BENCHMARKING THE FORECASTED COST OF OSHAWA PUC NETWORKS

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1. INTRODUCTION AND SUMMARY

1.1 Introduction

Oshawa PUC Networks Inc. ("OPUCN" or "the Company") is proposing a custom Incentive Regulation ("IR") plan for its power distributor services. The plan would be in effect for the five-year 2015-19 period. Proposed rates are based on the Company's forecast of its cost over these years. Under current policies of the Ontario Energy Board ("OEB" or "the Board"), the rate trend chosen for a custom IR plan must be informed by cost benchmarking evidence.

Pacific Economics Group Research LLC ("PEG") is a leading utility cost research consultancy. We have filed rigorous benchmarking and productivity studies in regulatory proceedings for two decades. In Ontario, we have filed benchmarking evidence for Enbridge Gas Distribution and Hydro One Networks ("HON") and twice developed power distributor benchmarking and productivity studies for the OEB. The Board has used our studies to set X factors in IR price escalation formulas. For the latest IR cycle we developed econometric total cost benchmarking models for the Board, along with a study of trends in the productivity of Ontario power distributors. OPUCN has retained PEG to appraise its forecasted total cost for the IR plan period using the Board's methodologies.

This document reports on our research. Following a brief summary of the work below, Section 2 provides relevant background information. Section 3 discusses our benchmarking work for OPUCN.

1.2 Summary of Research

We used the OEB's econometric total cost model for OPUCN to benchmark the Company's forecasts of its cost from 2015 to 2019. In this work, we utilized price forecasts from the Conference Board of Canada. The study revealed that OPUCN's cost performance will gradually rise from a level commensurate with a Group 3 stretch factor in 2015 to levels commensurate with a Group 2 stretch factor in later years of the plan. Forecasted cost will be 11.7% below the econometric cost benchmark on average.

In addition to the benchmarking exercise we calculated the productivity growth implicit in the Company's cost forecast. We found that the productivity of operation, maintenance, and administration ("OM&A") inputs would average 2.17% annual growth. The productivity of capital inputs would average 0.12% growth. Total factor productivity would average 0.87% annual growth. The OM&A and total factor productivity trends are well above the average historical trends for Ontario power distributors which we calculated in our recent work for the Board.

2. BACKGROUND

2.1 The Renewed Regulatory Framework

In October 2012 the OEB issued its *Renewed Regulatory Framework for Electricity Distributors* ("RRF"). This document establishes guidelines for the new round of multiyear rate plans. Three rate-setting methods are available. One of these, called fourth-generation IR, features price cap indexes with inflation – X escalation formulas. The X factor in these formulas is the sum of a productivity factor and a stretch factor. The productivity factor is based on the average total factor productivity ("TFP") trend of Ontario power distributors.

The OEB also sanctioned a "Custom IR" method it deemed most appropriate for distributors with multiyear or occasional capital expenditure ("capex") needs that exceed historical levels. The Board stated its expectation in the RRF that "a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five-year horizon."[1] Further,

> 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. [2]

The Board also called in the RRF for continuation of its own statistical research on power distributor cost. This research was to include statistical benchmarking and studies of trends in the input prices and productivity of Ontario power distributors. The benchmarking was to address *total* cost and consider the performance of all jurisdictional distributors for which data are available. Results of this benchmarking "will inform the Board's review and

[1] OEB, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 2012, p. 19.

[2] *ibid*, pp. 19-20.

approval of applications under the custom IR method."[3] PEG advised the OEB on the development of the RRF and was retained by the Board to undertake the TFP, input price, and benchmarking studies.

Our input price and productivity trend research employed indexing methods. Our benchmarking study used econometric models. The parameters of these models were estimated using historical data on the costs of Ontario power distributors and the business conditions they faced. Benchmarks are obtained for each company by summing the product of each parameter estimate and the company's value for the corresponding business condition variable.

The benchmarking and indexing studies were similar in several respects. Both used operating data for Ontario power distributors which were drawn from distributor information filings under the Board's Electricity Reporting and Record-Keeping Requirements ("RRR"). The required data were available for 73 distributors. We calculated total cost as the sum of capital cost and OM&A expenses. A standardized "service price" approach to the calculation of capital cost was employed. This approach used estimates of gross plant additions and imposed a common depreciation rate and weighted average cost of capital ("WACC") on the sampled companies. Utility plant was valued in current dollars. Taxes and most costs of conservation and demand management ("CDM") were excluded from the cost data.

The definition of cost in the benchmarking and productivity studies nevertheless differed in some respects. The benchmarking study, for instance, reflected the following data treatments not used in the indexing study:

- Contributions in aid of construction were included.
- Smart meter costs were included.
- Fees paid by distributors to HON for low voltage distributor services were included.
- Most costs of operating high voltage ("HV") substations (i.e. substations with primary voltage exceeding 50 kV) were excluded.

[3] *ibid*, p. 60.

The business condition variables in the econometric cost models were chosen based on runs using data for all 73 Ontario distributors. Once chosen, however, the benchmarks for each sampled company were based on unique parameter estimates for the variables that were estimated using a 72 company data set that excluded the benchmarked company.

Results of our indexing and benchmarking research for the Board were reported in November 2013.[4] Over the full ten-year 2003-2012 sample period, the *total* factor productivity growth of a group of 71 Ontario power distributors that excluded the two largest (HON and Toronto Hydro) was found to have declined by 0.33% annually on average. It is also possible to calculate the *partial* factor productivity trends of OM&A and capital inputs from the numbers we provided in the reports. For example, the OM&A productivity trend is the difference between the trends in the output index and the OM&A input quantity index. For the full sample period, the productivity of OM&A inputs averaged a 0.40% annual decline, while the productivity of capital averaged a smaller 0.26% annual decline.

The trend in the productivity of OM&A inputs was slowed by cost surges in 2012 that resulted in part from reclassifications of deferred expenses and changes in accounting standards. The annual growth in the productivity of OM&A inputs over the nine-year 2003-2011 period that excludes this cost surge averaged 0.51%. Capital and total factor productivity averaged 0.01% and 0.19% growth over the same period.

The OEB in a subsequent decision chose a productivity factor of 0% for all utilities operating under the 4th generation IR price cap index.[5] The Board also decided in this decision to base the stretch factor for each distributor in the 4th generation IR plan on our appraisal of its recent total cost performance using its econometric benchmarking model. These cost performance appraisals consider the average annual percentage difference between the Company's actual cost and the cost benchmark from the econometric model, over the three most recent years for which data are available.

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[4]Pacific Economics Group Research LLC, *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board*, November 2013.
[5]Ontario Energy Board, EB-2010-0379, Report of the Board, *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, November 21, 2013.

In setting the stretch factors, distributors are assigned to one of five groups based on their total cost appraisals. Those in each performance group are assigned a common stretch factor as follows:

Group	**Demarcation Points for Relative Cost Performance**	**Stretch Factor**
I	Actual costs are 25% or more below predicted cost	0.00%
II	Actual costs are 10-25% or more below predicted cost	0.15%
III	Actual costs are within +/-10% of predicted cost	0.30%
IV	Actual costs are 10-25% above predicted cost	0.45%
V	Actual costs are 25% or more above predicted cost	0.60%

The cost appraisals will be updated annually as new operating data become available, and the stretch factors will be reset as warranted to reflect the updated results. In these new appraisals, the parameters of the econometric benchmarking models will not be reestimated. Since the release of our November 2013 report, PEG has undertaken one such update for the Board to incorporate 2013 data. A report on this work was released in July 2014.[6]

2.2 Econometric Benchmarking Model

Details of the econometric model the OEB is using to benchmark the cost performance of OPUCN can be found in Table 1. The model is very similar to that estimated using the full sample of data and presented in our November 2013 report. Data on cost and the basic business condition variables in the model were mean scaled and logged. These variables are called "first-order" terms. Mean scaling ensures that the parameter estimate associated with each first-order term is an estimate of the elasticity of cost with respect to the variable at sample mean values of the business conditions.

The model also contains "second-order" (quadratic and interaction) terms for the input price and scale variables to impart some flexibility to the functional form. This makes it possible for the model to recognize differences in opportunities for utilities to realize economies of scale and scope. The resultant translogarithmic ("translog") functional form of the model is widely used in econometric cost research. Results for the second-order terms are shaded in the table.

[6] David Hovde and John Kalfayan, *Empirical Research in Support of Incentive Rate-Setting: 2013 Benchmarking Update*, PEG Research, July 2014.

Table 1

Board's Econometric Cost Model for OPUCN

VARIABLE KEY

Input Price:	WK =	Capital Price Index / OM&A Price Index
Outputs:	N =	Number of Retail Customers
	C =	Ratcheted Peak Demand
	D =	Retail Deliveries
Other Business Conditions:	L =	Average Line Length (km)
	NG =	% of 2012 Customers added in the last 10 years
	Trend =	Time Trend

BUSINESS CONDITION VARIABLES	ESTIMATED COEFFICIENTS	T STATISTICS	P-VALUES
WK*	0.627	84.54	0.000
N*	0.457	8.29	0.000
C*	0.151	3.02	0.003
D*	0.105	3.32	0.001
WKxWK*	0.125	4.49	0.000
NxN	-0.406	-1.73	0.083
CxC	0.186	0.92	0.359
DxD*	0.157	2.04	0.042
WKxN*	0.053	3.42	0.001
WKxC	0.010	0.73	0.467
WKxD	0.000	0.01	0.995
NxC	0.153	0.77	0.444
NxD	0.086	0.85	0.395
CxD*	-0.209	-2.38	0.017
L*	0.285	13.95	0.000
NG*	0.016	2.22	0.027
Trend*	0.017	12.43	0.000
Constant*	12.82	684.21	0.000
System Rbar-Squared	0.983		
Sample Period	2002-2012		
Number of Observations	791		

***Variable is significant at 95% confidence level**

The business condition variables in the model include separate input price indexes for capital and OM&A expenses. The capital price index was constructed from the Statistics Canada Electric Utility Price Index (“EUCPI”) for distribution systems and from an estimate of the weighted average cost of capital (“WACC”) based on OEB policies. The trend in the OM&A price index is a weighted average of the trends in Statistics Canada’s gross domestic product implicit price index for final domestic demand (“GDPIPI-FDD”) and in the Average Weekly Earnings (“AWE”) of the industrial aggregate in Ontario. Cost and the capital price were divided by the OM&A input price index before model estimation to enforce a prediction of cost theory.

The model includes the following three measures of a distributor’s operating scale:

- the number of customers served;
- delivery volume; and
- ratcheted peak demand.

Two additional variables represent the cost impact of other business conditions:

- % of 2012 customers added in the last ten years (a measure of system youth); and
- average total circuit kilometers (a variable chosen to capture the geographic dispersion of customers).

All first-order terms in the model have highly significant and plausibly signed parameter estimates. For example, total cost was higher the higher was the value of all three scale variables and was also higher with system youth and average line miles. It can be seen that the estimated cost elasticity of the customer variable (0.457%) is more than twice that of either of the other two scale variables. There is, additionally, a trend variable with a positively signed and highly significant parameter estimate.

3. Benchmarking OPUCN's Cost Forecast

3.1 OPUCN Background

OPUCN is a municipally owned power distributor serving the city of Oshawa. The Company receives the bulk of the power it delivers from HV substations owned and operated by HON. Sister companies are engaged in power generation and operate a local dark fiber optics communications network.

Oshawa is located at the eastern periphery of the Greater Toronto Area ("GTA"). The population of the city was more than 155,000 in 2013. OPUCN served about 54,000 customers in that year, which is close to the mean for Ontario distributors. A sizable portion of the distribution system is underground.

In addition to being an important automobile manufacturing center, Oshawa is starting to experience rapid residential sector growth as the GTA expands. The Company expects the number of customers, peak load, and line miles to rise rapidly. Volume is expected to grow more slowly due in part to conservation and demand management ("CDM") programs and the energy efficiency of new homes. Customer growth will occur chiefly in the less populated northern part of the service territory, where there are fewer opportunities to realize economies of density from "infills" of the existing distribution network.

High distribution system capex is planned for the next few years to accommodate the expanding local economy. HON is building a new substation in the area and OPUCN is required to make a financial contribution to this project. OPUCN is planning to construct a new substation to step down voltage from 44 kV to the primary level. Highway construction work such as the extension of Ontario Highway 407 will require relocation of some facilities.

3.2 Benchmarking Forecasted Cost

To benchmark OPUCN's forecasted total cost we obtained forecasts from the Company of its OM&A expenses, gross plant additions, the three scale variables, and the two other business condition variables. The values for the average line miles variable have been upgraded for the historical period to reflect new information and differ from those used in our previous studies. We used the gross plant addition data to calculate capital cost with the service price methodology from our recent studies for the Board. The cost forecasts were consistent with the cost definitions employed in those studies. This means that OPUCN's forecasted contribution to HON for its new HV substation was not considered in this study. Consider also that in our recent studies for the Board, plant is valued in current (aka replacement) dollars. Since the cost of older plant is higher when valued in this way, the percentage increase in cost due to a capex surge is less than under the historical (aka book) valuation of plant that is used in regulatory cost accounting and ratemaking.

