Exhibit K1.3
June 30, 2015

EB-2014-0101

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application by Oshawa PUC Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2015 and for each following year through to December 31, 2019

CROSS-EXAMINATION COMPENDIUM OF THE SCHOOL ENERGY COALITION (Panel 1)

June 30, 2015

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Updates – June 2015

OPUCN filed its Custom IR rate application on January 29, 2015. On May 13, 2015 OPUCN filed an updated set of rate models to incorporate actual results for 2014, in response to a number of interrogatories which requested various updates for 2014 and in advance of the Technical Conference held in respect of this application on May 21st and May 22nd, 2015.

Following the Technical Conference, and OPUCN's responses to undertakings taken during the Technical Conference, OPUCN is filing this update to the rate models underlying its application. OPUCN is also providing clarifications in respect of a number of its proposals, as identified below.

Rate Model Updates

Following is a table which summarises the change to the Base Revenue Requirement (dollars expressed in thousands unless noted otherwise) resulting from each update ("Updates") referenced in the discussion which follows. OPUCN is submitting updated Excel spreadsheets per the note below to accompany this report and provide further details including bill impacts.

Rate Application UPDATES - Revenue Requirement Impacts *23-Jun 2015*

	2015	2016	2017	2018	2019	Total	Cum. Total
Revenue Requirement As Filed Jan 29, 2015	***21,565***	***23,548***	***24,391***	***25,605***	***26,194***		
Revenue Requirement As Updated May 13, 2015	***21,647***	***23,408***	***24,384***	***26,217***	***27,431***		1,783
Revised Working Capital Proposal (Update June 2015)	21,432	23,191	24,163	25,992	27,206		
Increase / (Decrease)	(215)	(217)	(221)	(225)	(225)	(1,103)	681
% Increase / (Decrease)	-1.0%	-0.9%	-0.9%	-0.9%	-0.8%	-0.9%	
Revised Load Forecast (Update June 2015)	21,441	23,220	24,213	26,061	27,302		
Increase / (Decrease)	9	29	50	69	96	252	933
% Increase / (Decrease)	0.0%	0.1%	0.2%	0.3%	0.4%	0.2%	
Move MS9 Land to WIP in 2015 ($158.7k), Added back to Land 2018	21,428	23,208	24,201	26,054	27,302		
Increase / (Decrease)	(12)	(12)	(12)	(6)	0	(42)	890
% Increase / (Decrease)	-0.1%	-0.1%	-0.1%	0.0%	0.0%	0.0%	
Update Regulatory Expenses (higher rate application costs partially offset by lower forecast OEB assessment fees)	21,464	23,244	24,238	26,092	27,340		
Increase / (Decrease)	35	36	37	38	38	184	1,074
% Increase / (Decrease)	0.2%	0.2%	0.2%	0.1%	0.1%	0.2%	
Update Interest Rates for 2015 Loan ($15m loan drawn June 2015 at 2.71%)	21,293	22,926	23,823	25,747	26,969		
Increase / (Decrease)	(171)	(318)	(415)	(345)	(371)	(1,619)	(545)
% Increase / (Decrease)	-0.8%	-1.4%	-1.7%	-1.3%	-1.4%	-1.3%	

Revenue Changes

		2014	2015	2016	2017	2018	2019	2019 v 2014	*Source:*
2	Total Revenue (000)	$19,504							Ex.2, A, p.20, Table 2-6
3	Service Revenue Requirement (000)		$22,611	$24,399	$25,404	$27,132	$28,402		RRFW Run 4
4	**2019 v. 2014**							45.6%	
5									
6	Operating Revenue - From Dx Ratepayers	$18,114							Ex.2, A, p.20, Table 2-6
7	Base Revenue Requirement (000)		$21,293	$22,926	$23,823	$25,747	$26,969		RRWF Run 4
8	**2019 v. 2014**							48.9%	

forecast to be approximately $2.9 million. Thus the revenue deficiency at current rates accounts for almost 3/4^{ths} (7% of the 9.42%) of OPUCN's permitted return. If 2015 rates as applied for were to become effective half way through the year, the revenue deficiency would still be $1.5 million, putting OPUCN in an "off ramp" position with earnings at more than 350 basis points below Board approved levels.

In order to allow for timely restoration of earnings to a just and reasonable level, OPUCN has applied for 2015 rates to be set on a rebased cost of service, and for such rebased rates to be effective as of January 1, 2015. OPUCN proposes a new variance account (2015 Revenue Variance Account) to capture the difference between revenue at OPUCN's current interim rates and the revenue that would have been collected had OPUCN's final 2015 rates been in place as of January 1, 2015 and through the actual date of implementation of final 2015 rates, plus carrying costs at the Board approved rate. OPUCN has also requested an order for recovery of the balance in the 2015 Revenue Variance Account by way of a rate rider.

OPUCN has proposed that this rate rider will be effective from the date that final 2015 rates are implemented and through 2019. OPUCN proposes recovery of the revenue shortfall from January 1st to the date that final 2015 rates are implemented over the full term of the proposed Custom IR Plan in order to smooth the rate increase impact on customers in tandem with OPUCN's proposed methodology for rate smoothing as part of its Custom IR plan (as detailed in Exhibit 8).

Basis Upon Which OPUCN Applies for Custom IR

Under Section 2.2.1 of the RRFE, the Board made the following statement:

> *The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels.*

The main driver for OPUCN's application for approval of a Custom IR rate plan is OPUCN's large multi-year capital investment requirements. Driving these large multi-year capital investment requirements are:

1. Expected 3% annual average growth in customer connections and aggregate customer demand levels over the 2015 – 2019 plan period. These drivers require significant investment in both system expansion (i.e. new customer connection infrastructure) and system reinforcement (i.e. a new distribution station and upstream transmission capacity investment) in order for OPUCN to continue to provide reliable electricity distribution service; and

2. Significant capital expenditures for relocation of distribution assets to accommodate the infrastructure being developed to respond to the growth in population and business activity in Oshawa, particularly across the north end of the City due to the extension through Oshawa of the 407 ETR highway.

In response to customer and load growth forecasts informed by consultation with the City of Oshawa, the Region of Durham, and local developers, OPUCN's capital investment plan incorporates new assets to connect and serve the loads of 12,300 new customer connections (as compared with approximately 66,000 customer connections at the time of Oshawa's last cost of service rate approval for 2012 rates). In order to prudently plan for these needs, OPUCN needs to make investments in its infrastructure that will increase rate base by approximately $27 million between 2015 and 2019; a 31% increase over the proposed Custom IR plan term, and a 79% increase (approximately $50 million) when compared to the latest Board approved amount for 2012.

