Responses to Board Staff Interrogatories

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

AND IN THE MATTER OF an Application by Horizon Utilities Corporation to the Ontario Energy Board for an Order or Orders approving of fixing just and reasonable rates and other service charges for the distribution of electricity as of January 1, 2015, January 1, 2016, January 1, 2017, January 1, 2018 and January 1, 2019.

1-Staff-1 Custom IR – Rate Order

References:

1. Exhibit 1 Tab 12
2. Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012

Preamble:

On pages 18 and 19 of the Report in Reference 2, the Board states:

"This rate-setting method is intended to be customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor."

Please state what Horizon is expecting the Board to state in its rate order.

Response:

Horizon Utilities expects that the Board-approved Schedule of Rates and Charges for each year will appear similar to those typically issued by the Board. If Board staff are seeking comments on what Horizon Utilities expects that the Board may require it to include in its Draft Rate Order, Horizon Utilities has had the benefit of considering the Board's findings in this regard in its July 17, 2014 Decision with Reasons in the matter of Enbridge Gas Distribution Inc.'s 2014-18 Custom IR application (EB-2012-0459), and anticipates that the Draft Rate Order (the "DRO") will capture the following main items (these may be subject to change depending on the outcome of this proceeding):

- The new electricity distribution rates that will be in effect from January 1, 2015 to December 31, 2015;
- The approved values for capital and OM&A expenditures, together with calculations of items such as rate base and revenue requirement for each of 2016-2019. As was the case with Enbridge, Horizon Utilities anticipates that the Board will require Horizon Utilities to provide "Allowed Revenue" calculations for each year based on a combination of amounts approved in this proceeding (for example, capital and OM&A expenditures) and placeholder amounts for items that would be updated in advance of the start of each rate year.

  In its response to 1-Staff-2, Horizon Utilities provided the following list of items that are proposed to be subject to annual adjustments:

  1. changes in the cost of capital (Exhibit 5, Tab 1, Schedule1);
  2. changes to working capital (Exhibit 2, Tab 4, Schedule 1);
  3. changes in the tax rates (Exhibit 4, Tab 6, Schedule 2);
  4. changes in other third party pass through charges (Exhibit 8);
  5. CDM results that vary from plan (Exhibit 3, Tab 1, Schedule 2);
  6. disposition of deferral and variance accounts (Exhibit 9); and
  7. any additional annual adjustments as identified by the Board in developing the Custom IR Application process.

  Horizon Utilities suggests that it is premature at this time to create a complete list of placeholder items, as this can only be determined following the Board's disposition of the Application;
- Board direction that the January 1, 2015 rates will be adjusted annually by way of an administrative process for January 1 of each year of the rate plan (i.e., for 2016, 2017, 2018, and 2019) as filed in Appendix 2-Z, with any adjustments reflecting the Board's findings in this Decision; and
- Board confirmation that its approval of this Application will not prevent Horizon Utilities from filing future applications for adjustments to elements of the rate plan, as

appropriate, due to the unforeseen events discussed by Horizon Utilities in the Application. In its response to interrogatory 1-Staff-2, Horizon Utilities provided the following list of "reopeners" – significant events outside the normal course of business in respect of which Horizon Utilities may seek rate adjustments from the Board:

1. Changes to income tax rates and laws;
2. Changes to Ontario Market Rules or OEB Codes that would impact costs or revenues;
3. Changes to Board policies on distributor rate design;
4. Changes to environmental laws that would impact business requirements and processes resulting in increased expenditures;
5. Changes to technical requirements beyond the control of the utility;
6. Items that would meet the OEB's Z-factor criteria;
7. Ministerial Directives or similar required government action;
8. Accounting framework changes; and
9. Changes to the revenue allocated to unmetered load customers resulting from changes to Board policies on cost allocation for unmetered loads.

Horizon Utilities has discussed these further in its response to question 1-Staff-2.

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1-Staff-2 Custom IR – Unforeseen Events

References:

1. Exhibit 1 Tab 12
2. Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012

Preamble:

On page 13 of the RRFE Report, the Board states that the Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options.

On page 19 of the RRFE Report, the Board states that the adjudication of an application under the Custom IR method will require the expenditure of significant resources by both the Board and the applicant. The Board therefore expects that a distributor that applies under this method will be committed to that method for the duration of the approved term and will not seek early termination. As noted on page 13 of the RRFE Report, a regulatory review may be initiated if the distributor performs outside of the ±300 basis points earnings dead band or if its performance erodes to unacceptable levels.

Please compare Horizon's proposed adjustments outside of the normal course of business to the Board's policies in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors in relation to the treatment of unforeseen events and explain any differences. What circumstances, including those unique to Horizon, if any, support Horizon's proposed approach where it differs from the Board's policies?

Response:

Horizon Utilities has specified its proposals with respect to annual adjustments, reopeners and off-ramps to the rate plan in Exhibit 1, Tab 12, Schedule 1 and Schedule 2 of the Application.

Horizon Utilities proposed to adopt the Board's existing off-ramp policy should its financial performance measured by return on common equity vary ±300 basis points from the level underpinning its rates. The event of an off-ramp could cause a review of the main rate plan. Such is consistent with both the RRFE and the *Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors ("3GIRM Report")*.

Horizon Utilities has proposed annual adjustments for recurring events that are outside management's control. For ease of reference, the proposed adjustments are shown below as are references to specific exhibits:

1. changes in the cost of capital (Exhibit 5, Tab 1, Schedule1);
2. changes to working capital (Exhibit 2, Tab 4, Schedule 1);
3. changes in the tax rates (Exhibit 4, Tab 6, Schedule 2);
4. changes in other third party pass through charges (Exhibit 8);
5. CDM results that vary from plan (Exhibit 3, Tab 1, Schedule 2);
6. disposition of deferral and variance accounts (Exhibit 9); and
7. any additional annual adjustments as identified by the Board in developing the Custom IR Application process.

These are outside Management's control and, as identified, can be categorized as recurring events. Unlike off-ramps, the main rate plan would continue with only mechanistic rate adjustments required for the changes that flow from these recurring events.

Horizon Utilities has also proposed that adjustments be made at the appropriate time for significant events outside the normal course of business. These are discussed in Exhibit 1, Tab 12, Schedule 2 of the Application and are referred to as "reopeners". For ease of reference these include:

1. Changes to income tax rates and laws;
2. Changes to Ontario Market Rules or OEB Codes that would impact costs or revenues;
3. Changes to Board policies on distributor rate design;
4. Changes to environmental laws that would impact business requirements and processes resulting in increased expenditures;
5. Changes to technical requirements beyond the control of the utility;
6. Items that would meet the OEB's Z-factor criteria;
7. Ministerial Directives or similar required government action;
8. Accounting framework changes; and
9. Changes to the revenue allocated to unmetered load customers resulting from changes to Board policies on cost allocation for unmetered loads.

These events are also outside Management's control but are categorized as unforeseen rather than recurring. These may have a material impact on the utility. While they are termed "reopeners", to clarify, they should not necessarily cause the termination of the main rate plan. Rather "reopeners" should be understood as adjustments to certain elements of the main rate plan for unforeseen or non-recurring events. Of note, these events are expected to be limited and may not occur at all.

Horizon Utilities interprets Board's Staff's interrogatory to refer to the last set of proposals, termed reopeners in the Application. According to the 3GIRM Report, Z-factors are events that are not within Management's control. The proposed "reopeners" meet that criterion. A distributor may record amounts and seek recovery of such amounts through a Z-factor application, if the eligibility criteria of Causation, Materiality, and Prudence are met, according to the 3GIRM Report. While in principle the Board's Z-factor policy may be considered as capturing the unforeseen events noted above, to Horizon Utilities' knowledge, the Board's Z-factor policy has largely been applied to matters pertaining to storm damage costs or loss of load. Horizon Utilities has identified these unforeseen events because of their potential significant impact on the financial and thus operational integrity of the utility. Whether these events are captured by the Board's current Z-factor policy, or should be an adjunct to the rate plan as Horizon Utilities has proposed, is open for the Board to determine. Horizon Utilities does not have any reason to believe that the unforeseen events it has noted are necessarily unique to its circumstances.

Please see Horizon Utilities' response to 1-Energy Probe-5 for more information.

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1-Staff-3 Custom IR – Variances

Reference:

1. Exhibit 1 Tab 12
2. Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012

Preamble:

On page 20 of the RRFE Report, the Board states that once rates have been approved under Custom IR, the Board will monitor capital spending against the approved plan by requiring distributors to report annually on actual amounts spent. If actual spending is significantly different from the level reflected in a distributor's plan, the Board will investigate the matter and could, if necessary, terminate the distributor's rate-setting method. A distributor on the Custom IR method will have its rate base adjusted prospectively to reflect actual spend at the end of the term, when it commences a new rate-setting cycle. This is consistent with the Board's existing policies in relation to incremental capital under 3rd Generation IR.

a. How does Horizon propose to address actual in-service capital against planned in-service capital over the term of the plan?

b. How does Horizon propose to address any differences between actual capital spending and approved planned spending at the end of the term of the plan (i.e., how will variances be addressed)?

c. How does Horizon propose to address actual spending against approved planned spending over the term of the plan?

Response:

a) Horizon Utilities will manage actual in-service capital against planned in-service capital over the term of the plan through rigorous project management. Distribution system capital projects are managed through the planning and scheduling process called "iPass". Horizon Utilities provided a description of iPass in Exhibit 2, Tab 6, Appendix 2-4, page 53 of the Application. The centralized schedule allows internal stakeholders to view real time project information through the entire life cycle of the project. General plant projects are managed outside of the iPass process. General plant projects are managed by dedicated project managers who report regularly on: project timelines; adherence to budget; and issues for resolution, in order to keep the projects on schedule.

b) and c) On page 19 of the RRFE Report, the Board states that it expects distributors "*to demonstrate [their] ability to manage within the rates set, given that actual costs and revenues will vary from forecast.*" Horizon Utilities will address actual spending against approved planned spending over the term of the rate plan by managing its costs on an annual basis. Annual variations to expenditure levels will be addressed in the following year, with the overall expenditures over the 5-year period to be managed to the plan, as per the Board's expectations in the RRFE. Horizon Utilities has not proposed a regulatory account to capture the rate consequences of any variances between actual capital spending and Board-approved capital spending for true-up process either for each year of the rate plan or for the total term of the rate place. At the end of the rate plan term, the opening rate base for the next rate cycle to follow this 5-year plan will naturally reflect in-service capital to the end of 2019.

1-Staff-4 Custom IR – Benefit Sharing

Reference:

1. Exhibit 1 Tab 12
2. Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012

Preamble:

At page 12 of the RRFE Report, the Board states: "To ensure that the benefits from greater efficiencies are appropriately shared throughout the rate-setting term between the distributor/shareholder and the distributor's customers, the expected benefits will be taken into account in establishing the rate adjustment mechanisms applicable to each rate method through the X-factor."

a. In the absence of an X-factor, what process is Horizon proposing to ensure that benefits are appropriately shared throughout the rate term between Horizon and its customers?

b. How will Horizon share any <u>additional</u> productivity and/or total cost efficiency gains it achieves over the term of the plan with its customers?

Response:

a) Horizon Utilities has included forecasted productivity savings in Exhibit 4, Tab 3, Schedule 4 of the Application. Horizon Utilities pursues productivity to offset increased expenditures while maintaining and potentially enhancing its service to customers. Horizon Utilities has been tracking productivity since 2011 and the Application includes forecast total annual sustained productivity savings of approximately $6,645,000 by 2019. Table 4-43 in Exhibit 4, Tab 3, Schedule 4, page 4 provides the yearly productivity achievement, comprised of the incremental achievement as well as the sustained achievement from prior years. These savings will be shared throughout the rate plan term with Horizon Utilities' customers. In the absence of these productivity savings, by 2019 Horizon Utilities' total costs would be $6,645,000 higher than otherwise forecast in the Application. Therefore, both the revenue requirement and the related rate increases identified over the 2015-2019 term are lower due to the productivity savings embedded in this Application.

The forecasted total annual sustained savings of $6,645,000 by 2019 is guaranteed to ratepayers through the Revenue Requirement sought in this Application irrespective of whether Horizon Utilities achieves such savings. Customers do not bear the downside risk should Horizon Utilities not realize the above-mentioned savings over the IR term. In this event, the

result would be a negative impact on earnings. Horizon Utilities is therefore motivated to realize the productivity savings that it has forecast in the Application, as well as to achieve further incremental savings, should such be identified and realized during the IR term.

b) Horizon Utilities has identified $6,645,000 in total annual sustained savings by 2019. Horizon Utilities expects that these productivity achievements will be sustained in the years subsequent to the term of this Application as identified in Exhibit 4, Tab 3, Schedule 4, page 3.

Horizon Utilities has an impressive record of cost control leadership in Ontario's electricity distribution sector as identified in Exhibit 1, Tab 2, Schedule 6, page 31. Horizon Utilities has the 24th lowest average revenue per customer among the 73 Local Distribution Companies ("LDC") in the OEB's 2012 Yearbook of Electricity Distributors. This cost control success is evidenced in the benchmarking results of the *Report of the Board - Defining and Measuring Performance of Electricity Transmitters and Distributors* (EB-2010-0379), which was a component of the RRFE. Horizon Utilities was placed in the Group II stretch factor cohort, where a Group II utility is defined as having actual costs 10 to 25 percent below predicted costs under the OEB's econometric benchmarking framework. Additional savings will be harder to achieve for an already cost efficient utility, without adverse impacts on service and reliability.

Horizon Utilities will continue to seek efficiencies. Customers will benefit from a lower cost base for the next rate cycle, in the event that there are additional productivity gains over the current rate plan term.

1-Staff-5 Custom IR – Communicating Benefits

References:

1. Exhibit 2 Appendix 2-4 Horizon Utilities Distribution System Plan – Appendix D Innovative Customer Consultation Report
2. Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012

Preamble:

In Reference 2, the Board expects distributors to be responsive to identified customer preferences. In Reference 1, some customers appeared not to understand how regulated business is managed, and their suggestions, such as run-to-failure can only be taken in part.

a. Does Horizon have any plans in its Application to address any customers' misconceptions of operating in a regulated environment?

b. How will Horizon demonstrate its claim to its customers that its efficiency enhancing and total cost-minimizing strategies ultimately yield higher value and/or lower rates for customers?

Response:

a. No, the Application does not contain plans to address any customers' misconceptions of Horizon Utilities operating in a regulated environment. The prime reason for this is that the misconceptions observed require thorough consideration of how to best address them and there was little time to properly plan and do so before filing the Application. Until such time, as a first step, Horizon Utilities will consider utilizing the established avenues to increase customer awareness of operating in a regulated environment. These avenues would include: direct discussions with customers as they arise; scripted messaging through the Customer Care department; bill print messages; billing inserts; information booths at community events; information posted on the Horizon Utilities website; and messaging publicized through social media channels.

b. Horizon Utilities will continue to demonstrate its claim to its customers that its efficiency enhancing and total cost-minimizing strategies will yield higher value and/or lower rates for customers through: demonstration of Horizon Utilities' relative performance with other utilities through the Board's own publications; its actual costs relative to predicted costs per the Board's own model; the Board's determinations in rate reviews, such as the

current review; and customer satisfaction scores through the surveys that Horizon Utilities undertakes or commissions.

1-Staff-6 Custom IR – Annual Updates

Reference:

1. Exhibit 1 Tab 12

Preamble:

Horizon has listed 7 items on Schedule 1 of the referenced Tab that it proposes to update annually.

Horizon has also listed 9 items on Schedule 2 called Reopeners that could cause it to apply to the Board. Horizon states that adjustments would be sought for unexpected events that will have a material impact to the operation of the utility and are outside of management's control.

a. Does Horizon intend to use a materiality threshold when assessing whether an update is required?

b. If yes, what would the materiality threshold be, and why would it be set at that level?

c. When, in its regulatory cycle, would Horizon file its update application?

d. What would be the measure for materiality? By way of example, would a change in income tax rate be assessed on the magnitude of the rate change, or the impact on the revenue requirement?

e. For each Reopener, what would the materiality be, and why would it be set at that level?

Response:

Horizon Utilities' responses below are on the interpretation that parts a. to d. pertain to the annual adjustments only.

a) Horizon Utilities is proposing adjustments for recurring events that are mechanical in nature to be filed with the OEB annually. These adjustments are listed in Exhibit 1, Tab 12, Schedule 1 and are included in Horizon Utilities' response to 1-Staff-2, and 1-Energy Probe-5. These adjustments to revenue requirement are generally intended to represent an update to parameters underpinning the then existing rates and are calculated based on actual results and on parameters issued by the OEB or government agencies. Horizon Utilities is not proposing that these adjustments be subject to a materiality threshold.

Included in the list of annual adjustments is the disposition of deferral and variance accounts in compliance with the *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative* (the "EDDVAR Report") (EB-2008-0046) dated July 31, 2009. Horizon Utilities has proposed that these would be subject to the Board's established disposition threshold of +/-$0.001/kWh for Group 1 Accounts. At page 10 of the EDDVAR Report, the Board stated that "*When this threshold is exceeded, a distributor will file a proposal for the disposition of all revised Group 1 Account balances (including carrying charges). The onus will be on the distributor to justify why any Account balance should not be cleared*."

b) Please see Horizon Utilities' response to a) above.

c) Horizon Utilities anticipates that the annual updates will be filed with the OEB in the third quarter of the calendar year. This timeframe is consistent with the OEB's release of updated cost of capital parameters in the fourth quarter of each year.

d) Please see Horizon Utilities' response to c) above.

e) For reopeners, materiality would be measured based on the revenue requirement impact of unforeseen events (individually or cumulatively) over the term of the Application that exceed the materiality threshold ($564,780) calculated in Exhibit 1, Tab 6, Schedule 1.

1-Staff-7 Customer Focus – Outcomes

References:

1. Exhibit 1 Tab 2 Schedule 2
2. Exhibit 1 Tab 4 Schedule 1
3. Exhibit 2 Appendix 2-4 Horizon Utilities Distribution System Plan – Appendix D Innovative Customer Consultation Report

Preamble:

Horizon has filed evidence describing its activities in engaging its customers. A significant aspect described in Exhibit 1 is the use of technology. Another aspect is customer and community engagements described in Innovative Research Group's Customer Consultation Report. Board staff would like to better understand future outcomes of Horizon's efforts to date.

a. Regarding the My Account and the My Electric applications.

i. Please provide the number of subscribers by year for each application. Please include an estimate for 2014.
ii. What is the projected annual uptake of these services for 2015 – 2019?
iii. Are there mobile applications for these services available and if so, is Horizon planning to implement them?
iv. What is the business analysis that Horizon would use to asses mobile applications, and what would be the critical decision point for implementing the initiative?
v. Are there any reasons that the web based applications would be discontinued?
vi. Are there any reasons why mobile applications would not be introduced and maintained?

b. Board staff is interested in the comments recorded in the Innovative Research Group's Customer Consultation Report by some customers. On page 8, it states that In the online workbook and the facilitated discussion groups, customers agreed with Horizon Utilities on their "run-to-failure" strategy:

"More than 3-in-5 online workbook respondents (61%) said that "running- to-failure" is a good way to get full value from equipment so long as the resulting power service interruption is contained."

"33 of 41 facilitated discussion group participants support running-to-failure as opposed to 8 of 41 who support replacing equipment before it fails."

i. Please describe Horizon's "run-to-failure" strategy as presented to the customers.
ii. What changes, if any, has Horizon applied to its capital planning prior to the development of the Distribution Plan as a result of the strong support for the strategy.
iii. How has Horizon taken duration of interruption into consideration in applying the "run-to-failure" strategy?

iv. What components would be run-to-failure vs. planned replacement?

c. It appears that some customers have a misunderstanding of the financing requirements of a distribution system. Item 3 on page 9 states:

"3. Participants in every discussion group questioned the long-term financial processes of this sector. They did not understand why under the regulated process, Horizon Utilities did not save money in a reserve fund in anticipation of system renewal requirements. Business owners and managers in particular did not understand why there are no savings for these expenditures. They often explained that they, as business people, have to budget and put earnings aside in anticipation of replacing their equipment and business tools; "so why can't Horizon Utilities do the same"? The OEB may wish to consider this view."

i. How has Horizon addressed this difference in the economics of an essential utility and the economics of competitive businesses?
ii. If Horizon has not addressed this, are there plans to inform customers of how and why facilities are planned and financed?

d. On page 4 of the first reference, Horizon lists 5 initiatives in 2015 to 2019.

i. Please itemize and quantify the benefits to the customer that flow from these initiatives.
ii. Please state the measures that will be used to measure achievement.
iii. Please state the corrective actions planned to ensure achievement.

e. How do Horizon's forecasted outcomes for the next five years (i.e., those it will especially focus on and invest heavily in) align with Horizon's customers' preferences? Please provide a summary of the customer preferences addressed by each selected outcome.

Response:

a. i) As of June 30, 2014, 60,163 Horizon Utilities customers have subscribed to myAccount which can be accessed through the Horizon Utilities main and mobile websites.

MyElectric is a component of myAccount, and therefore, customers who subscribe to myAccount also have access to myElectric.

Table 1 below summarizes the number of myAccount and myElectric customer subscriptions since its implementation in mid-2012 and the number forecasted through to the end of the 2014 Bridge Year.

Table 1

myAccount customer subscriptions			
	2012	2013	2014F
Subscriptions	50,116	56,459	65,000

ii) Horizon Utilities will continue to promote the accessibility of on-line information and the value of the myAccount services and myElectric tools to customers. Horizon Utilities' forecast of the customer subscriptions myAccount for 2015 to 2019 is shown in Table 2 below.

Table 2

Forecasted myAccount customer subscriptions					
	2015	2016	2017	2018	2019
Subscriptions	75,000	85,000	100,000	115,000	130,000

iii) Horizon Utilities implemented its mobile website in early 2013, as identified in Exhibit 4, Tab 3, Schedule 2, page 4. Customers with personal devices may access myAccount and myElectric from the mobile website. The mobile website enables customers to perform a number of services from the convenience of their personal device including: view their account status; pay their bills; access myElectric; and view any current power outage notifications.

iv) As discussed in iii) above, Horizon Utilities implemented its mobile website in 2013. As described in Exhibit 4, Tab 3, Appendix 4-1, Horizon Utilities' 15th Annual Electrical Utility Customer Satisfaction Survey, page 17, 81% of Horizon Utilities' respondents have access to the internet. Horizon Utilities considered the high percentage of customers who own personal devices, the need to meet increasing customer expectations regarding accessibility of information, and the availability of affordable technology during its review of the potential of providing mobile capabilities.

v) Customers have provided feedback to Horizon Utilities' Call Centre staff indicating that they expect continued enhancements and evolution of on-line services. With uptake continuing to increase, Horizon Utilities does not foresee any rationale for the discontinuation of web-based applications.

vi) Horizon Utilities introduced its mobile website in 2013 and plans to maintain this service through the term of this Application. Please see Horizon Utilities' response to a) iii) above.

b. i) Horizon Utilities' "run-to-failure" ("RTF") or reactive replacement strategy for distribution assets is provided in Exhibit 2, Tab 6, Appendix 2-4, page 145. The strategy involves renewal of assets reactively where unplanned failures represent a low risk to: public or employee safety; significant restoration cost; system reliability; and customer service. Replacement parts are readily available, generally small numbers of customers are impacted, and restoration is relatively quick and straightforward. The example presented to customers as part of the Distribution System Plan Workbook Exhibit 2, Tab 6, Appendix 2-4, Appendix D page 16 was of a pole top distribution transformer.

In Horizon Utilities' Online Workbook, a voluntary consultation tool available to customers should they wish to voice an opinion on the DSP, respondents were provided the following preamble and then asked to select which statement best represented their view.

> *In order to secure the full value for its investment, Horizon Utilities allows some equipment to "run-to-failure". The equipment that is allowed to run-to-failure (such as pole top transformers) only creates power service interruptions for a very limited number of customers and can quickly be restored. While many utilities follow this practice, others do not.*
>
> *Which of the following best represents your view?*
>
> *Response Code 1 (61%selected) "Running-to-failure" is a good way to get full value from equipment so long as the resulting power service interruption is contained and quickly restored.*
>
> *Response Code 2 (26%selected) Horizon Utilities should ensure reliable power and not wait until equipment fails, even if that means it needs to spend more money replacing equipment that is still working.*
>
> *Response Code 98 (12% selected) Don't Know*

In the Workbook-led Facilitated Discussion Groups, the question related to RTF was worded exactly as it was in the Online Workbook. However, for the Facilitated Discussion Groups, a facilitator from Innovative Research Group ("Innovative"), the firm working with Horizon Utilities on the DSP-related customer outreach, was present to discuss the information provided in the Workbook by Horizon Utilities and to collect

customer preferences. The results from the Workbook-led Discussion Groups are provided in Table 3 below:

Table 3

Response	Community Stakeholders	GS > 50 kW	GS < 50 kW	Total	Community Stakeholders	GS > 50 kW	GS < 50 kW	Total	Count
"Running-to-failure" is a good way to get full value from equipment so long as the resulting power service interruption is contained and quickly restored.	3	8	7	**18**	4	4	7	**15**	33
Horizon Utilities should ensure reliable power and not wait until equipment fails, even if that means it needs to spend more money replacing equipment that is still working.	2	0	0	**2**	3	3	0	**6**	8
Don't know	0	0	0	**0**	0	0	0	**0**	0
Total	**5**	**8**	**7**	**20**	**7**	**7**	**7**	**21**	**41**
Missing values (i.e. non-responses) = 2									

ii) Horizon Utilities' "run-to-failure" strategy utilized in the capital planning process was developed prior to the execution of the customer engagement described in Innovative's Customer Consultation Report. The results of this engagement effort provided strong support for Horizon Utilities current "run-to-failure" strategy. The results reinforced that customers agreed with Horizon Utilities' current strategy. Horizon Utilities has not altered the current "run-to-failure" strategy as a result of the customer engagement activities.

iii) Horizon Utilities has taken the duration of interruption into consideration in applying the "run-to-failure" strategy. Horizon Utilities utilizes the "run-to-failure" or reactive replacement strategy as the primary replacement strategy where an unplanned failure represents a low risk to public or employee safety; low restoration cost, low impact to system reliability and customer service. Outage duration directly impacts system reliability and customer service. Failures where the impact can be significant in terms of public safety, cost, system reliability and customer service necessitate the use of a proactive replacement strategy. Asset groups, or geographic areas of the system, that experience prolonged outages with long durations result in the application of proactive replacement strategies through Horizon Utilities' Capital Investment Programs.

This methodology is consistent with customer preference as indicated on page 7 of the Innovative Research Group's Customer Consultation Report (Appendix D to Exhibit 2, Tab 6, Appendix 2-4).

iv) Horizon Utilities utilizes the "run-to-failure" or reactive replacement strategy for all asset categories. However, this strategy is not always the primary replacement strategy. A

summary of Horizon Utilities' primary and secondary replacement strategies was provided in Exhibit 2, Tab 6, Appendix 2-4 Table 22 and is provided in Table 4 below for ease of reference. For further details refer to Horizon Utilities' response to Interrogatory 2-SEC-15.

Table 4

Assets		Sub-Category	Primary Replacement Strategy	Secondary Replacement Strategy
Substation Transformers			Proactive	Reactive
Substation Circuit Breakers			Proactive	Reactive
Substation Switchgear			Proactive	Reactive
Pole Mounted Transformers			Reactive	Proactive
Overhead Conductors		Primary	Proactive	Reactive
		Secondary	Reactive	Proactive
		Service	Reactive	Proactive
Overhead Line Switches			Reactive	Proactive
Wood Poles			Proactive	Reactive
Concrete Poles			Reactive	Proactive
Underground Cables	XLPE	Primary	Proactive	Reactive
	PILC		Reactive	
	DB	Secondary	Reactive	Proactive
	ID		Reactive	Proactive
	DB	Service	Reactive	Proactive
	ID		Reactive	Proactive
Pad Mounted Transformers			Reactive	Proactive
Pad Mounted Switchgear			Reactive	
Vault Transformers			Reactive	Proactive
Utility Chambers			Reactive	
Vaults			Reactive	
Submersible LBD Switches			Reactive	Proactive

c. i) Horizon Utilities did not specifically address this issue in the consultation process as it was outside the scope of the consultation.

ii) Horizon Utilities did address how and why facilities are planned within its consultation process (please refer to pages 17 through 20 of the Distribution System Plan Review Workbook within the DSP, Appendix D). Page 30 of the Innovative Research Group Customer Consultation Report – Distribution System Plan Review includes the section: "What the Plan Means for Customers".

With respect to "Coverage of Distribution System Topics", the Innovative Report (page 30) states: "Almost three-quarters (73%) agreed that Horizon Utilities' Distribution System Plan covered the topics they expected to be covered" and "61% of respondents feel the proposed rate of system renewal is just right…and 8% indicated that the proposed rate of renewal is too slow." The Innovative Report states: "The main reason for those who stated it [the proposed rate of system renewal] is about right was that the proposal suggested seems reasonable."

Horizon Utilities did not address how and why facilities are financed. Horizon Utilities does not have specific plans at this time to address these issues with its customers. This notwithstanding, Horizon Utilities will take advantage of future customer engagement opportunities to inform its customers of how its facilities are financed and why they are financed in such manner with consideration for the economics of a regulated utility relative to other businesses.

d. i) As summarized in Exhibit 1, Tab 2, Schedule 2, page 3, Horizon Utilities has five main initiatives in 2015 to 2019 which support its customer focus outcomes as follows:

1. Increase customer accessibility and improve Call Centre response through the expanded utilization of an outsourced overflow service (2015 and beyond);
2. Implement the Outage Management System ("OMS") initiative (2015 and beyond);
3. Continuously improve the Horizon Utilities website to meet customer expectations, including software upgrade to the myAccount portal and myElectric;
4. Provide feedback survey opportunities to customer including the annual Customer Satisfaction Survey and bi-annual Contractor and Developer Survey; and
5. Renew aging, end-of-life infrastructure to mitigate system health degradation and related reliability risks and avoid further deterioration of service levels.

Horizon Utilities anticipates the following benefits from the aforementioned initiatives:

1. Outsourced overflow Call Centre service

   As described in Exhibit 4, Tab 3, Schedule 2, Page 12 and 13, the customer benefits of outsourced overflow Call Centre services are anticipated to include enhanced scheduling of resources to address call volumes that vary due to the time of day,

week, month and year; to augment the resources that are available to respond to customers during emergency events; the ability to offer extended hours of service; and improved customer experience through increased agent accessibility and decreased waiting times without increasing operating expenditures.

Please see Horizon Utilities' response to BOMA-8 for quantification of the benefits of this initiative.

2. Implementation of an Outage Management System ("OMS")

As identified in Exhibit 2, Tab 6, Schedule 1, page 72, 73 of 74, the customer benefits of the implementation of the Outage Management System ("OMS") initiative will provide a meaningful reduction in the duration of service outages, and enable multiple bi-directional communication channels to provide customers greater transparency into system operations and service restoration activities. Horizon Utilities has identified productivity savings of $355,000 associated with this initiative as identified in its response to Interrogatory 1-Staff-15a.

3. Website enhancements and software upgrades

As described in Exhibit 4, Tab 3, Schedule 2, Page 5, website enhancements enable Horizon Utilities to meet increasing customer expectations regarding the ability to manage their account activities conveniently through web-based applications, at any time of day and through personal devices in a more time and cost effective manner as compared to traditional telephone calls. The continued maintenance of the myAccount portal and myElectric service will enable new and enhanced tools to increase customer understanding of their electricity usage and costs and to manage their account.

The provision of pre-authorized payments as a web service is an example of a website enhancement which is anticipated to provide $30,000 annually in additional capacity to Customer Service through the automation of back office processes while increasing customer convenience.

4. Customer satisfaction surveys

As noted in Exhibit 1, Tab 4, Schedule 1, page 3 of 14, Customer satisfaction surveys provide customer benefits through the primary objective of gathering

information and feedback from residential and commercial customers to support internal discussions and action plans which drive customer service improvements. Customer feedback and input is used to inform and assist with the refinement of customer processes and practices.

Horizon Utilities has not quantified the benefits to the customer of customer satisfaction surveys.

5. Renewal of aging and end-of-life infrastructure

Renewal of aging and end-of-life infrastructure will improve the level of service experienced by Horizon Utilities' customers. As noted in Exhibit 2, Tab 6, Appendix 2-4, Section 1.3.2, Horizon Utilities' SAIDI, representing the average annual duration of interruptions experienced by all customers, has increased 17% from 2006 to 2013 (excluding the effects of 2013's major events).

As illustrated in Exhibit 2, Tab 6, Appendix 2-4, Figure 10, material and equipment failures are the largest single cause of customer minutes of outage over the previous five year period. In addition to equipment failures, as elements of the system age they become less resilient to adverse weather and foreign interference. These service failures are further exacerbated as the aged/failed assets require longer repair times or outright replacement, extending the duration of the outage that the customer experiences. Renewal of aging and end-of-life distribution assets will reduce the number of outages to due material and equipment failures and increase the distribution system's ability to withstand adverse weather and foreign interference events. This will result in improved service to customers.

Horizon Utilities has quantified the benefits to the customer of the infrastructure renewal program as it relates to improved system reliability. Please refer to Horizon Utilities' response to Interrogatory 1-Staff-11a which quantifies the anticipated improvement for System Renewal projects.

ii) The measures that will be used for each of the aforementioned initiatives include the following:

1. Outsourced overflow Call Centre service

Horizon Utilities currently measures the success of the Call Centre through measurement of the Service Quality Indicators including Telephone Accessibility (percentage of calls answered within 30 seconds) and Telephone Call Abandon Rate, and other metrics including Call Quality, calls completed per agent, and First Call Resolution.

Success of the overflow Call Centre service will be achieved by continuing to meet the Service Level Indicators, maintaining similar internal performance metrics including those related to customer call quality, and extending hours of customer service without introducing new incremental expenditures.

2. Implementation of an OMS

Horizon Utilities will utilize the System Average Interruption Duration Index ("SAIDI") metric to measure the reduction of service outages. Program success is measured through the provision of increased customer accessibility achieved through web and self-service channels instead of increasing the demands on more costly Call Centre resources.

3. Website enhancements and software upgrades

Horizon Utilities will continue to measure the number of customers who utilize the Horizon Utilities website and access services including the myAccount portal and myElectric service. Program success is measured through the provision of increased customer accessibility achieved through web and self-service channels instead of increasing the demands on more costly Call Centre resources.

4. Customer satisfaction surveys

Horizon Utilities benchmarks its performance in key areas including Customer Satisfaction against the Ontario and National averages. Program achievement is measured as a favourable result as compared to the Ontario average.

5. Renewal of aging and end-of-life infrastructure

Horizon Utilities will measure the improved level of service experienced by Horizon Utilities' customers through the SAIDI reliability metric and measuring the

contribution of material and equipment failures to Horizon Utilities' total reliability statistics.

iii) Horizon Utilities' corrective action plans to ensure program achievement are as follows:

1. Outsourced overflow Call Centre service

   Horizon Utilities would engage in discussions with the outsourced service provider aiming at mitigation and instituting financial penalties to ensure achievement of contractual service expectations regarding Call Quality and Telephone Accessibility.

2. Implementation of an OMS

   The implementation of Horizon Utilities' OMS is a corporate initiative and the project status and progress is regularly reported to Horizon Utilities executive. The project employs a full time project manager responsible to manage and monitor project timelines, adherence to budget and escalates issues for resolution.

3. Website enhancements and software upgrades

   Horizon Utilities tracks website issues on a monthly basis and meets regularly with the service provider to develop appropriate mitigation strategies.

4. Customer satisfaction surveys

   Horizon Utilities reviews the customer satisfaction results, data tables, and recommendations annually as provided by the external service provider. This valuable information is shared with staff and corrective action plans are developed as appropriate.

5. Renewal of aging and end-of-life infrastructure

   The renewal of aging and end-of-life infrastructure is a primary focus of Horizon Utilities Distribution System Plan provided in Exhibit 2, Tab 6, Appendix 2-4. Section 1.3 of the DSP describes the performance metrics and measurements undertaken by Horizon Utilities to manage the implementation of the DSP. Horizon Utilities will report progress on the DSP to the OEB annually through the RRR requirements.

e. Horizon Utilities plans a number of initiatives in the Test Years in support of customer focus outcomes as provided in Exhibit 1, Tab 2, Schedule 2, starting on page 3. The forecasted future outcomes that Horizon Utilities will be particularly focused on and for which there is a significant financial investment are: the implementation of the OMS; and the renewal of aging end-of-life infrastructure.

As provided in Appendix D of the DSP, Innovative Research Group Customer Consultation ("Innovative") report, Page 19, the customer consultations performed indicate that Horizon Utilities' customers support a focus on both reducing the number of power service interruptions and reducing the duration of outages.

Approximately three-quarters (72%) of respondents indicated that one hour or less without power is reasonable for a service interruption. The average duration of Horizon Utilities outages has been 2 hours 30 minutes; 1 hour 27 minutes, and 5 hours 58 minutes in 2011, 2012, and 2013 respectively, as provided in the DSP, Table 2.

The implementation of the OMS system is anticipated to reduce the duration of customer outages while the renewal of aging end of life infrastructure will primarily reduce the number of outages experienced by customers.

The Horizon Utilities Customer Consultation process results indicate its customers support the renewal of aging end-of-life infrastructure with the following findings provided on page 8 of the Innovative report:

- 61% of the online participants said the proposed rate of system renewal seemed "about right" with 14% saying "too fast" and 6% "too slow"
- 24 discussion participants felt the rate was "about right" with 6 saying "too fast" and 3 saying "too slow"
- 3 of 8 key account customers believe the pace of Horizon Utilities' proposed system renewal plan is "about right", while another 3 of the 8 believe it is too slow. The remaining key account customers (2 of 8) who provided feedback on pacing, believe the plan is moving "too fast".
- After a brief overview of Horizon Utilities' renewal plan, just over half (57%) of residential consumers preferred that Horizon Utilities should invest what it takes

to replace aging infrastructure even if rates go up while 29% chose reducing the level of investment, even if that means more or longer power outages.

1-Staff-8 Custom IR – Rate Increases and Inflation Index

Reference:

1. Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors EB-2010-00379

Preamble:

Consistent with the policy determinations set out in the reference issued on November 21, 2013 and corrected on December 4, 2013, the Board calculated the value of the inflation factor for incentive rate setting under 4th Generation IR (also referred to as Price Cap IR) and the Annual Index for rates effective in 2014 to be 1.7%. A detailed calculation is provided in Appendix C to that Report. A summary of the annual growth of this inflation factor since 2003 is also provided in Appendix B to that report.

a. Does Horizon expect that it will continue to seek a comparable level of revenue requirement and rate increases (i.e., increases greater than inflation) after 2019?

b. If so, for how many years and what circumstances – including those unique to Horizon, if any, support on-going annual increases that are greater than inflation?

Response:

a) Horizon Utilities interprets this question as asking about both comparable revenue requirement increases and rate increases. The latter is largely directly dependent on the former. Consequently, Horizon Utilities submits that growth in revenue requirement per customer is a reasonable proxy for growth in customer rates.

