Responses to Horizon Utilities Technical Conference Undertakings
EB-2014-0002

Delivered: August 22, 2014

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UNDERTAKING NO. TCJ1.1:

TO PRODUCE A WRITTEN MERGER AND ACQUISITION STRATEGY, IF AVAILABLE, RE: CITY OF HAMILTON'S RESPONSE TO TECHNICAL CONFERENCE QUESTION 12(e).

Response:

Horizon Utilities' written response to Technical Conference Question 12(e) clarified a previously submitted Interrogatory Response submitted by the City of Hamilton.

In its clarification, Horizon Utilities stated:

"*Rate competitiveness is important to the shareholder to support its merger and acquisition strategy through being an attractive merger partner*".

During the Technical Conference, Mr. Basilio made a further clarification that this statement was intended to convey the premise that if Horizon Utilities can maintain its position as a relatively low-cost provider of distribution services, then from a merger and acquisition perspective this makes Horizon an attractive partner for other utilities (Aug. 19 TC Transcript, p. 11, lines 13-16.)

During the Technical Conference, Mr. Basilio also indicated that only in a very general way did Horizon Utilities' M&A strategy have any impact on the structure of its Application (specifically in terms of rate levels and rate classes relative to other utilities) (Aug. 19, 2014 TC Transcript, p.11, lines 6-12),

Given the context of the clarifications provided, Horizon Utilities submits that the information asked for in the undertaking is, at best, marginally relevant to the issues before the Board.

Notwithstanding, Horizon Utilities attaches the most recent information and corresponding exhibits (as listed below) that generally describe the merger strategy including: shareholder and customer benefits; utility considerations for being an attractive merger partner; implications of Board ratemaking policy; transaction options analyses; and private equity investment and constraints including the implications of transfer and PILs departure taxes.

- UNDERTAKING NO.TCJ1.1_ATTCH_1_MA Strategy Description
- UNDERTAKING NO.TCJ1.1_ATTCH_2_MA Strat Descr – Exhibit 2.1-2.4
- UNDERTAKING NO.TCJ1.1_ATTCH_3_MA Strat Presentation

As agreed during the Technical Conference, the attachments are filed on a confidential basis and will be provided to counsel who have signed the Board's form of Declaration and Undertaking.

UNDERTAKING NO. TCJ1.2:

TO PROVIDE 2011 AND 2012 APPROVED FINANCIAL PLANS. (NOTE: REFUSED BY APPLICANT)

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UNDERTAKING NO. TCJ1.3:

TO PROVIDE A FULL EXPLANATION OF WHAT TABLE 1 IN SEC 19 IS INTENDED TO PORTRAY AND WHERE THE NUMBERS CAME FROM.

Response:

Table 1 which was included in Horizon Utilities' response to Interrogatory 2-SEC 19 was computed using actuals results for 2011-2012, and budgeted results for 2013 – 2014. The actuals are stated on an IFRS basis.

The approximate Revenue Requirements shown in the above-mentioned Table 1 are the same Revenue Requirements used in the DSP workbook which were presented to Horizon Utilities' customers. These Revenue Requirements were used to demonstrate the shortfall between Horizon Utilities' expenditure or anticipated expenditure in order to provide electricity service to their customers as compared to the revenues earned from distribution rates.

As discussed within: Horizon Utilities' prefiled evidence; Interrogatory Responses; and Technical Conference Responses (both written and oral), the needs of the utility exceed the inflationary increases granted through the IRM period. These Revenues Requirements were used to illustrate this point to Horizon Utilities' customers.

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UNDERTAKING NO. TCJ1.4:

TO UPDATE TABLE IN SEC-71-TC.

Response:

Horizon Utilities would like to clarify that the request in Undertaking TCJ1.4 to update the table in 2-SEC-71-TC is incorrect. The table to be updated is 2-EP-71-TC. Horizon Utilities provides a revised Table 1 below. Note that the revised Table 1 below includes an amount of $55,000 for 2015 which was omitted from the original table in error. The savings of $55,000 in each year as identified originally in 2-EP-71-TC in 2016 to 2019 were correct. Horizon Utilities plans to conduct corrective maintenance each year. The $55,000 of savings is a cost avoidance and represents a one-time reduction in corrective maintenance on certain assets in each year. The savings from one year do not persist into the next year as the avoided cost is not a recurring expenditure. Total savings from 2015 to 2019 is $275,000.

Revised Table 1 – O&M Reductions from Distribution System Capital Investments

Initiative	2015	2016	2017	2018	2019	Total
Station Decommissioning	$ -	$ 23,000	$ 82,000	$ 52,000	$ 178,000	$ 335,000
Corrective Maintenance	$ 55,000	$ 55,000	$ 55,000	$ 55,000	$ 55,000	$ 275,000
Total OM&A Reduction	**$ 55,000**	**$ 78,000**	**$ 137,000**	**$ 107,000**	**$ 233,000**	**$ 610,000**

Horizon Utilities also corrects its response to Interrogatory 2-SEC-20 part c as follows.

c) Horizon Utilities has forecast aggregate O&M reductions from distribution system capital investments in the amount of $610,000 for the 2015 to 2019 Test Years as identified below:

Station Decommissioning

- Estimated O&M reductions of $335,000 resulting from the decommissioning of nine substations in the 2015 to 2019 Test Years.
    - $23,000 realized in 2016
    - $82,000 realized in 2017
    - $52,000 realized in 2018
    - $178,000 realized in 2019

Corrective Maintenance

- Forecasted O&M reductions of $55,000 annually resulting from reduced reactive maintenance requirements anticipated due to the 4kV and 8kV Renewal Program investments as follows:
    - $55,000 realized in 2015;
    - $55,000 realized in 2016;
    - $55,000 realized in 2017;
    - $55,000 realized in 2018; and
    - $55,000 realized in 2019.

There are no further changes as a result of the change in the Undertaking.

UNDERTAKING NO. TCJ1.5:

TO PROVIDE A LIST OF THE LAST FIVE PROJECTS THAT WERE IMPLEMENTED UNDER HORIZON'S DEFINITION OF "DISCRETIONARY."

Response:

Horizon Utilities defines discretionary projects as follows:

a. Distribution Plant projects: a score of 1 or 2 as identified in column 1 of Table 1 of Horizon Utilities' interrogatory response to 1-Staff-12.

b. General Plant projects: a score of "Low" or "Medium" as identified in column 2 of Table 1 Horizon Utilities' interrogatory response to 1-Staff-12.

Horizon Utilities implemented only four discretionary projects since 2008 as identified in Table 1 below. Horizon Utilities does not have records before 2008 which identify discretionary vs. non-discretionary projects.

Table 1 – Discretionary Projects since 2008

Year	Project Name	Expenditure
2010-2012	E-mobile Work Order Management	$ 363,017
2011-2013	Solid Concrete Pole Replacement	$ 531,000
2011-2012	Activity Based Costing-Business Intelligence System	$ 119,000
2012-2013	Financial Planning Solution	$ 494,000

The discretionary projects from Table 1 are described below:

- E-mobile Work Order Management – Horizon Utilities implemented e-mobile work order management in 2011 to replace manual paper-based service order management. This was a discretionary productivity initiative. As identified in the corrected Table 4-46 in Horizon Utilities response to VECC-64TC Attachment 5, Horizon Utilities has realized productivity savings of $77,000, $438,000 and $636,000 in 2011, 2012 and 2013 respectively as a result of the implementation of e-mobile. These savings are expected to increase to $965,000 in 2014 and provide sustained savings of $1,112,000 in 2015 and $1,117,000 annually in 2016 and beyond.

- Solid Concrete Pole Replacements – Horizon Utilities has approximately 980 – 24' concrete poles that are on average 70 years old and require renewal. The sub-standard heights of these poles have the potential to cause minimum clearances issues for conductors that cross roadways. This project originally scored a two in the project prioritization process which would categorize this project as discretionary. In 2010, incidents with large trucks pulling secondary lines down prompted a review of this project and subsequently, 66 poles were selected for replacement over a three-year period. The 66 poles identified for replacement addressed locations where either primary or secondary conductor crossed a roadway. The remainder of the poles will be replaced as the areas are converted or if pole failures occur.
- Activity Base Costing ("ABC")-Business Intelligence System – Horizon Utilities implemented an ABC-Business Intelligence System in 2012 to provide easy to use tools for performing financial analysis, variance analysis, and CoS preparation. Horizon plans to build on this initiative in 2015. As identified in Table 4-52 on page 37 of Exhibit 4, Tab 3, Schedule 4, Horizon Utilities has realized productivity and capacity savings of approximately $20,000 in 2013 as a result of implementing the ABC-Business Intelligence System. These savings are expected to rise from $100,000 in 2014, to $200,000 per year from 2015 to 2019.
- Financial Planning Solution – Horizon Utilities began the implementation of an integrated software solution for financial planning and budgeting in 2012 which has realized productivity savings through a reduction in time spent on the annual budgeting and quarterly forecasting processes. As identified in Table 4-52 on page 37 of Exhibit 4, Tab 3, Schedule 4, Horizon Utilities is expecting to realize annual savings of $100,000 from 2014 onwards as a result of implementing the financial planning solution.

UNDERTAKING NO. TCJ1.6:

PROVIDE TOTAL O&M FOR STATIONS FOR 2011 THROUGH 2019, WITH FULL BREAKDOWN TO INDICATE WHERE SAVINGS ARE.

Response:

Horizon Utilities provides the total O&M for the substation cost centre for 2011 to 2019 in Table 1 below. The substation cost centre includes costs for the inspection and maintenance of Horizon Utilities' 28 Substations and 200 transformer rooms. The total O&M values provided in Table 1 below are not attributable to substations only.

Table 1: Substation Department Total O&M

	2011 Actual	2012 Actuals	2013 Actuals	2014 Bridge Year	2015	2016	2017	2018	2019
O&M - Substation Cost Centre	$ 769,133	$ 696,721	$ 490,902	$ 851,250	$ 657,270	$ 877,716	$ 900,006	$ 921,710	$ 943,131
Number of Substations Maintained	30	30	30	28	25	23	21	21	16

Total O&M by substation cannot be provided for 2014 to 2019; Horizon Utilities does not budget on a by substation basis. Horizon Utilities provides the actual O&M by substation, where available, for 2011 to 2013 in Table 2 below. Costs for outside service providers are not recorded by substation and are included in unallocated substation costs.

Table 2: Total O&M per Substation

Substation	2011 Actual	2012 Actual	2013 Actual
Aberdeen	$ 1,952	$ 14,686	$ 8,504
Bartonville	$ 11,635	$ 787	$ -
Baldwin	$ 24,960	$ 12,217	$ -
Bunting	$ 887	$ 264	$ -
Caroline	$ 12,547	$ 1,890	$ 964
Central	$ 4,179	$ 12,888	$ 1,901
Cope	$ 1,947	$ 5,377	$ 1,298
Deerhurst	$ 1,333	$ 8,255	$ 15,953
Dewitt	$ 10,637	$ 19,351	$ 3,537
Eastmount	$ 3,047	$ 3,475	$ 10,703
Elmwood	$ 2,436	$ 28,082	$ 146
Galbraith	$ 17,435	$ 3,868	$ 21,162
Grantham	$ 1,890	$ 2,473	$ -
Halson	$ 1,176	$ 197	$ -
Highland	$ 978	$ 326	$ 7,804
Hughson	$ 35,617	$ 349	$ -
John	$ 2,645	$ 22,535	$ 2,542
Kenilworth	$ 2,195	$ 1,688	$ 204
Mohawk	$ 2,836	$ 545	$ 1,953
Mountain	$ 10,617	$ 7,895	$ 3,526
Ottawa	$ 26,122	$ 732	$ -
Parkdale	$ 5,156	$ 602	$ -
Spadina	$ 5,184	$ 912	$ 5,589
Strouds	$ 22,645	$ 9,542	$ 577
Vine	$ 14,980	$ 8,044	$ -
Taylor	$ 2,948	$ 4,882	$ -
Webster	$ 1,108	$ 118	$ -
Welland	$ 22,848	$ 3,462	$ 5,737
Whitney	$ 3,282	$ 8,283	$ 542
Wellington	$ 7,438	$ 49,844	$ 85
Wentworth	$ 1,257	$ 2,323	$ 11,293
York	$ 1,527	$ 6,155	$ 5,208
Unallocated Substation Costs	$ 326,586	$ 275,721	$ 243,764
Total Substation O&M	**$ 592,030**	**$ 517,769**	**$ 352,994**

Horizon Utilities' provides a breakdown of estimated cost savings in 2015 to 2019 identified in Horizon Utilities' response to 2-EP-71TC by substation in Table 3 below:

Table 3: Estimated O&M Savings by Substation for 2016-2019

Substation	2016	2017	2018	2019	Total
Baldwin	$ -	$ -	$ -	$ 17,120	$ 17,120
Grantham	$ -	$ 29,215	$ 12,985	$ 34,540	$ 76,740
Highland	$ 11,685	$ 11,685	$ 12,985	$ 11,684	$ 48,039
John	$ -	$ -	$ -	$ 17,120	$ 17,120
Strouds	$ -	$ -	$ -	$ 17,120	$ 17,120
Vine	$ -	$ 29,215	$ 12,985	$ 34,540	$ 76,740
Welland	$ 11,685	$ 11,685	$ 12,985	$ 11,684	$ 48,039
Whitney	$ -	$ -	$ -	$ 17,120	$ 17,120
York	$ -	$ -	$ -	$ 17,120	$ 17,120
Total	**$ 23,370**	**$ 81,800**	**$ 51,940**	**$ 178,048**	**$ 335,158**

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UNDERTAKING NO. TCJ1.7:

TO PROVIDE, FOR THE CDM PROGRAMS IMPLEMENTED IN THE YEARS 2005 THROUGH 2013, A TABLE INDICATING PERSISTING SAVINGS FROM EACH OF THOSE PROGRAMS IN EACH OF THOSE YEARS, THE SAVINGS THAT WILL PERSIST IN 2012 AND 2013, TO PROVIDE A TOTAL SAVINGS FOR 2012 AND A TOTAL SAVINGS FOR 2013, AND FOR THOSE YEARS WHERE THERE IS NO VALUE OF PERSISTENCE THROUGH TO 2012 OR 2013, TO USE THE LAST ACTUAL VALUE FOR PERSISTENCE AND ASSUME THAT VALUE CONTINUES THROUGHOUT THE BALANCE OF THE PERIOD.

Response:

Horizon Utilities provides the following Tables 1 - 5 below for illustrative purposes to demonstrate the annual persistence of CDM programs implemented in the years 2005 through 2013 by customer class and on a total basis.

The persistent CDM savings values represented in the table below are verified net CDM persistent savings for 2005 – 2012 and draft net CDM savings for 2013 based on three distinct eras of CDM; third tranche programs 2005 – 2007, OPA contracted programs 2006 – 2010, and the current OPA 2011 – 2014 Province-Wide CDM program framework.

For the third tranche programs (2005-2007), a report developed by a 3rd party contractor retained by Horizon Utilities in 2009 to verify net CDM savings was utilized. For the 2006 – 2010 OPA Programs, the 2010 OPA reporting of verified net CDM savings was utilized. For the years 2011 - 2013 OPA programs, upon request of Horizon Utilities the OPA provided a report on August 22, 2014, that includes draft savings for 2013, 2011 and 2012 verified savings utilized. It is anticipated the OPA will publish Horizon Utilities 2013 verified savings on September 1, 2014.

Table 1: Residential CDM Persistence

	2005	2006	2007	2008	2009	2010	2011	2012	2013
2005 Programs	2,315,359	2,315,359	2,315,359	2,315,359	2,315,359	2,286,948	2,286,948	2,286,948	54,754
2006 Programs		21,530,654	21,530,654	21,530,654	21,530,654	21,523,650	21,302,130	21,302,130	21,283,419
2007 Programs			10,618,801	7,896,749	7,561,978	7,561,978	7,560,633	7,338,336	7,338,336
2008 Programs				9,175,514	8,100,348	8,100,348	8,100,348	7,375,874	7,373,604
2009 Programs					5,413,128	5,329,185	5,329,185	5,314,688	4,689,493
2010 Programs						4,406,679	4,310,864	4,288,727	4,280,387
2011 Programs							5,885,658	5,882,828	5,882,828
2012 Programs								4,017,245	4,003,595
2013 Programs									7,682,205

Table 2: GS < 50 kW CDM Persistence

	2005	2006	2007	2008	2009	2010	2011	2012	2013
2005 Programs	-	-	-	-	-	-	-	-	-
2006 Programs		-	-	-	-	-	-	-	-
2007 Programs			-	-	-	-	-	-	-
2008 Programs				1,083,507	1,083,507	989,609	989,609	989,609	989,609
2009 Programs					8,586,070	8,586,070	8,586,070	8,586,070	8,586,070
2010 Programs						4,979,114	4,979,114	4,979,114	4,979,114
2011 Programs							1,754,193	1,754,193	1,675,426
2012 Programs								1,875,038	1,875,038
2013 Programs									1,442,489

Table 3: GS > 50 kW CDM Persistence

	2005	2006	2007	2008	2009	2010	2011	2012	2013
2005 Programs	-	-	-	-	-	-	-	-	-
2006 Programs		157,037	157,037	157,037	157,037	157,037	157,037	157,037	157,037
2007 Programs			3,193,108	3,193,108	3,193,108	3,193,108	3,070,650	2,999,577	2,999,577
2008 Programs				678,832	678,828	678,828	678,828	678,828	678,828
2009 Programs					8,722,041	4,845,500	4,845,500	4,845,500	4,845,500
2010 Programs						15,701,712	9,856,128	9,856,128	9,856,128
2011 Programs							14,564,347	14,543,411	14,543,411
2012 Programs								11,370,847	10,815,239
2013 Programs									15,555,357

Table 4: Large Use CDM Persistence

	2005	2006	2007	2008	2009	2010	2011	2012	2013
2005 Programs	-	-	-	-	-	-	-	-	-
2006 Programs		-	-	-	-	-	-	-	-
2007 Programs			-	-	-	-	-	-	-
2008 Programs				407,781	407,778	407,778	407,778	407,778	407,778
2009 Programs					25,016	25,016	25,016	25,016	25,016
2010 Programs						206,948	206,948	206,948	206,948
2011 Programs							12,351,504	12,146,158	12,146,158
2012 Programs								155,311	479,921
2013 Programs									1,712,786

Table 5: Total Horizon Utilities CDM Persistence

	2005	2006	2007	2008	2009	2010	2011	2012	2013
2005 Programs	2,315,359	2,315,359	2,315,359	2,315,359	2,315,359	2,286,948	2,286,948	2,286,948	54,754
2006 Programs		21,687,691	21,687,691	21,687,691	21,687,691	21,680,687	21,459,167	21,459,167	21,440,456
2007 Programs			13,811,908	11,089,857	10,755,086	10,755,086	10,631,283	10,337,913	10,337,913
2008 Programs				11,345,634	10,270,461	10,176,563	10,176,563	9,452,089	9,449,819
2009 Programs					22,746,256	18,785,772	18,785,772	18,771,275	18,146,080
2010 Programs						25,294,453	19,353,054	19,330,917	19,322,577
2011 Programs							34,555,703	34,326,590	34,247,823
2012 Programs								17,418,441	17,173,793
2013 Programs									26,392,837

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UNDERTAKING NO. TCJ1.8:

TO PROVIDE BREAKDOWN OF LRAMVA EQUIVALENT NUMBERS IN TABLE 2 OF VECC TC 78.

Response:

Horizon Utilities has provided the threshold values for the LRAMVA account by rate class for 2014 through 2019 in Table 1 below.

Table 1: LRAMVA (kWh) by Rate Class

Rate Class	2014	2015	2016	2017	2018	2019
Residential	12,575,666	3,350,520	3,103,523	3,027,867	3,027,867	3,027,867
GS < 50 kW	4,393,315	928,649	846,487	846,487	846,487	846,487
GS > 50 kW	11,173,019	15,255,036	15,255,036	15,255,036	15,255,036	15,255,036
TOTAL	**28,142,000**	**19,534,205**	**19,205,046**	**19,129,390**	**19,129,390**	**19,129,390**

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UNDERTAKING NO. TCJ1.9:

TO PROVIDE THE MOST RECENT VARIANCE ANALYSIS FOR 2014.

Response:

As requested, Horizon Utilities has provided a copy of the June 2014 year-to-date variance analysis for Electricity Distribution Operations ("EDO"), as stated on an IFRS basis. Please refer to UNDERTAKING NO.TCJ1.9_ATTCH_1.

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UNDERTAKING NO.TCJ1.9_ATTCH_1_COVER

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HORIZON UTILITIES CORPORATION

Electricity Distribution Operations (“EDO”)

FOR THE QUARTER ENDED JUNE 30, 2014

BUDGET vs. ACTUAL

Net loss for the quarter was $6,227, or $8,153 unfavourable to the budgeted net income of $1,926; principally explained as follows:

- **Net electricity revenue** for the quarter was $11,946 or $11,794 lower than budget. The variance is principally as a result of: (i) lower than budgeted net non-distribution electricity revenue of $11,395; and (ii) lower distribution services and other revenue of $399. Net non-distribution electricity revenue represents timing differences in regulatory assets and liabilities that are not recognized on the balance sheet under IFRS. These amounts comprise differences between: (i) the amounts billed to customers for cost of power and other flow-through costs; (ii) the amounts charged by third parties, including the IESO; and (iii) settlements of past accumulated variances.