OPUCN's forecast of its annual capital expenditure requirements as compared to its annual depreciation expense are summarized in the Table 1:

Table 1: Annual Capital Expense vs. Depreciation

	Test Years				
	2015	2016	2017	2018	2019
Capital Expenditures	13,509,900	11,627,000	12,372,000	12,476,000	10,761,000
Depreciation Expense	4,491,588	4,847,338	5,000,972	5,203,071	5,370,697
Multiple	3	2	2	2	2

As has been the case since 2012, the pace of largely non-discretionary capital expenditures is forecast to continue to be at approximately two to three times the level of actual annual depreciation expense, which places financial pressure on OPUCN's ability to generate reasonable returns. Adjustments are necessary to recover the required growth in capital expense and the annual increase in depreciation expense, each of which out paces the inflation level increase in revenue that would be received under an IRM rate regime.

Table 2 identifies the increase in rate base resulting from OPUCN's forecast capital investment requirements and the related shortfall in deemed ROE resulting from a 4th Generation IRM rate model.

Table 2: Increase in Rate Base/Impact on ROE

	Test Years				
	2015	2016	2017	2018	2019
Rate Base	$ 104,990,575	$ 112,852,919	$ 119,890,558	$ 127,127,943	$ 133,201,327
Deemed Equity	40%	40%	40%	40%	40%
ROE	9.30%	9.30%	9.30%	9.30%	9.30%
Deemed Net Income	$ 3,905,649	$ 4,198,129	$ 4,459,929	$ 4,729,159	$ 4,955,089
Off Ramp Dead Band - Upper +3.0%	$ 5,165,536	$ 5,552,364	$ 5,898,615	$ 6,254,695	$ 6,553,505
Off Ramp Dead Band - Lower -3.0%	$ 2,645,762	$ 2,843,894	$ 3,021,242	$ 3,203,624	$ 3,356,673
Forecast Net Income Under IRM		$ 3,252,893	$ 3,435,339	$ 3,418,716	$ 3,884,099
Deemed ROE		7.21%	7.16%	6.72%	7.29%
Deemed ROE Deficiency		-2.09%	-2.14%	-2.58%	-2.01%

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Appendix 2-AA
Capital Projects Table ($'000s)

	A	B	C	D	E	F	G	H	I	J	K
13	**Projects**	**2010**	**2011**	**2012**	**2013**	**2014 Bridge Year**	**2015 Test Year**	**2016 Test Year**	**2017 Test Year**	**2018 Test Year**	**2019 Test Year**
14	**Reporting Basis**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
15						**Actual**					
16	**System Access**										
17	Subdivision Expansions	918	1,300	1,816	1,820	2,171	1,075	1,125	1,150	1,180	1,215
18	Service connections/requests	430	366	150	160	169	120	110	100	100	100
19	Service/Expansion Contributions	(2,034)	(931)	(1,271)	(1,459)	(2,143)	(650)	(675)	(690)	(705)	(730)
20	Hwy 407 Extension - Plant relocation					432	4,510	700			
21	Hwy 407 contribution					2	(3,580)	(400)			
22	Durham Region - Plant relocation	0	447	347	450	98	1,875	935	1,065	1,080	1,055
23	Durham Region Contribution	(139)	0	0	(150)	0	(506)	(235)	(265)	(280)	(255)
24	City of Oshawa - Plant relocation	0	20	0	258	47	680	595	470	460	470
25	City of Oshawa Contribution				(90)	(117)	(175)	(145)	(120)	(110)	(120)
26	Metering service connections	99	6,780	586	573	528	375	380	390	390	390
27	Remote Disconnect/Reconnect Metering						100	100	100	100	100
28	PrePaid Metering								150		
29	OEB's MIST Metering						150	150	125	125	125
30	Long Term load transfers (LTLT)				781	319					
31	MoE approved Micro Grid Project					0	110	45			
32											
33	**System Access Total**	(726)	7,982	1,628	2,343	1,506	4,084	2,685	2,475	2,340	2,350
34											
35	**System Renewal**										
36	O/H Rebuilds	2,288	2,215	1,390	2,407	2,885	2,410	2,455	2,055	2,510	2,117
37	U/G Rebuilds	684	1,416	1,013	1,789	1,392	1,133	1,007	1,087	921	904
38	Station Rebuilds	466	2,758	3,879	925	2,847	510	640	500	500	1,000
39	Station Rebuilds (MS14 Switchgear in WIP and 2014)					(1,060)	1,060				
40	Reactive/emergency Plant Replacement	1,199	650	880	850	1,034	830	830	830	830	830
41											
42	**System Renewal Total**	4,637	7,039	7,162	5,971	7,098	5,943	4,932	4,472	4,761	4,851
43											
44	**System Services**										
45	Wilson TS to Thornton TS Load Transfer - OH Plant Rebuild/Extension				1,903	1,169					
46	Thorton TS Capacity - HONI Contributions										
47	Wilson TS Capacity - HONI Contributions										
48	TS Capacity - HONI Contributions						1,350		5,400	6,750	
49	MS9 - 44kV/13.8kV Substation									7,000	
50	MS9 Proposed OH distribution feeders									4,000	3,500
51	Neutral Reactors						450	1,050			
52	Underground Distribution Automation Downtown UG Vaults, including Self Healing system - For Safety, Efficiency, Reliability & Power Quality Improvements					397	548	280	10	10	10
53	Overhead Automated Self healing Switching - Intellirupters switches (8 feeders 13 switches over 3 years)								350	350	255
54	Smart Fault Indicators						25	25	25	25	25
55	Volt-Var optimization & Reduction in Distribution Losses					0	0	0	0	225	225
56	Distribution System Supply Optimization						45	25	35	35	35
57											
58	**System Services Total**	0	0	0	1,903	1,566	2,418	1,380	5,820	18,395	4,050
59											
60	**General Plant**										
61	Fleet	245	585	1,438	17	153	420	415	440	190	170
62	Total Facilities Leasehold Improvements	36	354	174	17	76	225	50	50	50	50
63	Major Tools and Equipment	152	110	110	44	54	50	50	50	50	50
64	Outage Management System Implementation including interface with SCADA, GIS, CIS, AMI, IVR	0	0	0	0	70	850	0	0	0	0
65	Mobile Work force					0		50	50		
66	ODS Replacement due to enhanced operational requirements not available with existing ODS					0		400			
67	GIS Enhancements for operational needs including OMS					66		60	60	60	60
68	MAS Enhancements for operational needs					13		25	25	50	50
69	ODS/CIS Enhancements for operational needs									50	50
70	Office IT Capital Expenditure	64	165	167	270	54	130	130	80	280	80
71											
72	**General Plant Total**	497	1,214	1,889	348	486	1,675	1,180	755	730	510
73											
74	**Miscellaneous** (2018 $'s are MS9 land)	278	262	413	182	1				159	
75	**Total**	**4,686**	**16,497**	**11,092**	**10,747**	**10,657**	**14,120**	**10,177**	**13,522**	**26,385**	**11,761**
78											
79										2015 - 2019	75,965

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Appendix 2-AA
Capital Projects Table ($'000s)