Please refer to the response to 1-EP-3 and, specifically, 1-EP-3 Attachment 2 ("1-EP-3 Attch 2") and 1-EP-3 Attachment 6 ("1-EP-3 Attch 6") provided in respect of that response. The line "CAGR – Total Actual RR Growth" demonstrates that Horizon Utilities is seeking annual growth in Revenue Requirement per customer that averages 2.81% per year across the IR period of 2015 through 2019. Within this analysis, Horizon Utilities has estimated its own inflation factor (ranging from 2.15% to 2.17% from 2015 through 2019) based on estimates of:

- The mix of labour and non-labour components of its OM&A and Capital Expenditures;
- Labour inflation trends within the sector;
- A non-labour inflation index of 1.50% that is 0.50% below: i) the most recent GDP-IPI-FDD estimate provided in Appendix B of report reference; and ii) the Bank of Canada

target for inflation. This index has also been used as the assumption within the budget underlying this application for non-payroll based inflationary components of OM&A and incorporates an additional measure of productivity.

As well, please refer to Horizon Utilities' analysis and contentions in Exhibit 1, Tab 2, Schedule 6, pages 28 to 31 regarding the input indexes and weightings used by the Board within its Price Cap determination.

Based on the above referenced analysis, Horizon Utilities contends that the 2.81% compound annual growth in revenue requirement sought in the Application across 2015 to 2019 is approximately 0.8% above a Price Cap index (incorporating the most recent Board approved Productivity and Stretch factors) determined with reference to: Horizon Utilities' expectations for industry specific inflation trends incorporated into its budget; an estimation of labour and non-labour components of its Capital Expenditures and OM&A.

Horizon Utilities also identifies in 1-EP-3 Attch 2 that the annual trend of revenue requirement growth per customer from 2017 to 2019 ranges from a low of 0.80% to a high of 2.42% and a dollar weighted average of 1.75%; which is in close approximation to the annual index referenced in the question for 2014.

On this basis, Horizon Utilities submits that its revenue requirement growth per customer across 2015 through 2019 is modestly above an index comprising inflation and Board approved productivity factors. The excess is due to the real cost growth drivers articulated in the Application.

Horizon Utilities expects that its revenue requirement per customer growth trends will be modestly above inflation (similar to this application) for several years following 2019 as a result of capital expenditure requirements and trends that incorporate real growth, particularly renewal-based growth, as articulated in Exhibit 2 and appendices; collateral implications to operating programs of supporting capital growth; and industry specific inflation trends that have historically exceeded the broader Canada and Ontario wide inflation factors used by the Board in its Price Cap index. Other potential drivers of real growth in revenue requirement beyond those above include new regulatory requirements or changes to provincial energy policy that result in necessary operating or capital expenditures.

The above notwithstanding, and excluding regulatory or provincial policy changes, Horizon Utilities expects that the revenue requirement per customer growth trend beyond 2019 will be much smoother than that provided in this Application under a Custom IR approach.

b) Please refer to the response in a). Again, the principal driver of revenue requirement per customer growth above inflation is the long-term distribution system renewal program of Horizon Utilities. This is not necessarily unique to Horizon Utilities as many other distributors are being confronted with similar requirements.

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1-Staff-9 Benefits from Efficiencies

References:

1. Exhibit 1 Tab 12
2. Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012
3. Exhibit 4 Tab 3 Schedule 4
4. Exhibit 1 Tab 2 Schedule 6

On page 2 of Reference 1, the Board stated that, as one of the outcomes of the Renewed Regulatory Framework, it expects continuous improvement in productivity and cost performance. At Reference 2 in Table 1-12 Horizon has identified $6,645,000 in productivity. Board staff developed the following table showing the year-over-year productivity.

	For IR
Year	**Productivity**
2011	75,000
2012	1,465,000
2013	1,990,000
2014	1,460,000
2015	1,185,000
2016	160,000
2017	60,000
2018	100,000
2019	150,000
Total	6,645,000

c. Please review and confirm the annual productivity gains.

d. Please explain the significant decrease in gains that start in 2016.

e. What proposals are in Horizon's application so that there will be productivity gains continuing past 2019?

Response:

a. No question provided.

b. No question provided.

c. Horizon Utilities reviewed and confirms the annual productivity gains as provided in the Board staff table above. Annual gains are represented as sustained gains in the application such that the cumulative sustained gain increases across all IR years as provided in Table 1-12.

d. As summarized in Exhibit 4, Tab 3, Schedule 4, Horizon Utilities implemented several programs targeted to increase productivity including: e-mobile electronic service orders; and the Planning and Scheduling initiative in 2012 and 2013. Continued expansion and refinement of these two initiatives are anticipated to result in incremental productivity savings in 2014 and 2015.

Horizon Utilities also plans to implement additional programs in 2014 and 2015 where productivity achievements will be measured, including the IFS ERP Phase 2 and Phase 3 projects and the Financial Planning Solution.

Each of the aforementioned projects are foundational and the productivity projects listed in Horizon Utilities' response to 1-Staff-15 are anticipated to result in sustained savings beyond the year of initial implementation. Additional information regarding the initiatives and the sustained benefits is included in Horizon Utilities' response to BOMA-8 a).

Horizon Utilities submits that it has advanced very ambitious plans and productivity expectations in this Application based on its commitment towards sustaining the operating expenditure reductions, productivity improvements and headcount reductions achieved in 2012, 2013, the 2014 Bridge Year and 2015 Test year without negatively impacting service levels.

e. Horizon Utilities has not submitted any specific proposals for incremental productivity gains beyond 2019. Horizon Utilities' productivity achievement forecast of $6,645,000 to 2019 is anticipated to be sustained beyond 2019.

1-Staff-10 Distribution System Plans – Performance Indicators and Measurement

References:

1. Exhibit 2 Appendix 2-4 Section 1.3 Performance Measurement for Continuous Improvement
2. Exhibit 2 Tab 8 Schedule 1 Service Quality and Reliability Indicators

Preamble:

Horizon appears to be planning to introduce new performance measures as soon as the Outage Management System ("OMS") is in place. The measures are: Customers Experiencing Multiple Interruptions ("CEMI"); and Customers Experiencing Long Duration Interruptions ("CELDI"). In Reference 4, Horizon Utilities states that it will reverse the negative trend in system performance and improve system reliability through three initiatives and programs.

a. Has Horizon investigated benchmarks for CEMI and CELDI? If so what are they and what is the source for the benchmarks?

b. Will Horizon be setting targets to strive to meet for CEMI and CELDI in the 2015 – 2019 CIR period? Please explain them, or why Horizon has not set targets.

c. Has Horizon set targets for Service Reliability Indicators ("SRI") for the 2015 – 2019 CIR period? If it has set targets, what are they? If it has not, please state the reason for not setting a stretch factor for it to achieve?

Response:

a) Horizon Utilities has not investigated benchmarks for CEMI and CELDI. As noted in Exhibit 2, Tab 6, Appendix 2-4, page 21, Horizon Utilities is participating in the OEB Reliability Data Working Group, (EB-2010-0249) which is currently reviewing the use of the CEMI and CELDI metrics. Horizon Utilities will continue to participate in this working group in an effort to develop appropriate benchmarks for these two metrics.

b) Horizon Utilities' ability to measure CEMI and CELDI is dependent upon the development and deployment of the Outage Management System ("OMS") which is scheduled to be fully deployed by 2015. Horizon Utilities plans to develop CEMI and CELDI targets for 2018 and 2019 based on baseline measurements developed in 2016 and 2017.

c) Horizon Utilities has not developed reliability targets for 2015 – 2019 as yet using the current methodology. The methodology for determining the SRI target, explained in

Exhibit 2, Tab 6, Appendix 2-4, page 20, is dependent on reliability data from comparator utilities. Such data is only published annually in September in the Ontario Energy Board's Yearbook of Electricity Distributors. The reliability target for 2015 will be set in Q4 of 2014, once the 2013 reliability data is published for the comparator utilities. The reliability metric utilizes a 5-year average for comparator utilities; the 2015 target will be set using 2009- 2013 reliability data. Subsequent years' targets will be developed in a similar manner.

1-Staff-11 Distribution System Plans – Level of Service Targets

References:

1. Exhibit 2 Appendix 2-4 Section 1.3 Performance Measurement for Continuous Improvement
2. Exhibit 2 Appendix 2-4 Appendix A Tables 1 & 2 – Material Capital Expenditures
3. Exhibit 2 Appendix 2-4 Section 2.1 Asset Management Process Overview
4. Exhibit 2 Tab 8 Schedule 1 Service Quality and Reliability Indicators

Preamble:

At Reference 1, Horizon addresses cost efficiency and effectiveness. Staff notes that the iPass metrics are traditional project management metrics that are determined after the selection of a project and that none of the metrics discussed relate to the 'value for money' of a particular project.

At Reference 1, page 18, Horizon states that "value is extracted by identifying opportunities for improvement and productivity enhancements and allows for measurement to support business case development."

On continuous improvement, at pages 29-30 of Reference 1, Horizon indicates that the Health Index Metric will be used in conjunction with system reliability metrics to plan, prioritize and develop capital investment programs.

With respect to results reporting, at Reference 3, Horizon indicates that it intends to provide standardized and regular of asset management results to monitor and assess the efficiency of implementation and effectiveness in achieving planning objectives.

a. Given Reference 4, please identify the projects outlined at Tables 1 & 2 of Appendix A that will have an impact on Horizon's levels of service. Where feasible, please quantify the anticipated improvement for each year of the plan, and please highlight, where applicable, the price/improvement trade-off.

b. Please indicate which relevant maintenance activities planned for each year of the Distribution System Plan ("DSP") will impact levels of service. Please provide a cost figure, and quantify anticipated improvement.

Please use the suggested format below as guidance:

Driver	Expenditure	Activities	Results & Timing	Corresponding Projects and/or Programs in Appendix A
e.g Poor reliability	Capital Expenditure Operational Expenditure	Increase maintenance Perform system modifications and additions Install real-time monitoring assets	Improved reliability by month/year X Improvements in customer satisfaction	

c. If enhanced efficiencies are forecast over the DSP horizon or beyond as a result of the activities undertaken above (i.e. question "a") please provide an estimate of the savings for each efficiency.

d. Please indicate how Horizon intends to report on the 34 DSP planned projects referenced at Tables 1 & 2 of Appendix A.

Response:

a. Horizon Utilities identifies the projects outlined in Tables 1 & 2 of Appendix A that will have an impact on Horizon Utilities' level of service. System Access and General Plant projects are excluded from the table as they do not have a direct impact on level of service. The System Renewal projects identified in the table below impact service quality and reliability; they involve the renewal of aging infrastructure which has a high risk of failure. The System Service projects identified in the table below impact service quality and reliability because they provide operational contingency which reduces the impact of outages on occurrence (e.g. distribution automation). System renewal and system service investments will result in a reduction in the volume of outages resulting from material and equipment failures and as such facilitate improved system reliability.

The impact on SAIDI of not completing each project was used as a proxy for the impact on Horizon Utilities' level of service. The SAIDI value was determined by identifying the

reliability impact for the worst case equipment failure scenario for the assets being renewed.

Horizon Utilities has quantified the potential impact to SAIDI for each System Renewal and System Service project where feasible in the table below. Horizon Utilities has not calculated the price/improvement trade-off. Horizon Utilities does not calculate this metric.

Table 1: Impact to SAIDI

		Impact on Horizon Utilities' Level of Service (SAIDI)				
Program	**Project Name**	**2015**	**2016**	**2017**	**2018**	**2019**
System Renewal						
4kV & 8kV Renewal						
	Aberdeen S/S					
	AB-F5 Renewal - Dundurn Street			0.137		
	AB-F2 & AB-F4 Renewal - Aberdeen East				0.137	
	AB-F2 Renewal - Bold Street					0.137
	Baldwin S/S					
	BD-F1 Renewal - Cross Street				0.029	
	BD-F1 Renewal - Alma Street					0.029
	BD-F2 Renewal					0.029
	Central S/S					
	CE-F4 Renewal - Hunter/Stinson Street	0.039				
	CE-F5 Renewal - Forest Ave.			0.242		
	CE-F10 Renewal - John Street South				0.242	
	CE-F4 Renewal - Freeman Place					0.242
	Grantham S/S					
	GR-F4 Renewal	0.005				
	GR-F4 Renewal Charleen Circle U/G	0.015				
	GR-F1 Renewal - South of Facer Street		0.010			
	GR-F2 Renewal - Roehampton XLPE		0.003			
	GR-F2 Renewal - West of Vine Avenue		0.010			
	GR-F2 Renewal - East of Vive Avenue			0.025		
	Highland S/S					
	H1-F3 Renewal - Governor's Road	0.002				
	H1-F3 Renewal U/G Bridlewood URD	0.006				
	H1-F1 Renewal - U/G Conversion to 2D14X		0.025			
	H1-F2 Renewal - Conversion to 2D7X			0.003		
	John S/S					
	JN-F1 Renewal				0.025	
	JN-F1 Renewal					0.025
	JN-F2 Renewal					0.036
	Strouds S/S					
	ST-F7 Renewal - Part 1	0.016				
	ST-F7 Renewal - Part 2		0.024			
	ST-F2 & ST-F6 Renewal			0.050		
	ST-F3 & ST-F4 Renewal				0.125	
	Taylor S/S					
	Vine S/S					
	VE-F5 Renewal	0.020				
	VE-F1 Renewal - Queenston Street		0.015			
	VE-F5 Renewal - West of Haynes Avenue		0.020			
	VE-F1 Renewal - North of Queenston Street			0.015		
	VE-F3 Renewal			0.073		
	VE-F4 Renewal - Welland and North Street			0.022		
	Welland S/S					
	Whitney S/S					
	WH-F3 Renewal	0.027				
	WH-F3 Renewal - Rear Lot	0.007				
	WH-F5 Renewal - Main Street West		0.102			
	WH-F6 - Ewen Street			0.008		
	WH-F6 - Whitney Ave.				0.008	
	York S/S					
	YK-F1 Renewal - York Road					0.003
	YK-F2 Renewal - Watson's Lane					0.014

Table 1: Impact to SAIDI Continued

		Impact on Horizon Utilities' Level of Service (SAIDI)				
Program	**Project Name**	**2015**	**2016**	**2017**	**2018**	**2019**
U/G (XLPE) Renewal						
	Ancaster/Flamborough/Dundas					
	Hamilton Mountain		0.037	0.037	0.037	0.037
	St. Catharines	0.017	0.017	0.017	0.017	0.017
	Stoney Creek			0.012	0.012	
Other Renewal						
	Pole Residual Replacements	N/A	N/A	N/A	N/A	N/A
	LDBS Renewal	N/A	N/A	N/A	N/A	N/A
	Proactive TX Replacements	N/A	N/A	N/A	N/A	N/A
	Reactive Renewal	N/A	N/A	N/A	N/A	N/A
	Gage TS Egress Feeder Renewal		N/A			
	Substation Infrastructure Renewal	0.009	0.009	0.009	0.009	0.009
	Rear Lot Conversion		0.004	0.008	0.006	
System Service						
	# 6 Wire Replacement	0.021				
	Distribution Automation	N/A				
	Waterdown 3rd Feeder	0.228				
	Caroline/George Redundancy	0.034				
	Duct Structure - Elgin TS to King St.			0.162		
	East 16th and Mohawk Security Project				0.034	
	St. Paul Street Conductor Upgrade				0.021	
	Grays Road					0.084
	Mohawk/Nebo T/S Upgrade					N/A

b. Horizon Utilities conducts underground, substation and overhead maintenance which includes inspections and corrective or preventative work which is detailed in Exhibit 4, Tab 3, Schedule 2, beginning on page 22. Maintenance and inspections programs are primarily cyclical in nature and are generally not influenced by capital investments. Maintenance and inspections are planned to a level of detail that is intended to maintain the distribution system in a safe and serviceable condition and maximize the useful life of distribution assets. Failure to conduct Horizon Utilities' maintenance and inspection programs would lead to the degradation of service levels and increase risks to public and worker safety. In addition, asset life expectancy would be shortened.

Maintenance and inspection initiatives are an integral part of Horizon Utilities' asset management activities. While they contribute to the continued safe and reliable operation of the distribution system, they are not the primary driver for improvements in levels of service. Improved levels of service will be achieved through Horizon Utilities' Capital Investment Plans as identified in Horizon Utilities' DSP.

c. Horizon Utilities expects some enhanced efficiencies (i.e., productivity) as a result of the System Renewal and System Service investments identified in the table above. The

achievement of enhanced efficiencies is not the primary driver of System Renewal and System Service projects. The primary benefit from System Renewal and System Service investments are that such investments will lead to a reduction in the volume of outages. The result will be a decrease in material and equipment failures leading to improved system reliability. Efficiencies will be realized due to a reduction in outages (e.g. fewer truck rolls) and decreased emergency and reactive maintenance. These cannot be quantified at this time due to the number of unknown variables such as: time of outage occurrence; system configuration; location of incident; type of asset; and whether concurrent work is being performed.

d. All electricity distributors are required to file information with the Board, including reporting on their capital plan, in the manner specified by the Board in the Reporting and Record Keeping Requirements ("RRR"). Horizon Utilities intends to follow that which the Board stipulates in the RRR.

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1-Staff-12 Distribution System Plans – Planning Processes

References:

1. Exhibit 2 Tab 6 Schedule 1
2. Exhibit 2 Appendix 2-4 Section 3.2 Capital Expenditure Planning Process Overview
3. Exhibit 2 Appendix 2-4 Appendix A Material Capital Projects
4. Exhibit 2/ Appendix 2-4/Appendix G/ Material Capital Project Templates

Preamble:

At Reference 1, Horizon states in part how the Asset Condition Assessment ("ACA") is used to set investment levels for programs:

"The level of investment proposed for each program is guided by the level of investment derived from the flagged-for-action (i.e. at high risk of failure) asset volumes identified by Kinectrics ACA. Table 2-45 (from Section 3.1.3 in the DSP) maps assets with either a poor Health Index distribution (at least 20% of assets are in either 'poor' or 'very poor' health) or a significant 20-year investment requirement (greater than $5,000,000 over five years) against Horizon Utilities' capital investment programs."

At Reference 2, Horizon outlines its prioritization methodology, and identifies 5 categories used in the prioritization process which it indicates was elaborated in conjunction with Navigant Consulting, Inc. as part of Horizon's 2009 AM model improvement. That process leads to the following project and system capital classification:

Total Score	Description
5	Mandatory project – Deferral of project will result in: - Negative impact on customer - Inability to address an imminent safety concern
4	Required project – Deferral of project not recommended and will impact the schedule for multi-year programs.
3	Required project – Deferral of project not recommended. Project required to proceed and will displace projects in future years.
2	Desired project – Deferral of project can be accommodated and may not impact or displace projects in future years.
1	Optional project – Deferral of project does not have material impact on system operations or asset health.

Table 40 - Score Interpretation Guide

Horizon goes on to outline the prioritization of mandatory General Plant capital noting that it is similar to System capital and similarly based on the objectives of: safety; security; customer impact; regulatory/statutory compliance and environmental risk.

At Reference 3, it appears that Horizon uses different investment priority scales, one for distribution assets consistent with Table 40 above, and another for General Plant (e.g. 2015 General Plant projects are all 'High' priority while 2015 Renewal Projects labelled as "Required" or "Mandatory").

a. Please confirm that in accordance with the statement at Reference 1, Horizon's investment strategy in the distribution system is guided by Kinectrics' ACA.

b. On prioritizing system and non-system capital:

i. Please confirm that the prioritization of discretionary and non-discretionary investments in distribution assets follow Kinectrics' ACA method. If not, please explain.
ii. Does the prioritization of discretionary and non-discretionary investments in non-distribution assets follow the Table 40 method? If not, please explain.

c. Please explain / reconcile the investment priority scales at Appendix G.

d. Please file Horizon's prioritization strategy for both non-discretionary and discretionary projects (system and non-system).

e. Please amend tables 1 & 2 at Appendix A accordingly providing ranking for the 34 projects.

f. All of the 2015 General Plant are high priority projects. Please outline pacing considerations related to these future investments.

g. Please discuss scenarios that would affect Horizon's prioritization and asset optimization strategy, for instance a more resource constrained environment, or a varying load growth environment (higher/lower than forecast). Please specify conditions under which the current DSP would be modified and which current projects would be deferred and/or abandoned? Please define qualitatively and quantitatively the impact of such investment deferrals along outcome lines.

Response:

a. Horizon Utilities confirms that its investment strategy in the distribution system is guided by the Kinectrics' ACA.

b. (i) Prioritization of investments in distribution assets is not based solely on Kinectrics' ACA methodology. The results of Kinectrics' ACA are one of the key inputs into the prioritization of investments. System planning and operational performance planning, as described in section 2.1.2 of the DSP, are also key inputs into the prioritization of investments. The prioritization process components are further detailed in Exhibit 2, Tab

6, Appendix 2-4, Section 3.2.3. Horizon Utilities has not proposed any discretionary investments in distribution assets for the 2015 to 2019 Test Years.

b. ii) The prioritization of discretionary and non-discretionary investments in non-distribution assets does not follow the Table 40 method. System Capital prioritization criteria are less relevant to General Plant Capital prioritization (e.g. customer demand, road relocations) and there is no formulaic scoring mechanism for the General Plant capital. The prioritization methodology for General Plant investments is provided on pages 210-211 of Appendix 2-4 of Exhibit 2, Tab 6.

c. The prioritization scale as identified in Table 40 is used for investments in distribution assets (System Access, System Renewal, and System Service). A prioritization scale of high, medium and low is used for investments in non-distribution assets ("General Plant"). A mapping of the prioritization scale for General Plant, as identified in Appendix G, to the prioritization scale identified in Table 40 is provided in the table below.

Table 1: Prioritization Scale

Distribution Score	General Plant Score	Description
5	High	Mandatory project – Deferral of project will result in: - Negative impact on customer - Inability to address an imminent safety concern
4		Required project – Deferral of project not recommended and will impact the schedule for multi-year programs.
3		Required project – Deferral of project not recommended. Project required to proceed and will displace projects in future years.
2	Medium	Desired project – Deferral of project can be accommodated and may not impact or displace projects in future years.
1	Low	Optional project – Deferral of project does not have material impact on system operations or asset health.

d. Horizon Utilities' prioritization strategy for all projects is set out in Exhibit 2, Tab 6, Appendix 2-4, page 44, and pages 206 to 212.

e. Amended Tables 1 and 2 of Appendix A are provided in the excel file "1-Staff-12e_Attch_Revised Appendix A". The prioritization identified in the amended tables is based on the revised table provided in response to 1-Staff-12c.

f. The pacing considerations for the 2015 General Plant investments are provided below:

- GP-1: Annual Corporate Computer Replacement

  Horizon Utilities replaces it computers on a 3-year cycle. Approximately one third of Horizon Utilities' PCs are replaced annually which allows for a stable annual expenditure over the 2015 to 2019 Test Years. The justification for maintaining a 3-year replacement cycle is provided on page 36, Appendix A of Exhibit 2, Tab 6, Appendix 2-4.

- GP-2: Industrial Financial Systems ("IFS") "Enterprise Resource Planning ("ERP") Upgrade (2015)

  This project commenced in 2013 and has been allocated over a three-year period. The investment in the 2015 Test Year is required to complete the third and final phase of a multi-year investment to upgrade Horizon Utilities' IFS ERP system. The productivity savings identified in Exhibit 4, Tab 3, Schedule 4, are dependent upon the completion of this phase. The IFS ERP upgrade and the rationale for the three-year investment is discussed in further detail on pages 67-69 of Exhibit 2, Tab 6, Schedule 1.

- GP-3: Storage Area Network ("SAN') Expansion

  This project is required to support Horizon Utilities' annual data growth rate which, based on historical experience, exceeds 30% per annum. SAN expansion investment is paced to match the growth in data required to support Horizon Utilities IT infrastructure and occurs every other year. The data growth rate is expected to increase during the 2015-2019 Test Years as new applications such as GIS and OMS are implemented. Failure to provide adequate network storage and capacity creates a risk of failure of critical IT systems.

- GP-4: Enterprise Phone System Upgrade

This planned lifecycle replacement of the Horizon Utilities' phone system is required to ensure critical call centre software and the associated supporting hardware are at vendor supported versions. Horizon Utilities' phone system is a critical infrastructure component that is the primary method of communication with customers and, as such, needs to be at vendor supported levels to maintain optimum customer service levels. This project cannot be delayed past 2015 or implemented over multiple years. The vendor will cease to support the current phone hardware system in 2016. Operating the phone system without vendor support can impact phone system functionality and increases the risk of phone service interruptions due to software problems. Failure of the phone system directly impacts Horizon Utilities' Customer Service ability as communication by phone remains the primary communication channel for customers to contact Horizon Utilities.

- GP-6: Building Renovations – John and Hughson Street

Horizon Utilities has deferred investments in buildings and infrastructure systems for several years. In Horizon Utilities' last rate application EB-2010-0131, building renovations were deferred from 2008 to 2010 due to deferrals of key business requirements to address the revenue volatility and revenue risk experienced by the utility over this period. Capital expenditures for 2011 were deferred again to mitigate the non-discretionary increase in System Access obligations in 2011. Horizon Utilities developed a long term renovation plan in 2012 to pace necessary building and infrastructure systems renewal projects, including those deferred from 2008-2011, over an eight year period. Investments in buildings and infrastructure systems could not be deferred past 2012 due to the critical need to replace assets which have reached end-of-life and to address operational deficiencies, building accessibility, the removal of hazardous materials, security, and air quality. Horizon Utilities has paced investments in building and infrastructure systems from 2012 to 2019. Further details on these investments are provided in Exhibit 2, Tab 6, Appendix 2-4, pages 254 to 261.

- GP-8: Building Security Replacement

This investment is required to replace an end-of-life system to address security concerns and has been paced over a three-year period from 2014 to 2016. This project is discussed in further detail in Exhibit 2, Tab 6, Schedule 1, page 57.

- GP-9 and GP-11: John Street Roof Replacement and Window Replacements

  Horizon Utilities conducted a third party asset condition assessment on both the John Street roof (Roof Inspection Review filed as Appendix N in the DSP) and windows (Horizon Window Study Report filed as Appendix M in the DSP) which identified an immediate need to replace these assets.

  The roof has surpassed end of life and despite annual maintenance, leaks have caused damage to the floors below. Previous repairs to the roof have degraded. The roof replacement must be completed in one year due to the nature of the project. The condition of the windows is discussed in further detail in Exhibit 2, Tab 6, Schedule 1, page 42.

  Horizon Utilities has apportioned the investment required to replace the John Street windows over a three year period from 2015 to 2017. The windows at the John Street building, which have reached end-of-life, are in poor condition. The windows are no longer weather resistant or energy efficient and allow cold drafts to enter the building in the winter. Heat convection during the summer months leads to air conditioning inefficiency and additional stress on HVAC systems. The windows collect frost on the inside in the winter which melts and damages interior walls and carpeting. The condition of the windows is discussed in further detail in Exhibit 2, Tab 6, Schedule 1, page 42.

  Deferral of these investments past the dates proposed by Horizon Utilities will result in increased maintenance and repair costs.

- GP-10: Nebo Road Backup Generator

  The Nebo Road Service Centre is the only remaining main building without an adequate backup generator. Horizon Utilities has deferred this investment through the use of portable generators when required. The use of portable generators is no longer acceptable due to their non-conformance with safety regulations. Horizon Utilities has experienced outages to the Nebo Service Centre during large scale outages, and the dispatching of emergency crews and contractors was hampered. The installation of the back-up generator is discussed in further detail in Exhibit 2, Tab 6, Schedule 1, page 58.

- GP-12: Vehicle Replacement

Horizon Utilities vehicle replacement investment is based upon a long-term multi-year replacement plan. Vehicles are maintained and replaced to allow for a stable annual expenditure over the 2015 to 2019 Test Years.

- GP-13: Tools, Shop and Garage Equipment

Horizon Utilities' Tools, Shop and Garage Equipment is a multi-year project with stable annual expenditures.

g. Some scenarios or events that could affect Horizon Utilities' prioritization and asset optimization strategy are identified below. In the scenarios presented, the impacts on the Board's four RRFE Outcomes are self-explanatory.

- System Access investments

Expenditures related to customer connection and road relocation project costs are forecasted based on a number of factors which include: historical levels of activity and investment; known projects; a review of economic factors; and, inflationary adjustments for labour and materials. The initiation and timing of these projects is outside of Horizon Utilities' control and therefore the timing and value of investment required by Horizon Utilities is subject to change. The budget for these types of capital expenditures for 2015 to 2019 is based on known projects and historical trend analysis. Regulatory changes may require capital investment not currently included in the 2015 to 2019 revenue requirement.

- Extraordinary events

Extraordinary weather events, similar to the July 2013 windstorm, may result in a requirement for increased capital investment.

- Major building component failures

Failure of a major building component (e.g. major structural failure) may result in a requirement for increased capital investment for that building.

Horizon Utilities would need to evaluate and analyze the impact of a particular scenario prior to suggesting any modifications to its current DSP. Furthermore, the investments which Horizon Utilities is proposing in its DSP are necessary irrespective of changes in environment such as a varying load growth. Horizon Utilities serves two older, built out

communities with corresponding low customer growth rates and aging infrastructure as identified in Exhibit 1, Tab 2, Schedule 6. Renewal of Horizon Utilities' distribution system is imperative to mitigate system health degradation and related reliability risks. Horizon Utilities' buildings and infrastructure systems are at or nearing end of life and renewal is necessary to address poor equipment performance; increased risk of system failure; poor work environments for employees; and increased health and safety risks. A varying load growth environment does not change Horizon Utilities' investment profile or prioritization. Further deferrals may result in damage or loss that would increase capital costs particularly as it relates to basic building infrastructure requirements and security.

1-Staff-13 Distribution System Plans – Planning

References:

1. **Exhibit 2 Tab 6 Schedule 1 Table 2-45**
2. **Exhibit 2 Appendix 2-4 Appendix A Material Capital Projects**
3. **Exhibit 2 Appendix 2-4 Section 3.1 Capital Plan Expenditure**

Preamble:

Table 2-45 at Reference 1 presents summary investment information for certain assets that have a Health Index of 'very poor' or 'poor'. All 15 asset categories in the Kinectrics' ACA are represented.

Table 2-45 – Health Index Distribution and Capital Investment Programs by Asset Group

Asset Group	Kinectrics Recommended 5 Year Replacement Value	Percentage of Assets with 'Poor' or 'Very Poor' Health Index	4kV and 8kV Renewal Program	XLPE Cable Renewal Program	Pole Residual Program	Proactive Transformer Replacement	LBDS Maintenance	Reactive Replacement
Underground Cables (primary XLPE)	$ 54,684,156	29%		X				X
Wood Poles	$ 24,443,926	11%	X		X			
Underground Cables (secondary DB)	$ 17,265,561	42%		X				X
Underground Cables (primary PILC)	$ 14,472,205	1%						X
Overhead Conductors (service)	$ 12,565,410	11%	X					X
Underground Cables (service DB)	$ 12,248,968	63%		X				X
Pole Mounted Transformers	$ 11,840,422	6%	X			X		X
Overhead Conductors (secondary)	$ 11,818,950	9%	X					X
Vault Transformers	$ 9,643,423	49%		X				X
Overhead Conductors (primary)	$ 9,049,700	5%	X					
Substation Switchgear	$ 5,250,000	32%	X					
Underground Cables (secondary ID)	$ 2,555,198	42%		X				X
Substation Circuit Breakers	$ 1,665,000	23%	X					
Overhead Line Switches	$ 1,653,832	20%					X	
Submersible LBD Switches	$ 308,960	46%						

With respect to investment drivers, at Reference 2, Horizon states in part that:

"The increased investment is driven by the high volume of distribution assets with a Health Index of 'very poor' or 'poor' as identified in Kinectrics' ACA and confirmed by KPMG."

At Reference 3, Horizon notes that "the timing of replacements, as identified by Kinectrics, represent the optimum timing for asset renewal". Figure 77 shows the following investment profile:

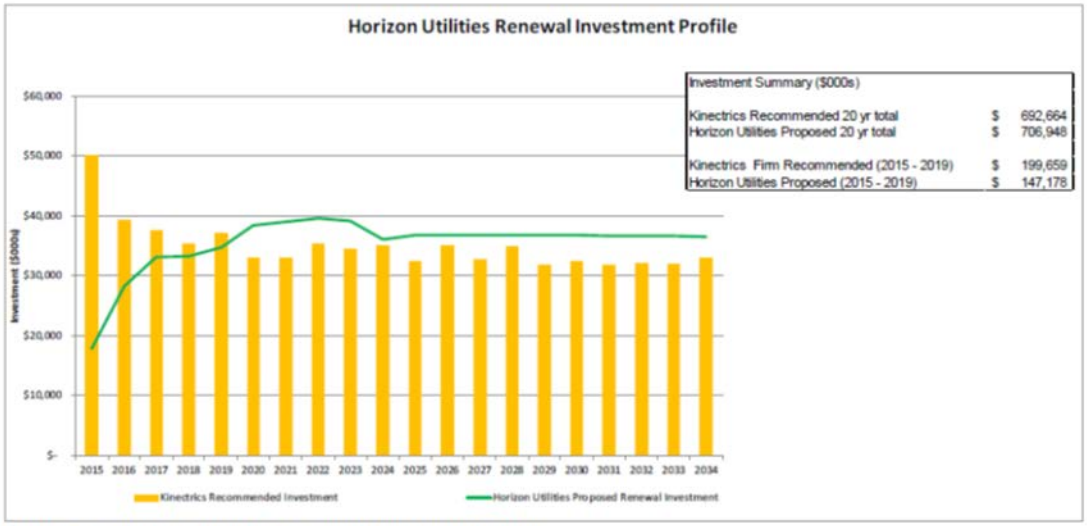

Figure 77 - Horizon Utilities Renewal Investment Profile

a. Staff notes that while Kinectrics' ACA distinguishes between distribution assets that have either a 'very poor' or 'poor' Health Index, Horizon's DSP for the purposes of investments lumps the two together. Please explain the reason for amalgamating these two groups. Would these 2 groups be ranked equally on the prioritization scale?

b. As a general practice, does Horizon perform life-cycle cost analyses for planning purposes?

c. Does Horizon perform any sensitivity analyses? For example, does Horizon assess increased/decreased levels of maintenance arising from its investments?

d. Figure 77 shows that Horizon is only partially following the Kinectrics ACA recommendations.

i. Please indicate what required system investments identified by Kinectrics were abandoned and/or delayed to a later stage.
ii. Please state the priority levels these projects scored.
iii. Please explain any remaining Horizon deviations from Kinectrics' recommendations.

Response:

a.

Horizon Utilities amalgamated the 'poor' and 'very poor' Heath Index categories because both categories represent an elevated risk of failure. The amalgamation of these two categories also facilitates long-term planning. Horizon Utilities employs a twenty-year planning horizon for forecasting renewal investment requirements.

Assets with a Health Index of 'poor' will degrade to 'very poor' within this planning timeframe and as such are amalgamated for planning purposes. These two categories are not ranked equally on the prioritization scale.

b.

Horizon Utilities performs life-cycle cost analyses for planning purposes as a general practice. Horizon Utilities' asset lifecycle optimization activities are described in Exhibit 2, Tab 6, Appendix 2-4, Section 2.3.1.

c.

Horizon Utilities performs sensitivity analyses and has provided examples as follows:

- Sensitivity analysis on capital investment levels and the impact on asset health which was performed for six asset categories: PILC primary cable, XLPE primary cable, vault transformers, wood poles, overhead primary conductor and overhead transformers. As an example, the sensitivity analysis for investment in the renewal of underground XLPE primary cable is provided on page 246 in the DSP filed as Appendix 2-4 of Exhibit 2.
- Assessment of the impact of near-term capital projects on long-term capital investments
    - Horizon Utilities chose to convert the 4kV and 8kV distribution system to a higher voltage to avoid the cost of the investment in the renewal of the substations. The proposed investments in the 4kV and 8kV Renewal Program will allow nine substations to be decommissioned between 2015 and 2019. The decommissioning of these nine substations will result in the avoided capital substation renewal investment of $22,500,000.
    - Horizon Utilities assessed the impact of migrating the ERP environment to a cloud-based managed service from IFS and eliminating the need to purchase and implement new in-house servers. The migration of the ERP environment to a cloud-based managed service reduced capital expenditures by approximately $450,000 as identified on page 68 of Exhibit 2, Tab 6, Schedule 1.
- Assessment of increased/decreased levels of maintenance arising from its investments
    - Horizon Utilities calculated the decreased level of maintenance arising from its proposed 4kV and 8kV Renewal Program investment. The decommissioning of

the nine substations as a result of this investment will provide operational cost savings of $335,000 over the rate plan term as identified on page 7 of Section 1.1.2 in the DSP filed as Appendix 2-4 of Exhibit 2.

- Assessed Horizon Utilities' vehicle replacement and maintenance criteria which resulted in the extension of the replacement age criteria by one year starting in 2012 as identified in the Fleet Replacement Plan attached as Appendix O of the DSP;

d.i.

Horizon Utilities has not abandoned any required system investments identified by the Kinectrics' ACA. Horizon Utilities implements asset renewal through the execution of Capital Investment Programs. The Kinectrics' ACA provided the Health Index and level of investment required for each asset category. Kinectrics did not identify the Capital Investment Programs required to renew the assets flagged-for-action. The Capital Investment Programs created by Horizon Utilities and identified in Section 3.1.1 of Exhibit 2, Tab 6, Appendix 2-4, are designed to address: multiple asset categories having poor Health Index distributions; asset categories having a high investment requirement; and areas with operational issues that have either caused, or have a high risk of causing significant customer impact. The mapping of Horizon Utilities' Capital Investment Programs to the asset categories in poor health is provided in Exhibit 2, Tab 6, Appendix 2-4, Table 31 and, for ease of reference, is reproduced below.

Table 31 (as provided in Exhibit 2, Tab 6, Appendix 2-4)

Asset Group	Kinectrics Recommended 5 Year Replacement Value	Percentage of Assets with 'Poor' or 'Very Poor' Health Index	4kV and 8kV Renewal Program	XLPE Cable Renewal Program	Pole Residual Program	Proactive Transformer Replacement	LBDS Maintenance	Reactive Replacement
Underground Cables (primary XLPE)	$ 54,684,156	29%		X				X
Wood Poles	$ 24,443,926	11%	X		X			
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Overhead Line Switches	$ 1,653,832	20%					X	
Submersible LBD Switches	$ 308,960	46%						

Horizon Utilities is planning to proceed with systems investments in all of the asset categories proposed by Kinectrics; however investments will be paced over a twenty-year horizon. Horizon Utilities' assessment of the investment level and profile recommended by Kinectrics determined that this investment profile would result in an unfair rate impact on the customer base within a short period of time, as identified in Exhibit 2, Tab 6, Schedule 1. Additionally, a sharp increase in investment to this level without supporting customer rates would not be affordable for Horizon Utilities. As such, Horizon Utilities is proposing to increase annual renewal investment at a graduated rate which results in a lower capital investment across all asset categories in 2015-2019 than that recommended by Kinectrics. The asset categories affected the most are those within the XLPE Cable Renewal Program and are as follows:

- Underground Cables (primary XLPE);
- Underground Cables (secondary Direct Buried);
- Underground Cables (service Direct Buried);
- Vault transformers; and
- Underground Cables (secondary In Duct).

d.ii.

Horizon Utilties did not abandon any projects that were identified by Kinectrics as stated in its response to part d.i) above. Horizon Utilities has paced its investment based on the level of affordability for it and for its customers as provided in Exhibit 2, Tab 6, Schedule 1. Given the pacing of the investments, Horizon Utilities did not develop, design, and prioritize projects within the Capital Investment Programs to the investment level identified in the Kinectrics' ACA. The prioritization score for proposed renewal projects planned for the 2015 to 2019 rate plan is either a three or four. A project with a prioritization score of a three or four is a required project which cannot be deferred; and will either impact the schedule for multi-year projects (prioritization score of four) or will displace projects in future years (prioritization score of three). It is Horizon Utilities' assessment that future projects would receive a similar prioritization score.

d.iii.