Table 2 combines historical and forecasted data on Oshawa's cost and external business conditions. The following results are noteworthy.

- OM&A expenses surged in 2011 due to replacement hires. They surged again in 2012 due to changes in accounting standards and the expensing of some cost deferrals.
- Brisk growth in customers and peak demand are forecasted in all years of the proposed IR plan.
- Despite current dollar valuation of plant, a surge in capital cost is forecasted in 2015 due to high capex. Capital cost growth is much slower in subsequent years.

As for input prices, we purchased inflation forecasts from the Conference Board of Canada for the following indexes.

- Average Weekly Wages & Salaries Per Employee, Ontario (Industrial Composite)
- GDPIPI Implicit Price Deflator (Canada)
- Implicit Price Index - Gross Fixed Capital Formation, Engineering Structures, Electric Power Generation, Transmission and Distribution (Canada).

The growth rates of these indexes were used to escalate the cost model's OM&A and capital price indexes.

Table 3 provides details of our input price calculations. It can be seen that the Conference Board forecasts AWE inflation to average 2.59% annually in the 2015-2019 period. The GDPIPI-FDD is forecasted to average 1.99% inflation, while the construction

Table 2

OPUCN Historical and Forecasted Data

	Cost						Output Quantities						Business Conditions	
Year	OM&A		Capital		Total		Customers		Delivery Volume		Ratcheted Peak Load		Average Line Length (km)	Customers Added in Last 10 yrs
	Level	GR	Level	GR		GR	Level	GR	Level	GR	Level	GR		
2002	8,874,750		10,329,498		19,204,248		47,533		1,163,442		222,000		*844*	12.3%
2003	8,050,337	-9.7%	10,830,071	4.7%	18,880,408	-1.7%	48,202	1.4%	1,192,940	2.5%	228,000	2.7%	*844*	12.3%
2004	7,593,543	-5.8%	11,356,940	4.8%	18,950,483	0.4%	48,675	1.0%	1,175,440	-1.5%	233,000	2.2%	*844*	12.3%
2005	7,675,842	1.1%	12,621,074	10.6%	20,296,916	6.9%	49,500	1.7%	1,128,827	-4.0%	233,000	0.0%	*844*	12.3%
2006	7,571,117	-1.4%	13,087,967	3.6%	20,659,084	1.8%	50,528	2.1%	1,107,170	-1.9%	233,000	0.0%	*844*	12.3%
2007	8,193,467	7.9%	14,129,194	7.7%	22,322,661	7.7%	50,980	0.9%	1,191,135	7.3%	233,000	0.0%	*844*	12.3%
2008	8,435,686	2.9%	14,997,591	6.0%	23,433,278	4.9%	51,813	1.6%	1,165,414	-2.2%	233,000	0.0%	*844*	12.3%
2009	8,399,846	-0.4%	15,420,296	2.8%	23,820,141	1.6%	52,184	0.7%	1,134,000	-2.7%	233,000	0.0%	*844*	12.3%
2010	8,362,787	-0.4%	16,578,322	7.2%	24,941,109	4.6%	52,710	1.0%	1,128,809	-0.5%	233,000	0.0%	*844*	12.3%
2011	9,463,962	12.4%	17,087,769	3.0%	26,551,731	6.3%	53,083	0.7%	1,097,497	-2.8%	234,849	0.8%	*844*	12.3%
2012	10,665,324	12.0%	16,555,731	-3.2%	27,221,055	2.5%	53,361	0.5%	1,080,898	-1.5%	234,849	0.0%	*844*	12.3%
2013	10,496,484	-1.6%	16,742,890	1.1%	27,239,374	0.1%	53,969	1.1%	1,071,585	-0.9%	234,849	0.0%	*849*	12.0%
2014	**10,708,176**	**2.0%**	**17,567,078**	**4.8%**	**28,275,254**	**3.7%**	**54,613**	**1.2%**	**1,096,999**	**2.3%**	**240,000**	**2.2%**	855	12.2%
2015	**11,414,600**	**6.4%**	**19,254,162**	**9.2%**	**30,668,763**	**8.1%**	**56,251**	**3.0%**	**1,103,830**	**0.6%**	**245,000**	**2.1%**	861	13.6%
2016	**11,880,618**	**4.0%**	**20,201,278**	**4.8%**	**32,081,897**	**4.5%**	**57,939**	**3.0%**	**1,114,293**	**0.9%**	**252,000**	**2.8%**	867	14.7%
2017	**12,137,178**	**2.1%**	**21,209,290**	**4.9%**	**33,346,469**	**3.9%**	**59,677**	**3.0%**	**1,119,638**	**0.5%**	**262,000**	**3.9%**	874	17.1%
2018	**12,344,107**	**1.7%**	**22,187,458**	**4.5%**	**34,531,565**	**3.5%**	**61,467**	**3.0%**	**1,128,027**	**0.7%**	**272,000**	**3.7%**	883	18.6%
2019	**12,401,734**	**0.5%**	**22,941,961**	**3.3%**	**35,343,696**	**2.3%**	**63,311**	**3.0%**	**1,136,771**	**0.8%**	**283,000**	**4.0%**	892	21.3%
Average														
2003-2014		**1.6%**		**4.4%**		**3.2%**		**1.2%**		**-0.5%**		**0.6%**	**845.0**	**12.2%**
2015-2019		**2.9%**		**5.3%**		**4.5%**		**3.0%**		**0.7%**		**3.3%**	**875.3**	**17.1%**

Table 3

Development of Input Price Forecasts

	Conference Board Inflation Forecasts			Other Components of Calculations				Input Price Forecasts	
				OM&A Index Weights					
	Average Weekly Earnings (Ontario)	**GDP-IPI (Canada)**	**Engineering Structures Electric Sector**	**Labor**	**Non-Labor**	**Rate of Return on Plant**	**Plant Depreciation Rate**	**OM&A**	**Capital**
2014	1.59%	2.08%	4.19%	70%	30%	5.96%	4.59%	1.73%	1.39%
2015	2.08%	1.60%	2.35%	70%	30%	5.96%	4.59%	1.93%	3.38%
2016	2.65%	2.01%	2.77%	70%	30%	5.96%	4.59%	2.45%	2.54%
2017	2.73%	2.13%	2.73%	70%	30%	5.96%	4.59%	2.55%	2.75%
2018	2.75%	2.16%	2.51%	70%	30%	5.96%	4.59%	2.57%	2.63%
2019	2.75%	2.07%	2.52%	70%	30%	5.96%	4.59%	2.55%	2.51%
Average 2015 - 2019	**2.59%**	**1.99%**	**2.58%**	**70%**	**30%**	**5.96%**	**4.59%**	**2.41%**	**2.76%**

cost index is forecasted to average 2.58% inflation. In calculating the capital price index, the depreciation rate was the same 4.59% rate used in our recent studies for the Board. The WACC was held constant at the 5.96% value we used in our recent benchmarking update study. Based on these results, we forecast our OM&A input price index to average 2.41% annual inflation and the capital price index to average 2.76% inflation.

Using the forecasts of external business conditions and the Board's OPUCN benchmarking model, we benchmarked the forecasted total cost of OPUCN during the years of the proposed IR plan. Results are presented in Table 4. It can be seen that OPUCN's forecasted costs are below the econometric benchmarks in all years, and are 11.7% below the benchmark on average over the years of the proposed plan. Cost performance is lowest in 2015, when the cost surge is anticipated, but thereafter improves steadily, attaining a level commensurate with a Group II stretch factor in the last three years of the plan.

3.3 Productivity Results

In addition to the benchmarking work, we calculated the growth in the OM&A, capital, and total factor productivity of OPUCN that is implicit in the Company's cost forecasts. These calculations were made using the same indexing methods used in our research for the Board but applied to the somewhat different definition of cost in our benchmarking studies. The weights for the output index and the OM&A input price index were the same as in our 2013 indexing study. Moreover, growth in the input quantity subindexes for OM&A and capital inputs were each calculated as the difference between the growth in cost and the input price index. The summary input quantity index, however, uses OPUCN-specific cost share weights based on the costs calculated in this benchmarking study.

Results of this exercise are reported in Table 5. Note first that the productivity growth was unusually slow in 2011 and 2012. This reflects the combination of high capex, the change in accounting standards, and replacement hirings which we mentioned above. TFP growth was fairly close to the Ontario norm in 2013, and similar growth is forecasted for 2014. In both years, the effect of high capex on cost is offset by brisk OM&A productivity growth.

Table 4

Summary of OPUCN Cost Performance Results

Year	Forecasted	Predicted by the Model	Cost Performance
2015	30,668,763	32,717,559	-6.5%
2016	32,081,897	34,829,446	-8.2%
2017	33,346,469	37,256,502	-11.1%
2018	34,531,565	39,817,355	-14.2%
2019	35,343,696	42,615,648	-18.7%
Average 2015-2019			**-11.7%**

Table 5

OPUCN Productivity Trends

	Growth Rates of Productivity Indexes and Components													
	Cost				Input Prices			Input Quantities			Productivity			
Year	OM&A	Capital	Total	Output Quantity	OM&A	Capital	Total	OM&A	Capital	Total	OM&A	Capital	Total
	[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H=A-E]	[I=B-F]	[J=C-G]	[D-H]	[D-I]	[D-J]
2010	-0.4%	7.2%	4.6%	0.6%	3.0%	2.0%	2.4%	-3.4%	5.2%	2.2%	4.0%	-4.6%	-1.7%
2011	12.4%	3.0%	6.3%	0.2%	1.7%	0.2%	0.7%	10.7%	2.9%	5.6%	-10.5%	-2.7%	-5.4%
2012	12.0%	-3.2%	2.5%	0.1%	1.6%	-5.2%	-2.7%	10.4%	2.0%	5.1%	-10.3%	-1.9%	-5.0%
2013	-1.6%	1.1%	0.1%	0.6%	1.6%	-2.4%	-0.9%	-3.1%	3.5%	0.9%	3.7%	-2.9%	-0.3%
2014	2.0%	4.8%	3.7%	1.6%	1.7%	1.4%	1.5%	0.3%	3.4%	2.2%	1.3%	-1.9%	-0.6%
2015	6.4%	9.2%	8.1%	2.4%	1.9%	3.4%	2.8%	4.5%	5.8%	5.3%	-2.0%	-3.4%	-2.9%
2016	4.0%	4.8%	4.5%	2.6%	2.5%	2.5%	2.5%	1.5%	2.3%	2.0%	1.1%	0.4%	0.6%
2017	2.1%	4.9%	3.9%	2.8%	2.5%	2.8%	2.7%	-0.4%	2.1%	1.2%	3.2%	0.7%	1.6%
2018	1.7%	4.5%	3.5%	2.8%	2.6%	2.6%	2.6%	-0.9%	1.9%	0.9%	3.7%	0.9%	1.9%
2019	0.5%	3.3%	2.3%	2.8%	2.5%	2.5%	2.5%	-2.1%	0.8%	-0.2%	4.9%	2.0%	3.0%
Average 2015-2019	**2.94%**	**5.34%**	**4.46%**	**2.70%**	**2.41%**	**2.76%**	**2.63%**	**0.53%**	**2.58%**	**1.83%**	**2.17%**	**0.12%**	**0.87%**

During the years of the proposed IR plan, OM&A and capital productivity growth are calculated to average 2.17% and 0.12%, respectively. TFP growth is calculated to average 0.87%. Negative capital and total factor productivity growth in 2015 reflect the forecasted cost surge. Capital productivity growth is positive from 2017-2019, due in part to depreciation of recent high capex.

Table 6 compares the forecasted productivity trends with the average trends for Ontario power distributors which we noted in our November 2013 report. Compared to both the nine-year 2003-2011 period and the ten-year 2003-2012 period, the forecasted OM&A and total factor productivity trends of OPUCN are well above the average historical trends for the industry.[7]

Table 6

Comparison of Productivity Trends

	OPUCN	**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 Factor	0.87%	0.19%	-0.33%

[7] This is all the more remarkable because the productivity trends in our study for the Board were not slowed by the cost of the AMI buildout.

CAPITAL PROJECT BUDGETARY COST ESTIMATES
2015 - 2019

November 12, 2014

I. Objectives:

NBM Engineering Inc. has been retained by OPUCN to independently prepare a high level budgetary cost estimates based on industry standards for various OPUCN capital projects for the years 2015 to 2019. Oshawa PUC did not share any information with respect to cost estimate that they prepared internally. The criteria for the high budgetary costing were provided by OPUCN. A meeting was held at OPUC office in order to capture the essential considerations for the estimates with details provided by OPUCN engineering and operations departments.

Over the past 20 years, NBM Engineering has been a premier provider of various Engineering Services to most of the electrical utility providers in the Greater Toronto and surrounding area.