- The unfavorable variance in **net non-distribution electricity revenue** of $11,395 principally resulted from: (i) unfavourable rates for global adjustment ($13,710); (ii) unfavourable network charges ($777); (iii) unfavourable connection services ($698); partially offset by (iv) favourable cost of power ($2,201); and (v) favourable wholesale market service charges ($1,617). While these variances are timing differences ultimately recoverable from ratepayers, they have a direct impact on cash, IFRS net income, and retained earnings with dilutive impact on debt: total capital until such recovery. The magnitude of this total variance at this time is not a cause for concern in these regards. However, management is concerned with the trend of these variances over the past few months and is monitoring such closely and investigating possible courses of proactive corrective action if these trends continue.

  The global adjustment (“GA”) is a component of electricity costs that pays for the cost of conservation programs and for the difference between the wholesale market price and the rates paid to regulated and contracted generators for electricity in Ontario. It is collected from all electricity ratepayers in Ontario. The GA can be positive or negative, depending on the level of prices in the wholesale electricity market. A lower wholesale market price is associated with a higher GA.

  The GA rate used for billing purposes for a month is based on a corresponding forward estimate received from the IESO at the end of the preceding month. The rate used to accrue GA expense is based on a second estimate from the IESO for the month that is received on the last business day of the month.

  The actual amount of GA for a month is not known until the IESO presents its invoice in the following month.

  Differences between GA billed and invoices are tracked in regulatory variance accounts and cleared, based on an application to and order of the OEB, over a twelve month period commencing at the end of a fiscal year for balances as at the end of the prior fiscal year.

- **Total distribution services and other revenue** for the quarter of $26,005 was $399 lower than the budget of $26,404; principally as a result of: (i) lower than anticipated fixed revenue in the Residential and GS > 50kW customer classes; and (ii) lower than budgeted variable revenue in the Residential customer class due to decreased consumption.

- Residential consumption for the quarter was 1.0% lower than budget. The variance is attributable to weather. Although the heating degree days for the quarter were higher than budget, the cooling degree days for the quarter were 27.0% lower than the 20 year weather normalized cooling degree days underlying the budgeted load forecast. The average temperature for April to May 2014 was negative 2.5 degrees Celsius, compared to the average temperature in the prior period of 0.9 degrees Celsius.

  GS < 50kW consumption was 0.9% higher than budget; principally attributable to the reclassification of customers from the GS > 50kW customer class. GS > 50kW consumption was 1.5% higher than budget.

  The Large User consumption was 0.7% higher than budget.

  Please refer to Exhibit 1 for a summary of distribution revenue variances by customer class.

- **Other income** for the quarter was $115 higher than budget; principally as a result of: (i) higher than anticipated CDM performance incentives from prior year programs ($75); (ii) higher than anticipated sale of scrap ($64); and (iii) partially offset by lower than anticipated customer connection and collection charges ($39).

- **Total expenses** for the quarter were $667 lower than budget and are principally explained by:

  - Lower **distribution and utilization expense** variances aggregating $568; primarily resulting from: (i) the timing of new hires and unanticipated retirements, resulting in a favourable variance in salaries and benefits ($308); (ii) lower than anticipated contract labour supporting the Geographic Information System ("GIS") and Phase II of the ERP Upgrade project ("ERP") ($106); (iii) higher allocation of wages and benefits charged to capital projects compared to operating project during the quarter ($102); (iv) lower software license and maintenance expenses principally explained by lower than anticipated expenditures related to the GIS initiative ($66); (v) lower repairs and maintenance expenditures primarily resulting from timing of reactive repairs within Construction and Maintenance ($61); and (iii) partially offset by the timing on overtime ($155).

  - Lower **credit losses** expense of $126 is explained by lower realized net write-offs for residential and commercial accounts. The allowance for doubtful accounts as at June 30, 2014 of approximately 2.1% of total accounts receivable is consistent as compared to the prior period.

  - Higher **general and administrative expense** of $144 is principally explained by: (i) lower allocation of wages and benefits to the planned ERP initiative during the quarter ($129); (ii) higher than anticipated professional fees to support the ERP initiative ($81); and (iii) partially offset by lower than anticipated software license and maintenance expenditures to support Information Systems Technology initiatives for the quarter ($66).

  - Lower **depreciation expense** of $147 is explained by lower than estimated depreciation on the prior year's asset base.

- **Loss on sale and disposal of assets** for the quarter was $135 higher than anticipated; primarily explained by more assets removed from service than estimated in the budget.

- Net **financing costs** for the quarter were $55 lower than budget; principally as a result of higher cash balances than anticipated. The budget anticipated that the obligation under capital cost recovery agreements owing to Hydro One Networks Inc. would be discharged at the end of the prior year.

<u>2014 vs. 2013</u>

Net income decreased $6,621 over the prior period. Significant variances compared to the prior period include:

- Lower **total net revenue** of $6,987; principally explained as follows:

    - Decrease in **distribution services and other revenue** of $243; principally resulting from: (i) lower rate rider dispositions of regulatory asset and liability balances in the current period as compared to the prior period ($419); and (ii) partially offset by higher fixed distribution services revenue across all customer classes ($196).

      Residential and GS < 50kW consumption for the quarter was 0.8% and 2.7% lower than prior period respectively. The variance is principally attributable to weather. GS > 50 kW consumption was 0.7% higher than the prior period. Large User consumption was 0.5% lower than the prior period.

    - Decrease in **net non-distribution electricity revenue** of $7,179, representing timing differences in regulatory assets and liabilities that are not recognized on the balance sheet under IFRS as previously explained. The decrease principally resulted from: (i) unfavourable global adjustment ($7,995); (ii) settlements of past accumulated variances ($1,320); and (iii) partially offset by favourable cost of power ($1,648).

    - Increase in **other income** of $435; principally resulting from: (i) higher sales of scrap ($123); (ii) higher management fee recoveries from Customer Services ($97); (iii) higher than anticipated CDM performance incentives from prior year programs ($75); (iv) higher recognition of revenue related to customer contributed capital ($51); and (v) higher pole and duct rental revenue ($31).

- Increase in **operating costs** of $1,662; principally explained as:

    - Increase in **distribution and utilization expenses** of $271; primarily attributable to: (i) wage and benefit increases, and wage allocations between operating and capital projects ($147); (ii) higher cable locates expenditures resulting from delays in customer requests due to colder weather in the first quarter as compared to the prior period ($56); and (iii) higher janitorial and landscaping service expenditures ($37).

    - Increase in **billing and collecting expenses** of $101; principally due to an increase in management fees charged from Customer Services resulting from higher operating costs.

    - Increase in **general and administrative expenses** of $1,084; primarily attributable to: (i) higher wages and benefits ($607); (ii) higher expenditures related to the 2015 Cost of Service application ($482); and (iii) higher professional service fees relating to Information Systems Technology and Supply Chain Management initiatives ($138).

    - Increase in **depreciation expense** of $232 arising from an increasing trend in the capital expenditure program.

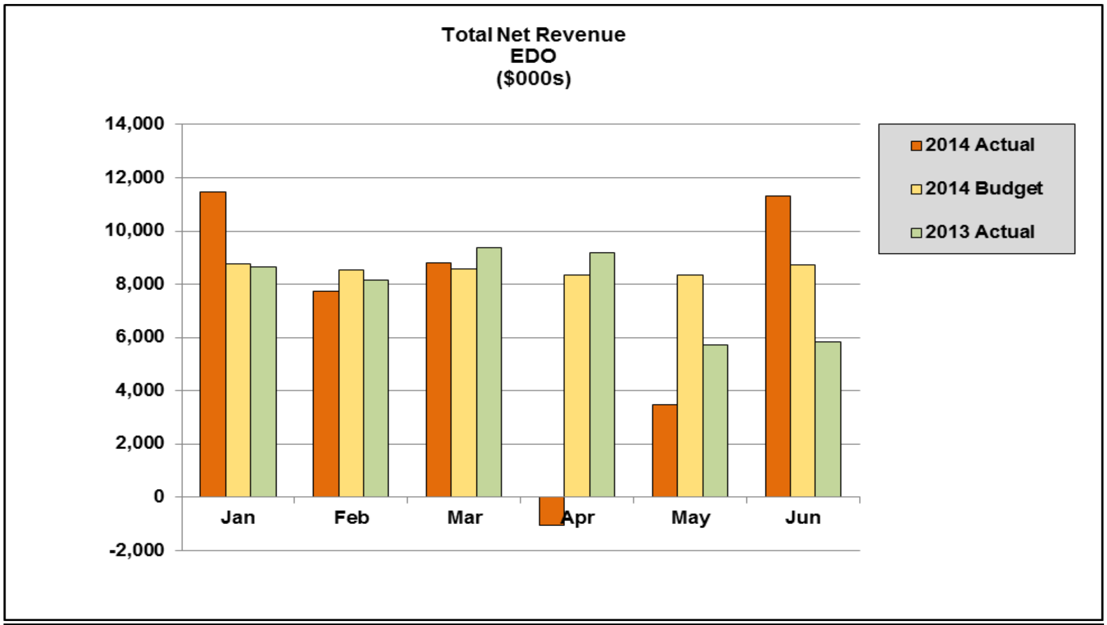
- **Loss on sale and disposal of assets** was $164 higher than the prior period; principally explained by more assets removed from service.

- Increase in net **financing costs** of $66; principally explained by interest income on lower cash balances.

FOR THE SIX MONTHS ENDED JUNE 30, 2014

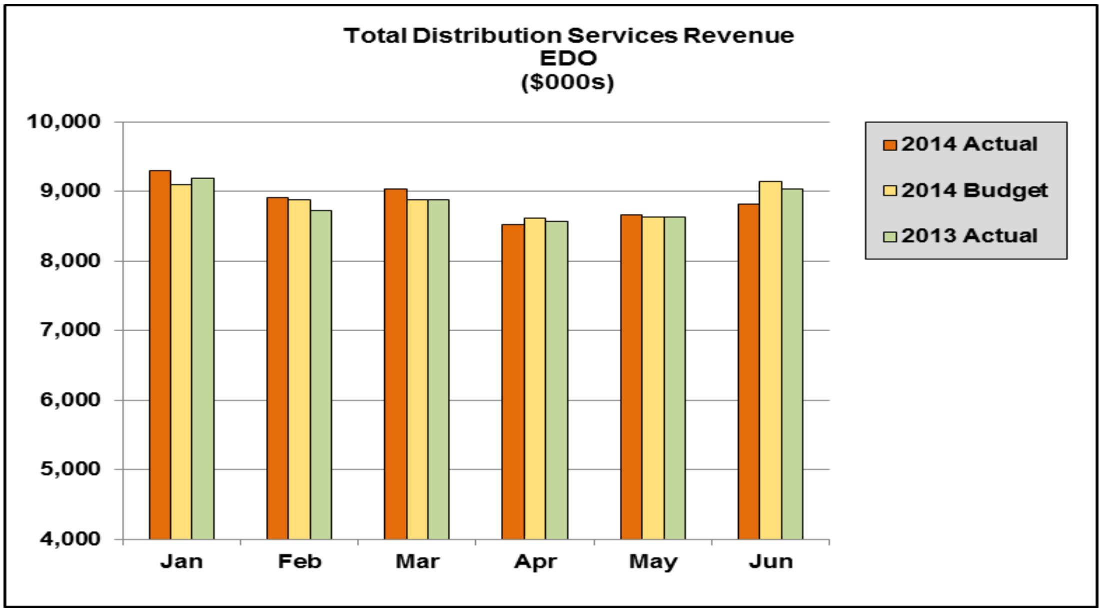
BUDGET vs. ACTUAL

- Net loss for the period was $1,818, or $5,596 unfavourable to budgeted net income of $3,778. Principal factors driving this result were: (i) unfavourable non-distribution electricity revenue variance ($9,634); (ii) favourable operating expenses variance ($1,833); (iii) favourable other income variance ($125); and (iv) favourable net finance income and finance charges variance ($112).



- **Net electricity revenue** for the period was $38,276, or $9,656 lower than budget. The variance is principally as a result of: (i) lower than budgeted net non-distribution electricity revenue of $9,634; and (ii) lower distribution services and other revenue of $22. Net non-distribution electricity revenue represents timing differences in regulatory assets and liabilities that are not recognized on the balance sheet under IFRS as explained for the quarter.

- The unfavorable variance in **net non-distribution electricity revenue** of $9,634 principally resulted from: (i) unfavourable global adjustment ($3,529); (ii) unfavourable wholesale market service charges ($2,841); (iii) unfavourable network charges ($1,486); (iv) unfavourable connection services ($1,000); and (v) unfavourable cost of power ($740).



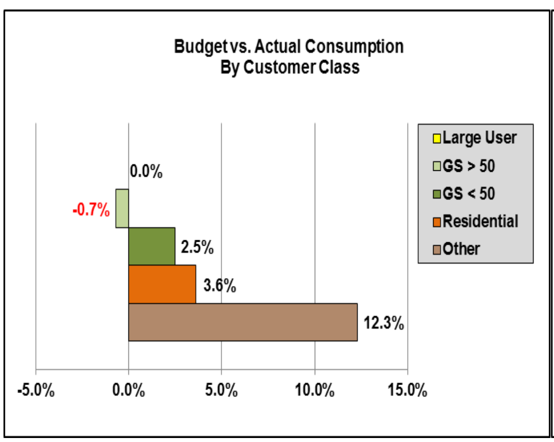
- **Total distribution services and other revenue** for the period of $53,253 was $22 lower than budget; principally as a result of higher than anticipated variable revenue in the Residential and GS < 50kW customer classes; partly offset by lower than budgeted fixed revenue for the GS > 50kW class due to customer reclassifications to the GS < 50kW class.

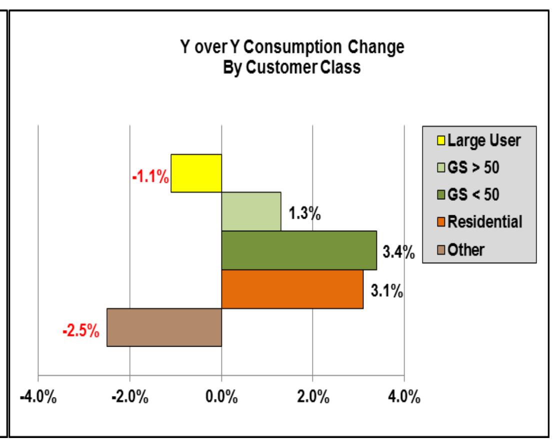
  Residential consumption for the period was 3.6% higher than budget. The variance is principally attributable to weather, where the heating degree days for the period were 45.9% higher than the 20 year weather normalized heating degree days underlying the budgeted load forecast. The average temperature for January to May 2014 was negative 6.0 degrees Celsius, compared to the average temperature in the prior period of negative 1.3 degrees Celsius.

  GS < 50kW consumption was 2.5% higher than budget. The GS < 50kW customers are similarly impacted by the weather. GS > 50kW consumption was 0.7% lower than budget; principally due to the reclassification of customers to the GS < 50kW customer class.

  The Large User consumption was consistent with budget.

  Please refer to Exhibit 1 for a summary of distribution revenue variances by customer class.





- **Other income** for the period was $125 higher than budget; principally as a result of: (i) higher than anticipated sales of scrap ($126); (ii) higher than anticipated CDM performance incentives from prior year programs ($100); and (iii) partially offset by lower than anticipated customer connection and collection charges ($90).

- **Total expenses** for the period were $1,833 lower than budget. The following tables summarize significant variances that are expected to be: (i) permanent for the balance of the year; and (ii) timing differences.

Permanent variances

Timing of recruitment	$1,005
Depreciation	276
Software license and maintenance	164
Allocation of wages and benefits (capital versus operating projects)	(225)
Various other	(105)
Total	$1,115

- Longer than expected timelines for recruitment have resulted in a permanent variance of $1,005. As at June 30, 2014, there were approximately 14 net vacancies, as compared to approximately 2 net vacancies at the beginning of the year. The salaries and benefits permanent difference is principally explained by: (i) the timing of new hires and unanticipated retirements, resulting in a favourable variance in salaries and benefits ($777); and (ii) lower than anticipated contract labour supporting the GIS initiative ($228).

- Lower depreciation expense of $276 is explained by lower than estimated depreciation on the asset base of the prior year.

- Lower software license and maintenance expense of $164 is principally explained by: (i) lower than anticipated expenditures related to the GIS initiative ($117); and (ii) lower than anticipated expenditures related to Human Resources initiatives ($40).

- The allocation of wages and benefits charged to capital projects compared to operating projects during the period were lower than anticipated. The variance is a result of the timing of labour capitalization for the ERP initiative.

Timing differences

Professional service fees	$390
Credit losses	176
Repairs and maintenance	137
Various other	15
Total	$718

- The professional service fees timing difference corresponds to planned expenditures for: (i) 2015 Cost of Service application expenditures ($258) - this variance is expected to reverse by the end of August; (ii) Construction and Maintenance expenditures corresponding to reactive substation repairs and Supply Chain Management expenditures corresponding to environmental audits ($146); (iii) Human Resources expenditures corresponded to departmental action planning initiatives ($53), employee development and leadership training ($44), and legal counsel representation for investigations ($50); and (iv) partially offset by higher than anticipated expenditures corresponding to the ERP initiative ($92).

- Credit losses are lower than anticipated and principally explained by lower realized net write-offs for residential and commercial accounts. The allowance for doubtful accounts as at June 30, 2014 of approximately 2.1% of total accounts receivable is consistent as compared to the prior period.

- Repairs and maintenance expenditures are lower than anticipated and principally explained by: (i) lower than anticipated reactive repairs to substation buildings ($83); and (ii) lower than anticipated reactive equipment repairs in substation equipment ($46).

- Net financing costs for the period were $112 lower than budget; principally as a result of higher cash balances than anticipated. The budget anticipated that the obligation under capital cost recovery agreements owing to Hydro One Networks Inc. would be discharged at the end of the prior year.

<u>2014 vs. 2013</u>

Net income for the period was $6,198 lower than prior period; principally as a result of lower net non-distribution electricity revenue, and higher expenditures on operating activities.

Significant variances compared to the prior period include:

- Lower **total net revenue** of $5,202; principally explained as follows:

  - Increase in **distribution services and other revenue** of $203; principally resulting from: (i) higher consumption in the Residential and GS < 50kW customer classes in the current period; and (ii) partially offset by lower rate rider dispositions of regulatory asset and liability balances in the current period as compared to the prior period.

    Residential and GS < 50kW consumption was 3.1% and 3.4% higher than prior period respectively. The increased consumption is principally attributable to weather. GS > 50kW consumption was 1.3% higher than the prior period. Large User consumption was 1.1% lower than the prior period.

  - Decrease in **net non-distribution electricity revenue** of $6,003, representing timing differences in regulatory assets and liabilities that are not recognized on the balance sheet under IFRS as previously explained. The decrease principally resulted from: (i) unfavourable wholesale market service charges ($5,675); (ii) settlements of past accumulated variances ($2,638); and (iii) partially offset by favourable global adjustment ($2,425).

  - Increase in **other income** of $598; principally resulting from: (i) higher management fee recoveries from Customer Services ($194); higher than anticipated CDM performance incentives from prior year programs ($100); (iii) higher sales of scrap ($99); (iv) higher recognition of revenue related to customer contributed capital ($82); and (ii) higher pole and duct rental revenue ($61).

- Increase in **operating costs** of $2,887; principally explained as follows:

  - Increase in **distribution and utilization expenses** of $798; primarily attributable to: (i) wage and benefit increases, and wage allocations between operating and capital projects ($175); (ii) higher tree trimming expenditures for the scheduled grid maintenance plan ($60); (iii) higher cable locate expenditures resulting from increases in customer requests ($51); and (iv) various other increases in expenditures including Facilities and Information Systems Technology costs.

- Increase in **billing and collecting expenses** of $193; principally due to an increase in management fees charged from Customer Services resulting from higher operating costs.

- Increase in **general and administrative expenses** of $1,566; primarily attributable to: (i) higher wages and benefits ($897); (ii) higher professional service fees relating to the 2015 Cost of Service application ($642); (iii) higher Information Systems Technology expenditures related to the ERP initiative ($98); and (iv) partially offset by lower service agreement expenses ($51).

- Increase in **depreciation expense** of $410 arising from an increasing trend in the capital expenditure program.

- Increase in net **financing costs** of $152; principally explained by interest income on lower cash balances.

