6)%	2.5715	2.5979	(0.0264)	(1.0)%
Typical Monthly Bill ($'s)	$3,452.35	$3,513.60	$(61.25)	(1.7)%	$3,572.35	$3,612.41	$(40.06)	(1.1)%
Large Use								
Fixed Charge / Mth	8,839.27	9,023.50	(184.23)	(2.0)%	9,200.61	9,320.91	(120.30)	(1.3)%
Volumetric Rate / kW	2.1530	2.1854	(0.0324)	(1.5)%	2.2165	2.2377	(0.0212)	(0.9)%
Typical Monthly Bill ($'s)	$25,692.95	$26,130.81	$(437.86)	(1.7)%	$26,551.37	$26,837.63	$(286.25)	(1.1)%

Street Lighting								
Fixed Charge / Mth	1.99	2.05	(0.06)	(2.8)%	2.07	2.12	(0.05)	(2.2)%
Volumetric Rate / kW	30.7493	31.6243	(0.8750)	(2.8)%	32.0063	32.6666	(0.6603)	(2.0)%
Typical Monthly Bill ($'s)	$4.45	$4.58	$(0.13)	(2.8)%	$4.63	$4.73	$(0.10)	(2.1)%
Sentinel Lighting								
Fixed Charge / Mth	5.57	5.68	(0.12)	(2.0)%	5.80	5.87	(0.07)	(1.2)%
Volumetric Rate / kW	7.9512	8.1169	(0.1657)	(2.0)%	8.2762	8.3844	(0.1082)	(1.3)%
Typical Monthly Bill ($'s)	$5.88	$6.01	$(0.12)	(2.0)%	$6.13	$6.20	$(0.07)	(1.2)%
Unmetered Scattered Load								
Fixed Charge / Mth	4.61	4.77	(0.16)	(3.3)%	4.80	4.93	(0.13)	(2.6)%
Volumetric Rate / kWh	0.0189	0.0195	(0.0006)	(3.1)%	0.0197	0.0201	(0.0004)	(2.0)%
Typical Monthly Bill ($'s)	$18.79	$19.40	$(0.61)	(3.1)%	$19.57	$20.00	$(0.43)	(2.1)%

54. Updated requested rates for 2018 and 2019 are lower than interim approved rates, as illustrated above. These reductions are driven primarily by lower cost of capital parameters and lower capital forecasts, partially offset by a lower load forecast (with lower consumption and lower customer count).

55. In this application OPUCN also requests:

(a) A rate rider to effect disposition of OPUCN's Group 1 Deferral and Variance Accounts; and

(b) An adjustment to implement approved Retail Transmission Service and Connection costs.

Deferral & Variance Account Rate Rider

56. The Deferral & Variance Account rate rider was calculated using the Deferral & Variance Account Worksheet provided by the Board. The Worksheet is attached to this Application. The Group 1 amounts are as follows:

Table 16

Group 1 Account	Account Number	Total Claim
RSVA - Wholesale Market Service Charge	1580	($2,905,617)
RSVA - Retail Transmission Network Charge	1584	$2,482,969
RSVA - Retail Transmission Connection Charge	1586	($1,294,730)
RSVA - Power (excluding Global Adjustment)	1588	$(128,863)
RSVA - Global Adjustment	1589	($656,675)
Total		($2,502,917)

Threshold Test	
Total Claim for Threshold Test (Group 1 Accounts excluding 1595 – balances already approved for disposition)	($2,502,917)
Forecasted Annual kwh	1,061,596,461
Threshold Test (Total claim per kWh – should exceed + or - $0.001/kwh)	($0.0024)

57. The Board's Electricity Distributors' Deferral and Variance Account Review Report (the "EDDVAR Report") provides that during the IRM plan term, the distributor's Group 1 audited account balances will be reviewed and disposed if the pre-set disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The OPUCN Group 1 balances result in a total claim per kWh greater than the pre-set threshold of $0.001 per kWh and as such disposition of these balances is requested, over a one year period, at the rates outlined below.