	Projects	2010	2011	2012	2013	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
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53	Overhead Automated Self healing Switching - Intellirupters switches (8 feeders 13 switches over 3 years)								350	350	255
54	Smart Fault Indicators						25	25	25	25	25
55	Volt-Var optimization & Reduction in Distribution Losses					0	0	0	0	225	225
56	Distribution System Supply Optimization						45	25	35	35	35
57											
58	**System Services Total**	0	0	0	1,903	1,566	1,068	1,380	420	645	550
59											
60	**General Plant**										
61	Fleet	245	585	1,438	17	153	420	415	440	190	170
62	Total Facilities Leasehold Improvements	36	354	174	17	76	225	50	50	50	50
63	Major Tools and Equipment	152	110	110	44	54	50	50	50	50	50
64	Outage Management System Implementation including interface with SCADA, GIS, CIS, AMI, IVR	0	0	0	0	70	850	0	0	0	0
65	Mobile Work force					0		50	50		
66	ODS Replacement due to enhanced operational requirements not available with existing ODS					0		400			
67	GIS Enhancements for operational needs including OMS					66		60	60	60	60
68	MAS Enhancements for operational needs					13		25	25	50	50
69	ODS/CIS Enhancements for operational needs									50	50
70	Office IT Capital Expenditure	64	165	167	270	54	130	130	80	280	80
71											
72	**General Plant Total**	497	1,214	1,889	348	486	1,675	1,180	755	730	510
73											
74	**Miscellaneous** (2018 $'s are MS9 land)	278	262	413	182	1				159	
75	**Total**	4,686	16,497	11,092	10,747	10,657	12,770	10,177	8,122	8,635	8,261
78											
79										2015 - 2019	47,965

#	Name	Test Year Capital Additions	Test Year Total Depreciation	Test Year Net Depreciation (1)	Test Year Capital Additions/Net Depreciation
	Capital Additions and Depreciation Ratio				
1	Name	Test Year Capital Additions	Test Year Total Depreciation	Test Year Net Depreciation (1)	Test Year Capital Additions/Net Depreciation
2	**Oshawa Application**				
3	Oshawa 2015	$ 14,119,900	$ 4,455,736	$ 4,455,736	**3.17**
4	Oshawa 2016	$ 10,177,000	$ 4,788,726	$ 4,788,726	**2.13**
5	Oshawa 2017	$ 13,522,000	$ 4,934,685	$ 4,934,685	**2.74**
6	Oshawa 2018	$ 26,384,723	$ 5,316,310	$ 5,316,310	**4.96**
7	Oshawa 2019	$ 11,761,000	$ 5,664,577	$ 5,664,577	**2.08**
8					
9	**Cost of Service Applications (2016) As filed**				
10	Waterloo North Hydro	$ 18,492,734	$ 8,905,686	$ 8,151,672	**2.27**
11	Guelph Hydro	$ 12,021,577	$ 6,302,186	$ 5,751,746	**2.09**
12					
13	**Cost of Service Applications (2015) Per Decision/Approved Settlement**				
14	Algoma Power	$ 8,876,073	$ 3,596,723	$ 3,596,723	**2.47**
15	Festival Hydro	$ 17,783,282	$ 2,239,556	$ 2,239,556	**7.94**
16	Hydro One Brampton	$ 32,518,047	$ 15,227,319	$ 15,794,025	**2.06**
17	Niagara Peninsula Energy	$ 10,871,580	$ 5,034,074	$ 5,034,074	**2.16**
18	St Thomas Energy Inc.	$ 2,059,820	$ 1,154,077	$ 1,154,077	**1.78**
19					
20	**Cost of Service Applications (2014) Per Decision/Approved Settlement**				
21	Burlington Hydro	$ 7,730,045	$ 4,126,034	$ 4,126,034	**1.87**
22	Cambridge and North Dumfries	$ 15,049,383	$ 4,959,263	$ 5,531,840	**2.72**
23	Cooperative Hydro	$ 474,595	$ 132,429	$ 132,429	**3.58**
24	Fort Frances Power Corp	$ 684,668	$ 227,659	$ 196,134	**3.49**
25	Haldimand County Hydro	$ 6,364,230	$ 2,067,965	$ 2,067,965	**3.08**
26	Hydro Hawkesbury	$ 1,807,902	$ 206,119	$ 192,554	**9.39**
27	Kitchener-Wilmot	$ 17,154,331	$ 8,203,869	$ 8,203,869	**2.09**
28	Niagara-on-the-Lake Hydro	$ 1,285,000	$ 1,005,631	$ 911,109	**1.41**
29	Oakville Hydro Electricity	$ 15,325,637	$ 8,124,658	$ 8,124,658	**1.89**
30	Orangeville Hydro	$ 1,726,637	$ 876,538	$ 816,068	**2.12**
31	Veridian Connections	$ 25,483,259	$ 11,232,271	$ 10,646,989	**2.39**
32					
33	**Oshawa Application (Removed TS Capacity HONI Capital Contributions and DS Costs)**				
34	Oshawa 2015	$ 12,769,900.00	$ 4,438,861.00	$ 4,438,861.00	**2.88**
35	Oshawa 2016	$ 10,177,000.00	$ 4,754,976.00	$ 4,754,976.00	**2.14**
36	Oshawa 2017	$ 8,122,000.00	$ 4,833,435.00	$ 4,833,435.00	**1.68**
37	Oshawa 2018	$ 8,634,723.00	$ 4,925,685.00	$ 4,925,685.00	**1.75**
38	Oshawa 2019	$ 8,261,000.00	$ 5,008,327.00	$ 5,008,327.00	**1.65**

(1) Net Depreciation = Total Depreciation - Fully Allocated Depreciation (if applicable)

Normalized Capital Additions / Depreciation Ratio

		2011	2012	2013	2014	2015	2016	2017	2018	2019
Capital Additions ($)		16,497,773	11,092,013	10,747,504	10,657,278	14,119,900	10,177,000	13,522,000	26,384,723	11,761,000
Depreciation Expense ($)		5,270,203	3,272,427	3,851,500	3,941,800	4,455,736	4,788,726	4,934,685	5,316,310	5,664,577
Ratio		**3.13**	**3.39**	**2.79**	**2.70**	**3.17**	**2.13**	**2.74**	**4.96**	**2.08**
TS & MS	HONI Capital Contributions ($)					1,350,000	0	5,400,000	6,750,000	0
	MS9/MS9 Feeders ($)					0	0	0	11,000,000	3,500,000
	Total ($)					**1,350,000**	**0**	**5,400,000**	**17,750,000**	**3,500,000**
Depreciation	1/2 year rule ($)					16,875	0	67,500	221,875	43,750
(40 years)	**Total ($)**					**16,875**	**33,750**	**101,250**	**390,625**	**656,250**
Capital Additions excl. TS & MS ($)		16,497,773	11,092,013	10,747,504	10,657,278	12,769,900	10,177,000	8,122,000	8,634,723	8,261,000
Depreciation Expense excl. TS & MS ($)		5,270,203	3,272,427	3,851,500	3,941,800	4,438,861	4,754,976	4,833,435	4,925,685	5,008,327
Adjusted Ratio		**3.13**	**3.39**	**2.79**	**2.70**	**2.88**	**2.14**	**1.68**	**1.75**	**1.65**

OSHAWA PUC NETWORKS INC.

