EB-2014-0002

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

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

REPLY ARGUMENT COMPENDIUM

FILED OCTOBER 23, 2014

EXHIBIT K6.1

REPLY ARGUMENT COMPENDIUM
HORIZON UTILITIES CORPORATION
EB-2014-0002

OCTOBER 23, 2014

16. Extracts from Board Decisions related to payment for assets used

17. EnWin customer class definitions:

    Large Use – Regular;

    Large Use – 3TS;

    Large Use – Ford Annex.

18. News reports on U.S. Steel Canada CCAA filing

TOR01: 5740902: v1

Ontario Energy Board

EB-2012-0410

Draft Report of the Board

Rate Design for Electricity Distributors

March 31, 2014

1 Introduction

The Ontario Energy Board has a new framework for the regulation of utilities. The Board's renewed regulatory framework is a comprehensive performance-based approach to regulation that aims to better align consumer and utility interests, support the achievement of important public policy objectives and place a greater focus on delivering value. Effective rate design for revenue recovery is an important element to achieving these objectives. While the regulatory and policy environment has evolved significantly over the years, the rate design has not been altered. The Board indicated in its Renewed Regulatory Framework for Electricity Report ("the RRFE Report") issued October 18, 2012, that it would proceed with the review of revenue decoupling that was suspended in 2010. Revenue decoupling is a regulatory framework that seeks to break the link between a distributor's revenue recovery and consumer consumption of energy.

The Board intends to pursue a fixed rate design solution to achieve revenue decoupling. The Board believes that a fixed rate design for recovery of electricity distribution costs is the most effective rate design for ensuring that rates reflect the cost drivers for the distribution system and best responds to the current environment.

- The Board believes that when consumers[1] understand what costs are being recovered in the amount they are being charged for the use of the distribution system, they are equipped to make informed choices about their use, their investments and the value of being connected.

- The Board's regulatory framework emphasizes the need for distributors to achieve sustained productivity improvements through effective asset management and planning that will optimize investments. The Board's rate

[1] Throughout this Report "consumer" is used to mean anyone who consumes energy while "customer" is used as someone who pays a distribution bill. Thus customer is synonymous with "ratepayer."

- design policy best provides predictable and stable revenues necessary to implement the distributor capital investment plans.

- The government has stated in its Long Term Energy Plan that distributors will have an increased responsibility in the delivery of conservation programs to customers to help achieve the Conservation First policy to meet future energy needs. The Board's policy direction eliminates any disincentive to that role.

The purpose of this draft Report is to articulate the Board policy on implementing a new rate design for electricity distributors; to explain why the Board recognizes that a change to the rate design is appropriate at this time and to solicit stakeholder input on the best approach and design for moving forward.

This draft Report presents three proposals to achieve revenue decoupling for stakeholder comment. In determining which rate design is most appropriate, the Board will have regard to the following objectives:

- Providing stability and predictability to consumers on their bills,
- Enhancing consumer literacy of energy rates
- Providing consumers with tools for managing their costs;
- Focusing distributors on optimal use of assets and improving productivity;
- Removing or reducing regulatory costs; and
- Supporting the achievement of public policy objectives.

The Board's final Report may select one proposal for implementation or allow distributors to choose.

1.1 Scope of this Report

In announcing its review of revenue decoupling in November 2012, the Board, indicated that it would consider decoupling for both electricity and natural gas distributors. The Board views the policy objectives for electricity and gas revenue decoupling to be common in many respects.

However, the Board will defer examination of natural gas until the completion of several other major initiatives planned for natural gas in 2014-2015. Later this year, the Board will be conducting a Natural Gas Market Review to assess Ontario natural gas market conditions and regulatory guidelines including planning in the gas sector and the state of pricing, supply and demand. The Board will also be reviewing the framework for the demand-side management programs to be undertaken by natural gas distributors beginning in 2015.

For these reasons, the Board intends to proceed initially with the decoupling of rates charged for the use of electricity distribution systems.

The current rate design in Ontario for electricity distributors includes a fixed monthly service charge and a variable rate.[2] For low volume consumers, the variable rate is based on the kWh of consumption. The split between the fixed monthly service charge and the per kilowatt hour charge varies between distributors. Distributors typically receive about half their distribution revenue for residential customers from fixed monthly service charges, but the ratio varies by distributor, from a low of 30% to a high of 65%[3].

Electricity use can be measured in two ways: ***Consumption*** is the amount of electricity that has been used in total over time and is measured in kilowatt hours (kWh). ***Demand*** is how fast the electricity is being used and is measured in kilowatts (kW).

[2] As of July 1, 2014, losses will be included in the Delivery line for all low volume consumers on a variable basis.

[3] Data from the 2012 Yearbook of Electricity Distributors calculated from the fixed monthly charges (actually per 30 day period), the number of customers and a total of 12.15 of the 30day periods in the year as a percentage of annual Residential Service Classification revenue.

The larger customer classes[4] i.e., those in the group with demand greater than 50 kW have a rate design made up of a fixed monthly service charge and a charge based on monthly maximum demand that is aligned with distribution cost drivers. These classes represent an enormous range of end uses, size of connection, impact on the system, both in terms of timing and size of peak demand. While the alignment of rates with maximum consumer demand better reflects the costs of service, these rates are not sensitive to when the consumer's maximum demand occurs. The Board, in EB-2013-0311, has proposed amendments to the Distribution System Code to ensure that all customers in this class are able to measure demand on an hourly basis. This will enable other rate options for this diverse group of consumers. For these reasons the Board will address the rate design for larger consumers in due course.

The electricity distribution rate design for "Residential Service Classification" and "General Service less than 50 kW Service Classification" customer classes ("low volume consumers") relies on a variable rate based on the kWh of consumption.

As discussed later in the Report, a variable charge based on kWh is not aligned with the cost drivers for distribution. The Board has considered the Navigant analysis (see Appendix A) showing a consumer trend of decreasing average use which is discussed later in the Report. This analysis in the context of the public policy objectives set out in the LTEP regarding conservation has lead the Board to **conclude that it will proceed with revenue decoupling for the low volume customer classes.**

[4] Distributors have various groupings for larger customers that are typically defined as General Service 50 to 999 kW Service Classification; General Service 1000 to 4999 kW Service Classification; and Large Use Service Classification. Other specific definitions for customer classes are also used.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2012-0033

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

AND IN THE MATTER OF an application by Enersource Hydro Mississauga Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2013 and January 1, 2014.

BEFORE: Cynthia Chaplin
Vice Chair and Presiding Member

Paula Conboy
Member

Christine Long
Member

DECISION AND ORDER

RATES

DECEMBER 13, 2012

The Proceeding

Enersource Hydro Mississauga Inc. ("Enersource") is a licensed electricity distributor serving approximately 250,000 customers in the City of Mississauga. Enersource filed an application on April 27, 2012, updated on May 17, 2012, under section 78 of the *Ontario Energy Board Act*, *1998*. Through this application Enersource seeks approval for changes to the rates that Enersource charges for electricity distribution, to be effective January 1, 2013 and January 1, 2014.

The Board issued a Notice of Application and Hearing on May 18, 2012. The Board granted intervenor status and cost eligibility to the following parties:

6. Cost Allocation

Issue 6.1– Is the proposed cost allocation methodology for 2013 appropriate?

Enersource relied on the Report of the Board on the Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219) in determining its cost allocation methodology. Intervenors were of the view that use of the Board's Cost Allocation Policy was appropriate but cautioned that the cost allocation methodology would need to be updated based on the revised revenue requirement and load forecast arising from the Board's Decision.

Board Findings

Enersource's proposed methodology for cost allocation follows the Board's policy and is therefore acceptable. The Board expects that Enersource will update the cost allocation methodology if necessary.

Issue 6.2 – Are the revenue-to-cost ratios for 2013 appropriate?

Enersource proposed to make changes to its revenue-to-cost ratios for 2013. These changes stem from a new cost allocation study conducted on 2013 costs and proposed rates. Enersource explained that its objective is to move each class closer to the Board target revenue-to-cost ratio.

Enersource's initial 2013 cost allocation study showed that two classes, GS Large Use and the USL class, fell outside the Board's target range. As a result, Enersource proposed to reallocate revenues among rate classes. Enersource explained that the revenue-to-cost ratio determined in the test year for the Residential Class based on the current rates was 85%, which was significantly lower than the 91.5% contained in the 2008 study. Accordingly, Enersource proposed adjusting the Residential Class from 85% to 90%.

Enersource proposed to make the following changes to rate classes.

Customer Class	2008 Settlement %	2013 Test Year %	2013 Test Year Proposed %	Target Revenue to Cost Ratio %
Residential	91.5	85	90	85-115
GS < 50kW	111	113	109	80-120
Small Commercial < 50kW	111	na	na	80-120
GS 50kW- 499kW	111	112	109	80-120
GS 500kW - 4999 kW	91.5	108	108	80-120
GS Large Use (> 5000kW)	111	124	109	85-115
Street lighting	91.5	96	96	70-120
Unmetered Scattered Load	111	147	109	80-120

SEC agreed with the Enersource proposal.

Energy Probe took the position that only the two classes outside the Board approved ranges should be reallocated. Energy Probe submitted that the allocations for these two classes should move to the top of the approved range and submitted that changing the Residential Class allocation from 85 to 86% would be sufficient to ensure revenue neutrality.

VECC submitted that Enersource's proposal was inconsistent with Board policy. VECC proposed moving the GS Large Use and USL classes down to 120%**.** VECC suggested that moving the Residential Class from 85% to 86% would be sufficient to ensure revenue neutrality.

Finally, AMPCO submitted that the proposed ratios did not demonstrate a material change toward unity for most rate classes. AMPCO took the position that the Residential Class should not move from 91.5% (as established in the 2008 settlement) to 90% and rather should stay at 91.5%. In AMPCO's view, reducing the ratio from the 2008 level would represent a move away from unity. Furthermore, AMPCO submitted that all ratios should move to 100% on a phased basis over the next two years. AMPCO did however submit that Enersource's 2013 study and cost allocation model does reflect an improvement in data and modelling since the 2008 study.

Board Findings

The Board in its Report on the Review of Electricity Distribution Cost Allocation Policy, (EB-2010-0219) addressed the importance of reasonably allocating the costs of providing services to various classes of consumers in establishing rates that are just and reasonable. Enersource provided evidence detailing the specifics of its cost allocation study. The company advised that its 2013 cost allocation study was more accurate than its first study in 2008. The Board accepts this evidence, and therefore will use the current study, and not the 2008 study, as the starting point for considering further changes to the ratios.

The current study shows that two rate classes fall outside the Board's target range. In order to rectify this, Enersource proposed to bring the two rate classes within the Board's target range and as a result raise the cost allocation of the Residential Class to 90%. The Board's Report does not state as one of its principles that any movement to within a range must be to the top of the target range as proposed by VECC, or that all ratios should move to unity as proposed by AMPCO. Rather the Board's policy sets out that distributors should endeavour to move their revenue-to-cost ratios closer to one if that is supported by improved cost allocations. The Board accepts Enersource's proposal on the basis that it is consistent with the Board's policy. The Board notes that these changes can be made without triggering the need for mitigation.

7. Rate Design

Issue 7.1 – Are the fixed to variable splits for each class for 2013 appropriate?

Enersource did not propose any changes to the existing ratios with respect to the fixed to variable split of the revenue requirement allocated to each customer class.

Board Findings

No changes to the ratios were proposed, and no party objected to company's proposals in this area. The Board finds that the fixed/variable split for each rate class for 2013 is appropriate.

Issue 7.2 – Is the proposed implementation of a Low Voltage Service Rate, the introduction of the Unmetered Scattered Load class, and the merger of the Small Commercial < 50kw class into the General Service < 50kw class appropriate?

<u>Low Voltage Service Rate</u>

Enersource currently records the charges from Hydro One Networks Inc. related to Low Voltage ("LV") to account 1550, which is a Group1 deferral and variance account. For

EB-2012-0165

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

AND IN THE MATTER OF an application by Sioux Lookout Hydro Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2013.

BEFORE: Paula Conboy
Presiding Member

Allison Duff
Member

DECISION AND ORDER
August 22, 2013

Sioux Lookout Hydro Inc. ("SLHI") filed an application with the Ontario Energy Board on February 22, 2013 under section 78 of the *Ontario Energy Board Act*, *1998*, seeking approval for changes to the rates that SLHI charges for electricity distribution, effective May 1, 2013. The Board issued a Notice of Application and Hearing on March 7, 2013.

The Vulnerable Energy Consumers Coalition ("VECC") and an individual, Mr. Douglas Shields, applied for and were granted intervenor status. VECC was also granted cost award eligibility. The hearing process included interrogatories, supplemental interrogatories, and written submissions. Mr. Shields filed a submission on May 29, 2013. Board staff and VECC filed submissions on June 28, 2013. SLHI filed its reply submission on July 5, 2013.

While the Board has considered the entire record in this proceeding, it has made reference only to the evidence necessary to provide context to its findings. The

Board's Cost of Capital Parameters	Rate
Return on Equity	8.98%
Deemed Short-term Debt	2.07%
Deemed Long-Term Debt	4.12%

Through the interrogatory process, SLHI updated its cost of capital parameters and calculated a weighted average cost of capital of 5.98%. Board staff agreed with SLHI's proposed 5.98%. VECC noted SLHI had changed its long-term debt rate from 3.44% to the Board's default value of 4.12%. As no change had been made to SLHI's third-party loan agreements, VECC submitted SHLI should revert back to the originally filed 3.44% rate for long-term debt based on its evidence of third-party loans.

In reply, SLHI submitted the change to the long-term debt rate was simply made in response to Board staff and VECC's interrogatories to update the cost of capital parameters to the most recent Board approved rates.

<u>Board Findings</u>
The Board's finds it appropriate for SLHI use the Board's deemed cost of capital rates of 8.98% for equity and 2.07% for short-term debt However, the Board agrees with VECC that SLHI's long-term debt rate should be 3.44% based on its loan contracts. The Board's default rate of 4.12% should only be used in the absence of third-party loans, as indicated in the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, Dec.11, 2009. As a result, the Board approves a 5.60% cost of capital in 2013.

Cost Allocation

SLHI conducted an updated Cost Allocation Study (the "Study"), provided revenue-to-cost ("R/C") ratios resulting from the Study and proposed R/C ratios for 2013.

R/C Ratios
2010 IRM and 2013 Cost Allocation Study and Proposed (updated via interrogatory process)

Customer Class	Range (%)		2010 IRM Application	2013 Cost Allocation Study	2013 Proposed
	Low	High			
Residential	85	115	98.09%	90.34%	96.35%
GS < 50 kW	80	120	96.26%	115.15%	109.85%
GS 50-4999 kW	80	120	129.16%	138.31%	119.84%
Street Lighting	70	120	70.00%	83.08%	74.91%
Unmetered Scattered Load	80	120	98.29%	81.30%	80.96%

Board staff took issue with SLHI's proposed ratios for SL and USL. While the proposed R/C ratios were within the Board's target range for each class, the resulting ratios moved further away from 100% and therefore, were not appropriate in Board staff's opinion. Board staff submitted the R/C ratios for the SL and USL classes should be set at 83.08% and 81.30% as derived by the Study with the additional revenue used to further decrease the ratio for the GS>50 kW class.

In VECC's view the cost allocation methodology, as applied by Sioux Lookout had not improved to warrant moving the ratio for the GS<50 kW class closer to one. VECC submitted ratios should be changed only if necessary to maintain revenue neutrality which was not the case in the current circumstances

In addition, VECC took issue with SLHI's proposals to reduce the R/C ratios for SL and USL further away from unity as the proposals contravened the Board's November 2007 Report, EB- 2007-0667 "Application of Cost Allocation for Electricity Distributors". VECC provided two proposals to increase the R/C ratios for the Residential, SL and USL classes:

1. Increase the ratios for SL and USL up to the status quo value for Residential and, then, increase all three ratios in tandem until revenue neutrality is achieved.
2. Adjust the ratios for SL and USL by two percentage points for every one percentage point increase applied to Residential.

VECC noted that the first approach was preferable from a strict R/C ratio setting perspective as adjustments would be applied first to ratios furthest from unity.

In its reply submission, SLHI agreed with Board Staff and indicated that if the Board decided the SL and USL class R/C ratios be should 83.08% and 81.30% respectively, it would be appropriate to further decrease the GS>50 kW class revenue requirement in order to maintain revenue neutrality.

<u>Board Findings</u>

The Board accepts SLHI's proposed R/C ratios for residential, GS<50 kW and GS> 50 kW and its revised proposal to adopt the R/C ratios produced by the Study of 83.03% for SL and 81.30% for the USL classes. The additional revenue from the SL and USL customer classes will be applied to the GS>50 kW customer class to further reduce its R/C ratio. The Board does not agree with VECC's proposal to increase the SL and USL ratios to the Residential ratio of 90.34% and then increase all three ratios in tandem. The Board finds VECC's proposal dismisses the class-specific R/C ratios provided by the Study.

Rate Design

Fixed/Variable Split

SLHI proposed to maintain the same fixed/variable ratios in its current 2012 rates for all customer classes. Board staff took no issue with SLHI's proposal.

VECC disagreed with SLHI's proposal as the fixed charges for the GS<50 kW and GS>50 kW classes exceeded the Study's ceiling values. VECC submitted the fixed service charges for these classes should be capped at the current 2012 rates, not the fixed/variable ratios.

Board Findings

The Board accepts SLHI's proposal to maintain the fixed/variable ratios. The Board notes this is consistent with other decisions[1] in which it has approved applications to increase monthly service charge that were already above the cost allocation ceiling, provided that the increase would not result in a higher revenue from the fixed charge relative to the volumetric charge.

Rate Mitigation

SLHI provided bill impact analysis in its application, updated though interrogatories.