NBM has been servicing the hydro utility industry since 1991 as an alternative source for project management, engineering and cost estimate of various projects. With extensive hydro utility experience over the past 23 years, NBM Engineering gained necessary knowledge in developing project cost estimates that accurately match industry standards and hydro utility realistic expectations.

II. Project Categories:

Majority of the planned Overhead & Underground Rebuilds falls under the category of Feeder & Distribution Cable & Conductor Rehabilitation Programs; also new substation build (MS9) is included in this estimate and will be spread over the 2016-2019 Capital Budget.

There are several categories of OPUCN Capital Projects that would cover nature of the projects planned for this period:

Distribution System Enhancement Program

Oshawa PUC needs to enhance and expand the main distribution system. Enhancement work must be completed to ensure all new and existing customers are provided with required capacity without constraining the supply to existing customers and negatively impacting system safety and reliability. By implementing distribution system expansion and enhancement programs Oshawa PUC is focusing on both underground and overhead main distribution circuits. Main goal is to keep optimal loading and maintaining system reliability.

Feeder and Distribution Cable/Conductor Rehabilitation or Replacement

Oshawa PUC's overhead and underground distribution systems include various cable and conductor types dating back 25 to 30 years with some areas with 50-60 years old poles. Certain areas within Oshawa PUC electrical distribution system are coming to an end of their useful life with increased occurrences of cable faults. Cable fault records were used to identify areas most in need of system rehabilitation or where necessary, cable or conductor replacement. Oshawa PUC's developed Asset Management and Assessment Program that generates all necessary Oshawa PUC distribution system data information. Cable age, loading, and cable fault history is kept in this data and helps in rehabilitation program scheduling in a timely fashion. Rehabilitation and replacement programs provide Oshawa PUC’s with an efficient instrument how to maintain its system reliability and customer satisfaction levels.

Substation Project MS9 - Cost Development

Oshawa PUC MS9 substation construction program project is designed to increase the capacity of the electrical distribution system by installing new transformers and feeders in response to system load growth forecasts and maintenance of reliability of the existing distribution system. Substation MS9 will transform power from 44kV to 13.8kV.
This project will involve the site plan approval and start of the construction of a new Substation land and building. In addition, the major equipment such as transformers, high voltage 44kV breakers, and low voltage 13.8kV switchgear are required. Other equipment such as battery charger, relays, breakers, tray work, transformer station service etc will also be required. All of this equipment will then need to installed and commissioned. All of the associated outside civil work and cable installation will need to be completed and connections and terminations made to the existing electrical distribution system.

As the Substation is being constructed or developed, the cost includes direct construction or development costs such as labour, materials and supplies, transportation, third party work, and other costs directly attributable to the construction or development activity.

Also costs of employee benefits arising directly from the labour related to the construction or acquisition of the item of property, plant and equipment are included.

In developing cost estimates for Oshawa PUC’s Substation projects, NBM Engineering used industry standards along with an in-house resource table. The resource table details equipment, materials and labour required in performing specific tasks at the substation. Accuracy and practicality of the table task was verified by former Hydro employees who are currently working under contract with NBM Engineering.

Feeder Egress Program for MS9 Substation

In order to meet continuous new customer capacity demand and maintaining reliability, and optimal loading demands for existing customers, Oshawa PUC must expand the 13.8kV distribution feeders connected to substations in Oshawa. In the near term, feeder egress construction will focus on feeder replacement areas supplied by MS9 substation. Individual projects are implemented through several stages to allow electrical distribution system expansion. This program is in line with the new MS9 substation implementation as well as with main distribution system enhancement programs.

Substation 13.8 kV Breaker Replacement Program – 2015-2016

Continuation of Breaker Replacement Program - Plant Modernization Air Magnetic to Vacuum (bus tie and main).

- Vacuum Main & Buss Tie Breakers Replacement Options
    a) Retrofit option like for like
    b) Retrofit option upgrading to arc resistant units with remote racking
    c) Upgrade to metal-clad indoor switchgear line-up fully arc resistant with remote racking

MS5 T2- Replace 25kVA Power Transformer including Oil Containment

- Unit is 30 years old. End of life and reliability issue. Replacement is needed as per poor oil gas analysis in 2013 confirmed by OPUCN.

44kV Oil Breakers - Replacement with SF6 breakers in outdoor enclosure – 2016-2018

- Obsolete, end of life 45+ years breaker – 44kV Oil Breaker Replacement Program

III. Cost Summary Table:

2015 Cost Estimate Summary	
Planned OH Projects	$2,858,334.07
Planned UG Projects	$962,687.65
MS-9 Station	$1,126,220.01
MS10 Maintenance	$105,000.00
MS11 Maintenance	$105,000.00
2015 Total Estimate:	***$5,157,241.72***

2016 Cost Estimate Summary	
Planned OH Projects	$2,344,241.52
Planned UG Projects	$1,367,338.42
MS-9 Station	$2,508,653.63
MS2 Maintenance	$105,000.00
MS15 Maintenance	$70,000.00
2016 Total Estimate:	***$6,395,233.57***

2017 Cost Estimate Summary	
Planned OH Projects	$1,978,695.91
Planned UG Projects	$1,413,165.00
MS-9 Station	$2,969,112.00
44.0kV OCB Replacement	$680,000.00
2017 Total Estimate:	***$7,040,972.91***

2018 Cost Estimate Summary	
Planned OH Projects	$2,174,744.72
Planned UG Projects	$1,868,038.00
MS-9 Station	$3,600,233.56
44.0kV OCB Replacement	$680,000.00
2018 Total Estimate:	***$8,323,016.28***

2019 Cost Estimate Summary	
Planned OH Projects	$2,063,930.92
Planned UG Projects	$994,736.58
MS-5 Station	$1,350,000.00
44.0kV OCB Replacement	$510,000.00
2019 Total Estimate:	***$4,918,667.50***

2015 - 2019 Cost Estimate Summary						
Project Year:	2015	2016	2017	2018	2019	TOTALS
Planned OH Projects	$2,858,334.07	$2,344,241.52	$1,978,695.91	$2,174,744.72	$2,063,930.92	$11,419,947.14
Planned UG Projects	$962,687.65	$1,367,338.42	$1,413,165.00	$1,868,038.00	$994,736.58	$6,605,965.65
MS-9 Station	$1,126,220.01	$2,508,653.63	$2,969,112.00	$3,600,233.56	0	$10,204,219.20
MS-5 Station	0	0	0	0	$1,350,000.00	$1,350,000.00
Station Breaker Replacement	$210,000.00	$175,000.00	0	$0.00	0	$385,000.00
44kV OCB Replacement	$0.00	$0.00	$680,000.00	$680,000.00	$510,000.00	$1,870,000.00
Total Project Estimate:	***$5,157,241.72***	***$6,395,233.57***	***$7,040,972.91***	***$8,323,016.28***	***$4,918,667.50***	***$31,835,131.99***

2015 to 2019 Capital Project Program:

Following project list describe type and scope of the work per each year between 2015 and 2019 with precise distinction between overhead and underground or both overhead & underground categories:

2015 Overhead Project Summary:

Planned OH Projects - 2015	
Project Name:	OH-2015-01
Project #:	Park Rd - Wenthworth - Rebuild
Location:	Stone/Lakesfield/Beaupre/Tremblay/Kenora/Gaspe/Laurentian/Lakeview/Lakeside
Capital Budget #:	OH-2015-01
Description:	185 Pole, 1 Ph, 35 Transformers, 7,400 m
Project Estimate:	$1,675,484.32
Project Name:	OH-2015-02
Project #:	Keewatin Rebuild
Location:	Melrose, Applegrove, Oriole, Willowdale, Springdale
Capital Budget #:	OH-2015-02
Description:	50 Pole, 35-1 Ph, 15-3 Ph, 24 Transformers, 1,400 m
Project Estimate:	$677,342.72
Project Name:	OH-2015-03
Project #:	Masson & Mary OH & UG Rebuild
Location:	Rear Lot - Masson & Mary
Capital Budget #:	OH-2015-03
Description:	35 Poles, 12 Transformers, 1,650 m (Combined Overhead & Undeground)
Project Estimate:	$505,507.03

2015 Underground Project Summary:

Planned UG Projects - 2015	
Project Name:	UG-2015-01
Project #:	Down Crescent Rebuild
Location:	Down Crescent/ Delmark Ct
Capital Budget #:	UG-2015-01
Description:	2 - Dip Poles, 900m - 1 Ph, 940m Cable Replacement, 2 of 11 Transformers Replacement
Project Estimate:	$163,752.00
Project Name:	UG-2015-02
Project #:	Mary St. North
Location:	1333 Mary St North
Capital Budget #:	UG-2015-02
Description:	2 - Dip Poles, 400m - 1 Ph, 495m Cable Replacement, 1 of 4 Transformers Replacement
Project Estimate:	$70,456.79

2015 Underground Project Summary (Continuation):

Project Name:	UG-2015-03
Project #:	Camelot Dr UG Rebuild
Location:	Camelot/Merlin/Percival/Lancelot
Capital Budget #:	UG-2015-03
Description:	2 - Dip Poles, 1850m - 1 Ph, 1970m Cable Replacement, 5 of 14 Transformers Replacement
Project Estimate:	$302,230.47

Project Name:	UG-2015-04
Project #:	Chandos & Calvert UG Rebuild
Location:	Chandos/Calvert Ct
Capital Budget #:	UG-2015-04
Description:	2 - Dip Poles, 300m - 1 Ph, 360m Cable Replacement, 0 of 3 Transformers Replacement
Project Estimate:	$39,104.88

Project Name:	UG-2015-05
Project #:	Oxford UG Rebuild
Location:	1300 Oxford St
Capital Budget #:	UG-2015-05
Description:	2 - Dip Poles, 400m - 1 Ph, 465m Cable Replacement, 0 of 3 Transformers Replacement
Project Estimate:	$59,470.25

Project Name:	UG-2015-06
Project #:	Cedar St. Rebuild
Location:	Cedar St/Balsam Cr/ Lakeview Ave/ Bon Echo Dr/ Chaleur Ave
Capital Budget #:	UG-2015-06
Description:	2 - Dip Poles, 2000m - 1 Ph, 6 of 15 Transformers Replacement
Project Estimate:	$327,673.26

2016 Overhead Project Summary:

Planned OH Projects - 2016	
Project Name:	OH-2016-01
Project #:	Rossland Rebuild
Location:	Rossland, Ritson to Wilson
Capital Budget #:	OH-2016-01
Description:	30 Pole, 2 Circuit - 3 Ph, 4 Transformers, 900 m
Project Estimate:	$486,860.71
Project Name:	OH-2016-02
Project #:	Athabasca Rebuild
Location:	Rockcliffe, Belvedere, Labrador, Lisgar, Winderemere, Ridgecrest, Wakefield
Capital Budget #:	OH-2016-02
Description:	67 Pole, 50 -1 Ph, 17 -3 Ph, 25 Transformers, 2650 m
Project Estimate:	$899,513.39
Project Name:	OH-2016-03
Project #:	Eastlawn Rebuild
Location:	Eastlawn, Winter, Mackenzie, Labrador
Capital Budget #:	OH-2016-03
Description:	32 Pole, 1 Ph, 6 Transformers, 1200 m
Project Estimate:	$406,447.87
Project Name:	OH-2016-04
Project #:	Bloor St. Rebuild - Oliver to MS-11
Location:	Bloor St. - Oliver to MS-11
Capital Budget #:	OH-2016-04
Description:	18 Pole, 3 Circuit - 3 Ph, 8 - 8 - 1 Ph, 3 - 3 Ph Transformers, 820 m
Project Estimate:	$551,419.55

2016 Underground Project Summary:

Planned UG Projects - 2016	
Project Name:	UG-2016-01
Project #:	Northdale UG Rebuild
Location:	Northdale/Mohawk/Beatrice Ct
Capital Budget #:	UG-2016-01
Description:	2 - Dip Poles, 1200m - 1 Ph, 1280m Cable Replacement, 1 of 6 Tx Replacement
Project Estimate:	$163,752.00
Project Name:	UG-2016-02
Project #:	401 Wenthworth UG Rebuild
Location:	401 Wenthworth Ave
Capital Budget #:	UG-2016-02
Description:	2 - Dip Poles, 400m - 1 Ph, 495m Cable Replacement, 1 of 3 Tx Replacement
Project Estimate:	$72,533.08
Project Name:	UG-2016-03
Project #:	1100 Oxford UG Rebuild
Location:	1100 Oxford St
Capital Budget #:	UG-2016-03
Description:	2 - Dip Poles, 1200m - 1 Ph, 1305m Cable Replacement, 2 of 7 Tx Replacement
Project Estimate:	$180,022.40
Project Name:	UG-2016-04
Project #:	Athabasca-Sutton UG Rebuild
Location:	Athabasca/Sutton/MarcClaren/Conwallis Ct
Capital Budget #:	UG-2016-04
Description:	2 - Dip Poles, 1000m - 1 Ph, 1120m Cable Replacement, 4 of 10 Tx Replacement
Project Estimate:	$204,705.98
Project Name:	UG-2016-05
Project #:	MS10 - 10F1 & 10F6 Lead Cable Replacement
Location:	MS10 Station
Capital Budget #:	UG-2016-05
Description:	2 - Dip Poles, 2 -3ph 600A Termination - 235m 3ph Cable Replacement /Civil Structures
Project Estimate:	$351,961.97
Project Name:	UG-2016-06
Project #:	Aruba Rebuild
Location:	Aruba Cr/Aruba St/ Waverly St/ Bermuda Ave/ Antigua Cr
Capital Budget #:	UG-2016-06
Description:	2 - Dip Poles, 2600m - 1 Ph, 2705m Cable Replacement, 6 of 15 Tx Replacement
Project Estimate:	$394,362.99