**Response to School Energy Coalition (SEC)
Interrogatory 1.0-SEC-8**

[Ex.1-D]

Did the Applicant do any customer engagement specific to this Custom IR application? If so, please provide details. Did any of those activities result in a change in the application?

Response:

Customer Focus with its sub-categories of Service Quality and Customer satisfaction is a major component of the scorecard. As such, OPUCN participated in the 16th Annual Customer Satisfaction survey conducted by UtilityPULSE. OPUCN has participated from time to time in the UP Annual survey since 2005; the last time in 2011.

The UP survey is a comprehensive survey covering multiple aspects of what it means to have Customer Focus. While the scorecard values a hard metric on items such as "Billing Accuracy", the UP survey does ask responds about "Accurate billing". It is a way of showing that a "hard metric" may not translate into the same "customer perception" rating.

For this rate application, OPUCN worked with UP to assist in designing some of the supplemental questions that were asked in the 16th Annual Survey. In addition OPUCN worked with UP, and commissioned them, to conduct a GS>50 customer survey.

OPUCN believed the Survey reinforced its Distribution System Plan ("Plan") to the extent the Plan addressed issues of interest to customers. OPUCN's Plan includes discretionary System Renewal activities the forecast amount of which is between $4 million and $5 million annually. The majority of the remaining planned expenditures are in response to City and Regional expansion plans, and Hydro One's regional activities which are mostly non-discretionary and therefore difficult to measure against customer's survey responses.

OSHAWA PUC NETWORKS INC.

Response to Greater Oshawa Chamber of Commerce (GOCC)
Interrogatory 1.0-GOCC-2

Exhibit 1, Tab 2, Schedule D

a) Did Oshawa PUC meet with any GS>50 to 999 kW customers in 2014 as part of its customer engagement process? If so, describe the concerns expressed and how the Application addresses such concerns.

b) Did Oshawa PUC consult with any GS>50 to 999 kW customers regarding the rate increases proposed in the Application?

c) Was there any difference between GS>50 to 999 kW customers and the responses from other rate classes? Please explain the basis for the answer.

Response:

a) OPUCN did commission UtilityPULSE to conduct a telephone survey from November 28 to December 9, 2013 of customers GS>50. The top two items coming from the survey were: Prices and Knowledgeable staff.

b) No. Please refer to part c) below.

c) Every GS>50 customer interviewed is asked for “one or two suggestions to help OPUCN improve their service”. The number one suggestion received by all classes of customers – residential, small commercial and GS>50 is to reduce rates. GS>50 customers will cite power quality and extended service hours with more frequency than residential customers. Residential customers will suggestion “better online presence” more frequently than GS>50 customers.

Table 1: Rate-Setting Overview - Elements of Three Methods

		4^{th} Generation IR	Custom IR	Annual IR Index
Setting of Rates				
"Going in" Rates		Determined in single forward test-year cost of service review	Determined in multi-year application review	No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism
Form		Price Cap Index	Custom Index	Price Cap Index
Coverage		Comprehensive (i.e., Capital and OM&A)		
Annual Adjustment Mechanism	**Inflation**	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts	Composite Index
	Productivity	Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor		Based on 4^{th} Generation IR X-factors
Role of Benchmarking		To assess reasonableness of distributor cost forecasts and to assign stretch factor		n/a
Sharing of Benefits		Productivity factor		
		Stretch factor	Case-by-case	Highest 4^{th} Generation IR stretch factor
Term		5 years (rebasing plus 4 years).	Minimum term of 5 years.	No fixed term.
Incremental Capital Module		On application	N/A	N/A
Treatment of Unforeseen Events		The Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3^{rd} Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options.		
Deferral and Variance		Status quo	Status quo, plus as needed to track capital spending against plan	Disposition limited to Group 1 Separate application for Group 2
Performance Reporting and Monitoring		A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.		

OSHAWA PUC NETWORKS INC.

Response to Board Staff Interrogatory 10.0-Staff-41

Ref: Exhibit 10, Tab D

Please confirm or correct the following list of adjustments proposed and the method of adjustment. Please note that in some cases the list in the application has been further disaggregated:

A. Adjustments to be made to base rates annually to account for changes in:

- Forecast revenue indicated by updated customer growth, demand and consumption forecasts
- Actual and forecast net new customer connection costs
- Cost of capital parameters (return on equity, short term debt rates and long term debt rate)
- Working capital allowance resulting from changes in the cost of power

Rates could also be adjusted as a result of a successful Z-factor application.

B. Rate riders added to rates once costs for the following are finalized:

- Revenue requirement impacts of contributions to Hydro One Networks Inc. Transmission
- Revenue requirement impacts of unbudgeted distribution projects required as a result of regional planning

In the meantime, the revenue requirement impacts of these costs will be tracked by OPUCN.

C. Deferral or variance accounts to be created to record changes in:

- Revenue requirement impacts of cost variances from forecast (embedded in rates) for distribution plant relocations in response to third party requests
- Revenue requirement impacts of cost variances from forecast (embedded in rates) for new customer connections

The two deferral accounts would be disposed of at the end of the plan term.

Response:

A. Confirmed.

In respect of the proposed adjustment for actual and forecast new customer connection costs, this adjustment would be made to rates for the upcoming test year. That is, there is no intent to recover, during the plan term, variances from new customer connection costs embedded in rates for the previous year. These previous year variances, for each year of the plan term, would be captured in the Net New Connection Cost Variance Account (NNCCVA) for disposition following the end of the 5 year plan term.

OPUCN's application also clarifies that OPUCN assumes applicability of the RRFE's "off ramp" mechanism, should earnings in any year of the plan term trigger that mechanism. [See Exhibit 1, Tab B, page 3, item 2.g.]

B. Confirmed.

OPUCN has proposed variance accounts for each of these uncontrollable cost categories. [See Exhibit 1, Tab c, page 38]

C. Confirmed.

included in OPUCN's Distribution System Plan, or if distribution system changes are required as a result of the regional planning solutions ultimately adopted. Finally, changes to upstream power costs and cost of capital over the 5 year Custom IR plan period should neither benefit nor burden OPUCN's shareholder or its ratepayers.

OPUCN is thus proposing an annual rate adjustment process, in which it will:

1. Seek adjustment of its Custom IR rates for the upcoming test year to reflect: i) updated customer connection, demand and volume forecasts; ii) associated net new connection cost actuals and forecasts; iii) updated cost of capital parameters; and iv) updated cost of power related working capital requirements.