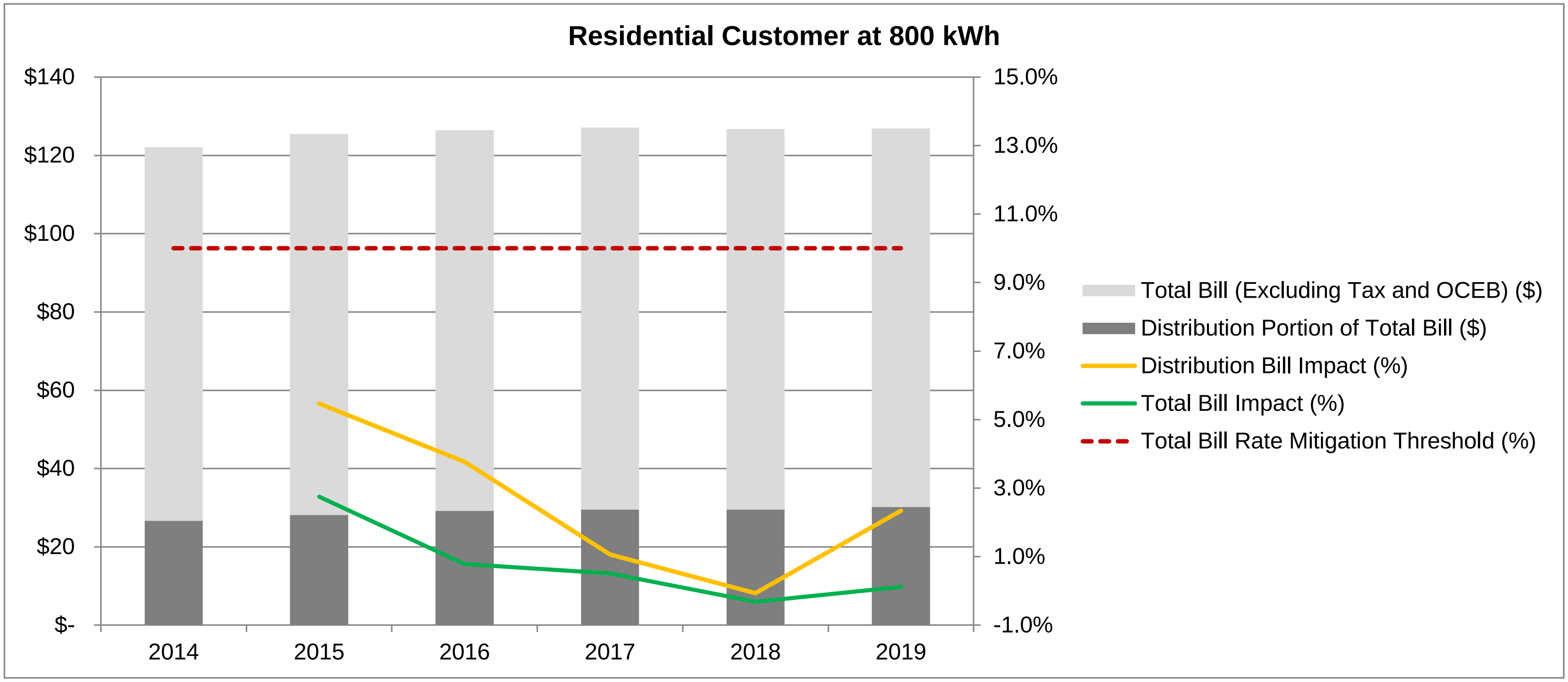
	Total Bill Impact %	
	Provided in Application	Updated through interrogatories
Residential	6.53%	6.14%
GS < 50 kW	2.71%	2.51%
GS 50 to 4,999 kW	0.52%	(0.03%)
Street Lighting	2.48%	1.79%
Unmetered Scattered Load	9.99%	10.46%

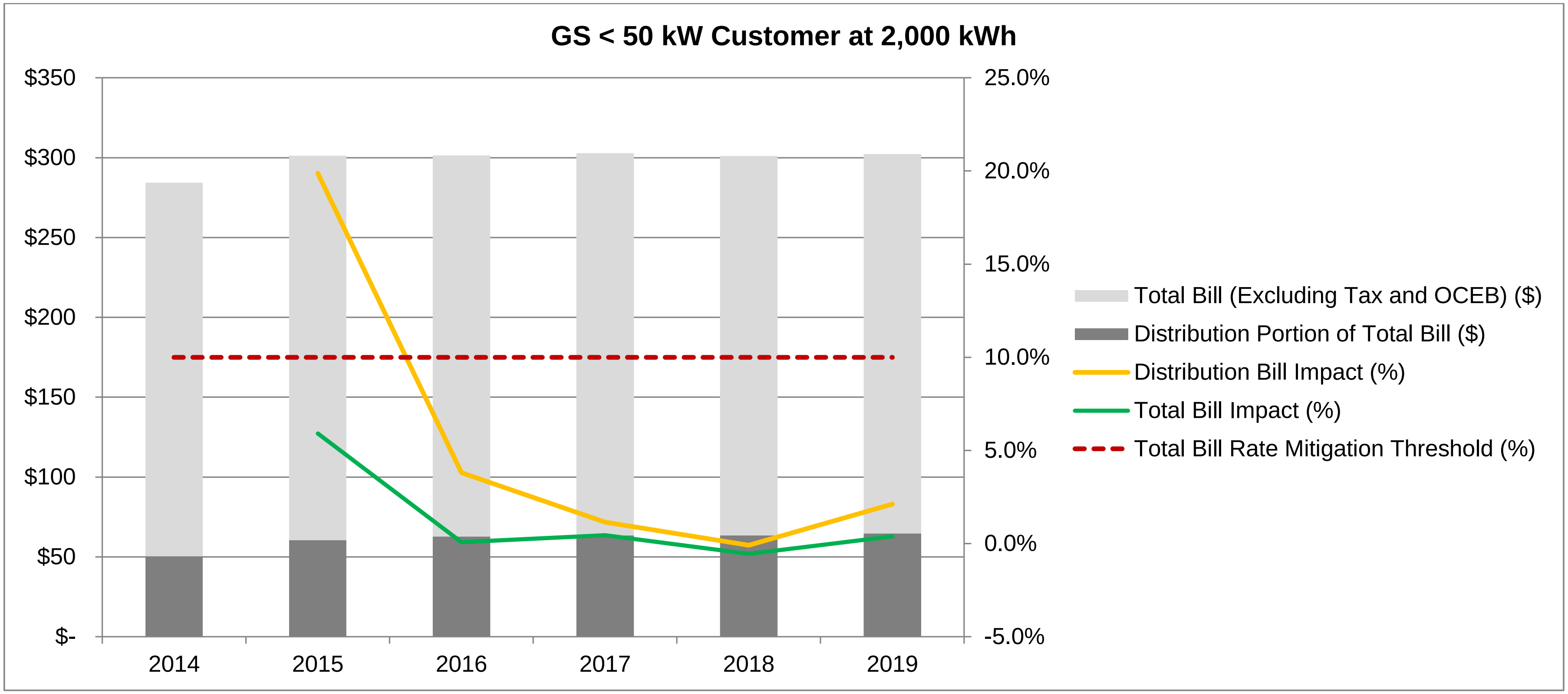
[1] Decision on Hydro One Brampton Inc. (EB-2010-0132), p. 38. Decision on Lakeland Power Distribution Ltd. (EB-2008-0234), p.29-30. Decision on London Hydro Inc. (EB-208-0235), p.42-43.

Distribution Bill (Horizon Utilities Proposal)	2015	2016	2017	2018	2019
Residential (800 kWh)	$ 28.14	$ 29.20	$ 29.51	$ 29.49	$ 30.18
GS < 50 kW (2,000 kWh)	$ 60.43	$ 62.73	$ 63.45	$ 63.39	$ 64.73
GS >50 to 4999 kW (250 kW)	$ 980.77	$ 1,015.02	$ 1,026.87	$ 1,025.57	$ 1,047.13
Large Use (1) (10,000 kW)	$ 26,434.03	$ 27,404.34	$ 27,660.20	$ 27,622.49	$ 28,247.28
Large Use (2) (20,000 kW)	$ 8,361.50	$ 9,558.96	$ 12,488.72	$ 12,470.91	$ 12,752.26
Sentinel Lights (216 kW)	$ 6,803.91	$ 7,053.71	$ 7,119.53	$ 7,109.81	$ 7,270.57
Street Lighting (6,800 kW)	$ 155,070.72	$ 160,912.36	$ 162,934.68	$ 162,712.96	$ 166,391.76
Unmetered and Scattered (500 kWh)	$ 14.67	$ 15.00	$ 15.13	$ 15.11	$ 15.45

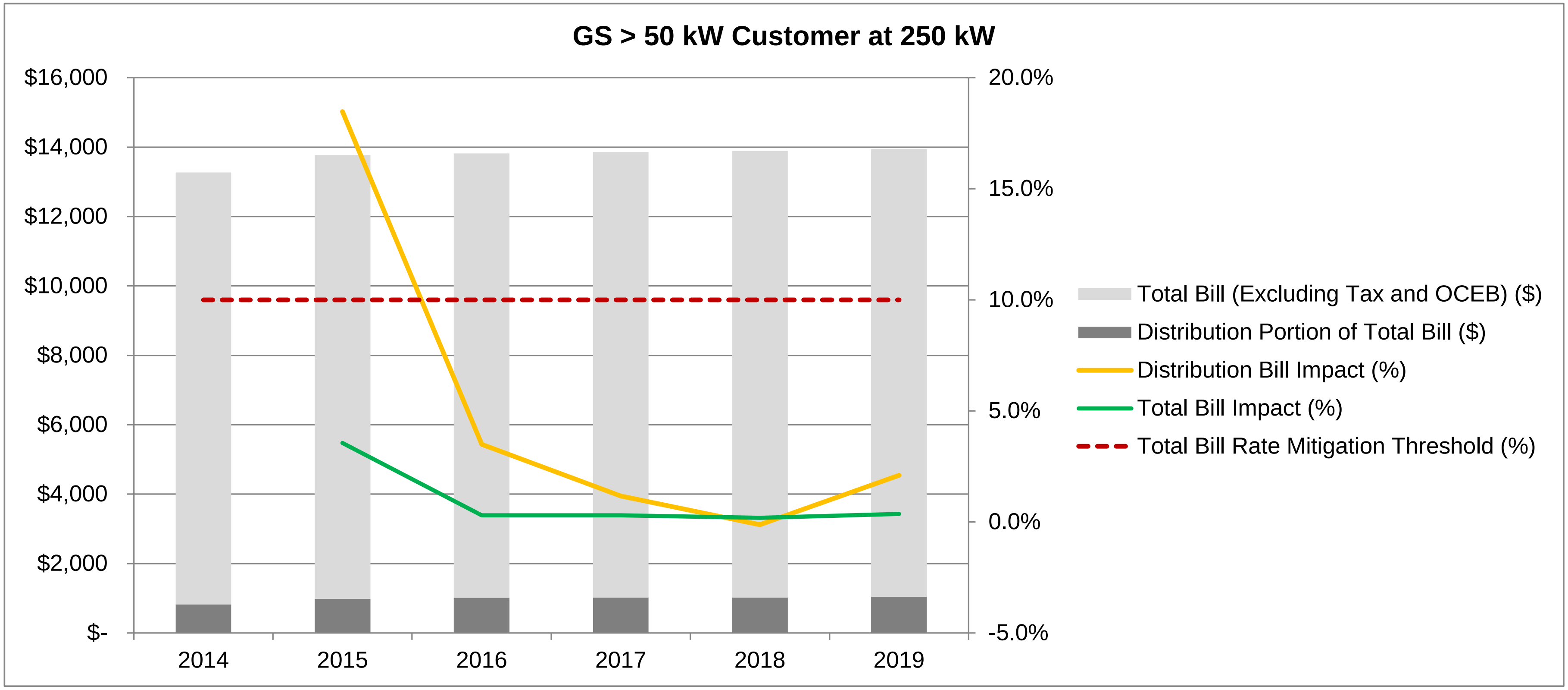
Distribution Bill (Energy Probe Proposal on Revenue Rebalancing)	2015	2016	2017	2018	2019
Residential (800 kWh)	$ 28.14	$ 29.21	$ 29.55	$ 29.53	$ 30.23
GS < 50 kW (2,000 kWh)	$ 57.85	$ 60.07	$ 60.76	$ 60.72	$ 62.03
GS >50 to 4999 kW (250 kW)	$ 992.18	$ 1,026.48	$ 1,038.45	$ 1,037.57	$ 1,059.69
Large Use (1) (10,000 kW)	$ 26,434.03	$ 26,986.22	$ 25,604.05	$ 25,580.04	$ 26,165.44
Large Use (2) (20,000 kW)	$ 8,361.50	$ 9,558.96	$ 12,488.72	$ 12,477.38	$ 12,762.44
Sentinel Lights (216 kW)	$ 6,486.48	$ 6,728.12	$ 6,812.44	$ 6,806.11	$ 6,961.98
Street Lighting (6,800 kW)	$ 178,997.80	$ 185,667.00	$ 187,993.60	$ 187,819.92	$ 192,120.80
Unmetered and Scattered (500 kWh)	$ 14.67	$ 13.74	$ 12.96	$ 12.95	$ 13.27

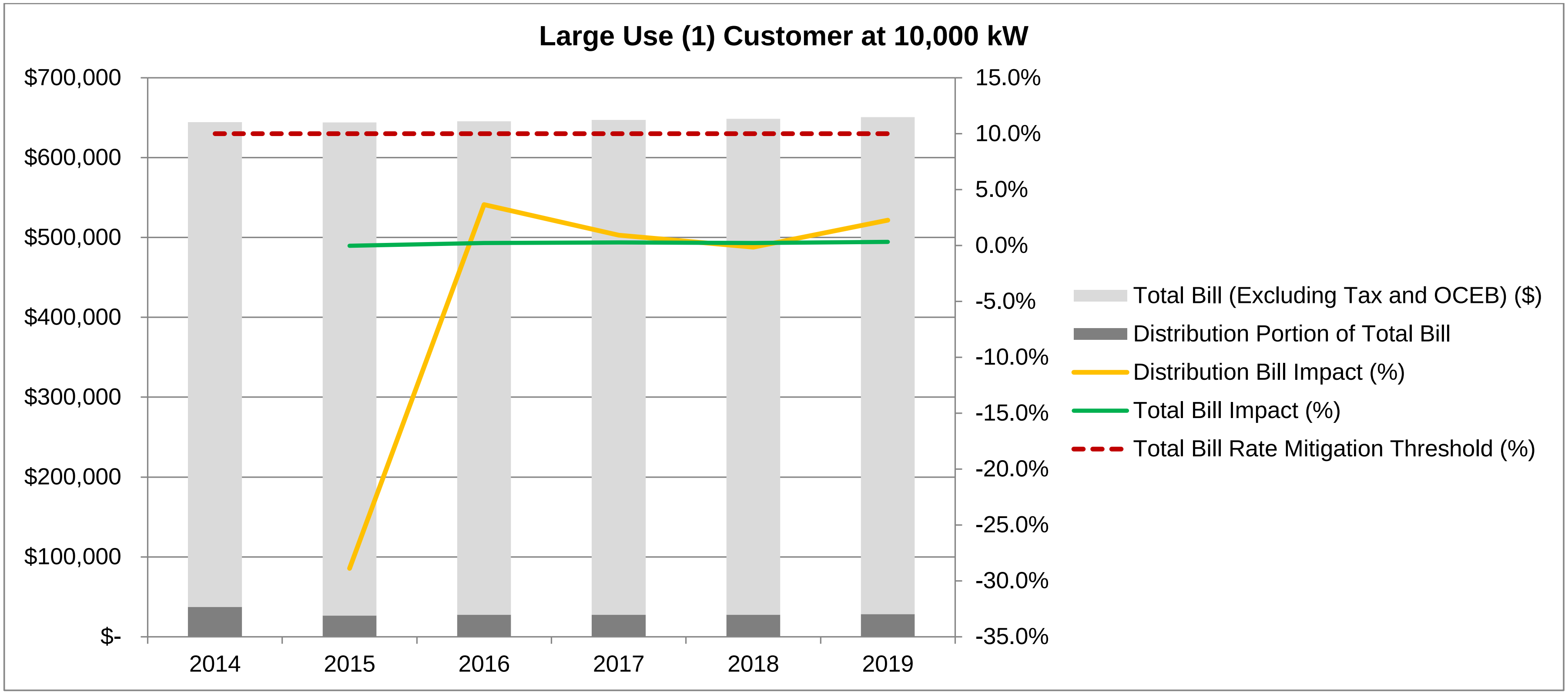
Increase/(Decrease) to Distribution Bill Using Energy Probe Proposal on Revenue Rebalancing	2015	2016	2017	2018	2019
Residential (800 kWh)	$ -	$ 0.01	$ 0.04	$ 0.04	$ 0.05
GS < 50 kW (2,000 kWh)	$ (2.58)	$ (2.66)	$ (2.69)	$ (2.67)	$ (2.70)
GS >50 to 4999 kW (250 kW)	$ 11.41	$ 11.46	$ 11.59	$ 12.00	$ 12.57
Large Use (1) (10,000 kW)	$ -	$ (418.12)	$ (2,056.15)	$ (2,042.45)	$ (2,081.84)
Large Use (2) (20,000 kW)	$ -	$ -	$ -	$ 6.47	$ 10.18
Sentinel Lights (216 kW)	$ (317.43)	$ (325.59)	$ (307.09)	$ (303.70)	$ (308.60)
Street Lighting (6,800 kW)	$ 23,927.08	$ 24,754.64	$ 25,058.92	$ 25,106.96	$ 25,729.04
Unmetered and Scattered (500 kWh)	$ -	$ (1.26)	$ (2.17)	$ (2.16)	$ (2.18)


Residential Customer at 800 kWh
$140
$120
$100
$80
$60
$40
$20
$-
15.0%
13.0%
11.0%
9.0%
7.0%
5.0%
3.0%
1.0%
-1.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Distribution Bill Impact (%)
Total Bill Impact (%)
Total Bill Rate Mitigation Threshold (%)