Please see Horizon Utilities' response to d.i) above.

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1-Staff-14 Benchmarking

Reference:

1. Exhibit 2/ Appendix 2-4/Appendix G/ Material Capital Project Templates

Preamble:

Horizon has provided for material project internal benchmarking, labelled as "Comparative Information from Equivalent Projects" in the summary sheets at Appendix G.

a. Is benchmarking either against comparable industry peers or with respect to best practices part of Horizon's capital and OM&A expenditure planning? If so, please specify.

b. If Benchmarking is not part of expenditure planning please explain why.

Response:

a) Horizon Utilities does not have a practice of benchmarking against comparable industry peers as part of its capital and OM&A expenditure planning, but it does have a practice of benchmarking with respect to best practices as part of its capital and OM&A expenditure planning.

Horizon Utilities commenced a multi-year initiative in 2011 to determine and implement best practices for the operation of an integrated and centralized work schedule for capital and maintenance programs. The resulting new processes have increased the efficient and effective use of: labour resources; vehicles; tools; and materials. Further details on this initiative are provided on page 27 in Exhibit 4, Tab 2, Schedule 2.

Horizon Utilities participated in a Review of Asset Management Practices in the Ontario Electricity Distribution Sector ("Review") conducted by KPMG and published March 10th, 2009. Horizon Utilities used the Review to determine best practices for Asset Management Planning.

Horizon Utilities engaged Navigant Consulting Incorporated ("NCI") to review four specific areas of its Utility Operations' business unit. The report "Asset Management Study" was completed October 29, 2008 and is filed as attachment 1-Staff-14_a_Attch_Navigant Consulting Asset Management Strategy - Final Oct 29 2008. The

four areas identified as presenting opportunities for immediate improvement based on Asset Management concepts were as follows:

- Proactive transformer replacement;
- Proactive pole replacement;
- Maintenance practices; and
- Equipment replacement practices.

Horizon Utilities benchmarked fleet replacement criteria against other LDCs in 2014 to determine if fleet replacement guidelines were aligned with utility best practices. KPMG performed a Comparison of Kinectrics' Flagged-for-Action Plan against Accepted Asset Life Standards as identified in Section 5.3.2 of the KPMG Assurance Review dated January 23, 2014 and filed as Appendix C of the DSP in Exhibit 2. The comparison was used to validate the failure curves used to calculate the Flagged-for-Action volumes identified in the Kinectrics' 2013 Asset Condition Assessment ("ACA") filed as Appendix B of the DSP in Exhibit 2. These Flagged-for –Action volumes form the basis of the level of investment identified in the Kinectrics' ACA.

b) Horizon Utilities does not have a practice of benchmarking against comparable industry peers as part of its capital and OM&A expenditure planning. The challenge of benchmarking based on comparable industry peers is the determination of what criteria is acceptable for establishing the peers and for what purposes the peers will be used, in this case for capital and OM&A expenditure planning. Among Ontario's 73 LDCs, there are great differences in the profiles of the LDCs. Horizon Utilities has outlined some of its "unique features" in Exhibit 1, Tab 2, Schedule 4, all of which have an effect on determining comparable industry peers. In Ontario, there are a large number of generally suburban LDCs that may reasonably be considered peers for capital and OM&A expenditure benchmarking purposes, but not a similar number of peers for large, high density urban and industrial utilities. In this regard, there are too few LDCs with similar characteristics to Horizon Utilities in order to establish a peer group.

An alternative approach would be to utilize the peer group to which the Board assigned Horizon Utilities in 3rd Generation IRM (EB-2007-0673) and the cohort to which the Board assigned Horizon Utilities in 4th Generation IRM or RRFE (EB-2010-0379). Neither

of these, however, would be valuable as a peer group for the purposes of capital and OM&A expenditure planning or possibly acceptable to the Board or intervenors.

With regard to the lack of suitable benchmarking for 3rd Generation IRM serving as a peer grouping, Horizon Utilities was assigned to the "Large City South High Undergrounding" peer group. While this is a Board established grouping, the challenge of this grouping for the current purpose is that there were only five (5) LDCs in the group, which is very small as a comparator group compared to the total number of LDCs, and three (3) of the five were relatively new suburban communities when compared to Horizon Utilities' older and more urban and industrial character. Moreover, the group's main criterion of of degree of undergrounding meant that Horizon Utilities had been grouped with utilities with largely newer underground residential characteristics compared to Horizon Utilities older underground in an urban core, heavy industrial area and older residential subdivisions.

The implications of this difference for capital and OM&A expenditure planning are evident in how Horizon Utilities differed from the other four LDCs on "Growth / Output Index" and line density (customers per kilometre of line). Horizon Utlities had a markedly lower "Growth / Output Index" and a markedly higher line density than all four of the other LDCs, which is evidence of its distinctiveness from the group as an older urban, high density, low growth community compared to a newer suburban high growth community.[1] On this basis, the "Large City Southern High Undergrounding" peer group is not a valuable comparator group for capital and OM&A expenditure planning and, in Horizon Utilities' judgement, would not be acceptable as a peer grouping for the Board or Intervenors.

With regard to the lack of suitable benchmarking for RRFE (4th Generation IRM) serving as a peer grouping, Horizon Utilities has been assigned to the Group II cohort. While this is a Board established grouping, it is a cohort established specifically for performance benchmarking purposes. This grouping is not a grouping of comparable industry peers based on utilities characteristics required for the purposes of capital and OM&A expenditure planning. Where 3rd Generation IRM had established peer groups as a

[1] "Getting it Right: Submission of the Coalition for an Effective Incentive Rate Mechanism to the OEB's Consultation on 3rd Generation IRM," December 15, 2008 (EB-2007-0673)

check on the econometric benchmarking, 4th generation IRM (or RRFE) had no comparable peer grouping element and was based solely on econometric benchmarking. The result is that the factors used in the RRFE benchmarking are broader than just capital and OM&A, and not specific to utility groupings like undergrounding and line density were in 3rd Generation IRM.

The result is that the strictly econometric benchmarking of 4th Generation creates cohorts of LDCs unrelated to peers specifically relevant to capital and OM&A expenditure planning. Of the 15 LDCs in the Cohort II group, Horizon Utilities is accompanied by many very small LDCs, such as Cooperative Hydro Embrun, some small and northern LDCs, such as Espanola Regional Hydro Distribution, and some are very rural LDCs, such as Haldimand County Hydro Inc. As a whole, the Cohort II group is too dissimilar in terms of utility characteristics to be valuable as comparable industry peers for Horizon Utilities' capital and OM&A expenditure planning. Moreover, the dissimilarities of the Cohort II LDCs from Horizon Utilities' capital and OM&A expenditure characteristics, in Horizon Utilities' judgment, would not make it an acceptable peer grouping for the Board or Intervenors.

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CONTENTS

NAVIGANT CONSULTING

LIST OF TABLES

NAVIGANT CONSULTING

LIST OF FIGURES

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BACKGROUND AND APPROACH

This report is the culmination of Navigant Consulting Incorporated's (NCI) "Quick Hits" review of four specific areas of Horizon Utilities Corporation's (Horizon) Utility Operations business unit. These areas were identified as presenting opportunities for immediate improvement based on Asset Management concepts.

NCI worked with Horizon's AM Team to develop business cases for the first two of the four AM related activities (i.e., the "Quick Hits") and conducted a high-level review of the other two – all of which relate to activities under consideration for Horizon's 2009 Budget Review, i.e.:

1. Proactive transformer replacement;
2. Proactive pole replacement;
3. Maintenance practices; and
4. Equipment replacement practices.

The distribution of tasks undertaken for the preparation of this document are outlined in Appendix A – Horizon, Initiatives for 2009 Budget. Per this task distribution, Navigant Consulting:

1. Reviewed Horizon's existing data, analysis and draft business cases as applicable, including 'methods' and 'procedures' developed by Horizon;
2. Conducted stakeholder interviews, including meetings with technical personnel, field operations staff and management, to discuss and record current practices;
3. Performed a leading practices review, including a comparison of Horizon's current practices against the leading practices of industry peers; and
4. Developed business cases/rationales, with documented results and recommendations for each area as requested.

We developed the business cases that support our recommendations through a combination of qualitative judgment (based on our experience with leading industry practices) and quantitative analyses, where applicable, based on data provided by Horizon.

Project Timeframe

NCI conducted this work over a five week timeframe commencing the week of August 18th, 2008. NCI conducted meetings with various members of Horizon's Asset Management Team and key stakeholders at Horizon's offices.

Horizon Utilities Team/Resources

Navigant Consulting maintained an ongoing dialogue with members of Horizon's Asset Management Team (principally Sheikh Nahyaan and Hani Taki) who provided key data and analysis, and coordinated meetings with Horizon staff throughout the engagement.

NAVIGANT CONSULTING

KEY FINDINGS AND RECOMMENDATIONS

Proactive Transformer Replacement Review

Horizon's proactive transformer replacement guidelines are representative of leading industry practices with regard to methods employed to evaluate transformer health and risk.

Horizon's replacement criteria target transformers deemed to be at high risk of failure; particularly those that impact critical customers or densely populated areas. Although initial results of the replacement ranking analysis show a weak correlation with actual replacements, this approach is based on sound asset management principles – principles that can (and should) be applied to other equipment categories as well.

While condition assessment methods, such as those employed to rank transformers, are critical to effective asset management, the proactive replacement of in-service distribution line transformers may not *always* be cost-effective, particularly when viewed in the context of overall reliability performance. Reliability statistics collected for the past three years alone do not justify proactive replacement, nor does the condition assessment data, the latter of which shows a weak correlation of devices listed as 'proactive replacements' versus devices actually replaced by field personnel (i.e., those replaced likely due to actual defects). The expense associated with re-certification also may not be justified for transformers with in-service lives of 5 years or more, as these devices generally exhibit relatively minimal near-term deterioration.

Accordingly, we recommend that Horizon adopt the following practices:

1. Continue asset condition and performance assessment practices to support proposed Asset Management Framework Implementation initiatives.
2. Modify replacement criteria to focus only on those transformers that exhibit visual signs of deterioration (e.g., leaking oil), one-of-a-kind devices that are difficult to replace or costly to maintain from an inventory standpoint, those located in dwellings or buildings where inspection or test results reveal a much higher than average likelihood of failure, or where load tests indicate loadings above continuous or normal ratings (this is generally viewed as a "run-to-failure" approach).
3. Continue to refine the process for evaluating the "health" and "risk" of distribution transformers. Employ similar asset condition and health evaluation methods for other equipment types, including devices that have a significant impact on reliability performance as measured by SAIFI and SAIDI.

4. Incorporate transformer load management in the evaluation process; implement methods to identify and replace transformers with low utilization, particularly larger devices.
5. Standardize and formalize the processes for recording the reasons for transformer replacements, particularly those that have failed, using clear and consistent descriptors or codes (this is also part of Horizon's Asset Management Framework Implementation).
6. Review current re-certification practices, including extension of the transformer age from 5 to 10 years (or more) for re-certification.
7. Apply field inspection methods, such as infra-red scans, to identify hot-spots or physical deterioration, and develop replacement criteria for transformers using inspection results (this approach and the replacement criteria can be applied to other defective or deteriorated distribution equipment as well).
8. Consider applying more rigorous criterion for inspecting and replacing transformers located within the customer premise, such as basements or transformer rooms. Options include more frequent inspections, replacement of devices that have experienced overloads or are currently overloaded and replacement of devices that are one-of-a-kind, or exhibit moderate deterioration.

Proactive Pole Replacement Review

NCI's findings are based on interviews with Horizon engineering, planning, construction management and support staff and review of the 2007 *Distribution System Capital & Maintenance Programs* document, and pole inspection records. We also reviewed Horizon's request for quotation (RFQ) for pole inspections for 2008, vendor responses and the industry publications provided. Our recommendations are also based on analytical studies and an assessment of data provided by Horizon, the results of a preliminary economic analyses, and a review of common industry practices. Recommendations based on economic studies should be considered preliminary and subject to revision following the completion of supplemental studies completed by Horizon and the results of the ongoing Asset Management Framework Implementation.

1. The methods and practices Horizon has historically employed to perform pole inspections are consistent with industry guidelines and current utility practices. These practices include inspection and non-destructive testing and are consistent with those

outlined in the American Wood Preservers' Association Standard (M13-07) and NCI's experience.[1]

2. The use of specialized testing methods such as the use of Resistograph and mechanical test equipment to predict condition and strength, is generally consistent with recommended practices, as they share a common objective of assessing pole condition and mechanical strength; however, the testing methods outlined above have not been universally applied by utilities. Further, the effectiveness of these methods may not be consistent with results obtained from the traditional approaches Horizon and other utilities have applied. Also, there may not be sufficient information at this time to ensure these newer approaches offer the most cost-effective option(s) for Horizon.
3. The "General" section of Horizon's RFQ for pole inspections for 2008 appears to mandate the use of the Resistograph inspection method. For the reasons cited above, NCI recommends that Horizon modify its RFQ to allow bidders to offer or suggest other approaches for pole inspections and non-destructive testing, which could include Resistograph and mechanical strength tests as an option by qualified vendors. Such modifications to the RFQ would be consistent with methods previously employed by Pole Care, the vendor that Horizon has employed for the past several years to perform pole inspections. Based on recent discussion with Horizon staff and a review of the documents provided, NCI offers its opinion that Pole Care's prior response to Horizon's RFQ is consistent with current utility practices.

Horizon's Proactive Pole Replacement guidelines are generally consistent with industry practices with regard to the replacement of poles deemed to be at high risk of failure. However, many utilities employ inspection methods that include remediation with pole treatment as an alternative to end-of-life replacement. Utilities recognize that replacement may not always be cost-effective when compared to pole treatment options, designed to extend the life of poles with adequate shell strength. Further, reliability statistics collected for the past three years alone do not justify an acceleration of pole replacements, a common finding among most utilities.

Accordingly, we recommend that Horizon adopt the following practices:

1. Assess the applicability and potential advantages of alternate approaches for pole inspections and replacements. The assessment should include an economic assessment of inspection techniques and mitigation options listed below, versus current inspection

[1] NCI notes that Horizon has not previously applied pole treatment methods. Accordingly, NCI anticipates that there will be a gradual transition to treatment applications as Horizon personnel gain experience and acceptance of treatment methods and results.

methods. It could include a combination of the following methods, a practice many utilities follow.[2]

i. Above ground visual and sound testing of all poles;

ii. Above ground boring to test for strength and internal decay;

iii. Partial excavation boring and visual inspection of poles exhibiting high levels of decay; or

iv. Full excavation boring and visual inspection of poles exhibiting high levels of decay.

2. Consider extending the inspection interval from 5 to at least 10 to years, particularly if partial or full excavation testing is adopted. A maximum ten-year inspection interval for all poles should be selected if Horizon elects to adopt the inspection methods described above.
3. If the alternate inspection methods described above are adopted, apply internal treatment to poles that exhibit internal decay, but which have sufficient shell strength to warrant continued use of the pole.
4. If alternate inspection methods described above are adopted, apply external pole treatment methods, where applicable, including fibreglass wrapping or C-Trusses to extend the usable life of poles that have sufficient strength above and below the area where shell strength has declined due to external decay or damage. C-Trusses are recommended only in areas where pole wrapping does not provide sufficient additional strength and in areas where aesthetics are not an overriding concern; for example, corner structures with multiple attachments and devices in urban areas may be candidate locations.
5. Continue to replace all poles with a remaining life 5 of years or less as scheduled, even if alternate inspection methods are adopted.
6. Tag all poles that have been inspected. Tags should include contractor name, date of inspection, and where applicable, test performed (the latter could be via clearly visible, colour-coded tags).
7. Implement a process for field review and quality assurance of contract inspection methods, including independent spot checking of contractor inspection results and assignments with pole database entries.

[2] Utilities sometimes stagger inspection methods; for example, visual inspection and selective boring may first be performed system-wide, followed by partial or full excavation several years later. Alternatively, poles that have been deemed to be in good condition following full excavation and boring may only require selective boring several years later. Similarly, if a pole has undergone remediation in the form of treatment of internal decay and/or pole reinforcement via fibreglass wraps or trusses, then less frequent and intrusive inspections may be needed thereafter.

Maintenance Practices Review

Horizon's equipment maintenance program is in line with or ahead of leading industry practices with regard to frequency of inspections. While inspections and condition assessments are critical to effective asset management, the frequency of Horizon's inspections may not *always* be cost-effective, particularly when viewed in the context of overall reliability performance. Reliability statistics collected for the past three years alone do not appear to justify the current inspection intervals for some equipment. One exception may be short-term vegetation management, where Horizon may accelerate trimming to "catch up" on circuits where maintenance has fallen behind scheduled trimming cycles. Horizon also may derive cost savings by combining field inspections, now performed independently for some lines and equipment, and still be in full compliance with the OEB's Distribution System Code.[3]

Accordingly, we recommend Horizon adopt the following:

1. **Visual Plant Inspections** - Identify approaches (as part of the ongoing Asset Management Framework Implementation) to consolidate or combine the OEB-mandated distribution line and equipment inspection 3-year schedule with other maintenance programs. For example, expand the pole inspection process to include other equipment to a level at which HU will be in compliance with the OEB mandate. Other programs that could be expanded to meet OEB requirements could include thermal inspections, vegetation management, or transformer inspections.
2. **Forestry/Vegetation Management** – Horizon should investigate the benefits and trade-offs of modifying maintenance policies to eventually transition to a 5-year inspection cycle. Continue with current 3-year trimming cycle until trimming activities reach a satisfactory level, where the reliability impacts due to tree-related causes suggest that the company can reasonably transition to a 5-year cycle. If a 5-year cycle is adopted, Horizon should consider coupling interim spot inspection and trimming on critical circuits or circuits demonstrating degraded reliability performance caused by tree-related outages.
3. **Thermal Scans** – Modify maintenance policies to transition to a 5-year thermography cycle. Continue with current cycle until inspection activities reach a level where HU can reasonably adopt a 5-year cycle.
4. **Load Break Switches** – Modify maintenance policies to transition a 5-year inspection cycle for overhead switches. Apply 3-year cycle to critical tie switches, including those relied on for load transfer on critical stations or customers (e.g., circuits feeding hospital load).

[3] Ontario Energy Board, Distribution System Code, February 1, 2006. Relevant sections include Section 4.4 – *System Inspection Requirements and Maintenance* and Appendix C – *Minimum Inspection Requirements.*

5. **Insulator Washing** – Continue with current program. Track insulator-related outages proactively to determine if this program is necessary or if the intervals should be extended.
6. **Substation Inspections and Predictive Maintenance** – NCI does not suggest any changes to maintenance inspection practices or intervals.[4]
7. **Inspection and Maintenance Policies and Practices** – In conjunction with the ERP implementation, Horizon should develop inspection and maintenance policies and guidelines to ensure conformance to these practices company-wide.
8. **Risk-Based Evaluation Methods** – Consider applying the "cost versus risk" methodology currently employed for other improvement programs to budget review and approval.

Equipment Replacement Practices Review

Given the high cost of equipment replacement and Horizon's ongoing effort to implement an asset management framework to guide equipment upgrade or replacement decisions, NCI recommends that Horizon adopts the procedures outlined in Appendix B. In addition, these policies and procedures will need to be communicated with field personnel and design technicians, and monitored to ensure compliance.

[4] NCI is aware that Horizon is considering enhancing maintenance procedures for substation metal-clad switchgear in 2009 to include internal visual inspections. This proposed action is in response to an arcing fault that occurred earlier this year on a busbar at one substation. Given that none of Horizon's substations have arc-proof switchgear, NCI agrees with the approach. NCI suggest that Horizon contact current suppliers of switchgear to develop remediation plans for switchgear that has deteriorated, which could include re-insulation or selective replacement.

NAVIGANT CONSULTING

INFRASTRUCTURE AND REPLACEMENT COST AND RELIABILITY DATA

Program Costs

Presented in Table 1 are costs included in Horizon's 2008 budget for infrastructure and replacement. The infrastructure programs include equipment from the four areas cited as "Quick Hits" opportunities. A preliminary assessment of areas with potential savings opportunities is provided below.[5] These opportunities are addressed in additional detail within the other sections of this report.

Table 1: Horizon 2008 Infrastructure and Replacement Costs

Types of Maintenance / Budget Costs	Total	Candidate for Savings?
Predictive Maintenance	**2008 Budget**	**Preliminary Assessment**
Load Tests	$ 4,014	Minimal
Infra-Red Scanning	$ 41,779	Yes
Plant Inspection	$ 227,712	Yes
Pole Testing	$ 108,396	Yes
Predictive Testing and Inspections (Substations)	$ 122,091	Minimal
Preventive Maintenance		
Load Break Switch Maintenance	$ 170,709	Yes
Insulator Washing	$ 31,465	Yes
Numbering switches/switching and work protection, misc repairs	$ 125,860	Minimal
Maintain Metal Enclosed Switchgear	$ 53,976	Yes
Paint Vault Covers (students)	$ 39,172	Yes
Clean/Inspect Transformer Rooms	$ 37,002	Yes
Clean manholes and vaults	$ 141,781	Minimal
Install eyes in manholes	$ 35,264	Minimal
Maintain SS Equipment	$ 188,724	Minimal
Maintain SS Buildings and Property	$ 262,620	Minimal
Grid Tree Trimming		
Trimming (3-Year Cycle)	$ 2,600,000	Yes
Corrective Maintenance		**Not Evaluated**
Remove Graffiti	$ 40,612	
Repairs from Infra-Red Scanning	$ 43,080	
Repairs from Plant Inspection	$ 177,972	
Tree Trimming	$ 83,778	
Other repairs	$ 719,914	
Repair Power Transformer	$ 32,954	
Repair other SS equipment	$ 81,135	
Emergency Maintenance (Not Evaluated in Quick Hits Study)		**Not Evaluated**
Sum of Emergency Maintenance Activities	$ 1,487,710	
Reactive Maintenance (Not Evaluated in Quick Hits Study)		
Response to Customer Issues - troubleshooting	$ 36,012	No
Repair of underground services	$ 170,364	No
Total	**$ 7,064,096**	

[5]NCI did not include Corrective or Emergency Maintenance in this "Quick Hits" review. Information pertaining to these areas appears in Table 1 for reference purposes only

This report also identifies (based on a preliminary review of available information) the level of annual savings, and the likely impact on annual budgets, that could be achieved if the "Quick Hits" recommendations outlined herein are adopted.

Potential maintenance savings of $3.26 million are in the "Yes" savings category and $0.9 million of the maintenance budget is assumed to have minimal savings potential. The remaining $2.1 million of the 2008 budget is assumed to have no "Quick Hits" savings potential. Approximately $1.7 million of the amount budgeted for emergency and reactive maintenance is excluded from the Quick Hits review.

Reliability Statistics

Reliability statistics were collected and analyzed for the last three years.[6] Table 2 presents Horizon's end-of-year reliability statistics for the last three years. Both SAIFI and SAIDI have shown a slight decline; however, the pattern and level of variation suggest overall reliability performance has been stable for the past three years. However, SAIDI performance appears more favourable than SAIFI. This result is typical for utilities with higher load density and smaller service territories per customer served, such as Horizon. We note, however, that reliability statistics show CAIDI levels at slightly above 30 minutes, a relatively low level compared to other utilities of a similar size and demographic.

Table 2: Horizon Reliability Statistics

	2005	2006	2007
SAIFI	1.67	1.44	1.59
SAIDI (Hrs)	1.09	0.94	1.01
CAIDI (Hrs)	0.65	0.65	0.63

Data was also summarized using Horizon "Cause Code" descriptions.[7] Of particular interest is data for defective equipment and tree-related outages, as these two areas capture outages related to the four areas investigated in this report. As shown in Table 3, the primary categories contributing to total SAIFI (outage frequency) under Horizon's control are:

- Defective equipment;
- Lightning; and
- Unknown cause codes.

[6] Note: Results that appear in several of the tables that follow use reliability data for August to July of each year.

[7] The Cause Code IDs listed follow OEB reporting conventions.

"Defective Equipment" is the most common cause code. It is also the most relevant cause code, as most areas of this investigation relate to equipment performance. The two areas not under Horizon's control are "Foreign Interference" and "Loss of Supply," and are generally not related to the four areas investigated herein.

Notably, "Tree Contact" is low (for utilities with significant tree cover such as Horizon) while the "Unknown/Other" cause code is used frequently. NCI's experience indicates that "Unknown/Other" cause code incidences are often weather-related, with "Tree Contact" caused by "Adverse Weather" being one of the leading causes. However, NCI did not independently confirm this premise for the statistics presented in the tables in this section.

Table 3: SAIFI Statistics (Percent Contribution)

Cause Code Description	2005/06	2006/07	2007/08
Scheduled Outage	6%	1%	2%
Tree Contact	3%	3%	2%
Unknown/Other	20%	15%	15%
Adverse Weather	19%	20%	15%
Defective Equipment	18%	26%	17%
Foreign Interference	16%	19%	10%
Loss of Supply	6%	7%	17%
Lightning	12%	8%	19%
Human Element	0%	1%	1%
Adverse Environment	0%	0%	1%
TOTAL SAIFI	**100%**	**100%**	**100%**

Table 4 presents SAIDI (outage duration) reliability statistics for the same three-year period. Results follow a similar pattern as SAIFI, as the greatest contributors to overall SAIDI are "Adverse Weather" and "Defective Equipment".

Table 4: SAIDI Statistics (Percent Contribution)

Cause Code Description	2005/06	2006/07	2007/08
Scheduled Outage	15%	6%	7%
Tree Contact	3%	8%	4%
Unknown/Other	3%	1%	5%
Adverse Weather	26%	24%	22%
Defective Equipment	25%	26%	25%
Foreign Interference	20%	15%	12%
Loss of Supply	7%	11%	8%
Lightning	1%	8%	13%
Human Element	0%	0%	1%
Adverse Environment	0%	0%	3%
TOTAL SAIDI	**100%**	**100%**	**100%**

Table 5 and Table 6 present SAIFI and SAIDI reliability statistics in greater detail via use of the Sub Cause Code Category. The statistics yield important insights into the outage contribution for equipment and maintenance activities investigated in this report. In particular, the percent contribution of pole and transformer outages to total SAIFI and SAIDI is relatively small – typically no more than 2 to 3 percent of total SAIFI and SAIDI. Proactive replacement is not likely to materially improve reliability over the short-term.

Table 5: SAIFI by Cause Code (covered within the scope of this project)

Sub Cause Code Category	2005/06		2006/07		2007/08	
	SAIFI	% of Total	SAIFI	% of Total	SAIFI	% of Total
Tree Contact-Direct & Weather	0.26	26%	0.36	36%	0.32	32%
Pole-Related	0.04	4%	0.05	5%	0.02	2%
Distribution Transformers-Line	0.03	3%	0.03	3%	0.02	2%
Distribution Transformers-Supply	0.01	1%	0.00	0%	0.00	0%
Load Break Switches	0.01	1%	0.05	5%	0.02	2%
Incorrect Use of Equipment	0.00	0%	0.00	0%	0.01	1%
Lightning Arrester Failure	0.05	5%	0.10	10%	0.06	6%
TOTAL SAIFI	**0.39**	**39%**	**0.58**	**58%**	**0.44**	**44%**

Notes:
1) All percentages presented are a percent of total SAIFI
2) "Distribution Transformer - Supply" refers to Horizon's substation power transformers

Similarly, "Load Break Switch" failures contribute little to overall SAIFI and SAIDI. This is in contrast to "Lightning Arrester Failure", which has a greater impact by a factor of five than "Load Break Switches".

Table 6: SAIDI by Cause Code

Cause Code Description	2005/06	2006/07	2007/08
Scheduled Outage	15%	6%	7%
Tree Contact	3%	8%	4%
Unknown/Other	3%	1%	5%
Adverse Weather	26%	24%	22%
Defective Equipment	25%	26%	25%
Foreign Interference	20%	15%	12%
Loss of Supply	7%	11%	8%
Lightning	1%	8%	13%
Human Element	0%	0%	1%
Adverse Environment	0%	0%	3%
TOTAL SAIDI	**100%**	**100%**	**100%**

Note: All percentages presented are a percent of total SAIDI

Under the assumption that "Adverse Weather" often causes tree-related outages, the percent contribution of tree-related failures is far higher than other outage causes. This observation is consistent with our experience and observations of other similar utilities. However, the low level of reported SAIFI and SAIDI for tree-related outages is lower than other utilities, suggesting that Horizon's 3-year trimming cycle has been effective from a reliability perspective.

The incidence of lightning-related outages (interruptions caused by lightning strikes and failed arresters) has increased over time and is a significant component of total SAIFI and SAIDI. Although lightning mitigation is not one of the four "Quick Hits" areas investigated, proactive maintenance and enhanced lightning protection appear to be areas in need of attention.

For Horizon's substations, transformer failures have had minimal reliability impact as measured by SAIFI and SAIDI. NCI notes that the incidence rate of substation transformers failures should remain low as these stations are retired over time due to voltage conversion projects.

PROACTIVE TRANSFORMER REPLACEMENT REVIEW

Background

Prior to 2007, the only transformers that were proactively replaced were those identified as "overloaded" or aged 70 years or greater. Beginning in 2007, proactive replacement of transformers included those deemed to be "high risk" using a ranking methodology that considered the health of the transformer and the impact of transformer failure.[8]

Analysis of Available Data

To determine the effectiveness of this ranking methodology, an analysis of transformer replacement statistics versus proposed replacements (based on ranking criteria) was conducted. The following information was used to support the analysis:

1. Transformer replacement ranking list for the Hamilton area;
2. Transformer replacement ranking list for the St. Catharines area;
3. Transformers selected for proactive replacement, derived from the replacement ranking lists;
4. List of actual transformer replacements up to July of 2007 (database maintained by Planning Department); and
5. Transformer files (from the AS400 database) - transformer files modified between January 2006 and July 2008 indicate which devices were replaced or upgraded. The database provides some description of events and rationale related to transformer replacement.

A list of transformers replaced between January 2006 and July 2008 was obtained by combining the list of transformer replacements up to July 2007 (Item #4 in the list above) and the transformer files information (Item #5 in the list above). The replacement ranking and health condition for each of the transformers replaced during this interval was then extracted from the replacement ranking lists (Items #1 and #2 in the list above). The reason for each transformer replacement was obtained by looking-up the work order in which the replacement was logged.

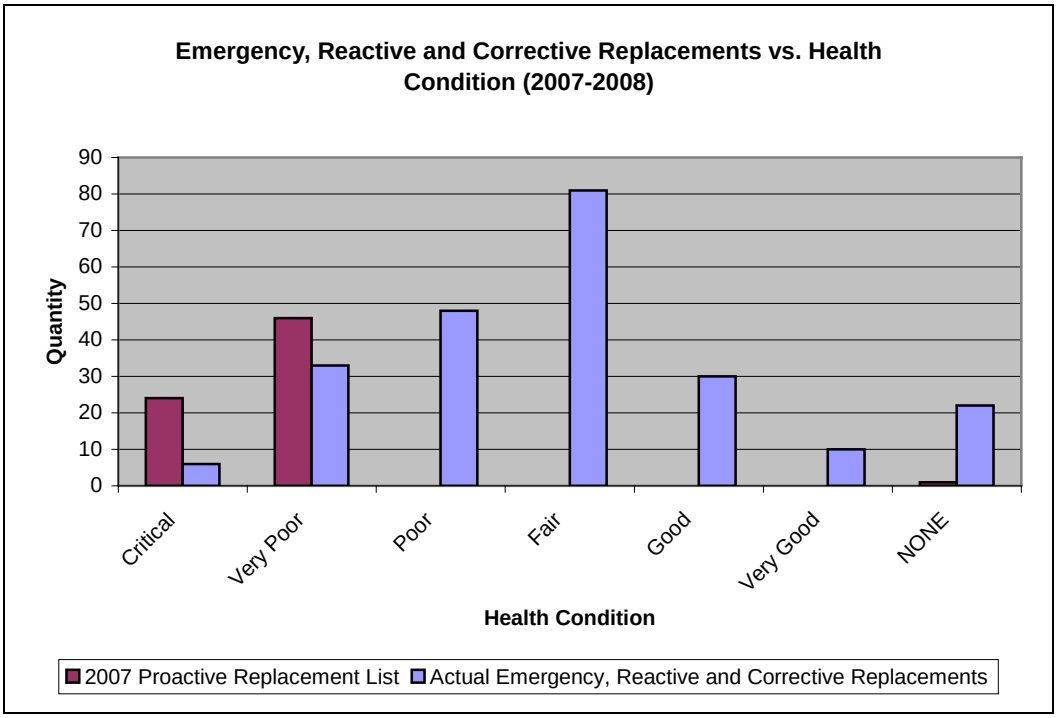
[8] Horizon initiated the transformer health evaluation process in 2004, which included preparing documentation and gathering information needed to develop a Transformer Health Index (e.g., evaluation based on transformer loading, fuse operations, condition, years in service, years idle in yard). Initially, Horizon ranked 20,000 transformers and derived health indices from 'critical' to 'very good'.

It was found that transformers replaced under emergency, reactive and corrective work orders were usually replaced after being deemed defective (due to leaking oil or other reasons). As such, a comparison was made between transformers identified as candidates for replacement using the ranking methodology and transformers that were actually replaced for emergency, reactive or corrective maintenance reasons.[9]

Figure 1 and Figure 2 present the results of this comparison and indicate a weak correlation between the proactive replacement ranking and likely defective transformers (those replaced under emergency, reactive and corrective work orders).

Figure 1 compares the health conditions (based on the replacement ranking methodology) of transformers identified for proactive replacement and likely defective transformers. Notably, the highest number of likely defective transformers had been given "Fair" health condition assessments by the replacement ranking. The lowest number of replacements was assigned to the "Critical" health condition category.

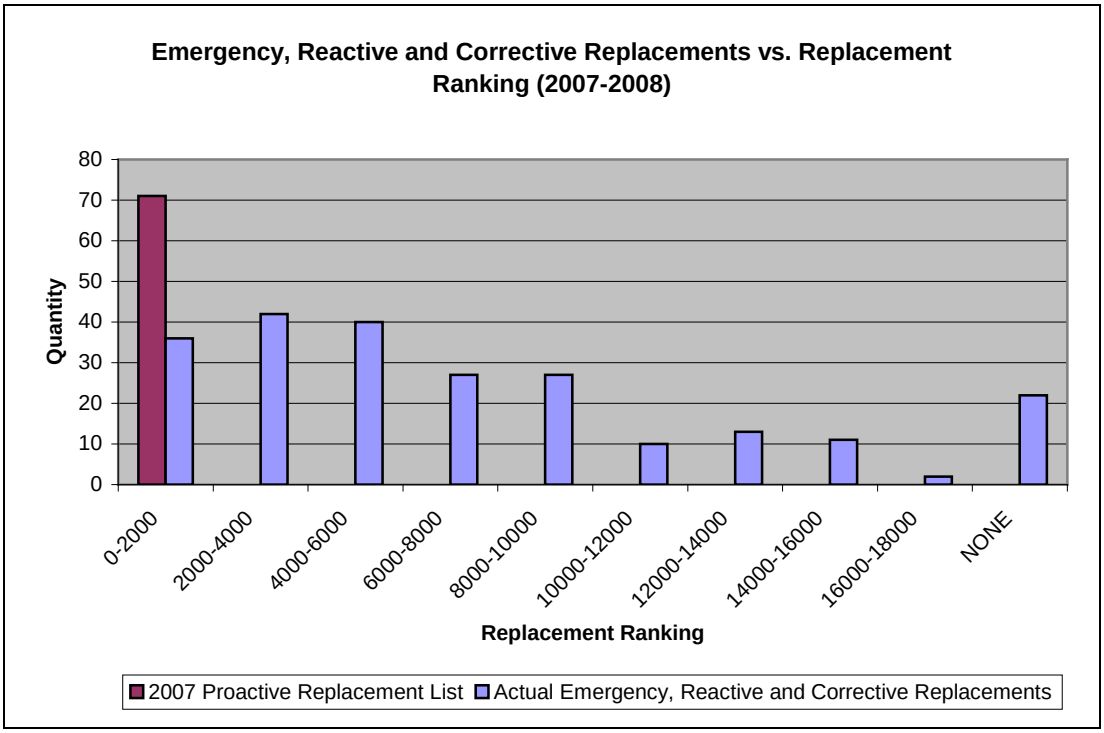
Figure 1: Emergency, Reactive and Corrective Replacements vs. Health Condition (2007-2008)



[9] Note: this comparison was made on transformers replaced between January 2007 and July 2008.

Figure 2 compares the transformer ranking of transformers identified for proactive replacement and actual transformer replacements during 2007 and 2008, year-to-date. Again, there is a weak correlation of likely defective transformers versus those included in the proactive replacement list.

Figure 2: Emergency, Reactive and Corrective Replacements vs. Replacement Ranking (2007-2008)



Costs of Proactive Transformer Replacement

As previously mentioned, before 2007, overloaded transformers and transformers aged 70 years or greater were replaced proactively. In 2006, a list was created of such transformers to be replaced. The total cost of replacing overloaded transformers from the 2006 list was $440,538 ($336,914 for overhead transformers and $103,624 for underground transformers).

In 2007, $171,676 was spent on replacing 16 transformers in Hamilton identified through the replacement ranking methodology. In St. Catharines, $39,208 was spent on proactive transformer replacements.

For 2008, $2,439,257 was budgeted for proactive transformer replacements ($1,980,323 for overhead transformers and $458,934 for underground transformers). Up to August 2008, only $453,829 had been spent. It is expected that the amount spent on proactive transformer replacements in 2008 will be less than budgeted.

Industry Practices

Most utilities replace in-service overhead and pad-mounted distribution transformers only when they are overloaded, damaged or clearly deteriorated. This mode of operation is often referred to as "Run-to-Failure (RTF)". Reasons why utilities accept an RTF mode of operation for distribution transformers include: relatively low failure rates, a relatively low number of customers affected by transformer failures ,and the high cost of replacement.[10] Utilities sometimes replace transformers that are one-of-a-kind and which are expensive to maintain backup inventory for. Often, older transformers are located on lower voltage lines – such as 4.16kV and 4.8kV – and are typically replaced during conversion to operate at a higher voltage.

Inventory Considerations

As older transformers, including those of uncommon sizes, winding connections or voltages, are removed from service, the need to maintain back-ups may decline. This may provide an opportunity to reduce inventory or in some cases, to remove certain units from inventory altogether. Depending on which recommendations are adopted, Horizon will need to review and adjust inventory to ensure it only includes devices that are essential for back-up. Accordingly, an inventory management plan for transformers should be completed following the adoption of recommendations outlined in the following section.

Findings and Recommendations

Horizon's proactive transformer replacement guidelines are representative of leading industry practices with regard to methods employed to evaluate transformer health and risk. Horizon's replacement criteria target transformers deemed to be at high risk of failure; particularly those that impact critical customers or densely populated areas. Although initial results of the replacement ranking analysis show a weak correlation with actual replacements, the approach is based on sound asset management principles – principles that can (and should) be applied to other equipment categories as well.