2. Provide updated evidence regarding capital investments related to two capital cost line items driven by third party requirements: i) contributions to Hydro One Transmission and distribution system investments required to respond to regional planning requirements; and ii) investments in distribution plant relocations in response to third party requests. The revenue requirement impact of changes in the amount or timing of these capital cost items would be tracked, and brought forward for future disposition (as described below).

The proposed annual rate adjustment process is intended to protect both OPUCN and its customers from uncontrollable, unpredictable and potentially material cost or revenue variances, and to thus avoid triggering an "off ramp" reopening of OPUCN's rates to full review during the 5 year plan period as a result of any of the foregoing variables.

OPUCN will rely on the "z-factor" adjustment facility, as contemplated by the RRFE, to address material cost increases or decreases which are caused by an unexpected, non-routine event other than those addressed in this evidence and not reasonably within the control of utility management or preventable by the exercise of due diligence. Subject to materiality, examples of such events include new government directives or legislation, assignments on the basis of total cost benchmarking evaluations. As is the case currently, each group will have its own specific stretch factor. The assignments will continue to be revised annually to reflect changes in efficiencies in the sector. The Board will further consider whether the current three stretch factor values of 0.2, 0.4, and 0.6 continue to be appropriate or whether there should be greater differentiation between the three values. The Board will determine the appropriate stretch factor values for the three efficiency groups in conjunction with its determination of the productivity factor for 4th Generation IR.

Incremental Capital Module (ICM)

The ICM is intended to address incremental capital investment needs that may arise during the IR term. Under 4th Generation IR, the Board's policies in respect of ICM in effect under 3rd Generation IR will continue to apply.

In 2011, the Board revised its *Filing Requirements for Electricity Transmission and Distribution Applications* to clarify the ICM specifications on how to calculate the incremental capital amount that may be recoverable when a distributor applies for an ICM. In the Filing Requirements issued in June 2012, the ICM was further revised to remove words such as "unusual" and "unanticipated" as prerequisites to an application for incremental capital, although the requirement that the proposed expenditures be non-discretionary remains.

Custom IR

In the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes. This Report provides the general policy direction for this rate-setting method, but the Board expects that the specifics of how the costs approved by the Board will be recovered through rates over the term will be determined in individual rate applications. This rate-setting method is intended to be customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor.

The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

The Board has determined that a minimum term of five years is appropriate. As is the case for 4^{th} Generation IR, this term will better align rate-setting and distributor planning, strengthen efficiency incentives, and support innovation. It will help to manage the pace of rate increases for customers through adjustments calculated to smooth the impact of forecasted expenditures.

The adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant. The Board therefore expects that a distributor that applies under this method will be committed to that method for the duration of the approved term and will not seek early termination. As noted above, however, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Annual Adjustment Mechanism

The allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including:

- the distributor's forecasts (revenues and costs, including inflation and productivity);

- the Board's inflation and productivity analyses; and
- benchmarking to assess the reasonableness of distributor forecasts.

Expected inflation and productivity gains will be built into the rate adjustment over the term.

<u>*Capital Spending*</u>

There will not be an ICM in the Custom IR method. Under this method, distributors will be expected to operate under their Board-determined multi-year rates.

Under Custom IR, planned capital spending is expected to be an important element of the rates distributors will be seeking, and hence will be subjected to thorough reviews by parties to the proceeding. Once rates have been approved, the Board will monitor capital spending against the approved plan by requiring distributors to report annually on actual amounts spent. If actual spending is significantly different from the level reflected in a distributor's plan, the Board will investigate the matter and could, if necessary, terminate the distributor's rate-setting method. A distributor on the Custom IR method will have its rate base adjusted prospectively to reflect actual spend at the end of the term, when it commences a new rate-setting cycle. This is consistent with the Board's existing policies in relation to incremental capital under 3rd Generation IR.

Annual IR Index

The Annual IR Index will be appropriate for distributors with primarily sustainment investment needs. The Annual IR Index is intended to provide a rate-setting approach that is simpler and more streamlined than the other two. Among other things, there is no forecast cost of service review under this method. Rates are adjusted by a simple price cap index formula. Initial rates are set by applying this adjustment to existing rates. The annual rate adjustments are designed to reflect "steady-state mode" operations – that is, rate adjustments will be comparatively minor.

- Overall lack of consistency and comparability with incentive rate-setting particularly with regard to the specification and use of a custom index approach to rate-setting that includes explicit, externally imposed improvement incentives.

In its May 30, 2014 evidence update, Hydro One provided eight outcomes by which to measure its five year plan. The company agreed to report annually on these outcomes, including the results achieved and actual amounts spent on the programs. Many parties submitted that additional reporting, for example, on actual capital spending and the results of the smart grid program, was necessary.

Parties submitted that the inadequacies of the application should be addressed by the OEB through either denial of the five year application (i.e. set rates for only one or two years) or substantive adjustments to the five year plan such as using 2015 as a base year and setting rates for 2016 – 2019 through an index.

Findings

The OEB has concluded, for the reasons set out below, that Hydro One's application is insufficient as a Custom IR application under RRFE and has determined that it will deny approval of the proposed five-year plan. Instead the OEB will approve rates for a three-year period based on the evidence provided. This change from what was applied for by Hydro One is due to a number of shortcomings with Hydro One's proposed approach. The OEB is directing Hydro One to address those shortcomings, set out below, over the next three years in preparation for the next rates application.

3.1 Inconsistency with outcome-based regulation

Hydro One chose to interpret the OEB's Custom IR option, referred to in the RRFE Report as "custom index", to include "custom cost of service". The OEB does not accept this interpretation. All three rate-setting methods are described in the Report as incentive rate-setting, not cost of service.

Cost of service rate-setting has an important role in performance-based regulation regimes to periodically examine in detail the costs and activities underpinning rates. However, the OEB continues to believe that multi-year incentive rate-setting, with its emphasis on results, is the most effective way to incent behaviour similar to that seen in commercially-oriented, consumer market-driven companies. Incentive rate-setting differs from cost of service rate-setting in that it relies less on a utility's internal cost, output, and service quality to establish rates, and more on benchmarks of cost, output, and service quality that are external to the utility revealing superior performance and encouraging best practice. The decoupling of rates from the utility's own costs simulates a competitive market environment and is more compatible with an outcomes-based approach to regulation.

The OEB finds that Hydro One's proposed plan is deficient in this regard, as it includes limited prospects for continuous improvement, lacks any externally imposed improvement incentives, includes limited cost and productivity benchmarking support, and fails to demonstrate value to customers commensurate with the forecasted spending.

3.2 Lack of externally imposed incentives

The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses.

The OEB does not believe that Hydro One's plan contains adequate efficiency incentives to drive year-over-year continuous improvement in the company. Furthermore, the plan lacks measurement of increased efficiency year-over-year in a form illustrating trends in a transparent fashion.