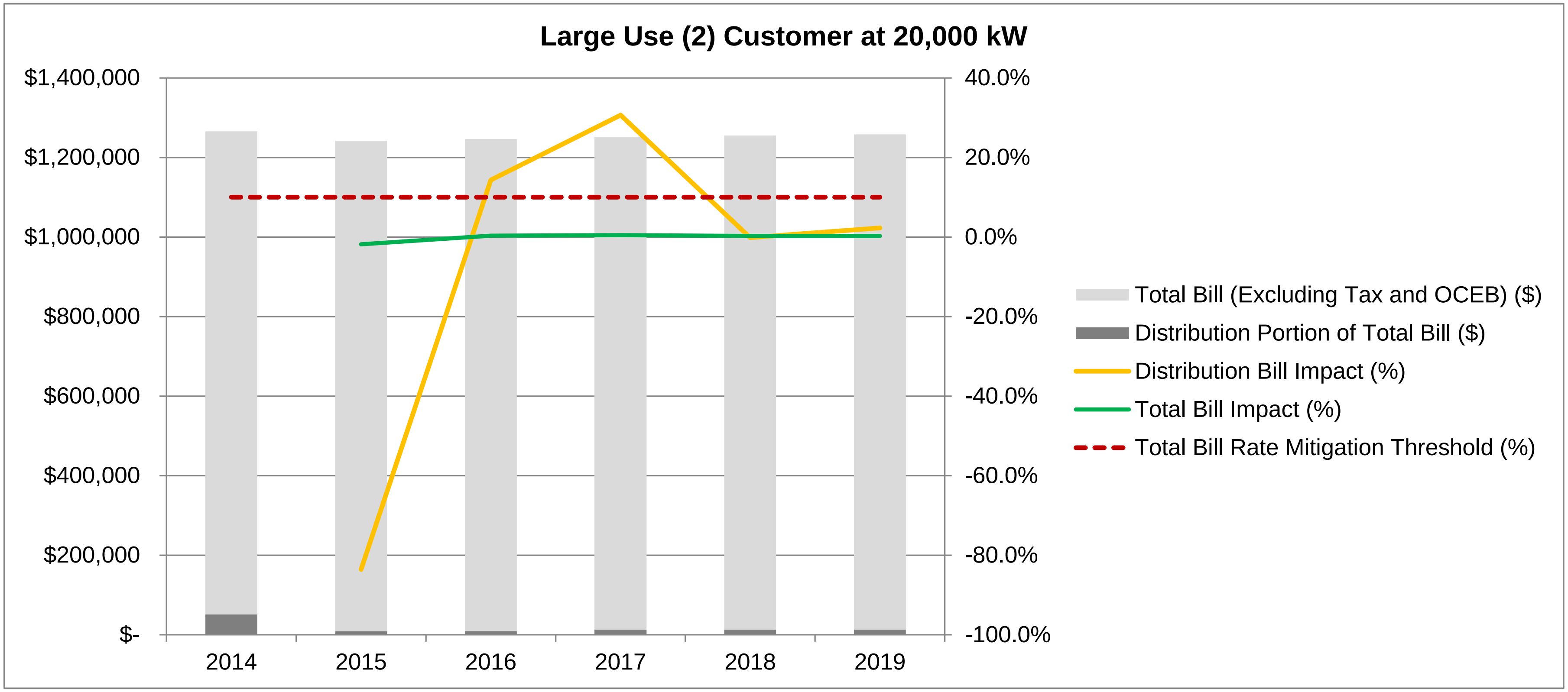


GS < 50 kW Customer at 2,000 kWh
$350
$300
$250
$200
$150
$100
$50
$-
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
-5.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Distribution Bill Impact (%)
Total Bill Impact (%)
Total Bill Rate Mitigation Threshold (%)

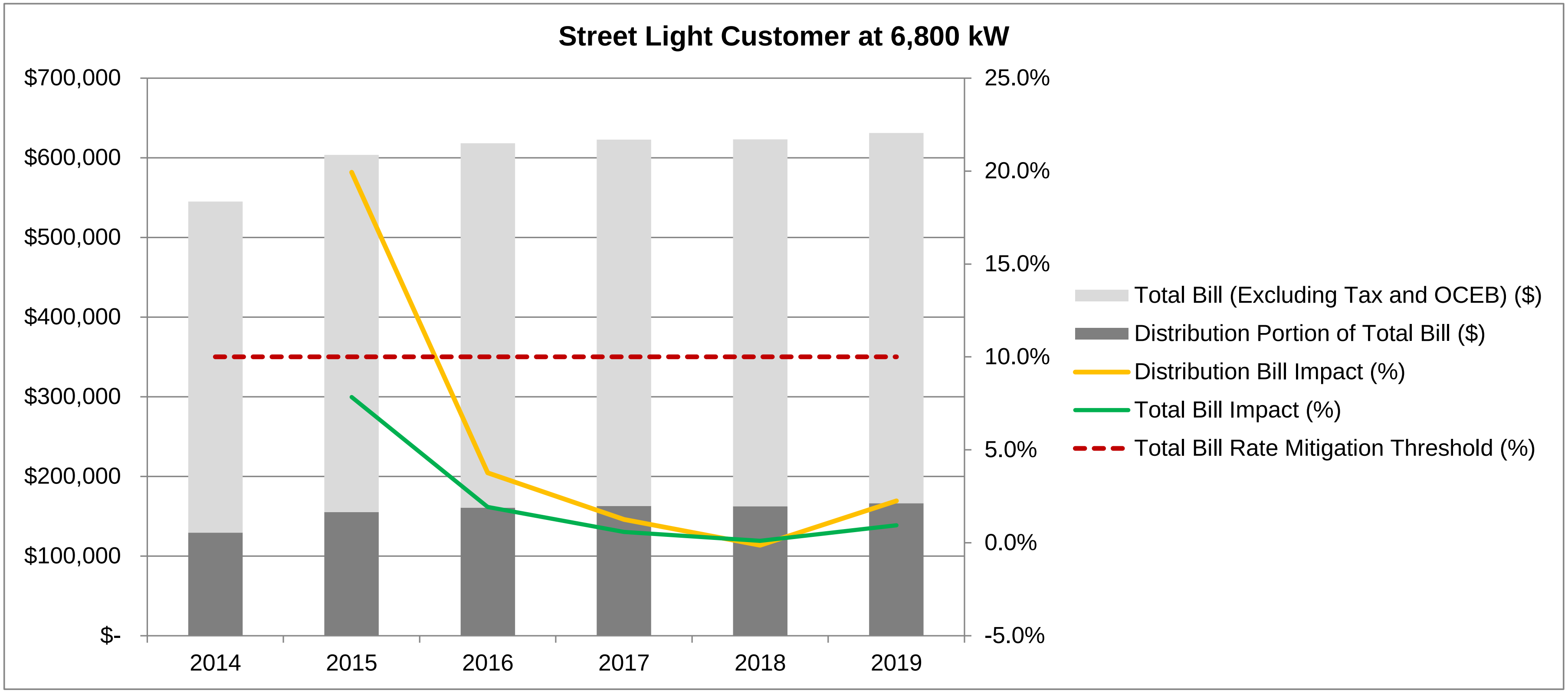

GS > 50 kW Customer at 250 kW
$16,000
$14,000
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$-
20.0%
15.0%
10.0%
5.0%
0.0%
-5.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Distribution Bill Impact (%)
Total Bill Impact (%)
Total Bill Rate Mitigation Threshold (%)

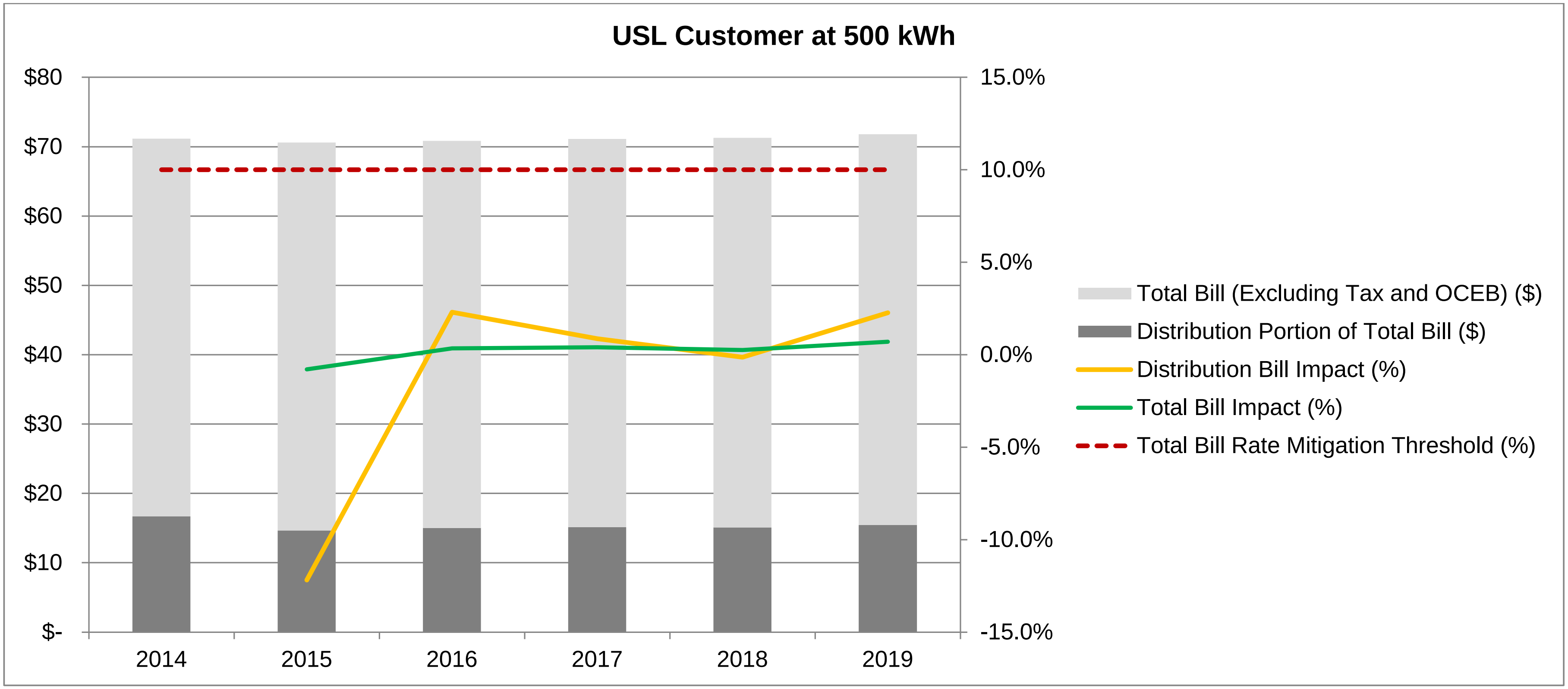


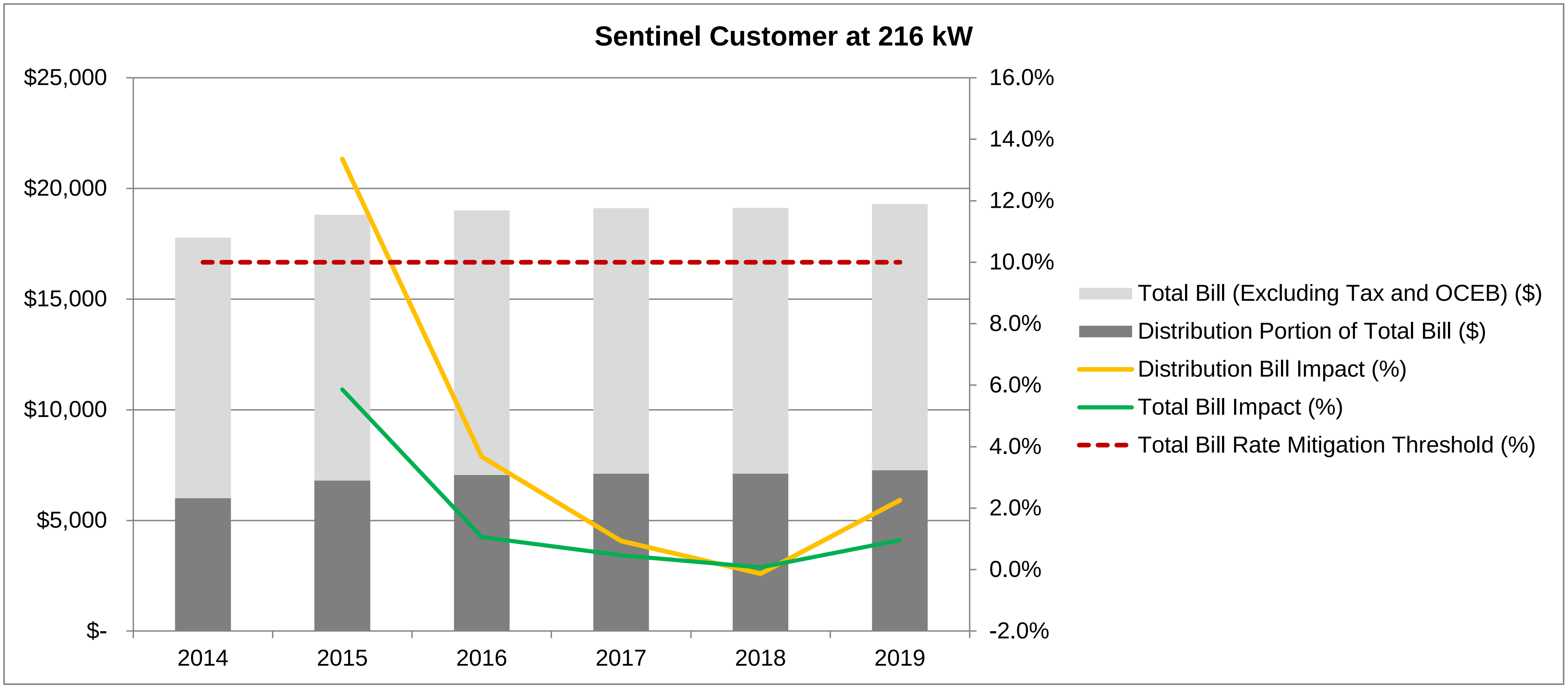
Large Use (1) Customer at 10,000 kW
$700,000
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$-
15.0%
10.0%
5.0%
0.0%
-5.0%
-10.0%
-15.0%
-20.0%
-25.0%
-30.0%
-35.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill
Distribution Bill Impact (%)
Total Bill Impact (%)
Total Bill Rate Mitigation Threshold (%)

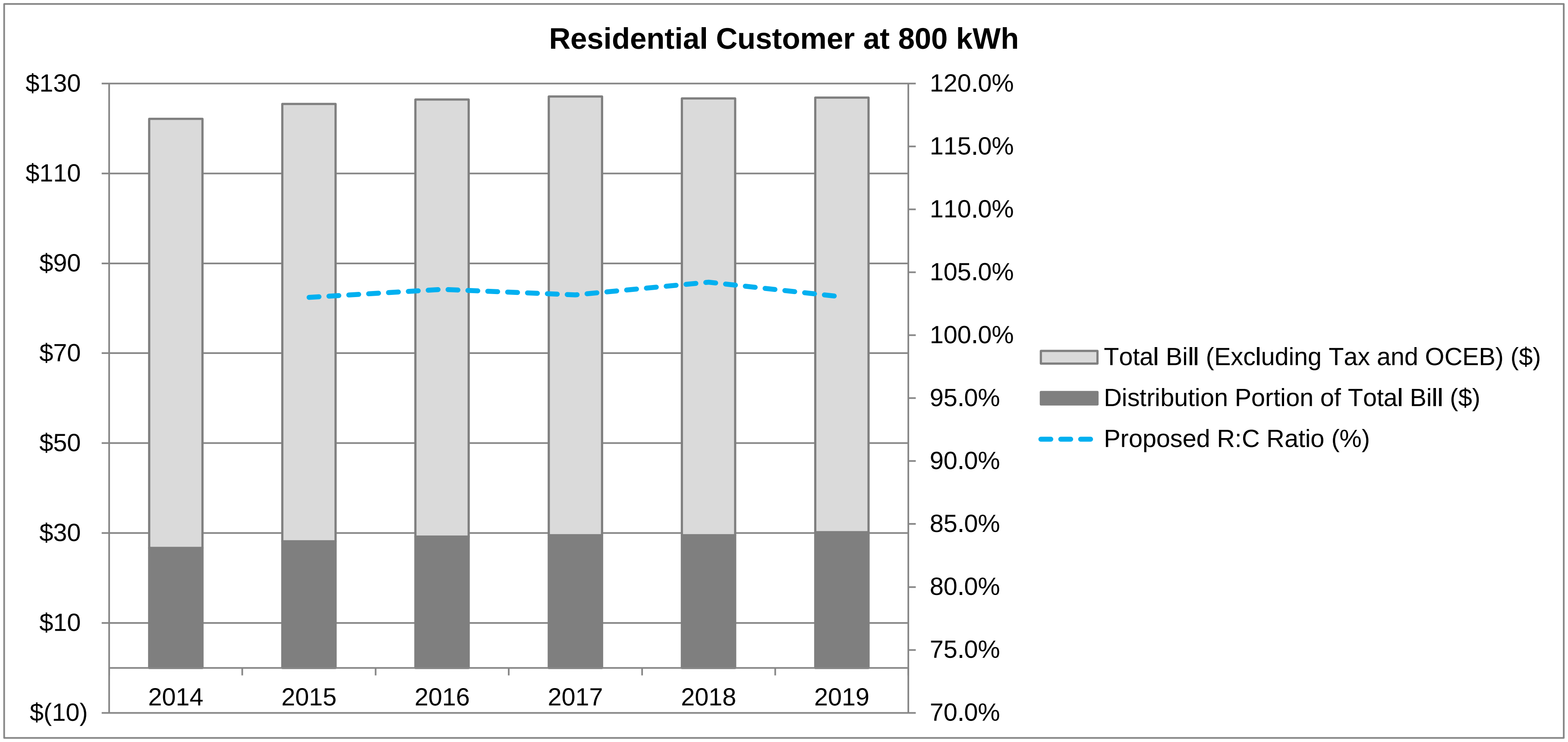


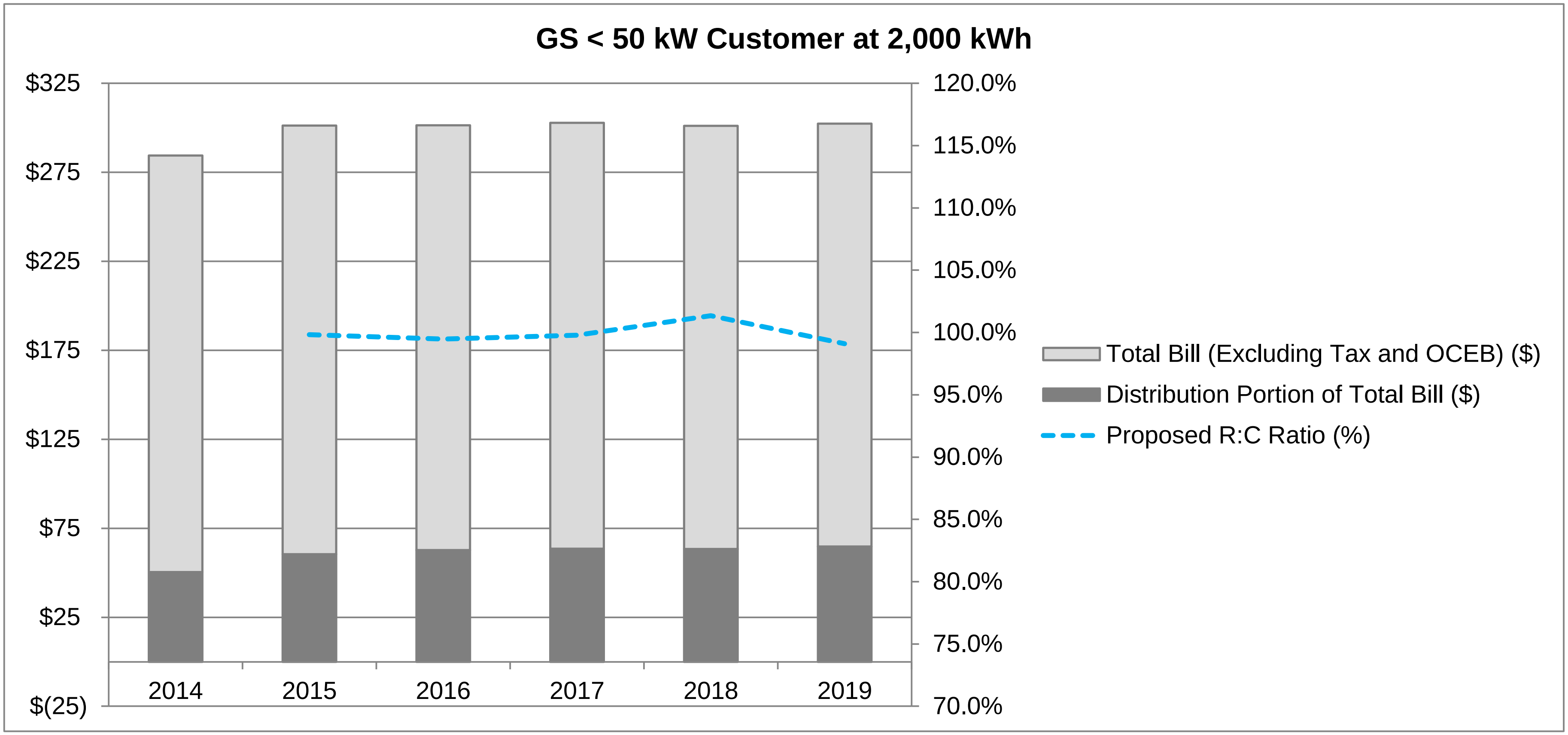
Large Use (2) Customer at 20,000 kW
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$-
40.0%
20.0%
0.0%
-20.0%
-40.0%
-60.0%
-80.0%
-100.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Distribution Bill Impact (%)
Total Bill Impact (%)
Total Bill Rate Mitigation Threshold (%)