Capital Expenditures

YTD Capital Expenditure Variances, net of Customer Contributions
EDO
($000s)

	YTD Actual	YTD Budget	Variance	FY Forecast	FY Budget	Variance
Distribution System	$ 13,603	$ 14,682	$ 1,079	$ 30,440	$ 28,987	$ (1,453)
Customer Contributions	(2,523)	(2,037)	486	(5,926)	(4,473)	1,453
Distribution System, net of Customer Contributions	11,080	12,645	1,565	24,514	24,514	-
Computer Hardware and Software	1,944	2,720	776	4,654	4,436	(218)
Buildings, Furniture and Fixtures	2,044	2,301	257	4,551	4,318	(233)
Meters	1,497	1,670	174	2,840	2,930	90
Tools, Shop and Garage Equipment	322	248	(74)	514	511	(3)
Transportation Equipment	213	260	47	740	785	45
Other	85	328	243	690	710	20
Total	$ 17,185	$ 20,173	$ 2,988	$ 38,502	$ 38,204	$ (298)

- Distribution system capital expenditures, net of customer contributions, were $1,565 lower than budget. The following table summarizes the significant variances for the period that correspond to: (i) customer contributions; and (ii) distribution system capital project category.

Customer contributions	$486
Distribution System capital projects:	
Customer Demand	(1,007)
Renewal	1,260
Safety	271
Substation Renewal	257
Various other	298
Total	$1,565

- Customer contributions were $486 higher than budget; principally attributable to: (i) the timing of completed customer development projects; (ii) additional contributions for expansion deposits for shortfalls in subdivision loads; and (iii) recognition of related customer capital contributions during the period as compared to budget.

- Gross distribution system capital expenditures were $1,079 lower than budget. The principal drivers of the variance are summarized as follows:

  - Total Customer Demand project expenditures were $1,007 higher than budget. Customer Demand expenditures corresponding to Distribution Capital were $1,274 higher than anticipated. The variance is principally a result of: (i) the timing of planned expenditures, and additional unplanned expenditures for Hamilton city road projects; and (ii) projects carried over from the prior year. Customer Demand expenditures corresponding to Customer Connections were $267 lower than anticipated due to the timing of projects. Projects in this category are customer initiated, and the timing of these projects is largely controlled by the customer and outside of the control of Horizon Utilities. A review of Customer Connections projects indicates that total capital expenditures for the year are expected to be consistent with budget.

  - Renewal, Substations and Safety expenditures were $1,788 lower than anticipated. This variance principally resulted from:

    i.) Poor weather resulting in construction delays in the first quarter 2014;
    ii.) Distribution system maintenance projects carried over from the prior year. This contributed to a higher operating versus capital expenditure ratio in the first quarter 2014 than budgeted;
    iii.) Reactive Renewal projects were lower than anticipated. Outages in the first quarter 2014 were primarily driven by Loss of Supply from Hydro One, which did not require reactive capital expenditures by Horizon Utilities. Capital expenditures related to Reactive Renewal are typically highest in June, July, and August. This variance may yet reverse by the end of the summer depending on weather and other conditions requiring reactive renewal;
    iv.) Certain projects have been rescheduled relative to the budget to accommodate crew and labour balancing. Examples include:
      – Stroud ST-6 Phase 2 (Hamilton): this 4kV and 8kV service Renewal project will be completed by external contractors as a result of project scheduling changes. The project was originally planned to be completed by Horizon Utilities crews at the time of the budget. The project will commence once the external contractors have completed the Whitney WH-1 (Hamilton) 4kV and 8kV service Renewal project, and is expected to be completed by the end of November;
      – Proactive Transformer Replacement Project: this project was planned to be completed in the first and second quarters of 2014 at the time of the budget. This project has been rescheduled and is expected to be completed by the end of the third quarter 2014 to accommodate the larger Renewal projects which were subject to construction delays resulting from weather conditions in the first quarter 2014, as previously identified;
      – Welland F4 (St. Catharines): this 13.8kV service Renewal project was planned to be substantially completed by the end of May at the time of the budget. However, Horizon Utilities crews were required to complete carry over work from the prior year before commencing this project;
      – Caroline CA-4 (Hamilton): this 13.8kV service Renewal project was planned to be completed by external crews at the time of the budget, but it has since been determined that the project will be completed by Horizon Utilities crews. The rescheduling of this project is dependent upon crew availability. This project will be completed in the fourth quarter 2014.
    v.) Additional engineering was required to facilitate the removal of old substation transformers from the Hughson (Hamilton) substation. This project is expected to be completed by the end of November.

- It is expected that more contract labour than planned will be required to complete capital activity for the year. An over absorption of labour into operating expenditures is not expected to result. The lead time to execute contract work will result in higher than budgeted capital expenditures in the third quarter 2014. Actual gross distribution system capital expenditures for June were $185 higher than budget. Planned gross distribution system capital expenditures for July are expected to be consistent with the budget of $2,700.
  The capital expenditure variance is forecast to decrease commencing in the third quarter; principally as a result of additional contract work as previously identified, and carry over work from the prior year. The variance is forecast to fully reverse by year end.

- Computer hardware and software expenditures were $776 lower than budget; principally as a result of:

  i.) a permanent variance for the ERP initiative ($308), resulting from: lower capitalized resource activity ($178); the elimination of a planned contract resource ($130); and timing of consultancy and internal labour corresponding to system modifications ($207);
  ii.) a change in the timing of software expenditures corresponding to the new GIS ($174) expected to be realized by the end of July;
  iii.) a permanent software variance for the Financial Reporting initiative corresponding to management's decision to implement a Cloud based solution ($63). Cloud based solutions are generally procured under management contracts, which result in operating costs rather than capital expenditures;
  iv.) partially offset by the permanent unfavourable variance relating to management's decision to upgrade the existing Planning and Scheduling software ($267); and
  v.) permanent hardware variance relating to the upgrade of meeting room projectors ($44).

- Buildings, furniture and fixtures expenditures were $257 lower than budget; principally as a result of:

  i.) delays in the project start date corresponding to the replacement of the chillers and HVAC units at the Hamilton John Street facility ($150), expected to be realized by the end of November;
  ii.) the timing of emergency generator upgrade expenditures to the Hamilton John Street facility ($120), expected to be realized by the end of September;
  iii.) partially offset by the accelerated timing of the self-serve computer work stations to enable employee training ($40); and
  iv.) a permanent variance related to the replacement of the HVAC rooftop fan at the St. Catharines Vansickle Road facility ($20).

- Meter expenditures were $174 lower than budget; principally as a result of the timing of metering program expenditures. This variance is expected to reverse by August.

- Tools, shop and garage equipment expenditures were $74 higher than budget, principally as a result of: (i) building security project expenditures ($193); and (ii) partially offset by timing on Construction and Maintenance expenditures ($148). The variance from budget for the building security project will be offset by the reduction of expenditures in the System supervisory equipment budget.

- Transportation equipment expenditures were $47 lower than budget; principally as a result of the timing of the acquisition of two single bucket trucks expected to be acquired in November and December.

- System supervisory equipment expenditures were $193 lower than budget; principally as a result of the reallocation of building security project expenditures to the tools, shop and garage equipment budget.

Total capital expenditures are forecast for the year at $38,502, or $298 higher than the budget of $38,204. The variance is principally attributable to: (i) higher than anticipated expenditures relating to the upgrade of the planning and scheduling system ($406); (ii) an increase in expenditures in respect of the building renovation projects at Hamilton Nebo Road ($232); and (iii) partially offset by the elimination of planned system modifications relating to the ERP initiative ($308).

FORECAST

The forecast provides for a net loss of ($1,441), compared to budgeted net income of $6,904; principally as a result of lower net revenue, partially offset by lower than anticipated operating expenses.

Significant forecast variances include:

- Decrease in **net electricity revenue** of $12,315 arising from:
    - Higher variable distribution services revenue from increased consumption from the residential and GS < 50kW rate classes relative to budget ($474);
    - Lower fixed distribution services revenue from the GS > 50kW rate classes as a result of customer reclassifications ($323); and
    - Decrease in net non-distribution electricity revenue ($12,459).
- Increase in **other income from operations** of $66; principally explained by; (i) higher than anticipated performance incentive revenue from conservation programs completed in prior years ($250); (ii) higher than anticipated rental revenue from Hamilton John Street facility and Stoney Creek service centre ($97); and (iii) partially offset by lower than expected recoveries of theft of power ($93).
- Lower **operating expenses** of $752; principally explained by:
    - Lower than anticipated salaries and benefits principally explained by: (i) the timing of new hires and unanticipated retirements; and (ii) lower than anticipated contract labour supporting the GIS and ERP initiatives ($1,351);
    - Lower depreciation expense principally explained by: (i) lower than budgeted depreciation on the asset base of the prior year; (ii) the timing of capitalization of the GIS initiative; and (iii) the permanent capital expenditure variance for the ERP initiative ($592) ;
    - Lower than anticipated software license and maintenance expenditures ($228); principally explained by: (i) timing of the implementation of GIS ($186); and (ii) lower than anticipated expenditures related to Human Resources initiatives ($42);
    - Higher professional service fees ($449); principally explained by: (i) higher than anticipated services to support the execution and sustainment of the GIS initiative ($200); (ii) higher than anticipated expenditures in Information Systems Technology corresponding to Enterprise Information Management Strategy, ERP maintenance costs, and support staff to offset vacancies ($175); (iii) higher than anticipated Construction and Maintenance costs related to restoration work and hydrovac excavation services in St. Catharines ($66); (iv) support staff in Health and Safety to offset vacancies ($58); and (v) partially offset by the elimination of planned Finance professional service expenditures ($80);

- Lower than anticipated capitalization of labour ($360); principally explained by: (i) elimination of system modifications relating to the ERP initiative ($225); and (ii) reduction of labour relating to the construction of the distribution system ($135);

- Higher than anticipated repairs and maintenance on buildings ($284); principally explained by: (i) required building code improvements at the Hamilton John Street facility ($208); (ii) maintenance at the Hamilton Nebo Road service centre to address necessary building improvements ($107); and (iii) offset by elimination of maintenance expenditures relating to substation buildings ($31);

- Higher janitorial, snow removal and landscaping expenditures related to the maintenance of the service centres ($198); principally explained by the colder weather resulting in higher than anticipated snow removal services;

- Higher billing and collecting costs ($73); principally explained by an increase in postage rates and corresponding charges effective March 31, 2014;

- Higher than anticipated property taxes relating to the St. Catharines Vansickle Road facility ($71); and

- Higher than anticipated general and property insurance premiums ($68).

Results of Electricity Distribution Operations
($000s)

	Quarter ended June 30					Six Months ended June 30					Year Ending		
	2014			2013	Q over Q	2014			2013	Y over Y	2014		
	Actual	Budget	Variance	Actual	Variance	Actual	Budget	Variance	Actual	Variance	Forecast	Budget	Variance
Distribution services revenue:													
Fixed	14,743	15,058	(315)	14,547	196	29,697	30,086	(389)	29,205	492	59,973	60,296	(323)
Variable	10,102	10,183	(81)	10,122	(20)	21,242	20,869	373	20,563	679	43,613	43,139	474
Total distribution services revenue	24,845	25,241	(396)	24,669	176	50,939	50,955	(16)	49,768	1,171	103,586	103,435	151
Other rider/adder revenue	1,160	1,163	(3)	1,579	(419)	2,314	2,320	(6)	3,282	(968)	4,632	4,639	(7)
Total distribution services and other revenue	26,005	26,404	(399)	26,248	(243)	53,253	53,275	(22)	53,050	203	108,218	108,074	144
Non-distribution electricity revenue:													
Electricity revenue	112,208	118,382	(6,174)	115,054	(2,846)	254,163	246,574	7,589	229,672	24,491	505,346	503,621	1,725
Electricity cost of sales	(123,648)	(118,376)	(5,272)	(120,635)	(3,013)	(263,899)	(246,563)	(17,336)	(236,043)	(27,856)	(517,856)	(503,594)	(14,262)
Settlements of past accumulated variances	(2,619)	(2,670)	51	(1,299)	(1,320)	(5,241)	(5,354)	113	(2,603)	(2,638)	(10,902)	(10,980)	78
Net non-distribution electricity revenue	(14,059)	(2,664)	(11,395)	(6,880)	(7,179)	(14,977)	(5,343)	(9,634)	(8,974)	(6,003)	(23,412)	(10,953)	(12,459)
Net electricity revenue	11,946	23,740	(11,794)	19,368	(7,422)	38,276	47,932	(9,656)	44,076	(5,800)	84,806	97,121	(12,315)
Other income from operations	1,793	1,678	115	1,358	435	3,459	3,334	125	2,861	598	6,785	6,719	66
Total net revenue	13,739	25,418	(11,679)	20,726	(6,987)	41,735	51,266	(9,531)	46,937	(5,202)	91,591	103,840	(12,249)
Expenses:													
Distribution and utilization	8,011	8,579	(568)	7,740	271	16,636	17,843	(1,207)	15,838	798	36,538	36,969	(431)
Billing and collecting	2,018	1,988	30	1,917	101	4,036	3,976	60	3,843	193	8,025	7,952	73
Credit losses	260	386	(126)	286	(26)	521	772	(251)	601	(80)	1,468	1,543	(75)
General and administrative	4,584	4,440	144	3,500	1,084	8,703	8,862	(159)	7,137	1,566	18,101	17,828	273
Depreciation and amortization	5,153	5,300	(147)	4,921	232	10,205	10,481	(276)	9,795	410	21,125	21,717	(592)
Total expenses	20,026	20,693	(667)	18,364	1,662	40,101	41,934	(1,833)	37,214	2,887	85,257	86,009	(752)
(Loss) income from operating activities	(6,287)	4,725	(11,012)	2,362	(8,649)	1,634	9,332	(7,698)	9,723	(8,089)	6,334	17,831	(11,497)
Loss on sale and disposal of assets	(478)	(343)	(135)	(314)	(164)	(707)	(687)	(20)	(655)	(52)	(1,179)	(1,373)	194
Finance income	10	25	(15)	87	(77)	29	51	(22)	184	(155)	104	101	3
Finance charges	(1,717)	(1,787)	70	(1,728)	11	(3,422)	(3,556)	134	(3,425)	3	(7,219)	(7,166)	(53)
(Loss) income before taxes	(8,472)	2,620	(11,092)	407	(8,879)	(2,466)	5,140	(7,606)	5,827	(8,293)	(1,960)	9,393	(11,353)
Payments in lieu of income taxes	2,245	(694)	2,939	(13)	2,258	648	(1,362)	2,010	(1,447)	2,095	519	(2,489)	3,008
Net (loss) income	(6,227)	1,926	(8,153)	394	(6,621)	(1,818)	3,778	(5,596)	4,380	(6,198)	(1,441)	6,904	(8,345)

EXHIBIT 1

Distribution Services Revenue Analysis
By Customer Class
($000s)

	Quarter ended June 30					Six Months ended June 30					Year Ending		
	2014			2013	Q over Q	2014			2013	Y over Y	2014		
	Actual	Budget	Variance	Actual	Variance	Actual	Budget	Variance	Actual	Variance	Forecast	Budget	Variance
Large Commercial - Fixed	2,661	2,765	(104)	2,631	30	5,352	5,285	67	5,325	27	10,851	10,851	-
- Variable	3,184	3,157	27	3,123	61	6,120	6,198	(78)	5,998	122	12,604	12,604	-
Sub-total	5,845	5,922	(77)	5,754	91	11,472	11,483	(11)	11,323	149	23,455	23,455	-
Small Commercial - Fixed	2,341	2,324	17	2,276	65	4,679	4,879	(200)	4,567	112	9,529	9,529	-
- Variable	1,655	1,630	25	1,688	(33)	3,441	3,332	109	3,335	106	6,652	6,652	-
Sub-total	3,996	3,954	42	3,964	32	8,120	8,211	(91)	7,902	218	16,181	16,181	-
Residential - Fixed	9,741	9,969	(228)	9,640	101	19,666	19,922	(256)	19,313	353	39,593	39,916	(323)
- Variable	5,263	5,396	(133)	5,311	(48)	11,681	11,339	342	11,230	451	24,357	23,883	474
Sub-total	15,004	15,365	(361)	14,951	53	31,347	31,261	86	30,543	804	63,950	63,799	151
Total distribution services revenue	24,845	25,241	(396)	24,669	176	50,939	50,955	(16)	49,768	1,171	103,586	103,435	151

UNDERTAKING NO. TCJ1.10:

TO PROVIDE UPDATED REVENUE REQUIREMENT WORK FORMS TO REFLECT ANY CHANGES AND/OR CORRECTIONS MADE FOR EACH OF THE YEARS, AND REDO THE COST ALLOCATION BASED ON ANY CHANGES IN REVENUE REQUIREMENTAND CHANGES AS TO WHAT COSTS SHOULD BE ALLOCATED TO SPECIFIC CUSTOMERS, AND CUSTOMER BILL IMPACTS.

Response:

Horizon Utilities has updated the Revenue Requirement Workform, Cost Allocation model, and Appendix 2-W bill impacts for the following items:

- Working Capital Allowance reduced from 12.7% to 12.0% (2-Staff-23)
- LEAP adjusted to calculate based on Service Revenue (4-SIA-34TC)
- Number of USL bills calculated based on the number of customers rather than connections (7-VECC-53)
- Directly allocated depreciation assigned to LU (2) class (7-VECC-89TC)
- Updated the Load forecast for CDM impacts (3-VECC-78TC)

As requested, Horizon Utilities provides the following updated attachments:

- UNDERTAKING NO. TCJ1.10 ATTCH_1_Revenue Requirement Work Form 2015 (IR Revised)
- UNDERTAKING NO. TCJ1.10 ATTCH_2_Revenue Requirement Work Form 2016 (IR Revised)
- UNDERTAKING NO. TCJ1.10 ATTCH_3_Revenue Requirement Work Form 2017 (IR Revised)
- UNDERTAKING NO. TCJ1.10 ATTCH_4_Revenue Requirement Work Form 2018 (IR Revised)
- UNDERTAKING NO. TCJ1.10 ATTCH_5_Revenue Requirement Work Form 2019 (IR Revised)
- UNDERTAKING NO. TCJ1.10 ATTCH_6_RRWF 2015 (IR Revised)
- UNDERTAKING NO. TCJ1.10 ATTCH_7_RRWF 2016 (IR Revised)

- UNDERTAKING NO. TCJ1.10 ATTCH_8_RRWF 2017 (IR Revised)
- UNDERTAKING NO. TCJ1.10 ATTCH_9_RRWF 2018 (IR Revised)
- UNDERTAKING NO. TCJ1.10 ATTCH_10_RRWF 2019 (IR Revised)
- UNDERTAKING NO. TCJ1.10 ATTCH_11_5.1 Cost Allocation 2015
- UNDERTAKING NO. TCJ1.10 ATTCH_12_5.1 Cost Allocation 2016
- UNDERTAKING NO. TCJ1.10 ATTCH_13_5.1 Cost Allocation 2017
- UNDERTAKING NO. TCJ1.10 ATTCH_14_5.1 Cost Allocation 2018
- UNDERTAKING NO. TCJ1.10 ATTCH_15_5.1 Cost Allocation 2019
- UNDERTAKING NO. TCJ1.10 ATTCH_16_7.0 App.2-W_Bill Impacts

UNDERTAKING NO. TCJ1.10 ATTCH_1_Revenue Requirement Work Form 2015 (IR Revised)

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Revenue Requirement Workform

Version 4.00

Utility Name	Horizon Utilities Corporation
Service Territory	*Hamilton and St.Catharines*
Assigned EB Number	EB-2014-0002
Name and Title	Indy J. Butany-DeSouza, VP Regulatory Affairs
Phone Number	905-317-4765
Email Address	Indy.Butany@Horizonutilities.com

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and

Revenue Requirement Workform

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

#	Item	Initial Application	(2)	Adjustments		Interrogatory Responses	(6)	Adjustments		Per Board Decision	
1	**Rate Base**										
	Gross Fixed Assets (average)	$497,423,660				$ 497,423,660				$497,423,660	
	Accumulated Depreciation (average)	($87,829,090)	(5)			($87,829,090)				($87,829,090)	
	Allowance for Working Capital:										
	Controllable Expenses	$62,632,679		$6,573	(10)	$ 62,639,252				$62,639,252	
	Cost of Power	$520,162,944		($746,247)	(11)	$ 519,416,697				$519,416,697	
	Working Capital Rate (%)	12.70%	(9)			12.00%	(9)			12.00%	(9)
2	**Utility Income**										
	Operating Revenues:										
	Distribution Revenue at Current Rates	$102,888,297		($82,219)		$102,806,078	(12)				
	Distribution Revenue at Proposed Rates	$112,956,026		($290,298)		$112,665,728	(13)				
	Other Revenue:										
	Specific Service Charges	$729,918		$0		$729,918					
	Late Payment Charges	$825,000		$0		$825,000					
	Other Distribution Revenue										
	Other Income and Deductions	$3,922,997		$0		$3,922,997					
	Total Revenue Offsets	$5,477,916	(7)	$0		$5,477,916					
	Operating Expenses:										
	OM+A Expenses	$62,332,489		$6,573	(10)	$ 62,339,062				$62,339,062	
	Depreciation/Amortization	$24,970,618				$ 24,970,618				$24,970,618	
	Property taxes	$300,190				$ 300,190				$300,190	
	Other expenses										
3	**Taxes/PILs**										
	Taxable Income:										
	Adjustments required to arrive at taxable income	($9,465,237)	(3)			($9,465,237)					
	Utility Income Taxes and Rates:										
	Income taxes (not grossed up)	$2,154,383				$2,113,016					
	Income taxes (grossed up)	$2,915,069				$2,858,808					
	Federal tax (%)	15.00%				15.00%					
	Provincial tax (%)	11.09%				11.09%					
	Income Tax Credits	($100,511)				($100,521)					
4	**Capitalization/Cost of Capital**										
	Capital Structure:										
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			4.0%	(8)				(8)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%					
	Prefered Shares Capitalization Ratio (%)	0.0%									
		100.0%				100.0%					
	Cost of Capital										
	Long-term debt Cost Rate (%)	3.47%				3.47%					
	Short-term debt Cost Rate (%)	2.11%				2.11%					
	Common Equity Cost Rate (%)	9.36%				9.36%					
	Prefered Shares Cost Rate (%)	0.00%									