It is not sufficient to embed savings in cost forecasts. As already noted, the OEB's Custom IR is an incentive rate-setting approach designed to drive efficiencies. Benefits from explicit, objectively determined productivity and efficiency adjustments such as stretch factors include mimicking competitive market conditions, sharing anticipated savings with ratepayers "up front", and facilitating a more outcome-based approach to regulation.

As already noted, traditional cost of service review will continue to entail detailed input cost assessments. However, Custom IR proceedings are intended to be framed more like performance inquiries resulting in multi-year outcome commitments and measures that facilitate year-over-year performance assessment. The productivity and efficiency elements allow the OEB to move away from detailed input cost assessment and focus more on utility performance. These factors provide utilities with strong incentives to continually seek efficiencies and share expected savings with ratepayers "up front" avoiding "after the fact" regulatory scrutiny.

3.3 Weak benchmarking evidence

The RRFE policy articulates the importance the OEB places on benchmarking. Benchmarking evidence, whether it compares a utility's performance to itself year-over-year, or to other utilities, is a critical input to the OEB's assessment of utility performance.

Benchmarking, when used in combination with specific cost drivers and other sources of utility performance information, allows for an overall assessment of a utility's cost and outcome performance.

A majority of parties were critical of the lack of benchmarking in Hydro One's plan. Hydro One described eight benchmarking or similar studies it had undertaken. The OEB agrees with the submissions of OEB staff and the majority of the intervenors that the studies provided in this proceeding by Hydro One, lack:

1) a top-down perspective of what the appropriate level of costs should be; and

2) measures of Hydro One's cost performance against other comparable utilities.

Table 11: OPUCN vs. Distributor Average Productivity Trends

	OPUCN Average	**Ontario Distributor Averages**	
	2015 – 2019	**2003 – 2011**	**2003 – 2012**
OM&A	**2.17%**	**0.51%**	**- 0.40%**
Capital	**0.12%**	**0.01%**	**- 0.26%**
Total Productivity Factor	**0.87%**	**0.19%**	**- 0.33%**

The PEG report provides independent evidence that OPUCN's proposed capital investments are efficient, fair and reasonable, and comparable to investment levels of other LDCs in the Province. In addition, the PEG report provides independent validation that the 2015 - 2019 OM&A cost levels embedded in this Custom IR application will remain among the most efficient in the province.

Total Cost Efficiency Carryover Mechanism (TCECM)

To ensure continued incentive for efficiency improvements, including in particular later in the Custom IR plan period, OPUCN is proposing a *Total Cost Efficiency Carryover Mechanism* (TCECM). As noted above, the Board has indicated its interest in efficiency carryover mechanisms in the RRFE.[6] Similar encouragement was provided in the Board's decision in Enbridge Gas Distribution Inc.'s (EGD) Custom IR rate application (EB-2012-0459). While rejecting EGD's particular efficiency carryover mechanism (ECM) incentive proposal, in its *Reasons for Decision* on EGD's application the Board found merit in such mechanisms in encouraging sustainable efficiency improvements, particularly near the end of the incentive regulation term.[7]

[6] RRFE, page 61.
[7] EB-2012-0459, *Decision with Reasons*, pg. 17

OPUCN has also taken guidance from recent approval by the Alberta Utilities Commission (AUC) of an ECM for ATCO Gas & Electric. On September 12, 2012 the AUC released its decision in its *Rate Regulation Initiative, Distribution Performance Based Regulation* (AUC PBR Decision)[8]. The performance based regulation model approved in this decision has since been used in Alberta to rate regulate electric and natural gas distribution companies. In its decision the AUC described the purpose of an ECM in the context of a performance based regulation (PBR) plan as follows:

> *A company's incentive to find efficiencies weakens as the end of the PBR term approaches, because there is less time remaining for the company to benefit from any efficiency gains. The purpose of an efficiency carry-over mechanism (ECM) is to address this problem by permitting the company to continue to benefit from any efficiency gains after the end of the PBR.*[9]

In that proceeding, ATCO proposed, and the AUC approved, an ROE ECM which was summarized in the AUB's findings as follows:

> *... a post PBR add on to the approved ROE equal to one half of the difference between the simple average ROE achieved over the term of the Plan and the simple average approved ROE over the term of the Plan (providing the difference is positive), multiplied by 50%, to a maximum of 0.5%. The "ROE bonus" would apply for 2 years after the end of the PBR Plan."*[10]

In accepting this proposal, the AUC specifically acknowledged that "the incentive properties of an ECM encourage companies to continue to make cost savings investments near the end of the PBR term" .[11]

Considering the RRFE, the Board's expressed views on the recently considered EGD ECM, and the AUC approval of Atco's ECM, OPUCN has developed and is proposing for its Custom IR Plan term a Total Cost Efficiency Carryover Mechanism (TCECM).

[8] Alberta Utilities Commission, *Rate Regulation Initiative, Distribution Performance Based Regulation*, September 12, 2012, pg. 165 at para 759.
[9] AUC PBR Decision, pg. 165 at para 759.
[10] AUC PBR Decision, pg. 167 at para 766.
[11] AUC PBR Decision, pg. 169 at para 775.

OPUCN's proposed mechanism will incent general efficiency initiatives throughout the Custom IR Plan period, including late in the plan period, by allowing the utility to capture resulting cost savings for a short period of time following the end of the rate plan period. The ECM would be applied as follows:

1. At the end of the 5 year Custom IR Plan period, actual earnings in each year of the rate plan period will be determined, inclusive of allowed flow through costs (but exclusive of costs and revenues associated with the two controllable capital programs subject to the CCEIEM - see below).

2. An average of the difference in each year of the plan between the actual ROE and the Board approved ROE will be calculated.

3. If that average difference in ROE is positive, OPUCN will be entitled to recover in rates in each of the next 2 years following the end of the Custom IR Plan an ECM "rate rider" equal to 50% of that difference, up to a maximum of 50 basis points.

This proposal is simple to calculate and apply, and the incentive thereby provided for incremental efficiency is supported by statistical and independent third party validation of the continuing efficiency already embedded in OPUCN's Custom IR Plan period cost forecasts, as detailed above and fully evidenced in the balance of this application (and in particular in OPUCN's comprehensive Distribution System Plan filed as Exhibit 2, Tab B).

OPUCN intends its TCECM mechanism to apply within the framework of the Board's "off ramp" policy for electricity distributors, in deference to the outside boundaries of efficiency reward tolerance already established by the Board.

Controllable Capital Investment Efficiency Incentive Mechanism (CCIEIM)

OPUCN is also proposing an innovative efficiency mechanism, reflecting OPUCN's view that avoided rate base has permanent and significant value to ratepayers. This proposal earnings, but then it would share any over-earnings beyond that level on a 90:10 basis in favour of ratepayers.