Table 17

Rate Rider Calculation for Group 1 DVA's (excl. Global Adj.)
1550, 1551, 1584, 1586

Rate Class	Units	kW / kWh	Allocated Balance (excl 1589)	Rate Rider
RESIDENTIAL	kWh	480,011,939	$(844,995)	(0.0018)
GS < 50 KW	kWh	129,585,178	$(228,117)	(0.0018)
GS 50 TO 999 KW (I1 & I4)	kW	834,069	$(557,654)	(0.6873)
GS 1,000 TO 4,999 KW (I2)	kW	167,714	$(132,095)	(0.7876)
LARGE USE (I3)	kW	90,488	$(70,075)	(0.7744)
STREET LIGHTING	kW	13,345	$(8,648)	(0.6480)
USL	kWh	2,612,659	$(4,599)	(0.0018)
SENTINEL LIGHTS	kW	97	$(59)	(0.6051)
Total			$(1,846,242)	

Table 18

Rate Rider Calculation for RSVA - Power - Global Adjustment
1589

Rate Class	Units	kWh	Allocated Balance (1589)	Rate Rider
RESIDENTIAL	kWh	33,600,836	$(61,666)	(0.0018)
GS < 50 KW	kWh	24,621,184	$(45,186)	(0.0018)
GS 50 TO 999 KW (I1 & I4)	kWh	219,588,677	$(402,999)	(0.0018)
GS 1,000 TO 4,999 KW (I2)	kWh	75,038,332	$(137,714)	(0.0018)
LARGE USE (I3)	kWh	0	$0	0.0000
STREET LIGHTING	kWh	4,912,438	$(9,016)	(0.0018)
USL	kWh	52,253	$(96)	(0.0018)
SENTINEL LIGHTS	kWh	0	$0	0.0000
Total			$(656,675)	

58. A completed copy of the Board approved Deferral and Variance Account (Continuity Schedule) Work Form is filed along with this evidence.

RTSR Adjustment

59. OPUCN has used the RTSR Adjustment Worksheet to calculate new rates for Network and Connection charges. The proposed new rates are shown below.

Table 19

Rate Class	Unit	2018 Proposed RTSR-Network	2018 Proposed RTSR-Connection
Residential	kWh	0.0076	0.0068
General Service Less Than 50 kW	kWh	0.0070	0.0063
General Service 50 to 999 kW	kW	2.5485	2.2013
General Service 50 to 999 kW - Interval Metered	kW	3.2665	2.7964
General Service 1,000 to 4,999 kW - Interval Metered	kW	3.2665	2.7964
Large Use > 5000 kW	kW	3.4805	3.0512
Unmetered Scattered Load	kWh	0.0070	0.0063
Sentinel Lighting	kW	1.7579	2.5840
Street Lighting	kW	1.7281	2.5404

60. The following table illustrates the change from the Board's approved 2017 Network and Connection rates, as part of the Decision and Order issued December 22, 2016, and the proposed 2018 Network and Connection Rates.

Table 20

Rate Class	Unit	2017 Approved RTSR-Network	2018 Proposed RTSR-Network	Increase/ (Decrease)	Change
Residential	kWh	0.0074	0.0076	0.0002	2.7%
General Service Less Than 50 kW	kWh	0.0069	0.0070	0.0001	1.4%
General Service 50 to 999 kW	kW	2.4961	2.5485	0.0524	2.1%
General Service 50 to 999 kW - Interval Metered	kW	3.1993	3.2665	0.0672	2.1%
General Service 1,000 to 4,999 kW - Int. Metered	kW	3.1993	3.2665	0.0672	2.1%
Large Use > 5000 kW	kW	3.4089	3.4805	0.0716	2.1%
Unmetered Scattered Load	kWh	0.0069	0.0070	0.0001	1.4%
Sentinel Lighting	kW	1.7217	1.7579	0.0362	2.1%
Street Lighting	kW	1.6925	1.7281	0.0356	2.1%

Rate Class	Unit	2017 Approved RTSR-Connection	2018 Proposed RTSR-Connection	Increase/ (Decrease)	Change
Residential	kWh	0.0062	0.0068	0.0006	9.7%
General Service Less Than 50 kW	kWh	0.0057	0.0063	0.0006	10.5%
General Service 50 to 999 kW	kW	2.0069	2.2013	0.1944	9.7%
General Service 50 to 999 kW - Interval Metered	kW	2.5494	2.7964	0.2470	9.7%
General Service 1,000 to 4,999 kW - Int. Metered	kW	2.5494	2.7964	0.2470	9.7%
Large Use > 5000 kW	kW	2.7817	3.0512	0.2695	9.7%
Unmetered Scattered Load	kWh	0.0057	0.0063	0.0006	10.5%
Sentinel Lighting	kW	2.3559	2.5840	0.2281	9.7%
Street Lighting	kW	2.3160	2.5404	0.2244	9.7%

61. A completed copy of the Board approved RTSR Work Form is filed along with this evidence.