While condition assessment methods, such as those employed to rank transformers, are critical to effective asset management, the proactive replacement of in-service distribution line transformers may not *always* be cost-effective, particularly when viewed in the context of overall reliability performance. Reliability statistics collected for the past three years alone do not justify proactive replacement, nor does the condition assessment data; the latter of which shows a weak correlation of devices listed as proactive replacements versus devices actually replaced by field personnel (i.e., those replaced likely due to actual defects). The expense of re-certification

[10] Note: Horizon's average cost of replacement is $5,000 to $8,000 per transformer, excluding pole replacement costs.

also may not be justified for transformers with in-service lives of 5 years or less, as these devices generally exhibit relatively minimal near-term deterioration.

Accordingly, we recommend Horizon adopt the following practices:

1. Continue asset condition and performance assessment practices to support proposed Asset Management Framework Implementation initiatives.
2. Modify replacement criteria to focus only on those transformers that exhibit visual signs of deterioration (e.g., leaking oil), one-of-a-kind devices that are difficult to replace or costly to maintain from an inventory standpoint, those located in dwellings or buildings where inspection or test results reveal a much higher than average likelihood of failure, or where load tests indicate loadings above continuous or normal ratings (this is generally viewed as a "run-to-failure" approach).
3. Continue to refine the process for evaluating the "health" and "risk" of distribution transformers. Employ similar asset condition and health evaluation methods for other equipment types, including devices that have a significant impact on reliability performance as measured by SAIFI and SAIDI.
4. Incorporate transformer load management in the evaluation process; implement methods to identify and replace transformers with low utilization, particularly larger devices.
5. Standardize and formalize the processes for recording the reasons for transformer replacements, particularly those that have failed, using clear and consistent descriptors or codes (this is also part of Horizon's Asset Management Framework Implementation).
6. Review current re-certification practices, including extension of the transformer age from 5 to 10 years (or more) for re-certification.
7. Apply field inspection methods, such as infra-red scans, to identify hot-spots or physical deterioration, and develop replacement criteria for transformers using inspection results (this approach and the replacement criteria can be applied to other defective or deteriorated distribution equipment as well).
8. Consider applying more rigorous criterion for inspecting and replacing transformers located within the customer premise, such as basements or transformer rooms. Options include more frequent inspections, replacement of devices that have experienced overloads or are currently overloaded and replacement of devices that are one-of-a-kind, or exhibit moderate deterioration.

PROACTIVE POLE REPLACEMENT REVIEW

Background

The pole residual program is a two-staged process that involves inspection of wood poles by an outside contractor using non-destructive inspection methods and replacement of poles identified (through inspection) as being at their end of life. Currently, only poles older than 25 years in age are inspected.

After a pole is inspected, its condition is reported with the following information:

- Mechanical condition – cracks, pole-top feathering, surface rot, woodpecker holes, etc;
- Overall condition – "poor", "fair", "good"; and
- Pole strength.

Based on the condition of the pole and the remaining strength, a recommendation is made by the outside contractor about whether the pole should be replaced within three years or re-tested in three to six years.

Analysis of Available Data

An analysis was performed on the results of pole inspections conducted in Hamilton between 2004 and 2007. In this time period, around 11,000 poles were inspected, amongst which 363 poles had been recommended for replacement within 1-3 years, a failure rate of 3.3%. NCI considers this failure rate to be at or slightly above the average it has observed at other utilities.[11]

The analysis focused on the relationship between the failed poles, poles inspected and poles existing in the entire system. The following criteria were considered:

- Age;
- Height;
- Species;
- Class; and

[11] NCI cautions that the criteria used to determine when a pole has failed may not be entirely comparable with other non-destructive testing methods.

- Location.

Based on each of these criteria, a distribution of failed poles, inspected poles and current poles in the system (depending on availability of data), was created. This was done to provide a good understanding of the underlying patterns in the performance of poles in the system. Figure 3 presents the distribution of total poles by age, those inspected by age, and failures by age.

Figure 3: Distribution of Failed Poles by Age, Inspected Poles by Age and System Poles by Age

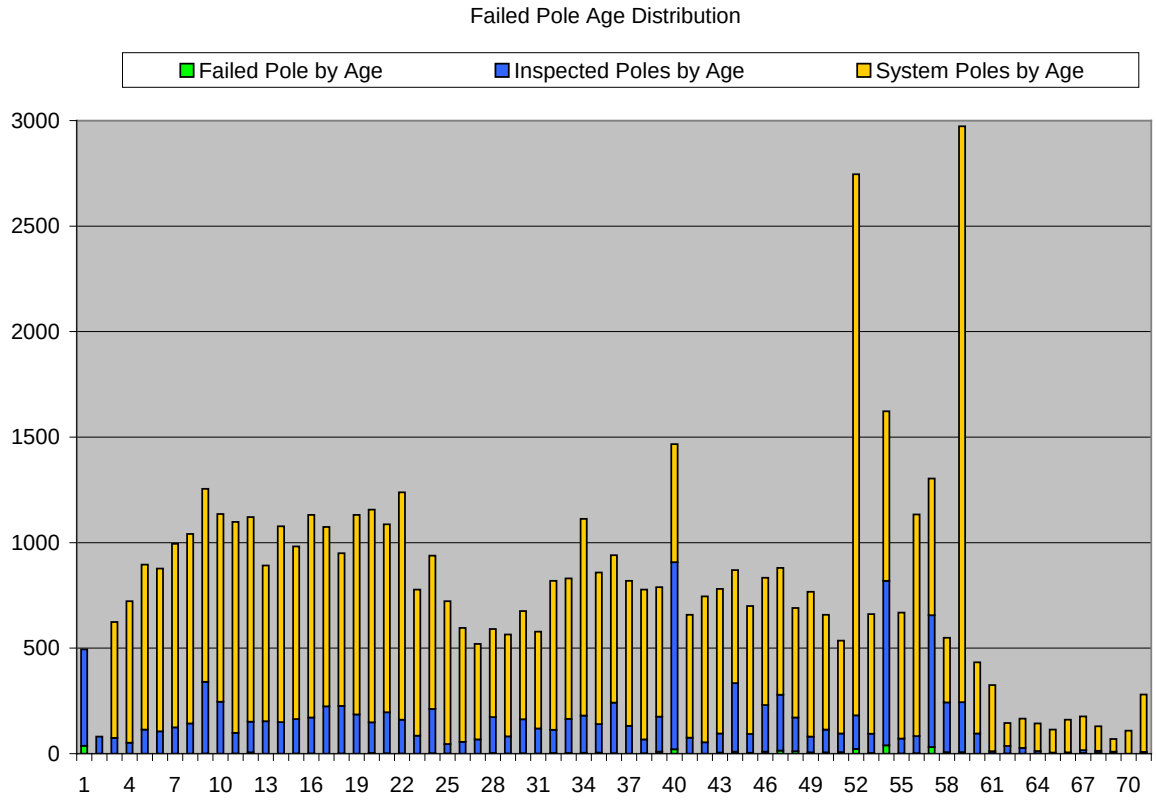
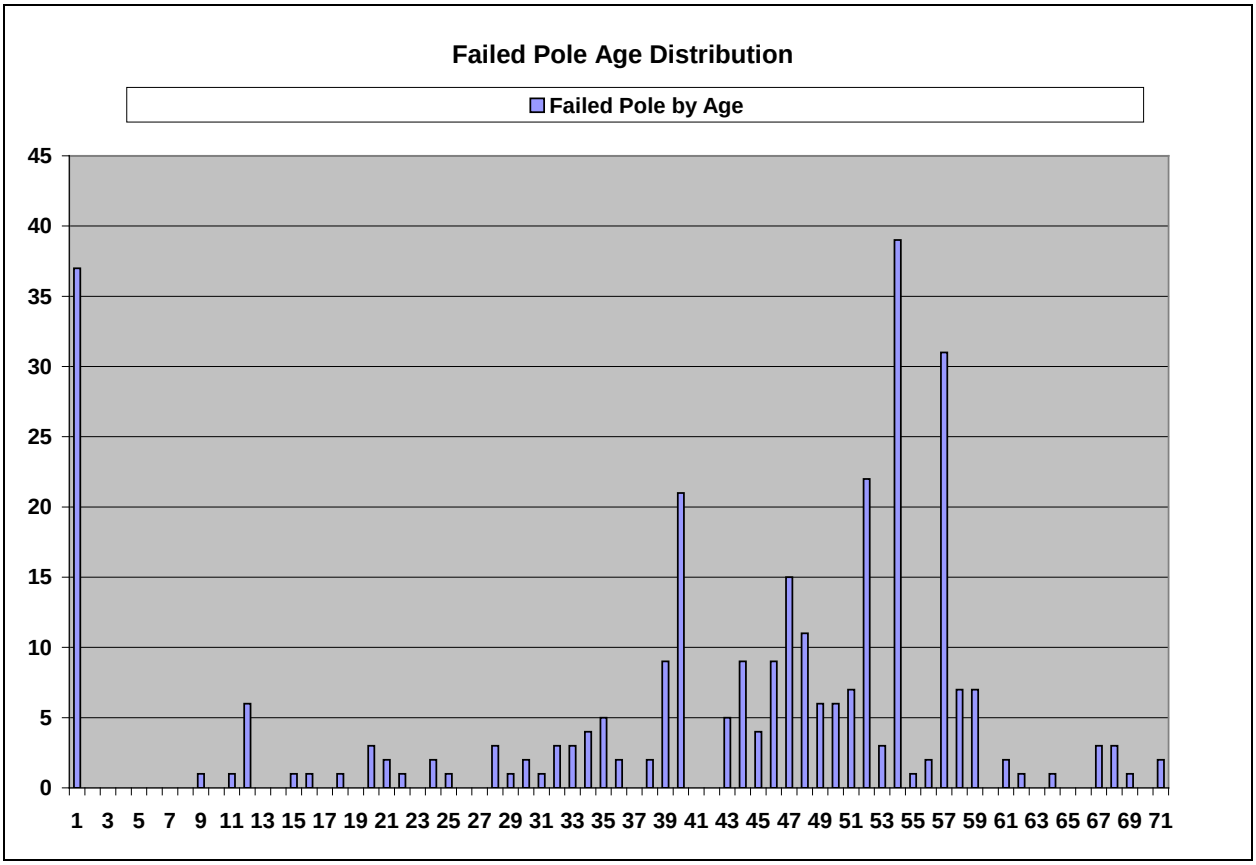


Figure 4 illustrates pole failures, by age, identified during inspections conducted over the past 3 years by Horizon's pole inspection contractor. Of the 363 poles that were deemed "failed", the large majority were 40 years or older, a common finding among utilities.

Figure 4: Failed Pole Age Distribution



Costs of Proactive Pole Replacement

The following highlights Horizon's cost for proactive pole replacements incurred in 2007, including average per unit inspection and replacement costs, and amounts budgeted for 2008. The data that appears below was used to support our assessment and estimates of annual cost savings that may be realized if the recommendations outlined in this subsection are adopted.

Horizon's costs for pole inspection are highlighted as follows:

- Regular Poles: $13/pole;
- Rear Lot Poles: $16/pole; and
- Retesting Poles: $18/pole.

Horizon's average per pole inspection cost, and actual and budgeted replacement costs, are summarized in Table 7.

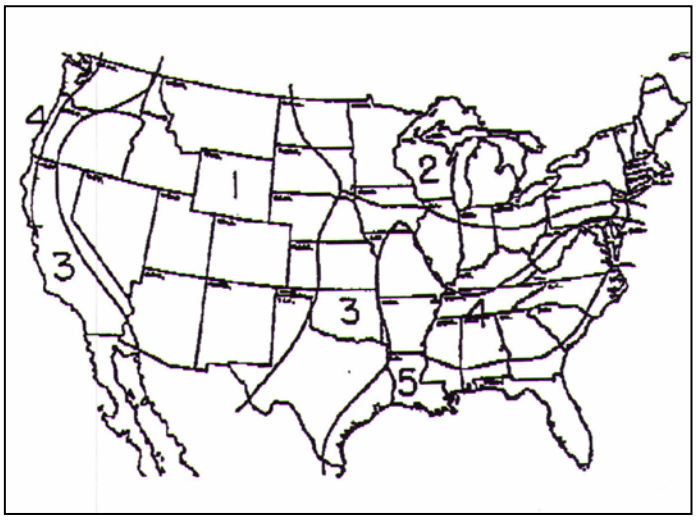
Table 7: Pole Inspection and Replacement Costs

	Poles Inspected		Inspection Cost (Unit)		Replacement Cost	
Year	Hamilton	St. Cath.	Hamilton	St. Cath.	Hamilton	St. Cath.
2007	3749	894	$ 15	$ 15	$ 487,202	$ 550,979
2008 (Budget)			$ 15	$ 15	$ 1,261,616	$ 832,603

Industry Practices

The U.S. Rural Utilities Services (RUS) has created decay zones which provide an indication of likely decay rates on wood poles. Figure 5 illustrates these zones, which are ranked from 1 (lowest decay) to 5 (highest decay). Horizon is located in a Zone 2 decay region as it is located near New York, which is located in Zone 2. Many utilities located in Zones 1 – 3 (and some in Zones 4 – 5) inspect poles on a 10-year cycle. Some utility commissions in the U.S. specify a 10-year inspection cycle.

Figure 5: Decay Severity Zones for Wood Poles



Many utilities apply life-extension methods, such as internal decay treatment and pole wrapping, as an alternative to complete replacement (Horizon's current approach) of failed poles.

Inventory Considerations

If Horizon adopts pole life extension practices as outlined in our recommendations, there may be an opportunity to reduce pole inventory. Depending on which practices are adopted, Horizon will need to review and adjust inventory. Accordingly, an inventory management plan

for poles should be completed following the adoption of recommendations outlined in the following section.

Findings and Recommendations

NCI's findings are based on interviews with Horizon engineering, planning, construction management and support staff and review of the 2007 *Distribution System Capital & Maintenance Programs* document, and pole inspection records. We also reviewed Horizon's request for quotation (RFQ) for pole inspections for 2008, vendor responses and the industry publications provided. Our recommendations are also based on analytical studies and an assessment of data provided by Horizon, the results of a preliminary economic analyses, and a review of common industry practices. Recommendations based on economic studies should be considered preliminary and subject to revision following the completion of supplemental studies completed by Horizon and the results of the ongoing Asset Management Framework Implementation.

1. The methods and practices Horizon has historically employed to perform pole inspections are consistent with industry guidelines and current utility practices. These practices include inspection and non-destructive testing and are consistent with those outlined in the American Wood Preservers' Association Standard (M13-07) and NCI's experience.[12]
2. The use of specialized testing methods such as the use of Resistograph and mechanical test equipment to predict condition and strength, is generally consistent with recommended practices, as they share a common objective of assessing pole condition and mechanical strength; however, the testing methods outlined above have not been universally applied by utilities. Further, the effectiveness of these methods may not be consistent with results obtained from the traditional approaches Horizon and other utilities have applied. Also, there may not be sufficient information at this time to ensure these newer approaches offer the most cost-effective option(s) for Horizon.
3. The "General" section of Horizon's RFQ for pole inspections for 2008 appears to mandate the use of the Resistograph inspection method. For the reasons cited above, NCI recommends that Horizon modify its RFQ to allow bidders to offer or suggest other approaches for pole inspections and non-destructive testing, which could include Resistograph and mechanical strength tests as an option by qualified vendors. Such modifications to the RFQ would be consistent with methods previously employed by Pole Care, the vendor that Horizon has employed for the past several years to perform

[12] NCI notes that Horizon has not previously applied pole treatment methods. Accordingly, NCI anticipates that there will be a gradual transition to treatment applications as Horizon personnel gain experience and acceptance of treatment methods and results.

pole inspections. Based on recent discussion with Horizon staff and a review of the documents provided, NCI offers its opinion that Pole Care's prior response to Horizon's RFQ is consistent with current utility practices.

Horizon's Proactive Pole Replacement guidelines are generally consistent with industry practices with regard to the replacement of poles deemed to be at high risk of failure. However, many utilities employ inspection methods that include remediation with pole treatment as an alternative to end-of-life replacement. Utilities recognize that replacement may not always be cost-effective when compared to pole treatment options, designed to extend the life of poles with adequate shell strength. Further, reliability statistics collected for the past three years alone do not justify an acceleration of pole replacements, a common finding among most utilities.

Accordingly, we recommend that Horizon adopt the following practices:

1. Assess the applicability and potential advantages of alternate approaches for pole inspections and replacements. The assessment should include an economic assessment of inspection techniques and mitigation options listed below, versus current inspection methods. It could include a combination of the following methods, a practice many utilities follow.[13]
    i. Above ground visual and sound testing of all poles;
    ii. Above ground boring to test for strength and internal decay;
    iii. Partial excavation boring and visual inspection of poles exhibiting high levels of decay; or
    iv. Full excavation boring and visual inspection of poles exhibiting high levels of decay.
2. Consider extending the inspection interval from 5 to at least 10 to years, particularly if partial or full excavation testing is adopted. A maximum ten-year inspection interval for all poles should be selected if Horizon elects to adopt the inspection methods described above.
3. If the alternate inspection methods described above are adopted, apply internal treatment to poles that exhibit internal decay, but which have sufficient shell strength to warrant continued use of the pole.

[13] Utilities sometimes stagger inspection methods; for example, visual inspection and selective boring may first be performed system-wide, followed by partial or full excavation several years later. Alternatively, poles that have been deemed to be in good condition following full excavation and boring may only require selective boring several years later. Similarly, if a pole has undergone remediation in the form of treatment of internal decay and/or pole reinforcement via fibreglass wraps or trusses, then less frequent and intrusive inspections may be needed thereafter.

4. If alternate inspection methods described above are adopted, apply external pole treatment methods, where applicable, including fibreglass wrapping or C-Trusses to extend the usable life of poles that have sufficient strength above and below the area where shell strength has declined due to external decay or damage. C-Trusses are recommended only in areas where pole wrapping does not provide sufficient additional strength and in areas where aesthetics are not an overriding concern; for example, corner structures with multiple attachments and devices in urban areas may be candidate locations.
5. Continue to replace all poles with a remaining life 5 of years or less as scheduled, even if alternate inspection methods are adopted.
6. Tag all poles that have been inspected. Tags should include contractor name, date of inspection, and where applicable, test performed (the latter could be via clearly visible, colour-coded tags).
7. Implement a process for field review and quality assurance of contract inspection methods, including independent spot checking of contractor inspection results and assignments with pole database entries.

MAINTENANCE PRACTICES REVIEW

Background

Horizon's maintenance practices are mostly cycle-based, with set schedules for equipment inspection and maintenance intervals. Inspection intervals and follow-up remediation are designed to comply with the OEB's *Distribution System Code*, which specifies a 3-year inspection interval with directives to establish policies regarding remediation options following inspections.

Our assessment includes a high-level review of Horizon's system inspection practices with regard to OEB Code compliance and leading industry practices. NCI targeted 6 areas for in-depth review, including substations. To the extent differences exist between Hamilton and St. Catharines, these are addressed as well.

Analysis of Available Data

Horizon's inspection and maintenance practices include assignment of dedicated staff to inspect distribution lines on a 3-year, rolling basis. These inspections are in addition to other inspection and maintenance activities performed on poles, switches and other specific equipment. Table 8 presents Horizon's inspection and maintenance intervals for key equipment categories.

Table 8: Horizon Inspection Schedules

Inspection/Maintenance Categories	Inspection Interval
Predictive/Preventative Maintenance	**Schedules**
Infra-Red Scanning	Yes
Plant Inspection	3-year
Pole Testing	5-year
Predictive Testing and Inspections (Substations)	1-year TOA; 2-3 year other
Load Break Switch Maintenance	3-year OH; 6-year UG
Insulator Washing	As Needed
Scheduled Trimming	3-year

Note: TOA - Transformer Oil Analysis

Interviews with Horizon management and supervisory staff revealed that the depth and type of inspection activities performed for equipment and lines in St. Catharines and Hamilton likely differ. For example, switch inspections can range from visual inspection and operational tests (i.e., making sure the switch is operable), to disassembly and inspection of specific components. Differences in other inspection methods likely exist as well. This finding is common among utilities that have recently merged, as maintenance practices reflect legacy approaches and

methods. Further, the absence or lack of compliance with written procedures for inspections can cause differences in applications and methods. The recent implementation of ERP software provides an opportunity to apply greater consistency, as job planning and maintenance histories are incorporated in ERP modules.

Horizon's inspection and maintenance practices do not always consider benefits versus costs; for example, the level of reliability improvement expected by the actions taken. Although Horizon must comply with OEB inspection requirements, inspection and maintenance practices above and beyond Code requirements could be analyzed from a cost-effectiveness standpoint, with a goal of balancing costs versus reliability performance. Our review excludes a detailed cost analysis, but compares Horizon's practices with other utilities that assess cost versus benefits of inspection and maintenance programs.

Industry Practices

Based on NCI's experience with other utilities in the U.S. and Canada, we find Horizon's equipment and system inspection and maintenance intervals to be in line with or ahead of leading practices. However, these practices do not always translate into advisable practices; namely Horizon's inspection and maintenance practices may not always be cost-effective. Utilities that have adopted best practices generally select intervals based on asset condition, and seek to balance cost versus benefits (i.e., avoided risk of failure).

Findings and Recommendations

Horizon's equipment maintenance program is in line with or ahead of leading industry practices with regard to frequency of inspections. While inspections and condition assessments are critical to effective asset management, the frequency of Horizon's inspections may not *always* be cost-effective, particularly when viewed in the context of overall reliability performance. Reliability statistics collected for the past three years alone do not appear to justify the current inspection intervals for some equipment. One exception may be short-term vegetation management, where Horizon may accelerate trimming to "catch up" on circuits where maintenance has fallen behind scheduled trimming cycles. Horizon also may derive cost savings by combining field inspections, now performed independently for some lines and equipment, and still be in full compliance with the OEB's Distribution System Code.[14]

Accordingly, we recommend Horizon adopt the following:

[14] Ontario Energy Board, Distribution System Code, February 1, 2006. Relevant sections include Section 4.4 – *System Inspection Requirements and Maintenance* and Appendix C – *Minimum Inspection Requirements.*

1. **Visual Plant Inspections** - Identify approaches (as part of the ongoing Asset Management Framework Implementation) to consolidate or combine the OEB-mandated distribution line and equipment inspection 3-year schedule with other maintenance programs. For example, expand the pole inspection process to include other equipment to a level at which HU will be in compliance with the OEB mandate. Other programs that could be expanded to meet OEB requirements could include thermal inspections, vegetation management, or transformer inspections.
2. **Forestry/Vegetation Management** – Horizon should investigate the benefits and trade-offs of modifying maintenance policies to eventually transition to a 5-year inspection cycle. Continue with current 3-year trimming cycle until trimming activities reach a satisfactory level, where the reliability impacts due to tree-related causes suggest that the company can reasonably transition to a 5-year cycle. If a 5-year cycle is adopted, Horizon should consider coupling interim spot inspection and trimming on critical circuits or circuits demonstrating degraded reliability performance caused by tree-related outages.
3. **Thermal Scans** – Modify maintenance policies to transition to a 5-year thermography cycle. Continue with current cycle until inspection activities reach a level where HU can reasonably adopt a 5-year cycle.
4. **Load Break Switches** – Modify maintenance policies to transition a 5-year inspection cycle for overhead switches. Apply 3-year cycle to critical tie switches, including those relied on for load transfer on critical stations or customers (e.g., circuits feeding hospital load).
5. **Insulator Washing** – Continue with current program. Track insulator-related outages proactively to determine if this program is necessary or if the intervals should be extended.
6. **Substation Inspections and Predictive Maintenance** – NCI does not suggest any changes to maintenance inspection practices or intervals.[15]
7. **Inspection and Maintenance Policies and Practices** – In conjunction with the ERP implementation, Horizon should develop inspection and maintenance policies and guidelines to ensure conformance to these practices company-wide.

[15] NCI is aware that Horizon is considering enhancing maintenance procedures for substation metal-clad switchgear in 2009 to include internal visual inspections. This proposed action is in response to an arcing fault that occurred earlier this year on a busbar at one substation. Given that none of Horizon's substations have arc-proof switchgear, NCI agrees with the approach. NCI suggest that Horizon contact current suppliers of switchgear to develop remediation plans for switchgear that has deteriorated, which could include re-insulation or selective replacement.

8. **Risk-Based Evaluation Methods** – Consider applying the "cost versus risk" methodology currently employed for other improvement programs to budget review and approval.

EQUIPMENT REPLACEMENT PRACTICES REVIEW

Background

Horizon's field crews and distribution supervisors have the authority to change-out equipment that is deemed to have deteriorated, particularly when other work is being performed. For example, crews with the involvement of design technicians often suggest change-out of a pole when a transformer is replaced, or vice-versa. This pattern follows historical precedent, where a commonly held view is that it is cost-effective to replace both poles and transformers when either device is scheduled for replacement, or in response to a failure or outage.

Given the increasing cost of poles and transformers (and other equipment) and Horizon's adoption of asset management focussed initiatives, this practice may no longer be the best choice from an economic standpoint. Notably, the cost of both poles and transformers often exceeds $5,000, an amount NCI deems to be sufficiently high to warrant review and approval by engineering and design technicians prior to replacement. Accordingly, Horizon has developed a set of guidelines that field personnel and design technicians can follow when there is an opportunity to replace other equipment during a routine job or following emergency replacements. These guidelines are outlined in Appendix B.

Assessment of Current Practices

Industry Practices

Based on NCI's experience with other utilities in the U.S. and Canada, we find Horizon's practice of enabling first line supervisors or field personnel to authorize change-out or upgrade of major equipment to be increasingly less common. This finding reflects utilities' adoption of asset management practices to guide replacement or repair decisions. Utilities recognize that decisions at the field level may not reflect the best economic choice nor result in a material improvement in reliability. Exceptions to the approach, of course, exclude change-outs for equipment that clearly is damaged beyond repair, or which may jeopardize crew or public safety. Other exceptions often include minor maintenance items or capital change-outs that fall below a specified cost threshold. To ensure change-outs are appropriate, utilities may establish replacement rules or guidelines that are clearly communicated and easy-to-follow by field and supervisory personnel.

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Findings and Recommendations

Given the high cost of equipment replacement and Horizon's ongoing effort to implement an asset management framework to guide equipment upgrade or replacement decisions, NCI recommends that Horizon adopts the procedures outlined in Appendix B. In addition, these policies and procedures will need to be communicated with field personnel and design technicians, and monitored to ensure compliance.

PROGRAM COST SAVINGS

Based on our review of the "Quick Hits" opportunities outlined herein, NCI developed preliminary estimates of potential annual savings associated with each of the four Quick Hits. Table 9 outlines NCI's high level estimate of the cost savings that could be achieved if the recommendations outlined in this report are adopted.[16] Note that savings that appear in Table 9 exclude direct and indirect costs that Horizon will incur to implement program changes. For example, we have investigated the additional administrative, engineering and systems costs that typically accompany a shift in maintenance methods and programs.

Table 9: Preliminary Savings Estimates

Inspection/Maintenance Categories	Annual Savings	Capital	Expense
Proactive Pole Replacements	$ 240,000	$ 240,000	$ -
Proactive Transformer Replacement	$ 175,000	$ 175,000	$ -
Equipment Replacement Program	$ 250,000	$ 250,000	$ -
Maintenance Programs			
Infra-Red Scanning	$ 8,356	$ -	$ 8,356
Plant Inspection	$ 45,542	$ -	$ 45,542
Pole Testing	$ 21,679	$ -	$ 21,679
Predictive Testing and Inspections (Substations)	$ -	$ -	$ -
Load Break Switch Maintenance	$ 34,142	$ -	$ 34,142
Insulator Washing	$ -	$ -	$ -
Scheduled Trimming	TBD	$ -	TBD
Totals	**$ 774,719**	**$ 665,000**	**$ 109,719**

Table 9 presents the savings that could be attributable to the 4 areas in question by "expense" and "capital", with additional sub-categories and the savings that could accrue to each, identified where appropriate.[17] This analysis identifies that Horizon's maintenance guidelines, offer the greatest potential for savings. The opportunity to reduce capital expenditures by fewer transformer and pole change-outs also produces favourable results.

Specific assumptions and methods used to derive estimated savings are highlighted below for each of the Quick Hits categories.

[16] Note: As indicated throughout this report, some further investigation is required in several areas. In particular, estimates for pro-active pole replacement should be considered to be very high level. Horizon should conduct a more in-depth analysis to asses the viability of adopting the recommendations and then update the preliminary savings studies contained in this section.

[17] The table excludes an estimate for tree trimming as Horizon will need to conduct studies and develop a transition plan to evaluate the cost-effectiveness and impact of expanding trimming cycles, including when the company could implement the plan without jeopardizing reliability performance.

- **Proactive Pole Replacements** – Data provided by Horizon indicates an average of 4,000 poles are inspected annually under current inspections methods. Of the total number of poles inspected, approximately three percent (120 poles) are classified as having less than three years of remaining life. The average cost of a replacement is assumed to about $5,000 - $8,000 per pole. Navigant Consulting estimates that at least 50 percent of poles deemed to have less than three years of remaining life would be candidates for life extension (60 poles); that is, remediation via fibreglass wrapping, trusses or other reinforcement methods. We conservatively estimate the costs of remediation to be $1,000 per pole, resulting in a net $4,000 per pole cost reduction. When applied to the estimated 60 poles that would be candidates for life extension, an annual savings of $240,000 can be achieved.

- **Proactive Transformer Replacements** – Figure 2 reveals that about one-half or 36 of the number of transformers that would have been scheduled for proactive replacement (71) were replaced for emergency, reactive or corrective maintenance – the remaining 35 can be deemed candidates for deferral; that is, these devices should not be replaced proactively. Assuming an average replacement cost of $2,500 per transformer yields an annual savings of $87,500. Because Horizon's practice is to proactively replace poles, where applicable, when transformers are replaced, we assume 50 percent of the 35 transformers deferred (18), would yield additional annual savings of $87,500 (18 poles multiplied by $5,000, the estimated cost of a pole replacement), for a total savings of $175,000.

- **Equipment Replacement Guidelines** – Based on discussions with Horizon office staff and field supervisors, Navigant estimates the number of poles and transformers replaced that had more than five years of service life remaining to be 50 and 24, respectively. At $2,500 per transformer and $5,000 per pole, the total savings would be $250,000 annually.

- **Maintenance Programs** – NCI conservatively estimates that maintenance schedules for six categories could be reduced, on average, by 20 percent. A portion of these savings is achieved by consolidating some of the plant inspections performed to meet OEB *Distribution System Code* requirements while other maintenance activities are performed; for example, expanding pole inspections to include an inspection of other equipment and lines. For equipment with three-year maintenance cycles, the new cycle would be approximately four years.

It should be noted that the saving estimates outlined in Table 9 assume full implementation of NCI's recommendations in Year 1. Since it is likely that Horizon's adoption and implementation of NCI's recommendations could take several years to complete/phase-in, realization of complete savings could take more than one year to achieve.

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APPENDIX A: HORIZON, INITIATIVES FOR 2009 BUDGET

horizon UTILITIES

ASSET MANAGEMENT IMPLEMENTATION PROGRAM

Initiatives for 2009 Budget

1. **Proactive transformer replacement study**
   Stages:
   i. Gather and analyze data on all transformers replaced due to failure; look for trends/patterns
   ii. Gather and analyze data on all proactively replaced transformers
   iii. Investigate commonalities between proactively and reactively replaced transformers
   iv. Identify risks of transformer failure
   v. Determine costs of program – inspection and replacement costs (proactive and reactive)
   vi. Identify additional steps required to adequately create business case – **Navigant's assistance required**
   vii. Determine adequate levels of inventory for proactive and reactive
   viii. Investigate industry best practices – **Navigant's assistance required**
   ix. Develop business case to propose continuation of current program, reduction in scope of current program or elimination of current program – **Navigant's assistance required**

2. **Proactive pole replacement study**
   Stages:
   i. Evaluate proposals that were submitted for 2008 pole inspections and recommend most appropriate inspection method – **Navigant's assistance required**
   ii. Gather and analyze data on all poles identified to be at end of life; look for trends/patterns
   iii. Identify risks of pole failure
   iv. Determine costs of program – inspection and replacement costs (proactive and reactive)
   v. Determine adequate levels of inventory for proactive and reactive
   vi. Identify additional steps required to adequately create business case – **Navigant's assistance required**
   vii. Investigate industry best practices – **Navigant's assistance required**
   viii. Develop business case to propose continuation of current program, reduction in scope of current program or elimination of current program – **Navigant's assistance required**
   ix. Develop business case to propose continuation of pole inspections, reduction in scope of pole inspections or elimination of pole inspections – **Navigant's assistance required**
   x. Investigate possible training opportunities for employees involved – **Navigant's assistance required**

3. **Maintenance practices**
   Stages:
   i Choose 5-6 maintenance programs to study.
   ii Answer the following questions:
   - Is the program necessary? What are its benefits?
   - Are we taking the right approach? What improvements can be made? What are industry best practices? **Navigant's assistance required**
   - What dollar savings can be achieved through modifying this program? **Navigant's assistance required**
   - What risks are being addressed by the program?

Page 1 of 2

- Are there any inconsistencies between Hamilton and St. Catharines?

iii Develop business case(s) to modify maintenance programs. **Navigant's assistance required**

Other opportunities:

- Substation manager to propose improvements to substation maintenance
- Construction managers to propose improvements to maintenance programs in general

4. **Practices regarding replacement of equipment**

Focus on:

- Crew replacing pole during transformer replacement
- Crew replacing transformer during pole replacement
- Replacement of equipment at the discretion of crews / design techs.

Stages:

i. Conduct interviews with construction managers and supervisors
ii. Develop checklists or guidelines for crews – **Navigant's assistance required**

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APPENDIX B: EQUIPMENT REPLACEMENT GUIDELINES

Wood Pole Replacement Criteria

These criteria are to be used by Design Technicians and Construction Supervisors to determine if a wood pole should be replaced.

Criterion 1

Look up the pole in the pole inspection results database. Has the remaining life of the pole been estimated to be 5 years or less?

☐ No

☐ Yes ⟶ REPLACE POLE

↓ PROCEED TO CRITERION 2

Criterion 2

Visually inspect the pole. Do you observe any of the following?

- The pole is leaning and is in imminent danger of falling over.
- There is serious damage to the pole caused by a vehicle, equipment or animals.
- There is major shell rotting around the whole circumference of the pole base.
- The pole is splitting significantly at its top.

☐ No

☐ Yes ⟶ REPLACE POLE

↓ PROCEED TO CRITERION 3

Criterion 3

Will the pole be replaced through an identified capital project?

☐ No

☐ Yes ⟶ LEAVE POLE

↓ PROCEED TO CRITERION 4

Criterion 4

It seems like the condition of the pole does not warrant its replacement. If the reason for the replacement of the pole is not the condition of the pole, then is there any solution to the problem that avoids replacement of the pole?

☐ No

☐ Yes ⟶ LEAVE POLE

↓

REPLACE POLE

Transformer Replacement Criteria

These criteria are to be used by Lead Hands, Construction Supervisors and Design Technicians to determine if a transformer should be replaced. These criteria also apply when replacement of a transformer is being considered as a result of the replacement of the pole on which the transformer is mounted.

Criterion 1

Visually inspect the transformer. Do you observe any of the following?

- The transformer is leaking oil.
- The transformer is badly rusted.

☐ No → PROCEED TO CRITERION 2

☐ Yes → REPLACE TRANSFORMER

Criterion 2

Will a long outage be required to replace this transformer if it fails (considering configuration, mounting, connections, etc.)?

☐ Yes → PROCEED TO CRITERION 3

☐ No → LEAVE TRANSFORMER

Criterion 3

Will the transformer be replaced through an identified capital project?

☐ Yes → LEAVE TRANSFORMER

☐ No → REPLACE TRANSFORMER

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1-Staff-15 Monetizing Benefits

References:

1. Exhibit 1 Tab 2 Schedule 2
2. Exhibit 4 Tab 3 Schedule 4

Preamble:

In the first reference on starting on page 4, Horizon has listed seven benefits from its programmes from 2011 to 2014, but has monetized only one. In the second reference Horizon is showing the productivity savings from 2011, restated in MIFRS to 2019 in Table 4-44.

a. Please quantify the six non-monetized benefits found in Reference 1.

b. Please state which benefits are sustainable.

c. Please provide a break-down, and the cost savings of each of the programmes/changes that underpin the productivity savings in Table 4-44.

Response:

a)

Horizon Utilities understands this question to refer to the program benefits detailed in the bullets listed in Exhibit 1, Tab 2, Schedule 2, beginning on Page 5 under the heading "Operational Effectiveness".

The benefits listed relate to operational effectiveness and, where applicable, reference cost and productivity savings elaborated upon in Table 4-44 of Exhibit 4, Tab 3, Schedule 4. Not all of the programs listed generate quantifiable cost and productivity savings. However, these programs have benefits, such as ensuring the safe and reliable delivery of electricity; improving operational effectiveness; ensuring a safe work environment; and monitoring and improving employee engagement.

Horizon Utilities has quantified the monetary benefits below, where applicable, for the programs listed on page 4 of Exhibit 1 Tab 2 Schedule 2.

Programs with Monetized Benefits

Planning & Scheduling initiative

The Planning and Scheduling initiative produced $100,000 in sustained OM&A reductions and $1,230,000 in capacity and productivity improvements in 2013. These savings are expected to be sustained at this level from 2014 to 2019. A full description of the initiative and its benefits is provided in Exhibit 4, Tab 3, Schedule 4, starting on Page 19.

e-mobile initiative

The e-mobile initiative produced $1,075,000 in aggregated operating cost reduction, building of capacity, and future cost avoidance to the end of 2013 as provided in Exhibit 4, Tab 3, Schedule 4, Page 9. Forecasted annual productivity savings are estimated to be $1,750,000 annually beginning in the 2014 Bridge Year and sustained thereafter for the balance of the rate plan term.

IFS ERP Upgrade

Each phase of the IFS ERP upgrade is forecasted to produce productivity savings. Phase 2 of the upgrade project will be completed in the 2014 Bridge Year. Realized benefits to the end of 2014 will be $200,000 in OM&A reductions; $140,000 in additional productivity and staff capacity; and cost avoidance estimated to be $658,000. The initiative and its benefits are provided in Exhibit 4, Tab 3, Schedule 4, beginning on Page 31 and further detailed in Horizon Utilities' response to Interrogatory BOMA 8 a).

GIS/OMS

The operational and customer benefits of the GIS/OMS systems are provided in Exhibit 2, Tab 6, Schedule 1, beginning on page 72. The GIS system has reached end-of-life. It does not have the capacity to satisfy the Horizon Utilities' information needs at an enterprise level and is foundational to the implementation of the OMS.

Productivity improvements, in the form of organizational capacity, are estimated at $0.36MM annually commencing after the OMS is implemented in the 2014 Bridge Year and the 2015 Test Year and beyond. The corresponding payback on the OMS investment is just over three years.

The OMS will be implemented in phases, increasing its value proposition to the organization and customers in each of the Test Years. Horizon Utilities plans to develop metrics to measure the productivity improvements and staff capacity enhancements as they are realized including the benefits due to the provision and maintenance of a single set of maps, improved asset

management analytics, consolidation of systems, the interrogation of Smart Meters for outage response, and automated call handling.

Future potential benefits of the GIS and OMS include::

- a meaningful reduction in the duration of service outages for customers
- proactive customer communication on outage (i.e., post on the web, record on the IVR, and/ or e-mail/ telephone contact with customer in advance of the customer calling us to identify their outage – we have already identified it)
- improved productivity as power outage can be identified without sending out a truck to investigate.
- improved productivity as a result of the elimination of the current manual process of entering outage data from SCADA into CIS and other systems to manage outages under the status quo.