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale. Horizon WC % updated from 12.7% to 12.0% per 2-Staff-23

(10) Updated LEAP amount to be based on Service Revenue per 4-SIA-34TC

(11) Updated Cost of Power due to the Load Forecast impact of 3-VECC-78TC (removed 4 month CDM lag)

(12) Change to Revenue at existing rates due to Load Forecast impact of 3-VECC-78TC (removed 4 month CDM lag)

(13) Changed to Revenue at proposed rates due to Load Forecast impact of 3-VECC-78TC, as well as Revenue Requirement impact of 4-SIA-34TC and 2-Staff-23

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$497,423,660	$ -	$497,423,660	$ -	$497,423,660
2	Accumulated Depreciation (average)	(3)	($87,829,090)	$ -	($87,829,090)	$ -	($87,829,090)
3	Net Fixed Assets (average)	(3)	$409,594,570	$ -	$409,594,570	$ -	$409,594,570
4	Allowance for Working Capital	(1)	$74,015,044	($4,168,330)	$69,846,714	$ -	$69,846,714
5	**Total Rate Base**		$483,609,614	($4,168,330)	$479,441,284	$ -	$479,441,284

(1) ### Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$62,632,679	$6,573	(4)	$62,639,252	$ -	$62,639,252
7	Cost of Power		$520,162,944	($746,247)	(5)	$519,416,697	$ -	$519,416,697
8	Working Capital Base		$582,795,623	($739,674)		$582,055,948	$ -	$582,055,948
9	Working Capital Rate %	(2)	12.70%	-0.70%	(6)	12.00%	0.00%	12.00%
10	Working Capital Allowance		$74,015,044	($4,168,330)		$69,846,714	$ -	$69,846,714

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.
(3) Average of opening and closing balances for the year.
(4) Updated LEAP amount to be based on Service Revenue per 4-SIA-34TC
(5) Updated Cost of Power due to the Load Forecast impact of 3-VECC-78TC (removed 4 month CDM lag)
(6) Horizon WC % updated from 12.7% to 12.0% per 2-Staff-23

Revenue Requirement Workform

Utility Income

Line No.	Particulars	Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)	$112,956,026	($290,298)	(2)	$112,665,728	$ -	$112,665,728
2	Other Revenue (1)	$5,477,916	$ -		$5,477,916	$ -	$5,477,916
3	Total Operating Revenues	$118,433,942	($290,298)		$118,143,644	$ -	$118,143,644
	Operating Expenses:						
4	OM+A Expenses	$62,332,489	$6,573	(3)	$62,339,062	$ -	$62,339,062
5	Depreciation/Amortization	$24,970,618	$ -		$24,970,618	$ -	$24,970,618
6	Property taxes	$300,190	$ -		$300,190	$ -	$300,190
7	Capital taxes	$ -	$ -		$ -	$ -	$ -
8	Other expense	$ -	$ -			$ -	
9	Subtotal (lines 4 to 8)	$87,603,297	$6,573		$87,609,870	$ -	$87,609,870
10	Deemed Interest Expense	$9,809,232	($84,548)		$9,724,684	$ -	$9,724,684
11	Total Expenses (lines 9 to 10)	$97,412,529	($77,975)		$97,334,554	$ -	$97,334,554
12	**Utility income before income taxes**	$21,021,413	($212,323)		$20,809,089	$ -	$20,809,089
13	Income taxes (grossed-up)	$2,915,069	($56,261)		$2,858,808	$ -	$2,858,808
14	**Utility net income**	$18,106,344	($156,062)		$17,950,282	$ -	$17,950,282

Notes

Other Revenues / Revenue Offsets

Notes	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$729,918	$ -	$729,918		$729,918
	Late Payment Charges	$825,000	$ -	$825,000		$825,000
	Other Distribution Revenue	$ -		$ -		$ -
	Other Income and Deductions	$3,922,997	$ -	$3,922,997		$3,922,997
	Total Revenue Offsets	$5,477,916	$ -	$5,477,916	$ -	$5,477,916

(2) Changed to Revenue at proposed rates due to Load Forecast impact of 3-VECC-78TC, as well as Revenue Requirement impact of 4-SIA-34TC and 2-Staff-23
(3) Updated LEAP amount to be based on Service Revenue per 4-SIA-34TC

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$18,106,344	$17,950,282	$17,950,282
2	Adjustments required to arrive at taxable utility income	($9,465,237)	($9,465,237)	($9,465,237)
3	Taxable income	$8,641,107	$8,485,045	$8,485,045
	Calculation of Utility income Taxes			
4	Income taxes	$2,154,383	$2,113,016	$2,113,016
6	Total taxes	$2,154,383	$2,113,016	$2,113,016
7	Gross-up of Income Taxes	$760,686	$745,792	$745,792
8	Grossed-up Income Taxes	$2,915,069	$2,858,808	$2,858,808
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$2,915,069	$2,858,808	$2,858,808
10	Other tax Credits	($100,511)	($100,521)	($100,521)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.09%	11.09%	11.09%
13	Total tax rate (%)	26.09%	26.09%	26.09%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$270,821,384	3.47%	$9,401,065
2	Short-term Debt	4.00%	$19,344,385	2.11%	$408,167
3	**Total Debt**	60.00%	$290,165,769	3.38%	$9,809,232
	Equity				
4	Common Equity	40.00%	$193,443,846	9.36%	$18,106,344
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$193,443,846	9.36%	$18,106,344
7	**Total**	100.00%	$483,609,614	5.77%	$27,915,576
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$268,487,119	3.47%	$9,320,036
2	Short-term Debt	4.00%	$19,177,651	2.11%	$404,648
3	**Total Debt**	60.00%	$287,664,770	3.38%	$9,724,684
	Equity				
4	Common Equity	40.00%	$191,776,514	9.36%	$17,950,282
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$191,776,514	9.36%	$17,950,282
7	**Total**	100.00%	$479,441,284	5.77%	$27,674,966
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$268,487,119	3.47%	$9,320,036
9	Short-term Debt	4.00%	$19,177,651	2.11%	$404,648
10	**Total Debt**	60.00%	$287,664,770	3.38%	$9,724,684
	Equity				
11	Common Equity	40.00%	$191,776,514	9.36%	$17,950,282
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$191,776,514	9.36%	$17,950,282
14	**Total**	100.00%	$479,441,284	5.77%	$27,674,966

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$10,067,729		$9,859,650		$9,859,650
2	Distribution Revenue	$102,888,297	$102,888,297	$102,806,078	$102,806,078	$102,806,078	$102,806,078
3	Other Operating Revenue Offsets - net	$5,477,916	$5,477,916	$5,477,916	$5,477,916	$5,477,916	$5,477,916
4	**Total Revenue**	$108,366,213	$118,433,942	$108,283,994	$118,143,644	$108,283,994	$118,143,644
5	Operating Expenses	$87,603,297	$87,603,297	$87,609,870	$87,609,870	$87,609,870	$87,609,870
6	Deemed Interest Expense	$9,809,232	$9,809,232	$9,724,684	$9,724,684	$9,724,684	$9,724,684
8	**Total Cost and Expenses**	$97,412,529	$97,412,529	$97,334,554	$97,334,554	$97,334,554	$97,334,554
9	**Utility Income Before Income Taxes**	$10,953,684	$21,021,413	$10,949,439	$20,809,089	$10,949,439	$20,809,089
10	Tax Adjustments to Accounting Income per 2013 PILs model	($9,465,237)	($9,465,237)	($9,465,237)	($9,465,237)	($9,465,237)	($9,465,237)
11	**Taxable Income**	$1,488,447	$11,556,176	$1,484,203	$11,343,853	$1,484,203	$11,343,853
12	Income Tax Rate	26.09%	26.09%	26.09%	26.09%	26.09%	26.09%
13	**Income Tax on Taxable Income**	$388,410	$3,015,579	$387,192	$2,959,329	$387,192	$2,959,329
14	**Income Tax Credits**	($100,511)	($100,511)	($100,521)	($100,521)	($100,521)	($100,521)
15	**Utility Net Income**	$10,665,785	$18,106,344	$10,662,769	$17,950,282	$10,662,769	$17,950,282
16	**Utility Rate Base**	$483,609,614	$483,609,614	$479,441,284	$479,441,284	$479,441,284	$479,441,284
17	Deemed Equity Portion of Rate Base	$193,443,846	$193,443,846	$191,776,514	$191,776,514	$191,776,514	$191,776,514
18	Income/(Equity Portion of Rate Base)	5.51%	9.36%	5.56%	9.36%	5.56%	9.36%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-3.85%	0.00%	-3.80%	0.00%	-3.80%	0.00%
21	Indicated Rate of Return	4.23%	5.77%	4.25%	5.77%	4.25%	5.77%
22	Requested Rate of Return on Rate Base	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%
23	Deficiency/Sufficiency in Rate of Return	-1.54%	0.00%	-1.52%	0.00%	-1.52%	0.00%
24	Target Return on Equity	$18,106,344	$18,106,344	$17,950,282	$17,950,282	$17,950,282	$17,950,282
25	Revenue Deficiency/(Sufficiency)	$7,440,559	$ -	$7,287,513	$ -	$7,287,513	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$10,067,729 **(1)**		$9,859,650 **(1)**		$9,859,650 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$62,332,489		$62,339,062		$62,339,062	
2	Amortization/Depreciation	$24,970,618		$24,970,618		$24,970,618	
3	Property Taxes	$300,190		$300,190		$300,190	
5	Income Taxes (Grossed up)	$2,915,069		$2,858,808		$2,858,808	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$9,809,232		$9,724,684		$9,724,684	
	Return on Deemed Equity	$18,106,344		$17,950,282		$17,950,282	
8	**Service Revenue Requirement (before Revenues)**	$118,433,942		$118,143,644		$118,143,644	
9	Revenue Offsets	$5,477,916		$5,477,916		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$112,956,026		$112,665,728		$118,143,644	
11	Distribution revenue	$112,956,026		$112,665,728		$112,665,728	
12	Other revenue	$5,477,916		$5,477,916		$5,477,916	
13	**Total revenue**	$118,433,942		$118,143,644		$118,143,644	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	**(1)**	$ -	**(1)**	$ -	**(1)**

Notes

(1) Line 11 - Line 8

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Revenue Requirement Workform

Version 4.00

Utility Name	Horizon Utilities Corporation
Service Territory	*Hamilton & St Catharines*
Assigned EB Number	EB-2014-0002
Name and Title	Indy Butany-DeSouza, VP Regulatory Affairs
Phone Number	905-317-4765
Email Address	indy.butany@horizonutilities.com

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Data Input (1)

		Initial Application	(2)	Adjustments		Interrogatory Responses	(6)	Adjustments		Per Board Decision	
1	**Rate Base**										
	Gross Fixed Assets (average)	$535,997,407				$ 535,997,407				$535,997,407	
	Accumulated Depreciation (average)	($110,984,932)	(5)			($110,984,932)				($110,984,932)	
	Allowance for Working Capital:										
	Controllable Expenses	$64,394,131		$6,620	(10)	$ 64,400,751				$64,400,751	
	Cost of Power	$541,395,015		($721,368)	(11)	$ 540,673,647				$540,673,647	
	Working Capital Rate (%)	12.70%	(9)			12.00%	(9)			12.00%	(9)
2	**Utility Income**										
	Operating Revenues:										
	Distribution Revenue at Current Rates	$113,328,920		($221,279)		$113,107,641	(12)				
	Distribution Revenue at Proposed Rates	$118,628,501		($301,505)		$118,326,996	(13)				
	Other Revenue:										
	Specific Service Charges	$735,335		$0		$735,335					
	Late Payment Charges	$825,000		$0		$825,000					
	Other Distribution Revenue										
	Other Income and Deductions	$3,956,175		$0		$3,956,175					
	Total Revenue Offsets	$5,516,509	(7)	$0		$5,516,509					
	Operating Expenses:										
	OM+A Expenses	$64,089,437		$6,620	(10)	$ 64,096,057				$64,096,057	
	Depreciation/Amortization	$26,487,624				$ 26,487,624				$26,487,624	
	Property taxes	$304,693				$ 304,693				$304,693	
	Other expenses										
3	**Taxes/PILs**										
	Taxable Income:										
	Adjustments required to arrive at taxable income	($6,329,306)	(3)			($6,329,306)					
	Utility Income Taxes and Rates:										
	Income taxes (not grossed up)	$3,164,565				$3,121,636					
	Income taxes (grossed up)	$4,289,143				$4,230,747					
	Federal tax (%)	15.00%				15.00%					
	Provincial tax (%)	11.22%				11.22%					
	Income Tax Credits	($103,293)				($103,298)					
4	**Capitalization/Cost of Capital**										
	Capital Structure:										
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			4.0%	(8)				(8)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%					
	Prefered Shares Capitalization Ratio (%)	0.0%									
		100.0%				100.0%					
	Cost of Capital										
	Long-term debt Cost Rate (%)	3.47%				3.47%					
	Short-term debt Cost Rate (%)	2.11%				2.11%					
	Common Equity Cost Rate (%)	9.36%				9.36%					
	Prefered Shares Cost Rate (%)	0.00%									

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale. Horizon WC % updated from 12.7% to 12.0% per 2-Staff-23

(10) Updated LEAP to be based on Service Revenue per 4-SIA-34TC

(11) Updated Cost of Power due to the Load Forecast impact of 3-VECC-78TC (removed 4 month CDM lag)

(12) Change to Revenue at existing rates due to Load Forecast impact of 3-VECC-17 (RE updated CDM appendix 2-I) and 3-VECC-78TC (removed 4 month CDM lag)

(13) Changed to Revenue at proposed rates due to Load Forecast impact of 3-VECC-78TC, as well as Revenue Requirement impact of 4-SIA-34TC and 2-Staff-23

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$535,997,407	$ -		$535,997,407	$ -	$535,997,407
2	Accumulated Depreciation (average)	(3)	($110,984,932)	$ -		($110,984,932)	$ -	($110,984,932)
3	Net Fixed Assets (average)	(3)	$425,012,475	$ -		$425,012,475	$ -	$425,012,475
4	Allowance for Working Capital	(1)	$76,935,221	($4,326,294)		$72,608,928	$ -	$72,608,928
5	**Total Rate Base**		$501,947,697	($4,326,294)		$497,621,403	$ -	$497,621,403

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$64,394,131	$6,620	(4)	$64,400,751	$ -	$64,400,751
7	Cost of Power		$541,395,015	($721,368)	(5)	$540,673,647	$ -	$540,673,647
8	Working Capital Base		$605,789,145	($714,748)		$605,074,398	$ -	$605,074,398
9	Working Capital Rate %	(2)	12.70%	-0.70%	(6)	12.00%	0.00%	12.00%
10	Working Capital Allowance		$76,935,221	($4,326,294)		$72,608,928	$ -	$72,608,928

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.
(3) Average of opening and closing balances for the year.
(4) Updated LEAP amount to be based on Service Revenue per 4-SIA-34TC
(5) Updated Cost of Power due to the Load Forecast impact of 3-VECC-78TC (removed 4 month CDM lag)
(6) Horizon WC % updated from 12.7% to 12.0% per 2-Staff-23

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:							
1	Distribution Revenue (at Proposed Rates)		$118,628,501	($301,505)	(2)	$118,326,996	$ -	$118,326,996
2	Other Revenue	(1)	$5,516,509	$ -		$5,516,509	$ -	$5,516,509
3	Total Operating Revenues		$124,145,010	($301,505)		$123,843,505	$ -	$123,843,505
	Operating Expenses:							
4	OM+A Expenses		$64,089,437	$6,620	(3)	$64,096,057	$ -	$64,096,057
5	Depreciation/Amortization		$26,487,624	$ -		$26,487,624	$ -	$26,487,624
6	Property taxes		$304,693	$ -		$304,693	$ -	$304,693
7	Capital taxes		$ -	$ -		$ -	$ -	$ -
8	Other expense		$ -	$ -			$ -	
9	Subtotal (lines 4 to 8)		$90,881,755	$6,620		$90,888,375	$ -	$90,888,375
10	Deemed Interest Expense		$10,181,190	($87,752)		$10,093,438	$ -	$10,093,438
11	Total Expenses (lines 9 to 10)		$101,062,945	($81,132)		$100,981,813	$ -	$100,981,813
12	**Utility income before income taxes**		$23,082,065	($220,373)		$22,861,692	$ -	$22,861,692
13	Income taxes (grossed-up)		$4,289,143	($58,396)		$4,230,747	$ -	$4,230,747
14	**Utility net income**		$18,792,922	($161,976)		$18,630,945	$ -	$18,630,945

Notes

Other Revenues / Revenue Offsets

		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$735,335	$ -	$735,335		$735,335
	Late Payment Charges	$825,000	$ -	$825,000		$825,000
	Other Distribution Revenue	$ -		$ -		$ -
	Other Income and Deductions	$3,956,175	$ -	$3,956,175		$3,956,175
	Total Revenue Offsets	$5,516,509	$ -	$5,516,509	$ -	$5,516,509

(2) Changed to Revenue at proposed rates due to Load Forecast impact of 3-VECC-78TC, as well as Revenue Requirement impact of 4-SIA-34TC and 2-Staff-23
(3) Updated LEAP amount to be based on Service Revenue per 4-SIA-34TC

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$18,792,922	$18,630,945	$18,630,945
2	Adjustments required to arrive at taxable utility income	($6,329,306)	($6,329,306)	($6,329,306)
3	Taxable income	$12,463,615	$12,301,639	$12,301,639
	Calculation of Utility income Taxes			
4	Income taxes	$3,164,565	$3,121,636	$3,121,636
6	Total taxes	$3,164,565	$3,121,636	$3,121,636
7	Gross-up of Income Taxes	$1,124,578	$1,109,111	$1,109,111
8	Grossed-up Income Taxes	$4,289,143	$4,230,747	$4,230,747
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$4,289,143	$4,230,747	$4,230,747
10	Other tax Credits	($103,293)	($103,298)	($103,298)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.22%	11.22%	11.22%
13	Total tax rate (%)	26.22%	26.22%	26.22%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Initial Application

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$281,090,710	3.47%	$9,757,546
2	Short-term Debt	4.00%	$20,077,908	2.11%	$423,644
3	**Total Debt**	60.00%	$301,168,618	3.38%	$10,181,190
	Equity				
4	Common Equity	40.00%	$200,779,079	9.36%	$18,792,922
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$200,779,079	9.36%	$18,792,922
7	**Total**	100.00%	$501,947,697	5.77%	$28,974,112

Interrogatory Responses

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	$278,667,986	3.47%	$9,673,446
2	Short-term Debt	4.00%	$19,904,856	2.11%	$419,992
3	**Total Debt**	60.00%	$298,572,842	3.38%	$10,093,438
	Equity				
4	Common Equity	40.00%	$199,048,561	9.36%	$18,630,945
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$199,048,561	9.36%	$18,630,945
7	**Total**	100.00%	$497,621,403	5.77%	$28,724,384

Per Board Decision

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
8	Long-term Debt	56.00%	$278,667,986	3.47%	$9,673,446
9	Short-term Debt	4.00%	$19,904,856	2.11%	$419,992
10	**Total Debt**	60.00%	$298,572,842	3.38%	$10,093,438
	Equity				
11	Common Equity	40.00%	$199,048,561	9.36%	$18,630,945
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$199,048,561	9.36%	$18,630,945
14	**Total**	100.00%	$497,621,403	5.77%	$28,724,384