The Board finds that the dead band should be eliminated and that all over-earnings will be shared 50:50 between ratepayers and shareholders. The Board agrees that the central issue is that the sharing with ratepayers needs to be balanced with an incentive to find and retain efficiencies. The Board also agrees with CCC that a key consideration is the overall IR framework and the other parameters. The Board is approving a Custom IR for Enbridge, but must address the shortcomings of the plan. The lack of total cost benchmarking and the lack of independent budget assessments result in a greater risk that costs have been over-forecast. Therefore, the Board concludes that additional ratepayer protection is warranted. A 100 basis point dead band provides insufficient protection for ratepayers, and therefore the Board finds that the dead band should be eliminated for this Custom IR plan. However, the Board is also concerned that there be suitable performance incentives for Enbridge and finds that a sharing ratio of 90:10 in favour of ratepayers largely eliminates the performance incentive for Enbridge. The Board finds that a sharing ratio of 50:50 provides a suitable incentive level for the company while still ensuring significant benefits for ratepayers. The Board also addresses risk sharing and efficiency levels further in the capital expenditure and O&M expenditure sections of this decision.

Sustainable Efficiency Incentive Mechanism ("SEIM")

Enbridge proposed a Sustainable Efficiency Incentive Mechanism ("SEIM") which it claims will promote long-term sustainable efficiencies within the custom IR framework, including near the end of the IR term. Enbridge explained that IR plans tend to incent short-term cost cutting and discourage the adoption of new productivity measures near the end of the plan term. The SEIM is an attempt to address these issues by providing a financial reward to the company for undertaking sustainable efficiency improvements.

The proposed SEIM has three steps, which would be undertaken within Enbridge's rebasing application for 2019:

- Calculating the potential reward: The potential reward would equal one half of the difference between the average ROE achieved during the IR term and the average ROE allowed during the IR term. The potential reward would form a premium on the ROE that applies to rates for the rebasing year and the following year (2019 and 2020). The potential reward for each year would be capped at 50 basis points above the allowed ROE. The ROE premium would be expressed as a dollar amount, based on the forecast 2019 rate base.

- Determining whether the potential reward is justified: To qualify for the SEIM reward, Enbridge must show that the net present value of the long-term benefits generated by productivity initiatives undertaken during the IR term is greater than the reward. The company must also show that its Service Quality Reporting performance has been maintained at or above the 2013 level for at least three of the five years of the IR term.

- Implementing the reward: If Enbridge is successful in establishing its entitlement to a SEIM reward, then the reward would be administered within the 2019 rebasing case and the 2020 rates case. The reward amount would be added to the revenue requirement in the rebasing year for collection in that year. The same amount would be applied to the 2020 rates.

Board staff and intervenors opposed the proposal. While a number of parties supported the objectives of the SEIM and commended Enbridge on its efforts, they concluded that the flaws were too significant to go forward as proposed. APPrO, Energy Probe and SEC each proposed alternatives.

Board Findings

The Board will not accept the current SEIM proposal. The Board finds that there are significant flaws in the proposal which make it likely that the objectives will not be achieved. The Board does see merit in a mechanism which serves to incent long-term sustainable productivity improvements. The Board is also encouraged by Enbridge's ongoing commitment to improving the proposal and addressing the concerns raised. The Board concludes that Enbridge should undertake a consultation process over the next year, in order to address the concerns identified below (and in parties' submissions) and to develop a revised proposal to bring forward as part of its 2015 or 2016 rates application.

CME argued that there is no need for a SEIM because it is redundant in an IR plan which already includes incentives. CME submitted that a more appropriate way of ensuring the achievement of sustainable efficiencies during an IR plan is to penalize a distributor for creating efficiencies which are not sustainable. Enbridge responded that it is a reasonable inference from the importance attached to the discussion of "incentives for sustainable efficiency improvements" within the NGF Report that the Board recognized the need for a specific incentive for sustainable efficiencies. The Board finds merit in two approaches to encouraging greater efficiency: robust forecasts which incorporate expected efficiency improvements during the IR term and the potential for carry-over incentives for sustainable efficiency improvements near the end of the IR term. Dr. Kaufmann and Ms. Frayer[6] each acknowledged that one of the shortcomings of IR is a focus on short-term cost-cutting rather than sustainable efficiency improvements, particularly at the end of the plan term. The Board finds that it is appropriate in a Custom IR plan to attempt to address this shortcoming.

A number of parties argued that the SEIM issue should be considered and determined in a generic proceeding because it has application to all distributors. The Board is examining this issue through its electricity rate-setting policy consultations. However, the Board finds that it is appropriate to address Enbridge's proposal within the context of the current application and to allow Enbridge to undertake a focussed consultation to develop a revised proposal within the overall framework of its Custom IR.

The Board finds that the following aspects of the current SEIM proposal are of particular concern:

- The reward will be cash to the utility while the benefits to ratepayers are in the form of forecast future savings, which are not verified. This is an imbalance which should be addressed.
- The proposal does not appear to distinguish between early term productivity measures and late-term productivity measures, and therefore may not adequately address the concern about diminishing incentives to invest in productivity toward the end of an IR term.
- The SEIM has the potential to reward inflated forecasts for capital or operating expenditures.
- It is not clear whether grossing up the reward for taxes is a balanced approach given the method by which the ratepayer benefits are determined.

Both APPrO and Energy Probe made a number of specific proposals. The Board encourages parties to consider these, as well as other alternatives, as part of the consultation process.

[6] Enbridge retained London Economics International LLC ("LEI") to provide analysis of incentive regulation, and Ms. Frayer of LEI testified at the oral hearing.

boundaries within which distributors should operate; the more rigorous implementation of benchmarking in rate proceedings; and the adoption of a "balanced scorecard" approach to benchmarking to reflect customer and distributor diversity.

The Board's Conclusions

The Board concludes that benchmarking models will continue to be used to inform rate setting. The Board will continue to build on its approach to benchmarking with further empirical work on the electricity distribution sector in relation to the distributor customer service and cost performance outcomes, including: total cost benchmarking; an Ontario TFP study; and input price trend research. The Board will engage stakeholders in this effort.

The empirical work on the electricity distribution sector will inform the rate-adjustment mechanisms under 4^{th} Generation IR and the Annual IR Index, and will inform the Board's review and approval of applications under the Custom IR method. Consequently, regardless of the rate-setting plan under which a distributor's rates are set, the distributor will continue to be included in the Board's benchmarking analyses.

Benchmarking will also continue to be used to assess distributor performance. The results of further statistical methods for evaluating distributor performance will also assist the Board in assessing distributor infrastructure investment plans and in determining appropriate cost levels in rates associated with those plans. The publication of benchmark results will also continue to inform the public about distributor performance and facilitate comparisons among distributors.