2017 Overhead Project Summary:

Planned OH Projects - 2017	
Project Name:	OH-2017-01
Project #:	Central Park Blvd North Rebuild
Location:	Central Park Blvd North - Brentwood, Hoomewood to Hardwood
Capital Budget #:	OH-2017-01
Description:	50 Pole, 10 - 3 Ph, 40 - 1 Ph, 16 Transformers, 2000 m
Project Estimate:	$609,742.77
Project Name:	OH-2017-02
Project #:	Landsdowne Rebuild
Location:	Landsdowne - Dover, Digby, Surrey, Sussex
Capital Budget #:	OH-2017-02
Description:	33 Pole, 1 Ph, 8 Transformers, 1300 m
Project Estimate:	$379,094.21
Project Name:	OH-2017-03
Project #:	Shakespear Rebuild
Location:	Shakespear - Addison, Chaucer, McCauly, Loring, Tennyson, Addison Ct, Carmen Ct.
Capital Budget #:	OH-2017-03
Description:	40 Pole, 1 Ph, 12 Transformers, 1600 m
Project Estimate:	$484,900.90
Project Name:	OH-2017-04
Project #:	Rebuild - Fisher ST, Albert St, Avenue St & Quebec St.
Location:	Fisher ST, Albert St, Avenue St & Quebec St.
Capital Budget #:	OH-2017-04
Description:	18 Pole, 3 Ph, 5 Ph Transformers, 700 m
Project Estimate:	$310,733.23
Project Name:	OH-2017-05
Project #:	GrenFell Rebuild
Location:	GrenFell South of Gibb, Marland, Montrave
Capital Budget #:	OH-2017-05
Description:	16 Pole, 8 - 3 Ph, 8 - 1 Ph, 4 Transformers, 500 m
Project Estimate:	$194,224.80

2017 Underground Project Summary:

Planned UG Projects - 2017	
Project Name:	UG-2017-01
Project #:	1010 Glen St. UG Rebuild
Location:	1010 Glen St.
Capital Budget #:	UG-2017-01
Description:	2 - Dip Poles, 1000m - 1 Ph, 1095m Cable Replacement, 4 of 9 Tx Replacement
Project Estimate:	$225,799.06
Project Name:	UG-2017-02
Project #:	Annandale St. UG Rebuild
Location:	Annandale/Capiliano Cres/Capiliano Ct.
Capital Budget #:	UG-2017-02
Description:	2 - Dip Poles, 1100m - 1 Ph, 1195m Cable Replacement, 4 of 9 Tx Replacement
Project Estimate:	$225,725.16
Project Name:	UG-2017-03
Project #:	Cherry Down UG Rebuild
Location:	Cherry Down/ SunnyBrae Dr
Capital Budget #:	UG-2017-03
Description:	2 - Dip Poles, 1000m - 1 Ph, 1095m Cable Replacement, 4 of 14 Tx Replacement
Project Estimate:	$225,213.83
Project Name:	UG-2017-04
Project #:	Birkdale St. UG Rebuild
Location:	Birkdale/Muirfield/Pinehurst/Sunningdale
Capital Budget #:	UG-2017-04
Description:	2 - Dip Poles, 1500m - 1 Ph, 1640m Cable Replacement, 2 of 8 Tx Replacement
Project Estimate:	$240,051.87
Project Name:	UG-2017-05
Project #:	Maryland Ave UG Rebuild
Location:	291 Maryland Ave
Capital Budget #:	UG-2017-05
Description:	80m - 3 Ph, 180m Cable Replacement, 3 x 50kVA Vault Replacement
Project Estimate:	$72,993.06
Project Name:	UG-2017-06
Project #:	Marland Ave UG Rebuild
Location:	321 Marland Ave
Capital Budget #:	UG-2017-06
Description:	80m - 3 Ph, 330m Cable Replacement, 3 x 50kVA Vault Replacement
Project Estimate:	$82,153.16

2017 Underground Project Summary (Continuation):

Project Name:	UG-2017-07
Project #:	282-290 Marland Ave UG Rebuild
Location:	282 Marland Ave
Capital Budget #:	UG-2017-07
Description:	80m - 3 Ph, 330m Cable Replacement, 3 x 50kVA Vault Replacement
Project Estimate:	$82,153.16

Project Name:	UG-2017-08
Project #:	310 Marland Ave UG Rebuild
Location:	310 Marland Ave
Capital Budget #:	UG-2017-08
Description:	80m - 1 Ph, 105m Cable Replacement, 1 x 75kVA Vault Replacement
Project Estimate:	$59,663.55

Project Name:	UG-2017-09
Project #:	300 Grenfell UG Rebuild
Location:	300 Grenfell
Capital Budget #:	UG-2017-09
Description:	120m - 3 Ph, 180m Cable Replacement, 3 x 50kVA Vault Replacement
Project Estimate:	$55,306.51

Project Name:	UG-2017-10
Project #:	400 Grenfell UG Rebuild
Location:	400 Grenfell
Capital Budget #:	UG-2017-09
Description:	120m - 3 Ph, 180m Cable Replacement, 3 x 250kVA Vault Replacement
Project Estimate:	$90,344.04

Project Name:	UG-2017-11
Project #:	Tennyson Ct UG Rebuild
Location:	Tennyson Ct
Capital Budget #:	UG-2017-11
Description:	2 - Dip Poles, 300m - 1 Ph, 335m Cable Replacement, 0 of 2 Tx Replacement
Project Estimate:	$53,761.60

2018 Overhead Project Summary:

Planned OH Projects - 2018	
Project Name:	OH-2018-01
Project #:	Juliana Dr & Bernhard Crescent Rebuild
Location:	Juliana Dr & Bernhard Crescent
Capital Budget #:	OH-2018-01
Description:	22 Pole, 1 Ph, 6 Transformers, 850 m
Project Estimate:	$268,071.63
Project Name:	OH-2018-02
Project #:	Mary St Rebuild
Location:	Mary St - Rossland to Aberdeen
Capital Budget #:	OH-2018-02
Description:	25 Pole, 1 Ph, 5 Transformers, 1000 m
Project Estimate:	$203,704.56
Project Name:	OH-2018-03
Project #:	Gibbons Rebuild
Location:	Glengrove,Rossmount,Glendale,Glen Forest,Glen Alan,Glen Rush,Glenbrae,Glencastle
Capital Budget #:	OH-2018-03
Description:	55 Pole, 1 Ph, 17 Transformers, 2200 m
Project Estimate:	$740,799.40
Project Name:	OH-2018-04
Project #:	Riverside Dr South Rebuild
Location:	Riverside Dr South - Palace St & Hoskin Ave
Capital Budget #:	OH-2018-04
Description:	26 Pole, 1 Ph, 4 Ph Transformers, 1000 m
Project Estimate:	$233,281.37
Project Name:	OH-2018-05
Project #:	Riverside Dr North Rebuild
Location:	Riverside Dr N-Regent,EastHaven,EastGrove,Eastdale,Eastborne,EastGlen,Florian Ct.
Capital Budget #:	OH-2018-05
Description:	59 Pole, 1 Ph, 15 Transformers, 2350 m
Project Estimate:	$728,887.76

2018 Underground Project Summary:

Planned UG Projects - 2018	
Project Name:	UG-2018-01
Project #:	Gladfern UG Rebuild
Location:	Gladfern/Gallahad/Gentry/Gaylord
Capital Budget #:	UG-2018-01
Description:	3 - Dip Poles, 1605m - 1 Ph, 1840m - 2 Ph, 2664m - 3 Ph, 6460m Cable Replacement, 9 of 41 Tx Replacement
Project Estimate:	$917,760.59
Project Name:	UG-2018-02
Project #:	Traddles UG Rebuild
Location:	Traddles/Dickens/Wickham
Capital Budget #:	UG-2018-02
Description:	3 - Dip Poles, 1890m - 1 Ph, 310m - 2 Ph, 380m - 3 Ph, 4100m Cable Replacement, 12 of 30 Tx Replacement
Project Estimate:	$605,403.63
Project Name:	UG-2018-03
Project #:	Outlet Dr UG Rebuild
Location:	Outlet/Birchcliffe/Lakeview/Valley
Capital Budget #:	UG-2019-01
Description:	2 - Dip Poles, 1500m - 1 Ph, 1635m Cable Replacement, 8 of 17 Tx Replacement
Project Estimate:	$344,873.78

2019 Overhead Project Summary:

Planned OH Projects - 2019	
Project Name:	OH-2019-01
Project #:	King St East Rebuild
Location:	King St East 10F1 (Keewatin to Townline)
Capital Budget #:	OH-2019-01
Description:	25 Pole, 3 Ph, 7 Transformers, 1000 m
Project Estimate:	$380,517.72
Project Name:	OH-2019-02
Project #:	Vimy Avenuet Rebuild
Location:	Vimy Avenue, Lasalle Avenue
Capital Budget #:	OH-2019-02
Description:	13 Pole, 1 Ph, 4 Transformers, 500 m
Project Estimate:	$183,261.79
Project Name:	OH-2019-03
Project #:	Waverly Rebuild
Location:	Waverly - Cabot, Cartier, Montlam, Harlow, Vancouver, Healy, Valdez, Durham
Capital Budget #:	OH-2019-03
Description:	115 Pole, 85 -1 Ph, 30 - 3 Ph, 35 Transformers, 4550 m
Project Estimate:	$1,312,827.26
Project Name:	OH-2019-04
Project #:	Grandview, Beaufort & Newbury Rebuild
Location:	Grandview, Beaufort & Newbury
Capital Budget #:	OH-2019-04
Description:	15 Pole, 1 Ph, 3 Ph Transformers, 600 m
Project Estimate:	$187,324.15

2019 Underground Project Summary:

Planned UG Projects - 2019	
Project Name:	UG-2019-02
Project #:	Central Park Blvd UG Rebuild
Location:	Central Park/Exeter St/Townbridge
Capital Budget #:	UG-2019-02
Description:	2 - Dip Poles, 2000m - 1 Ph, 2110m Cable Replacement, 4 of 12 Tx Replacement
Project Estimate:	$321,794.81
Project Name:	UG-2019-03
Project #:	Ormond Dr UG Rebuild
Location:	Ormond/Everglades/ Palmetto/ Pompano Ct.
Capital Budget #:	UG-2019-03
Description:	2 - Dip Poles, 1800m - 1 Ph, 1890m Cable Replacement, 2 of 8 Tx Replacement
Project Estimate:	$274,089.24
Project Name:	UG-2019-04
Project #:	Beaufort Ct UG Rebuild
Location:	Beaufort Ct
Capital Budget #:	UG-2019-04
Description:	2 - Dip Poles, 1 New Pole, 950m - 1 Ph, 1000m Cable Replacement, 2 of 5 Tx Replacement
Project Estimate:	$169,918.76
Project Name:	UG-2019-05
Project #:	Marwood UG Rebuild
Location:	Marwood Dr
Capital Budget #:	UG-2019-05
Description:	2 - Dip Poles, 850m - 3 Ph, 2775m Cable Replacement, 0 of 5 Transformers Replacement
Project Estimate:	$228,933.77

MS – 9 Project Summary:

MS - 9 Cost Estimate Summary	
Project Name:	Substation Project MS9 - Cost Development
Project #:	MS - 9
Location:	Harmony & Conlin, Oshawa On.
Capital Budget #:	MS - 9
Description:	2-25/30/35 KVA 44kV-13.8KV, 2 or 3 Feeder Egress Distribution Capacity - Construct new MS 9 - 13.8kV Substation to address load growth in North Oshawa mainly due to extension of 407
Unaccounted Costs:	Land Acquisition - $150,000.00 to $300,000.00 Environmental Assessment - $250,000.00 to $500,000.00
Project Estimate:	$10,204,219.20