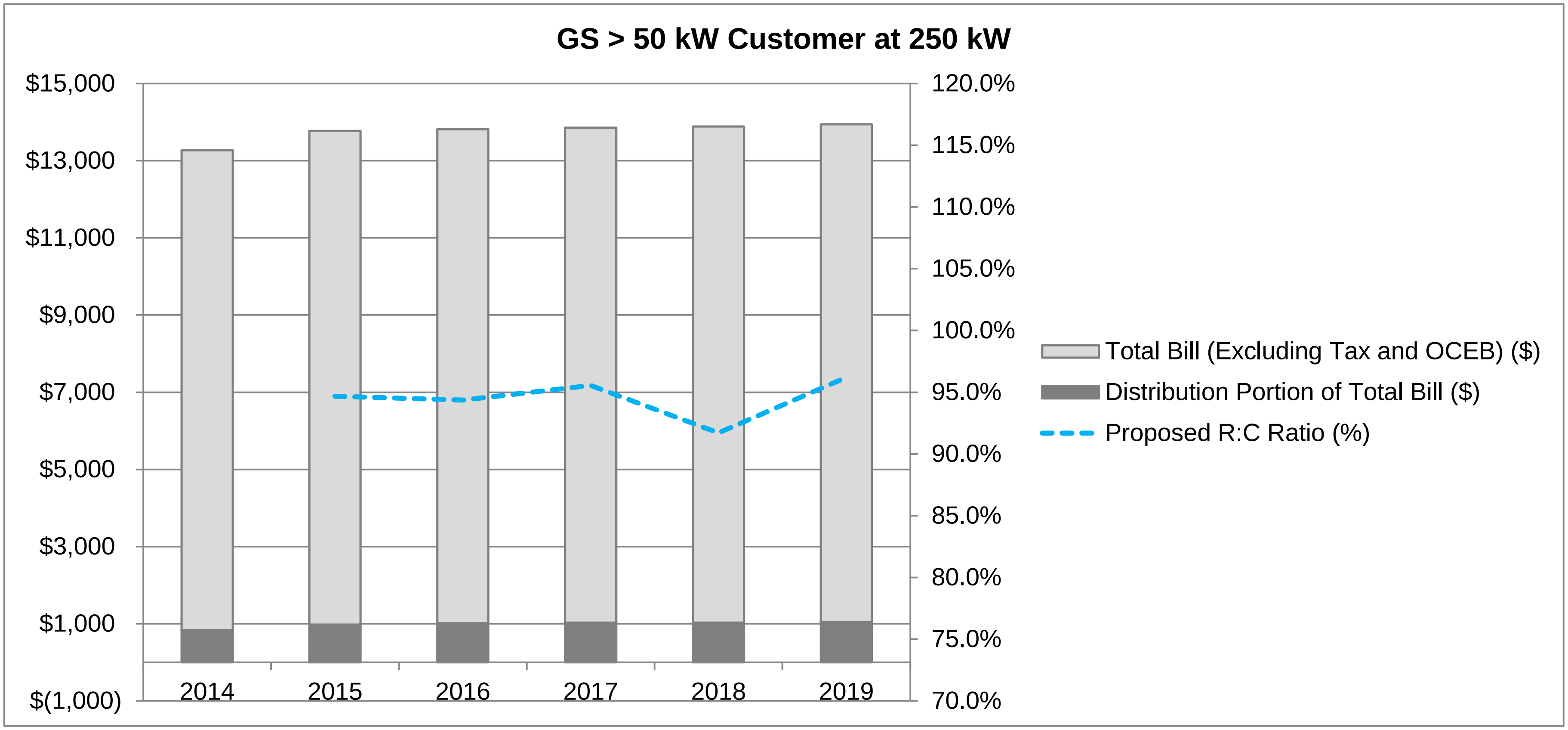

Street Light Customer at 6,800 kW
$700,000
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$-
25.0%
20.0%
15.0%
10.0%
5.0%
0.0%
-5.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Distribution Bill Impact (%)
Total Bill Impact (%)
Total Bill Rate Mitigation Threshold (%)

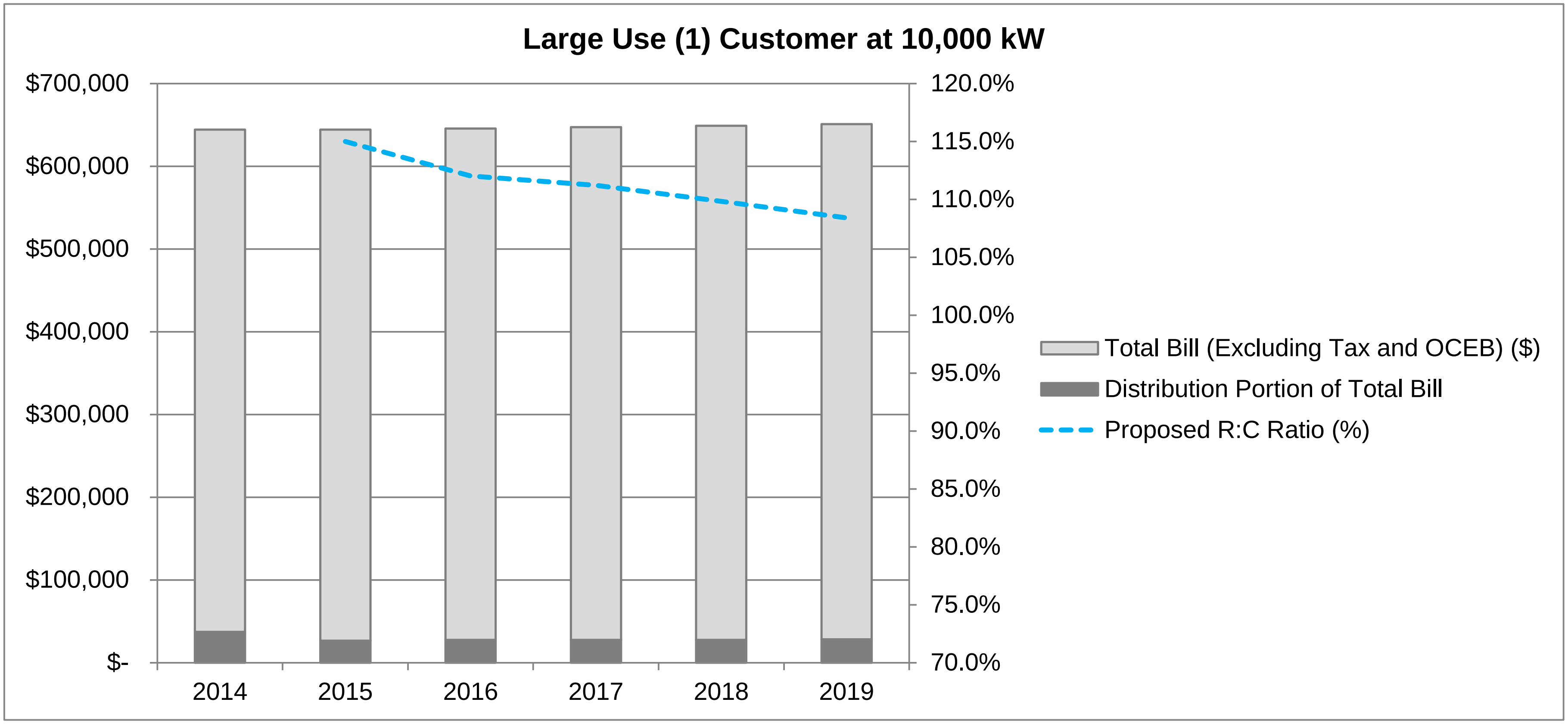

USL Customer at 500 kWh
$80
$70
$60
$50
$40
$30
$20
$10
$-
15.0%
10.0%
5.0%
0.0%
-5.0%
-10.0%
-15.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Distribution Bill Impact (%)
Total Bill Impact (%)
Total Bill Rate Mitigation Threshold (%)

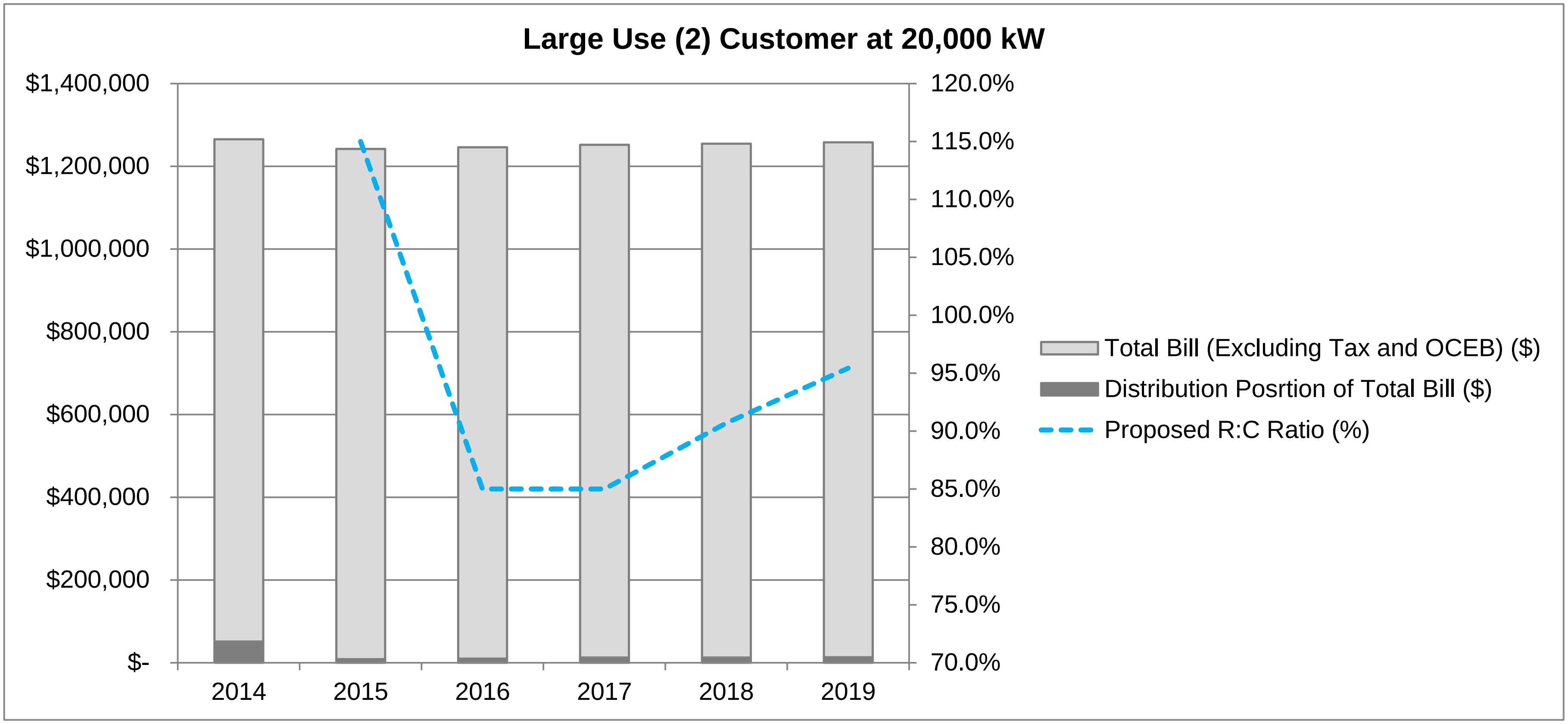

Sentinel Customer at 216 kW
$25,000
$20,000
$15,000
$10,000
$5,000
$-
16.0%
14.0%
12.0%
10.0%
8.0%
6.0%
4.0%
2.0%
0.0%
-2.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Distribution Bill Impact (%)
Total Bill Impact (%)
Total Bill Rate Mitigation Threshold (%)

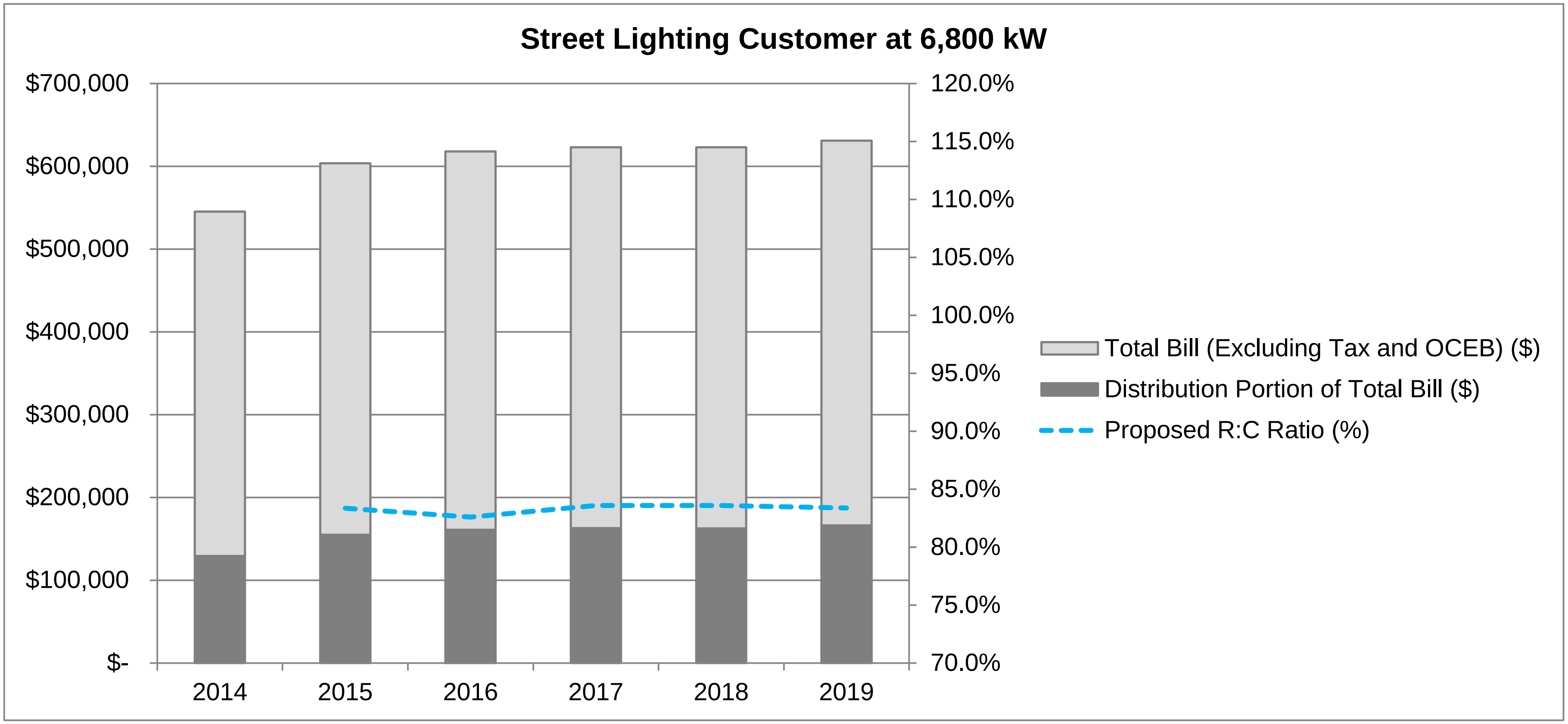

Residential Customer at 800 kWh
$130
$110
$90
$70
$50
$30
$10
$(10)
120.0%
115.0%
110.0%
105.0%
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
70.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Proposed R:C Ratio (%)