Programs with non-monetized Benefits:

Asset Condition Assessments and the Replacement and Renewal of Distribution System and Buildings Infrastructure

Horizon Utilities has not monetized the benefits related to Asset Condition Assessments and the Replacement and Renewal of Distribution System and Facilities Buildings Infrastructure.

The benefits of the asset condition assessment work is difficult to monetize, as the benefit is proactive risk management to ensure the continued safe, reliable delivery of electricity to customer through identification of the health of the distribution system and the long-term investment requirements. As identified in Exhibit 2, Tab 6, Schedule 1, Page 11, the failure to address the conditions of the distribution assets could result in deteriorating reliability performance; taking unnecessary risks associated with failures of assets with significant consequence of failure; and creating future investment needs that would be substantially higher than historical levels.

The investment in Horizon Utilities' distribution system renewal is critical to mitigate system health degradation and related reliability risks. As identified in section 3.5.3 of the Distribution System Plan, failure to invest at the proposed levels will result in increasing risk, which will

escalate to a point beyond Horizon Utilities' ability to address within reasonable timeframes or at reasonable costs.

As provided in Exhibit 2, Tab 6, Schedule 1, beginning on Page 27, the replacement and renewal of Horizon Utilities' building infrastructure will make more effective and efficient use of available space, replace end-of-life systems, and eliminate unsafe working environments. Horizon Utilities has had increased expenditures related to increased maintenance on end-of-life systems, required structural repairs, and additional expense to procure replacements parts for obsolete systems. Horizon Utilities' increased expenditures, identified in Table 2-54 of Exhibit 2, Tab 6, Schedule 1, will be contained through the replacement and renewal of the building infrastructure.

CSA Z1000 Health and Safety Program

The value of a continuous improvement safety program and building a high performing safety culture with all employees is difficult to quantify, but very important to Horizon Utilities as an employer in the electricity sector. Horizon Utilities' Health and Safety Program is a top priority for the organization and key to driving toward zero workplace injuries. Horizon Utilities selected the Canadian Standards Association ("CSA") Z1000 standard to enhance its safety program; which is a proven, systematic and focused approach to managing safety as described in Exhibit 1, Tab 2, Schedule 2, p.7.

A software-based approach was implemented to leverage the CSA Z1000 standard and framework, and to manage compliance with legislative, regulatory, industry and corporate health and safety requirements. This improves the overall efficiency of the Health and Safety system and its users across the organization by automating many of the requirements of the Occupational Health and Safety Management System such as tracking and notification of policy and procedure reviews, health and safety reporting, and key performance tracking such as workplace incidents and injuries, vehicle incidents, medical aids, first aids, and contractor compliance. Enhanced health and safety information provided in real time across the organization will allow for faster and better informed decisions to reduce and prevent workplace incidents and injuries.

Horizon Utilities has not quantified the benefits of its Health and Safety program. However, it is Horizon Utilities' expectation that the successful implementation of CSA Z1000 will assist in building the structure, discipline and accountability necessary to achieve continuous

improvements regarding workplace incidents, medical aids, and injuries and associated reductions in downtime, absenteeism and disability costs

Employee Satisfaction Surveys

Horizon Utilities has not quantified the benefits associated with improved employee engagement. However, as indicated in Exhibit 1, Tab 2, Schedule 2, Page 8, the positive impacts on organizational health and performance are well documented globally and appear as incremental benefits in many ways. Engaged employees drive productivity through more efficient, effective and safe work practices, as well as higher levels of customer satisfaction. A focus on employee engagement is considered by Horizon Utilities to be a continuous improvement opportunity and one that is supportive of its corporate objectives, particularly "Be the Best Performing Utility", and "Be a Great Place to Work" as illustrated in Exhibit 1, Tab 2, Schedule 1, p.2.

b)

Horizon Utilities has built measurement mechanisms into its material projects and initiatives to document the operating expenditure reductions and productivity savings achieved to date and to forecast the estimated quantifiable productivity over the rate plan term. Expenditure reductions and avoidances are sustained through the rate plan and are anticipated to be permanent.

Each of the initiatives listed in Exhibit 4, Tab 3, Schedule 4, Table 4-43 – Productivity Achievement – Actual and Forecast are sustained savings and a continued direct benefit to Horizon Utilities' customers. Horizon Utilities' response to Building Owners and Managers Association, Greater Toronto ("BOMA") interrogatory 8 part b) provides additional information regarding the sustainability of each of the initiatives.

c)

Horizon Utilities provides the break-down, and the cost savings of each of the program/changes that underpin the productivity savings in Table 4-44 in the table below. Further details are provided in Horizon Utilities' response to BOMA 8 a).

Table 1: Cost Savings

Department	Department		2011 Actual	2012 Actual	2013 Actual	2014 Test Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year
Construction & Maintenance	Planning & Sched.	Oper. Reductions	$ -	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000
Construction & Maintenance		Prod.Impr/Cap	$ -	$ 310,000	$ 1,230,000	$ 1,230,000	$ 1,230,000	$ 1,230,000	$ 1,230,000	$ 1,230,000	$ 1,230,000
Construction & Maintenance	Outsourcing	Oper. Reductions	$ -	$ -	$ -	$ 200,000	$ 300,000	$ 400,000	$ 400,000	$ 400,000	$ 400,000
Construction & Maintenance		Prod.Impr/Cap	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Construction & Maintenance	Downtime	Oper. Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Construction & Maintenance	Reduction	Prod.Impr/Cap	$ -	$ 190,000	$ 370,000	$ 370,000	$ 370,000	$ 370,000	$ 370,000	$ 370,000	$ 370,000
Construction & Maintenance	Absenteeism	Oper. Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Construction & Maintenance	Reduction	Prod.Impr/Cap	$ -	$ 100,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000	$ 120,000
Construction & Maintenance	**Construction &**	Oper. Reductions	**$ -**	**$ 100,000**	**$ 100,000**	**$ 300,000**	**$ 400,000**	**$ 500,000**	**$ 500,000**	**$ 500,000**	**$ 500,000**
Construction & Maintenance	**Maintenance**	Prod.Impr/Cap	**$ -**	**$ 600,000**	**$ 1,720,000**	**$ 1,720,000**	**$ 1,720,000**	**$ 1,720,000**	**$ 1,720,000**	**$ 1,720,000**	**$ 1,720,000**
Information Systems & Technology	IFS ERP Phase 1	Oper. Reductions	$ -	$ -	$ 60,000	$ 170,000	$ 170,000	$ 170,000	$ 170,000	$ 170,000	$ 170,000
Information Systems & Technology		Prod.Impr/Cap	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Information Systems & Technology	IFS ERP Phase 2	Oper. Reductions	$ -	$ -	$ -	$ 30,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000	$ 50,000
Information Systems & Technology		Prod.Impr/Cap	$ -	$ -	$ -	$ 30,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000
Information Systems & Technology	IFS ERP Phase 3	Oper. Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Information Systems & Technology		Prod.Impr/Cap	$ -	$ -	$ -	$ 110,000	$ 700,000	$ 700,000	$ 700,000	$ 700,000	$ 700,000
Information Systems & Technology	IFS ERP Upgrade	Oper. Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Information Systems & Technology		Prod.Impr/Cap	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 30,000	$ 130,000
Information Systems & Technology	Enterprise Unified	Oper. Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Information Systems & Technology	Comm.	Prod.Impr/Cap	$ -	$ -	$ -	$ -	$ 280,000	$ 280,000	$ 280,000	$ 280,000	$ 280,000
Information Systems & Technology	**Information**	Oper. Reductions	**$ -**	**$ -**	**$ 60,000**	**$ 200,000**	**$ 220,000**	**$ 220,000**	**$ 220,000**	**$ 220,000**	**$ 220,000**
Information Systems & Technology	**Systems &**	Prod.Impr/Cap	**$ -**	**$ -**	**$ -**	**$ 140,000**	**$ 1,020,000**	**$ 1,020,000**	**$ 1,020,000**	**$ 1,050,000**	**$ 1,150,000**
Customer Services	E-mobile	Oper. Reductions	$ 25,000	$ 200,000	$ 400,000	$ 600,000	$ 600,000	$ 600,000	$ 600,000	$ 600,000	$ 600,000
Customer Services		Prod.Impr/Cap	$ 50,000	$ 300,000	$ 675,000	$ 1,150,000	$ 1,150,000	$ 1,150,000	$ 1,150,000	$ 1,150,000	$ 1,150,000
Customer Services	Customer	Oper. Reductions	$ -	$ -	$ 60,000	$ 70,000	$ 60,000	$ 70,000	$ 80,000	$ 90,000	$ 100,000
Customer Services	Service/Outsourcin	Prod.Impr/Cap	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Customer Services	Customer Service -	Oper. Reductions	$ -	$ 175,000	$ 250,000	$ 250,000	$ 325,000	$ 345,000	$ 365,000	$ 385,000	$ 405,000
Customer Services	Misc.	Prod.Impr/Cap	$ -	$ 125,000	$ 125,000	$ 150,000	$ 150,000	$ 170,000	$ 190,000	$ 200,000	$ 210,000
Customer Services	**Customer Services**	Oper. Reductions	**$ 25,000**	**$ 375,000**	**$ 710,000**	**$ 920,000**	**$ 985,000**	**$ 1,015,000**	**$ 1,045,000**	**$ 1,075,000**	**$ 1,105,000**
Customer Services		Prod.Impr/Cap	**$ 50,000**	**$ 425,000**	**$ 800,000**	**$ 1,300,000**	**$ 1,300,000**	**$ 1,320,000**	**$ 1,340,000**	**$ 1,350,000**	**$ 1,360,000**
Supply Chain Management	Fleet Initiatives	Oper. Reductions	$ -	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
Supply Chain Management		Prod.Impr/Cap	$ -	$ -	$ -	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Supply Chain Management	Procurement	Oper. Reductions	$ -	$ -	$ -	$ 30,000	$ 40,000	$ 40,000	$ 40,000	$ 50,000	$ 50,000
Supply Chain Management	Initiatives	Prod.Impr/Cap	$ -	$ -	$ -	$ 20,000	$ 20,000	$ 30,000	$ 30,000	$ 40,000	$ 40,000
Supply Chain Management	Logistics Initiatives	Oper. Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supply Chain Management		Prod.Impr/Cap	$ -	$ -	$ -	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 40,000	$ 60,000
Supply Chain Management	Facilities Initiatives	Oper. Reductions	$ -	$ -	$ 20,000	$ 30,000	$ 40,000	$ 40,000	$ 50,000	$ 50,000	$ 40,000
Supply Chain Management		Prod.Impr/Cap	$ -	$ -	$ 30,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000
Supply Chain Management	Reduction SCM	Oper. Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Supply Chain Management	Meetings	Prod.Impr/Cap	$ -	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000	$ 20,000
Supply Chain Management	**Supply Chain**	Oper. Reductions	**$ -**	**$ 20,000**	**$ 40,000**	**$ 80,000**	**$ 100,000**	**$ 100,000**	**$ 110,000**	**$ 120,000**	**$ 110,000**
Supply Chain Management	**Management**	Prod.Impr/Cap	**$ -**	**$ 20,000**	**$ 50,000**	**$ 90,000**	**$ 90,000**	**$ 100,000**	**$ 100,000**	**$ 120,000**	**$ 140,000**
Finance	Activity Based	Oper. Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Finance	Costing /	Prod.Impr/Cap	$ -	$ -	$ 20,000	$ 100,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000	$ 200,000
Finance	Financial Planning	Oper. Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Finance	Solution	Prod.Impr/Cap	$ -	$ -	$ -	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000
Finance	Elec. Funds	Oper. Reductions	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Finance	Transfer ("EFT")	Prod.Impr/Cap	$ -	$ -	$ 30,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000
Finance	**Finance**	Oper. Reductions	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Finance		Prod.Impr/Cap	**$ -**	**$ -**	**$ 50,000**	**$ 240,000**	**$ 340,000**	**$ 340,000**	**$ 340,000**	**$ 340,000**	**$ 340,000**
Total			**$ 75,000**	**$ 1,540,000**	**$ 3,530,000**	**$ 4,990,000**	**$ 6,175,000**	**$ 6,335,000**	**$ 6,395,000**	**$ 6,495,000**	**$ 6,645,000**

1-Staff-16 Total Productivity Factor

References:

1. Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012
2. Exhibit 1 Tab 2

Preamble:

On page 20 of the RRFE Report, the Board states that expected inflation and productivity gains will be built into the rate adjustment over the term.

The Board calibrates the productivity factor used in its Price Cap IR and Annual Index rate setting methods using a measure of industry total factor productivity ("TFP") growth. An individual distributor's TFP growth can also be calculated. A TFP index is the ratio of an output quantity index to an input quantity index. The growth trend in a TFP trend index is the difference between the trends in the component output quantity and input quantity indexes. TFP is explained further in Section 2.2 of an EB-2010-0379 report prepared by, Dr. Lawrence Kaufmann and his team at Pacific Economics Group Research, LLC, entitled "Empirical Research in Support of Incentive Rate-Setting: Final Report to the Ontario Energy Board."[1]

Using PEG's Excel file that is posted on the Board's web site and which contains all the data used in PEG's productivity and benchmarking research in support of incentive rate setting in Ontario (i.e., the results of PEG's index-based input price and productivity computations, and related work papers), Board staff isolated the output quantity, input quantity and productivity indexes for Horizon. Staff made no changes to the data or to the calculations in the worksheets. To be able to isolate Horizon's data in the TFP calculations, staff used the existing "Observation Used in TFP Work" flag column in each of the following sheets: 2. BM Database, 3. TFP Database, and 5. Capital Calculations for TFP. Staff set the value in these columns to "1" for Horizon and to "0" for all other distributors. The resultant productivity trends for Horizon, based on PEG's worksheet are provided in Attachment to 1 Staff 14.pdf.

Using Horizon's forecasts in this application and the PEG documentation and worksheets that are posted on the Board's web site (links entitled "Part I – Documentation for Working Papers" and "Part II - TFP and BM database calculation" are provided below) or Horizon's comparable analyses please provide Horizon's forecasted total factor productivity trends for the period 2013 through to 2019.

Nov 21-13 ***Updated Dec 20-13 and***	**The Board has released a report prepared by Board staff's expert consultant, Dr. Lawrence Kaufmann and**

[1] Pacific Economics Group Research, LLC. Empirical Research in Support Of Incentive Rate Setting in Ontario. November, 2013. (http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379_Final_PEG_Report_20131111.pdf)

Jan 24-14	**his team at Pacific Economics Group Research, LLC, entitled "*Empirical Research in Support of Incentive Rate-Setting: Final Report to the Ontario Energy Board*."**
	• **Cover Letter**
	• **Final PEG Report (as corrected on Dec 19, 2013 and Jan 24, 2014)**
	  o **Tables in Final PEG Report (.xlsx, 3 MB) (as corrected on Dec 19, 2013 and Jan 24, 2014)**
	• **PEG's Working Papers**
	  o **Part I – Documentation for Working Papers**
	  o **Part II - TFP and BM database calculation (.xlsx, 8 MB) (as corrected on Dec 19, 2013 and Jan 24, 2014)**
	• **Price Cap IR Benchmarking Algorithm (.xlsx, 2 MB) (as corrected on Dec 19, 2013 and Jan 24, 2014)**

Response:

Horizon Utilities has reviewed the PEG documentation and worksheets that are posted on the Board's web site (links entitled "Part I – Documentation for Working Papers" and "Part II - TFP and BM database calculation" are provided below). Horizon Utilities is unable to successfully recreate a model specific to itself in a manner that would provide an accurate or reliable forecasted total factor productivity trends for the period 2013 through to 2019.

The Board is requesting Horizon Utilities to modify the PEG model from its original purpose of providing an industry TFP trend and expanding the model beyond its scope in years. The intended purpose of the model was to determine a general industry productivity factor based on multiple data points and multiple utilities; not to isolate individual utilities and assess TFPs on that basis. The original model provided TFP trends based on the historical actual data of the entire local distribution company ("LDC") sector. Certain of these variables have values that are hardcoded in the model and Horizon Utilities cannot determine how to extrapolate them and other determinants forward.

Despite its best efforts to do so, Horizon Utilities has been unable to update the complicated 23-tab model and verify the impact of each input on productivity when inputs are hard to trace and/or hard-coded; and the rationale for using a particular formula is not clear. Furthermore, Horizon Utilities does not have an in-depth conceptual understanding of the PEG model that contains relatively technical statistical modeling and computer programming; nor can it reasonably be expected to have such.

Some of the assumptions used to calculate TFP do not apply to Horizon Utilities such as i) 4.59% or a useful life of approximately 21 years; and ii) 0.50% retirement rate.

Despite being unable to create a forward-looking TFP using the PEG model, Horizon is not certain such information would have been useful in assessing its individual productivity achievement or commitment for the following reasons:

1. The output growth in the PEG model is based on a weighted average of growth for three output measures: total customers; billed kWh; and system capacity. Horizon Utilities serves two older, built out communities with corresponding low customer growth rates as identified in Exhibit 1, Tab 2, Schedule 6. Consequently, Horizon Utilities expects to experience a weighted average growth of 0.5% per annum or less from 2013 to 2019, based on the output quantities in the PEG model (customers, billed kWh and system capacity).

   Horizon Utilities and LDCs in general have virtually no control over output growth, which is entirely driven by: connections growth and retention; and customer choices regarding their own energy needs and consumption. Relatively low output growth and relatively high input growth results in an obvious drag on the TPF.

2. Input growth is based on a weighted average of growth for two output measures: capital; and OM&A. Horizon Utilities expects to experience real cost growth in excess of inflation and output growth. The nature of this growth is described in the Application.

Such costs and related real growth is necessary irrespective of changes in output, over which Horizon Utilities has no control. Horizon Utilities expects that the application of the PEG model would likely produce negative total factor productivity trends based on Horizon Utilities operating cost and capital expenditure profile relative to its customer growth and billed kWh profiles. This result would be misleading as it would mask the productivity achieved and committed within this Application within the overall necessary cost growth in real terms as described above. Horizon Utilities differs from newer LDCs in suburban municipalities with comparatively higher output growth rates and relatively new distribution systems requiring lower capital expenditure (net of customer contributions) and maintenance costs. Increased capital and OM&A expenditures to support growth directly correlate to an increase in output for newer LDCs – more customers and higher kWh deliveries. Horizon Utilities' rising investments and costs are largely renewal and sustainment based to ensure the reliable and safe delivery of electricity to a relatively unchanging customer base.

3. Outputs are on a non-monetary basis and inputs are on a monetary basis. In a "no-output" growth scenario, inflationary growth in costs partly offset by productivity results in a negative productivity trend in the PEG model. The model does not provide for an analysis of potential productivity in the sector; it only provides a trend relative to changes in historical inputs and outputs within the sector based on analysis of inputs and outputs for the entire sector.

4. The PEG model does not distinguish between real cost growth and inflationary growth. There is no correlation between inflationary growth and outputs. However in a low output growth scenario such as Horizon Utilities, an increase in costs due to inflation less productivity could incorrectly result in a negative productivity trend in the PEG model.

5. Horizon Utilities either cannot verify some of the prior year assumptions or there are changes in the assumptions for a variable (e.g. kWh deliveries) used in the PEG model from year to year.

Horizon Utilities has provided certain analysis in the Application and in response to corresponding interrogatories that identify its revenue and cost growth relative to IPI-X and calibrate such to its unique features and relative cost positioning in the sector:

- E1/T2/S4/p.1-6 that describe Horizon Utilities unique features;

- E1/T2/S6/p.24-31 that provides OM&A analysis relative to the IPI-X and transparently identifies real cost increases net of productivity above this trend (which is one of the principal purposes for the Custom IR application. In response to 1-EP-3 and 1-BOMA-7, this analysis is expanded to include broader revenue requirement and OM&A trend analysis relative to IPI-X trends using Board-approved factors and Horizon Utilities estimated factors;
- E1/T2/S6/p.31-32 provides a comparison of Horizon Utilities' costs to the LDC Sector.

The analysis at E1/T2/S6/p.24-31 and corresponding IRs identified above clearly and transparently demonstrate that, based on cost/ revenue growth inputs and customer growth outputs, Horizon Utilities requires cost and revenue growth in excess of its own estimated specific and Board specified inflation and TFP factors. This is the principal basis for filing the Custom IR application. However, the PEG TFP methodology does not appear to isolate for real cost growth relative to inflationary growth nor does it consider the unique or distinguishing features of LDCs in various stages of growth and renewal or with differentiated customer and load growth profiles.

Horizon Utilities has net real cost and revenue per customer growth above: i) inflation and ii) sustained productivity achieved and committed from 2011 through 2019. The necessity and prudency of the drivers of such cost growth is provided broadly in the Application.

Horizon Utilities also offers the following analysis as indicative of its TPF cost performance from 2011 to 2019 (1-Staff-16 Attch 1_TPF):

A live Excel version of this model has also been provided to facilitate a review of underlying calculations.

The purpose of the above attachment is to demonstrate the effect of productivity achieved and committed in this Application on OM&A and Revenue Requirement. The analysis provides the impact of such productivity on the Compound Annual Growth Rate ("CAGR") of OM&A and Revenue Requirement per customer from 2011 to 2019. Such impact is determined by taking the difference between: i) the actual and forecast OM&A/ Revenue Requirement CAGR per customer as provided in this Application; and ii) the same as i) but adjusted to remove the impact of productivity as provided in E4/T3/S4/p.4.

The analysis indicates that productivity has and will contribute: i) a favourable 1.17% CAGR impact on OM&A from 2011 to 2019; ii) a favourable 0.64% CAGR impact on Revenue

Requirement from 2011 to 2019. Horizon Utilities submits that, relative to the Board approved metrics for TPF, including stretch factor, during this period (1.12% from 2011 to 2013 and 0.15% from 2014 to 2019), this is a very favourable result.

1-Staff-16 Attch 1_TPF

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HORIZON UTILITIES
Productivity Trend Analysis
2011 to 2019

	2011 Actual MIFRS	2012 Actual MIFRS	2013 Actual MIFRS	2014 Bridge Year MIFRS	2015 Test Year MIFRS	2016 Test Year MIFRS	2017 Test Year MIFRS	2018 Test Year MIFRS	2019 Test Year MIFRS
Total OM&A (including Smart Meters)	$ 50,790,410	$ 51,478,365	$ 54,516,505	$ 60,387,369	$ 62,632,679	$ 64,394,131	$ 66,255,827	$ 67,708,658	$ 69,140,489
Total Revenue Requirement ("RR") (including Smart Meters)	$ 99,934,633	$104,901,463	$105,099,210	$107,230,228	$113,490,384	$118,628,501	$121,743,444	$123,920,317	$127,881,899
Cumulative Productivity Achieved/ Forecast (E4/T3/S4/p.4)	$ 75,000	$ 1,540,000	$ 3,530,000	$ 4,990,000	$ 6,175,000	$ 6,335,000	$ 6,395,000	$ 6,495,000	$ 6,645,000
Total OM&A before Productivity	$ 50,865,410	$ 53,018,365	$ 58,046,505	$ 65,377,369	$ 68,807,679	$ 70,729,131	$ 72,650,827	$ 74,203,658	$ 75,785,489
Total RR before Productivity	$ 100,009,633	$106,441,463	$108,629,210	$112,220,228	$119,665,384	$124,963,501	$128,138,444	$130,415,317	$134,526,899
Customer/ Connections Counts	237,161	238,488	240,114	241,692	243,319	245,123	247,036	249,021	250,909
Total OM&A per Customer	$ 214.16	$ 215.85	$ 227.04	$ 249.85	$ 257.41	$ 262.70	$ 268.20	$ 271.90	$ 275.56
Total RR per Customer	$ 421.38	$ 439.86	$ 437.71	$ 443.66	$ 466.43	$ 483.95	$ 492.82	$ 497.63	$ 509.67
Total Productivity per Customer	$ 0.32	$ 6.46	$ 14.70	$ 20.65	$ 25.38	$ 25.84	$ 25.89	$ 26.08	$ 26.48
Total OM&A before Productivity per Customer	$ 214.48	$ 222.31	$ 241.75	$ 270.50	$ 282.79	$ 288.55	$ 294.09	$ 297.98	$ 302.04
Total RR before Productivity per Customer	$ 421.70	$ 446.32	$ 452.41	$ 464.31	$ 491.80	$ 509.80	$ 518.70	$ 523.71	$ 536.16
Implied Productivity in OM&A/ Customer									
CAGR - Total OM&A/ Customer		0.79%	2.96%	5.27%	4.71%	4.17%	3.82%	3.47%	3.20%
CAGR - Total OM&A/Customer before Productivity		3.65%	6.17%	8.04%	7.16%	6.11%	5.40%	4.81%	4.37%
CAGR Difference - Implied Productivity in OM&A/ Customer		-2.86%	-3.20%	-2.77%	-2.45%	-1.94%	-1.58%	-1.34%	-1.17%
Implied Productivity in Revenue Requirement									
CAGR - Total RR/ Customer		4.39%	1.92%	1.73%	2.57%	2.81%	2.64%	2.40%	2.41%
CAGR - Total RR/ Customer before Productivity		5.84%	3.58%	3.26%	3.92%	3.87%	3.51%	3.14%	3.05%
CAGR Difference - Implied Productivity in RR/ Customer		-1.45%	-1.66%	-1.53%	-1.35%	-1.06%	-0.87%	-0.74%	-0.64%

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2-Staff-17 Pacing of Investments

References:

1. Exhibit 2 Appendix 2-4 Section 3.1 Summary of Capital Expenditure Plan
2. Exhibit 2 Appendix 2-4 Appendix D Innovative Customer Consultation Report

Reference 1 shows Horizon's planned investment profile versus the one recommended by Kinectrics. Horizon states that "the front loading of investments identified by Kinectrics is consistent with a backlog of assets requiring renewal and overdue for replacement." Commenting on its investment trajectory, Horizon noted that Kinectrics' recommendation would result in an "unfair rate impact".

a. With respect to the statement at Reference 1, on what basis did Horizon make this judgement?

b. How did Horizon take into account value for present customers versus future customers?

c. What outcomes from the Innovative Customer Consultation Report, did Horizon use to help set the capital spending levels?

Response:

a. Horizon Utilities' assessment that the investment profile identified by the Kinectrics' ACA is consistent with a backlog of assets requiring renewal was based on the similarity between the investment profile identified by Kinectrics' ACA and Horizon Utilities previous asset management studies provided in the 2011 Cost of Service application (EB-2010-0131). Horizon Utilities' previous asset management studies identified a high number of assets overdue for replacement ("backlog") which created a high immediate investment requirement. The level of investment decreases as the number of assets requiring renewal decreases. This investment profile is similar to the investment profile identified by the Kinectrics' ACA. This similarity was the basis of Horizon Utilities' statement that *"the front loading of investments identified by Kinectrics is consistent with a backlog of assets requiring renewal and overdue for replacement."*

Horizon Utilities' assessment that implementing the Kinectrics recommendation would result in an "unfair rate impact" was based on a comparison of the investment profile proposed in this Application to that recommended by Kinectrics. Kinectrics' recommended investment in 2015 and over the rate plan term is $32.4MM and $52.5MM higher than that proposed in

this Application, respectively. Rate mitigation is a primary, but not the only consideration for Horizon Utilities in determining the appropriate level of capital investment. A sharp increase in investment to the Kinectrics' level without supporting customer rates would not be affordable for Horizon Utilities. Additionally, Horizon Utilities does not have the ability, at proposed staffing levels, to perform the volume of work that the Kinectrics recommendation would require. Kinectrics' recommended investment level for 2015 of $60.3MM is 216% higher than the level proposed in the Application.

b. Horizon Utilities took into account value for present versus future customers by pacing its investments over a 20-year planning horizon. Horizon Utilities took a measured approach in determining its level of capital expenditures in order to mitigate rate impacts and ensure that present customers did not bear a disproportionate portion of the renewal costs. At the same time, Horizon Utilities recognized that continuing with the present level of capital expenditure would exacerbate trends of declining reliability and increasing service disruption, increase public and employee safety risks and shift the burden of renewal to future customers. Investments in system renewal during the term of the application will benefit present customers by improving reliability and decreasing public safety risks.

The 2013 Asset Condition Assessment conducted by Kinectrics and filed as Appendix D of Appendix 2-4 in Exhibit 2 provides clear corroboration for the assertion that, based on sound engineering principles and best asset management practices, the health of Horizon Utilities' distribution system is unacceptable for certain assets, and generally degrading. Increased investment is required to halt further system health degradation to increasingly unacceptable levels. Kinectrics identified a 20 year System Renewal 5-year investment requirement of $199,659,000 as identified in Figure 2-2 in Exhibit 2, Tab 6 Schedule 1. Horizon Utilities' assessment of the investment level and profile recommended by Kinectrics determined that this level of investment would result in a very large and material rate impact on the customer base within a short period of time. Doing nothing to address the end-of-life of these assets, however, would be irresponsible. Horizon Utilities proposed an investment requirement of $147,178,000 in its Application by delaying a portion of the renewal to future years in order to allocate costs equitably between present and future customers. Proceeding with Kinectrics' recommendation would unfairly burden present customers with a high cost of renewal – renewal which would also benefit future customers. As such, Horizon Utilities

c. Horizon Utilities used the outcomes from the Innovative Customer Consultation Report to validate and confirm that the capital investment levels were set appropriately versus using the outcomes to help set the capital investment levels. The 2015 to 2019 Test Year capital investment levels were set prior to the execution of the customer engagement process. The timelines for Horizon Utilities' Application required that the DSP and the 2015 to 2019 capital plans be developed, reviewed and assessed prior to receiving the Innovative Customer Consultation Report. The outcomes of the customer engagement process did validate that the approach adopted in Horizon Utilities' DSP, with its emphasis on system renewal over the 2015-2019 Test Year period, is consistent with the customer preferences expressed through the customer engagement process. The majority of customers accepted the need for system renewal, notwithstanding that this may involve increased distribution rates. The DSP's focus is consistent with these findings and as such, Horizon Utilities did not alter its capital investment levels based on the outcomes from the Innovative Customer Consultation Report. The results of Horizon Utilities customer engagement are provided in Exhibit 2, Tab 6, Appendix 2-4, pages 212 to 217.

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2-Staff-18 Asset Condition Assessment

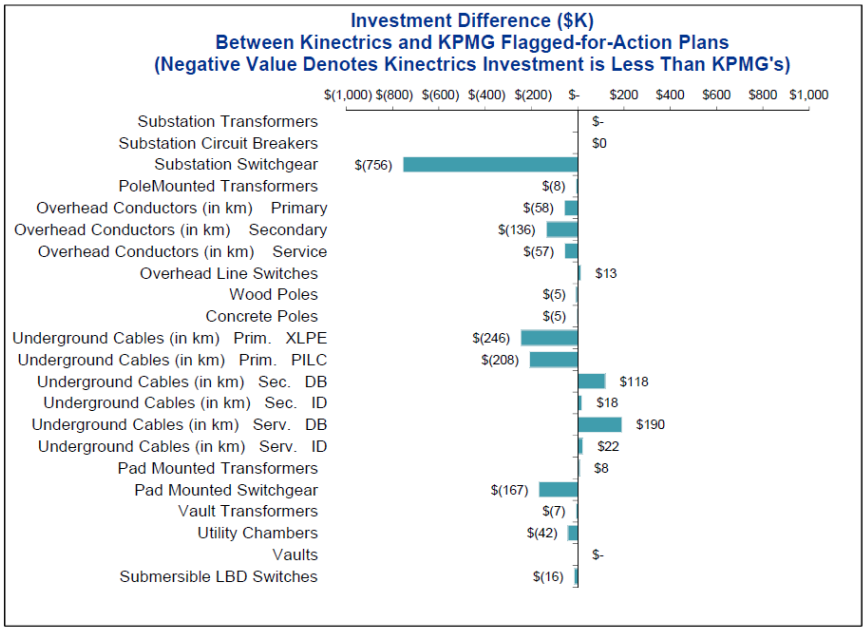
References:

1. Exhibit 2 Appendix 2-4 Appendix B Kinectrics' 2013 Asset Condition Assessment
2. Exhibit 2 Appendix 2-4 Appendix C KPMG Assurance Review of Kinectrics' Asset Condition Assessment Review
3. Exhibit 2 Appendix 2-4 Section 3.1 Summary of Capital Expenditure Plan

Preamble:

Reference 2 shows a comparison of required investments by asset category between Kinectrics' plan and KPMG's:

Figure 8: Comparison of Estimated Value of Flagged-for-Action Plans between Kinectrics and KPMG



a. Does the DSP contain an economic evaluation component indicating what the most cost effective actions are for the various categories identified in Figure 8 of the KPMG Report shown above? If so, please point to where this is reflected in the evidence.

b. Please submit the standard unit costs used in the determination of the Flagged-for-Action investment plans.

c. Please comment on the investment difference between Kinectrics and KPMG Plans, and whether the lower investment considerations in KPMG's assurance review were incorporated and taken into account by Horizon in its final DSP. If not, why not? Please use the Substation Switchgear asset category and discuss how adopting KPMGs number would alter the current DSP.

d. Why did Horizon decide not to incorporate each and every one of the lower investment recommendations found in KPMG's comparative analysis?

e. Please confirm that Appendix A of the ACA establishes measurable specifications of how the asset should perform not only those owned by Horizon, but in general for these types of assets. Please point to where this is reflected in the evidence.

Response:

a) The DSP contains an economic evaluation component indicating what the most cost effective actions are for its Capital Investment Programs. Horizon Utilities' System Renewal investment is accomplished through the execution of Capital Investment Programs as identified in Exhibit 2, Tab 6, Appendix 2-4, Section 3.1.3. Horizon Utilities prioritizes assets requiring replacement based on investment need. Capital Investment Programs are subsequently designed to address: multiple asset categories which have a poor Health Index distribution; asset categories having a high investment requirement; and areas with operational issues that have either caused, or have a high risk of causing significant customer impact.

The mapping of Horizon Utilities' asset categories in poor health to Capital Investment Programs is provided below and in Exhibit 2, Tab 6, Appendix 2-4, Table 31.

Table 31 from Exhibit 2, Tab 6, Appendix 2-4, Table 31

Asset Group	Kinectrics Recommended 5 Year Replacement Value	Percentage of Assets with 'Poor' or 'Very Poor' Health Index	4kV and 8kV Renewal Program	XLPE Cable Renewal Program	Pole Residual Program	Proactive Transformer Replacement	LBDS Maintenance	Reactive Replacement
Underground Cables (primary XLPE)	$ 54,684,156	29%		X				X
Wood Poles	$ 24,443,926	11%	X		X			
Underground Cables (secondary DB)	$ 17,265,561	42%		X				X
Underground Cables (primary PILC)	$ 14,472,205	1%						X
Overhead Conductors (service)	$ 12,565,410	11%	X					X
Underground Cables (service DB)	$ 12,248,968	63%		X				X
Pole Mounted Transformers	$ 11,840,422	6%	X			X		X
Overhead Conductors (secondary)	$ 11,818,950	9%	X					X
Vault Transformers	$ 9,643,423	49%		X				X
Overhead Conductors (primary)	$ 9,049,700	5%	X					
Substation Switchgear	$ 5,250,000	32%	X					
Underground Cables (secondary ID)	$ 2,555,198	42%		X				X
Substation Circuit Breakers	$ 1,665,000	23%	X					
Overhead Line Switches	$ 1,653,832	20%					X	
Submersible LBD Switches	$ 308,960	46%						

Horizon Utilities has provided an economic evaluation component (defined as "the comparative analysis of alternative courses of action in both their costs and consequences") for its Capital Investment Programs in Section 3.5.3 of the DSP provided as Exhibit 2, Tab 6, Appendix 2-4.

b) Horizon Utilities provides the standard unit costs used in the determination of the "Flagged-for-Action" investment plans Table 1 below. The unit costs used throughout the DSP are based on 2013 values and are not adjusted for inflation.

Table 1

Assets	Sub-Category		Replacement Cost
Substation Transformers			$ 150,000.00
Substation Circuit Breakers			$ 45,000.00
Substation Switchgear			$ 750,000.00
Pole Mounted Transformers			$ 7,713.63
Overhead Conductors	Primary (per meter, per hase)		$ 43.30
	Secondary (per meter)		$ 41.47
	Service (per meter)		$ 41.47
Overhead Line Switches			$ 13,556.00
Wood Poles			$ 4,424.24
Concrete Poles			$ 5,000.00
Underground Cables	Primary	XLPE (per meter, per phase)	$ 108.25
		PILC (per meter)	$ 247.05
	Secondary	DB (per meter)	$ 124.89
		ID (per meter)	$ 24.89
	Service	DB (per meter)	$ 124.89
		ID (per meter)	$ 24.89
Pad Mounted Transformers			$ 16,667.12
Pad Mounted Switchgear			$ 55,000.00
Vault Transformers			$ 6,815.14
Utility Chambers			$ 20,890.00
Vaults			$ 8,193.00
Submersible LBD Switches			$ 7,724.00

c) The investment identified by KPMG differs from the investment identified by Kinectrics by $1,800,000 over the 2015 to 2019 Test Years and by $1,100,000 over Horizon Utilities' twenty-year planning horizon as identified in Table 2 below.

Table 2

	2015 - 2019 Investment	Total 20-year Investment
KPMG	$ 195,700,000	$ 694,800,000
Kinectrics	$ 197,500,000	$ 693,700,000
$ Variance	$ (1,800,000)	$ 1,100,000
% Variance	(0.9%)	0.2%

The differences resulting from KPMG's calculations versus Kinectrics' calculations do not reflect a materially different investment requirement. The purpose of KPMG's

assurance review was to provide an opinion on Kinectrics' methodology and the resultant findings and recommendations contained in the report. As stated by KPMG on pages 13 of Appendix C to Exhibit 2, Tab 6, Appendix 2-4:

"This monetized plan is meant to serve as a normalized comparison in dollar terms between the two respective Flagged-for-Action plans and it is not meant to be used as the definitive guide for Horizon's future capital investments. The two plans returned very similar total investment values over the twenty year span supporting the reasonableness of the calculations presented in the Kinectrics report."

The lower investment considerations in KPMG's assurance review for 2015-2019 were not materially different from Kinectrics and both were significantly higher than Horizon Utilities' proposed investment. As such, they were not incorporated and taken into account by Horizon Utilities in its final DSP. As stated in Exhibit 2, Tab 6, Schedule 1, the investment level and profile recommended by Kinectrics would result in a very large and material rate impact on the customer base within a short period of time. Horizon Utilities proposes increasing annual renewal investment at a graduated rate in order to balance distribution system risks and customer bill impacts. Horizon Utilities' proposed capital expenditures for all asset categories for the 2015-2019 period are lower than the investment recommendations found in KPMG's comparative analysis.

Substation Switchgear Category

KPMG identified that 27 switchgear would have to be replaced over Horizon Utilities' twenty-year planning horizon. Kinectrics identified that 26 switchgear would have to be replaced as identified in Table 3 below.