MS - 9 Cost Estimate -Year Distribution					
Project Year:	2015	2016	2017	2018	TOTALS
Engineering	$148,125.00	$148,125.00	$148,125.00	$148,125.00	$592,500.00
Civil Structures	$600,000.00	$600,000.00			$1,200,000.00
Station Primary Devices		$1,382,433.62	$1,382,433.62	$1,382,433.62	$4,147,300.87
UG Primary Structures			$602,558.26	$602,558.26	$1,205,116.51
Primary Structures & Devices			$457,900.12	$457,900.12	$915,800.24
Testing & Commissioning				$631,121.56	$631,121.56
Contingency	$378,095.01	$378,095.01	$378,095.01	$378,095.01	$1,512,380.02
Total Project Estimate:	***$1,126,220.01***	***$2,508,653.63***	***$2,969,112.00***	***$3,600,233.56***	***$10,204,219.20***

Station Maintenance Costing Summary:

MS - 5 (25MVA Transformer with Oil Containment)	
Project Name:	MS5 T2- Replace 25kVA Power Transformer including Oil Containment
Project #:	MS - 5
Location:	Oshawa On.
Capital Budget #:	MS - 5
Description:	Replace Power transformer with new 25kVA Tx unit c/w Oil Containment
Project Estimate:	$1,350,000.00

44kV Oil Circuit Breaker Replacement - (Per Unit Cost)	
Project Name:	44kV oil circuit breakers
Project #:	Oil Circuit Breaker Replacement
Location:	Various - Oshawa On.
Capital Budget #:	Oil Circuit Breaker Replacement
Description:	Proposed Replacement of OCB - Replace with SF6 breakers in outdoor enclosure
Project Estimate:	$170,000.00

Vacuum Main & Buss Tie Breakers:	
Project Name:	Vacuum Main & Buss Tie Breakers:
Option 1:	Retrofit, Like for Like
Cost Estimate:	$35,000.00
Option 2:	retrofit option upgrading to arc resistant units with remote racking
Cost Estimate:	$62,500.00
Option 3:	Upgrade to metal-clad indoor switchgear line-up fully arc resistant with remote racking
Cost Estimate:	$97,500.00

IV. Cost Estimate Criteria:

Overhead Rebuilds:

For the Overhead Rebuild, the following are the factors considered:

- Single Phase Primary Circuit
  - 1/0 ACSR Primary Conductors, unless otherwise provided by OPUCN
  - 45' CL. 2 Wood Poles, 40m spans
  - 28kV Insulators for 13.8kV System

- Three Phase Primary Circuit:
  - 556 MCM ASC Primary Conductors, unless otherwise provided by OPUCN
  - Pole selection is based on the nos. of circuits and voltage (combined with lower voltage), standard selection is 55' CL. 2 Wood Pole, 40-45m Spans
  - 28kV Insulators for 13.8kV System and 46kV Insulators for 44.0kV systems

- Neutral/Secondary:
  - 3/0 AACSR + 2x3/0 AAC Field Lashed
  - Secondary services are not to be replaced but will be tapped on the new secondary bus.

- Pole Installations:
  - Based on pole selection and materials.
  - Installation includes delivery and pole erection by conventional means.
  - We added an 'x' amount of pole for stub poles.

- Transformers:
  - A standard 75kVA 120/240V transformer and it's equivalent fuse link rating and arresters were used for costing for all transformer replacements, unless otherwise specified by OPUCN

- Framing, Stringing, Device Installations & setup.
    - Rates for framing, conductor stringing, and setups are based on a per unit assumption and span lengths. A table for recurring task was developed in order to come up with a per unit value and length rate involving specific number of staff, vehicle & materials.

- Removals:
    - Pole removals, including all necessary hardware and devices are based on a 10% cost of installation.

Underground Rebuilds:

For the Underground Rebuild, the following are the factors considered:

- Primary Cables
    - 1/0 Al. 15kV Primary Cables
    - Additional 5m of cables as primary slack in every transformer foundation.
    - Additional 25m of cables as primary riser for each riser terminations.
    - As the measurement provided for estimates, no additional buffer were included.

- Primary Risers & Terminations
    - All primary risers are replaced and split if they are on the same riser poles.

- Faulted Circuit Indicators
    - All primary incoming are installed with faulted circuit indicators.

- Primary Splices
    - As a rule of thumb, NBM determined that there should be at least 2 primary splice for every Kilometer of conductor.

- Civil Structures
  - 50mm HDPE Duct, by Directional Boring Method, unless otherwise specified.
  - For 3 phase system, 1-100mm separate ducts for each phases.
  - No spare ducts and electronic ball markers were considered
  - Abandon all existing direct buried UG Primary Cables
  - No Inspection work/allocation was considered in all of the UG Works.

- Transformers
  - As a rule of thumb, OPUCN requested that for every 5 transformers 2 will be replaced.
  - All foundations are considered to be re-used/existing including grounding.
  - Unless otherwise specified, a standard 75kVA Padmount Loop feed transformer was considered for all the Transformer Replacements.
  - 200A load break elbows are all replaced.
  - Removals are based on 4 staff + Vehicle cost

- Secondary Terminations:
  - Secondary terminations are based on the number of Transformers that are replaced.
  - Assumption of 8 services per Transformer was considered.

V. <u>Man Power, Vehicle Allocation & Costing:</u>

- Lead Hand – 43.9425 per Hour
- Regular Staff – 40.8765 per Hour
- Large Truck – 21 per Hour
- Small Truck – 21 per Hour

VI. Engineering:

- Engineering cost is based on an estimated 10% of the total construction estimate: Engineering is broken down into the following category:
    - Engineer – 10%
    - Technician – 35%
    - Drafting – 50%
    - Administration – 5%

VII. Professional Survey & Pole Staking:

- Professional Survey is based on a per kilometer rate of $10,000 for Overhead surveys and $19,000 for Underground surveys.
- Pole Staking is based on a ½ hr. per pole estimate.

VIII. Others:

- Municipal Consents are estimated to be $550.
- A 0.71 per m cost is included as part of the municipal application allocation.

IX. Burdens:

- Labour – Burdened at 50.23%
- Vehicle – Burdened at 34.00%
- Material – Burdened at 10.00%
- Foreman – Burdened at 54.00%
- Engineering – Unburdened
- Removals – are Burdened the same way as the installations

X. Contingencies:

- Overhead Rebuilds are considered to have 15% Contingency
- Underground Rebuilds are considered to have 25% Contingency (Factors for restorations are not considered on the estimates)
- Contingency applies to the total of the costs.

XI. Inflation:

- A 2.4% inflation rate is included as contingency for every incremental year.

Report Prepared by:

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Principal Engineer
NBM Engineering Inc.

INCENTIVE PROPOSALS

The Board's *Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach* (RRFE) continues the Board's emphasis on incenting Ontario's electricity distributors towards continuous improvement in productivity and cost performance, and sustainable savings from operational effectiveness.[1] In respect of Custom IR plans in particular, the Board has stated an expectation that productivity gains will be built into the rate adjustment over the term.[2] The RRFE also references consideration of incentives directed at innovation and encouragement of asset optimization (including through establishment of an "efficiency carry-over mechanism").[3]

OPUCN has built 3 forms of productivity incentive into its Custom IR proposal:

1. Self-imposed expectations for continued superior cost efficiency built into the budgets underlying OPUCN's revenue requirement forecasts, as validated by independent cost and produtivity benchmarking analysis.

2. A proposed *Total Cost Efficiency Carryover Mechanism* (TCECM), to continue to incent general efficiency initiatives, particularly later in the Custom IR rate plan period.

3. An innovative *Controllable Capital Investment Efficiency Incentive Mechanism* (CCIEIM) is proposed to incent OPUCN to control the costs of two major controllable capital investment programs. This proposed capital efficiency incentive mechanism reflects OPUCN's view that avoided rate base has permanent and significant value to ratepayers, and responds to the Board's stated interest in encouragement of innovation and asset optimization.

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[1] RRFE, page 2.
[2] RRFE, page 20 (top).
[3] RRFE, page 61.

Embedded Efficiencies

OPUCN is currently among the most cost efficient of Ontario's LDCs, and at the forecast costs underpinning this Custom IR proposal, it will remain so throughout the proposed rate plan period. The analysis which follows illustrates that:

1. OPUCN's capital expenditure per customer has historically averaged third lowest among its comparator group of Ontario LDCs, and OPUCN's average fixed assets per customer has historically been significantly below its comparator LDCs.

2. OPUCN's forecast average net fixed assets per customer in 2019 remains below the 2013 average for the comparable LDCs.

3. Historically OPUCN has managed with among the lowest levels of OM&A costs per customer of Ontario LDCs.

4. OPUCN's forecast OM&A cost per customer for 2019 is unchanged from its 2013 level. OPUCN has built into its revenue requirement requests an expectation of holding its annual average OM&A cost increases at approximately 2%, which is in line with core-inflation forecast and despite an annual customer growth forecast of 3%.

Embedded Capital Cost Efficiencies

The data presented in the following tables is taken from the Board's *Annual Yearbook of Electricity Distributors* and tracks the following measures for the years 2009 through 2013:

- Customer Growth
- Capital Expenditures per year
- Capital Expenditures per customer

- Net Fixed Assets per customer

Table 1: Comparator LDC Customer Growth Data

Customers	Brantford	Burlington	Cambridge	Guelph	Halton Hills	Kitchener	Milton	Newmarket	Oakville	Oshawa	Waterloo	Whitby	Veridian
2009	37,668	63,558	50,201	49,299	21,184	85,998	27,506	32,827	62,858	52,488	51,089	39,513	111,994
2010	37,654	64,329	50,890	50,250	20,790	86,611	29,142	32,911	62,674	52,710	51,914	39,669	112,569
2011	37,964	64,329	51,584	50,859	21,232	87,964	30,485	33,338	63,614	53,083	52,611	40,337	113,709
2012	38,260	65,377	51,983	51,553	20,893	89,025	32,324	33,883	64,106	53,361	53,387	40,915	115,280
2013	38,260	65,377	51,983	51,553	20,893	89,025	32,324	33,883	64,106	53,361	53,387	40,915	115,280
Average	37,961	64,594	51,328	50,703	20,998	87,725	30,356	33,368	63,472	53,001	52,478	40,270	113,766

Table 2: Comparator LDC Capital Expenditure Data

Capital Expenditures Per Year (Thousands)	Brantford	Burlington	Cambridge	Guelph	Halton Hills	Kitchener	Milton	Newmarket	Oakville	Oshawa	Waterloo	Whitby	Veridian
2009	5,760	18,081	10,500	16,475	3,366	15,260	7,367	5,921	19,045	6,351	17,409	5,525	30,741
2010	6,277	12,495	11,484	18,997	3,125	20,832	13,675	5,458	29,692	6,115	24,257	6,179	27,840
2011	4,877	10,310	9,845	24,307	4,345	22,910	9,626	6,433	29,861	18,284	38,215	5,080	25,290
2012	4,572	18,297	16,493	11,492	7,401	20,502	13,122	11,242	12,964	12,540	24,614	4,429	15,858
2013	4,572	18,297	16,493	11,492	7,401	20,502	13,122	11,242	12,964	12,540	24,614	4,429	15,858
Average	5,212	15,496	12,963	16,553	5,128	20,001	11,382	8,059	20,905	11,166	25,822	5,128	23,117

Table 3: Comparator LDC Capital Expenditure per Customer Data

Capital Expenditures Per Customer	Brantford	Burlington	Cambridge	Guelph	Halton Hills	Kitchener	Milton	Newmarket	Oakville	Oshawa	Waterloo	Whitby	Veridian
2009	153	284	209	334	159	177	268	180	303	121	341	140	274
2010	167	194	226	378	150	241	469	166	474	116	467	156	247
2011	128	160	191	478	205	260	316	193	469	344	726	126	222
2012	119	280	317	223	354	230	406	332	202	235	461	108	138
2013	119	280	317	223	354	230	406	332	202	235	461	108	138
Average	137	240	252	327	244	228	373	241	330	210	491	128	204

Table 4: Comparator LDC Net Fixed Assets per Customer Data

Net Fixed Assets Per Customer	Brantford	Burlington	Cambridge	Guelph	Halton Hills	Kitchener	Milton	Newmarket	Oakville	Oshawa	Waterloo	Whitby	Veridian
2009	1,592	1,330	1,669	1,838	1,404	1,638	1,560	1,522	1,766	992	2,154	1,582	1,330
2010	1,648	1,323	1,638	1,783	1,448	1,699	1,715	1,550	1,998	988	2,461	1,585	1,484
2011	1,645	1,339	1,655	2,222	1,485	1,780	1,770	1,549	2,223	1,178	2,933	1,559	1,565
2012	1,552	1,561	1,848	2,494	1,924	1,938	1,833	1,590	2,395	1,325	3,227	1,530	1,654
2013	1,547	1,553	1,999	2,561	2,125	2,011	1,784	1,597	2,422	1,436	3,279	1,671	1,720
Average	1,597	1,421	1,762	2,180	1,677	1,813	1,732	1,562	2,161	1,184	2,811	1,585	1,551

Consideration of this data for OPUCN and comparable Ontario LDCs indicates that:

- OPUCN's capital expenditure per customer for this historical period averaged third lowest among its comparators.
- OPUCN's average fixed assets per customer continues to be significantly below its comparator LDCs.