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$5,299,581		$5,219,355		$5,219,355
2	Distribution Revenue	$113,328,920	$113,328,920	$113,107,641	$113,107,641	$113,107,641	$113,107,641
3	Other Operating Revenue Offsets - net	$5,516,509	$5,516,509	$5,516,509	$5,516,509	$5,516,509	$5,516,509
4	**Total Revenue**	$118,845,429	$124,145,010	$118,624,151	$123,843,505	$118,624,151	$123,843,505
5	Operating Expenses	$90,881,755	$90,881,755	$90,888,375	$90,888,375	$90,888,375	$90,888,375
6	Deemed Interest Expense	$10,181,190	$10,181,190	$10,093,438	$10,093,438	$10,093,438	$10,093,438
8	**Total Cost and Expenses**	$101,062,945	$101,062,945	$100,981,813	$100,981,813	$100,981,813	$100,981,813
9	**Utility Income Before Income Taxes**	$17,782,484	$23,082,065	$17,642,338	$22,861,692	$17,642,338	$22,861,692
10	Tax Adjustments to Accounting Income per 2013 PILs model	($6,329,306)	($6,329,306)	($6,329,306)	($6,329,306)	($6,329,306)	($6,329,306)
11	**Taxable Income**	$11,453,178	$16,752,759	$11,313,031	$16,532,386	$11,313,031	$16,532,386
12	Income Tax Rate	26.22%	26.22%	26.22%	26.22%	26.22%	26.22%
13	**Income Tax on Taxable Income**	$3,002,930	$4,392,436	$2,965,766	$4,334,045	$2,965,766	$4,334,045
14	**Income Tax Credits**	($103,293)	($103,293)	($103,298)	($103,298)	($103,298)	($103,298)
15	**Utility Net Income**	$14,882,848	$18,792,922	$14,779,870	$18,630,945	$14,779,870	$18,630,945
16	**Utility Rate Base**	$501,947,697	$501,947,697	$497,621,403	$497,621,403	$497,621,403	$497,621,403
17	Deemed Equity Portion of Rate Base	$200,779,079	$200,779,079	$199,048,561	$199,048,561	$199,048,561	$199,048,561
18	Income/(Equity Portion of Rate Base)	7.41%	9.36%	7.43%	9.36%	7.43%	9.36%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-1.95%	0.00%	-1.93%	0.00%	-1.93%	0.00%
21	Indicated Rate of Return	4.99%	5.77%	5.00%	5.77%	5.00%	5.77%
22	Requested Rate of Return on Rate Base	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%
23	Deficiency/Sufficiency in Rate of Return	-0.78%	0.00%	-0.77%	0.00%	-0.77%	0.00%
24	Target Return on Equity	$18,792,922	$18,792,922	$18,630,945	$18,630,945	$18,630,945	$18,630,945
25	Revenue Deficiency/(Sufficiency)	$3,910,074	$ -	$3,851,075	$ -	$3,851,075	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$5,299,581 **(1)**		$5,219,355 **(1)**		$5,219,355 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$64,089,437		$64,096,057		$64,096,057	
2	Amortization/Depreciation	$26,487,624		$26,487,624		$26,487,624	
3	Property Taxes	$304,693		$304,693		$304,693	
5	Income Taxes (Grossed up)	$4,289,143		$4,230,747		$4,230,747	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$10,181,190		$10,093,438		$10,093,438	
	Return on Deemed Equity	$18,792,922		$18,630,945		$18,630,945	
8	**Service Revenue Requirement (before Revenues)**	$124,145,010		$123,843,505		$123,843,505	
9	Revenue Offsets	$5,516,509		$5,516,509		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$118,628,501		$118,326,996		$123,843,505	
11	Distribution revenue	$118,628,501		$118,326,996		$118,326,996	
12	Other revenue	$5,516,509		$5,516,509		$5,516,509	
13	**Total revenue**	$124,145,010		$123,843,505		$123,843,505	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	**(1)**	$ -	**(1)**	$ -	**(1)**

Notes

(1) Line 11 - Line 8

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Revenue Requirement Workform

Version **4.00**

Utility Name	Horizon Utilities Corporation
Service Territory	*Hamilton and St. Catharines*
Assigned EB Number	EB-2014-0002
Name and Title	Indy J. Butany-DeSouza, VP Regulatory Affairs
Phone Number	905-317-4765
Email Address	indy.butany@horizonutilities.com

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and

Revenue Requirement Workform

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input (1)

		Initial Application	(2)	Adjustments		Interrogatory Responses	(6)	Adjustments	Per Board Decision	
1	**Rate Base**									
	Gross Fixed Assets (average)	$577,762,960				$ 577,762,960			$577,762,960	
	Accumulated Depreciation (average)	($134,451,262)	(5)			($134,451,262)			($134,451,262)	
	Allowance for Working Capital:									
	Controllable Expenses	$66,255,827		$6,667	(10)	$ 66,262,494			$66,262,494	
	Cost of Power	$561,407,753		($747,702)	(11)	$ 560,660,052			$560,660,052	
	Working Capital Rate (%)	12.70%	(9)			12.00%	(9)		12.00%	(9)
2	**Utility Income**									
	Operating Revenues:									
	Distribution Revenue at Current Rates	$118,938,011		($247,346)		$118,690,665	(12)			
	Distribution Revenue at Proposed Rates	$121,743,444		($312,588)		$121,430,855	(13)			
	Other Revenue:									
	Specific Service Charges	$741,093		$0		$741,093				
	Late Payment Charges	$825,000		$0		$825,000				
	Other Distribution Revenue									
	Other Income and Deductions	$3,989,844		$0		$3,989,844				
	Total Revenue Offsets	$5,555,937	(7)	$0		$5,555,937				
	Operating Expenses:									
	OM+A Expenses	$65,946,564		$6,667	(10)	$ 65,953,231			$65,953,231	
	Depreciation/Amortization	$26,379,676				$ 26,379,676			$26,379,676	
	Property taxes	$309,263				$ 309,263			$309,263	
	Other expenses									
3	**Taxes/PILs**									
	Taxable Income:									
	Adjustments required to arrive at taxable income	($6,563,773)	(3)			($6,563,773)				
	Utility Income Taxes and Rates:									
	Income taxes (not grossed up)	$3,299,765				$3,255,286				
	Income taxes (grossed up)	$4,473,115				$4,412,608				
	Federal tax (%)	15.00%				15.00%				
	Provincial tax (%)	11.23%				11.23%				
	Income Tax Credits	($115,079)				($115,085)				
4	**Capitalization/Cost of Capital**									
	Capital Structure:									
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%				
	Prefered Shares Capitalization Ratio (%)	0.0%								
		100.0%				100.0%				
	Cost of Capital									
	Long-term debt Cost Rate (%)	3.47%				3.47%				
	Short-term debt Cost Rate (%)	2.11%				2.11%				
	Common Equity Cost Rate (%)	9.36%				9.36%				
	Prefered Shares Cost Rate (%)	0.00%								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale. Horizon WC % updated from 12.7% to 12.0% per 2-Staff-23

(10) Updated LEAP to be based on Service Revenue per 4-SIA-34TC

(11) Updated Cost of Power due to the Load Forecast impact of 3-VECC-17 (RE updated CDM appendix 2-I) and 3-VECC-78TC (removed 4 month CDM lag)

(12) Change to Revenue at existing rates due to Load Forecast impact 3-VECC-78TC (removed 4 month CDM lag)

(13) Changed to Revenue at proposed rates due to Load Forecast 3-VECC-78TC, as well as Revenue Requirement impact of 4-SIA-34TC and 2-Staff-23

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$577,762,960	$ -	$577,762,960	$ -	$577,762,960
2	Accumulated Depreciation (average)	(3)	($134,451,262)	$ -	($134,451,262)	$ -	($134,451,262)
3	Net Fixed Assets (average)	(3)	$443,311,698	$ -	$443,311,698	$ -	$443,311,698
4	Allowance for Working Capital	(1)	$79,713,275	($4,482,569)	$75,230,705	$ -	$75,230,705
5	**Total Rate Base**		$523,024,973	($4,482,569)	$518,542,403	$ -	$518,542,403

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$66,255,827	$6,667	(4)	$66,262,494	$ -	$66,262,494
7	Cost of Power		$561,407,753	($747,702)	(5)	$560,660,052	$ -	$560,660,052
8	Working Capital Base		$627,663,580	($741,035)		$626,922,545	$ -	$626,922,545
9	Working Capital Rate %	(2)	12.70%	-0.70%	(6)	12.00%	0.00%	12.00%
10	Working Capital Allowance		$79,713,275	($4,482,569)		$75,230,705	$ -	$75,230,705

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.
(3) Average of opening and closing balances for the year.
(4) Updated LEAP amount to be based on Service Revenue per 4-SIA-34TC
(5) Updated Cost of Power due to the Load Forecast impact of 3-VECC-78TC (removed 4 month CDM lag)
(6) Horizon WC % updated from 12.7% to 12.0% per 2-Staff-23

Revenue Requirement Workform

Utility Income

Line No.	Particulars	Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)	$121,743,444	($312,588)	(2)	$121,430,855	$ -	$121,430,855
2	Other Revenue (1)	$5,555,937	$ -		$5,555,937	$ -	$5,555,937
3	Total Operating Revenues	$127,299,380	($312,588)		$126,986,792	$ -	$126,986,792
	Operating Expenses:						
4	OM+A Expenses	$65,946,564	$6,667	(3)	$65,953,231	$ -	$65,953,231
5	Depreciation/Amortization	$26,379,676	$ -		$26,379,676	$ -	$26,379,676
6	Property taxes	$309,263	$ -		$309,263	$ -	$309,263
7	Capital taxes	$ -	$ -		$ -	$ -	$ -
8	Other expense	$ -	$ -			$ -	
9	Subtotal (lines 4 to 8)	$92,635,503	$6,667		$92,642,170	$ -	$92,642,170
10	Deemed Interest Expense	$10,608,708	($90,922)		$10,517,787	$ -	$10,517,787
11	Total Expenses (lines 9 to 10)	$103,244,211	($84,255)		$103,159,956	$ -	$103,159,956
12	**Utility income before income taxes**	$24,055,170	($228,334)		$23,826,836	$ -	$23,826,836
13	Income taxes (grossed-up)	$4,473,115	($60,506)		$4,412,608	$ -	$4,412,608
14	**Utility net income**	$19,582,055	($167,827)		$19,414,228	$ -	$19,414,228

Notes

Other Revenues / Revenue Offsets

Note	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$741,093	$ -	$741,093		$741,093
	Late Payment Charges	$825,000	$ -	$825,000		$825,000
	Other Distribution Revenue	$ -		$ -		$ -
	Other Income and Deductions	$3,989,844	$ -	$3,989,844		$3,989,844
	Total Revenue Offsets	$5,555,937	$ -	$5,555,937	$ -	$5,555,937

(2) Changed to Revenue at proposed rates due to Load Forecast impact of 3-VECC-78TC, as well as Revenue Requirement impact of 4-SIA-34TC and 2-Staff-23
(3) Updated LEAP amount to be based on Service Revenue per 4-SIA-34TC

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$19,582,055	$19,414,228	$19,414,228
2	Adjustments required to arrive at taxable utility income	($6,563,773)	($6,563,773)	($6,563,773)
3	Taxable income	$13,018,282	$12,850,454	$12,850,454
	Calculation of Utility income Taxes			
4	Income taxes	$3,299,765	$3,255,286	$3,255,286
6	Total taxes	$3,299,765	$3,255,286	$3,255,286
7	Gross-up of Income Taxes	$1,173,349	$1,157,323	$1,157,323
8	Grossed-up Income Taxes	$4,473,115	$4,412,608	$4,412,608
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$4,473,115	$4,412,608	$4,412,608
10	Other tax Credits	($115,079)	($115,085)	($115,085)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.23%	11.23%	11.23%
13	Total tax rate (%)	26.23%	26.23%	26.23%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Initial Application				
	Debt				
1	Long-term Debt	56.00%	$292,893,985	3.47%	$10,167,275
2	Short-term Debt	4.00%	$20,920,999	2.11%	$441,433
3	**Total Debt**	60.00%	$313,814,984	3.38%	$10,608,708
	Equity				
4	Common Equity	40.00%	$209,209,989	9.36%	$19,582,055
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$209,209,989	9.36%	$19,582,055
7	**Total**	100.00%	$523,024,973	5.77%	$30,190,763
	Interrogatory Responses				
	Debt				
1	Long-term Debt	56.00%	$290,383,746	3.47%	$10,080,137
2	Short-term Debt	4.00%	$20,741,696	2.11%	$437,650
3	**Total Debt**	60.00%	$311,125,442	3.38%	$10,517,787
	Equity				
4	Common Equity	40.00%	$207,416,961	9.36%	$19,414,228
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$207,416,961	9.36%	$19,414,228
7	**Total**	100.00%	$518,542,403	5.77%	$29,932,014
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$290,383,746	3.47%	$10,080,137
9	Short-term Debt	4.00%	$20,741,696	2.11%	$437,650
10	**Total Debt**	60.00%	$311,125,442	3.38%	$10,517,787
	Equity				
11	Common Equity	40.00%	$207,416,961	9.36%	$19,414,228
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$207,416,961	9.36%	$19,414,228
14	**Total**	100.00%	$518,542,403	5.77%	$29,932,014

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$2,805,433		$2,740,190		$2,740,190
2	Distribution Revenue	$118,938,011	$118,938,011	$118,690,665	$118,690,665	$118,690,665	$118,690,665
3	Other Operating Revenue Offsets - net	$5,555,937	$5,555,937	$5,555,937	$5,555,937	$5,555,937	$5,555,937
4	**Total Revenue**	$124,493,948	$127,299,380	$124,246,602	$126,986,792	$124,246,602	$126,986,792
5	Operating Expenses	$92,635,503	$92,635,503	$92,642,170	$92,642,170	$92,642,170	$92,642,170
6	Deemed Interest Expense	$10,608,708	$10,608,708	$10,517,787	$10,517,787	$10,517,787	$10,517,787
8	**Total Cost and Expenses**	$103,244,211	$103,244,211	$103,159,956	$103,159,956	$103,159,956	$103,159,956
9	**Utility Income Before Income Taxes**	$21,249,737	$24,055,170	$21,086,646	$23,826,836	$21,086,646	$23,826,836
10	Tax Adjustments to Accounting Income per 2013 PILs model	($6,563,773)	($6,563,773)	($6,563,773)	($6,563,773)	($6,563,773)	($6,563,773)
11	**Taxable Income**	$14,685,964	$17,491,396	$14,522,872	$17,263,063	$14,522,872	$17,263,063
12	Income Tax Rate	26.23%	26.23%	26.23%	26.23%	26.23%	26.23%
13	**Income Tax on Taxable Income**	$3,852,297	$4,588,194	$3,809,006	$4,527,693	$3,809,006	$4,527,693
14	**Income Tax Credits**	($115,079)	($115,079)	($115,085)	($115,085)	($115,085)	($115,085)
15	**Utility Net Income**	$17,512,519	$19,582,055	$17,392,724	$19,414,228	$17,392,724	$19,414,228
16	**Utility Rate Base**	$523,024,973	$523,024,973	$518,542,403	$518,542,403	$518,542,403	$518,542,403
17	Deemed Equity Portion of Rate Base	$209,209,989	$209,209,989	$207,416,961	$207,416,961	$207,416,961	$207,416,961
18	Income/(Equity Portion of Rate Base)	8.37%	9.36%	8.39%	9.36%	8.39%	9.36%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-0.99%	0.00%	-0.97%	0.00%	-0.97%	0.00%
21	Indicated Rate of Return	5.38%	5.77%	5.38%	5.77%	5.38%	5.77%
22	Requested Rate of Return on Rate Base	5.77%	5.77%	5.77%	5.77%	5.77%	5.77%
23	Deficiency/Sufficiency in Rate of Return	-0.40%	0.00%	-0.39%	0.00%	-0.39%	0.00%
24	Target Return on Equity	$19,582,055	$19,582,055	$19,414,228	$19,414,228	$19,414,228	$19,414,228
25	Revenue Deficiency/(Sufficiency)	$2,069,535	$ -	$2,021,503	$ -	$2,021,503	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$2,805,433 **(1)**		$2,740,190 **(1)**		$2,740,190 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$65,946,564		$65,953,231		$65,953,231	
2	Amortization/Depreciation	$26,379,676		$26,379,676		$26,379,676	
3	Property Taxes	$309,263		$309,263		$309,263	
5	Income Taxes (Grossed up)	$4,473,115		$4,412,608		$4,412,608	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$10,608,708		$10,517,787		$10,517,787	
	Return on Deemed Equity	$19,582,055		$19,414,228		$19,414,228	
8	**Service Revenue Requirement (before Revenues)**	$127,299,380		$126,986,792		$126,986,792	
9	Revenue Offsets	$5,555,937		$5,555,937		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$121,743,444		$121,430,855		$126,986,792	
11	Distribution revenue	$121,743,444		$121,430,855		$121,430,855	
12	Other revenue	$5,555,937		$5,555,937		$5,555,937	
13	**Total revenue**	$127,299,380		$126,986,792		$126,986,792	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	$ -	(1)

Notes

(1) Line 11 - Line 8

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Revenue Requirement Workform

Version 4.00

Utility Name	Horizon Utilities Corporation
Service Territory	*Hamilton and St. Catharines*
Assigned EB Number	EB-2014-0002
Name and Title	Indy J. Butany-DeSouza, VP Regulatory Affairs
Phone Number	905-317-4765
Email Address	indy.butany@horizonutilities.com

While this model has been provided in Excel format and is required to be filed with the applications, the onus remains on the applicant to ensure the accuracy of the data and

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)	Adjustments		Interrogatory Responses	(6)	Adjustments	Per Board Decision	
1	**Rate Base**									
	Gross Fixed Assets (average)	$622,779,528				$ 622,779,528			$622,779,528	
	Accumulated Depreciation (average)	($157,863,151)	(5)			($157,863,151)			($157,863,151)	
	Allowance for Working Capital:									
	Controllable Expenses	$67,708,658		$6,799	(10)	$ 67,715,457			$67,715,457	
	Cost of Power	$581,873,212		($775,840)	(11)	$ 581,097,371			$581,097,371	
	Working Capital Rate (%)	12.70%	(9)			12.00%	(9)		12.00%	(9)
2	**Utility Income**									
	Operating Revenues:									
	Distribution Revenue at Current Rates	$122,174,673		($309,859)		$121,864,814	(12)			
	Distribution Revenue at Proposed Rates	$123,920,317		($327,878)		$123,592,439	(13)			
	Other Revenue:									
	Specific Service Charges	$747,081		$0		$747,081				
	Late Payment Charges	$825,000		$0		$825,000				
	Other Distribution Revenue									
	Other Income and Deductions	$4,094,118		$0		$4,094,118				
	Total Revenue Offsets	$5,666,198	(7)	$0		$5,666,198				
	Operating Expenses:									
	OM+A Expenses	$67,394,756		$6,799	(10)	$ 67,401,555			$67,401,555	
	Depreciation/Amortization	$25,824,486				$ 25,824,486			$25,824,486	
	Property taxes	$313,902				$ 313,902			$313,902	
	Other expenses									
3	**Taxes/PILs**									
	Taxable Income:									
	Adjustments required to arrive at taxable income	($8,826,055)	(3)			($8,826,055)				
	Utility Income Taxes and Rates:									
	Income taxes (not grossed up)	$2,917,091				$2,871,053				
	Income taxes (grossed up)	$3,952,701				$3,890,080				
	Federal tax (%)	15.00%				15.00%				
	Provincial tax (%)	11.20%				11.20%				
	Income Tax Credits	($140,220)				($140,228)				
4	**Capitalization/Cost of Capital**									
	Capital Structure:									
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%				
	Prefered Shares Capitalization Ratio (%)	0.0%								
		100.0%				100.0%				
	Cost of Capital									
	Long-term debt Cost Rate (%)	3.64%				3.64%				
	Short-term debt Cost Rate (%)	2.11%				2.11%				
	Common Equity Cost Rate (%)	9.36%				9.36%				
	Prefered Shares Cost Rate (%)	0.00%								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale. Horizon WC % updated from 12.7% to 12.0% per 2-Staff-23

(10) Updated LEAP to be based on Service Revene per 4-SIA-34TC

(11) Updated Cost of Power due to oad Forecast impact of 3-VECC-17 (RE updated CDM appendix 2-I) and 3-VECC-78TC (removed 4 month CDM lag)

(12) Change to Revenue at existing rates due to Load Forecast impact of and 3-VECC-78TC (removed 4 month CDM lag)

(13) Changed to Revenue at proposed rates due to Load Forecast impact of 3-VECC-78TC, as well as Revenue Requirement impact of 4-SIA-34TC and 2-Staff-23

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application		Adjustments		Interrogatory Responses		Adjustments		Per Board Decision
1	Gross Fixed Assets (average)	(3)	$622,779,528		$ -		$622,779,528		$ -		$622,779,528
2	Accumulated Depreciation (average)	(3)	($157,863,151)		$ -		($157,863,151)		$ -		($157,863,151)
3	Net Fixed Assets (average)	(3)	$464,916,377		$ -		$464,916,377		$ -		$464,916,377
4	Allowance for Working Capital	(1)	$82,496,897		($4,639,358)		$77,857,539		$ -		$77,857,539
5	**Total Rate Base**		$547,413,274		($4,639,358)		$542,773,916		$ -		$542,773,916

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application		Adjustments		Interrogatory Responses		Adjustments		Per Board Decision
6	Controllable Expenses		$67,708,658		$6,799	(4)	$67,715,457		$ -		$67,715,457
7	Cost of Power		$581,873,212		($775,840)	(5)	$581,097,371		$ -		$581,097,371
8	Working Capital Base		$649,581,870		($769,041)		$648,812,828		$ -		$648,812,828
9	Working Capital Rate %	(2)	12.70%		-0.70%	(6)	12.00%		0.00%		12.00%
10	Working Capital Allowance		$82,496,897		($4,639,358)		$77,857,539		$ -		$77,857,539

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.
(3) Average of opening and closing balances for the year.
(4) Updated LEAP amount to be based on Service Revenue per 4-SIA-34TC
(5) Updated Cost of Power due to the Load Forecast impact of 3-VECC-78TC (removed 4 month CDM lag)
(6) Horizon WC % updated from 12.7% to 12.0% per 2-Staff-23