Table 3

	# of Substation Switchgear	Substation Switchgear ($000s)
KPMG	27	$ 20,412
Kinectrics	26	$ 19,656
$ Variance	(1)	$ 756

The KPMG assurance review validated Kinectrics' recommendation that 26 switchgear would need to be replaced over the twenty-year planning horizon. There is no impact to

Horizon Utilities' current DSP over the 2015-2019 period as Horizon Utilities does not plan to replace any switchgear during this period.

d) As explained in part (c), Horizon Utilities' proposed capital expenditures for all asset categories for the 2015-2019 period are lower than the investment recommendations found in KPMG's comparative analysis.

e) Horizon Utilities confirms that Appendix A of Kinectrics Asset Condition Assessment ("ACA"), provided as Appendix B to Exhibit 2, Tab 6, Appendix 2-4, establishes measureable specifications on how assets should perform. The measurable specification on how assets should perform is based on the life expectancy of the asset groups included in the ACA. Horizon Utilities uses survival curves to measure asset performance. The ACA identifies the probability of failures and resulting survival curves for each asset group. The probability of failure and survival curves identified in the ACA for each asset group are specific to Horizon Utilities but are consistent with industry standards. A sensitivity analysis of the probability of failure and survival curves used in the ACA was performed by KPMG as part of its assurance review. KPMG stated on page 17 of KPMG's Assurance Review filed as Appendix C to Exhibit 2, Tab 6, Appendix 2-4:

"This comparison substantiates the life curves used by Kinectrics in their models are reasonably close to industry accepted useful life data. The Kinectrics' life curves have longer average expected life-spans for some of the asset classes leading to fewer asset investments identified for the immediate short term. When compared to the OEB results [identified in Figure 11 "Comparison of Flagged-For-Action Investment Profiles" in the Kinectrics' ACA]*, the Kinectrics Flagged-for-Action plan is not overstated and is reasonably within the industry accepted asset replacement or refurbishment practices for distribution utilities in Ontario."*

Horizon Utilities' failure curves for each asset category are provided in Appendix A of the Kinectrics' ACA filed as Appendix B to the DSP filed as Appendix 2-4 of Exhibit 2, Tab 6 on the pages identified in the table below.

Table 4: Failure Curve Reference

Assets		Page
Substation Transformers		44
Substation Circuit Breakers		55
Substation Switchgear		65
Pole Mounted Transformers		74
Overhead Conductors		81
Overhead Line Switches		94
Wood Poles		103
Concrete Poles		110
Underground Cables	Primary XLPE	117
	Primary PILC	118
	Secondary/Service	118
Pad Mounted Transformers		134
Pad Mounted Switchgear		145
Vault Transformers		153
Utility Chambers		163
Vaults		170
Submersible LBD Switches		175

2-Staff-19 Asset Condition Assessment (2)

Reference:

1. Exhibit 2/ Appendix 2-4/Appendix B/ Kinectrics' 2013 Asset Condition Assessment

Preamble:

The reference states that the probability of failure is determined by an asset's Health Index. And that in the ACA, the metric used to measure consequence of failure is referred to as criticality.

For pro-actively replaced assets, the ACA says that "a unit becomes a candidate for replacement when its risk value, the product of its probability of failure and criticality, is greater than or equal to 1." In the example shown below, Asset 1 and Asset 2 are candidates for proactive replacement.

Table II-4 Sample Replacement Ranking

Asset Name	Age	Health Index (HI)	Consequence of Failure (Criticality)	Probability of Failure (POF) Corresponding to HI	Risk (POF*Criticality)	Replacement Ranking
Asset 1	41	30.00%	2	82.5%	1.630	1
Asset 2	29	30.00%	1.5	82.5%	1.237	2
Asset 3	37	30.00%	1	78.20%	0.782	3
Asset 4	42	50.00%	2	12.80%	0.256	4
Asset 5	18	50.00%	1.5	12.80%	0.192	5
Asset 6	20	50.00%	1	12.80%	0.128	6

Appendix A of Reference 1 discusses results and findings for each asset category, including Substation Transformers, for which it shows the following:

VI - Appendix A: Results and Findings for Each Asset Category

Table 1-9 Criticality Factors

Criticality Factor (CF)	Description	Weight (WCF)	Score (CFS)	
Load criticality	--- Number of customers --- Customer importance (e.g. hospitals, provincial buildings, restoration time sensitive customers)	30	Low	0
			High	1
Physical Protection	oil containment, blast wall, deluge system	15	Yes	0
			No	1
Location	public exposure, environmental impact	15	No	0
			Yes	1
Expected Outage Duration	Back-up unit unavailable, alternate feeds unavailable	20	No	0
			Yes	1
Operation & Maintenance	--- obsolescence of spare parts (e.g. manufacturers cease to produce old types of spare parts) --- known issues (e.g. not economical to have routine maintenance)	20	No	0
			Yes	1

The risk matrix above suggests that if a substation transformer failure occurs that operational disruptions and income loss for Horizon would occur.

a. For continuity purposes, please provide the End of Life ("EOL") analysis performed in 2010-2013.

b. For substation transformers:

i. How is the risk assessment described above (load risk; inherent safety risk; locational safety risk; operational risk; technological risk) in the case of substation transformers translate into a measurable risk unit such as dollars
ii. How is the Weight of Condition Factor ("WCF") a useful and instructive measure?
iii. How is the criticality factor score determined? How is it useful, and how is such a measure taken into account by Horizon in its planning?
iv. The consequence of failure in the study is defined as criticality. How does criticality translate to a measurable risk once it is multiplied by the probability of failure?
c. Using the proactively replaced asset example:

i. Please confirm that the probability of failure takes into account the age parameter.
ii. Please confirm that higher risk assets are considered to be more urgent replacements. If otherwise, please explain.

iii. Please explain the replacement ranking provided at the table. Is the determining factor in replacement ranking the probability of failure or the risk of failure

Response:

a. Horizon Utilities' End of Life ("EOL") analysis completed in 2010, 2011 and 2012 is summarized in Tables 1 to 3 below. The tables identify the percentage of assets within each asset category which are beyond EOL, near EOL and Optimal. Horizon Utilities migrated from EOL analysis to using the Health Index measurement in 2013, as identified in Kinectrics Asset Condition Assessment ("ACA") filed as Appendix B to the DSP. As such EOL analysis was not performed in and is not available for 2013.

Table 1

2010 - Asset Type	Beyond End of Life	Near End of Life	Optimal
Substation Switchgear (40 year life span)	88%	12%	0%
Substation Breakers (40 year life span)	72%	19%	9%
Substation Power Transformers (50 year life span)	43%	43%	14%
Cable - Primary XLPE (30 year life span)	31%	29%	40%
Poles - Wood (50 year life span)	29%	28%	43%
Cable - Secondary/Service (40 year life span)	24%	53%	23%
Civil - Junction Boxes, Switching Cabinets (40 year life span)	20%	41%	39%
Overhead Transformer (40 year life span)	19%	31%	50%
Conductor - Primary (50 year life span)	17%	27%	56%
Poles - Concrete/Steel (60 year life span)	12%	32%	56%
Conductor - Secondary/Service (60 year life span)	12%	47%	41%
Submersible Transformer (40 year life span)	5%	47%	48%
Cable - Primary PILC (70 year life span)	1%	52%	47%
Padmounted Transformer (40 year life span)	2%	33%	65%
Civil - Manhole, Vaults, Pads (80 year life span)	0%	15%	85%
Duct	0%	19%	81%
Switches	27%	31%	42%
Total Asset Breakdown	**24%**	**33%**	**43%**

1 **Table 2**

2011- Asset Type	Beyond End of Life	Near End of Life	Optimal
Substation Switchgear (40 year life span)	86%	12%	2%
Substation Breakers (40 year life span)	70%	18%	12%
Substation Power Transformers (50 year life span)	47%	43%	10%
Cable - Primary XLPE (30 year life span)	33%	28%	39%
Poles - Wood (50 year life span)	31%	27%	42%
Cable - Secondary/Service (40 year life span)	25%	42%	33%
Civil - Junction Boxes, Switching Cabinets (40 year life span)	24%	38%	37%
Overhead Transformer (40 year life span)	21%	32%	47%
Conductor - Primary (50 year life span)	18%	28%	54%
Poles - Concrete/Steel (60 year life span)	14%	31%	56%
Conductor - Secondary/Service (60 year life span)	25%	38%	37%
Submersible Transformer (40 year life span)	9%	57%	34%
Cable - Primary PILC (70 year life span)	1%	46%	53%
Padmounted Transformer (40 year life span)	2%	36%	62%
Civil - Manhole, Vaults, Pads (80 year life span)	0%	17%	83%
Duct (80 year life span)	0%	23%	77%
Switches (40 year life span)	30%	29%	42%
Total Asset Breakdown	**26%**	**32%**	**42%**

2 **Table 3**

2012- Asset Type	Beyond End of Life	Near End of Life	Optimal
Substation Switchgear (40 year life span)	84%	14%	3%
Substation Breakers (40 year life span)	62%	19%	19%
Substation Power Transformers (50 year life span)	41%	47%	11%
Cable - Primary XLPE (30 year life span)	34%	28%	39%
Poles - Wood (50 year life span)	31%	27%	42%
Cable - Secondary/Service (40 year life span)	27%	39%	34%
Civil - Junction Boxes, Switching Cabinets (40 year life span)	23%	41%	36%
Overhead Transformer (40 year life span)	22%	33%	45%
Conductor - Primary (50 year life span)	19%	29%	52%
Poles - Concrete/Steel (60 year life span)	13%	31%	56%
Conductor - Secondary/Service (60 year life span)	28%	37%	36%
Submersible Transformer (40 year life span)	11%	56%	33%
Cable - Primary PILC (70 year life span)	1%	46%	53%
Padmounted Transformer (40 year life span)	2%	37%	61%
Civil - Manhole, Vaults, Pads (80 year life span)	0%	15%	85%
Duct (80 year life span)	0%	23%	77%
Switches (40 year life span)	29%	28%	44%
Total Asset Breakdown	**25%**	**32%**	**43%**

3

b.

i. The risk assessment described in Table 1-9 translates into a measurable risk unit called "Risk Score". The criticality factors are components used to calculate the criticality multiplier. The product of the criticality multiplier and the probability of failure results in a Risk Score. The Risk Score is discussed in further detail part b.iv. of this interrogatory response. The Risk Score is used for all substation assets not just for substation transformers. For further details on criticality factors and risk scores, please refer the Kinectrics' 2013 Asset Condition Assessment filed as Appendix B of the DSP filed as Appendix 2-4 of Exhibit 2, Tab 6.

ii. A weighting or Weight of Condition Factor ("WCF") is assigned to each criticality factor ("CF") for a particular asset category. The WCF is a useful and instructive measure because it reflects the importance of each CF in the asset's Criticality Factor Score ("CFS"). Without the WCF each CF would be weighted evenly when determining the CFS. The higher the WCF, the more important the individual CF is in determining overall criticality or CFS. The relative values of WCF reflect Horizon's perspective on each CF's importance. Load criticality is assigned a WCF of 30 for substation transformers in Table 1-9 indicating that number of customers and customer importance is weighted more heavily than other criticality factors.

iii. The CFS of each CF is based on substation transformer specific factors such as maintenance and inspection records, load served, physical station characteristics and knowledge of load served by the substation transformer.

The CFS is useful because it provides the ability to differentiate the criticality of each individual substation transformer when calculating the risk score. The criticality of the substation transformer is utilized in the proactive replacement calculation methodology as explained on page 14 of Kinectrics' ACA. Horizon Utilities applied this methodology for calculating the flagged-for-action values for substation transformers, substation switchgear, and substation circuit breakers.

iv. The product of criticality and probability of failure results in a Risk Score for an asset. The Risk Score is a metric representing the combination of probability of failure and impact of failure and is a measurement of risk. It does not represent a monetary value or an operational consequence. Assets having a Risk Score exceeding a defined

threshold are identified and flagged-for-action. This methodology applies to substation transformers, substation switchgear, and substation circuit breakers.

c. Using the proactively replaced asset example:

i. Horizon Utilities confirms that the probability of failure takes into account the age parameter. The probability of failure is based on the assets' Health Index, which is a composite index calculated from multiple parameters, including chronological age.

ii. Horizon Utilities confirms that higher risk assets are considered to be more urgent replacements.

iii. The replacement ranking provided in the table prioritizes the order in which the assets should be replaced. The Risk Score, calculated by multiplying the probability of failure with the criticality of failure, and identified in the 6th column in Table II-4, is the metric used to determine the replacement ranking.

2-Staff-20 Asset Management Overview

References:

1. OEB Distribution Filing Requirements, Chapter 5, 5.4.5.1 Justifying Capital Expenditures/ p. 19
2. Exhibit 2/ Appendix 2-4/ Section 3.4 Capital Expenditure Summary/ Table 2-Appendix 2-AB

Preamble:

Chapter 5 at Reference 1 states, in part:
To support the overall quantum of investments included in a DSP by category, a distributor should include information on:

- **comparative expenditures by category over the historical period;**
- **the forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts;**
- **the 'drivers' of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);**

Based on information provided at Reference 3, as updated on May 21, 2014, staff notes the following trends:

CATEGORY	EXPENDITURES ($000)																	
	HISTORICAL							BRIDGE				FORECAST						
	2010	2011 CGAAP	2011 MIFRS	y/o/y	2012	y/o/y	2013	y/o/y	2014	y/o/y	2015	y/o/y	2016	y/o/y	2017	y/o/y	2018	y/o/y	2019
System Access	13,358	8,914	5,629	17%	6,602	-4%	6,369	18%	7,540	9%	8,243	3%	8,472	-7%	7,896	2%	8,092	2%	8,273
System Renewal	14,082	22,475	17,171	-18%	14,091	31%	18,425	-17%	15,372	18%	18,070	57%	28,294	17%	33,168	0.12%	33,208	5%	34,706
System Service	3,583	3,125	2,374	22%	2,885	-25%	2,151	91%	4,101	1%	4,140	-93%	295	81%	535	280%	2,032	1%	2,057
General Plant	6,208	4,584	4,584	91%	8,748	44%	12,559	-14%	10,760	-12%	9,487	-38%	5,887	-1%	5,827	-4%	5,611	11%	6,236
Total Expenditures before Smart Meters	37,432	39,098	29,758	9%	32,326	22%	39,505	-4%	37,773	6%	39,940	8%	42,948	10%	47,426	3%	48,943	5%	51,272
System O&M	18,742	19,654	N/A		27,755	8%	29,928	13%	33,776	2%	34,571	3%	35,504	2%	36,355	3%	37,337	2%	38,084

Source:
Appendix 2-AB
Table 2- Capital Expenditure Summary from Chapter 5 Consolidated DSP FRs
Updated May 21, 2014

	HISTORICAL				BRIDGE			FORECAST			
	2010	2011	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPITAL											
Access Exp./ Total Exp. Excl. SM	36%	23%	19%	20%	16%	20%	21%	20%	17%	17%	16%
System Exp./ Total Exp. Excl. SM	38%	57%	58%	44%	47%	41%	45%	66%	70%	68%	68%
Service Exp./ Total Exp. Excl. SM	10%	8%	8%	9%	5%	11%	10%	1%	1%	4%	4%
General Plant Exp./ Total Exp. Excl. SM	17%	12%	15%	27%	32%	28%	24%	14%	12%	11%	12%
O&M											
System O&M/Total Exp. Excl. SM	50%	50%	N/A	86%	76%	89%	87%	83%	77%	76%	74%

Periodic Averages	2010-2014	2015-1019
Access Exp./ Total Exp. Excl. SM	22%	18%
System Exp./ Total Exp. Excl. SM	47%	63%
Service Exp./ Total Exp. Excl. SM	8%	4%
General Plant Exp./ Total Exp. Excl. SM	22%	15%
O&M		
System O&M/Total Exp. Excl. SM	70%	79%

Note: Periodic averages exclude the effect of changes in accounting methodology

Based on:
Appendix 2-AB
Table 2- Capital Expenditure Summary from Chapter 5 Consolidated DSP FRs
Updated May 21, 2014

a. To provide an expenditure picture that allows a comparative analysis, please include capital and OM&A in the same schedule for each system asset category and non-system categories (IT, Fleet, buildings, etc...) Please distinguish, where applicable, between planned and reactive OM&A.

b. Please provide trends over time for all relevant capital expenditures, capital vs. OM&A (planned vs. unplanned) and capital vs. depreciation for the 10 year-period. And provide explanations of trends and outliers.

Response:

a) Horizon Utilities is unable to provide the requested comparative analysis between capital and OM&A. OM&A costs are not reported on or budgeted for the system asset categories identified in Appendix 2-AB (System Access, System Renewal, System Service and General Plant). The costs associated with operating and maintenance programs typically benefit the entire distribution system not one specific category.

Section 5.1 of the Chapter 5 Consolidated Distribution System Plan Filing Requirements ("Chapter 5 Filing Requirements"), which defines the four system categories, states than these requirements introduce a standard approach to "a distributor's filings of asset management and capital expenditure information in support of a rate application". The Chapter 5 filing requirements do not specify that this information is required for OM&A expenditures.

b) Horizon Utilities provides trends over time for (i) Capital Expenditures vs. Depreciation Expense for Distribution Plant and General Plant and ii) Capital Expenditures vs. Operating and Maintenance ("O&M") expenditures in the table below. Horizon Utilities does not track planned versus unplanned O&M. Horizon Utilities records O&M by Uniform System of Accounts ("USoA") in accordance with the Accounting Procedures Handbook. The USoA or Horizon Utilities' general ledger does not segregate planned versus unplanned O&M. Horizon Utilities does not have a methodology to break out O&M in this manner. Horizon Utilities has provided a detailed variance analysis on Construction and Maintenance expenditures on pages 63-72 of Exhibit 4, Tab 3, Schedule 3 and an O&M analysis on page 4 in Exhibit 4, Tab 2, Schedule 1.

Table 1: CAPEX

	Distribution Plant CAPEX vs. Depreciation Expense	General Plant CAPEX vs. Depreciation Expense	Total CAPEX vs. System O&M
2010 CGAAP	1.40	1.07	2.00
2011 CGAAP	1.61	0.73	1.99
2012 MIFRS	1.97	1.40	1.16
2013 MIFRS	2.10	1.93	1.32
2014 MIFRS	1.95	1.50	1.12
2015 MIFRS	2.08	1.08	1.16
2016 MIFRS	2.42	0.66	1.21
2017 MIFRS	2.56	0.73	1.30
2018 MIFRS	2.53	0.89	1.31
2019 MIFRS	2.49	1.07	1.35
Average 2010 - 2019	**2.11**	**1.11**	**1.39**
Average MIFRS	**2.26**	**1.16**	**1.24**

The ratio of Capital Expenditures vs. Depreciation Expense ("Productive Asset Investment Ratio") is an indication of a company's level of investment in capital assets. Companies with a ratio over 1.0 are typically expanding as more fixed assets are added than have depreciated over the same time.

Horizon Utilities' average Productive Asset Investment Ratio for Distribution Plant over the 10-year period from 2010-2019 is 2.11 which is consistent with Horizon Utilities' ongoing need to increase investment in the renewal of aging distribution system infrastructure, as identified in pages 9 to 14 of Exhibit 1, Tab 2, Schedule 6; Section 3.5.3 of the DSP filed as Appendix 2-4 of Exhibit 2, Tab 6; and the Kinectrics' 2013 Asset Condition Assessment filed as Appendix B of the DSP. The Productive Asset Investment Ratio increases from 2.08 in 2015 to 2.42 in 2016 and remains at approximately 2.5 from 2017 to 2019. This is indicative of Horizon Utilities' necessary investment in system renewal to address the declining health of its distribution system, particularly the 4kV and 8kV Renewal and XLPE Cable Renewal programs which are identified in Exhibit 2, Tab 6, Schedule 1.

Horizon Utilities' average Productive Asset Investment Ratio for General Plant over the 10-year period from 2010-2019 is 1.11. The higher ratios in 2012 to 2015 are a result of Horizon Utilities' increased investment in buildings, infrastructure systems and Information Systems Technology ("IST"). Building renovations are required to address: operational deficiencies;

building accessibility; the removal of hazardous materials; security; and air quality as identified on pages 14-15 of Exhibit 1, Tab 2, Schedule 6; pages 27-58 of Exhibit 2, Tab 6, Schedule 1; and pages 254-264 in Section 3.5.3 of the DSP filed as Appendix 2-4 of Exhibit 2, Tab 6. Horizon Utilities needs to replace assets which have reached End-of-Life ("EOL") and ensure compliance with Ontario Building and Fire Codes. IST investments are principally comprised of necessary replacements and upgrades of EOL systems that are no longer supported by vendors; necessary systems to sustain operations; and systems required to advance efficiency, effectiveness, and security objectives. These investments are discussed in further detail on pages 14-15 of Exhibit 1, Tab 2, Schedule 6. The ratios in 2016 to 2018 are lower than prior years as major IST upgrades and replacements are expected to be completed in 2015. Building renovations are expected to continue but at a lower investment level than in 2015 and prior years.

The ratio of capital expenditures to O&M expenditures is another indicator of a company's level of investment in capital assets or long-term value. Horizon Utilities' average ratio of capital expenditures to O&M expenditures over the 10-year period from 2010-2019 is 1.39. The ratios in 2015 to 2019 are increasing gradually which reflects Horizon Utilities' balanced approach to investing in the necessary renewal of its distribution system, buildings and related underlying systems and processes. Capital expenditures are growing at a higher rate than O&M expenditures which accounts for the increase year-over-year since 2014.

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2-Staff-21 Justification of DS Plan

References:

1. OEB Distribution Filing Requirements, Chapter 5, 5.4.5.1 Justifying Capital Expenditures/ p. 19
2. Exhibit 2/ Appendix 2-4/Appendix A/ Tables 1 & 2 _ Material Capital Expenditures
3. Exhibit 2/ Appendix 2-4/Appendix G/ Material Capital Project Templates
4. Exhibit 2/ Appendix 2-4/Appendix F/ 4kV and 8kV Renewal Program
5. Exhibit 2/ Appendix 2-4/Appendix J/ Resource and Office Space Utilization Study
6. Exhibit 2/ Appendix 2-4/Appendix K/ Building Condition Assessment 2013
7. Exhibit 2/ Appendix 2-4/Appendix L/ Physical Security Report
8. Exhibit 2/ Appendix 2-4/Appendix M/ Head Office Window Assessment
9. Exhibit 2/ Appendix 2-4/Appendix N/ Roof Inspection Review
10. Exhibit 2/ Appendix 2-4/Appendix O/ Fleet Replacement Plan

Preamble:

Chapter 5 at Reference 1 says in part that:

Filings must enable the Board to assess whether and how a distributor's DS Plan delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures.

With respect to project alternatives, for example, the 2015 Tools, Shop and Garage Equipment summary sheet at Appendix G states that "tools and equipment over $5000 are procured through a competitive process and alternatives are considered at the time of requisition". Staff interprets alternatives to mean the evaluation of options before the selection of a solution.

References (2) and (3), Appendices A and G contain detailed information related to planned investments for the DSP period of 2015-2019. However, there are areas that relate to the fundamentals outlined in the RRFE Report and the Filing Requirements where additional information could be helpful.

By way of example, Board staff notes the following:

Recommendations included at Reference 5, provide a section on the cost/benefit methodology that is qualitative in nature. While the report further provides estimated budget costs for the planned office space expenditures, benefits are not equally supported by figures. Horizon does say that "additional detail to support the analysis can be found at appendix G". Notwithstanding the filed information, staff would be assisted by further 'value for money' facts.

On costs and benefits, Reference 2 on the 4kV and 8kV Renewal program shows the following anticipated expenditures at table 6 and states further that "the decommissioning of these nine substations will result in the avoided capital substation

renewal investment of $22,500,000." Reference (4) provides other technical information related to the planned solution. Staff would be assisted if it could compare the renewal alternative versus the planned modification to 13.8kV or 27.6kV.

With respect to building renovations, the Hughson substation is being restored. Staff would like to understand how the decision to remediate/occupy vs. remediate/sell was more sensible (to help employees who travel 20km for training purposes) and whether when all factors, including the potential new use of the Stoney Creek training centre as a storage facility, are taken into account the benefits outweigh costs.

With respect to fleet replacement, one of Horizon's stated objective is to "align [its] vehicle replacement criteria with utility standards." Staff would like to ensure that current spending is in line with industry peers.

Please consolidate relevant information found in various appendices and include relevant elements of Exhibit 4 and amend Appendix A accordingly:

a. For material projects, please distinguish between discretionary and non-discretionary ones, and provide the project elements set out below. Staff would lie to determine whether the most cost-effective actions have been adopted, whether pacing of the investments is appropriate, and establish the value and rate impacts of these activities on ratepayers:

i. In the project overview section, please provide:
- **The overall priority of the project;**
- **Benefits to be incurred from maintaining/upgrading or replacing the asset(s), such as lower operating costs. Where applicable, please include a discussion on value for the business and/or customers;**

ii. In the project cost section, please provide:
- **An overview of the economics of the project (e.g. assumptions, NPV calculation) and a discussion of alternatives in that context ; and**
- **Where applicable please reference or submit additional documentation, such as independent studies that support a recommended option;**

iii. The impact of the project on rates;
iv. Any investment pacing considerations related to the project;

b. For programs (e.g. Vegetation Management), please provide the following program elements to establish whether the most cost-effective actions have been adopted and the value and rate impacts of these activities on ratepayers. Please provide any other justifications as Horizon sees necessary.

i. In the overview of the program, please highlight:
- **The expenditure cycle;**
- **Benefits to be incurred from planned expenditures on program, such as lower operating costs, increased reliability. Where applicable, please include a discussion on value for the business and/or customers;**

ii. In the program cost section, please include an overview of the economics of the program and a discussion of alternatives;

iii. The impact of the program on rates;
iv. Any investment pacing considerations related to the program and the cycle adopted; and
v. Any benchmarking (historical/internal; industry peers/external; general/best practices)

c. Please link the planned projects at Appendix A to the four RRFE Outcomes.

Response:

a)

Table 1 below provides the material capital projects from Exhibit 2, Tab 6, Appendix 2-4, Appendix A, Tables 1 and 2. The table consolidates relevant information into this table to address:

i) overall priority and benefits of the project;
ii) project economics;
iii) impact on rates; and
iv) pacing considerations.

Horizon Utilities views all of the projects included in this response and provided in the Application as non-discretionary based extensive evidence and supporting 3rd party studies provided in the Exhibits 2 and 4 and the Distribution System Plan of the Application. Renewal of Horizon Utilities' distribution system is imperative to mitigate system health degradation and related reliability risks. Horizon Utilities' buildings and infrastructure systems are at or nearing end of life and renewal is necessary to address poor equipment performance; increased risk of system failure; poor work environments for employees; and increased health and safety risks.

Also included in column 3 of Table 1 is a mapping of each project to the four RRFE outcomes as requested in part c).

RRFE Outcomes	
Customer Focus	**CF**
Operational Effectiveness	**OE**
Public Policy Responsiveness	**PPR**
Financial Performance	**FP**

Table 1 – Material Capital Projects

Project Name		RRFE Outcomes	Priority (discretionary/non- discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SA-1	Customer Connections*	CF	Non-Discretionary	Ensure timely response to outages Mitigate reliability and safety risks Ensure compliance with regulatory requirements outlined in the DSC and Horizon Utilities Conditions of Service	This work is demand driven by new load connections. Economic Evaluations which include NPV calculations are performed on services greater than 400 amps.	0.62%	This work is demand driven; pacing is based on external demand. Reference: Exhibit 2, Tab 6, Appendix 2-4, pages 231-232 and Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 4-5

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SA-2	Road Relocations*	CF	Non-Discretionary	Satisfy the obligations to perform line relocation work at the request of road authorities in compliance with the *Public Service Works on Highways Act,* 1990	This work is demand driven by the City of Hamilton, the City of St. Catharines, the Region of Niagara, and the Ministry of Transportation. Horizon Utilities follows the *Public Service Works on Highways Act*, 1990 and associated regulations governing the recovery of costs related to road reconstruction work by collecting contributed capital for 50% of the labour; labour saving devices, and equipment rentals. NPV calculations are not performed for this type of program.	0.32%	This work is demand driven; pacing is based on external demand. Reference: Exhibit 2, Tab 6, Appendix 2-4, pages 232-234 and Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 6-8

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SA-3	Meters*	CF	Non-Discretionary	Ensure a timely availability of metering equipment to minimize outage duration due to failed meters. Ensure compliance with regulatory requirements imposed by Measurement Canada, the *Electricity & Gas Inspection Act*, IESO Market Rules and Distribution System Code. Ensure accurate and timely billing which will lead to customer satisfaction.	Metering work is Measurement Canada and customer driven and the technology is primarily based on the metering products available from a sole source supplier. As such no alternatives are considered. NPV calculations are not performed for this type of program.	0.52%	Pacing is reflected in the year-by-year plan of meter replacements throughout the rate plan term. Pacing is determined primarily by historical failure rates. System expansion, if required, to connect customers within this category is based on Horizon Utilities' Conditions of Service, Section 2.1.2.1. Reference: Exhibit 2, Tab 6, Appendix 2-4, pages 234-235 and Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 9-10

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SR-1	4kV & 8kV Renewal*	OE CF	Non-Discretionary	Renewal of assets at end-of-life; increased reliability; decreased equipment failure Ensures the safe and reliable operation of the distribution system. Ensures compliance with the Distribution System Code.	4kV and 8kV distribution system and the Horizon Utilities-owned substations are at the end of their useful lives. Voltage conversion also allows for avoided capital expenditures. Two alternatives considered: 1. Renewal of substations and distribution assets at current voltage; 2. Conversion of distribution assets to higher voltage and decommissioning of substations. See Table 1A below for further analysis NPV calculations are not performed for this type of program.	1.81%	Pacing is reflected in the year-by-year plan of projects throughout the rate plan term. Pacing is based on the probability and impact of failures on service to customers. The timing of projects is determined through the assessment of the distribution system health and the health of the substation assets servicing the area. Renewal will allow for the decommissioning of the substation assets thereby avoiding the need for capital investment for substations. Reference: Exhibit 2, Tab 6, Appendix 2-4, pages 235-244 and Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 11-20

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SR-2	U/G (XLPE) Renewal*	OE CF	Non-Discretionary	Mitigate end-of-life issues; iincreased reliability; decreased equipment failure Ensures the safe and reliable operation of the distribution system. Ensures compliance with the Distribution System Code.	Projects are needs-driven, based on age, condition, performance, and operational issues. Alternatives considered were: 1.area replacement; 2. reactive replacement; 3.selective replacement; 4. refurbishment as identified on pages 248-250 in Section 3.5.3. of the DSP NPV calculations are not performed for this type of program.	0.89%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate plan term. Pacing is based on the probability and impact of failures on service to customers. Reference: Exhibit 2, Tab 6, Appendix 2-4, pages 245-252 and Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 21-24

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SR-3	Reactive Renewal*	OE CF	Non-Discretionary	Ensures timely response to outages. Ensures the safe and reliable operation of the distribution system. Ensures compliance with the Distribution System Code.	This work is demand driven by emergency response to equipment failure, safety, and power quality issues. NPV calculations are not performed for this type of program.	0.72%	This work is demand driven; pacing is based on external demand resulting from unplanned failures. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 25-26
SR-4	Substation Infrastructure Renewal*	OE CF	Non-Discretionary	Address end of life and/or deteriorated station components. Ensures the safe and reliable operation of the distribution system. Ensures compliance with Distribution System Code.	Projects are needs-driven, based on age, condition, performance, and operational issues, versus the "Do-Nothing" alternative. NPV calculations are not performed for this type of program.	0.08%	Pacing is reflected in the year-by-year plan of component replacements throughout the rate-filing period. Pacing considerations are driven by the criticality of the work and the risk of failure Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 27-28

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SR-5	Pole Residual Replacements*	OE CF	Non-Discretionary	Mitigate end-of-life issues. Reduce public safety and reliability risks on the distribution system. Ensures compliance with utility standards and the Distribution System Code.	Projects are needs-driven, based on the output of Horizon Utilities wood pole testing program NPV calculations are not performed for this type of program.	0.20%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate- filing period. Pacing considerations include: inspection data as well as demographics, performance, and criticality. These projects are reactive in nature and address assets at risk of failure. Horizon Utilities replaces poles requiring immediate replacement as soon as possible to mitigate the risk of service interruptions and the risk to public safety resulting from a failure of the pole. Less urgent poles are planned for replacement the following year. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 29-30

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SR-6	Load Break Disconnect Switch ("LBDS") Renewal*	OE	Non-Discretionary	Mitigate end-of-life issues. Improve safety and reliability risks on the distribution system. Ensure compliance with utility standards.	Projects are needs-driven, based on age, condition, performance, and operational issues. NPV calculations are not performed for this type of program.	0.05%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate plan term. Pacing considerations include: Failure of an LBDS to operate when required can impact Horizon Utilities' operational ability which can adversely affect the service experienced by customers Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 31.

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SR-7	Proactive TX Replacements*	OE CF	Non-Discretionary	Reduce safety, environmental and reliability risks on the distribution system. Ensures compliance with the Distribution System Code. Ensure compliance with Federal Polychlorinated biphenyl ("PCB") Legislation.	There are three options to proactively replacing transformers: Run to failure; Proactively change transformers due to: 4 pre-determined criteria (refer to Exhibit 2, Tab 6, Appendix 2-4, page 176); and proactively replace transformers with PCB contamination as per government regulations NPV calculations are not performed for this type of program.	0.06%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate filing period. Pacing is determined based on inspection and test results. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 32-33

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SR-8	Gage TS Egress Feeder Renewal	OE CF	Non-Discretionary	Mitigate end-of-life issues at Gage TS. Reduce safety and reliability risks on the distribution system.	Project is needs driven based on the requirement to relocate existing feeders to new Transformer Station demarcation points. NPV calculations are not performed for this type of program.	0.21%	The project is demand driven; pacing is based on Hydro One's plan to renew Gage TS. Pacing considerations include: maintaining service continuity for three large industrial customers. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 70

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SR-9	Rear Lot Conversion	OE CF	Non-Discretionary	Replacement of end-of-life assets. Reduction of reliability and safety issues surrounding rear lot distribution systems due to damaged caused from customer owned trees and lack of access for utility crews to repair or replace equipment. Ensures compliance with the Distribution System Code.	Replacement options for consideration include: Relocation of primary and secondary to front lot underground; or Relocation of primary and secondary to front lot overhead; or Relocate primary only and leave secondary in the rear. Each option is considered on a project by project basis. NPV calculations are not performed for this type of program.	0.12%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate filing period. Pacing considerations – are dictated by competing projects for available capital investment Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 34-35

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SS-1	#6 Wire Replacement	OE CF	Non-Discretionary	Replacement of end of life assets. Reduce safety and reliability risks on the distribution system. Ensures compliance with the Distribution System Code.	The #6 Wire Replacement projects are primarily initiated to reduce risk to public safety due to the higher failure rates associated with #6 wire. Where possible, these projects are coordinated with 4kV and 8kV renewal projects. NPV calculations are not performed for this type of program.	0.03%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate filing period. Where possible, #6 Wire replacement projects are coordinated with 4kV and 8KV renewal projects. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 61-62

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SS-2	Distribution Automation	OE CF	Non-Discretionary	Decrease the duration of service interruptions to offset the impact on the customer of an increasing volume of interruptions due to equipment failures associated with the declining health of the distribution system. Mitigate the impact of service interruptions resulting from significant weather events. When automation is fully deployed throughout the distribution system, reliability is expected to improve by 10%.	Automation is planned per Horizon Utilities approved GEA Plan. NPV calculations are not performed for this type of program.	0.07%	Pacing is reflected in the year-by-year GEA Plan Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 63-64

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SS-3	Waterdown 3rd Feeder	OE CF	Non-Discretionary	Provides benefits to customers by providing improved security to the village of Waterdown. Reduce safety and reliability risks on the distribution system.	This work is required to provide increased capacity and security to the village of Waterdown. The project timelines are driven by the Highway 5 and Highway 6 grade separation and requires co-ordination with the City of Hamilton and the Ministry of Transportation.	0.06%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate filing period. Pacing considerations include: The Highway 5 and Highway 6 grade separation is a prerequisite and must be completed in 2015. The project will require significant co-ordination with the Ministry of Transportation and the City of Hamilton. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 65

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SS-4	Caroline/George Redundancy	OE CF	Non-Discretionary	Provides benefits to customers by providing improved security to Downtown Hamilton area. Reduce safety and reliability risks on the distribution system.	Increase the inter-tie capacity within the Hamilton Downtown core currently undergoing redevelopment. NPV calculations are performed for this type of program.	0.05%	Pacing is demand driven and considerations include: improved operability and redundancy within the Hamilton downtown core area required due to redevelopment and load growth. This work is demand driven and will be required to provide back-up to the Hamilton downtown core where significant development is occurring. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 66

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SS-5	Duct Structure – Elgin TS to King St.	OE CF	Non-Discretionary	Provides benefits to customers by providing improved security to Downtown Hamilton area. Reduce safety and reliability risks on the distribution system.	Increase the inter-tie capacity within the Hamilton Downtown core currently undergoing redevelopment.	0.02%	Pacing is demand driven and considerations include: improved operability and redundancy within the Hamilton downtown core area required due to redevelopment and load growth. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 71
SS-6	East 16th and Mohawk Security Project	OE CF	Non-Discretionary	Provides improved security for 1,000 customers who have experienced poor reliability. Reduce safety and reliability risks on the distribution system. Ensures compliance with the Distribution System Code.	Project is needs-driven, based on age, condition, performance, and operational issues. Alternatives include leaving customers on a radial feed with poor reliability, or providing a loop feed which will improve reliability. NPV calculations are performed for this type of program.	0.01%	Pacing considerations – are dictated by competing projects for available capital investment Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 72

1

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SS-7	St. Paul Street Conductor Upgrade	OE CF	Non-Discretionary	Address aging and undersized distribution assets serving central St. Catharines. Improve load transfer capabilities which will improve reliability. Reduce safety and reliability risks on the distribution system. Ensures compliance with the Distribution System Code.	Project is needs-driven, based on age, condition, performance, and operational issues. Alternative is to "do-nothing" which potentially has customer reliability impacts. NPV calculations are performed for this type of program.	0.03%	Pacing Considerations - This project is the final project required to complete the interconnection through the removal of a capacity constraint along St. Paul Street. Projects to address capacity and load transferring ability between stations have been paced since 2010. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 73.

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SS-8	Grays Road	OE CF	Non-Discretionary	Improves security by addressing aging and undersized radial distribution feeder serving East Hamilton Reduce safety and reliability risks on the distribution system. Ensures compliance with Distribution System Code	Project is needs-driven, based on age, condition, performance, and operational issues. Alternative is to "do-nothing" which potentially has customer reliability impacts. NPV calculations are performed for this type of program.	0.00%	Pacing Considerations - A 24 hour outage in 2013, has increased the priority of this project, and will be completed in 2019 in order to accommodate higher priorities. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 74

1

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
SS-9	Mohawk/Nebo TS Upgrade	OE CF	Non-Discretionary	Provide additional capacity in the Hamilton Mountain operating area. Load will be approaching the 10 day LTR Reduce safety and reliability risks on the distribution system	There are three Hydro One transformer stations that supply this area and Horizon Utilities will co-ordinate with Hydro One to determine the most appropriate station to upgrade. The loading of each of the existing transformer stations; the area where the load growth is occurring; and the investment required to upgrade each station will be leveraged to determine the best option.	0.01%	Pacing is reflective of the advanced planning horizon required to plan and execute a Transformer Station Upgrade. Planning for a TS upgrade is typically a minimum of 2 years in advance. Pacing consideration include: involves the upgrade of a Hydro One owned TS. Horizon Utilities will co-ordinate the investment requirements with Hydro One. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 75

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-1	Annual Corporate Computer Replacement	OE	Non-Discretionary	Equipment refresh maintains or reduces maintenance costs. Improve staff productivity Supports investments in new applications, infrastructure and business capabilities.	No alternatives are considered since the recommended work is determined based on industry lifecycle best practices and vendor support.	0.17%	A three-year PC refresh cycle reduces the total cost of ownership by reducing the number of models of PCs supported, which results in the reduction of the IST service desk effort required to deploy, secure, and manage new systems and applications. The reduction in the number of supported models has allowed Horizon Utilities to introduce mobile computing for remote field workers and to increase the number of supported PCs by over 100 devices since 2011, without an increase in IST service desk support staff. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 36-37 Please refer to Horizon Utilities' response to Interrogatory 1-Staff-12f for further details on pacing considerations.