Comparing the average of the average net fixed assets per customer of the other LDCs for 2013 ($1,977), with OPUCN's average net fixed assets per customer ($1,436), and multiplying the difference ($1,977 - $1,436 = $541) by the OPUCN number of customers in 2013 (53,969), the difference in OPUCN's net fixed assets from the average of its comparators is approximately $29 million.

OPUCN's Distribution System Plan (Exhibit 2, Tab B) forecasts OPUCN's total net fixed assets in 2019 at $11,117,616. OPUCN's forecast number of customers in 2019 is 63,311 (using the definition of "customer" adopted by the Board for yearbook reporting purposes, which excludes street lighting, sentinel lighting, and USL connections). OPUCN's forecast average net fixed assets per customer in 2019 is $1,818, which remains below the 2013 average for the comparable LDCs. This analysis indicates to OPUCN that its planned capital investment levels remain fair and reasonable, and maintain OPUCN's current superior efficiency levels.

OPUCN retained NBM Engineering Inc. (NBM) to provide an independent view on the expected costs of OPUCN's System Renewal and System Service projects, as a benchmark against which the reasonableness of OPUCN's own Capital Investment Program cost forecasts can be assessed. A copy of NBM's report is filed as Exhibit 10, Tab B.

Page 4 of the NBM report presents NBM's cost estimates for each of the OPUCN plan period programs that NBM reviewed. NBM was not provided with OPUCN's cost forecasts for these programs, but rather was asked to develop its own cost estimates independently based on project descriptions provided by OPUCN and NBM's own inquiries of OPUCN to complete its understanding of the projects. Table 5 below maps the NBM cost summary for each of these programs against OPUCN's own costing for the subject programs, by plan year. The comparison illustrates the reasonableness of OPUCN's cost forecasts, which in each case are equal to, or less than, the cost estimates derived by NBM. (In the case of the proposed MS-9 DS, timing differences between NBM's estimates and OPUCN's forecast impact the annual costs, but total station costs over the period are lower in OPUCN's forecast than in NBM's estimate.)

Table 5: Comparison Between NBM and OPUCN Project Estimates

Summary Comparison between NBM and OPUCN Planned Projects Estimates			
2015 Cost Estimate Summary			
	NBM	**OPUCN**	**Comment**
Planned OH Projects	$2,858,334.07	$2,410,000.00	
Planned UG Projects	$962,687.65	$843,000.00	
Prop MS-9 Station	$1,126,220.01	$750,000.00	
MS10 Breaker Replace	$105,000.00	$105,000.00	
MS11 breaker replace	$105,000.00	$105,000.00	
2015 Total Estimate:	***$5,157,241.72***	***$4,213,000.00***	
2016 Cost Estimate Summary			
	NBM	**OPUCN**	**Comment**
Planned OH Projects	$2,344,241.52	$2,255,000.00	Does not include pole replacement program
Planned UG Projects	$1,367,338.42	$1,007,000.00	
Prop MS-9 Station	$2,508,653.63	$1,000,000.00	
MS2 Breaker Replace	$105,000.00	$100,000.00	
MS15 Breaker replace	$70,000.00	$40,000.00	
2016 Total Estimate:	***$6,395,233.57***	***$4,402,000.00***	
2017 Cost Estimate Summary			
	NBM	**OPUCN**	
Planned OH Projects	$1,978,695.91	$1,855,000.00	Does not include pole replacement program
Planned UG Projects	$1,413,165.00	$1,087,000.00	
Prop MS-9 Station	$2,969,112.00	$3,250,000.00	
44kV OCB Replacement	$680,000.00	$500,000.00	
2017 Total Estimate:	***$7,040,972.91***	***$6,692,000.00***	
2018 Cost Estimate Summary			
	NBM	**OPUCN**	**Comment**
Planned OH Projects	$2,174,744.72	$2,310,000.00	Does not include pole replacement program
Planned UG Projects	$1,868,038.00	$921,000.00	
MS-9 Station	$3,600,233.56	$3,000,000.00	
44kV OCB Replacement	$680,000.00	$500,000.00	
2018 Total Estimate:	***$8,323,016.28***	***$6,731,000.00***	
2019 Cost Estimate Summary			
	NBM	**OPUCN**	**Comment**
Planned OH Projects	$2,063,930.92	$1,917,000.00	Does not include pole replacement program
Planned UG Projects	$994,736.58	$904,000.00	
MS-5 Station	$1,350,000.00	$1,000,000.00	
44kV OCB Replacement	$510,000.00	$500,000.00	
2019 Total Estimate:	***$4,918,667.50***	***$4,321,000.00***	

Note: OPUCN's DS Plan includes $1M in 2019 for MS9 investments which is not included in this table. NBM assumed MS9 investment completed in 2018. OPUCN forecasts completing MS9 investment in 2019. NBM does not include MS9 amounts in 2019, so the presentation of OPUCN costs in this table excludes 2019 MS9 costs as well. Total forecast OPUCN cost for MS9 and associated feeders is $9 million compared to NBM's total cost of $10.2 million.

OPUCN also retained METSCO Energy Solutions (METSCO) to provide an *Asset Condition Assessment Report and Asset Management Plan* which documents METSCO's review of the status of OPUCN's distribution infrastructure and identification of critical and high priority asset investment requirements. Though not commissioned to do so, METSCO also produced summary costing for the capital investments identified in the METSCO report for sustainment of OPUCN's fixed assets.

Table 6 below maps MESTCO's cost estimates against OPUCN's for each of the relevant System Renewal capital program categories during the plan period.

Table 6: METSCO and OPUCN Budget Summary Comparison

SYSTEM RENEWAL - METSCO AND OPUCN BUDGET SUMMARY COMPARISON

CAPITAL INVESTMENTS CATEGORY	2015 OPUCN	2015 METSCO	2016	2016 METSCO	2017	2017 METSCO	2018	2018 METSCO	2019	2019 METSCO	Total OPUCN 2015-2019	Total METSCO 2015 - 2019
SYSTEM RENEWAL	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**	**$'000**
OH REBUILDS	2,410	2,727	2,455	2,727	2,055	2,347	2,510	2,347	2,117	2,347	11,547	12,498
UG REBUILDS	1,133	1,394	1,007	1,394	1,087	1,394	921	1,594	904	1,444	5,052	7,223
STATIONS REBUILDS	510	183	640	183	500	500	500	500	1,000	1,375	3,150	2,744
Total Planned Plant Rebuilds	***4,053***	***4,304***	***4,102***	***4,304***	***3,642***	***4,241***	***3,931***	***4,441***	***4,021***	***5,166***	***19,749***	***22,465***
Reactive/emergency Plant Replacement	830		830		830		830		830		4,150	
TOTAL SYSTEM RENEWAL (OH, UG and Stations rebuilds)	**4,883**	**4,304**	**4,932**	**4,304**	**4,472**	**4,241**	**4,761**	**4,441**	**4,851**	**5,166**	**23,899**	**22,465**

Note:
1) METSCO's Capital Budgetary investments include only Planned replacements.
2) In 2015, OPUCN Station rebuilds included MS14 Switchgear Carry over
3) OPUCN starts the 3 year replacement program of the 44KV Oil circuit breakers in 2016; whereas METSCO suggested start date is 2017
4) Over the 5 year period, OPUCN is higher than METSCO by ~$1.4M but this gap is subject to the amount of actual Emergency replacements that occur annually

OPUCN's forecast costs for these programs exceed those provided by METSCO by approximately 6.7% over the plan period (approximately $1.5 million). However, OPUCN's comparative figures include unplanned, "reactive" asset replacements[4], a separate provision for which totals approximately $830,000 per year, or $4.15 million over the plan term, in <u>addition</u> to identified System Renewal projects. METSCO's figures do not include provision for such unplanned "reactive" asset replacements. When OPUCN's reactive System Renewal provisions are deducted from OPUCN's total forecast costs for these System Renewal programs, OPUCN's forecast costs for the

[4] Discussed in OPUCN's Distribution System Plan (Exhibit 2, Tab B) at Part I, Section 2., subsection c.(ii)

subject programs are less than METSCO's cost estimates by approximately $2.65 million over the plan period, or $543 thousand annually.

Embedded OM&A Cost Efficiencies

OPUCN also compared its historical net OM&A per customer levels with those of its comparators, as indicated in Table 7.

Table 7: Comparator LDC Net OM&A per Customer Data

Net OM&A Per Customer	Brantford	Burlington	Cambridge	Guelph	Halton Hills	Kitchener	Milton	Newmarket	Oakville	Oshawa	Waterloo	Whitby	Veridian
2009	205	208	197	194	209	142	195	199	163	168	172	214	174
2010	201	218	188	195	211	142	192	203	176	168	191	223	183
2011	176	225	209	251	227	155	210	198	206	191	182	214	181
2012	199	252	266	267	283	189	209	240	223	211	220	219	238
2013	199	252	266	267	283	189	209	240	223	211	220	219	238
Average	196	231	225	235	243	163	203	216	198	190	197	218	203

This data indicates that historically OPUCN has managed with among the lowest levels of OM&A costs per customer.

Table 8 sets out OPUCN's forecast OM&A costs for the Custom IR plan period (along with 2012 Board approved, 2012 and 2013 actuals, and preliminary 2014 actuals):

Table 8: Actual & Forecast OM&A Costs

Account Description	Board-Approved	Actual		Bridge Year	Test Years at Proposed Rates				
	2012	2012	2013	2014	2015	2016	2017	2018	2019
OM&A Costs	11,480,220	11,240,450	11,210,095	11,291,473	12,145,702	12,614,203	12,886,688	13,109,806	13,183,490

Annual OM&A is forecast to increase $1.7 million from the last Board approved amount by 2019. This is an average annual increase of 2%. The Conference Board of Canada published Consumer Price Index (CPI) percentage increases for Oshawa are set out in Table 9.

Table 9: Conference Board of Canada CPI for Oshawa

Year	2012	2013	2014	2015	2016	2017	2018
CPI	1.7%	1.3%	2.3%	2.6%	2.6%	2.7%	2.7%

OPUCN's forecast average annual OM&A increase for the 2015 – 2018 period of 2% is below the Conference Board of Canada forecasts for Oshawa.

OPUCN forecasts its OM&A cost per customer for 2019 (using the 63,311 customer number for 2019 as indicated above under the embedded capital cost efficiency analysis) at $208, unchanged from 2013. This results from forecast OM&A costs increases being held at approximately 2% per year, in the face of customer growth forecast at 3% per year. In order to maintain OM&A per customer costs at current levels, OPUCN must operate more efficiently in future than it does presently.

The key driver to this achievement will be maintaining full-time equivalent employees (FTEs) at today's level. Labour and benefit costs represent over 60% of gross OM&A costs. Table 10 presents customers per FTE reported in the Board's *Annual Yearbook of Electricity Distributors* for OPUCN and comparable LDCs for the years and LDCs for which data is available in the Board's reports.

Table 10: Ontario LDC Customers per FTE Data

Customers per FTE	Brantford	Burlington	Cambridge	Guelph	Halton Hills
2011	584	684	543	484	433
2012	554	711	541	491	418
2013	602	695	517	459	413
Average	580	697	534	478	422

Customers per FTE	Milton	Newmarket	Oakville	Oshawa	Waterloo	Veridian
2011	663	585	595	717	454	519
2012	673	594	583	711	449	517
2013	655	607	579	750	395	517
Average	664	596	585	726	433	518

Oshawa's average for the three year historical period (726) is well above the other LDCs and the overall average for the LDCs listed (551), indicating that OPUCN has been serving customers in an efficient manner. OPUCN's Customers per FTE is forecast to be 782 in 2019, which is an efficiency enhancement equivalent to avoiding approximately 6 FTEs that would otherwise be added.

Other OM&A costs are forecast to increase by $0.7 million or 2% on average per year, still below externally forecast inflation levels for Oshawa.

All of the foregoing analysis demonstrates that over the Custom IR plan period, OPUCN will continue to maintain and improve its customer service at sector leading cost levels.

Total Cost Benchmarking Analysis

The RRFE indicates the Board's conclusion that total cost benchmarking will continue to be important in informing rate setting.[5]

In support of its Custom IR proposal, OPUCN retained Pacific Economics Group LLC (PEG) to appraise OPUCN's forecast total cost for the Custom IR Plan period against an econometrically determined forecast benchmark total cost. PEG's analysis indicates that OPUCN's Custom IR Plan cost forecasts maintain superior cost efficiency levels.

PEG is a leading utility cost research consultancy and has filed rigorous benchmarking and productivity studies in regulatory proceedings for two decades. In Ontario PEG has provided benchmarking evidence for Enbridge Gas Distribution and Hydro One Networks, and has twice developed power distributor benchmarking and productivity studies for the Board. The Board has used PEG's studies to set x factors in IR price escalation formulas and to develop econometric total cost benchmarking models along with a study of trends in the productivity of Ontario power distributors in support of the

[5] RRFE, page 60.