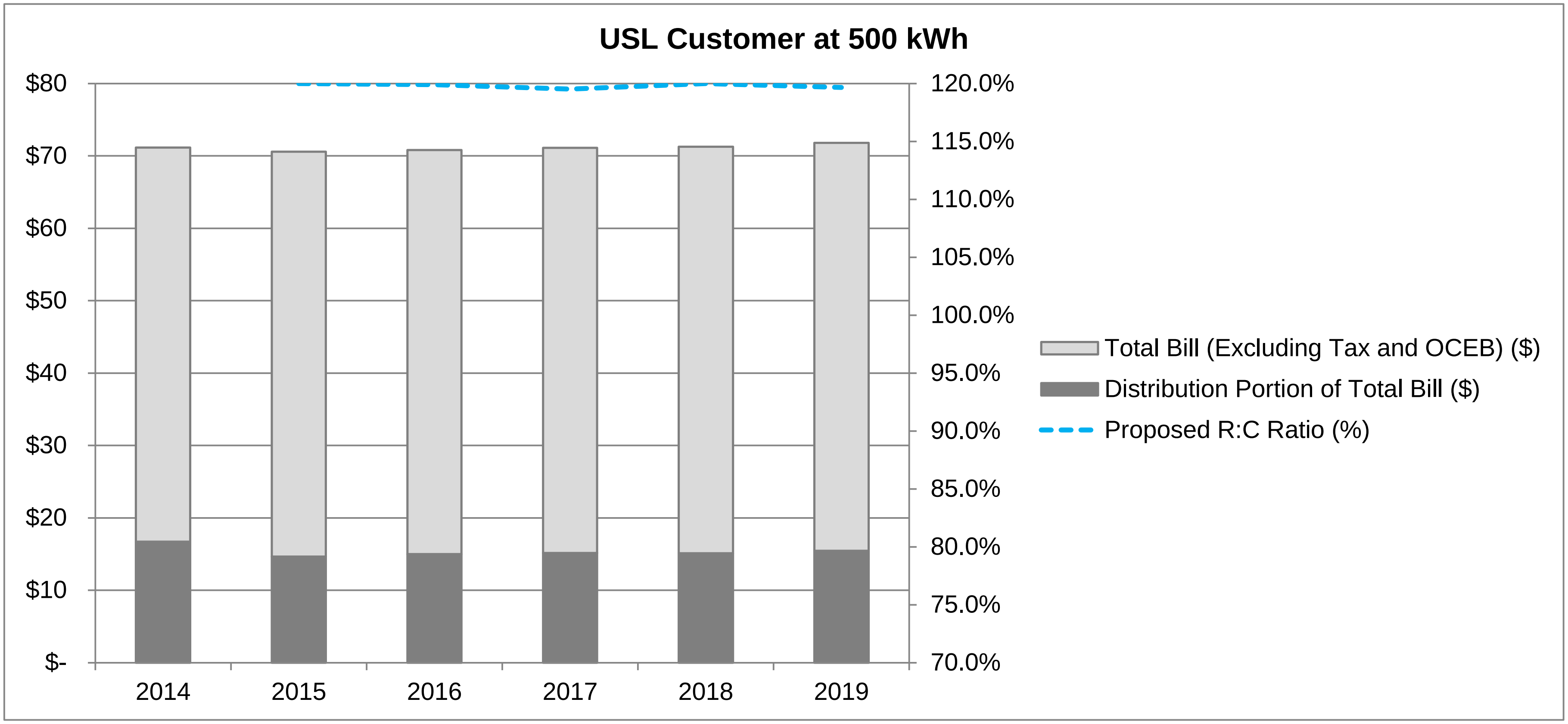

GS < 50 kW Customer at 2,000 kWh
$325
$275
$225
$175
$125
$75
$25
$(25)
120.0%
115.0%
110.0%
105.0%
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
70.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Proposed R:C Ratio (%)

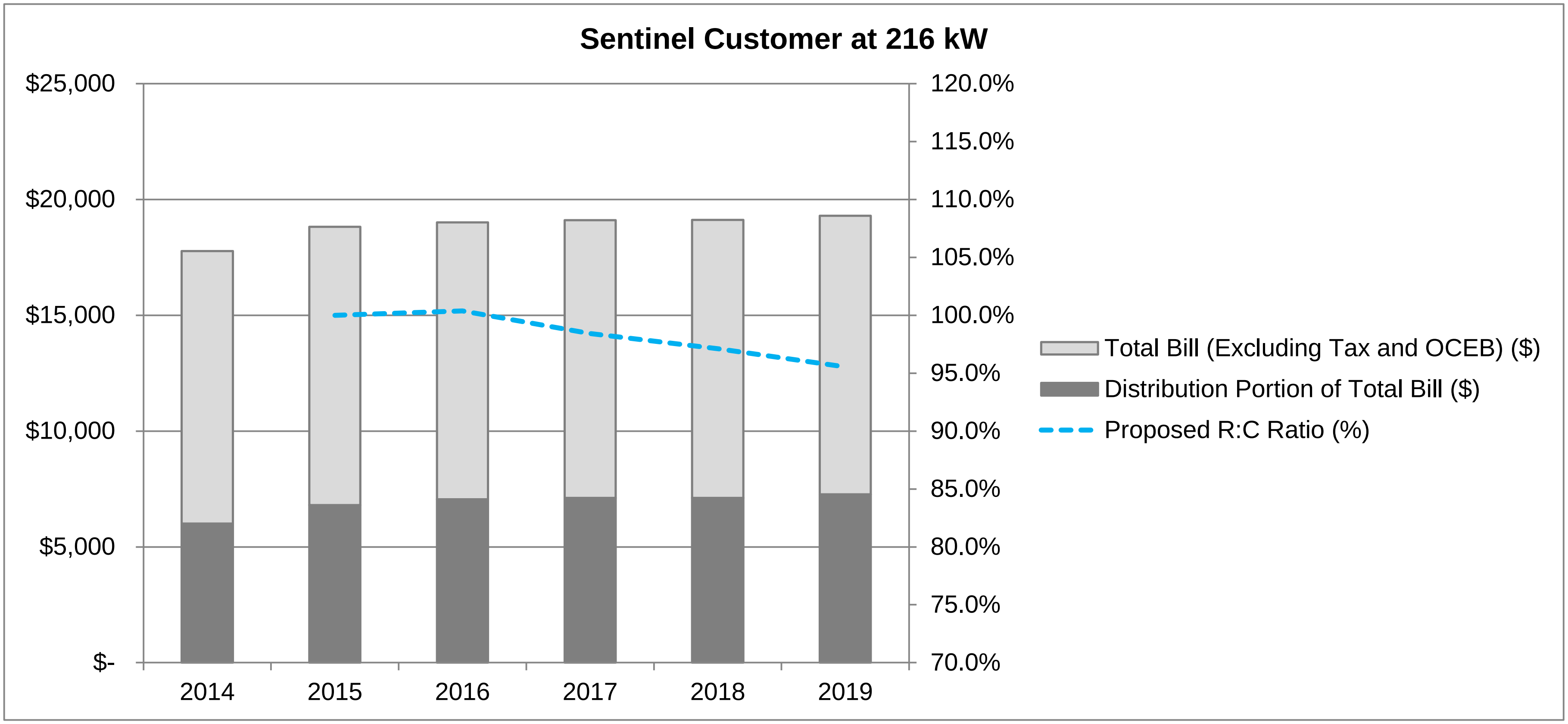

GS > 50 kW Customer at 250 kW
$15,000
$13,000
$11,000
$9,000
$7,000
$5,000
$3,000
$1,000
$(1,000)
120.0%
115.0%
110.0%
105.0%
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
70.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Proposed R:C Ratio (%)


Large Use (1) Customer at 10,000 kW
$700,000
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$-
120.0%
115.0%
110.0%
105.0%
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
70.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill
Proposed R:C Ratio (%)


Large Use (2) Customer at 20,000 kW
$1,400,000
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$-
120.0%
115.0%
110.0%
105.0%
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
70.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Posrtion of Total Bill ($)
Proposed R:C Ratio (%)


Street Lighting Customer at 6,800 kW
$700,000
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$-
120.0%
115.0%
110.0%
105.0%
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
70.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Proposed R:C Ratio (%)


USL Customer at 500 kWh
$80
$70
$60
$50
$40
$30
$20
$10
$-
120.0%
115.0%
110.0%
105.0%
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
70.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Proposed R:C Ratio (%)


Sentinel Customer at 216 kW
$25,000
$20,000
$15,000
$10,000
$5,000
$-
120.0%
115.0%
110.0%
105.0%
100.0%
95.0%
90.0%
85.0%
80.0%
75.0%
70.0%
2014
2015
2016
2017
2018
2019
Total Bill (Excluding Tax and OCEB) ($)
Distribution Portion of Total Bill ($)
Proposed R:C Ratio (%)

EB-2007-0697

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998,* S.O. 1998, c. 15, Sch.B, as amended;

AND IN THE MATTER OF an Application by Horizon Utilities Corporation pursuant to section 78 of the *Ontario Energy Board Act* for an Order or Orders approving just and reasonable rates for the delivery and distribution of electricity.

Written Argument Of
The Consumers Council of Canada

WeirFoulds LLP
Barristers and Solicitors
Suite 1600 Exchange Tower
130 King Street West
Toronto, Ontario M9N 2H6
Robert B. Warren
(416) 365-1110
(416) 365-1876 (FAX)
Counsel to the Consumers Council of Canada

11. If the working capital requirement is set too high Horizon recovers more from its ratepayers than is required.

52. Horizon has not carried out a lead-lag study to assess its working capital requirements and in the absence of such a study is seeking approval of 15%. Horizon has not presented evidence to support the fact that it actually requires the $69.5 million working capital allowance that results from the application of the 15%. Two of the other larger LDCs in the province have carried out lead-lag studies resulting in lower allowances and two have accepted that the 15% is too high. The Board has approved the lower amounts for each of those LDCs.

53. The Council submits that Horizon should be directed to calculate its working capital allowance on the same basis as THESL, using 12.45%. THESL's working capital allowance was based on an actual lead lag study for a service territory similar to Horizon's. This amount is higher than that approved for Hydro One Networks, but lower than the proxy value applied to a broad range of LDCs.

COST ALLOCATION AND RATE DESIGN:

REVENUE TO COST RATIOS:

54. On November 28, 2007, the Board released its report entitled, *Application of Cost Allocation for Electricity Distributors.* In that Report, the Board created bands or ranges of tolerance around revenue to cost ratios of one. The Board concluded that an incremental approach was appropriate and a range approach preferable to the implementation of specific revenue to cost ratio. The ranges established by the Board are intended to be minimum requirements. The Board determined that to the extent distributors can address influencing factors that are within their control (such as data quality) they should attempt to do so and to move revenue to cost ratios nearer to one.

55. Horizon has set out in the evidence its proposed revenue to cost ratios resulting from its 2006 cost allocation filing and to adjust for transformer allowances. The ratios are set out below:

- Residential: 123.6%
- GS < 50 kW: 92.0%
- GS > 50 kW: 72.1%
- Large Users: 49.8%
- Street Lights: 15.6%
- Sentinel Lights: 34.8%
- USL: 34.2%
- Back-up/Standby: 51.0% (H/T1/S2/p. 4)

Horizon has proposed 2008 revenue to cost ratios consistent with the Board's Report. Those ratios are set out below:

- Residential: 112.44%
- GS < 50 kW: 92.5%
- GS > 50 kW: 86.31%
- Large Users: 92.12%
- Street Lights: 23.79%
- Sentinel Lights: 91.49%
- USL: 88.05%
- Back-up/Standby: 65.84% (H/T1/S2/p. 7)

56. The Council is generally supportive of the ratios proposed by Horizon, as they are consistent with the Board's Report with one exception. The street lighting class continues to significantly under-contribute relative to the costs of serving that class. Residential customers continue to subsidize this class. It is the Council's understanding that street lighting is provided by the City of Hamilton, one of the owners of the utility. Horizon's reluctance to move the street lighting ratio closer to one is likely driven by its ultimate owner.

57. The Council submits that Horizon should be required to move the street lighting revenue to cost ratio to 70%, consistent with the range outlined in the Board's Report. To the extent Horizon is directed to do so any additional revenue should be used to reduce the ratio for the residential class. Horizon has indicated that its proposal with respect to street lighting is driven by a need to mitigate the total bill impact for this class to less than 10%. (AIC, p. 25) The Council submits that the 10% is a guide and given the nature of the customers in this class a larger bill impact could and should be tolerated. Clearly, there should be a greater effort made to reduce the cross subsidization of street lighting by residential customers.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2007-0697

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

AND IN THE MATTER OF an application by Horizon Utilities Corporation for an order approving or fixing just and reasonable rates and other charges for the distribution of electricity to be effective May 1, 2008.

BEFORE: Gordon Kaiser
Vice Chair and Presiding Member

Cynthia Chaplin
Member

Decision With Reasons

October 3, 2008

BACKGROUND

Horizon Utilities Corporation ("Horizon") filed an application with the Ontario Energy Board (the "Board") on October 22, 2007, under section 78 of the *Ontario Energy Board Act*, *1998*, seeking approval for changes to the rates that it charges for electricity distribution, to be effective May 1, 2008. Horizon is the licensed electricity distributor serving a customer base of approximately 232,000 customers in the cities of Hamilton and St. Catharines.

COST ALLOCATION AND RATE DESIGN

The following issues are addressed in this section:

- Line Losses
- Revenue to Cost Ratios
- Fixed Variable Split
- Transformer Ownership Allowance
- Retail Transmission Service Rates
- Credit Card Convenience Charge

Line Losses

Horizon is seeking approval of a Total Loss Factor of 1.0421 for secondary metered customers < 5,000 kW. Horizon developed its forecast loss factor for 2008 on the basis of averaging losses for the period May 1, 2002 to June 30, 2007. No intervenor objected to this proposal.

Board findings

The Board accepts Horizon's proposed total loss factor of 1.0421.

Revenue to Cost Ratios

The following table sets out the results of Horizon's cost allocation study, its proposed revenue to cost ratios and the target ranges as contained in the Board's report on *Cost Allocation for Electricity Distributors*, which was issued Board's November 28, 2007.

Revenue to Cost Ratios

Rate Class	**Cost Allocation Study** Col 1	**Application** Col 2	**Target Range** Col 3
Residential	123.6	112.4	85 – 115
GS < 50 kW	92.0	92.5	80 – 120
GS > 50 kW	72.1	86.3	80 – 180
Large Use > 5 MW	49.8	92.1	85 – 115
Street Light	15.6	23.8	70 – 120
Sentinel	34.8	91.5	70 – 120
USL	34.2	88.1	80 – 120
Back-up/Standby	51.0	65.8	n/a

VECC submitted that Horizon's approach to determining the proposed allocations leads to anomalous results. In particular VECC submitted that the proposed change in Large User rates could not increase the revenue to cost ratio from 49.8% to 92.1% as claimed by Horizon, and provided a calculation that the proposed change would yield a ratio of 57.45%. Horizon responded that its methodology was correct and that VECC's approach was in error. Horizon noted that the Large User allocated share of cost is 6.84%, or $6,487,111 based on a revenue requirement of $94,859,978, and argued that the proposed revenue is in fact 92.1% of the class revenue requirement.

All the intervenors submitted that the Streetlighting ratio should be increased by more than the proposed amount. Board staff and Schools submitted that the rates should be increased to yield a ratio of 43%, half-way to the bottom of the Board's target range of, namely 70%. The Council submitted that it should be increased to yield a ratio of 70%.

Board staff noted that the proposed rates would increase the revenue to cost ratio for Sentinel Lights from 34.8% to 91.5%, and would entail a bill increase of approximately 67%. Schools supported the proposed ratio for this class. VECC suggested a less aggressive change than proposed.

Board staff noted that the proposed rates would increase the revenue to cost ratio for Unmetered Scattered Load from 34.2% to 88.1%, and would entail a bill increase of approximately 35%. Schools supported the proposed ratio, while VECC suggested a less aggressive change than proposed. With regard to both Sentinel Lights and USL, VECC submitted that caution should be taken when moving to a ratio closer to 100% than required by the Board's policy range.

VECC and the Council submitted that, to the extent that adjustments to other classes would yield revenues higher than that proposed by Horizon, the benefit should be felt by the Residential class. The reason for this is that only this class has been proposed to have a ratio above 100%. Horizon did not agree with VECC in this regard, and pointed out that the application entailed a bill decrease for Residential customers.

Board Findings

The Board is satisfied with Horizon's explanation of its methodology and finds that the ratios in column 2 of the table are appropriate for purposes of reviewing the revenue to cost ratios for 2008. Having reviewed the record of Horizon's previous re-basing (RP-2005-0020/EB-2005-0375) along with the cost allocation study submitted by Horizon with this application, the Board has concluded that there were data errors in the cost allocation study and that the initial ratio of 49.8% should be disregarded. VECC's submission was helpful in identifying inconsistencies in the initial application, which is the information summarized in column 1.

The Board notes Horizon's proposal to bring the Sentinel and Unmetered Scattered Load classes within the Board target ranges and the large rate impacts involved. However, the Board has already acknowledged the uncertainties associated with the cost allocation work. The Board concludes that it is more appropriate for the Sentinel and Unmetered Scattered Load classes to be moved to the bottom of the target ranges, 70% and 80%, respectively, and directs Horizon to do so.

The Board concludes that the Streetlighting class should be moved closer to the Board target range. This is consistent with other recent Board decisions on this issue. The revenue to cost ratio will be 43% for Streetlighting in 2008. The Board notes that Horizon did not object to this approach. The Board further directs Horizon to move the ratio to 70% as part of its 2009 IRM application.

If additional revenue arises due to these adjustments, the benefit will be allocated to the Residential rate class because it continues to have a revenue-to-cost ratio in excess of 1.

Fixed-variable Split

Horizon proposed to maintain the fixed-variable split at previously approved levels, and noted the ongoing Board proceeding on fundamental rate design. Both staff and VECC noted that the fixed charges are higher than the range calculated in the cost allocation study. Board staff submitted that the fixed charges proposed would be consistent with Board policy. The Council supported the proposed approach.

Board staff and Schools noted that the variable rate for the GS<50 kW class is proposed to increase by a higher percentage than the fixed rate. Schools submitted that the two rates should be changed by an equal percentage. For the GS> 50 kW class, Schools submitted that Horizon's fixed rate is high relative to that of other distributors, and submitted that the rate should be left unchanged at its current amount. Horizon responded that it would be inappropriate to provide different treatment to these two classes than to the other classes, given the ongoing work in this area.

Horizon Utilities
Streetlighting Costs 2007 to 2015
City of Hamilton

		Impact				Percentage Changes			
Year	**Revenue to Cost Ratio**	**Change in R: C Ratio**	**Change in HUC Cost Structure**	**Total Change in Distribution Revenue**	**Total Distribution Revenue**	**Change in R: C Ratio**	**Change in HUC Cost Structure**	**Total Change in Distribution Revenue**	**Notes**
2007	15.6%	[redacted]			279,079				2007 cost prior to 2008 CoS application
2008	43.0%	531,317	7,256	538,573	817,652	190.4%	2.6%	193.0%	Board ordered transition to 70% over 2 years
2009	70.0%	462,144	9,648	471,792	1,289,444	56.5%	1.2%	57.7%	Board ordered transition to 70% over 2 years
2010	70.0%	-	-	-	1,289,444	0.0%	0.0%	0.0%	0.18% IRM change - no impact
2011	75.0%	92,103	119,062	211,165	1,500,609	7.1%	9.2%	16.4%	Natural progression to 70% without adjustment
2012	75.0%		7,233	7,233	1,507,842	0.0%	0.5%	0.5%	IRM
2013	75.0%		18,419	18,419	1,526,261	0.0%	1.2%	1.2%	IRM
2014	75.0%		25,203	25,203	1,551,464	0.0%	1.7%	1.7%	IRM
2015	83.3%	224,247	85,138	309,384	1,860,848	14.5%	5.5%	19.9%	Daisy chain ratio 1.3 from 2.0/ LU Cost alloc/ HUC cost incr.
2015/2007	83.3%	1,309,811	271,959	1,581,769	1,860,848	469.3%	97.4%	566.8%	

This is Exhibit “P” referred to in the

Affidavit of Gord McGuire

sworn before me this 6th day of October, 2014.