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-2	IFS ERP Upgrade	OE	Non-Discretionary	Enables staff productivity improvements. Cost reductions and cost avoidance will be achieved.	The IFS ERP System is an enterprise-wide system used to manage business processes in Finance, Human Resources, Supply Chain, and Engineering Project Management. Optimization of business processes in IFS will delivery annual staff productivity/capacity improvements estimated at $603,500 and annual cost reductions/future cost avoidance estimated at $100,000. Please refer to Exhibit 4, Tab 3, Schedule 4.	0.24%	The ERP upgrades have been paced over a 3 year period (2013/2014/2015) Version upgrade will commence in 2018. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 38-40 Please refer to Horizon Utilities' response to Interrogatory 1-Staff-12f for further details on pacing considerations.

1

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-3	SAN Expansion	OE	Non-Discretionary	This project is required to support Horizon Utilities' annual data growth rate which, based on historical experience, exceeds 30% per annum. The data growth rate is expected to increase during the 2015-2019 Test Years as new applications such as, GIS and OMS are implemented and operationalized.	The proposed work is based on industry lifecycle management best practices and vendor support. This investment in SAN expansion will eliminate risk related to insufficient storage capacity to support day-to-day business operations. The risk of not proceeding with this project is that Horizon Utilities will not have enough disk storage capacity to sustain its systems environment to meet business requirements.	0.04%	Pacing is reflected in the year-by-year plan of asset replacements in 2015/2017/2019. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 41 Please refer to Horizon Utilities' response to Interrogatory 1-Staff-12f for further details on pacing considerations.

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-4	Enterprise Phone System Upgrade	OE	Non-Discretionary	Planned lifecycle upgrade to mitigate risk related to end of vendor support for Horizon Utilities' phone system and phone system management software installed in 2010. The phone system is a key communications vehicle used by customers to contact Horizon Utilities.	The proposed work is based on industry lifecycle management best practices and vendor support This is a risk mitigation project to ensure continued vendor support for the primary method of communications with Horizon Utilities' customers.	0.04%	Pacing considerations – unacceptable risk for a vital customer communication tool resulting from end of vendor support for the phone system hardware and software. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 67. Please refer to Horizon Utilities' response to Interrogatory 1-Staff-12f for further details on pacing considerations.

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-5	Capital Lease - IBM	OE CF	Non-Discretionary	Replacement of the IBM iSeries hardware at end-of-life reduces the likelihood of hardware failures that could disrupt normal business operations, impacting Horizon Utilities' ability to: read Smart Meters; bill customers; apply customer payments; manage customer interactions; and manage customer work orders.	The proposed project is based on the end of existing lease and end of manufacturer warranty of the server hardware running Horizon Utilities' customer information system ("CIS"). The CIS includes all meter-to-cash functions and customer service order management.	0.24%	Pacing considerations: unacceptable risk for a critical system resulting from end of lease/warranty Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 42

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-6	Building Renovations – John and Hughson Street	OE	Non-Discretionary	Address operational deficiencies, building accessibility, the removal of hazardous materials, security, and air quality Rationalization of existing office spaces and creation of new office spaces to meet operational requirements. Creation of necessary common spaces, washrooms, and lunchrooms to accommodate the needs of 440 employees. Re-claiming under-utilized spaces. Updating security to provide for controlled access to buildings and employees.	These projects were identified as part of the multiyear building renewal & renovation plan in 2012. It included: reclaiming substation space for office space; replacing aging and end-of-life equipment; relocating business units; improving air and climate levels; and removing hazardous materials. See Table 1B for further analysis.	0.36%	Pacing considerations – impact of operational deficiencies, building accessibility, the removal of hazardous materials, security, and air quality on customers and employees; bill impact to the ratepayer; compliance with Ontario Building Codes Please refer to Horizon Utilities' response to Interrogatory 1-Staff-12f. Further details on these investments are provided in Exhibit 2, Tab 6, Appendix 2-4, pages 254 to 261.

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-7	Building Renovations – Stoney Creek	OE	Non-Discretionary	The replacement of end-of-life plumbing, lighting, and HVAC; The replacement of fire and life support systems; The renovation of the locker, washroom, and shower space to replace end-of life assets; [redacted] The creation of a centralized storage location for records retention and storage of furniture and assets.	The Stoney Creek Service Centre is a centralized trades training location for Horizon Utilities. Stoney Creek is also the service centre that houses Utility Operations staff that service the east end of the Hamilton Service Territory. The project will include the renovation of the locker, washroom, and shower space, and it will replace end-of-life plumbing, lighting, HVAC, and fire and life support systems. See Table 1C for benchmarking against other utilities.	0.01%	Pacing considerations – the project was planned for 2019 in order for other refurbishments to be completed in prior years and mitigate rate impacts. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 76-77

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-8	Building Security Replacement*	OE	Non-Discretionary	Replace end of life systems enhancing the building security. Update the safety and security of all buildings to protect employees, corporate assets, and critical supporting systems and documentation.	[redacted]	0.03%	Pacing and timing of project include considerations for risk and reliability requirements and are paced over 2015 and 2016 to mitigate the impact on rates. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 51-52 Please refer to Horizon Utilities' response to Interrogatory 1-Staff-12f for further details on pacing considerations.

					[redacted]		

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-9	John Street Roof Replacement	OE	Non-Discretionary	The roof replacement will prevent further damage to the floor and windows on the floor below the roof. Operating repair costs will be reduced.	The roof has reached end of life.	0.07%	Due to the nature of the project, the work cannot be paced over more than one year. Timing is critical for 2015 to prevent further damage. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 68
GP-10	Nebo Road Emergency Backup Generator	OE CF	Non-Discretionary	Maintain continuous uninterrupted supply of power for continued operations of Horizon Utilities largest emergency control centre.	Required for business continuity. The current use of portable generators is no longer an option due to their non-conformance with safety regulations.	0.02%	Increased storms and large scale outages increase the risk for interrupted business continuity. Please refer to Horizon Utilities' response to Interrogatory 1-Staff-12f for further details on pacing considerations. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, page 69

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-11	John Street Window Replacement*	OE	Non-Discretionary	Improve energy performance as the windows are no longer weather resistant. Prevent further damage to interior walls and facilities related components. Prevent further damage to the building exterior structure.	Windows have reached end of life. New windows will be procured through a competitive process and alternatives are considered at the time of requisition, and before the selection of a solution.	0.05%	Pacing and timing of project include considerations for risk and to prevent further damage. The project has been paced over several years (2015/2016/2017) to mitigate impact on rates. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 53-54

Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-12	Vehicle Replacement*	OE CF	Non-Discretionary	Maintain vehicle reliability and availability for crews. Reduction in fuel consumption and emissions. Reduce down time required to conduct maintenance and repairs.	Vehicles have reached end of life. Replacement vs refurbishment strategies have been evaluated. Fleet replacements costs have been benchmarked against other LDCs and Horizon Utilities' replacement criteria are longer than comparative LDCs. Please refer to Table 1B below.	0.30%	Horizon Utilities vehicle replacement investment is based upon a long-term multi-year replacement plan. Vehicles are maintained and replaced to allow for a stable annual expenditure over the 2015 to 2019 Test Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 55-58 Please refer to Horizon Utilities' response to Interrogatory 1-Staff-12f for further details on pacing considerations.

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Project Name		RRFE Outcomes	Priority (discretionary/non - discretionary)	Benefits of Project	Project Economics	Rate Impact **	Pacing Considerations
Capital Programs							
GP-13	Tools, Shop and Garage Equipment*	OE	Non-Discretionary	Replacement of tools, shop and garage equipment, which are either worn, have come to the end of their useful life, or the continued use of such creates health and safety risks.	Tools and equipment over $5,000 are procured through a competitive process and alternatives are considered at the time of requisition, and before the selection of a solution.	0.16%	Horizon Utilities' Tools, Shop and Garage Equipment is a multi-year project with stable annual expenditures. Reference: Exhibit 2, Tab 6, Appendix 2-4, Appendix A, pages 59-60

* Project names with a * are multi-year projects. ** The rate impact shown represents the proportionate amount of the average distribution rate increase based on the project's contribution to total revenue requirement over the rate plan term. A dollar weighted average was used. It is used for illustrative purposes only.

Table 1A

4kV and 8kV Conversion Program

The analysis in Table 1A below illustrates the cost difference between converting 4kV assets to 13.8kV and renewing the assets at 4kV without performing a voltage conversion. Using Aberdeen Substation as an example, Horizon has estimated the conversion of Aberdeen Substation Phase 1 (scheduled for 2017) using 4kV equipment for pole line hardware and transformers and extrapolated those costs over all five phases (2017 to 2021). A comparison of the cost of a voltage conversion to 13.8kV versus the renewal of the distribution and substation assets at 4kV, results in an incremental $964,417 in costs over five years to renew the assets at 4kV. In this example, station decommissioning costs of approximately $150,000 and sale of scrap material have not been included in the 13kV conversion. In addition on-going operating and maintenance costs have been excluded from the 4kV renewal example for simplicity. This table illustrates the difference in the cost of voltage conversion vs straight renewal.

Table 1A – 4kV and 8kV Conversion to 13.8kV compared to Renewal at 4kV

	Conversion Comparison			
Aberdeen Conversion - Phase 1 of 5	**13kV**	**4kV**	**Difference**	**Comments**
Poles-Wood and Concrete	$921,486	$917,331		Line hardware and transformer cost differences between 4kV and 13.8kV rated assets
OH Conductors & Devices	$924,217	$924,217		
Line Transformers-Overhead	$346,496	$270,535		
TOTAL OVERHEAD	**$2,192,199**	**$2,112,083**	**-$80,116**	
Underground Conduit & Chamber	$31,492	$31,492		Underground costs are the same due to Horizon Utilities material standards are 13.8kV or 27.6kV for underground assets.
UG Conductors & Devices	$6,071	$6,071		
TOTAL UNDERGROUND	**$47,709**	**$47,709**	**$0**	
TOTAL ENGINEERING	**$178,511**	**$178,511**	**$0**	Engineering costs are the same
Conversion Costs for one phase	**$2,418,420**	**$2,338,303**		
5 Phases of Aberdeen Conversion	**$12,092,098**	**$11,691,515**	**-$400,583**	
Aberdeen Station Upgrades				Only 4kV conversions have associated substation costs. 13.8kV conversion allows for decommissioning of substations.
Station Transformer	n/a	$300,000		
Switchgear and Circuit Breakers	n/a	$1,065,000		
TOTAL SUB-STATION COST	$0	**$1,365,000**	**$1,365,000**	
TOTAL PROJECT COST	**$12,092,098**	**$13,056,515**	**-$964,417**	**Over the 5 years to convert Aberdeen Substation, it is $964,417 less to convert to 13.8kV**

Table 1B – Fleet Replacement Benchmarking

Fleet Replacement Benchmarking

Table 1B below provides a comparison of vehicle replacement criteria between Horizon Utilities and other LDCs. Horizon Utilities compares favorably to other LDCs in that Heavy and Light Duty Vehicles are replaced later than those at comparator utilities as identified in Table 1B below. Vehicle replacements are paced and aligned with Horizon Utilities' replacement criteria.

Table 1B – Vehicle Replacement Benchmarking

Vehicles Replacement Criteria Comparison Table		
Vehicle Type	**Heavy Duty Vehicles**	**Light Duty Vehicles**
Horizon Utilities	16 to 19 Years or/and 200K km.	6 to 8 Years or/and 150K Km
Enersource	10 to 12 Years or/and 230K Km.	3 to 5 Years or/and 170K Km.
Toronto Hydro	10 Years Plus or/and 200K Km.	6 Years Plus or/and 150K Km.
Hydro Ottawa	12 Years Plus - No Km stipulation	7 Years Plus - No Km stipulation
Guelph Hydro	12 Years - No Km stipulation	Various factors

Table 1-C – Building Renovations Benchmarking

Building Renovations Benchmarking

Horizon Utilities' unit costs in Table 1-C below are based on: Horizon Utilities' actual project expenditures to date; and forecasted expenditures based on recent projects of similar scope within the cities of Hamilton and St. Catharines as provided by Evans Consulting Services.

Table 1C – Facilities Renovations Options

Building	Options	Total Renovation Sq. Ft.	Total Renovation Costs	Cost per Sq. Ft
Horizon Utilities	Renovate current buildings	79,000	$12,407,000	$157.05
PowerStream	Build new and relocate	92,000	$27,700,000	$301.09
Enersource	Build new and relocate	79,000	$20,000,000	$253.16

Note - Horizon Utilities cost per sq. ft. based on recent project actuals and forecasts. PowerStream and Enersource cost per sq. ft. data from recent cost of service applications.

b)

Table 2 provides Operating and Maintenance Programs as described in Exhibit 2, Tab 6, Appendix 2-4, pages 152-160. The table consolidates relevant information into this table to address:

i) the expenditure cycle, and benefits of the program;
ii) project economics;
iii) impact on rates;
iv) pacing considerations; and
v) benchmarking.

The individual programs within Horizon Utilities' Operating and Maintenance ("O&M") costs, with the exception of two programs, do not meet the materiality threshold defined by the Ontario Energy Board' s Filing Requirements as identified in Exhibit 1, Tab 6, Schedule 1, and as such O&M programs have been aggregated into three categories: Overhead Maintenance, Underground Maintenance and Substation Maintenance. The two programs which exceed the materiality threshold are tree trimming and cable locating.

1 **Table 2 – Operating and Maintenance Programs**

Planned OM&A Programs						
Program Name	**Expenditure Cycle**	**Benefits of Project**	**Project Economics**	**Rate Impact***	**Pacing Considerations**	**Benchmarking**
Overhead Maintenance						
Residual Wood Pole Testing	7-year cycle	Predictive maintenance includes testing for potential failures so that action can be taken to prevent a failure or to avoid the consequences of a failure. Improves public and worker safety by identifying replacement needs and potential safety hazards. Reduces unplanned outages due to pre-mature equipment failure. Ensures compliance with Distribution System Code minimum inspection requirements.	Predictive maintenance programs are based on planned inspection cycles.	0.48%	Pacing considerations include: timely response to demand and corrective maintenance activities, minimum inspection requirements outlined by the distribution system code and Horizon Utilities asset management plan	Navigant Consulting Inc. reviewed Horizon Utilities' maintenance programs and determined them to be representative of industry leading practices. Further details are provided in the response to Interrogatory 1-Staff-14a. Reference: Asset Management Strategy, Navigant Consulting Inc., October 29, 2008, page 3. Included in Horizon Utilities' response to Interrogatory 1-Staff-14. No other benchmarking information is available.
Overhead Thermography Scanning	3-year cycle					
Visual Plant Inspections	3-year cycle					
Tree Trimming	3-year cycle	Preventive maintenance includes regularly scheduled programs conducted to service network components. Improves public and worker safety by identifying and correcting defective equipment and/or potential safety hazards posed by trees in proximity to energized lines. Reduces unplanned outages	These proactive programs are normally deployed at specific time intervals and are applied to network components regardless of their apparent condition at the time. They are conducted to prevent network components from failing.			
Load Break Switch Maintenance	5-year cycle					
Insulator Washing	As Required					

Planned OM&A Programs						
Program Name	**Expenditure Cycle**	**Benefits of Project**	**Project Economics**	**Rate Impact***	**Pacing Considerations**	**Benchmarking**
		due to pre-mature equipment failure or tree contacts. Ensures compliance with Distribution System Code minimum inspection requirements.				
Repairs from distribution plant inspections	Annually	Corrective maintenance includes the replacement of defective components found to be inoperable, failing or have already failed. Ensures timely response to urgent and non-urgent repairs from inspection programs. Ensures compliance with Distribution System Code minimum inspection requirements.	The Visual Plant Inspection program will identify asset repairs as Standard, Timely, or Urgent. Urgent repairs identified during predictive maintenance activities are completed as soon as practical during the inspection year. Standard and timely repairs are planned for and completed during the following year. Urgent repairs represent serious problems within the distribution system plant that can impact the reliability of the distribution system or public safety.		Pacing considerations include: timely response to demand and corrective maintenance activities, minimum inspection requirements outlined by the distribution system code and Horizon Utilities asset management plan	

Planned OM&A Programs						
Program Name	**Expenditure Cycle**	**Benefits of Project**	**Project Economics**	**Rate Impact***	**Pacing Considerations**	**Benchmarking**
Underground Maintenance						
Underground Cable Locating	Annually	Preventive maintenance includes regularly scheduled programs conducted to service network components. Improves public and worker safety by identifying and correcting defective equipment and/or potential safety hazards posed by trees in proximity to energized lines. Reduces unplanned outages due to pre-mature equipment failure or tree contacts. Ensures compliance with Distribution System Code minimum inspection requirements.	These proactive programs are normally deployed at specific time intervals and are applied to network components regardless of their apparent condition at the time. They are conducted to prevent network components from failing.	0.28%	Pacing considerations include: timely response to demand and corrective maintenance activities, minimum inspection requirements outlined by the distribution system code and Horizon Utilities' asset management plan	Navigant Consulting Inc. reviewed Horizon Utilities' maintenance programs and determined them to be representative of industry leading practices. Further details are provided in the response to Interrogatory 1-Staff-14a. No other benchmarking information is available.
Dry Ice Cleaning	5-year cycle					
Transformer Room/vault/chamber inspection and cleaning	3-year cycle					
Visual Plant Inspections	3-year cycle					
Thermography Scanning	3-year cycle					
Repairs from distribution plant inspections	Annually	Corrective maintenance includes the replacement of defective components found to be inoperable, failing or have already failed. Ensures timely response to urgent and non-urgent repairs from inspection programs. Ensures compliance with Distribution System Code minimum inspection	The Visual Plant Inspection program will identify asset repairs as Standard, Timely, or Urgent. Urgent repairs identified during predictive maintenance activities are completed as soon as practical during the inspection year. Standard and timely repairs are planned for and completed during the following year. Urgent repairs			

Planned OM&A Programs						
Program Name	**Expenditure Cycle**	**Benefits of Project**	**Project Economics**	**Rate Impact***	**Pacing Considerations**	**Benchmarking**
		requirements.	represent serious problems within the distribution system plant that can impact the reliability of the distribution system or public safety.			

1

Planned OM&A Programs						
Program Name	**Expenditure Cycle**	**Benefits of Project**	**Project Economics**	**Rate Impact***	**Pacing Considerations**	**Benchmarking**
Substation Maintenance						
Substation Breakers and Relays	6-year cycle	Predictive maintenance includes testing for potential failures so that action can be taken to prevent a failure or to avoid the consequences of a failure. Improves public and worker safety by identifying replacement needs and potential safety hazards. Reduces unplanned outages due to pre-mature equipment failure. Ensures compliance with Distribution System Code minimum inspection requirements.	Predictive maintenance programs are based on planned inspection cycles.	0.08%	Pacing considerations include: timely response to demand and corrective maintenance activities, minimum inspection requirements outlined by the distribution system code and Horizon Utilities asset management plan.	Navigant Consulting Inc. reviewed Horizon Utilities maintenance programs and determined them to be representative of industry leading practices. Further details are provided in the response to 1-Staff-14a. No other benchmarking information is available.
Power Transformer oil analysis	Annually					
Partial discharge testing of metal-clad switchgear	5-year cycle					
Internal resistance testing of substation storage battery sets	Annually					
Thermography Scanning	3-year cycle					

Planned OM&A Programs						
Program Name	**Expenditure Cycle**	**Benefits of Project**	**Project Economics**	**Rate Impact***	**Pacing Considerations**	**Benchmarking**
Substation Maintenance						
Inspections of substation buildings and equipment	monthly	Preventive maintenance includes regularly scheduled programs conducted to service network components. Improves public and worker safety by identifying and correcting defective equipment and/or potential safety hazards posed by trees in proximity to energized lines. Reduces unplanned outages due to pre-mature equipment failure or tree contacts; Ensures compliance with Distribution System Code minimum inspection requirements.	These proactive programs are normally deployed at specific time intervals and are applied to substation assets including building components regardless of their apparent condition at the time. They are conducted to prevent assets from failing.		Pacing considerations include: timely response to demand and corrective maintenance activities, minimum inspection requirements outlined by the distribution system code and Horizon Utilities' asset management plan	

*The rate impact shown in the above table represents the proportionate amount of the average distribution rate increase based on the project's contribution to total revenue requirement for 2015. It is used for illustrative purposes only.

c) Please refer to the response to part (a)

2-Staff-22 Stranded Meters

Reference:

1. Exhibit 2 Tab 5 Schedule1
2. Guideline G-2011-0001 Smart Meter Funding and Cost Recovery – Final Disposition December 15, 2011
3. Chapter 2 Filing Requirements (2014), Section 2.5.1.4

Preamble:

Horizon states in Reference 1 that it is seeking approval to leave stranded meters in rate base until they are fully depreciated. Horizon states that there was an option in Guideline G-2008-0002: Smart Meter Funding and Cost Recovery, October 22, 2008. On page 8 of Reference 2, the Board states that although the decision in the Combined Proceeding provided some direction in relation to stranded meters, accounting procedures and cost recovery through rates, the Board's view had changed.

At Reference 3, it states:

- **"The total estimated NBV of the stranded meters as of December 31, 2013, or a revised amount calculated in accordance with the above-noted accounting guidance, must be removed from rate base (see Appendix 2-S). The 2014 revenue requirement must not include either a return on capital (i.e. debt cost and return on equity) or depreciation expense associated with the total estimated stranded meter costs removed from rate base;"**
- **The total estimated NBV of the stranded meters must be recovered through separate rate riders for the applicable customer classes. A distributor must outline the manner in which it intends to allocate recovery of the NBV of the stranded meters to the applicable customer rate classes and the rationale for the selected approach;**
- **The total estimated stranded meter costs must be tracked in "Sub-account Stranded Meter Costs" of Account 1555; and**
- **The associated recoveries from the separate rate riders must also be recorded in this sub-account to reduce the balance in the sub-account."**

a. Please provide a scenario where the stranded meters are removed from rate base and recovery is implemented in accordance with Appendix A-1 Accounting Treatment for Approved Stranded Meter Costs found in Reference 2.

b. If the proposed SMRR is for a period greater than 4 years, please provide an explanation.

Response:

a) The revenue requirement impacts identified by Horizon Utilities in Table 2-43 on page 5 of Exhibit 2, Tab 5, Schedule 1 calculated the revenue requirement impact of leaving the stranded meters in rate base using a short-term debt cost rate of 2.46% for the deemed component of short-term debt supporting the stranded meter component of rate base. Horizon Utilities provides a revised Table 2-43 below which calculates the revenue requirement impact of leaving the stranded meters in rate base but with a revised short-term debt cost rate of 2.11% as updated in the Ontario Energy Board's letter: *Cost of Capital Parameters for 2014 Cost of Service Applications,* dated November 25, 2013. The responses below are based on this revised Table 2-43.

Revised Table 2-43

Description	2015	2016	2017	2018	2019	Total 2015-2019	2020	2021	2022	Total 2015-2022
Revenue Requirement with Stranded Meters in Rate Base	$1,529,293	$1,458,298	$1,387,302	$1,320,420	$1,251,044	$6,946,356	$1,178,409	$1,105,775	$1,033,141	$10,263,682
Revenue Requirement with NBV recovered over 5 year IR term	$2,106,089	$1,992,495	$1,878,902	$1,767,503	$1,653,025	$9,398,014	$0	$0	$0	$9,398,014
Difference	($576,795)	($534,198)	($491,600)	($447,082)	($401,982)	($2,451,658)	$1,178,409	$1,105,775	$1,033,141	$865,668

Horizon Utilities provides the scenario below where the stranded meters are removed from rate base and recovery is implemented in accordance with Appendix A-1 Accounting Treatment for Approved Stranded Meter Costs (Table 1). The stranded meter NBV eligible for recovery purposes comprises the gross costs of the stranded meters, net of any capital contributions, less accumulated depreciation calculated to December 31, 2014. Recovery is identified by rate class.

Horizon Utilities includes a regulated rate of return component to determine the amount to be recovered from customers. Horizon Utilities has assumed that the Board guidance in general and in Reference 3 above provides scope for the continued recovery of Cost of Capital. Otherwise, Horizon Utilities submits that the recovery of only the NBV of the stranded meters is punitive in that it does not provide Horizon Utilities with a fair return on the capital it has invested in conventional meters. The implementation of Smart Meters was a public policy change mandated by the Ministry of Energy and as such Horizon Utilities was obligated to replace conventional meters with Smart Meters for all Residential and GS<50kW customers. As such, the amount recovered from customers through a rate rider includes a regulated return on capital. If recovery is through a rate rider, Horizon Utilities proposes a disposition period of eight years as a form of rate mitigation, provided that the recovery includes a regulated rate of return.

Table 1

Customer Class	# of Active Metered Customers (average 2015)	NBV of Stranded Meters including Rate of Return	Monthly Charge	Charge per Year
Residential	220,565	$7,903,976	$0.37	$987,997
GS< 50kW	18,428	$2,009,243	$1.14	$251,155
GS>50kW	2,198	$350,462	$1.66	$43,808
Total	**241,190**	**$10,263,682**		**$1,282,960**

If disposition is through a rider which is disposed of over eight years as identified in Table 1 above, the impact to revenue requirement would be a cumulative reduction to revenue requirement of $6,946,356 from 2015 to 2019 and as identified in the revised Table 2-43 above. This would be offset by the revenue from the rate rider from 2015 to 2019 of $6,414,800 ($1,282,960 X 5 years) The impact to revenue requirement for the final three years (2016 to 2019) would be a cumulative reduction to revenue requirement of $3,317,326 which would be offset by the revenue from the rate rider of $3,848,880 ($1,282,960 X 3 years).

b) Horizon Utilities would propose disposition over an eight-year period if recovery is through a rate rider. An eight-year period addresses rate mitigation which is a key consideration for Horizon Utilities. Horizon Utilities is prepared to recover the NBV of the

stranded meters over the remaining amortization period of eight years on the assumption that the recovery includes a regulatory rate of return.

2-Staff-23 Working Capital Allowance

Reference:

1. Exhibit 2 Tab 4 Appendix 2-3 - A Determination of the Working Capital Requirements of Horizon Utilities' Distribution Business

Preamble:

Horizon retained Navigant Consulting Inc. to perform a lead lag study to establish the working capital factor to be applied to controllable OM&A and the cost of power for setting the level of working capital to be included in rate base. The analysis resulted in a Billing Service Lag of 27.6 days.

a. Please provide the details of the calculation of the Billing Service Lag of 27.6 days.

b. Is Horizon planning to bill monthly at any time during the CIR period? If so, when?

Response:

a. Subsequent to the submission of its Application, Horizon Utilities reviewed the inputs used to calculate the Billing Service Lag of 27.06. It determined that some of the revenue allocations between monthly and bi-monthly billing were incorrect.

Navigant Consulting Inc. ("Navigant") recalculates the Billing Service Lag to be 25.02 days, based on the correct revenue allocations. The details of the calculation of the Billing Service Lag of 25.02 days are filed as attachment 2-Staff-23a_Attch 3_Service Lag Revised Table. Horizon Utilities has provided the revised Navigant Report, which incorporates the revised Billing Service Lag as 2-Staff-23a_Attch 1_Revised Navigant Working Capital Report. Horizon Utilities has also provided a marked-up (track changes) version of the same report as 2-Staff-23a_Attch 2_Revised Navigant Working Capital Report_Track Changes. The revised Navigant Report was also updated for minor typographical errors in the original report (Tables 5, 6 and 7 as well as the expense lead time for Property Taxes on page 16 - revised Navigant Working Capital Report and service, payment and expense lead times for Payments in Lieu of Taxes on page 16 – revised Navigant Working Capital Report). None of the typographical errors affected the Working Capital % calculation.

The revised Billing Service Lag of 25.02 has been used to calculate a revised Working Capital Allowance. This revision results in a reduction in the Working Capital Allowance of 0.7% from 12.7% to 12.0%.

The impact on revenue requirement due to the change in Working Capital Allowance is identified in the table below:

Table 1: Impact on Revenue Requirement

	2015	2016	2017	2018	2019
Submitted Base Revenue Requirement	$ 112,956,026	$ 118,628,501	$ 121,743,444	$ 123,920,317	$ 127,881,899
Base Revenue Requirement (WC at 12%)	$ 112,665,477	$ 118,326,485	$ 121,430,522	$ 123,592,298	$ 127,540,488
Variance in Revenue Requirement	$ (290,549)	$ (302,016)	$ (312,922)	$ (328,019)	$ (341,411)

b. Horizon Utilities is not planning to transition customers to monthly billing at any time during the CIR period.

Horizon Utilities is aware of the recent policy review initiated by the Board on July 27, 2014 related to *Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance* (EB-2014-0198). Changes to billing practices during the term of the rate plan may result from this policy review.

Please also see Horizon Utilities' response to Interrogatory 2-EP-11 b) for a discussion of the one-time and ongoing incremental costs for such a transition.

2-Staff-23a_Attch 1_ Revised Navigant Working Capital Report

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NAVIGANT

A Determination of the Working Capital Requirements of Horizon Utilities' Distribution Business

Prepared for:

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NAVIGANT

Table of Contents

NAVIGANT

List of Tables

Section I: Executive Summary

Summary

In preparation for HUC's 2014 Distribution Cost of Service Rate Application before the Ontario Energy Board ("OEB" or "Board"), Horizon Utilities Corporation ("HUC") retained Navigant Consulting Ltd. ("Navigant") to perform a lead-lag study using the most recent data available, and to derive HUC's Working Capital Amount ("WCA") using historical 2012 data with known and measurable forward looking changes applied. This report provides the results of the study and the WCA of HUC's distribution business.

This report includes the following changes from the previous report dated March 31, 2014:

- The updated report reflects a change from the prior study in which the revenues associated with Residential, General Service <50, Unmetered and Scattered, and Streetlighting customer classes were reflected as being billed on a bi-monthly basis, instead of being billed based upon a split between monthly and bi-monthly frequencies. As a result of this change, the WCA of 12.7% in the previous report was overstated. When the correction was captured in the analysis the resulting WCA becomes 12.0%.
- Typographical errors were corrected in the following sections of the report which had no impact on the resulting WCA percentage:
  - Pg 11 – Table 5: Delivery month for IESO COP;
  - Pg 11 – Table 6: Service lead time for Hydro One COP;
  - Pg 12 & 13 – Table 7: Expense lead time for Group Life Insurance & LTD Insurance;
  - Pg 16 – Expense lead time for Property Taxes; and
  - Pg 16 – Service, payment and expense lead times for Payments in Lieu of Taxes.
- All calculation changes in this report are a result of the change in frequency of monthly versus bi-monthly customer billing for the service lag component.

Results from the lead-lag study applied to HUC's 2012 distribution expenses identify an average working capital percentage of 12.0% of the Cost of Power and OM&A Expenses for the 2014-2019 test years. This report also represents the 2014-2019 time periods. Inasmuch as slight variation exists from year-to-year in our analysis Navigant believes application of the 12.0% provides an accurate recovery of the cost of working capital for the time period 2014 through 2019. Based upon the working capital dollar amounts for each of the test years, the weighted average working capital was calculated to be 12.0%. Table 1 below provides the estimated working capital dollars and percentages for the test years 2014-2019.

Table 1: Estimated Working Capital Requirements

	2014	2015	2016	2017	2018	2019	2014 to 2019
Estimated Working Capital Requirements ($)	$69,456,886	$70,287,875	$72,767,684	$75,440,421	$78,139,129	$80,754,758	$74,474,459
Estimated Working Capital Requirements (%)	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%	12.0%

Organization of the Report

Section I of this report is the Executive Summary and discusses the key findings and conclusions from this study.

Section II presents the methods and assumptions used in determining the lead-lag approach. Included in this section is a description of two key concepts; the mid-point method and the statutory approach for services and materials provided and expensed.

Section III of this report discusses the lags associated with HUC's collections of revenues. This includes a description of the sources of such revenues, how they were treated for the purposes of deriving an overall revenue lag, and how it affects HUC's distribution operations.

Section IV presents a description of the various expenses and their attendant lead times. Included in this discussion are the lead times on Payroll and Benefits, OM&A, Taxes, Interest, Debt Retirement Charges and the Harmonized Sales Tax ("HST"). The methods used to calculate the expense lead times associated with each of the items as well as the results from the application of the methods are described.

Section V presents the cash WCA of HUC's distribution business including the WCA associated with the HST.

Section II: Methodology Used to Estimate Cash Working Capital

Working capital is the amount of funds that are required to finance the day-to-day operations of a utility and are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for the determination of working capital and was used by Navigant for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date customers' payments are available to HUC (or "lag") together with the time between which HUC receives goods and services from its vendors and pays for them at a later date (or "lead")[1]. "Leads" and "Lags" are both measured in days and are generally where appropriate, dollar-weighted.[2] The dollar-weighted net lag (i.e., lag minus lead) days is divided by 365 (or 366 if a leap year is selected) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. The resulting amount of working capital is then included as part of HUC's rate base for the purpose of deriving revenue requirement.

Key Concepts

Two key concepts need to be defined up-front as they appear throughout the lead-lag study described in this report:

Mid-Point Method: When a service is provided to (or by) HUC over a period of time, the service is deemed to have been provided (or received) evenly over the midpoint of the period, unless specific information regarding the provision (or receipt) of that service is available indicating otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using the formula:

$$\text{Mid-Point} = \frac{([\text{Y-X}]+1)}{2}$$

When specific start and end dates are unknown but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is typically used is shown below. The formula uses the number of days in a year ("A") and the number of periods in a year ("B"):

$$\text{Mid-Point} = \frac{\text{A/B}}{2}$$

Statutory Approach: In conjunction with the use of the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made by HUC. In some instances, particularly for the HST, the due dates for payments are established by statute or by regulation with significant penalties in place for late payments. In these instances, the due date established by statute has been used in lieu of when payments were actually made.

[1] A positive lag (or lead) indicates that payments are received (or paid for) after the provision of a good or service.

[2] The notion of dollar-weighting is pursued further in the sub-section titled "Key Concepts".

Expense Lead Components: As used in this study, Expense Leads are defined to consist of two components:

1. A Service Lead component (i.e., services are assumed to be provided to HUC evenly around the mid-point of the service period); and
2. A Payment Lead component (i.e., the time period from the end of the service period to the time payment was made and the funds left HUC's possession).

Dollar-Weighting: Both "Leads" and "Lags" should be dollar-weighted where appropriate and where data is available to more accurately reflect the flow of dollars. As an example, suppose that a transaction has a Cash Outflow Lead time of 100 days and its dollar value was $100. Suppose further that another transaction has a Cash Outflow Lead time of 30 days with a dollar value of $1M. A simple un-weighted average of the two transactions would give us a Cash Outflow Lead time of 65 days ([100+30]/2). On the other hand, dollar-weighting the two transactions gives us a Cash Outflow Lead time closer to 30 days; an answer which is more representative of how the dollars actually flowed in this example.

Methodology

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated business works, (i.e., in terms of products and services sold to customers or purchased from vendors and the collections and payment policies and procedures that govern such transactions); and
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of HUC's operations, interviews with HUC personnel were conducted. Key questions that were addressed during the interviews included:

1. What is being sold (or bought)? If a service is being provided (purchased), over what time period was the service provided (or purchased);
2. Who are the buyers (sellers);
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
4. Are any changes expected to the terms for payment either driven by industry or internally by HUC? What is the basis for such changes (if any);
5. Are there any new rules and regulations governing such transactions that are expected to materialize over the time frame considered in this report; and
6. How payments are made (i.e., cash, check, electronic funds transfer).

Data for calendar year 2012 was used in the analysis. Development of the data set entailed gathering raw data from the HUC's General Accounting, Accounts Payable, Customer Service, Payroll, and Tax Systems. Once the raw data had been gathered from the multiple in-house systems, data validation was performed to the extent necessary and appropriate.

Section III: Revenue Lags

A distribution utility providing service to its customers generally derives its revenue from bills paid for service by its customers. A revenue lag represents the number of days from the date service is rendered by HUC until the date payments are received from customers and funds are available to HUC.

Interviews with HUC personnel indicate that its distribution business primarily receives funds from Retail Customers. The Ontario Clean Energy Benefit ("OCEB") was considered in this study, however since the OCEB expires on December 31, 2015 and since Horizon is applying for a 2014-2019 rate application, the OCEB will be excluded from the calculation of Retail Customer Revenue lag.

Retail Customer Revenue lag consists of the four following sequential components:

1. Service Lag;
2. Billing Lag;
3. Collections Lag; and
4. Payment Processing Lag.

The lag times for each of the above components, when added together, results in the Retail Customer Revenue Lag for the purpose of calculating the WCA for HUC's distribution business. Table 2 below summarizes the total weighted average Revenue Lag.

Table 2: Summary of Weighted Average Revenue Lag Days

Description	Lag Days
Retail Revenue	67.30

Table 3 below summarizes the components of Retail Revenue Lag.

Table 3: Summary of Retail Revenue Lag

Description	Weighted Lag Days
Service Lag	25.02
Billing Lag	18.98
Collections Lag	21.77
Payment Lag	1.54
Total	**67.30**

The estimation of each component of the Retail Revenue Lag is described below.

Service Lag

The Service Lag is the time from HUC's provision of electricity to a customer, to the time the customer's service period ends, which is typically defined as when the meter is read. Interviews with Customer Service Staff at HUC indicated that "Residential Retail", "General Service < 50", "Unmetered and Scattered" and "Sentinel" customers are on a monthly and bi-monthly service schedule, and "General Service > 50", "Large User" and "Streetlight" customers are on a monthly service schedule. Taking this information into account and using a mid-point methodology, the Service Lag was estimated to be 25.02 days. Note that this report reflects an update from the Navigant study dated March 31, 2014. The prior study had a larger percentage of customers billed on a bi-monthly basis, which resulted in a WCA of 12.7%. The 12.0% WCA shown in this report reflects updated data from the client regarding the customer monthly/bi-monthly split, which was provided by HUC to Navigant after the March 31, 2014 report submission.

Billing Lag

The Billing Lag is the time period from when the customer's service period ends, which is typically defined as when the meter is read, and the time that the customer's bill is generated and provided to the customer. Interviews with Billing Staff at HUC and analyses regarding meter reading and billing dates both indicated that both Residential and General Service customers have an average billing lag of 18.98 days.

Collections Lag

The Collections Lag is the time period from when the customer's bill is provided to the customer, to the time period that the customer provides a payment to HUC and when that payment is recorded in HUC's billing system. This period of time is measured by analyzing the receivables aging data contained in receivables reports used by HUC for normal business purposes. Using such data provided by HUC for the calendar year 2012, a dollar-weighted average collections lag of 21.77 days was determined for HUC's operations.