Board's IR rate-setting framework. PEG's report - *Benchmarking the Forecasted Cost of Oshawa PUC Networks (18 December 2014)* – is filed as Exhibit 10, Tab A.

Using the Board's econometric total cost model for OPUCN PEG benchmarked the 2015 – 2019 cost forecasts underlying this Custom IR application. PEG's conclusion is that OPUCN's cost performance will gradually rise from a level commensurate with a Group III stretch factor in 2015 to levels commensurate with a Group II stretch factor in later years of the plan. Forecast cost will be 11.7% below the econometric cost benchmark on average.

In addition to the benchmarking analysis, PEG calculated the productivity growth implicit in OPUCN's cost forecast. PEG found that the productivity of OPUCN's operation, maintenance, and administration inputs would average 2.17% annual growth. The productivity of OPUCN's capital inputs would average 0.12% growth. Total factor productivity would average 0.87% annual growth.

Table 11 compares the productivity trends embedded in OPUCN's Custom IR application as assessed by PEG with the average trends for Ontario power distributors. Compared to both the nine-year 2003 through 2011 period and the ten-year 2003 through 2012 period, the forecasted 2015 through 2019 OM&A and total factor productivity trends of OPUCN are well above the average historical trends for the industry.

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).

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[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 is also responsive to the Board's stated intention in the RRFE to develop incentives to encourage innovation and asset optimization.[12]

The purpose of OPUCN's proposed CCIEIM is to mitigate, to some extent, the <u>dis</u>incentive to control capital expenditure and thus avoid rate base. The CCEIM is designed to incent OPUCN to control the costs of its controllable capital investment programs (its System Renewal Capital Investment Program and its investment in a new municipal substation and associated feeders) by allowing revenue requirement impacts of variances between forecast and actual capital investment for these programs to be shared between OPUCN and its ratepayers.

The CCIEIM would be applied as follows:

1. Two major capital investment programs are identified for incentive treatment:

    a. System renewal program (overhead, underground and station rebuilds required to maintain grid reliability) forecast at approximately $19.75 million; and

    b. New municipal substation and associated distribution feeders forecast at approximately $9 million.

2. Actual costs over the plan period will be tracked for each of these programs.

3. Variances from approved capital costs for each of these programs will be subject to the following efficiency incentive treatment:

    For each program, the revenue requirement benefit/burden of variances from the approved capital spending forecast will be shared between OPUCN and ratepayers on a 50:50 basis;

    i. If the variance is positive (i.e. OPUCN executes the capital program at a cost lower than approved), OPUCN will earn an incentive equal to the revenue requirement impact of 50% of the avoided rate base

[12] RRFE, page 61.

costs, for the duration of the average depreciation period for the capital items included in the program; or

ii. If the variance is negative (i.e. OPUCN spends more on the capital program than approved), OPUCN will only be able to include 50% of the incremental capital costs in its rate base following the end of the Custom Rate Plan term.

The incremental benefit/burden accruing to OPUCN under the CCIEIM would be included in any off ramp calculation following the inclusion of such benefit/burden in OPUCN rates. (That is, the CCIEIM would effectively be subject to, and thus bounded by, the Board's general off ramp parameters.)

If any capital projects included in the subject capital program are not completed by the end of the Custom IR Plan term for reasons beyond OPUCN's reasonable control (examples would include labour stoppages, weather or environmental delays, equipment delivery delays), the costs of those projects not completed will be removed for the purpose of applying the CCIEIM to the balance of the completed program.

OPUCN is requesting approval of a new variance account to capture that portion of the variance in its actual from forecast costs for execution of the two controllable capital programs (proposed as 50%) that is eligible for CCIEIM treatment (with a sub-account for each of the programs to allow for separate tracking). At the end of the rate plan period, OPUCN will bring forward its request for disposition of the revenue requirement impact of the balance in this account through a rate rider in accord with the CCIEIM as proposed. Such application for disposal and CCIEIM rate rider will be supported by evidence demonstrating completion of the subject capital program (subject to uncontrollable delays as noted above) and detailing the final scope of the program (relative to the scope and criteria proposed in OPUCN's Distribution System Plan filed as Exhibit 2, Tab B in this application) and its final costs. The onus will be on OPUCN to demonstrate that the completed projects achieve the results of the capital program as reflected in the scope and criteria for the projects defined in OPUCN's Distribution System Plan.

OPUCN's CCIEIM proposal is innovative, but not unprecedented. It is informed by, and to some extent modelled on, an incentive mechanism developed by the U.K. Office of Gas and Electricity Markets (Ofgem) in its *Revenue Using Incentives to Deliver Innovation and Outputs Model* (RIIO Model).[13]

The RIIO Model focuses on risk sharing and efficiency incentives within the term of the extended price control period applied by Ofgem to regulated gas and electricity network services providers. The RIIO Model establishes an upfront (ex ante) price control that sets the outputs that network companies, including electricity distribution companies, are required to deliver, and the revenue they are entitled to earn for delivering these outputs. The RIIO Model contemplates an eight year price control period. During this period, a utility will be assigned an efficiency incentive rate.

Under the RIIO incentive model, the Regulatory Asset Value (RAV)[14] of the utility (which is effectively its rate base for price setting purposes) will be adjusted upward (from ex ante determined) at a fraction of any over spend[15]. The RAV will be adjusted downward (from ex ante determined) at a fraction of any under spend. The fraction is determined by application of the pre-set, symmetric efficiency rate.

[13] Ofgem is currently in the process of finalizing its RIIO-ED1 Business Plan, which will set the outputs that distribution network operators (DNOs) are allowed to collect. It is intended that this will apply to DNOs for 8 years from April 1, 2015 to March 31, 2023. Ofgem is also in the process of finalizing its ET1 Price Control Financial Handbook.
[14] RAV is defined by Ofgem as the value ascribed by Ofgem to the capital employed in the licensee's regulated distribution or (as the case may be) transmission business (the regulated asset base). The AV is calculated by summing an estimate of the initial market value of each licensee's regulated asset base at privatization and all subsequent allowed additions to it at historical cost, and deducting annual depreciation amounts calculated in accordance with established regulated methods… The RAV is indexed to RPI in order to allow for the effects of inflation on the licensee's capital stock.
[15] Handbook, pg. 87 at s. 10.17.

Ofgem's RIIO Handbook describes the efficiency incentive regime in the following manner:

> *10.16 The rules will give equal treatment to different types of expenditure. For example, the breakdown of over-spend (or under-spend) between operating and capital expenditure will not affect the amount, or timing, of money the company is allowed to collect from customers. A fixed proportion of any over-spend (or under-spend) will feed through to the revenue the company can collect in the subsequent year. The remainder will feed through to the RAV and, in turn, affect the revenue the company can collect in future years. Within the price control period we will make revenue adjustments reflecting this change to the RAV.*
>
> *10.17 The level of the incentive rate will determine the extent to which the RAV is adjusted in light of a given over-spend or under-spend. For instance, in the case of an over-spend in a given year, there will be an upward adjustment to the RAV but, as the incentive rate will be above zero, the adjustment will be smaller than the overspend itself. The higher the incentive rate, the larger the adjustment. As such, the RAV will not track actual expenditure but reflect a combination of expenditure forecast by Ofgem at the price control review and the actual expenditure incurred.*
>
> *…*
>
> *10.19 Provided that a company delivered the outputs agreed at the price control review, it will enjoy the benefit of any under spend relative to the expenditure assumed in the price control, in line with the specified incentive rate.*
>
> *10.20 If a company spends more than envisaged at the price control review it will receive additional revenue, in line with the commitment given by the incentive rate (e.g. 40 percent of the value of the over-spend). We will not provide additional funding on a discretionary basis to compensate for unexpectedly high expenditure.*[16]

The RIIO Handbook includes the following brief example of how the efficiency incentive regime operates:

[16] Handbook, pg. 87-88.

> *If the efficiency incentive is set at 40 percent, the company's investors will earn $40 profit (before tax) for each $100 that the company saves during the price control period and bear $40 for each additional $100 the company spends. The remainder will be passed on to consumers through lower or higher network charges.*[17]

OPUCN's CCIEIM proposal incorporates the basic design of Ofgem's RIIO incentive model. As Ontario does not use a "RAV" mechanism for setting rates, OPUCN proposes to implement its CCIEIM through application of a rate rider to a cost of service determined rate base recognizing the benefit/burden resulting from the application of the RIIO incentive principles to OPUCN's two identified major controllable capital investment programs. Like RIIO's incentive model, OPUCN's CCIEIM proposal:

a. Introduces innovation in managing capital invest programs to reflect the long-term value to ratepayers of avoided rate base investment, provided that the same service outcomes are achieved.

b. Is symmetrical, such that OPUCN will have the incentive to earn a premium on a fraction of the permanently avoided rate base investment, and conversely will suffer the burden of only being able to earn the allowed return on a fraction of the rate base that exceeds its approved and committed investment forecast.

OPUCN proposes that its CCIEIM will apply only to two discrete, but significant, controllable capital programs. This will allow the Board, OPUCN, and other interested parties to adopt a novel and considered risk/reward mechanism in a controllable fashion. OPUCN also intends its CCIEIM mechanism to apply within the framework of the Board's "off ramp" policy for electricity distributors, in order to protect both OPUCN's shareholder and OPUCN's ratepayers at the outside boundaries of risk/reward tolerance already established by the Board.

[17] Handbook, pg. 84 at s. 10.5.

CUSTOM IR PLAN ANNUAL RATE ADJUSTMENT PROCESS

OPUCN has applied to set its rates for the distribution of electricity for the year commencing January 1, 2015. OPUCN has also applied to set its rates now for each of the years commencing January 1, 2016, January 1, 2017, January 1, 2018 and January 1, 2019 (collectively the Future Test Years). In support of its requests, OPUCN has provided detailed cost of service evidence, including a robust Distribution System Plan (DS Plan), covering the proposed 5 year Custom IR Plan period.

Given the 5 year term of OPUCN's proposed Custom IR rate plan, OPUCN is proposing that its rates determined now for the Future Test Years be subject to certain adjustments to reflect cost and revenue changes which could be material and which arise from external developments which are beyond OPUCN's ability to accurately predict or to control.

OPUCN recognizes that despite a careful and rigorous approach to its forecast of new customer loads and associated capital expenditures, and its best planning in response to information regarding third party requirements for relocation of distribution infrastructure, there are significant risks of forecast error in these parameters over the five-year planning period. OPUCN is particularly concerned that events outside of its control could delay or reduce the expected growth in the community and/or the schedule for asset relocation in response to municipal, regional and third party requirements. Without adjustment during the plan term for such delay or reduction in development activity, the rates approved at this time could significantly over-recover or under-recover relative to OPUCN's later year costs. Significant under recovery is possible in the event that as a result of the current regional planning process for the GTA East region the contribution required of OPUCN for upstream transmission reinforcement by Hydro One Transmission materially exceeds the $6.5 million currently 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, changes to codes or standards and changes in accounting requirements or the regulatory framework.

OPUCN has not requested disposition of its 2013 deferral accounts, as their balances at December 31, 2013 were not material. OPUCN is proposing an annual review of its deferral account balances and in the event that those balances become sufficiently large OPUCN will seek an order to dispose of such balances in the following test year.

Contributions to Hydro One Networks Inc. and Distribution System Regional Planning Investments

OPUCN has included $6.5 million in its Capital Investment Plan for contributions to Hydro One Networks Inc. (HONI) Transmission to address transmission capacity constraints in supply to the City of Oshawa. This figure was initially developed in consultation with HONI, in response to identification of a solution involving the addition of two new feeder breaker positions at each of the Wilson and Thornton transmission stations. The discussions giving rise to this estimate predated the formal Regional Planning initiative now in process.

Since commencement of a formal Regional Planning Process for the GTA East Region mid-way through 2014, and as set out in HONI's most recent updated regional planning status letter (dated December 12, 2014, see Exhibit 2, Tab B, Schedule 2), HONI, as Lead Transmitter in that process has indicated that: i) in light of the updated total peak load forecast for the GTA East Region, the option of adding two new feeder breaker positions at each of the Wilson and Thornton transmission stations is no longer deemed to be a viable permanent solution and a new 230/44 KV transmission station will be required to be in service in 2018/2019; and ii) the local planning study team is also reviewing interim options to ensure sufficient supply capacity to the region pending the now anticipated transmission station coming into service in 2018/2019.

HONI has been unable to date to confirm OPUCN's contribution for the permanent (transmission station) capacity constraint relief solution, but has indicated that such contribution "could be in the range of $10 million to $12 million". [1] Additional contribution for an interim solution is not yet quantified. In the absence of better information, OPUCN has retained its initial $6.5 million estimate in this DS Plan for transmission investment contributions to HONI. HONI has indicated that it expects the local planning to be complete in Q1, 2015, at which time this estimate can be updated.