A COMMISSIONER FOR TAKING AFFIDAVITS

McGuire, Gord

From:	Parker, Shelley <shelley.parker@horizonutilities.com>
Sent:	August-07-14 7:00 PM
To:	McGuire, Gord; Thachuk, Bruce; Lerette, Kathy
Cc:	Locs, Peter; Field, Mike; Lauricella, Charlie; Moore, Gary
Subject:	RE: Streetlight Data Base
Attachments:	RE: Street Light Data Base updates - from meeting June 11th; Milestone Timelines-HorizonProposal.xlsx; Milestone Timelines-HorizonProposal-7Aug2014.xlsx; March 27 2014 Minutes.doc; ATT1390474.txt

Hello Gord;

Horizon Utilities is equally invested and committed to the resolution of the Connections Audit. The Connections Audit was undertaken at considerable expense to both parties with the principle intended outcome to be the verification of installed street lighting assets. It is vital that the audit be completed with the same rigor of process as with which it was undertaken, otherwise we risk not achieving our original goal and wasting resources.

Bruce has previously provided project plans for your review, most recently on June 16th (attached as Milestone Timelines – HorizonProposal). This plan, which includes proposed the cut-over timeframe, has been circulated to the City a number of times previously.

A lot of great work has been achieved to date on the Connections Audit. We have mutual agreement on 95% of the 39,267 street lights that were originally identified and by the end of this week Horizon Utilities will have completed all of the field work on the known Horizon exceptions. Specifically, the field work was completed on the duplicate lights and the new poles where Horizon Utilities was the probable owner. The recommendation(s) regarding each asset will be forwarded to the City for final verification.

Horizon Utilities is anticipating the same ability to verify City-identified recommendations. That is, to complete our validation, we need to have a full dataset of the 39,267 audit records, in a tabular format (i.e. Excel) where the City or Horizon recommendation for asset resolution can be identified, and the verification / acceptance be documented by the other party. Bruce has asked for the full record set to be made available, however; we are currently missing the approximately 2,600 assets that the City has identified as "metered". To complete the audit, we need the opportunity to validate this assumption.

Based on the joint progress to date, Bruce has once again taken the liberty of updating a project plan (attached as Milestone Timelines-HorizonProposal-7August2014). This plan would have us addressing exceptions and unfreezing the database by the end of the year. Full project closure, including the completion of the demarcation points would occur by the end of Q2 2015. We would be happy to discuss the project plan and timing at our meeting next week.

The continued freezing of the database is very problematic to Horizon Utilities as well. The application of the backlog of light changes and retro-billing adjustments will be a significant effort and we are looking forward to a common dataset with improved joint processes.

Sincerely,
Shelley

Shelley Parker
Director, Customer Service
Horizon Utilities Corporation
55 John Street North, Hamilton, Ontario L8N 3E4
Tel: 905-521-4909
Toll-free: 1-866-458-1236
Cell: 905-961-2943
Email: shelley.parker@horizonutilities.com
www.horizonutilities.com

determination until that time sometime in the future.

And alternatively, to make the determination as to rates, but to make them interim, which means you haven't really made the determination yet; you're just temporarily making it until such time as you can fix it, retroactively.

And that's the key to interim, is your ability to be retroactive later. Otherwise it doesn't matter.

So let me deal with the two of them.

First, should you decline to set just and reasonable rates at this time? It's clear that you have the power to do that. You can -- faced with an application, you can say either: We don't have enough evidence to make a determination on this issue or that issue, or: We don't think this is the right time to make the decision. We think it should be done in two years or in five years or whenever.

Here, there is clearly sufficient evidence before you on the record to make a determination on the issue of rates. We don't agree on what they should be, but there is evidence before you. And you haven't heard anybody say there is not evidence.

Now, is it true that more evidence would be available later, and it might be? Absolutely that's true. Every proceeding that I've ever been in, that's always been true of every issue, that, yes, there may be evidence in the future that will help us better understand the issues.

But as they say, the perfect is the enemy of the good. Right now you have evidence before you, and you have sufficient to make a determination. If you decline -- if you do as the city says and you decline to set street lighting rates, you only really have two choices, as Ms. Spoel has, I think, correctly pointed out. You either decline to set rates for everybody, because you can't set rates for one and not the other. It is a zero-sum game. Or you say, Okay. We'll set rates for everybody else but not for street lighting, in which case you are deliberately deciding not to comply with the fair-return standard, because it's a zero-sum game.

So if you change the number on street lighting, Horizon then isn't getting their duly determined revenue requirement. They aren't being given the opportunity to earn a fair return, so you can't do that.

So our view is it is not appropriate for you to decline to set the rates. And I should point out that we've heard all morning now evidence on the substance of the matter. Why couldn't that have been in the proceeding? Why wasn't that filed? Why weren't these disputes put before the Board? I don't know why. I haven't heard anybody say why. A motion doesn't appear to be the right way to deal with something that is a live issue in the proceeding.

So then the second thing is, well, should you declare the rates interim? Well, the theory of the city appears to be this: There is new evidence coming. As a result of that new evidence a new policy is possible. And when the Board implements this theoretical new policy -- and this is report. The construct was, if there are changes beyond the purview of Horizon that are imposed on the sector, whether that be from government or from the Board that would have a rate impact, the idea is that Horizon wouldn't be punished by having to make changes and not be able to recoup.

So that's why I say if it was a matter of everything from cost of capital to something like a new smart-grid policy or a new Board policy, that this is how we are going to change rates -- standby rates would be a good example. At some point you are going to make a determination on that, and whatever those new standby rates are would be flowed through and changed in the annual update.

MS. SPOEL: Sorry, Mr. Rodger, I will just ask a follow up on that. Would it be your view or your client's view that -- and the other parties to the settlement agreement's view that since cost allocation and rate design are not settled issues, that the re-openers -- that the re-openers would -- I mean, if the matter of cost allocation were reopened, but didn't affect the revenue requirement or any of the other matters dealt with in the settled portions of this case, that -- those -- would those re-opener conditions apply to cost allocation and rate design anyway, if they had no effect on the other aspects of the case? I'm thinking aloud a bit, but I want to hear parties' input on these before we go off and do something strange on our own.

You don't have to respond to that question right now. It is just one to think about.

MR. WARREN: I think in response to Ms. Long's question, though, if that re-opener provision did capture the outcome of whatever the Board does, with what I'll call the Navigant process, then that addresses my client's concern.

MS. LONG: Those are the Board's questions.

Mr. Rodger?

MR. RODGER: Thank you, Madam Chair.

SUBMISSIONS BY MR. RODGER:

MR. RODGER: Madam Chair, Horizon opposes the city of Hamilton motion and submits that it should be dismissed by the Board. The Board made a very clear decision in dismissing what is essentially the same motion that the city of Hamilton brought in the recent Hydro One case, and the Board should render the same decision on this motion in this case.

I have six points that I want to raise. Firstly, the relief sought in the amended motion has not changed in substance. The original motion was to freeze street lighting rates or make street lighting rates interim pending the outcome of the Board's policy review, and the amended motion is to not set street lighting rates and make street lighting rates interim until a consultant's report is received and acted upon, whatever "acted upon" means. Does it mean the Board adopting the report, or does it mean my friend reciting a Shakespeare soliloquy while standing on the report?

The amended wording and the relief sought amounts to a the part they don't tell you -- when they implement this policy, the Board will not implement transition rules that are fair to the city. That's necessarily true, otherwise you don't need to declare rates interim.

There is no basis in our mind to assume that the Board will be unfair in establishing any new policy, unfair to the city, unfair to Horizon, or unfair to everybody else, or anybody else.

They -- the Board's practice is to look at how a new policy should be implemented, and to do it in the fairest possible way. The city may not like it at the time, but it will be for the Board to decide when it implements the new policy.

And I just want to comment in this respect on the settlement agreement. My understanding of what was agreed in the settlement agreement is that what we're trying to explain is that the settlement agreement is not intended to pre-empt the Board from having new policies and having them apply to Horizon.

We're trying to make clear that as new policies come in over the next five years, to the extent that the Board determines that they're applicable to Horizon, the settlement agreement, and your order based on that settlement agreement, should not stand in the way of that.

It is not intended to say the opposite, which is new policies immediately apply to Horizon no matter what the Board says. That's not what it says.

So finally, I want to say this: In any case before

Meeting Notes #2
Cost Allocation Working Group
Thursday, March 27, 2003
9:30 a.m. - 3:15 p.m.

1. Review of Developments Since Last Meeting

Staff reviewed new timelines set out in Board correspondence. This working group will focus on what data utilities should start collecting (e.g. on January 1, 2004), with a view to later completing their cost allocation studies (e.g. in the Spring of 2005).

Issues relating to how to complete the cost allocation studies (e.g. use of a "minimum system" approach) will be examined later.

General concern was expressed over the cost to the industry of completing the studies. The key role played by the Minister of Energy, under Bill 210, in approving new rate applications was discussed. Staff noted the financial concerns expressed and explained the subsequent sessions would examine in detail how good technical results could be obtained in a cost-effective manner.

Whether the Badali Report had any direct implications for the mandate of this phase of the cost allocation working group was discussed. It was thought the primary goal of the cost allocation studies was to check for any cross-subsidization between rate classes, and that pure rate design issues (such as the merits of fixed v. variable rates) should be examined later in the planned 2006 "going-in rates" consultations

2. Review of Working Group Schedule

The future agenda of the working group was discussed and based on participants feedback, two extra items were added to the agenda:

- What data should be collected as of January 1, 2004 to better inform subsequent rate design debates.
- The significance of direct assignment of costs.

Staff also explained that members of the work group would be asked to kickoff the discussion on each technical topic, and that the entire group would be asked to prepare a report by around June 2003.

3. Goals of Cost Allocation Studies

After the group discussed widely accepted principles of rate setting (as found, for example, in Bonbright), it was agreed that the primary purpose of the cost allocation studies was to ensure fairness between rate classes. The paramount role of cost causality in determining fairness was acknowledged. In this regard, the Board's comments on cost allocation in RP-1999-0034 (para.2.0.13) were highlighted ("utilities will be required to undertake cost allocation studies to better align rates among customer classes with cost causation in second generation PBR").

The importance of coming up with practical ways for the Ontario electricity distribution sector to complete potentially 90plus cost allocation studies was stressed.

The group also acknowledged rate stability as a secondary goal. There was some discussion about the potential role of efficiency, and it was decided it would be examined further at the rate design stage.

4. Alternative Methods of Allocating Demand-related Dx Costs

In a discussion kicked off by Bill Harper, Roger White and Hydro One, the strengths and weaknesses of various methods of allocating demand-related distribution costs (coincident peak, non-coincident peak ("NCP"), average and excess) was debated. Experiences in other jurisdictions were discussed, and it was noted NCP is the method most frequently used to allocate demand-related distribution costs (while the other approaches are widely used in the generation and transmission sectors).

After reviewing the merits of the various approaches, the initial views of the majority of the group was that:

1) NCP should be the general method (i.e. "default") used to allocate demand-related distribution costs in the forthcoming cost allocation studies, since:

- In general, distribution facilities are the facilities that are closest to the customers and are sized to meet the individual customer's demand and not the aggregated demand.
- Using non-coincident demand would better match cost allocation between customer classes with costs recovery from the same customer classes.
- Non-coincident demand would allocate a fairer share of costs to customer groups that use the facilities, but are not consuming much electricity at the time of the LDC peak.
- Customers would have better control over their non-coincident demand.
- Non-coincident demand is generally more stable and easier to forecast.
- Non-coincident demand is relatively easier to measure, track, and understand.
- Development of DSM initiatives may be easier if the starting basis is NCP demand.

2) Under some circumstances, use of CP could be an attractive choice to allocate demand-related distribution costs (e.g. with sub-stations and associated subtransmission lines for utilities with a single point of supply). It was therefore recommended that Ontario LDCs be given the option of using the coincident peak method to allocate demand-related Dx costs in their forthcoming cost allocation studies, provided they provide a reasonable explanation of their preference for using the CP method. To provide assistance to subsequent parties, the working group would endeavour to provide some comments as to when LDC use of CP may be seriously considered.

3) The group did not believe the OEB should mandate use of Class 1 NCP, where the non-coincident demand allocator is determined by considering all of the customers in the class as one service point and determining the associated maximum annual demand for the class. The group believed that, in some situations, it may be appropriate to allocate demand-related distribution costs using NCP for each customer class averaged over a number of months (for example, 12 NCP has been by Hydro One Networks). It was agreed this choice should be left to each utility, who could justify a particular choice based on its unique circumstances. The working group would attempt to issue some general comments to assist utilities.

4) To ensure flexibility in completing the studies, both class and customer NCP values should be gathered.

Initial Decision: Bill Harper would prepare a short set of guidelines, reflecting the above, for future review by the group.

4. Other

- A copy of a October 1, 1996 Ontario Hydro document entitled “Cost of Service Methods: A Guide for Ontario Municipal Utilities” was made available for the Board’s library.

Attendance

Bluewater Power - Ron LaPier, Kathy Gadsby
Brantford Power - Heather Wyatt
Canadian Niagara Power Inc. - Doug Bradbury
Chatham-Kent Hydro - Jim Hogan
Guelph Hydro - Jim Fallis
Hamilton Hydro - Cameron McKenzie,Terry Karp
Hydro One - Mike Roger
Hydro One Brampton - Scott Miller
London Hydro - Ken Walsh, Dave Williams
Milton Hydro - Don Thorne
Newmarket Hydro - Gaye-Donna Young
Oakville Hydro - Gary Parent
Ottawa Hydro - Lynne Anderson
Toronto Hydro - Anthony Lam
Thunder Bay Hydro - Cynthia Domjancic
Veridian - Laurie Stickwood
Woodstock Hydro - Ken Quesnelle

Econalysis - Bill Harper
ECMI - Roger White, Andy Bateman
EDA - Maurice Tucci; John Wong
RCS - Mike McLead; Peter Ioannou
Upper Canada Energy Alliance - Jim Richardson
FOCA - John McGee
Bob Mason
Chris Amos
Barker, Dunn & Rossi - Paula Zarnett, Neill Winger

Board Staff:
John Vrantsidis
Neil Yeung

REPORT ON THE OEB COST ASSESSMENT MODEL DEVELOPMENT AND CONSULTATION PROCESS

March 14, 2005

2. CLASSES OF MARKET PARTICIPANTS TO BE INCLUDED IN THE GENERAL ASSESSMENT, AND THE IMPLICATIONS WITH RESPECT TO THE PRINCIPAL OF COST CAUSALITY

Most stakeholder feedback addressed the issue of which categories of market participants should be included in the general assessment (i.e. Classes).

Cost causality was a key principal underpinning the model's development. Initially cost causality was considered in terms of the how the Board's interaction with market participant groups drives Board costs. However, input (mainly from competitive market participants) presented a compelling argument for cost causality being analyzed from the perspective of impact on the ultimate customer.

The OEB recognized a need to establish criteria for inclusion in the general assessment process. After considering the Navigant report and stakeholder feedback, the OEB decided to include market participants in the general assessment process if:

- their rates are regulated by the OEB; and
- their key activities are subject to regular and routine supervision by the OEB; and
- their contribution would not lead to inequitable results for customers.

Market Participants not included in the General Assessment

The Independent Electricity System Operator and the Ontario Power Authority

Under the preceding criteria, the Ontario Power Authority (OPA) and the Independent Electricity System Operator (IESO) would be included in the cost assessment.

The OPA has been established and is preparing to take on its responsibilities and the role of the IESO as it relates to the OPA is being clarified. These changes will have significant impact on the level and type of activity and interaction with the Board. The Board will closely observe how this part of the sector evolves so that it can ensure the most appropriate approach going forward and make recommendations to the Government to adjust this transitional arrangement as required, commencing in 2006-07.

Ontario Energy Board

Application of Cost Allocation for Electricity Distributors

Report of the Board

EB-2007-0667

November 28, 2007

1 Introduction

1.1 Scope

This Report sets out the Board's policies in relation to specific cost allocation matters for electricity distributors, and represents the culmination of a consultation process that began several years ago. It addresses a number of issues, most significantly the relationship between the class revenue and the class total allocated costs (the "revenue-to-cost ratio"). This Report also discusses the treatment of the Monthly Service Charge, metering credits for the unmetered scattered load class, transformer credits for customer-owned transformers, and charges for the provision of standby power for customers with load displacement generation.

1.2 Background

While electricity rates have been unbundled for some time, the basic historical cost relationship among rate classes has remained largely unchanged for the past twenty years.

Consultations on cost allocation have been on-going since 2002, and have benefited from the significant involvement of, and collaboration by, stakeholders and Board staff. An important milestone in this process was the issuance, on September 29, 2006, of a report of the Board entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors*,[1] which articulated a number of principles and established the cost allocation methodology to be used by distributors for the purpose of electricity rate design (the "Methodology"). To enable the Board to evaluate the Methodology, distributors were directed to use it in association with their respective approved 2006 revenue requirement for the purpose of making informational filings at the end of 2006 and through the spring of 2007.

The results of Board staff's analysis of the informational filings were set out in a staff Discussion Paper issued on June 28, 2007 and entitled *On the Implications Arising from a Review of the Electricity Distributors' Cost Allocation Filings*[2] (the "Discussion Paper"). Among other things, the Discussion Paper proposed an incremental approach for adjusting rates based on the Methodology. Interested parties were invited to comment on the Discussion Paper, and those that did so are listed in Appendix A.

[1] Available on the Board's website at http://www.oeb.gov.on.ca/documents/cases/EB-2005-0317/report_directions_290906.pdf.
[2] Available on the Board's website at http://www.oeb.gov.on.ca/documents/cases/EB-2007-0667/staff-discussion-paper_20070628.pdf.

1.3 Approach to Cost Allocation

The establishment of specific revenue requirements through cost causality determinations is a fundamental rate-making principle. Cost allocation is key to implementing that principle. Cost allocation policies reasonably allocate the costs of providing service to various classes of consumers and, as such, provide an important reference for establishing rates that are just and reasonable.

The Board is cognizant of factors that currently limit or otherwise affect the ability or desirability of moving immediately to a cost allocation framework that might, from a theoretical perspective, be considered the ideal. These influencing factors include data quality issues and limited modelling experience, and are discussed in greater detail in section 2.3 of this Report. The Board also recognizes however, that cost allocation is, by its very nature, a matter that calls for the exercise of some judgment, both in terms of the cost allocation methodology itself and in terms of how and where cost allocation principles fit within the broader spectrum of rate setting principles that apply to – and the objectives sought to be achieved in – the setting of utility rates. The existence of the influencing factors does not outweigh the merit in moving forward on cost allocation. Rather, the Board considers that it is both important and appropriate to implement cost allocation policies at this time, and believes that the policies set out in this Report are directionally sound. With better quality data, greater experience with cost allocation modeling and further developments in relation to other rate design issues, the policies will be refined as required.

The policies set out in this Report have been informed by the Discussion Paper and the comments of interested parties on it. The Board is grateful to all that have participated in the consultations that have enabled the Board to complete this phase of its cost allocation work.