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:							
1	Distribution Revenue (at Proposed Rates)		$123,920,317	($327,878)	(2)	$123,592,439	$ -	$123,592,439
2	Other Revenue	(1)	$5,666,198	$ -		$5,666,198	$ -	$5,666,198
3	Total Operating Revenues		$129,586,516	($327,878)		$129,258,638	$ -	$129,258,638
	Operating Expenses:							
4	OM+A Expenses		$67,394,756	$6,799	(3)	$67,401,555	$ -	$67,401,555
5	Depreciation/Amortization		$25,824,486	$ -		$25,824,486	$ -	$25,824,486
6	Property taxes		$313,902	$ -		$313,902	$ -	$313,902
7	Capital taxes		$ -	$ -		$ -	$ -	$ -
8	Other expense		$ -	$ -			$ -	
9	Subtotal (lines 4 to 8)		$93,533,143	$6,799		$93,539,942	$ -	$93,539,942
10	Deemed Interest Expense		$11,605,518	($98,357)		$11,507,160	$ -	$11,507,160
11	Total Expenses (lines 9 to 10)		$105,138,661	($91,558)		$105,047,103	$ -	$105,047,103
12	**Utility income before income taxes**		$24,447,854	($236,319)		$24,211,535	$ -	$24,211,535
13	Income taxes (grossed-up)		$3,952,701	($62,622)		$3,890,080	$ -	$3,890,080
14	**Utility net income**		$20,495,153	($173,698)		$20,321,455	$ -	$20,321,455

Notes

Other Revenues / Revenue Offsets

		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$747,081	$ -	$747,081		$747,081
	Late Payment Charges	$825,000	$ -	$825,000		$825,000
	Other Distribution Revenue	$ -		$ -		$ -
	Other Income and Deductions	$4,094,118	$ -	$4,094,118		$4,094,118
	Total Revenue Offsets	$5,666,198	$ -	$5,666,198	$ -	$5,666,198

(2) Changed to Revenue at proposed rates due to Load Forecast impact of 3-VECC-78TC, as well as Revenue Requirement impact of 4-SIA-34TC and 2-Staff-23
(3) Updated LEAP amount to be based on Service Revenue per 4-SIA-34TC

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$20,495,153	$20,321,455	$20,321,455
2	Adjustments required to arrive at taxable utility income	($8,826,055)	($8,826,055)	($8,826,055)
3	Taxable income	$11,669,098	$11,495,401	$11,495,401
	Calculation of Utility income Taxes			
4	Income taxes	$2,917,091	$2,871,053	$2,871,053
6	Total taxes	$2,917,091	$2,871,053	$2,871,053
7	Gross-up of Income Taxes	$1,035,610	$1,019,027	$1,019,027
8	Grossed-up Income Taxes	$3,952,701	$3,890,080	$3,890,080
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$3,952,701	$3,890,080	$3,890,080
10	Other tax Credits	($140,220)	($140,228)	($140,228)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.20%	11.20%	11.20%
13	Total tax rate (%)	26.20%	26.20%	26.20%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$306,551,434	3.64%	$11,143,501
2	Short-term Debt	4.00%	$21,896,531	2.11%	$462,017
3	**Total Debt**	60.00%	$328,447,965	3.53%	$11,605,518
	Equity				
4	Common Equity	40.00%	$218,965,310	9.36%	$20,495,153
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$218,965,310	9.36%	$20,495,153
7	**Total**	100.00%	$547,413,274	5.86%	$32,100,671
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$303,953,393	3.64%	$11,049,059
2	Short-term Debt	4.00%	$21,710,957	2.11%	$458,101
3	**Total Debt**	60.00%	$325,664,350	3.53%	$11,507,160
	Equity				
4	Common Equity	40.00%	$217,109,567	9.36%	$20,321,455
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$217,109,567	9.36%	$20,321,455
7	**Total**	100.00%	$542,773,916	5.86%	$31,828,616
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$303,953,393	3.64%	$11,049,059
9	Short-term Debt	4.00%	$21,710,957	2.11%	$458,101
10	**Total Debt**	60.00%	$325,664,350	3.53%	$11,507,160
	Equity				
11	Common Equity	40.00%	$217,109,567	9.36%	$20,321,455
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$217,109,567	9.36%	$20,321,455
14	**Total**	100.00%	$542,773,916	5.86%	$31,828,616

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,745,644		$1,727,626		$1,727,626
2	Distribution Revenue	$122,174,673	$122,174,673	$121,864,814	$121,864,814	$121,864,814	$121,864,814
3	Other Operating Revenue Offsets - net	$5,666,198	$5,666,198	$5,666,198	$5,666,198	$5,666,198	$5,666,198
4	**Total Revenue**	$127,840,872	$129,586,516	$127,531,012	$129,258,638	$127,531,012	$129,258,638
5	Operating Expenses	$93,533,143	$93,533,143	$93,539,942	$93,539,942	$93,539,942	$93,539,942
6	Deemed Interest Expense	$11,605,518	$11,605,518	$11,507,160	$11,507,160	$11,507,160	$11,507,160
8	**Total Cost and Expenses**	$105,138,661	$105,138,661	$105,047,103	$105,047,103	$105,047,103	$105,047,103
9	**Utility Income Before Income Taxes**	$22,702,210	$24,447,854	$22,483,909	$24,211,535	$22,483,909	$24,211,535
10	Tax Adjustments to Accounting Income per 2013 PILs model	($8,826,055)	($8,826,055)	($8,826,055)	($8,826,055)	($8,826,055)	($8,826,055)
11	**Taxable Income**	$13,876,155	$15,621,799	$13,657,855	$15,385,480	$13,657,855	$15,385,480
12	Income Tax Rate	26.20%	26.20%	26.20%	26.20%	26.20%	26.20%
13	**Income Tax on Taxable Income**	$3,635,561	$4,092,921	$3,577,747	$4,030,308	$3,577,747	$4,030,308
14	**Income Tax Credits**	($140,220)	($140,220)	($140,228)	($140,228)	($140,228)	($140,228)
15	**Utility Net Income**	$19,206,869	$20,495,153	$19,046,391	$20,321,455	$19,046,391	$20,321,455
16	**Utility Rate Base**	$547,413,274	$547,413,274	$542,773,916	$542,773,916	$542,773,916	$542,773,916
17	Deemed Equity Portion of Rate Base	$218,965,310	$218,965,310	$217,109,567	$217,109,567	$217,109,567	$217,109,567
18	Income/(Equity Portion of Rate Base)	8.77%	9.36%	8.77%	9.36%	8.77%	9.36%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-0.59%	0.00%	-0.59%	0.00%	-0.59%	0.00%
21	Indicated Rate of Return	5.63%	5.86%	5.63%	5.86%	5.63%	5.86%
22	Requested Rate of Return on Rate Base	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%
23	Deficiency/Sufficiency in Rate of Return	-0.24%	0.00%	-0.23%	0.00%	-0.23%	0.00%
24	Target Return on Equity	$20,495,153	$20,495,153	$20,321,455	$20,321,455	$20,321,455	$20,321,455
25	Revenue Deficiency/(Sufficiency)	$1,288,284	$ -	$1,275,065	$ -	$1,275,065	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$1,745,644 **(1)**		$1,727,626 **(1)**		$1,727,626 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$67,394,756		$67,401,555		$67,401,555	
2	Amortization/Depreciation	$25,824,486		$25,824,486		$25,824,486	
3	Property Taxes	$313,902		$313,902		$313,902	
5	Income Taxes (Grossed up)	$3,952,701		$3,890,080		$3,890,080	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$11,605,518		$11,507,160		$11,507,160	
	Return on Deemed Equity	$20,495,153		$20,321,455		$20,321,455	
8	**Service Revenue Requirement (before Revenues)**	$129,586,516		$129,258,638		$129,258,638	
9	Revenue Offsets	$5,666,198		$5,666,198		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$123,920,317		$123,592,439		$129,258,638	
11	Distribution revenue	$123,920,317		$123,592,439		$123,592,439	
12	Other revenue	$5,666,198		$5,666,198		$5,666,198	
13	**Total revenue**	$129,586,516		$129,258,638		$129,258,638	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	**(1)**	$ -	**(1)**	$ -	**(1)**

Notes

(1) Line 11 - Line 8

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Revenue Requirement Workform

Version 4.00

Utility Name	Horizon Utilities Corporation
Service Territory	*Hamilton and St. Catharines*
Assigned EB Number	EB-2014-0002
Name and Title	Indy J. Butany-DeSouza, VP Regulatory Affairs
Phone Number	905-317-4765
Email Address	indy.butany@horizonutilities.com

Revenue Requirement Workform

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Revenue Requirement Workform

Data Input [1]

		Initial Application	(2)	Adjustments		Interrogatory Responses	(6)	Adjustments		Per Board Decision	
1	**Rate Base**										
	Gross Fixed Assets (average)	$668,929,104				$ 668,929,104				$668,929,104	
	Accumulated Depreciation (average)	($180,591,646)	(5)			($180,591,646)				($180,591,646)	
	Allowance for Working Capital:										
	Controllable Expenses	$69,140,489		$6,905	(10)	$ 69,147,394				$69,147,394	
	Cost of Power	$600,222,979		($803,732)	(11)	$ 599,419,247				$599,419,247	
	Working Capital Rate (%)	12.70%	(9)			12.00%	(9)			12.00%	(9)
2	**Utility Income**										
	Operating Revenues:										
	Distribution Revenue at Current Rates	$124,313,123		($314,644)		$123,998,479	(12)				
	Distribution Revenue at Proposed Rates	$127,881,899		($341,473)		$127,540,425	(13)				
	Other Revenue:										
	Specific Service Charges	$752,724		$0		$752,724					
	Late Payment Charges	$825,000		$0		$825,000					
	Other Distribution Revenue										
	Other Income and Deductions	$4,176,175		$0		$4,176,175					
	Total Revenue Offsets	$5,753,899	(7)	$0		$5,753,899					
	Operating Expenses:										
	OM+A Expenses	$68,821,878		$6,905	(10)	$ 68,828,783				$68,828,783	
	Depreciation/Amortization	$26,490,670				$ 26,490,670				$26,490,670	
	Property taxes	$318,611				$ 318,611				$318,611	
	Other expenses										
3	**Taxes/PILs**										
	Taxable Income:										
	Adjustments required to arrive at taxable income	($9,641,214)	(3)			($9,641,214)					
	Utility Income Taxes and Rates:										
	Income taxes (not grossed up)	$2,927,388				$2,879,940					
	Income taxes (grossed up)	$3,966,866				$3,902,330					
	Federal tax (%)	15.00%				15.00%					
	Provincial tax (%)	11.20%				11.20%					
	Income Tax Credits	($171,207)				($171,217)					
4	**Capitalization/Cost of Capital**										
	Capital Structure:										
	Long-term debt Capitalization Ratio (%)	56.0%				56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)			4.0%	(8)				(8)
	Common Equity Capitalization Ratio (%)	40.0%				40.0%					
	Prefered Shares Capitalization Ratio (%)	0.0%									
		100.0%				100.0%					
	Cost of Capital										
	Long-term debt Cost Rate (%)	3.76%				3.76%					
	Short-term debt Cost Rate (%)	2.11%				2.11%					
	Common Equity Cost Rate (%)	9.36%				9.36%					
	Prefered Shares Cost Rate (%)	0.00%									

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) Starting with 2013, default Working Capital Allowance factor is 13% (of Cost of Power plus controllable expenses). Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale. Horizon WC % updated from 12.7% to 12.0% per 2-Staff-23

(10) Updated LEAP to be based on Service Revenue per 4-SIA-34TC

(11) Updated Cost of Power due to the Load Forecast impact of 3-VECC-17 (RE updated CDM appendix 2-I) and 3-VECC-78TC (removed 4 month CDM lag)

(12) Change to Revenue at existing rates due to Load Forecast impact of 3-VECC-78TC (removed 4 month CDM lag)

(13) Changed to Revenue at proposed rates due to Load Forecast impact of 3-VECC-78TC, as well as Revenue Requirement impact of 4-SIA-34TC and 2-Staff-23

Revenue Requirement Workform

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$668,929,104	$ -		$668,929,104	$ -	$668,929,104
2	Accumulated Depreciation (average)	(3)	($180,591,646)	$ -		($180,591,646)	$ -	($180,591,646)
3	Net Fixed Assets (average)	(3)	$488,337,458	$ -		$488,337,458	$ -	$488,337,458
4	Allowance for Working Capital	(1)	$85,009,160	($4,781,163)		$80,227,997	$ -	$80,227,997
5	**Total Rate Base**		$573,346,618	($4,781,163)		$568,565,455	$ -	$568,565,455

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$69,140,489	$6,905	(4)	$69,147,394	$ -	$69,147,394
7	Cost of Power		$600,222,979	($803,732)	(5)	$599,419,247	$ -	$599,419,247
8	Working Capital Base		$669,363,467	($796,827)		$668,566,640	$ -	$668,566,640
9	Working Capital Rate %	(2)	12.70%	-0.70%	(6)	12.00%	0.00%	12.00%
10	Working Capital Allowance		$85,009,160	($4,781,163)		$80,227,997	$ -	$80,227,997

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2014 cost of service applications is 13%.
(3) Average of opening and closing balances for the year.
(4) Updated LEAP amount to be based on Service Revenue per 4-SIA-34TC
(5) Updated Cost of Power due to the Load Forecast impact of 3-VECC-78TC (removed 4 month CDM lag)
(6) Horizon WC % updated from 12.7% to 12.0% per 2-Staff-23

Revenue Requirement Workform

Utility Income

Line No.	Particulars		Initial Application	Adjustments		Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:							
1	Distribution Revenue (at Proposed Rates)		$127,881,899	($341,473)	(2)	$127,540,425	$ -	$127,540,425
2	Other Revenue	(1)	$5,753,899	$ -		$5,753,899	$ -	$5,753,899
3	Total Operating Revenues		$133,635,798	($341,473)		$133,294,324	$ -	$133,294,324
	Operating Expenses:							
4	OM+A Expenses		$68,821,878	$6,905	(3)	$68,828,783	$ -	$68,828,783
5	Depreciation/Amortization		$26,490,670	$ -		$26,490,670	$ -	$26,490,670
6	Property taxes		$318,611	$ -		$318,611	$ -	$318,611
7	Capital taxes		$ -	$ -		$ -	$ -	$ -
8	Other expense		$ -	$ -			$ -	
9	Subtotal (lines 4 to 8)		$95,631,159	$6,905		$95,638,064	$ -	$95,638,064
10	Deemed Interest Expense		$12,571,676	($104,836)		$12,466,840	$ -	$12,466,840
11	Total Expenses (lines 9 to 10)		$108,202,835	($97,931)		$108,104,904	$ -	$108,104,904
12	**Utility income before income taxes**		$25,432,963	($243,543)		$25,189,420	$ -	$25,189,420
13	Income taxes (grossed-up)		$3,966,866	($64,536)		$3,902,330	$ -	$3,902,330
14	**Utility net income**		$21,466,097	($179,007)		$21,287,091	$ -	$21,287,091

Notes

Other Revenues / Revenue Offsets

Notes	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$752,724	$ -	$752,724		$752,724
	Late Payment Charges	$825,000	$ -	$825,000		$825,000
	Other Distribution Revenue	$ -		$ -		$ -
	Other Income and Deductions	$4,176,175	$ -	$4,176,175		$4,176,175
	Total Revenue Offsets	$5,753,899	$ -	$5,753,899	$ -	$5,753,899

(2) Changed to Revenue at proposed rates due to Load Forecast impact of 3-VECC-78TC, as well as Revenue Requirement impact of 4-SIA-34TC and 2-Staff-23
(3) Updated LEAP amount to be based on Service Revenue per 4-SIA-34TC

Revenue Requirement Workform

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$21,466,097	$21,287,091	$21,287,091
2	Adjustments required to arrive at taxable utility income	($9,641,214)	($9,641,214)	($9,641,214)
3	Taxable income	$11,824,884	$11,645,877	$11,645,877
	Calculation of Utility income Taxes			
4	Income taxes	$2,927,388	$2,879,940	$2,879,940
6	Total taxes	$2,927,388	$2,879,940	$2,879,940
7	Gross-up of Income Taxes	$1,039,478	$1,022,389	$1,022,389
8	Grossed-up Income Taxes	$3,966,866	$3,902,330	$3,902,330
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$3,966,866	$3,902,330	$3,902,330
10	Other tax Credits	($171,207)	($171,217)	($171,217)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.20%	11.20%	11.20%
13	Total tax rate (%)	26.20%	26.20%	26.20%

Notes

Revenue Requirement Workform

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Initial Application				
	Debt				
1	Long-term Debt	56.00%	$321,074,106	3.76%	$12,087,771
2	Short-term Debt	4.00%	$22,933,865	2.11%	$483,905
3	**Total Debt**	60.00%	$344,007,971	3.65%	$12,571,676
	Equity				
4	Common Equity	40.00%	$229,338,647	9.36%	$21,466,097
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$229,338,647	9.36%	$21,466,097
7	**Total**	100.00%	$573,346,618	5.94%	$34,037,773

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Interrogatory Responses				
	Debt				
1	Long-term Debt	56.00%	$318,396,655	3.76%	$11,986,971
2	Short-term Debt	4.00%	$22,742,618	2.11%	$479,869
3	**Total Debt**	60.00%	$341,139,273	3.65%	$12,466,840
	Equity				
4	Common Equity	40.00%	$227,426,182	9.36%	$21,287,091
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$227,426,182	9.36%	$21,287,091
7	**Total**	100.00%	$568,565,455	5.94%	$33,753,931

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Per Board Decision				
	Debt				
8	Long-term Debt	56.00%	$318,396,655	3.76%	$11,986,971
9	Short-term Debt	4.00%	$22,742,618	2.11%	$479,869
10	**Total Debt**	60.00%	$341,139,273	3.65%	$12,466,840
	Equity				
11	Common Equity	40.00%	$227,426,182	9.36%	$21,287,091
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$227,426,182	9.36%	$21,287,091
14	**Total**	100.00%	$568,565,455	5.94%	$33,753,931

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Revenue Requirement Workform

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$3,568,776		$3,541,947		$3,541,947
2	Distribution Revenue	$124,313,123	$124,313,123	$123,998,479	$123,998,479	$123,998,479	$123,998,479
3	Other Operating Revenue Offsets - net	$5,753,899	$5,753,899	$5,753,899	$5,753,899	$5,753,899	$5,753,899
4	**Total Revenue**	$130,067,021	$133,635,798	$129,752,377	$133,294,324	$129,752,377	$133,294,324
5	Operating Expenses	$95,631,159	$95,631,159	$95,638,064	$95,638,064	$95,638,064	$95,638,064
6	Deemed Interest Expense	$12,571,676	$12,571,676	$12,466,840	$12,466,840	$12,466,840	$12,466,840
8	**Total Cost and Expenses**	$108,202,835	$108,202,835	$108,104,904	$108,104,904	$108,104,904	$108,104,904
9	**Utility Income Before Income Taxes**	$21,864,187	$25,432,963	$21,647,474	$25,189,420	$21,647,474	$25,189,420
10	Tax Adjustments to Accounting Income per 2013 PILs model	($9,641,214)	($9,641,214)	($9,641,214)	($9,641,214)	($9,641,214)	($9,641,214)
11	**Taxable Income**	$12,222,973	$15,791,749	$12,006,260	$15,548,207	$12,006,260	$15,548,207
12	Income Tax Rate	26.20%	26.20%	26.20%	26.20%	26.20%	26.20%
13	**Income Tax on Taxable Income**	$3,202,910	$4,138,072	$3,145,576	$4,073,547	$3,145,576	$4,073,547
14	**Income Tax Credits**	($171,207)	($171,207)	($171,217)	($171,217)	($171,217)	($171,217)
15	**Utility Net Income**	$18,832,484	$21,466,097	$18,673,115	$21,287,091	$18,673,115	$21,287,091
16	**Utility Rate Base**	$573,346,618	$573,346,618	$568,565,455	$568,565,455	$568,565,455	$568,565,455
17	Deemed Equity Portion of Rate Base	$229,338,647	$229,338,647	$227,426,182	$227,426,182	$227,426,182	$227,426,182
18	Income/(Equity Portion of Rate Base)	8.21%	9.36%	8.21%	9.36%	8.21%	9.36%
19	Target Return - Equity on Rate Base	9.36%	9.36%	9.36%	9.36%	9.36%	9.36%
20	Deficiency/Sufficiency in Return on Equity	-1.15%	0.00%	-1.15%	0.00%	-1.15%	0.00%
21	Indicated Rate of Return	5.48%	5.94%	5.48%	5.94%	5.48%	5.94%
22	Requested Rate of Return on Rate Base	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%
23	Deficiency/Sufficiency in Rate of Return	-0.46%	0.00%	-0.46%	0.00%	-0.46%	0.00%
24	Target Return on Equity	$21,466,097	$21,466,097	$21,287,091	$21,287,091	$21,287,091	$21,287,091
25	Revenue Deficiency/(Sufficiency)	$2,633,614	$ -	$2,613,976	$ -	$2,613,976	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,568,776 **(1)**		$3,541,947 **(1)**		$3,541,947 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Revenue Requirement Workform

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$68,821,878		$68,828,783		$68,828,783	
2	Amortization/Depreciation	$26,490,670		$26,490,670		$26,490,670	
3	Property Taxes	$318,611		$318,611		$318,611	
5	Income Taxes (Grossed up)	$3,966,866		$3,902,330		$3,902,330	
6	Other Expenses	$ -					
7	Return						
	Deemed Interest Expense	$12,571,676		$12,466,840		$12,466,840	
	Return on Deemed Equity	$21,466,097		$21,287,091		$21,287,091	
8	**Service Revenue Requirement (before Revenues)**	$133,635,798		$133,294,324		$133,294,324	
9	Revenue Offsets	$5,753,899		$5,753,899		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$127,881,899		$127,540,425		$133,294,324	
11	Distribution revenue	$127,881,899		$127,540,425		$127,540,425	
12	Other revenue	$5,753,899		$5,753,899		$5,753,899	
13	**Total revenue**	$133,635,798		$133,294,324		$133,294,324	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	**(1)**	$ -	**(1)**	$ -	**(1)**

Notes

(1) Line 11 - Line 8

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UNDERTAKING NO. TCJ1.10 ATTCH_6_RRWF 2015 (IR Revised)

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UNDERTAKING NO. TCJ1.10 ATTCH_7_RRWF 2016 (IR Revised)

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UNDERTAKING NO. TCJ1.10 ATTCH_8_RRWF 2017 (IR Revised)

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UNDERTAKING NO. TCJ1.10 ATTCH_9_RRWF 2018 (IR Revised)

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UNDERTAKING NO. TCJ1.10 ATTCH_10_RRWF 2019 (IR Revised)

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UNDERTAKING NO. TCJ1.10 ATTCH_11_5.1 Cost Allocation 2015

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UNDERTAKING NO. TCJ1.10 ATTCH_12_5.1 Cost Allocation 2016

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UNDERTAKING NO. TCJ1.10 ATTCH_13_5.1 Cost Allocation 2017

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UNDERTAKING NO. TCJ1.10 ATTCH_14_5.1 Cost Allocation 2018

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UNDERTAKING NO. TCJ1.10 ATTCH_15_5.1 Cost Allocation 2019

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UNDERTAKING NO. TCJ1.10 ATTCH_16_7.0 App.2-W_Bill Impacts

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UNDERTAKING NO. TCJ1.11:

TO PROVIDE SPREADSHEETS, IF PREPARED, RE: SEC-81-TC.