4.3 Regulatory Mechanisms

The Board is committed to ensuring optimal performance and value for customers, and will continue to enhance its regulatory mechanisms where necessary to achieve this goal. In initiating the performance-based approach, the Board will maintain its existing regulatory mechanisms, subject to certain refinements. Specifically, the X-factor will be refined as discussed in Chapter 2 and the "publication of distributor results" mechanisms referred to above (among possible others) will be integrated into the electricity distributor scorecard.

The Board's incentive regulation approach to rate-setting creates incentives for distributors to innovate in order to operate within the price cap while continuing to meet the needs and expectations of their customers. The Board will further consider incentives directed at innovation to address system and customer requirements. While this work should consider the Board's current policies as set out in the *Report of the Board on the Regulatory Treatment of Infrastructure Investment for Ontario's Electricity Transmitters and Distributors*, the Board expects that new approaches may be required.

In addition, appropriate consequences should flow from unsatisfactory performance against the Board's standards, in order to maintain the integrity of the Board's outcome-based approach and its approach to rate-setting.

Additional regulatory mechanisms may be necessary to achieve the objectives of the renewed regulatory framework. The Board will engage stakeholders in further consultation on the following in due course:

- The establishment of an "efficiency carry-over" mechanism;
- Development of incentives to;
    - reward superior performance;
    - encourage innovation;
    - encourage asset optimization; and
- Potential consequences for inferior performance.

The development of these regulatory mechanisms will be aligned with the standards and measures referred to above.

Appendix 2-JA
Summary of Recoverable OM&A Expenses

	A	B	C	D	E	F	G	H	I	J	K
13		2011 Actuals	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
14	*Reporting Basis*										
15	Operations	749,243	982,254	1,167,906	919,397	1,374,416	1,288,019	1,484,147	1,593,497	1,579,144	1,410,513
16	Maintenance	1,048,680	1,409,450	1,094,190	1,313,715	1,096,733	1,346,279	1,375,515	1,405,469	1,436,077	1,467,354
17	**SubTotal**	**1,797,923**	**2,391,704**	**2,262,096**	**2,233,112**	**2,471,149**	**2,634,298**	**2,859,662**	**2,998,966**	**3,015,221**	**2,877,866**
18	%Change (year over year)				-1.3%	10.7%	6.6%	8.6%	4.9%	0.5%	-4.6%
19	%Change (Test Year vs Last Rebasing Year - Actual)						16.5%	26.4%	32.6%	33.3%	27.2%
20	Billing and Collecting	2,358,686	2,433,401	2,398,127	2,462,960	2,464,873	2,653,062	2,715,401	2,780,102	2,846,477	2,914,572
21	Community Relations	973,010	945,160	1,004,587	1,092,298	1,131,482	1,161,723	1,309,846	1,337,732	1,366,218	1,395,314
22	Administrative and General	5,022,130	5,560,605	5,402,280	5,245,121	5,002,232	5,604,762	5,647,747	5,707,425	5,804,965	5,914,459
23	**SubTotal**	**8,353,826**	**8,939,166**	**8,804,993**	**8,800,379**	**8,598,586**	**9,419,547**	**9,672,993**	**9,825,260**	**10,017,660**	**10,224,346**
24	%Change (year over year)			-1.5%	-0.1%	-2.3%	9.5%	2.7%	1.6%	2.0%	2.1%
25	%Change (Test Year vs Last Rebasing Year - Actual)						7.0%	9.9%	11.6%	13.8%	16.1%
26	**Total**	**10,151,749**	**11,330,870**	**11,067,089**	**11,033,491**	**11,069,735**	**12,053,844**	**12,532,655**	**12,824,225**	**13,032,881**	**13,102,212**
27	%Change (year over year)			-2.3%	-0.3%	0.3%	8.9%	4.0%	2.3%	1.6%	0.5%
28											
29											
30		**2011 Actuals**	**Last Rebasing Year (2012 Board-Approved)**	**Last Rebasing Year (2012 Actuals)**	**2013 Actuals**	**2014 Bridge Year**	**2015 Test Year**	**2016 Test Year**	**2017 Test Year**	**2018 Test Year**	**2019 Test Year**
31	Operations	749,243	982,254	1,167,906	919,397	1,374,416	1,288,019	1,484,147	1,593,497	1,579,144	1,410,513
32	Maintenance	1,048,680	1,409,450	1,094,190	1,313,715	1,096,733	1,346,279	1,375,515	1,405,469	1,436,077	1,467,354
33	Billing and Collecting	2,358,686	2,433,401	2,398,127	2,462,960	2,464,873	2,653,062	2,715,401	2,780,102	2,846,477	2,914,572
34	Community Relations	973,010	945,160	1,004,587	1,092,298	1,131,482	1,161,723	1,309,846	1,337,732	1,366,218	1,395,314
35	Administrative and General	5,022,130	5,560,605	5,402,280	5,245,121	5,002,232	5,604,762	5,647,747	5,707,425	5,804,965	5,914,459
36	**Total**	**10,151,749**	**11,330,870**	**11,067,089**	**11,033,491**	**11,069,735**	**12,053,844**	**12,532,655**	**12,824,225**	**13,032,881**	**13,102,212**
37	%Change (year over year)			-2.3%	-0.3%	0.3%	8.9%	4.0%	2.3%	1.6%	0.5%

OSHAWA PUC NETWORKS INC.

Undertaking TC2.4

To update the table in 1-SEC-2 to include forecast inflation and load growth.

Response:

Year	EB-2014-01 Updated for TC	Price Escalator	Revenue From Price Escalator
2015	21,647	1.45%	21,647
2016	23,408	1.63%	22,113
2017	24,384	1.44%	22,854
2018	26,217	2.05%	23,779
2019	27,431	2.16%	24,680

Year	Inflation Rate per PEG	OEB IRM Price Escalator	OPUCN Stretch Factor	Price Escalator
2014	1.93%	1.70%	0.15%	1.55%
2015	1.74%	1.60%	0.15%	1.45%
2016	2.20%	1.93%	0.30%	1.63%
2017	2.31%	1.74%	0.30%	1.44%
2018	2.33%	2.20%	0.15%	2.05%
2019	2.27%	2.31%	0.15%	2.16%

In the first table, OPUCN assumes it rebases rates for 2015. The first column presents the base revenue requirement proposed in OPUCN's Custom IR rate application. For comparison, OPUCN was asked to provide estimated base revenue requirements for each of the Test Years using a price escalator estimated based upon the OEB's current practice for 4th Generation IRM rate applications.

In determining a price escalator, PEG provided an inflation rate based upon the OEB's methodology from data inputs used in their Benchmarking Report prepared for OPUCN (refer to Column – Inflation Rate per PEG). In the next column OPUCN is applying inflation factors from PEG's results assuming a two year lag consistent with the OEB's current practice. From the estimated OEB IRM Price escalator, OPUCN is deducting the expected stretch factor based upon the OEB's current stretch factor rates and PEG's estimate of OPUCN's performance from their Benchmarking Report to compute an estimated Price Escalator for the first table.