1.4 Organization of the Report

This Report is organized as follows:

- Section 2: **Revenue-to-cost Ratios – A Range Approach**, summarizes the Board's approach to revenue-to-cost ratios.
- Section 3: **Revenue-to-cost Ratios – Ranges by Rate Class**, sets out the class-specific revenue-to-cost ratio ranges that have been established for each customer class.
- Section 4: **Other Rate Matters**, discusses the treatment of the upper and lower bounds for the level of the Monthly Service Charges, metering credits for the unmetered scattered load class, transformer credits for customer-owned transformers, and charges for the provision of standby power for customers with load displacement generation.
- Section 5: **Implementation**, identifies how the policies set out in this Report are expected to be applied by distributors.

level, there's enough white space, if you will, on a demand curve such that they won't -- there won't be a constant migration or reclassification back and forth between the classes.

DR. ELSAYED: I understand that. I guess the question mainly is, why have the megawatt criterion in there altogether, as opposed to having dedicated assets as the only criterion?

[Witness panel confers]

MR. ROGER: Theoretically speaking, you could have something that is dedicated assets, but it could be also that we're talking about different types of customers. It could be customers that -- between 20, 30, 40 megawatts of dedicated assets.

It could be for some reason you could have a small general-service customer with dedicated assets, and the type of assets there are not the same. And that's the reason that we felt that we needed also a size, the limiter there.

DR. ELSAYED: Thank you.

MR. JANIGAN: Panel, if I could address another question to you. I wonder if you could turn up tab 3 of my compendium. And here we've asked about a wholesale meter costs allocated to the Large Use (2) class. You explain that two of the customers own their own meters, while the other two, the costs of the current meters are fully depreciated.

You then go on to say that for both of these customers

Undertaking No. J2.2

Reference: Page 65 of Transcripts Volume 2

To provide information on whether the existing customer at 9 megawatts with a dedicated feeder should be separated out into a new customer class, and whether a new customer class would be created for future customers that fall into the same category.

Response:

In preparation for this application, Horizon Utilities engaged Elenchus Research Associates Inc. ("Elenchus") to undertake a review of Horizon Utilities' 2011 CA Model that included a detailed examination of the actual facilities included in the accounts that serve as inputs to the model to determine whether there could be refinements that would better reflect the principle of cost causality in allocating costs to customers.

One of the determinations of this review was that the largest customers in Horizon Utilities' Large Use customer class are served exclusively with dedicated facilities, and maintaining these customers in the current Large Use class results in them being allocated costs for pooled distribution facilities that they do not use. In order to appropriately address cost causation, and the uniqueness of some of its customers, Horizon Utilities has proposed a new Large Use 2 ("LU (2)") customer class, for customers with demand over 15 MW, who also are served by dedicated assets.

As part of the Oral Hearing, held on September 30th and October 1st 2014, some questions were posed to Horizon Utilities regarding the LU (2) class criterion of 15MW. In particular, VECC asked of Horizon Utilities (see Transcript Volume 2, Page 61) "What is the relevance of setting the 15-megawatt criterion for being part of the Large Use (2) class? In other words, why not make it customers served by dedicated assets alone?"

In response to this question, Horizon Utilities' witness panel advised that the dual criteria for the LU (2) customer class were used as it provided for homogeneity among the customers within the class. All of the proposed customers within the class are served with dedicated facilities, and have demands that far exceed the 15MW minimum. Using both of these criteria, Horizon Utilities was satisfied that they would not, under normal operating circumstances, run the risk of customers moving between the LU (1) and LU (2) customer class. Ongoing customer reclassification, wherein customers fall in and out of the class would be problematic.

Board Panel Member Dr. Elsayed asked the following question at page 67 of Tr. Vol. 2:

DR. ELSAYED: I understand that. I guess the question mainly is, why have the megawatt criterion in there altogether, as opposed to having dedicated assets as the only criterion?

Horizon Utilities has revisited the 15MW criterion in light of the discussion in the hearing, and has determined that it sees the merits in the potential alternative of using a demand criterion of 5MW (as is applicable to all Large Use customers) and the dedicated assets criterion. This would bring the 9 MW customer into the LU (2) class.

Horizon Utilities would be amenable to such an outcome, should the Board so find. To further assist the Board and Parties, Horizon Utilities has illustrated the implications of this alternative in the tables below. Table 1 provides a comparison of the Fully Allocated Costs and Distribution Revenues by rate class as filed with the Settlement Proposal and with the LU (2) demand criteria set at 5MW. The impact of changing this criterion is not material to any rate class.

Horizon Utilities has also considered two associated matters – first, whether the removal of the demand threshold could make it more likely that customers will move in and out of the LU (2) class; and second, whether, if the criteria of dedicated assets becomes the sole criterion for membership in the class, it would be appropriate to open membership in this class to GS > 50 customers as well.

With respect to the first matter, Horizon Utilities believes that it is not likely that LU (2) customers will frequently move in and out of the class if the 15 MW threshold is removed. Horizon Utilities believes that once assets have been constructed for use by a particular customer, it would be unusual for the assets to become shared, even where there were fluctuations in demand over time, because the assets would have to remain available for the customer to whose use they were originally dedicated.

With respect to the second matter, Horizon Utilities believes that while the removal of the 15MW threshold for membership in the LU (2) class may be appropriate, it would not be appropriate to remove the demand threshold in its entirety. While it is possible that a smaller General Service customer (that is, with demand under 5MW) may be served by a dedicated feeder, a customer with that level of demand would not require a dedicated feeder. Dedicating a 13.8 kV feeder to a single General Service customer is neither technically necessary nor an efficient use of

Horizon Utilities' distribution assets. Horizon Utilities would typically share the feeder among a group of customers of that size, so that notwithstanding that the feeder was not being shared at a particular time, it would be capable of being shared because there would be available capacity on the line.

Accordingly, Horizon Utilities submits that a reasonable alternative to its 15MW/dedicated assets criteria would be a dual 5MW/dedicated assets qualification for membership in the class. In other words, membership would be open to those customers that already qualify for membership in the Large Use class by virtue of their demand, and that are served by dedicated assets.

Table 1: Comparison of 2015 Distribution Revenues and Fully Allocated Costs

	Fully Allocated Costs (Per Settlement Agreement)	Fully Allocated Costs (With LU (2) Classification at 5MW)	Variance	Distribution Revenues (Per Settlement Agreement)	Distribution Revenues(With LU (2) Classification at 5MW)	Variance
Residential	$ 68,263,922	$ 68,306,448	$ 42,527	$ 66,927,936	$ 66,936,992	$ 9,055
GS < 50 kW	$ 15,617,872	$ 15,648,687	$ 30,815	$ 14,825,036	$ 14,887,980	$ 62,944
GS >50 to 4999 kW	$ 22,962,722	$ 23,041,790	$ 79,069	$ 20,614,214	$ 20,692,165	$ 77,951
Standby	$ 1,452,849	$ 1,460,691	$ 7,843	$ 715,033	$ 717,749	$ 2,717
Large Use (1)	$ 1,919,882	$ 1,598,406	$ (321,476)	$ 2,067,358	$ 1,715,287	$ (352,071)
Large Use (2)	$ 440,080	$ 607,641	$ 167,560	$ 487,871	$ 678,787	$ 190,916
Sentinel Lights	$ 44,722	$ 44,656	$ (66)	$ 44,838	$ 42,556	$ (2,281)
Street Lighting	$ 3,342,981	$ 3,337,033	$ (5,949)	$ 2,629,966	$ 2,641,132	$ 11,166
Unmetered and Scattered	$ 393,301	$ 392,978	$ (323)	$ 448,163	$ 447,766	$ (397)

Horizon Utilities has also provided the updated Revenue to Cost Ratios in Table 2. Table 3 provides the updated distribution bill impacts. There has not been a material impact to either the Revenue to Cost Ratios or the Bill Impacts of any rate class as a result of reducing the demand criteria of the LU (2) class to 5MW.

Table 2: 2015 – 2019 Revenue to Cost Ratios

Class	Proposed Revenue-to-Cost Ratios					Policy Range
	2015	2016	2017	2018	2019	
	%	%	%	%	%	%
Residential	103.01	103.65	103.21	104.22	103.06	85 - 115
GS < 50 kW	99.82	99.48	99.78	101.35	99.09	80 - 120
GS > 50 kW	94.69	94.36	95.55	91.71	96.19	80 - 120
Large Use (1)	115.00	112.02	111.21	109.82	108.41	85 - 115
Large Use (2)	115.00	85.00	85.00	90.68	95.42	85 - 115
Street Lighting	83.34	82.59	83.60	83.59	83.37	70 - 120
Sentinel Lighting	100.00	100.37	98.43	97.11	95.55	80 - 120
Unmetered Scattered Load (USL)	120.00	119.89	119.53	120.00	119.67	80 - 120
Standby	54.76	54.34	53.89	54.02	53.94	Undefined

Ontario Energy Board

Report of the Board

Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

October 18, 2012

3.2.3 Facilitating the Implementation of Regional Infrastructure Planning through Amendment of Board Codes

Two issues relating to cost responsibility for transmission connection assets have been identified as potential impediments to the implementation of regional infrastructure planning and the execution of regional infrastructure plans.

The first issue (the “Otherwise Planned and Refund” issue) is centered on sections 6.3.6 and 6.2.24 of the Transmission System Code (“TSC”). As a general rule under the TSC, cost responsibility for transmission connection assets lies with the transmission customer, who may be required to make a capital contribution before the asset is built. Section 6.3.6 of the TSC creates an exception by stating that a capital contribution is not required for connection facilities that are “otherwise planned” by the transmitter. Section 6.2.24 of the TSC contemplates that, where a customer has made a capital contribution for the construction of a connection facility and that capital contribution includes the cost of capacity not needed by the customer, the customer is entitled to a refund of a portion of the capital contribution if that capacity is later assigned to another customer. However, that entitlement to a refund ends five years after the connection facility comes into service.

The second issue (the “Transmission Asset Definition” issue) pertains to the definition of certain transmission connection assets and the cost responsibility consequences that flow from that definition. Specifically, the question is whether certain line connection assets are more appropriately treated as network assets for cost responsibility purposes.

Stakeholder Views

Otherwise Planned and Refund Issue

Stakeholders generally agreed that changes to the current TSC cost responsibility rules for line connection assets are required to facilitate regional infrastructure planning and the ultimate execution of regional plans. Stakeholders were also broadly supportive of a shift away from the current emphasis on a 'trigger' pays model in relation to new or upgraded line connection investments.

It was noted that section 6.3.6 of the TSC can act as a disincentive to joint planning between the transmitter and distributors and that there are ambiguities in relation to when or how that section applies, as previously acknowledged by the Board.[14]

Some stakeholders identified that the effect of the five-year sunset proviso in section 6.2.24 of the TSC is that later-arriving customers that benefit from a connection asset are able to avoid contributing to the cost of that asset. It was noted that this can create an inappropriate incentive for a distributor to delay requesting additional capacity until after the five year period expires.

The Transmission Asset Definition Issue

Stakeholders were generally supportive of redefining line connection assets. Among the concerns noted with the current cost responsibility regime is that it does not take into account the evolutionary nature of the transmission system and that, in some

[14] In its September 7, 2007 Decision and Order issued in respect of a combined proceeding regarding the connection procedures of two transmitters (EB-2006-0189/EB-2006-0200), the Board stated that *"[T]here can be ambiguity with respect to whether an enhancement of the system is one which is designed primarily to address system integrity and reliability issues as identified by the transmitter, on the one hand, and those which are primarily of benefit to one or a small group of customers who have a pressing local need, on the other….That ambiguity is most easily resolved where the transmitter can demonstrate that the enhancement was identified as part of its planning process and not merely because a customer has requested it. To be clear, where planning involves joint studies between Hydro One and one or more distributor(s) to meet different timing and supply needs such as load growth, the Board views such plans as customer-driven, where a capital contribution would be required."*

cases, a distributor is responsible for the costs associated with line connection assets that perform functions beyond simply supplying the distributor.

However, stakeholders were divided on the scope of the proposed redefinition. Some stakeholders suggested that line connection assets be defined as network assets in all cases. Others proposed that line connections be so defined only in cases where such line connection assets provide other functions beyond supplying a distributor, citing the example of Dual Function Lines.[15]

It was also noted that line connection assets are not currently classified in a consistent manner. In particular, in about 50% of the cases 115/230 kV auto-transformers are currently classified as network assets (and the costs recovered from all Ontario ratepayers), while in the remaining 50% of the cases they are classified as line connection assets (and the costs recovered from only the triggering distributor and its customers). It was further noted that all distributors in a region benefit from a 115/230 kV auto-transformer, and that it is essentially impossible to determine the extent to which each transmission customer benefits from such an asset.

The Board's Conclusions

Otherwise Planned and Refund Issue

The Board concludes that a reconsideration of the TSC cost responsibility rules is desirable to facilitate the implementation of regional infrastructure planning and the execution of regional infrastructure plans. The Board believes that a shift in emphasis away from the 'trigger' pays principle to the 'beneficiary' pays principle is appropriate in that regard.

[15] The definition of certain line connections as Dual Function Lines was approved by the Board in Hydro One's EB-2006-0501 transmission rate proceeding. It addressed the Board's concerns associated with the Line Connection pool in the RP-1999-0044 transmission rate proceeding, where the Board stated that it expected the definition of the Line Connection pool to be reconsidered in Hydro One's next cost allocation and rate design proceeding.

The reference to “otherwise planned” in section 6.3.6 of the TSC implies that a transmitter is expected to plan investments without the input of transmission customers, including distributors. This is incompatible with the Board’s approach to regional infrastructure planning set out above. The Board will therefore initiate a process to propose the removal of section 6.3.6 of the TSC.

The Board also concludes that the five year limit on the requirement to provide a refund to the initial transmission customer or customers that provided a capital contribution may be creating unintended effects. The Board will therefore also propose amendments to section 6.2.24 of the TSC regarding the five-year sunset provision.

These TSC amendments would apply on a go forward basis only (i.e., only to initial customers that make a capital contribution after the amendment comes into force).

Transmission Asset Definition Issue

The Board concludes that no redefinition is required in relation to transformation connection assets for the purpose of facilitating regional infrastructure planning. However, the Board also concludes that the redefinition of certain line connection assets in a manner that better reflects the function that each asset performs will facilitate the implementation of regional infrastructure planning, and should also place distributors (and therefore all Ontario customers) on a more level playing field in terms of cost responsibility. To the extent that line connection assets are defined based on function, distributors (and their customers) will be responsible only for the costs associated with upgrades to assets that are used solely to supply a distributor or group of distributors (i.e., where such distributors are the sole beneficiaries). The end result will be somewhat akin to ‘partial’ province-wide pooling with the uploading of some transmission assets from the line connection pool to the network pool. At the same time, all distributors will remain responsible for the costs associated with some line connection assets. This approach should maintain cost discipline.

The Board has concluded that all 115/230 kV auto-transformers and the associated switchgear should consistently be defined as network assets. The rationale for classifying this subset of transmission assets as network assets was previously explained by the Board as follows:

> These unique system elements in some instances accommodate loads that are beyond a customer's requirement (e.g., autotransformers connecting the 230 kV transmission system to the 115 kV transmission system) …. In particular, use of autotransformers is seen as a means to optimize use of the transmission system as a whole in accommodating new loads safely and reliably and, most of all, in a timely manner.[16]

The Board will further engage stakeholders in the identification of all line connection assets that perform one or more functions beyond supplying the distributor and in developing criteria to be used to assess new assets and future upgrades to existing assets for redefinition purposes. That consultation will take into account the function the asset performs, reflect the 'beneficiary' pays principle and consider the frequency with which line connection assets should be reviewed to ascertain the function they provide for the purpose of future transmission rate proceedings.

Once the stakeholder consultation has been completed, the Board expects to propose amendments to the relevant provisions of the TSC with a view to integrating the new treatment of all applicable line connection assets, and will proceed with any other changes to its regulatory instruments as may be required to give effect to those amendments.

These changes are expected to apply on a go forward basis only (i.e., to new line connection assets or to upgrades to existing line connection assets that are built after the amendment comes into force). This approach will avoid retroactive changes in cost allocation and the associated rates. As a consequence, the Board notes, only future

[16] September 7, 2007 Decision and Order issued in respect of a combined proceeding regarding the connection procedures of two transmitters (EB-2006-0189/EB-2006-0200), pages 24-25.

line connection upgrades have the potential to affect the execution of regional infrastructure plans.

Pooling

During the consultation process, stakeholders provided insight into the relative merits of implementing changes to the Board's cost responsibility regime that are of a more transformative nature than those discussed above. Specifically, stakeholders commented on the potential to move to the regional or province-wide pooling of transmission connection facility costs, in whole or in part. The Board has concluded that a shift to province-wide pooling carries with it the risk of cross-subsidization, the potential for transmission overbuild and an inappropriate cost shifting between regions in the province. Regional pooling would only address those risks to some extent, and would be too complex to implement as regions may change over time and a number of distributors would be included in more than one regional pool. Moreover, the Board is satisfied that a move to any form of pooling of costs is neither necessary nor desirable at this time for the purpose of facilitating regional infrastructure planning and the execution of regional plans, given how the Board is addressing the cost responsibility issues discussed above.

3.3 Development of the Smart Grid

3.3.1 Background

With the coming into force of the *Green Energy and Green Economy Act, 2009*, several provisions were added to the OEB Act in relation to the development and implementation of a smart grid in Ontario. The Board now has a statutory objective to facilitate the implementation of a smart grid on Ontario, and it is a deemed condition of

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August 26, 2013

NOTICE OF AMENDMENTS TO CODES

AMENDMENTS TO THE TRANSMISSION SYSTEM CODE AND THE DISTRIBUTION SYSTEM CODE

AND

NOTICE OF PROPOSAL TO AMEND A CODE

SUPPLEMENTARY PROPOSED AMENDMENT TO THE TRANSMISSION SYSTEM CODE

BOARD FILE NO.: EB-2011-0043

To: All Licensed Electricity Distributors
All Licensed Electricity Transmitters
All Participants in Consultation Process EB-2011-0043
All Other Interested Parties

The Ontario Energy Board (the "Board") has today issued amendments to the Transmission System Code ("TSC") and the Distribution System Code ("DSC") pursuant to section 70.2 of the *Ontario Energy Board Act, 1998* (the "Act"), as described in section B.

The Board is also giving notice of a supplementary proposed amendment to the TSC pursuant to section 70.2 of the Act, as described in section C.

the subject of ongoing studies being undertaken by the Independent Electricity System Operator ("IESO") in relation to transmission rates proceedings. In relation to item (iii), the Board notes that there would already be no refund, where an asset becomes stranded, as there would not be a connected customer to which a refund could be provided. The Board does not believe that item (iv) needs to be addressed through code amendments at this time.