Given that the actual amount and timing of contributions to Hydro One Transmission by OPUCN to secure continued reliable electricity supply to OPUCN's customers are: i) subject to material change; and ii) completely outside of OPUCN's control or ability to forecast, OPUCN is proposing to track the revenue requirement impact of any variance from the approved budget for this cost item.

OPUCN is also proposing to track revenue requirement impact of the cost of other unbudgeted distribution projects that may be required as a result of regional planning and in order to serve OPUCN's distribution area.

OPUCN anticipates that once these contributions and any other unbudgeted regional planning driven costs, and the timing for such contributions and costs, are finalized, it would file in the next annual rate adjustment process the calculations demonstrating the revenue requirement impact of variances in this cost item and would seek a rate rider adjustment to provide for recovery of such revenue requirement impacts in rates for the balance of the Custom IR term.

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[1] If a new transmission station is the permanent capacity constraint relief solution, then in addition to contribution towards the cost of a new transmission station OPUCN would have to make additional distribution system investments. OPUCN has preliminarily identified the potential need for approximately 5 km of 44 kV overhead primary distribution lines extending from the proposed transmission station to OPUCN's new proposed distribution station (MS9), at an additional, distribution system, investment of approximately $3.5 million in the 2018/2019 time frame.

Hydro One Transmission and the OPA expect it will take four to five years to complete all the Regional Plans. Apart from contributions to Hydro One Transmission for required upgrades to transmission infrastructure as addressed above, if any of the Regional Plans create the need for an unbudgeted distribution project during the Custom IR term, a rate rider would be sought to effect recovery of the adjusted revenue requirement during the balance of the Custom IR Plan period.

Relocation of OPUCN Distribution Plant in Response to 3rd Party Requests

One of the main drivers of OPUCN's Capital Investment Plan and its Custom IR Plan proposal is 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. OPUCN has included in its Distribution System Plan approximately $8 million for plant relocation in relation to the extension of the 407 ETR Highway and related municipal roadway redirection. The timing and estimated cost for these projects could change materially from OPUCN's estimates, and is entirely dependent on the timing and scope of the infrastructure projects of third parties. Variances in OPUCN costs arising from changes in third party requirements and timing could either increase or decrease costs, or both, in any given year and overall over the Custom IR plan term.

OPUCN thus proposes to capture in a variance account - Distribution Plant Relocation Cost Variance Account (DPRCVA) - the revenue requirement impact of variances in the costs of externally driven plant relocations embedded in its forecasts for the Custom IR plan period. Given that the direction of such variances could vary over the course of the plan period (i.e. up or down, or both), OPUCN proposes to bring the balance in this account forward for disposition at the end of the 5 year plan period.

OPUCN will include information about the updated variance account balance and drivers for changes in the account balance as part of its annual rate adjustment process filing, so that the Board and interested parties can track changes in this account and the reasons therefore.

Updated Customer Connection & Volume Forecasts

A second key driver of OPUCN's Capital Investment Plan and this Custom IR Plan proposal is the forecast 3% annual average growth in customer connections and aggregate customer demand levels over the 2015 – 2019 plan period.

In addition to driving OPUCN's capital expenditures, the timing of new customer connections has a major impact on distribution revenue for a given rate level. While development in the City of Oshawa is proceeding quickly, any development slowdown within OPUCN's 5 year plan term could significantly erode forecast distribution revenue at the rates approved now, which is a particular risk in the later years of the plan. Further, such distribution revenue could be reduced despite the capital investments to support the eventual addition of load (such as investment in OPUCN's new distribution station) having been made.

It is difficult to predict with assurance the pace of new customer connections up to 5 years forward. Realizing the expected population growth of nearly 20% (relative to 2012) through 2019 is premised upon the completion of the 407 ETR Highway, and the timing and magnitude of residential and commercial development. Further, even if load materializes when forecast, CDM activities and new home energy efficiency standards could significantly impact customer volumes, and are again difficult to predict with assurance up to 5 years in the future. OPUCN does not believe it appropriate for customers to pay for net new connection costs forecast but which fail to materialize within the time frames currently anticipated.

Accordingly, OPUCN is proposing to adjust its rates annually to account for changes in: i) forecast revenue indicated by updated customer growth, demand and consumption forecasts; and ii) associated actual and forecast net new connection costs (including system expansion and metering costs).

OPUCN has also proposed a variance account - the Net New Connection Cost Variance Account (NNCCVA) - to capture the revenue requirement impact of the difference between the net costs of new customer connections (including system expansion and metering costs) embedded in its forecasts for each of the Custom IR plan period test years and actual net costs incurred to connect new customers in each year of the plan term. Given that the direction of such variances could vary over the course of the plan period (i.e. up or down, or both), OPUCN proposes to bring the balance in this account forward for disposition at the end of the 5 year plan period.

OPUCN will file evidence in its annual rate adjustment process regarding its updated customer growth, demand and consumption forecasts, and its actual net new connection costs.

Updated Cost of Capital

As documented in the *Report of the Board on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379) issued November 21, 2013, the Board intends to update the Cost of Capital parameters for setting rates in applications once per year. As indicated in Exhibit 5 – Cost of Capital and Capital Structure, for purposes of this rate application, OPUCN has used the most recent cost of capital parameters issued by the Board on November 20, 2014 in its *Cost of Capital Parameter Updates for 2015 Applications for Rates with Effective Dates in 2015* (Cost of Capital Updates) for the 2015 through 2019 Test Years.

OPUCN proposes to update the ROE and short term debt rates in the annual rate adjustment process for each of the Future Test Years. OPUCN also proposes to update each year its long term debt rate as required to reflect; i) the then current weighted average of actual rates applicable to OPUCN's funded long term debt; and ii) revisions to the Board's prescribed long term debt rate for unfunded deemed debt.

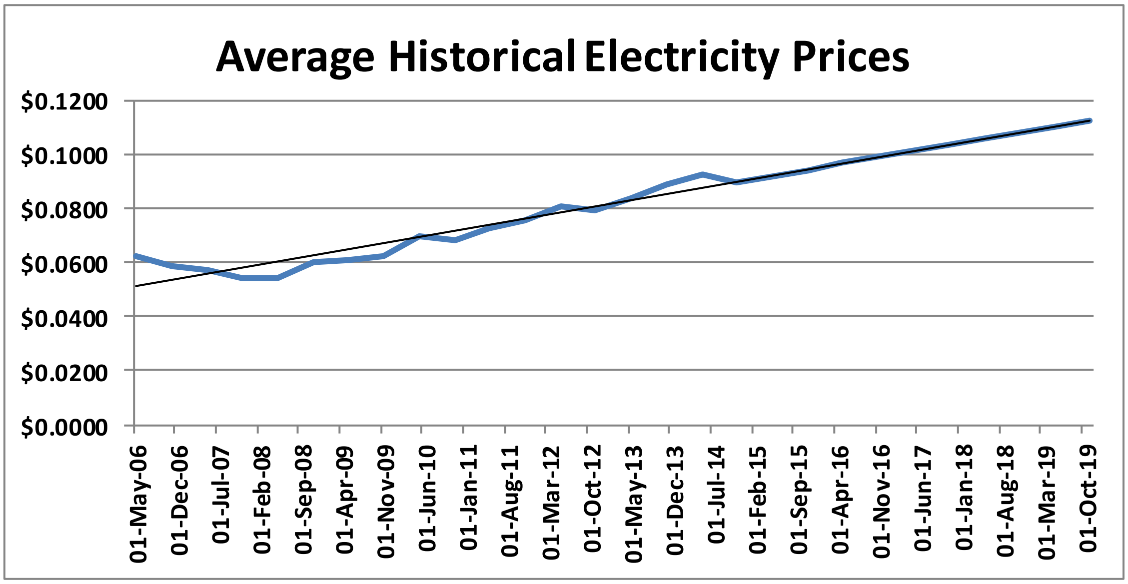
OPUCN will file as part of its annual rate adjustment process revised cost of capital and resulting rate adjustment calculations for the upcoming test year.

Cost of Power Related Updates

OPUCN's working capital allowance will vary depending on the commodity prices it has to pay for electricity and other third party flow through charges. OPUCN must purchase the electricity for its customers and then bill and collect for that amount from customers at a later date.

As illustrated in Figure 1, historically the change in rates for cost of power and other flow through charges has been volatile and in recent years the increases have been substantially greater than inflation. The figure plots the linear trend from historical average electricity price data available from 2006.

Figure 1



Since the commodity cost and other charges are beyond the control of distributors and the appropriate amount can be calculated in a consistent and transparent manner, OPUCN is proposing to adjust its forecast working capital allowance to reflect changes in cost of power as published by the Board each year, rather than speculating now on power costs up to 5 years in the future.

As part of its annual rate adjustment process, OPUCN will file an updated working capital calculation based on the most recent OEB cost of power forecast. In this manner, OPUCN assumes the risk for changes in cost of power within the test year, but is not exposed to escalating working capital requirements accumulating and compounding over the five year period as a result of ongoing escalation in the cost of power.

ANNUAL REPORTING

OPUCN has separately described (Exhibit 10, Tab E) an annual rate adjustment process in which it will:

1. Seek adjustment of its Custom IR rates for the upcoming test years 2016 through 2019 to reflect; i) updated customer connection, demand and volume forecasts, and associated new connection capital investment requirements (including system expansion and metering); ii) updated cost of capital parameters; and iii) updated cost of power related working capital requirements. Evidence in respect of each of these annual adjustments will be filed.

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 will be tracked, and brought forward for future disposition (once the Hydro One contributions and associated regional planning distribution investment requirements are known, in the case of that cost item, and at the end of the Custom IR Plan period in the case of the third party requirements cost item).

In the *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (RRFE) the Board indicated its intention to monitor Custom IR period approved capital spending by requiring distributors to report annually on actual amounts spent.[1] OPUCN has filed in support of this Custom IR application a comprehensive Distribution System Plan (DS Plan), which includes program level planned capital investment details, categorized in accord with the investment categories defined in the Board's *Filing Requirements for Electricity Distributor Rate Applications (July 17, 2013)*

[1] RRFE Report, page 20.

(i.e. system access, system renewal, system service and general plant). To respond to the Board's stated objective of monitoring Custom IR period capital spending against the approved Capital Investment Plan, OPUCN proposes to annually file program level capital spending updates using these categories, and a comparison of updated capital program spending compared to the DS Plan program spending as presented and approved in this application. Such updates will include identification and discussion of the reasons for any material variance between OPUCN's capital investment plan as approved in this proceeding and updated actual and forecast capital spending as at the time of the annual rate adjustment filing. OPUCN will provide sufficient detail to allow the Board to monitor OPUCN's adherence to its Capital Investment Plan approved in this proceeding.

OPUCN is also subject to comprehensive reporting requirements under the Board's *Electricity Reporting & Record Keeping Requirements* (RRR), as recently updated (Version dated March 7, 2014) to incorporate incremental reporting requirements to implement the Board's electricity distributor Scorecard. These RRR requirements include reporting on many parameters relevant to OPUCN's request for Custom IR Plan approval, including:

a. Deferral and variance account balances.

b. Customer numbers.

c. Annual consumption.

d. Annual load.

e. Service quality and performance metrics (new service connection responsiveness, appointment scheduling, telephone answering, written inquiry response, emergency response, reconnection performance, system reliability metrics [SAIDI/SAIFI], outage causes).

f. System performance impacts of adoption of new distribution system technologies.

g. Employee numbers and total salary levels.

h. Circuit kilometers of line.

i. Regulated ROE.

j. Load control devices installed.

k. Customer satisfaction survey results.

l. Distribution System Plan implementation progress.

As was the case in the Custom IR approvals recently granted to Enbridge Gas Distribution[2] and Horizon Utilities Corporation[3], OPUCN proposes to provide interested parties with its RRR filings, through inclusion in its annual rate adjustment applications of the information provided in these filings.

In respect of customer numbers, annual consumption and annual load, OPUCN will also be filing annually updated forecasts, in support of its requested annual rate adjustment to account for revenue and cost variances from forecast driven by changes in the extent and timing of new customer connections.

OPUCN also proposes to include in its annual rate adjustment filings the information not already included in its RRR filings or in the evidence required to support its annual rate adjustments, and which Union Gas Limited[4] and Enbridge Gas Distribution[5] agreed to file annually during their respective most recently approved 5 year rate plans. This information is as follows, in each case for the most recent historical year:

a. Calculation of revenue deficiency/sufficiency.

b. Statement of utility income.

c. Statement of earnings before interest and taxes.

d. Summary of cost of capital.

[2] EB-2012-0459, Decision with Reasons, page 79.
[3] EB-2014-0002, Settlement Proposal, page 29.
[4] EB-2013-0202, Settlement Agreement, page 26.
[5] EB-2012-0459, Decision with Reasons, page 79.

e. Other revenue.

f. Operating and maintenance expense by cost type.

g. Calculation of PILS.

h. Calculation of capital cost allowance.

i. Provision for depreciation, amortization and depletion.

j. Statement of utility rate base.

k. Audited financial statements.