Response:

Horizon Utilities provides the supporting calculations for SEC-81-TC as UNDERTAKING NO.TCJ1.11_ATTCH_1 Benchmarking and UNDERTAKING NO.TCJ1.11_ATTCH_2 Benchmarking Calculation.

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UNDERTAKING NO.TCJ1.11_ATTCH_1 Benchmarking

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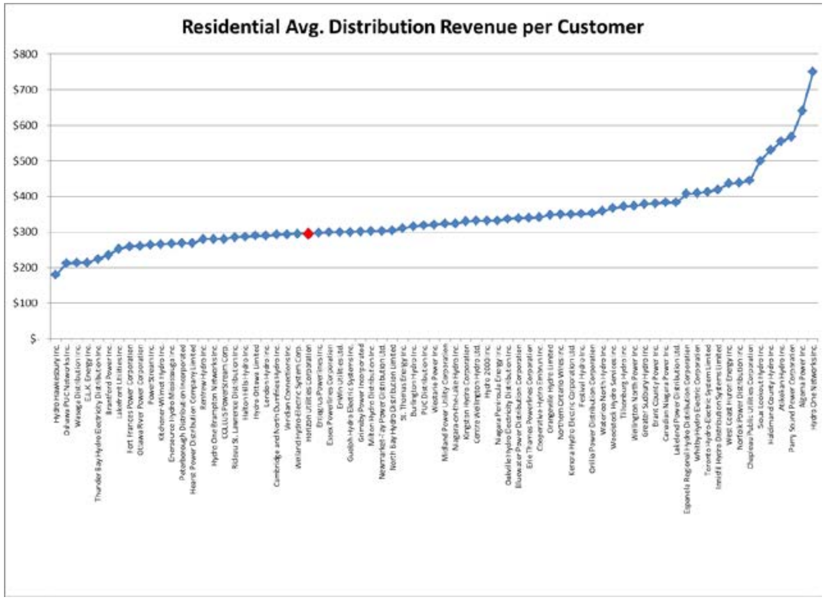
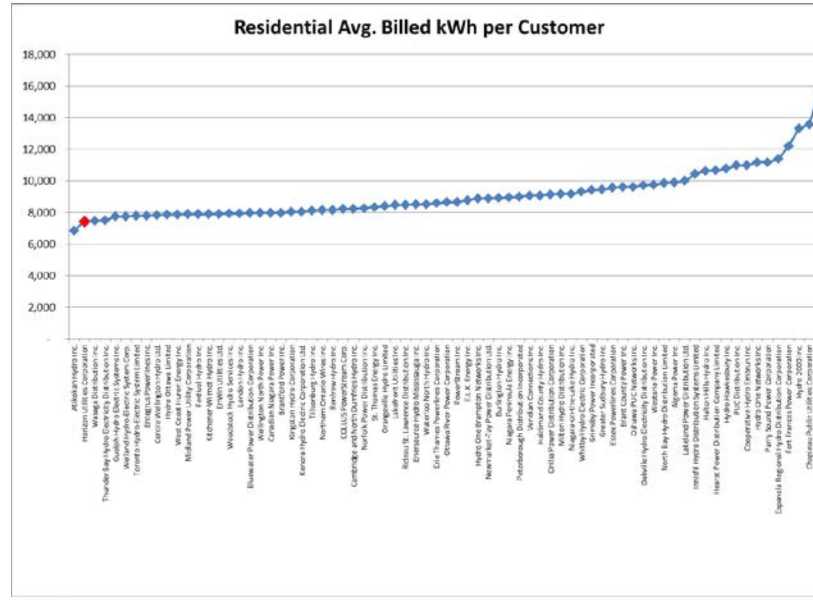
6-SEC-81TC

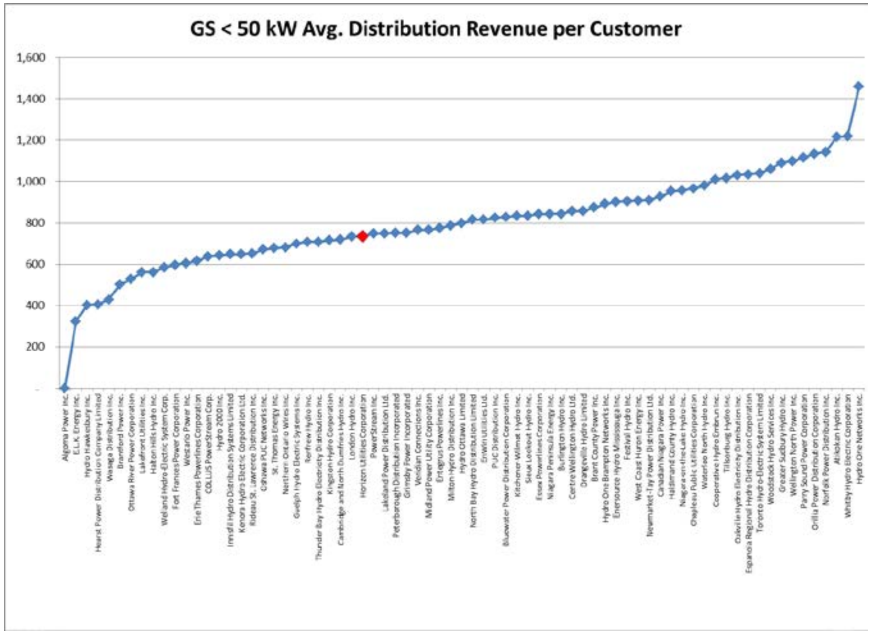
Residential

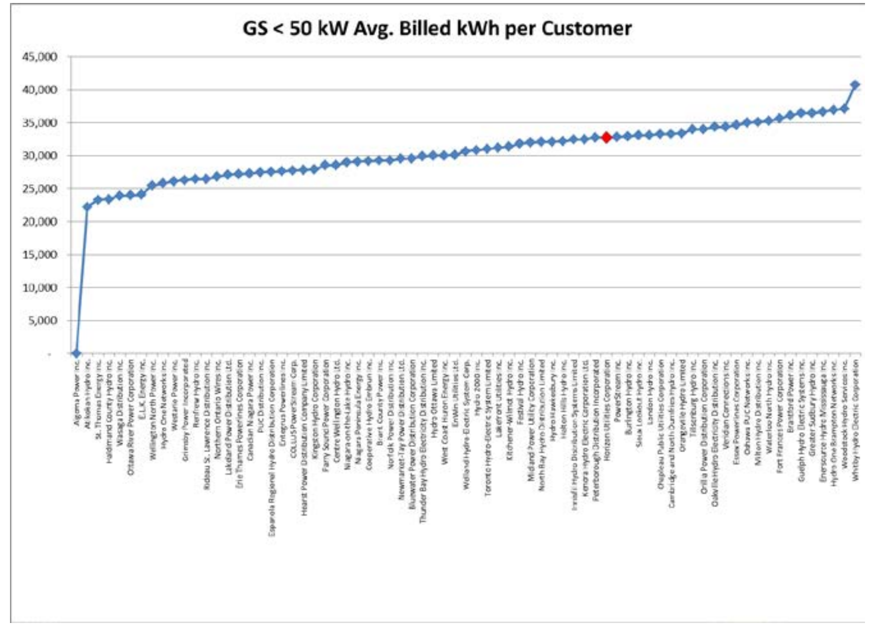




- Horizon ranks 25th lowest on average revenue per customer of 73 LDCs
- Horizon ranks 2nd lowest on billed kWh of 73 LDCs

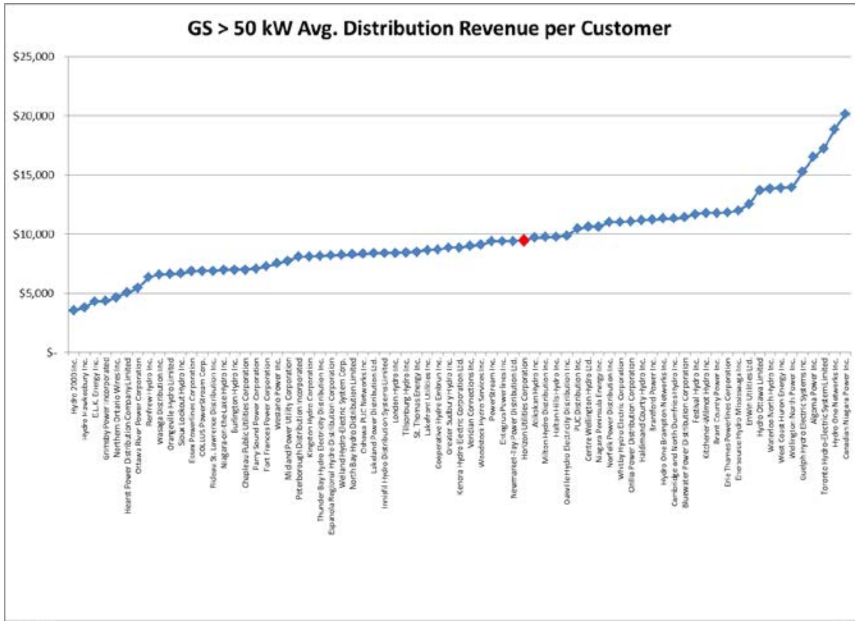
GS < 50 kW

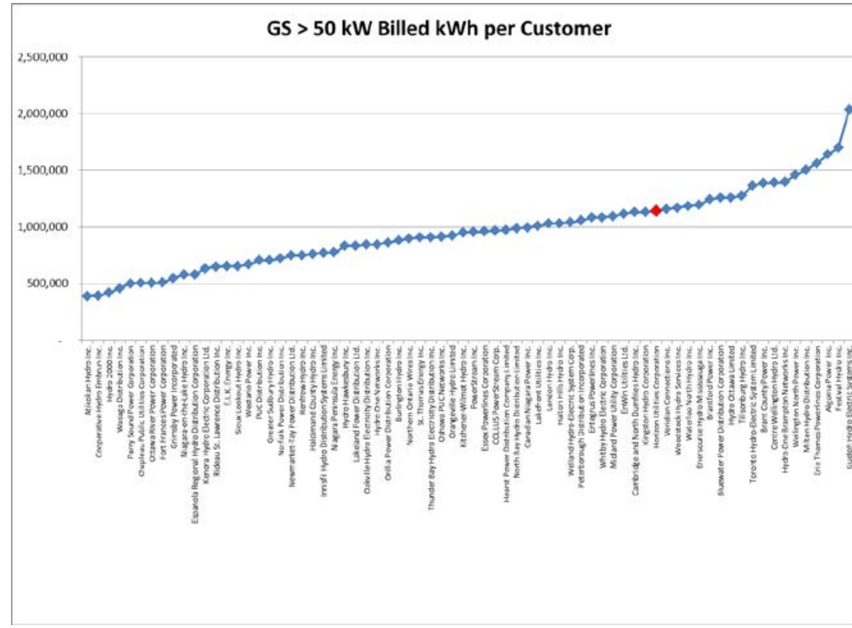




- Horizon ranks 27th lowest on Revenue of 72 LDC with filed data
- Horizon ranks 49th on billed kWh of 72 with filed data
- Ranking lower on Revenue per customer than Billed kWh per customer against the sector suggests revenue need per customer is actually better than that represented in the ranking against other LDCs

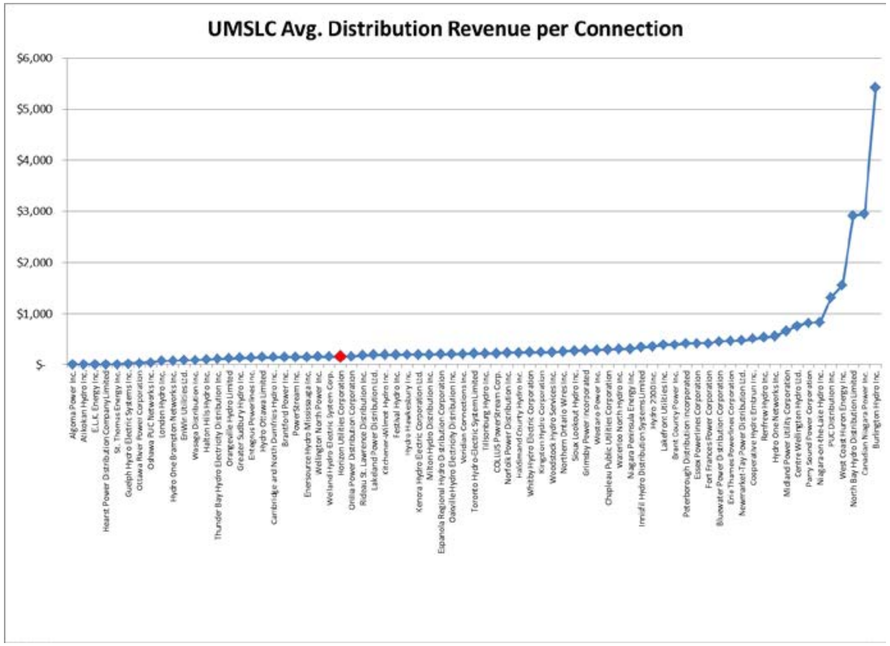
GS > 50 kW

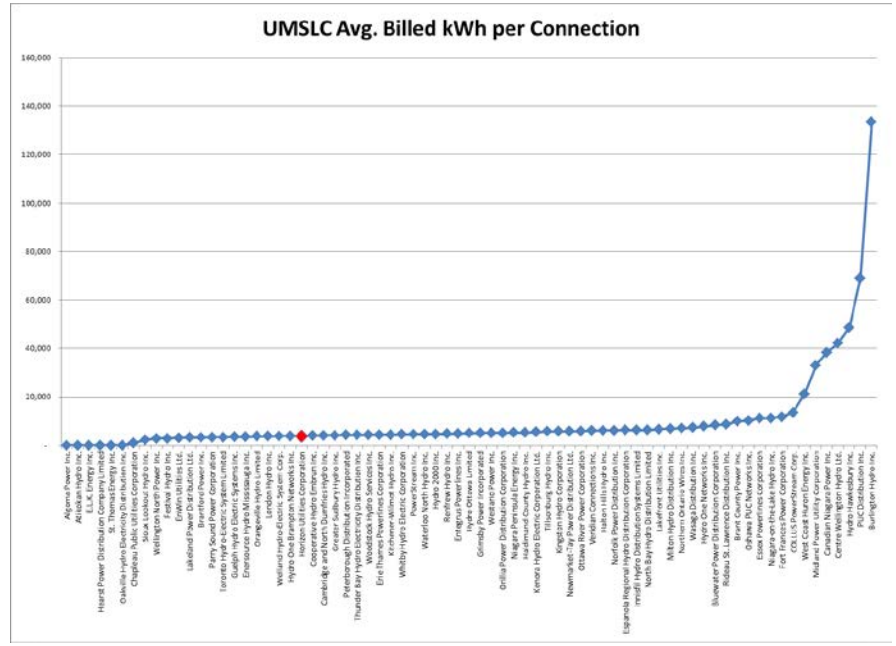




- Horizon rank 43rd lowest on Revenue of 73 LDCs – this ranking has the caveat that not all LDCs have Large users and Horizon has 11
- Horizon ranked 54th on Billed kWh of 73 LDCs
- Ranking lower on revenue than on consumption suggests Horizon's GS > 50 kW customers are larger on balance, which would explain higher revenue per customer
- In addition, this means that Horizon's average revenue per customer, which is in the middle of the pack of LDCs, is shaped by having larger customers on average than the class

UMSLC





- Ranked 20th lowest on Revenue of 68 LDCs with filed data
- Ranked 17th lowest on Billed kWh of 68 LDC with filed data

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UNDERTAKING NO.TCJ1.11_ATTCH_2 Benchmarking Calculation

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UNDERTAKING NO. TCJ1.12:

TO CIRCULATE ATTACHMENT 1 TO EP-78-TC.

Response:

Horizon Utilities has provided Attachment 1 to EP-78-TC as UNDERTAKING NO.TCJ1.12_Attch 1_8-EP-78TC_Attch 1_DRH Schedule 11.2 to this response.