No stakeholder objected to the elimination of section 6.3.6 from the TSC (the "otherwise planned" provision). However, Hydro One did suggest the need for an alternative provision, which is discussed in section C below.

4. Anticipated Costs and Benefits

The anticipated costs and benefits of the May Proposed Amendments were set out in the May Notice, and interested parties should refer to that Notice for further information in that regard. The Board believes that the revisions made to the May Proposed Amendments as described above will provide greater clarity for all concerned, and will not result in material incremental costs to distributors, transmitters or ratepayers.

5. Coming Into Force

As contemplated in the May Notice, the Final Amendments to the TSC and the DSC set out in Attachments A and B, respectively, come into force today, being the date on which they are posted on the Board's website after having been made by the Board.

C. Supplementary Proposed Amendment to the TSC

1. Proposal to Add a New Section to the TSC

As noted above, although there was support for the elimination of section 6.3.6 from the TSC, Hydro One suggested that it is important to preserve the concept of fairness in assigning cost responsibility where a new or modified connection facility is intended to provide benefits to the overall transmission system as well as to a particular connecting customer. Hydro One expressed concern about the fairness of the Board's approach to cost responsibility, as set out in the May Proposed Amendments, and recommended that the Board accept the notion that connecting customers should not be held responsible for the costs of facilities that are primarily required to address system needs. Hydro One suggested that this could be addressed by amending section 6.3.8 of the TSC by including the following: "A transmitter shall not require a customer to make a capital contribution in relation to a new or modified connection facility for any costs associated with meeting the general reliability and integrity needs of the transmission system." In Hydro One's view, the elimination of section 6.3.6 of the TSC without an alternative mitigating provision of this nature may lead to imprudent investments from a regional perspective, as distributors may be motivated to pursue "cheaper" local options (e.g., a sub-optimal distribution alternative) in order to avoid subsidizing transmission investments that address common needs.

Hydro One suggested two possible approaches to cost responsibility in such cases, both of which it stated could be accommodated by its proposed amendment to section 6.3.8. In one case, cost responsibility for the entire investment would be assigned to the network pool (i.e., all ratepayers) based on an independent assessment by, and input from, the OPA and/or the IESO. Alternatively, cost responsibility could be determined based on the proportional benefit between the connecting customer and the overall system, although Hydro One noted that this may be difficult to accomplish with precision in practice.

The Board sees merit in addressing the issue raised by Hydro One. The Board is of the view that the first approach proposed by Hydro One, where all of the costs would be borne by the network pool, would not be appropriate. As noted above, Hydro One's rationale for its proposed amendment is that the triggering customer(s) would unfairly bear the costs associated with any system benefits. Under Hydro One's first approach, however, unfairness would also exist; that is, it would rest with ratepayers who would bear all of the costs even though the triggering customer(s) would receive a benefit. The Board therefore believes that apportionment of the costs would be more appropriate. An approach based on apportionment is more consistent with the RRFE Board Report, where the Board identified a shift in emphasis to the "beneficiary pays" principle.[3] It is also consistent with Hydro One's suggestion that it is important to preserve the concept of fairness in assigning cost responsibility.

The Board believes that the issue identified by Hydro One is most likely manifested in one scenario in particular; namely, where the construction of and/or modification to one or more transmitter-owned connection facilities is a more cost effective means of meeting the needs of one or more load customers than the construction or modification of the transmitter's network facilities. Under such a scenario, it is expected that the construction or modification of network facilities can only be avoided by the construction of and/or modification to transmitter-owned connection facilities that exceed the capacity needs of the triggering load customer(s). In such a case, it is appropriate that the load

[3] The RRFE Board Report stated "The Board concludes that a reconsideration of the TSC cost responsibility rules is desirable to facilitate the implementation of regional infrastructure planning and the execution of regional infrastructure plans. The Board believes that a shift in emphasis away from the 'trigger' pays principle to the 'beneficiary' pays principle is appropriate in that regard."

customer(s) whose needs trigger the project should only bear the cost to the extent that they benefit from the construction of and/or modification to the transmitter-owned connection facilities. Any incremental costs should be attributed to the transmitter and recovered from the network pool, as the costs associated with the avoided construction of or modification to the transmitter's network facilities would have been recovered from the network pool.

The Board is therefore proposing to amend the TSC to add new sections 6.3.8A, 6.3.8B and 6.3.8C to address this particular circumstance, which the Board expects will only arise on an exceptional basis. Where it does arise, as independently confirmed based on an assessment by the IESO, it is proposed that the transmitter be required to apportion the cost of the transmitter-owned connection facilities based on the non-coincident incremental peak load requirements of the triggering load customer(s), and to apply to the Board for approval of that apportionment. The Board believes that apportionment based on non-coincident incremental peak load should achieve an adequate level of precision in terms of the respective benefits. The load customer(s) whose needs trigger the project should neither be better off nor worse off by reason of a decision to implement a solution that results in investments that exceed the triggering customer(s) capacity needs but is more cost effective than an investment in network facilities. The Board also notes that this proposed approach is akin to the approach set out in section 6.3.5 of the TSC, under which a transmitter may in exceptional circumstances apply to the Board for permission to obtain a capital contribution from a customer in relation to the construction of or modifications to network facilities.

The Board recognizes that the more cost effective solution confirmed by the IESO may involve the modification of a transmitter-owned connection facility that serves one or more customer(s) other than the triggering load customer(s). This may occur where the transmitter modifies or constructs connection facilities to shift load from the triggering customer's connection facility to another connection facility with excess capacity. The non-triggering customer(s), who have no need for additional capacity, should not bear the cost of that modification or construction, and the Board is therefore proposing to include a new section 6.3.8C in the TSC to that effect.

The text of the proposed new sections 6.3.8A, 6.3.8B and 6.3.8C of the TSC is set out in Attachment E to this Notice. The Board remains of the view that section 6.3.6 should be eliminated from the TSC irrespective of the outcome of the consultation on the proposed new sections. The Board has therefore not considered it necessary to defer the elimination of section 6.3.6 (or any other of the Final Amendments relating to cost responsibility or other matters) pending the outcome of that consultation.

ENWIN Utilities Ltd.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date August 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2014-0156

LARGE USE - REGULAR SERVICE CLASSIFICATION

A customer is in the regular large use rate class when its monthly peak load, averaged over 12 consecutive months, is equal to or greater than 5,000 kW. The premises for this class of customer is predominantly used for large industrial or institutional purposes located on a parcel of land occupied by a single customer. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	7,756.50
Distribution Volumetric Rate	$/kW	2.2361
Rate Rider for Disposition of Deferred PILs Variance Account 1562 (2012) - effective until April 30, 2015	$/kW	0.0873
Rate Rider for Application of Tax Change - effective until April 30, 2015	$/kW	(0.0278)
Rate Rider for Deferral/Variance Account Disposition (2014) - effective until July 31, 2015	$/kW	0.4387
Rate Rider for Deferral/Variance Account Disposition (2014) - effective until July 31, 2015 Applicable only for non-Wholesale Market Participants	$/kW	(2.7009)
Rate Rider for Global Adjustment Account Disposition (2014) - effective until April 30, 2016 Applicable only for non-RPP customers, excluding Wholesale Market Participants	$/kW	0.9444
Retail Transmission Rate - Network Service Rate	$/kW	3.4849
Retail Transmission Rate - Line Connection Service Rate	$/kW	1.4994
Retail Transmission Rate - Transformation Connection Service Rate	$/kW	0.6021

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

ENWIN Utilities Ltd.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date August 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2014-0156

LARGE USE - 3TS SERVICE CLASSIFICATION

This classification applies to a customer whose monthly peak load, averaged over 12 consecutive months, is equal to or greater than 5,000 kW and the premise is serviced by a dedicated Transformer Station. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	27,467.52
Distribution Volumetric Rate	$/kW	2.7906
Rate Rider for Disposition of Deferred PILs Variance Account 1562 (2012) - effective until April 30, 2015	$/kW	0.1207
Rate Rider for Application of Tax Change - effective until April 30, 2015	$/kW	(0.0369)
Rate Rider for Deferral/Variance Account Disposition (2014) - effective until July 31, 2015	$/kW	0.6262
Rate Rider for Deferral/Variance Account Disposition (2014) - effective until July 31, 2015		
Applicable only for non-Wholesale Market Participants	$/kW	(2.8369)
Rate Rider for Global Adjustment Account Disposition (2014) - effective until April 30, 2016		
Applicable only for non-RPP customers, excluding Wholesale Market Participants	$/kW	1.2891
Retail Transmission Rate - Network Service Rate	$/kW	3.4849
Retail Transmission Rate - Line Connection Service Rate	$/kW	0.6021

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

ENWIN Utilities Ltd.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date August 1, 2014

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2014-0156

LARGE USE - FORD ANNEX SERVICE CLASSIFICATION

This classification applies to a customer whose monthly peak load, averaged over 12 consecutive months, is equal to or greater than 5,000 kW and the premise is serviced by the dedicated Ford Annex Transformer Station. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale participant.

It should be noted that this schedule does not list any charges, assessments or credits that are required by law to be invoiced by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, the Global Adjustment, the Ontario Clean Energy Benefit and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	104,025.87
Rate Rider for Disposition of Deferred PILs Variance Account 1562 (2012) - effective until April 30, 2015	$/kW	0.4511
Rate Rider for Application of Tax Change - effective until April 30, 2015	$/kW	(0.0796)
Rate Rider for Deferral/Variance Account Disposition (2014) - effective until July 31, 2015	$/kW	0.7027
Retail Transmission Rate - Network Service Rate	$/kW	3.4849
Retail Transmission Rate - Line Connection Service Rate	$/kW	0.6021

MONTHLY RATES AND CHARGES - Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0044
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0013
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

CBC Website

U.S. Steel Canada files for protection from creditors

Company has obtained court order from Ontario Superior Court of Justice for creditor protection

The Canadian PressPosted: Sep 16, 2014 8:36 PM ETLast Updated: Sep 17, 2014 3:09 PM ET

U.S. Steel Canada, citing years of operating losses, has filled for court-supervised protection to give the company a chance to restructure in hopes of being able to better compete in the North American steel industry.

The former Stelco Inc, which U.S. Steel bought in 2007, has recorded a loss from operations in each of the last five years for an aggregate operaing loss of about $2.4 billion since 2009, the company and its parent, U.S. Steel, said in statements issued after markets closed on Tuesday.

"The company has obtained a court order from the Ontario Superior Court of Justice for creditor protection under the Companies' Creditors Arrangement Act," U.S. Steel Canada said.

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The order provides a stay of certain creditor claims against during the CCAA process and appoints Ernst and Young as monitor.

Under the CCAA process, U.S. Steel Canada will carry on business as usual while it develops and implements a comprehensive restructuring solution, the company said.

In a separate announcement issued by U.S. Steel from its Pittsburgh headquarters, the company said it had agreed to provide the Canadian operation with $185 million (about $165 million US) of secured debtor-in-possession financing to support current operations through the end of 2015.

Restructuring is 'critical' to outlook

"Despite substantial efforts over the past several years to make U. S. Steel Canada profitable, it is clear that restructuring U.S. Steel Canada is critical to improving our long-term business outlook, Michael McQuade, president and general manager of U.S. Steel Canada, said in a statement.

"Operational changes, cost reduction initiatives and streamlining of operations cannot on their own make it competitive in the current environment. Entering CCAA was the only responsible course of action under the circumstances and it was taken only after all other options were thoroughly explored."

Globe + Mail

U.S. Steel Canada files for creditor protection

Greg Keenan - **Steel Industry Reporter**
Toronto — The Globe and Mail
Published Tuesday, Sep. 16 2014, 5:58 PM EDT
Last updatedTuesday, Sep. 16 2014, 10:03 PM EDT

United States Steel Corp. could sell all or part of the assets of U.S. Steel Canada Inc., as it restructures its Canadian unit, which was granted protection from creditors Tuesday under the Companies' Creditors Arrangement Act.

U.S. Steel Canada, (USSC) consists of the operations of the former Stelco Inc., that U.S. Steel purchased in 2007. The filing culminates almost seven years of turmoil at what was once Canada's largest steel maker and one of the country's blue-chip manufacturers. Since the takeover of Stelco, U.S. Steel has locked out employees at operations in Hamilton, Ont., and Nanticoke, Ont., and engaged in a battle with the federal government companies--later settled --over whether the steel giant was breaking promises it made to Ottawa when it bought Stelco.

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"The stay of proceedings and related relief sought in this application will provide USSC with the necessary 'breathing room' to allow it to carry out a restructuring, including continuing discussions with its key stakeholders," U.S. Steel Canada said in a court filing, "and to explore restructuring solutions including, potentially, a consensual restructuring of certain material obligations, a sales process to solicit interest in purchasing all or part of USSC's business, and/or other restructuring processes."

The company filed for protection after racking up losses before interest, taxes, depreciation and amortization of $1.5-billion between 2008 and 2013, it said in the filing. That period included the recession of 2008-2009, when steel demand shrank dramatically in North America as auto makers slashed production and construction slowed to a trickle.

Stelco went through a protracted and bitter restructuring under the CCAA that began in 2004, at the time citing a looming pension deficit.

U.S. Steel Canada noted a similar pension crisis in its court filings Tuesday, saying its pension plans for workers in Hamilton and its Lake Erie works in Nanticoke face a solvency deficiency of $838.7-million.

Liabilities for other employee benefits amount to $787.9-million.

Interest payments of $162.5-million are due to U.S. Steel by the end of the year, Paul Steep, a lawyer for the Canadian unit, told the Ontario Superior Court of Justice Tuesday evening.

The parent company is prepared to provide debtor-in-possession financing of $185-million, which should be sufficient through the end of 2015, Mr. Steep said.

A $150-million loan to Stelco made by the Ontario government to help finance annual pension payments, was assumed by U.S. Steel and is due at the end of 2015.

Steel making at the Hamilton operations was halted in 2010 and U.S. Steel has since permanently shut the blast furnaces.

About 600 unionized workers are employed at the Hamilton operation and another 1,100 work at the more modern steel mill and a pickling line in Nanticoke. There are 425 salaried employees between the two mills and 169 corporate employees.

There are about 9,000 retirees from the Hamilton mills.

The Canadian division has appointed a chief restructuring officer to guide the operation through bankruptcy protection under the Companies' Creditors Arrangement Act.

Rolf Gerstenberger, who heads local 1005 of the United Steelworkers union, said the Pittsburgh-based giant has been scheming to shut down production in Canada since it bought Stelco in 2007.

NEWS Financial Post

U.S. Steel Corp's Canadian unit files for creditor protection

ANDREW MAYEDA, BLOOMBERG NEWS | September 16, 2014 | Last Updated: Sep 16 6:34 PM ET
More from Bloomberg News

U S. Steel's Canadian unit has two locations, in Hamilton and Nanticoke, Ontario. Glenn Lowson photo for National Post

The Canadian unit of U.S. Steel Corp. filed for court protection from creditors to restructure its operations.

The steelmaker applied to the Ontario Superior Court today for protection under Canada's Companies' Creditors Arrangement Act, U.S. Steel Canada said today in a statement obtained by Bloomberg News.

U.S. Steel, the biggest U.S. steelmaker by volume, will provide $185 million in debtor-in-possession financing to the Canadian unit during the restructuring.

"Despite substantial efforts over the past several years to make U.S. Steel Canada profitable, it is clear that restructuring U.S. Steel Canada is critical to improving our long-term business outlook," U.S. Steel Canada President Michael McQuade said in the statement.

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U.S. Steel locks out nearly 1,000 workers at Lake Erie Works in Nanticoke, Ont.

U.S. Steel to shutter Hamilton steelmaking operations at end of year

U.S. Steel acquired its Canadian operations in 2007 when it purchased Hamilton, Ontario-based Stelco Inc. for $1.1 billion. The Canadian government sued U.S. Steel

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U.S Steel stock soars after Canadian unit files for credit protection

Experts say it's too early to say what the restructuring plan will look like, or what affect it will have on pensions.

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U.S. Steel says its U.S. Steel Canada subsidiary has lost $2.4 billion since December 2009. CANADIAN PRESS FILE PHOTO

By:Madhavi Acharya-Tom YewBusiness Reporter, Published on Wed Sep 17 2014

Shares of U.S. Steel Corp. soared on Wednesday, a day after the beleaguered steelmaker put its Canadian unit in creditor protection.

The stock gains came as Ontario politicians and experts cautioned that the coming restructuring of U.S. Steel Canada will take time.

"Yesterday a big rock got thrown into the pond. A lot of people want a lot of answers. We're just going to have to be patient. 'Am I going to lose my job? Are they going to sell the plant?' We honestly don't know," said Marvin Ryder, assistant professor at the DeGroote School of Business at McMaster University

"My feeling is that the restructuring plan is not going to be minor tinkering around the edges."

For now, investors cheered what the Pittsburgh-based company refers to as the "de-consolidation" of its operations in Hamilton and Nanticoke – a move that would see it shift nearly $1 billion in pension liabilities from its balance sheet.

"They're doing better than people thought and the exit out of Canada was done in a way that investors are happy with. At least optically, they're shedding a billion dollars in pension liabilities," said one industry analyst who asked not to be named.

The stock gained $4.20 – 10.1 per cent – to close at $45.61 (U.S.) on the New York Stock Exchange on Wednesday. The shares touched a 52-week high of $46.55 during the trading session.

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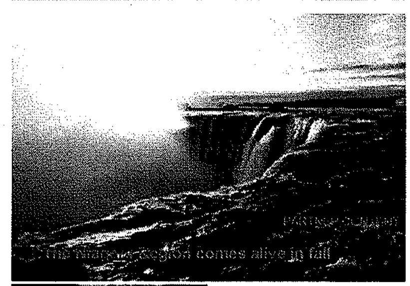

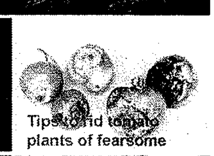

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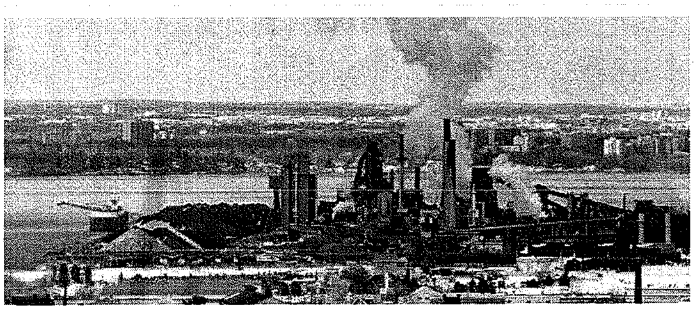
U.S. Steel Canada Files For Bankruptcy

CP

Posted: 09/17/2014 8:44 am EDT | Updated: 09/17/2014 8:59 am EDT



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