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UNDERTAKING NO.TCJ1.12_Attch 1_8-EP-78TC_Attch 1_DRH Schedule 11.2

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Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

Derivation of Standard Rates and Model for Deriving Distributor Specific Rates					
Specific Service Charge Description:		**$15 Specific Service Charge Calculation**			

Used For:

Arrears certificate
Statement of account
Pulling post dated cheques
Duplicate invoices for previous billing
Request for other billing information
Easement letter
Income tax letter
Notification charge
Account history
Credit reference/credit check (plus credit agency costs)
Returned cheque charge (plus bank charges)
Charge to certify cheque
Legal letter charge

			Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (inside staff) Straight Time		39.32	0.4		$15.73
A	Direct Labour (inside staff) Overtime					
B	Direct Labour (field staff) Straight Time		65.84			
O	Direct Labour (field staff) Overtime					
U	Other Labour (Specify)					
R	Payroll Burden %					$0.00
		Total Labour Cost				$15.73
O	Small Vehicle Time		3.65			
T	Large Vehicle Time		8.03			
H	Other:	Material				
E		Contract				
R		Other	2.00			$2.00
		Total Other				$2.00
Total Cost						$17.73
	Specific Service Charge Value Requested - Round to nearest $5					**$20.00**

Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

Derivation of Standard Rates and Model for Deriving Distributor Specific Rates	
Specific Service Charge Description:	**$30 Specific Service Charge Calculation**

Used For:

Account set up charge/change of occupancy charge (plus credit agency costs if applicable)
Special meter reads
Collection of account charge - no disconnection
Meter dispute charge plus Measurement Canada fees (if meter found correct)
Service call - customer-owned equipment

			Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (inside staff) Straight Time		39.32	0.5		$19.66
A	Direct Labour (inside staff) Overtime					
B	Direct Labour (field staff) Straight Time		65.84	0.3		$19.75
O	Direct Labour (field staff) Overtime					
U	Other Labour (Specify)					
R	Payroll Burden %					$0.00
		Total Labour Cost				$39.41
O	Small Vehicle Time		3.65	0.3		$1.10
T	Large Vehicle Time		8.03			
H	Other:	Material				
E		Contract				
R		Other	2.00			$2.00
		Total Other				$3.10
Total Cost						$42.51
	Specific Service Charge Value Requested - Round to nearest $5					**$45.00**

Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

Derivation of Standard Rates and Model for Deriving Distributor Specific Rates	
Specific Service Charge Description:	**$65 Specific Service Charge Calculation**

Used For:

Disconnect/Reconnect at meter - during regular hours

Install/Remove load control device - during regular hours

			Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (inside staff) Straight Time		39.32	0.5		$19.66
A	Direct Labour (inside staff) Overtime					
B	Direct Labour (field staff) Straight Time		65.84	1.0		$65.84
O	Direct Labour (field staff) Overtime					
U	Other Labour (Specify)					
R	Payroll Burden %					$0.00
		Total Labour Cost				$85.50
O	Small Vehicle Time		3.65	1.0		$3.65
T	Large Vehicle Time		8.03			
H	Other:	Material				
E		Contract				
R		Other	3.00			$3.00
		Total Other				$6.65
Total Cost						$92.15
	Specific Service Charge Value Requested - Round to nearest $5					**$90.00**

Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

Derivation of Standard Rates and Model for Deriving Distributor Specific Rates	
Specific Service Charge Description:	**$165 Specific Service Charge Calculation**

Used For:

Collection of account charge - no disconnection - after regular hours

Service call - after regular hours

			Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time		39.32	0.6		$23.59
A	Direct Labour (inside staff) Overtime					
B	Direct Labour (field staff) Straight Time		65.84			
O	Direct Labour (field staff) Overtime		65.84	2.0	2	$263.36
U	Other Labour (Specify)					
R	Payroll Burden %					$0.00
		Total Labour Cost				$286.95
O	Small Vehicle Time		3.65	0.3		$1.10
T	Large Vehicle Time		8.03			
H	Other:	Material				
E		Contract				
R		Other	3.00			$3.00
		Total Other				$4.10
Total Cost						$291.05
	Specific Service Charge Value Requested - Round to nearest $5					**$290.00**

Assumes 1 person - One visit on overtime & minimum 2 hr call out

Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

Derivation of Standard Rates and Model for Deriving Distributor Specific Rates	
Specific Service Charge Description:	**$185 Specific Service Charge Calculation**

Used For:

Disconnect/Reconnect at meter - after regular hours

Install/Remove load control device - after regular hours

		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (inside staff) Straight Time	39.32	0.5		$19.66
A	Direct Labour (inside staff) Overtime				
B	Direct Labour (field staff) Straight Time	65.84	0.5		$32.92
O	Direct Labour (field staff) Overtime	65.84	2.0	2	$263.36
U	Other Labour (Specify)				
R	Payroll Burden %				$0.00
	Total Labour Cost				$315.94
O	Small Vehicle Time	3.65	1.0		$3.65
T	Large Vehicle Time	8.03			
H	Other: Material				
E	Contract				
R	Other	2.00			$2.00
	Total Other				$5.65
Total Cost					$321.59
	Specific Service Charge Value Requested - Round to nearest $5				**$320.00**

Assumes 1 person - One visit on overtime & minimum 2 hr call out

Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

Derivation of Standard Rates and Model for Deriving Distributor Specific Rates	
Specific Service Charge Description:	**$185 Specific Service Charge Calculation- 2 Person Line Crew**

Used For:

Disconnect/Reconnect at pole - during regular hours

		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (inside staff) Straight Time	39.32	0.5		$19.66
A	Direct Labour (inside staff) Overtime				
B	Direct Labour (field staff) Straight Time	65.84	3.0		$197.52
O	Direct Labour (field staff) Overtime	65.84		2	
U	Other Labour (Specify)				
R	Payroll Burden %				$0.00
	Total Labour Cost				$217.18
O	Small Vehicle Time	3.65			
T	Large Vehicle Time	8.03	1.5		$12.05
H	Other: Material				
E	Contract				
R	Other	2.00			$2.00
	Total Other				$14.05
Total Cost					$231.23
	Specific Service Charge Value Requested - Round to nearest $5				**$230.00**

Assumes 2 person line crew

Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

Derivation of Standard Rates and Model for Deriving Distributor Specific Rates	
Specific Service Charge Description:	**$415 Specific Service Charge Calculation**

Used For:

Disconnect/Reconnect at pole - after regular hours

			Rate/Amount	**Hours/Units**	**O/T Factor**	**Calculated Cost**
L	Direct Labour (inside staff) Straight Time		39.32	0.5		$19.66
A	Direct Labour (inside staff) Overtime					
B	Direct Labour (field staff) Straight Time		65.84	1.5		$98.76
O	Direct Labour (field staff) Overtime		65.84	4.0	2	$526.72
U	Other Labour (Specify)					
R	Payroll Burden %					$0.00
		Total Labour Cost				$645.14
O	Small Vehicle Time		3.65			
T	Large Vehicle Time		8.03	1.5		$12.05
H	Other:	Material				
E		Contract				
R		Other	2.00			$2.00
		Total Other				$14.05
Total Cost						$659.19
	Specific Service Charge Value Requested - Round to nearest $5					**$660.00**

Assumes 2 person line crew - One visit on overtime & minimum 2 hr call out

Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

Derivation of Standard Rates and Model for Deriving Distributor Specific Rates	
Specific Service Charge Description:	**$300 Specific Service Charge Calculation**

Used For:

Temporary service install & remove - underground - no transformer

		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (inside staff) Straight Time	39.32			
A	Direct Labour (inside staff) Overtime				
B	Direct Labour (field staff) Straight Time	65.84	5.5		$362.12
O	Direct Labour (field staff) Overtime				
U	Other Labour (Specify)				
R	Payroll Burden %				$0.00
	Total Labour Cost				$362.12
O	Small Vehicle Time	3.65	1.5		$5.48
T	Large Vehicle Time	8.03	2.0		$16.06
H	Other: Material				
E	Contract				
R	Other	3.00			$3.00
	Total Other				$24.54
Total Cost					$386.66
	Specific Service Charge Value Requested - Round to nearest $5				**$385.00**

Assumes 1.5 hours for engineering plus 2 people 2 hours each to install/remove

Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

Derivation of Standard Rates and Model for Deriving Distributor Specific Rates	
Specific Service Charge Description:	**$500 Specific Service Charge Calculation**

Used For:

Temporary service install & remove - overhead - no transformer

		Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (inside staff) Straight Time	39.32			
A	Direct Labour (inside staff) Overtime				
B	Direct Labour (field staff) Straight Time	65.84	7.5		$493.80
O	Direct Labour (field staff) Overtime				
U	Other Labour (Specify)				
R	Payroll Burden %				$0.00
	Total Labour Cost				$493.80
O	Small Vehicle Time	3.65	1.5		$5.48
T	Large Vehicle Time	8.03	3.0		$24.09
H	Other: Material				
E	Contract				
R	Other	3.00			$3.00
	Total Other				$32.57
Total Cost					$526.37
	Specific Service Charge Value Requested - Round to nearest $5				**$525.00**

Assumes 1.5 hours for engineering plus 2 people 3 hours each to install/remove

Schedule 11-2: Specific Service Charges: Standard Formula and Amounts

Derivation of Standard Rates and Model for Deriving Distributor Specific Rates	
Specific Service Charge Description:	**$1000 Specific Service Charge Calculation**

Used For:

Temporary service install & remove - overhead - with transformer

			Rate/Amount	Hours/Units	O/T Factor	Calculated Cost
L	Direct Labour (inside staff) Straight Time		39.32			
A	Direct Labour (inside staff) Overtime					
B	Direct Labour (field staff) Straight Time		65.84	15.5		$1,020.52
O	Direct Labour (field staff) Overtime					
U	Other Labour (Specify)					
R	Payroll Burden %					$0.00
		Total Labour Cost				$1,020.52
O	Small Vehicle Time		3.65	1.5		$5.48
T	Large Vehicle Time		8.03	7.0		$56.21
H	Other:	Material				
E		Contract				
R		Other	3.00			$3.00
		Total Other				$64.69
Total Cost						$1,085.21
	Specific Service Charge Value Requested - Round to nearest $5					**$1,085.00**

Assumes 1.5 hours for engineering plus 2 people 7 hours each to install/remove

UNDERTAKING NO. TCJ1.13:

TO PROVIDE RESPONSES TO QUESTIONS 1 THROUGH 6 OF BOMA IN WRITING.

Response:

Horizon Utilities provides responses to the BOMA Technical Conference questions 1 - 6 in the following pages.

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BOMA-1TC

Ref: BOMA #2 Attachment 2 Pages 9 and 11

a) **You state that converting to a higher voltage negatively affects the reliability statistics because a fault in any part of a 13.8kv or 27.6kv voltage level system would affect a larger number of customers. What is the cost of that loss in reliability? How does the Company propose to offset that likely increase. If it can't be offset what is the cost of the increased number of outages?**

b) **Please provide the Cost Analysis Tool referenced on Page 11.**

c) **Based on experience with the conversion program to date, what is the increase in the number of customers impacted y outages due to the conversion from 4/8kV to 13.8/2.6kV.**

d) **Based on experience with the conversion program to date, what has been the reduction in maintenance costs due to converting to the 13.8/27.6kv circuits?**

Response:

a. Horizon Utilities would like to correct this statement from Attachment 2 to Horizon Utilities' response to Interrogatory BOMA-2, which is the 2009 version of the 4kV and 8kV Renewal Plan. Converting to a higher voltage does not negatively affect the reliability statistics. The statement on page 9 of attachment 2 refers to the higher number of customers per feeder on the 13.8kV and 27.6kV distribution system relative to the 4kV and 8kV distributions. This does result in a higher number of customers affected for a feeder level outage but the impact is offset by a number of factors including:

- Improved redundancy available on the 13.8kV and 27.6kV distributions as described on page 19 of the 2009 4kV and 8kV Renewal Plan;
- Improved interoperability as described in on page 19 of Horizon Utilities response to interrogatory BOMA-2; and
- The improved performance of Horizon Utilities' 13.8kV and 27.6kV distribution system relative to the 4kV and 8kV distribution system as illustrated in Figure 79 of the DSP filed as Appendix 2-4 of Exhibit 2. This figure illustrates the higher rate of

service interruptions per circuit km experienced by the 4kV and 8kV distribution system relative to the 13.8kV and 27.6kV distribution systems.

There is no loss in reliability and as such there is no cost to a loss in reliability. One of the drivers for the 4kV and 8kV Renewal Program is the declining reliability of the distribution system. This program will contribute to improved service reliability to customers.

b. Horizon Utilities will not be providing a copy of the Cost Analysis tool as described in the 2009 version of the 4kV and 8kV Renewal Plan. This tool is obsolete and has not been updated or used since 2009. It is not relevant to the current plan for 2015 – 2019. The methodology that Horizon Utilities uses to prioritize projects within the 4kV and 8kV Renewal Program is provided in Horizon Utilities' response to Interrogatory BOMA-2c.

c. Horizon Utilities cannot demonstrate the impacts on outage frequency and duration for prior and post conversion. Pre-conversion outage information is available for a substation or substation feeder. Post-conversion outage information is not available. Substation connected feeders, when converted to a higher voltage system, are connected to multiple existing feeders on the higher voltage distribution system. A one to one mapping of data from pre to post conversion is not possible. Please refer to Horizon Utilities' response to Interrogatory BOMA-2 part d. viii. for further information on the ability to measure reliability pre and post conversion.

Horizon Utilities does not record maintenance costs (planned or unplanned) for the distribution system by operating area or by feeder. Horizon Utilities cannot quantify the actual reduction in maintenance costs for the distribution system resulting from the historical renewal of the 4kV and 8kV distribution systems. Horizon Utilities' capital investments will address the decreasing reliability levels but it will take multiple years before material reductions in maintenance expenditures are realized as identified on page 150 of the DSP filed as Appendix 2-4 of Exhibit 2. Horizon Utilities has estimated that the decreased corrective maintenance in 2015 to 2019 resulting from the renewal of distribution assets to be $55,000 annually as identified in the response to Undertaking TJC1.4.

Horizon Utilities has estimated O&M reductions of $335,000 in 2015 to 2019 resulting from the decommissioning of nine substations as identified in the response to Interrogatory 2-SEC-20 part (c).

BOMA-2TC

Ref: BOMA #2 Attachment 3

a) Page 3 - Do the expenditures reflect the introduction of the "nearly maintenance free" equipment, such as vacuum circuit breakers and electronic relays? What percentage of relays and circuit breakers are currently of their type? What will be the rate of adoption of the breakers and relays of the 12 month period.

Response:

Horizon Utilities' forecasted operating and maintenance costs for substations do reflect the introduction of "nearly maintenance free" equipment as referenced on page 3 of Attachment 3 of Horizon Utilities' response to Interrogatory BOMA-2 b): the 2010 Substation Asset Condition Assessment.

In terms of "nearly maintenance free" equipment, approximately 40% of circuit breakers are new vacuum circuit breakers, and 45% of relays are electronic.

No further installation of these types of breakers or relays is planned for the period 2015-2019, unless an existing breaker or relay fails and requires replacement.

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BOMA-3TC

Ref: BOMA #2 Attachment 3 Page 17

Response:

Horizon Utilities received notification from Tom Brett, Counsel for BOMA on August 20, 2014 that a response was not required for this Technical Question.

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BOMA-4TC

Ref: BOMA #3

a) Please provide copies of the feedback you and the company provided to KPMG.

b) Page 2
   i. What is "islanding"? What are the effects?
   ii. Does Horizon Support the introduction of net-metering in its franchise for non-FIT/MicroFit embedded generation?
   iii. Page 3 – does the 1MW allocation to NEBO station to Horizon mean that Horizon can allow up to 1MW of Distributed Generation in that area.

Response:

a. Horizon Utilities received confirmation from Tom Brett, Counsel for BOMA on August 20, 2014 that the reference for BOMA-4-TC part a) was BOMA-4 Attachment 1. Horizon Utilities has prepared its response accordingly. Horizon Utilities provided feedback to KPMG verbally and is therefore unable to provide copies of the feedback.

b.

i. Horizon Utilities received confirmation from Tom Brett, Counsel for BOMA on August 20, 2014 that the reference for BOMA-4-TC part b) part i. was page 2 of Interrogatory BOMA-5. Horizon Utilities has prepared its response accordingly.

The term 'islanding' refers to the condition in which a distributed generator ("DG") continues to power a location even though supply from the electrical utilities' distribution system is no longer present. Islanding can be dangerous to utility workers, who may not realize that that a circuit is still energized. It may also prevent automatic re-connection of devices.

ii. Horizon Utilities allows net metering as identified in Section 2.3.6.4.2 of Horizon Utilities' Conditions of Service which states:

"Horizon Utilities will offer a net metering option to load customers who install a Generation Facility in accordance with Ontario Ministry of Energy Regulation 541/05, and who meet the following criteria:

- *the electricity generated by the Generating Facility is primarily for the Generator's own use; and*
- *the electricity generated by the Generating Facility is from a renewable energy source as approved by the Ministry of Energy; and*
- *the maximum accumulative output capacity of the Generating Facility does not exceed 500 kW; and*
- *the Generator conveys the electricity from the point of generation to the point of consumption within the same service location without utilizing Horizon Utilities' distribution system."*

iii. Horizon Utilities has been allocated 1MW of DG capacity at Nebo TS which means that 1MW of DG can be connected to the 27.6kV distribution system supplied by Nebo TS.

BOMA-5TC

Ref: BOMA-6 Page 2

"The total generation allowed is a function of the thermal and short circuit limitations of the feeders and the minimum feeder loading. The thermal and short circuit limitations vary per feeder and are not necessarily a function of the voltage".

Please explain how the thermal and short circuit limitations:

a) Come to exist and are maintained and how and why they vary in magnitude from feeder to feeder

b) Impact the ability of the feeder to accommodate generation

c) Are a function of which the voltage level at which feeders operate, if at all, and to what extent.

d) Affect as a practical matter impact the level of generation that can be accommodated on the feeds.

Response:

a. The thermal and short circuit limitations are limitations that exist on the Transformer Stations ("TS") circuit breakers and power transformers. All seventeen TSs that supply Horizon Utilities' service territory are owned by Hydro One Networks Incorporated ("HONI"). HONI is responsible for the determination of the thermal and short circuit limitations; Horizon Utilities is not able to comment on the determination of these limits.

b. The thermal and short circuit limitations impact the ability of the feeder to accommodate generation as follows:

- Short circuit limitations identify the maximum amount of fault current that the equipment at the TS is able to withstand during a fault. All sources of generation contribute to fault current and the total contribution from all sources must not exceed the limit for the feeder. The maximum fault current allowed from all Distributed Generators ("DGs") is calculated by taking the feeder limit and subtracting the fault current contributed by the transmission grid. A proposal to connect a DG would be denied if the fault current contribution from that DG would result in the total fault current exceeding the feeder limit.

The short circuit contribution of a generator depends on the generator technology (i.e. inverter based or rotating machine) and the distance from the station (the greater the distance the lower the short circuit contribution); and

- Thermal limitations refer to the ability of the power transformers at the TS to withstand reverse power flow. HONI TSs have been designed, rated and operated as step-down substations with power flowing from higher system voltages to lower system voltages. A large accumulation of distributed generation on a substation could result in the reversal of normal power flows which, depending upon the design of the TS, may cause an excessive imbalance in the secondary windings of the power transformer which in turn causes overheating and a potential failure of the power transformer. The total amount of DG connected to the feeders supplied by a power transformer at the TS is limited to prevent the potential for reverse power flow. This limit is not static as it is dependent on the loading on the power transformer which changes over time.

c. The thermal and short circuit limitations are not a function of the voltage levels at which the feeders operate.

d. Please refer to the response to part (b) of the question for a discussion on how the thermal and short circuit limitations affect the level of generation that can be accommodated.

BOMA-6TC

Ref: BOMA #1 (f) (i) and (ii)

a) **What is meant by "significant" at page 6 of 23.**

b) **Please explain what is meant by primary and secondary replacement strategy. Please explain and provide examples of cases where the primary strategy would be proactive and the secondary strategy reactive.**

c) **Define what you mean by a "prolonged outage" in 2 SEC 15 page 2.**

Response:

a. Horizon Utilities considers an outage caused by equipment failure not to have “significant restoration costs” when replacement parts are readily available; generally a small number of customers is impacted; and restoration is relatively quick and straightforward. For example, overhead and underground transformers typically service up to fourteen customers and replacement transformers are readily available in inventory. As such restoration costs would not be significant.

b. Primary replacement strategy refers to Horizon Utilities’ preferred or default method of renewal for the asset category. Secondary replacement strategy refers to Horizon Utilities’ alternative method of renewal for the asset category.

An example of an asset category for which the primary replacement strategy is proactive is XLPE Primary Cable. The high impact of failure combined with the higher reactive replacement cost versus proactive replacement has led Horizon Utilities to establish a Capital Investment Program to proactively replace XLPE primary cable; this program will be the primary vehicle for the replacement of XLPE cable. Please refer to pages 145-147 of Section 2.3.1 of the DSP filed as Appendix 2-4 of Exhibit 2 for further information.

Another example of an asset category for which the primary replacement strategy is proactive is Substation Transformers. Failure of the substation transformer can result in the entire substation being removed from service (for substations with a single transformer), or part of a substation being removed from service (for substations with multiple transformers) for extended periods of time. Substation transformers are expensive and can have lead times for delivery in excess of twelve months. Consequently, substation transformers are a critical component of a distribution system and Horizon Utilities employs proactive replacement as the primary renewal strategy. Please refer to pages 108-109 of the DSP filed as Appendix 2-4 of Exhibit 2 for further information.

c. Horizon Utilities considers a “prolonged outage” as an outage exceeding four hours in duration.

UNDERTAKING NO. TCJ1.14:

TO EXPLAIN WHETHER THE $1.180 MILLION RELATED TO SMART METER COSTS ARE THOSE INCREMENTAL, ONGOING COSTS, AND IF NOT, TO PROVIDE INCREMENTAL, ONGOING SMART METER COSTS FOR 2014 AS COMPARED TO BEFORE SMART METER IMPLEMENTATION OR TO EXPLAIN WHY THIS CANNOT BE PROVIDED

Response:

The $1,180,103 related to Smart Meter costs identified in Table 4-19 is the total operating costs associated with operating and administering Smart Meters in 2011. These costs were recorded in a deferral and variance account in 2011 and as such were excluded from reported OM&A in the 2011 Board-Approved of $42,136,201 and the 2011 Actuals of $41,644,654. As a result of the Board's Decision in Horizon Utilities' 2011 Smart Meter Prudence Application (EB-2011-0417) ("the Decision") on May 1, 2012, ongoing Smart Meter OM&A costs incurred in 2012 and future years are recorded in regular operating expense accounts, (as identified under Implementation on page 9 of the Decision), and as such are embedded in OM&A. In order to state OM&A on a comparable basis from 2011 onwards an adjustment was made to the 2011 reported OM&A in Table 4-19 to include Smart Meter costs.

The $1,180,103 related to Smart Meter costs does not represent the incremental cost of operating and administering Smart Meters in 2011, nor does it net out the savings from conventional meter reading. Horizon Utilities is unable to provide these savings which would need to include a comparison of not only direct per meter reading costs but indirect and allocated costs including but not limited to, employee salaries and benefits, licensing fees and information technology costs.

The implementation of Smart Meters was a public policy change mandated by the Ministry of Energy. Horizon Utilities was obligated to replace conventional meters with Smart Meters for all Residential and GS<50kW customers. Horizon Utilities did not undertake a cost/benefit analysis nor did it keep records in a manner which would facilitate the comparison of Smart Meter operating costs in 2014 to operating costs as if Smart Meters had not been implemented. Additionally, Horizon Utilities did not record total Smart Meter costs separately from 2012 onwards.

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