Payment Processing Lag

The Payment Processing Lag is the time period between the recording of a payment as having been received by HUC from the customer, and the payment being deposited into HUC's bank account. Based on interviews with HUC's staff, it was discovered that different payment methods result in different dates in which the payment is received in HUC's bank account. The following payment processing methods were considered in this study:

1. If the customer paid by Credit Card, that payment is in HUC's bank account two days after;
2. If the customer paid by Cheques or through ATM/Tellers, that payment is in the HUC's bank account three days after; and
3. If the customer paid by Internet, or Pre-authorization, that payment is in HUC's bank account two days after.

Taking into account HUC's different Payment Processing methods, an overall Payment Processing Lag of 1.54 days is the result and was used in the determination of HUC's overall revenue lag time.

Section IV: Expense Leads

The determination of working capital requires both a measurement of the lag in the collection of revenues for services provided by HUC's distribution business, and the lead times associated with payments for services provided to HUC. Therefore, in conjunction with the calculation of the revenue lag, expense lead times were calculated for the following items:

1. Cost of Power;
2. Payroll and Benefits;
3. OM&A Expenses;
4. Payments in Lieu of Taxes;
5. Interest Expenses; and
6. Debt Retirement Charge.

HUC's benefits and costs in terms of the WCA associated with the HST are discussed separately.

Cost of Power

HUC purchases its power supply requirements on a monthly basis from the IESO and pays for such supplies on a schedule defined within the IESO's billing and settlement procedures. HUC also settles payments to Hydro One for the use of their transmission system. Taking all this information on actual payments made by HUC in 2012, a dollar-weighted Cost of Power expense lead time of 32.86 days was calculated. Table 4 below summarizes the components of the Cost of Power expense lead calculation. Table 5 and Table 6 show the derivation of the weighted lag days for the components of Cost of Power.

Table 4: Summary of Cost of Power Expenses

Description	Amounts ($M)	Weighting Factor %	Lead Time	Weighted Lead Time
IESO	$399.68	98.93%	32.58	32.23
Hydro One	$4.32	1.07%	58.84	0.63
Total	**$404.00**	**100.00%**		**32.86**

Table 5: Summary of IESO Cost of Power Expenses

Delivery Month[3]	Amounts ($M)	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Dec 11	$32.62	8.16%	1/18/2012	15.50	18.00	33.50	2.73
Jan 12	$32.05	8.02%	2/16/2012	15.50	16.00	31.50	2.53
Feb 12	$31.31	7.83%	3/16/2012	14.50	16.00	30.50	2.39
Mar 12	$30.95	7.74%	4/19/2012	15.50	19.00	34.50	2.67
Apr 12	$28.82	7.21%	5/16/2012	15.00	16.00	31.00	2.24
May 12	$31.80	7.96%	6/18/2012	15.50	18.00	33.50	2.67
Jun 12	$36.89	9.23%	7/18/2012	15.00	18.00	33.00	3.05
Jul 12	$39.47	9.88%	8/17/2012	15.50	17.00	32.50	3.21
Aug 12	$42.81	10.71%	9/19/2012	15.50	19.00	34.50	3.69
Sep 12	$29.52	7.39%	10/17/2012	15.00	17.00	32.00	2.36
Oct 12	$30.99	7.75%	11/15/2012	15.50	15.00	30.50	2.37
Nov 12	$32.46	8.12%	12/18/2012	15.00	18.00	33.00	2.68
Total	**$399.68**	**100.00%**					**32.58**

Table 6: Summary of Hydro One Cost of Power Expenses

Delivery Month	Amounts ($M)	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	$0.32	7.38%	3/20/2012	16.00	42.00	58.00	4.28
Feb 12	$0.31	7.24%	4/19/2012	15.00	43.00	58.00	4.20
Mar 12	$0.29	6.74%	5/18/2012	15.00	43.00	58.00	3.91
Apr 12	$0.28	6.44%	6/20/2012	17.00	43.00	60.00	3.86
May 12	$0.40	9.20%	7/19/2012	15.00	43.00	58.00	5.33
Jun 12	$0.45	10.53%	8/16/2012	15.50	41.00	56.50	5.95
Jul 12	$0.46	10.66%	9/18/2012	15.00	45.00	60.00	6.40
Aug 12	$0.42	9.84%	10/18/2012	17.00	42.00	59.00	5.81
Sep 12	$0.38	8.76%	11/19/2012	15.00	45.00	60.00	5.25
Oct 12	$0.30	7.01%	12/18/2012	16.50	42.00	58.50	4.10
Nov 12	$0.32	7.47%	1/21/2013	15.50	46.00	61.50	4.60
Dec 12	$0.38	8.74%	2/19/2013	17.00	42.00	59.00	5.16
Total	**$4.32**	**100.00%**					**58.84**

Payroll and Benefits

For the purpose of the distribution lead-lag study, the following items were considered to be expenses related to the Payroll and Benefits of HUC:

1. Regular Staff Payroll;
2. Board of Director Payroll;
3. Great West Life – MDV;
4. Great West Life – HCS;
5. Group Life Insurance & LTD Insurance;
6. WSIB; and,
7. Pensions.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 11.82 days for Payroll and Benefit expenses. A summary of the dollar-weighted expense lead time is provided in Table 7 below.

Table 7: Summary of Payroll and Benefit Expenses

Description	Amounts ($M)	Weighting Factor %	Lead (Lag) Time	Weighted Lead Time
Regular Staff Payroll	$37.64	78.95%	6.00	4.74
Board of Directors Payroll	$0.43	0.90%	47.75	0.43
Great West Life – MDV	$3.01	6.32%	27.93	1.77
Great West Life – HCS	$0.04	0.09%	53.13	0.05
Group Life Insurance & LTD Insurance	$3.01	6.32%	27.36	1.73
WSIB	$0.31	0.66%	29.30	0.19
Pensions (OMERS)	$3.22	6.76%	43.09	2.91
Total	**$47.67**	**100.00%**		**11.82**

Regular Payroll

HUC's Regular Payroll Staff are paid on a weekly basis on every Wednesday of every week for the prior week's services. Based on HUC's payroll data for 2012, an average service lead time of 4.00 days and an average payment lag time of 2.00 days were determined. Taking this information into account, a dollar-weighted net expense lead time of 6.00 days was determined for Regular Staff Payroll.

Board of Directors Payroll

HUC's Board of Directors Staff is paid to ADP on a quarterly basis on every second day of the quarter beginning month for the prior quarters pay period services. Based on HUC's payroll data for 2012, an average service lead time of 45.75 days and an average payment lead time of 2.00 days were determined. Taking this information into account, a dollar-weighted expense lead time of 47.75 days was determined for Board of Directors Payroll.

Great West Life – Medical, Dental, and Vision

HUC pays for Medical, Dental, and Vision medical coverage in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.25 days and an average payment lead time of 12.68 days were determined. Taking this information into account, a dollar-weighted expense lead time of 27.93 days was determined for Great West Life – Medical, Dental and Vision medical coverage.

Great West Life – Health Care Spending Account

HUC pays for employee Health Care Spending accounts in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.23 days and an average payment lead time of 37.90 days were determined. Taking this information into account, a dollar-weighted expense lead time of 53.13 days was determined for Great West Life – Medical, Dental and Vision medical coverage.

Group Life & Long Term Disability Insurance

HUC pays for employee Group Life & Long Term Disability Insurance in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.25 days and an average payment lead time of 12.11 days were determined. Taking this information into account, a dollar-weighted expense lead time of 27.36 days was determined for Group Life & Long Term Disability Insurance.

Workplace Safety & Insurance Board

HUC pays for employee Workplace Safety & Insurance Board payments in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.23 days and an average payment lead time of 14.08 days were determined. Taking this information into account, a dollar-weighted expense lead time of 29.30 days was determined for Workplace Safety & Insurance Board payments.

Pensions (OMERS)

HUC pays for employee Pensions, also known as Ontario Municipal Employees Retirement System ("OMERS") payments in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.23 days and an average payment lead time of 27.86 days were determined. Taking this information into account, a dollar-weighted expense lead time of 43.09 days was determined for Pensions (OMERS) payments.

OM&A Expenses

For the purpose of the distribution lead-lag study, OM&A expenses were considered to consist of payments made by HUC to its vendors in the following categories:

1. P Card;
2. Contract Labour;
3. Vehicles;
4. Computer Maintenance;
5. Software;
6. Cellphone & Pager;
7. Wireless;
8. Freight, Postage & Delivery;
9. Consulting;
10. Tree Trimming;
11. Outside Services; and,
12. Property Taxes.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 1.23 days for OM&A expenses. A summary of the dollar-weighted expense lead time is provided in Table 8 below.

Table 8: Summary of OM&A Expenses

Description	Amounts ($M)	Weighting Factor %	Lead Time	Weighted Lead Time
Credit Card	$0.30	2.86%	44.21	1.27
Contract Labour	$0.21	2.02%	29.30	0.59
Vehicles	$0.02	0.16%	31.65	0.05
Computer Maintenance	$0.63	6.03%	(357.55)	(21.57)
Software	$2.42	23.23%	15.21	3.53
Cell & Pager	$0.29	2.76%	29.45	0.81
Wireless	$0.23	2.22%	31.84	0.71
Freight / Postage / Delivery	$0.11	1.09%	33.31	0.36
Consulting Services	$2.37	22.75%	33.03	7.52
Tree Trimming	$0.55	5.27%	33.71	1.78
Outside Services	$2.62	25.11%	31.76	7.98
Property Taxes	$0.68	6.47%	(27.66)	(1.79)
Total	**$10.43**	**100.00%**		**1.23**

P Card

During 2012, HUC used Credit Cards for a variety of services procured by its employees. Based on HUC's Credit Card expense data for 2012, an average service lead time of 15.24 days and an average payment lead time of 28.97 days were determined. Taking this information into account, a dollar-weighted expense lead time of 44.21 days was determined for Credit Card expenses.

Contract Labour

During 2012, HUC procured Contract Labour for a variety of services required for distribution services. Based on HUC's Contract Labour data for 2012, an average service lead time of 15.26 days and an average payment lead time of 14.03 days were determined. Taking this information into account, a dollar-weighted expense lead time of 29.30 days was determined for Contract Labour.

Vehicles

During 2012, HUC expensed Vehicles for a variety of services required for distribution services. Based on HUC's Vehicle spending data for 2012, an average service lead time of 15.38 days and an average payment lead time of 16.27 days were determined. Taking this information into account, a dollar-weighted expense lead time of 31.65 days was determined for Vehicle expenses.

Computer Maintenance

During 2012, HUC procured services from multiple vendors for Computer Maintenance agreements. Based on HUC's Computer Maintenance Procurement data for 2012, an average service lead time of 373.61 days and an average payment lead time of (731.16) days were determined. Taking this information into account, a dollar-weighted expense lead time of (357.55) days were determined for Computer Maintenance.

Software

During 2012, HUC procured licenses from multiple vendors for computer Software. Based on HUC's Software Procurement data for 2012, an average service lead time of 23.93 days and an average payment lead time of (8.71) days were determined. Taking this information into account, a dollar-weighted expense lead time of 15.21 days was determined for Software expenses.

Cellphone & Pager

During 2012, HUC expensed Cellphone & Pager use for a variety of services required for distribution services. Based on HUC's Cellphone & Pager data for 2012, an average service lead time of 15.25 days and an average payment lead time of 14.20 days were determined. Taking this information into account, a dollar-weighted expense lead time of 29.45 days was determined for Cellphone & Pager expenses.

Wireless Services

During 2012, HUC expensed Wireless Services for a variety of services required for distribution services. Based on HUC's Wireless Services data for 2012, an average service lead time of 15.28 days and an average payment lead time of 16.55 days were determined. Taking this information into account, a dollar-weighted expense lead time of 31.84 days was determined for Wireless expenses.

Freight / Postage / Delivery

During 2012, HUC expensed Freight / Postage / Delivery services for a variety of activities required for distribution services. Based on HUC's Freight / Postage / Delivery data for 2012, an average service lead time of 15.25 days and an average payment lead time of 18.06 days were determined. Taking this information into account, a dollar-weighted expense lead time of 33.31 days was determined for Freight / Postage / Delivery expenses.

Consulting Services

During 2012, HUC procured Consulting Services required for a variety of activities related to distribution services. Based on HUC's Consulting Services data for 2012, an average service lead time of 15.23 days and an average payment lead time of 17.79 days were determined. Taking this information into account, a dollar-weighted expense lead time of 33.03 days was determined for Consulting Services.

Tree Trimming

During 2012, HUC expensed Tree Trimming services required for distribution services. Based on HUC's Tree Trimming spending data for 2012, an average service lead time of 15.17 days and an average payment lead time of 18.53 days were determined. Taking this information into account, a dollar-weighted expense lead time of 33.71 days was determined for Tree Trimming expenses.

Outside Services

During 2012, HUC procured Outside Services for a variety of activities required for distribution services. Based on HUC's Outside Services data for 2012, an average service lead time of 15.28 days and an average payment lead time of 16.48 days were determined. Taking this information into account, a dollar-weighted expense lead time of 31.76 days was determined for Outside Services.

Property Taxes

During 2012, HUC paid property tax payments to the following municipalities:

1. City of Hamilton; and,
2. City of St. Catharines.

Based on HUC's Property Tax data for 2012, an average service lead time of 183.00 days and an average payment lead (lag) time of (210.66) days were determined. Since property taxes are an annual expense, services were rendered on an annual basis, with (27.66) days resulting as the expense lead time associated with property taxes.

Payments in Lieu of Taxes

HUC makes payments in lieu of taxes ("PILs") in monthly installments to the relevant taxing authorities. In 2012, HUC made (12) payments for each month of the year. Based on HUC's PILs data for 2012, an average service lead time of 183.00 days and an average payment lead (lag) time of (168.50) days were determined. Taking this information into account, a dollar-weighted expense lead time of 14.50 days was determined for PILs.

Debt Retirement Charge

HUC makes a Debt Retirement Charge in monthly installments to the Ontario Electricity Finance Corporation. The payment for the current charge month is made during the middle of the following month. Based on HUC's Debt Retirement Charge data for 2012, an average service lead time of 15.26 days and an average payment lead time of 10.34 days were determined. Taking this information into account, a dollar-weighted expense lead time of 25.59 days was determined for Debt Retirement Charge.

Interest Expense

HUC has two outstanding debt issuances which incur interest expenses. Based on HUC's Interest Expense data for 2012, an average service lead time of 91.50 days and an average payment lead (lag) time of (158.65) days were determined. Taking this information into account, a dollar-weighted expense lead (lag) time of (67.15) days were determined for Interest Expense.

Harmonized Sales Tax

The expense lead (lag) times associated with the following items that attract HST were considered in this study:

1. Customer Revenues including Cost of Power;
2. Cost of Power expenses; and
3. OM&A Expenses.

Effective July 1, 2010, the Ontario government implemented the harmonization of the Provincial Sales Tax with the Federal Goods and Service Tax into a single Harmonized Sales Tax. Given this is a known and measurable change forward looking; the WCA was calculated using the HST rate of 13.00%. Note that the statutory approach described at the outset was used to determine the expense lead times associated with HUC's remittances and disbursements of HST (i.e., both remittances and collections are generally on the last day of the month following the date of the applicable invoice)
A summary of the expense lead (lag) times associated with each of the above items is provided in Table 10 and Table 10 below.

Table 9: HST Working Capital Factor

HST Category	HST Lead/Lag Days	Working Capital Factor	Working Capital Factor (Leap Year)
HST Rate	13%	13%	13%
Revenues [inc. COP] Lead Days	(23.12)	(6.33%)	(6.32%)
Cost of Power Lead Days	43.73	11.98%	11.95%
OM&A Lead Days	2.55	0.70%	0.70%

Table 10: Summary of Expense Lead Times Associated With HST

HST Category	2014	2015	2016	2017	2018	2019
Revenues [incl. COP]	$622,203,415	$638,342,404	$664,944,611	$688,586,511	$711,468,938	$734,283,591
HST Rate	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%
Cost of Power	$514,946,434	$520,720,617	$542,171,542	$562,422,662	$583,269,859	$602,042,446
OM&A	$30,783,301	$29,728,985	$29,849,980	$30,659,445	$31,709,813	$33,108,690
Revenues [incl. COP]	-$5,123,216	-$5,256,105	-$5,460,188	-$5,669,814	-$5,858,228	-$6,046,083
Cost of Power	$8,020,726	$8,110,664	$8,421,707	$8,760,209	$9,084,921	$9,377,320
OM&A	$28,011	$27,052	$27,088	$27,899	$28,854	$30,127
Total	**$2,925,521**	**$2,881,611**	**$2,988,607**	**$3,118,293**	**$3,255,548**	**$3,361,364**

Section V: HUC's Working Capital Allowance

Using the results described under the discussion of revenue lags and expense leads, and applying them to HUC's distribution expenses for 2014-2019, the weighted average WCA was determined to be 12.0% of HUC's distribution OM&A expenses (including Cost of Power) for each of the test years 2014-2019. A summary of HUC's WCA for individual 2014-2019 years is provided in the subsequent tables below. These tables include HST amounts which have been derived from Table 10 above.

Table 11: Summary of Working Capital Allowance - 2014

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	67.30	32.86	34.44	9.4%	$514,946,434	$48,584,754
OM&A Expenses[4]	67.30	7.30	60.00	16.4%	$64,986,015	$10,683,086
PILs	67.30	14.50	52.80	14.5%	$555,146	$80,303
Debt Retirement Charge	67.30	25.59	41.70	11.4%	$32,180,619	$3,676,858
Interest Expense	67.30	(67.15)	134.45	36.8%	$9,519,067	$3,506,363
Sub-Total					**$622,187,281**	**$66,531,364**
HST						$2,925,521
Total						**$69,456,886**
WCA as a % of OM&A (incl. Cost of Power)						**12.0%**

Table 12: Summary of Working Capital Allowance - 2015

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	67.30	32.86	34.44	9.4%	$520,720,617	$49,129,543
OM&A Expenses[5]	67.30	7.30	60.00	16.4%	$64,479,807	$10,599,871
PILs	67.30	14.50	52.80	14.5%	$2,874,217	$415,763
Debt Retirement Charge	67.30	25.59	41.70	11.4%	$31,854,423	$3,639,588
Interest Expense	67.30	(67.15)	134.45	36.8%	$9,831,640	$3,621,500
Sub-Total					**$629,760,705**	**$67,406,264**
HST						$2,881,611
Total						**$70,287,875**
WCA as a % of OM&A (incl. Cost of Power)						**12.0%**

[4] Includes Payroll and Benefits
[5] Includes Payroll and Benefits

Table 13: Summary of Working Capital Allowance - 2016

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	67.30	32.86	34.44	9.4%	$542,171,542	$51,013,656
OM&A Expenses[6]	67.30	7.30	60.00	16.4%	$65,940,947	$10,810,450
PILs	67.30	14.50	52.80	14.4%	$4,252,792	$613,496
Debt Retirement Charge	67.30	25.59	41.70	11.4%	$31,531,534	$3,592,852
Interest Expense	67.30	(67.15)	134.45	36.7%	$10,204,633	$3,748,622
Sub-Total					**$654,101,448**	**$69,779,077**
HST						$2,988,607
Total						**$72,767,684**
WCA as a % of OM&A (incl. Cost of Power)						**12.0%**

Table 14: Summary of Working Capital Allowance - 2017

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	67.30	32.86	34.44	9.4%	$562,422,662	$53,064,095
OM&A Expenses[7]	67.30	7.30	60.00	16.4%	$67,692,855	$11,128,065
PILs	67.30	14.50	52.80	14.5%	$4,496,240	$650,392
Debt Retirement Charge	67.30	25.59	41.70	11.4%	$31,211,917	$3,566,177
Interest Expense	67.30	(67.15)	134.45	36.8%	$10,624,086	$3,913,398
Sub-Total					**$676,447,760**	**$72,322,128**
HST						$3,118,293
Total						**$75,440,421**
WCA as a % of OM&A (incl. Cost of Power)						**12.0%**

[6] Includes Payroll and Benefits
[7] Includes Payroll and Benefits

Table 15: Summary of Working Capital Allowance - 2018

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	67.30	32.86	34.44	9.4%	$583,269,859	$55,031,010
OM&A Expenses[8]	67.30	7.30	60.00	16.4%	$69,773,217	$11,470,057
PILs	67.30	14.50	52.80	14.5%	$3,925,141	$567,781
Debt Retirement Charge	67.30	25.59	41.70	11.4%	$30,895,541	$3,530,029
Interest Expense	67.30	(67.15)	134.45	36.8%	$11,632,105	$4,284,704
Sub-Total					**$699,495,863**	**$74,883,581**
HST						$3,255,548
Total						**$78,139,129**
WCA as a % of OM&A (incl. Cost of Power)						**12.0%**

Table 16: Summary of Working Capital Allowance - 2019

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	67.30	32.86	34.44	9.4%	$602,042,446	$56,802,187
OM&A Expenses[9]	67.30	7.30	60.00	16.4%	$72,228,903	$11,873,749
PILs	67.30	14.50	52.80	14.5%	$4,021,290	$581,690
Debt Retirement Charge	67.30	25.59	41.70	11.4%	$30,582,371	$3,494,247
Interest Expense	67.30	(67.15)	134.45	36.8%	$12,600,791	$4,641,521
Sub-Total					**$721,475,801**	**$77,393,394**
HST						$3,361,364
Total						**$80,754,758**
WCA as a % of OM&A (incl. Cost of Power)						**12.0%**

[8] Includes Payroll and Benefits
[9] Includes Payroll and Benefits

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A Determination of the Working Capital Requirements of Horizon Utilities' Distribution Business

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March 31, 2014

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This report (the "report") was prepared for Horizon Inc. ("Horizon"), by Navigant Consulting, Ltd. ("Navigant"). The report was prepared solely for the purposes of the 2013 Distribution Cost of Service Application to be filed before the Ontario Energy Board and may not be used for any other purpose. Use of this report by any third party outside of Horizon's application is prohibited. Use of this report should not, and does not, absolve the third party from using due diligence in verifying the report's contents. Any use which a third party makes of this report, or any reliance on it, is the responsibility of the third party. Navigant extends no warranty to any third party.

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Table of Contents

NAVIGANT

List of Tables

Section I: Executive Summary

Summary

In preparation for HUC's 2014 Distribution Cost of Service Rate Application before the Ontario Energy Board ("OEB" or "Board"), Horizon Utilities Corporation ("HUC") retained Navigant Consulting Ltd. ("Navigant") to perform a lead-lag study using the most recent data available, and to derive HUC's ~~WCA~~Working Capital Amount ("WCA") using historical 2012 data with known and measurable forward looking changes applied. This report provides the results of the study and the WCA of HUC's distribution business.

This report includes the following changes from the previous report dated March 31, 2014:

- The updated report reflects a change from the prior study in which the revenues associated with Residential, General Service <50, Unmetered and Scattered, and Streetlighting customer classes were reflected as being billed on a bi-monthly basis, instead of being billed based upon a split between monthly and bi-monthly frequencies. As a result of this change, the WCA of 12.7% in the previous report was overstated. When the correction was captured in the analysis the resulting WCA becomes 12.0%.
- Typographical errors were corrected in the following sections of the report which had no impact on the resulting WCA percentage:
  - Pg 11 – Table 5: Delivery month for IESO COP;
  - Pg 11 – Table 6: Service lead time for Hydro One COP;
  - Pg 12 & 13 – Table 7: Expense lead time for Group Life Insurance & LTD Insurance;
  - Pg 16 – Expense lead time for Property Taxes; and
  - Pg 16 – Service, payment and expense lead times for Payments in Lieu of Taxes.
- All calculation changes in this report are a result of the change in frequency of monthly versus bi-monthly customer billing for the service lag component.

Results from the lead-lag study applied to HUC's 2012 distribution expenses identify ~~that~~ an average working capital percentage of 12.~~7~~0% of the Cost of Power and OM&A Expenses for the 2014-2019 test years. This report also represents ~~an average of 12.7% of HUC's distribution OM&A expenses for~~ the 2014-2019 time periods. Inasmuch as slight variation exists from year-to-year in our analysis Navigant believes application of the 12.~~7~~0% provides an accurate recovery of the cost of working capital for the time period 2014 through 2019. Based upon the working capital dollar amounts for each of the test years, the weighted average working capital was calculated to be 12.~~7~~0%. Table 1 below provides the estimated working capital dollars and percentages for the test years 2014-2019.

Table 1—: Estimated Working Capital Requirements

	2014	2015	2016	2017	2018	2019	2014 to 2019
Estimated Working Capital Requirements ($)	$~~73,386,661~~69,456,886	$~~74,271,709~~70,287,875	$~~76,895,589~~72,767,684	$~~79,721,717~~75,440,421	$~~82,565,878~~78,139,129	$~~85,320,939~~80,754,758	$~~458,010,166~~74,474,459

Estimated Working Capital Requirements (%)	12.~~7~~0%	12.~~7~~0%	12.~~6~~0%	12.~~7~~0%	12.~~6~~0%	12.~~7~~0%	12.~~7~~0%

Organization of the Report

Section I of this report is the Executive Summary and discusses the key findings and conclusions from this study.

Section II presents the methods and assumptions used in determining the lead-lag approach. Included in this section is a description of two key concepts; the mid-point method and the statutory approach for services and materials provided and expensed.

Section III of this report discusses the lags associated with HUC's collections of revenues. This includes a description of the sources of such revenues, how they were treated for the purposes of deriving an overall revenue lag, and how it affects HUC's distribution operations.

Section IV presents a description of the various expenses and their attendant lead times. Included in this discussion are the lead times on Payroll and Benefits, OM&A, Taxes, Interest, Debt Retirement Charges and the Harmonized Sales Tax ("HST"). The methods used to calculate the expense lead times associated with each of the items as well as the results from the application of the methods are described.

Section V presents the cash WCA of HUC's distribution business including the WCA associated with the HST.

Section II: Methodology Used to Estimate Cash Working Capital

Working capital is the amount of funds that are required to finance the day-to-day operations of a utility and are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for the determination of working capital and was used by Navigant for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date customers' payments are available to HUC (or "lag") together with the time between which HUC receives goods and services from its vendors and pays for them at a later date (or "lead")[1]. "Leads" and "Lags" are both measured in days and are generally where appropriate, dollar-weighted.[2] The dollar-weighted net lag (i.e., lag minus lead) days is divided by 365 (or 366 if a leap year is selected) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. The resulting amount of working capital is then included as part of HUC's rate base for the purpose of deriving revenue requirement.

Key Concepts

Two key concepts need to be defined up-front as they appear throughout the lead-lag study described in this report:

Mid-Point Method: When a service is provided to (or by) HUC over a period of time, the service is deemed to have been provided (or received) evenly over the midpoint of the period, unless specific information regarding the provision (or receipt) of that service is available indicating otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using the formula:

$$\text{Mid-Point} = \frac{([\text{Y-X}]+1)}{2}$$

When specific start and end dates are unknown but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is typically used is shown below. The formula uses the number of days in a year ("A") and the number of periods in a year ("B"):

$$\text{Mid-Point} = \frac{\text{A/B}}{2}$$

Statutory Approach: In conjunction with the use of the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made by HUC. In some instances, particularly for the HST, the due dates for payments are established by statute or by regulation with significant penalties in place for late payments. In these instances, the due date established by statute has been used in lieu of when payments were actually made.

[1] A positive lag (or lead) indicates that payments are received (or paid for) after the provision of a good or service.

[2] The notion of dollar-weighting is pursued further in the sub-section titled "Key Concepts".

Expense Lead Components: As used in this study, Expense Leads are defined to consist of two components:

1. A Service Lead component (i.e., services are assumed to be provided to HUC evenly around the mid-point of the service period); and
2. A Payment Lead component (i.e., the time period from the end of the service period to the time payment was made and the funds left HUC's possession).

Dollar-Weighting: Both "Leads" and "Lags" should be dollar-weighted where appropriate and where data is available to more accurately reflect the flow of dollars. As an example, suppose that a transaction has a Cash Outflow Lead time of 100 days and its dollar value was $100. Suppose further that another transaction has a Cash Outflow Lead time of 30 days with a dollar value of $1M. A simple un-weighted average of the two transactions would give us a Cash Outflow Lead time of 65 days ([100+30]/2). On the other hand, dollar-weighting the two transactions gives us a Cash Outflow Lead time closer to 30 days; an answer which is more representative of how the dollars actually flowed in this example.

Methodology

Performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated business works, (i.e., in terms of products and services sold to customers or purchased from vendors and the collections and payment policies and procedures that govern such transactions); and
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of HUC's operations, interviews with HUC personnel were conducted. Key questions that were addressed during the interviews included:

1. What is being sold (or bought)? If a service is being provided (purchased), over what time period was the service provided (or purchased);
2. Who are the buyers (sellers);
3. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment;
4. Are any changes expected to the terms for payment either driven by industry or internally by HUC? What is the basis for such changes (if any);
5. Are there any new rules and regulations governing such transactions that are expected to materialize over the time frame considered in this report; and
6. How payments are made (i.e., cash, check, electronic funds transfer~~)~~).

Data for calendar year 2012 was used in the analysis. Development of the data set entailed gathering raw data from the HUC's General Accounting, Accounts Payable, Customer Service, Payroll, and Tax Systems. Once the raw data had been gathered from the multiple in-house systems, data validation was performed to the extent necessary and appropriate.

Section III: Revenue Lags

A distribution utility providing service to its customers generally derives its revenue from bills paid for service by its customers. A revenue lag represents the number of days from the date service is rendered by HUC until the date payments are received from customers and funds are available to HUC.

Interviews with HUC personnel indicate that its distribution business primarily receives funds from Retail Customers. The Ontario Clean Energy Benefit ("OCEB") was considered in this study, however since the OCEB expires on December 31, 2015 and since Horizon is applying for a 2014-2019 rate application, the OCEB will be excluded from the calculation of Retail Customer Revenue lag.

Retail Customer Revenue lag consists of the four following sequential components:

1. Service Lag;
2. Billing Lag;
3. Collections Lag; and
4. Payment Processing Lag.

The lag times for each of the above components, when added together, results in the Retail Customer Revenue Lag for the purpose of calculating the WCA for HUC's distribution business. Table 2 below summarizes the total weighted average Revenue Lag.

Table 2: Summary of Weighted Average Revenue Lag Days

Description	Lag Days
Retail Revenue	~~69.34~~67.30

Table 3 below summarizes the components of Retail Revenue Lag.

Table 3: Summary of Retail Revenue Lag

Description	Weighted Lag Days
Service Lag	~~27.06~~25.02
Billing Lag	18.98
Collections Lag	21.77
Payment Lag	1.54
Total	~~69.34~~67.30

The estimation of each component of the Retail Revenue Lag is described below.

Service Lag

The Service Lag is the time from HUC's provision of electricity to a customer, to the time the customer's service period ends, which is typically defined as when the meter is read. Interviews with Customer Service Staff at HUC indicated that "Residential Retail", "General Service < 50", "Unmetered and Scattered" and "Sentinel" customers are on a monthly and bi-monthly service schedule, and "General Service > 50", "Large User" and "Streetlight" customers are on a monthly service schedule. Taking this information into account and using a mid-point methodology, the Service Lag was estimated to be ~~27.06 days.~~25.02 days. Note that this report reflects an update from the Navigant study dated March 31, 2014. The prior study had a larger percentage of customers billed on a bi-monthly basis, which resulted in a WCA of 12.7%. The 12.0% WCA shown in this report reflects updated data from the client regarding the customer monthly/bi-monthly split, which was provided by HUC to Navigant after the March 31, 2014 report submission.

Billing Lag

The Billing Lag is the time period from when the customer's service period ends, which is typically defined as when the meter is read, and the time that the customer's bill is generated and provided to the customer. Interviews with Billing Staff at HUC and analyses regarding meter reading and billing dates both indicated that both Residential and General Service customers have an average billing lag of 18.98 days.

Collections Lag

The Collections Lag is the time period from when the customer's bill is provided to the customer, to the time period that the customer provides a payment to HUC and when that payment is recorded in HUC's billing system. This period of time is measured by analyzing the receivables aging data contained in receivables reports used by HUC for normal business purposes. Using such data provided by HUC for the calendar year 2012, a dollar-weighted average collections lag of 21.77 days was determined for HUC's operations.

Payment Processing Lag

The Payment Processing Lag is the time period between the recording of a payment as having been received by HUC from the customer, and the payment being deposited into HUC's bank account. Based on interviews with HUC's staff, it was discovered that different payment methods result in different dates in which the payment is received in HUC's bank account. The following payment processing methods were considered in this study:

1. If the customer paid by Credit Card, that payment is in HUC's bank account two days after;
2. If the customer paid by Cheques or through ATM/Tellers, that payment is in the HUC's bank account three days after; and
3. If the customer paid by Internet, or Pre-authorization, that payment is in HUC's bank account two days after.

Taking into account HUC's different Payment Processing methods, an overall Payment Processing Lag of 1.54 days is the result and was used in the determination of HUC's overall revenue lag time.

Section IV: Expense Leads

The determination of working capital requires both a measurement of the lag in the collection of revenues for services provided by HUC's distribution business, and the lead times associated with payments for services provided to HUC. Therefore, in conjunction with the calculation of the revenue lag, expense lead times were calculated for the following items:

1. Cost of Power;
2. Payroll and Benefits;
3. OM&A Expenses;
4. Payments in Lieu of Taxes;
5. Interest Expenses; and
6. Debt Retirement Charge.

HUC's benefits and costs in terms of the WCA associated with the HST are discussed separately.

Cost of Power

HUC purchases its power supply requirements on a monthly basis from the IESO and pays for such supplies on a schedule defined within the IESO's billing and settlement procedures. HUC also settles payments to Hydro One for the use of their transmission system. Taking all this information on actual payments made by HUC in 2012, a dollar-weighted Cost of Power expense lead time of 32.86 days was calculated. Table 4 below summarizes the components of the Cost of Power expense lead calculation. Table 5 and Table 6 show the derivation of the weighted lag days for the components of Cost of Power.

Table 4: Summary of Cost of Power Expenses

Description	Amounts ($M)	Weighting Factor %	Lead Time	Weighted Lead Time
IESO	$399.68	98.93%	32.58	32.23
Hydro One	$4.32	1.07%	58.84	0.63
Total	**$404.00**	**100.00%**		**32.86**

Table 5: Summary of IESO Cost of Power Expenses

Delivery Month[3]	Amounts ($M)	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
~~Jan 12~~Dec 11	$32.62	8.16%	1/18/2012	15.50	18.00	33.50	2.73
~~Feb~~Jan 12	$32.05	8.02%	2/16/2012	15.50	16.00	31.50	2.53
~~Mar~~Feb 12	$31.31	7.83%	3/16/2012	14.~~00~~50	16.00	30.50	2.39
~~Apr~~Mar 12	$30.95	7.74%	4/19/2012	15.50	19.00	34.50	2.67
~~May~~Apr 12	$28.82	7.21%	5/16/2012	15.00	16.00	31.00	2.24
~~Jun~~May 12	$31.80	7.96%	6/18/2012	15.50	18.00	33.50	2.67
~~Jul~~Jun 12	$36.89	9.23%	7/18/2012	15.00	18.00	33.00	3.05
~~Aug~~Jul 12	$39.47	9.88%	8/17/2012	15.50	17.00	32.50	3.21
~~Sep~~Aug 12	$42.81	10.71%	9/19/2012	15.50	19.00	34.50	3.69
~~Oct~~Sep 12	$29.52	7.39%	10/17/2012	15.00	17.00	32.00	2.36
~~Nov~~Oct 12	$30.99	7.75%	11/15/2012	15.50	15.00	30.50	2.37
~~Dec~~Nov 12	$32.46	8.12%	12/18/2012	15.00	18.00	33.00	2.68
Total	**$399.68**	**100.00%**					**32.58**

Table 6: Summary of Hydro One Cost of Power Expenses

Delivery Month	Amounts ($M)	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
Jan 12	-$0.32	7.38%	3/20/2012	~~15~~16.00	42.00	58.00	4.28
Feb 12	$0.31	7.24%	4/19/2012	15.~~50~~00	43.00	58.00	4.20
Mar 12	$0.29	6.74%	5/18/2012	15.~~50~~00	43.00	58.00	3.91
Apr 12	$0.28	6.44%	6/20/2012	~~14~~17.00	43.00	60.00	3.86
May 12	$0.40	9.20%	7/19/2012	15.~~50~~00	43.00	58.00	5.33
Jun 12	$0.45	10.53%	8/16/2012	15.~~00~~50	41.00	56.50	5.95
Jul 12	$0.46	10.66%	9/18/2012	15.~~50~~00	45.00	60.00	6.40
Aug 12	$0.42	9.84%	10/18/2012	~~15~~17.00	42.00	59.00	5.81
Sep 12	$0.38	8.76%	11/19/2012	15.~~50~~00	45.00	60.00	5.25
Oct 12	$0.30	7.01%	12/18/2012	~~15~~16.50	42.00	58.50	4.10
Nov 12	$0.32	7.47%	1/21/2013	15.~~00~~50	46.00	61.50	4.60

Dec 12	$0.38	8.74%	2/19/2013	~~15.50~~17.00	42.00	59.00	5.16
Total	**$4.32**	**100.00%**					**58.84**

Payroll and Benefits

For the purpose of the distribution lead-lag study, the following items were considered to be expenses related to the Payroll and Benefits of HUC:

1. Regular Staff Payroll;
2. Board of Director Payroll;
3. Great West Life – MDV;
4. Great West Life – HCS;
5. Group Life Insurance & LTD Insurance;
6. WSIB; and,
7. Pensions.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 11.~~13~~82 days for Payroll and Benefit expenses. A summary of the dollar-weighted expense lead time is provided in Table 7 below.

Table 7: Summary of Payroll and Benefit Expenses

Description	Amounts ($M)	Weighting Factor %	Lead (Lag) Time	Weighted Lead Time
Regular Staff Payroll	$37.64	~~82.42~~78.95%	6.00	4.~~94~~74
Board of Directors Payroll	$0.43	0.~~94~~90%	47.75	0.~~45~~43
Great West Life – MDV	$3.01	6.~~60~~32%	27.93	1.~~84~~77
Great West Life – HCS	$0.04	0.09%	53.13	0.05
Group Life Insurance & LTD Insurance	~~$1~~$3.01	~~2.21~~6.32%	27.~~31~~36	~~0.60~~1.73
WSIB	$0.31	0.~~69~~66%	29.30	0.~~20~~19
Pensions (OMERS)	$3.22	~~7.06~~6.76%	43.09	~~3.04~~2.91
Total	**$~~45~~47.67**	**100.00~~$~~%**		**11.~~13~~82**

Regular Payroll

HUC's Regular Payroll Staff are paid on a weekly basis on every Wednesday of every week for the prior week's services. Based on HUC's payroll data for 2012, an average service lead time of 4.00 days and an average payment lag time of 2.00 days were determined. Taking this information into account, a dollar-weighted net expense lead time of 6.00 days was determined for Regular Staff Payroll.

Board of Directors Payroll

HUC's Board of Directors Staff is paid to ADP on a quarterly basis on every second day of the quarter beginning month for the prior quarters pay period services. Based on HUC's payroll data for 2012, an average service lead time of 45.75 days and an average payment lead time of 2.00 days were determined. Taking this information into account, a dollar-weighted expense lead time of 47.75 days was determined for Board of Directors Payroll.

Great West Life – Medical, Dental, and Vision

HUC pays for Medical, Dental, and Vision medical coverage in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.25 days and an average payment lead time of 12.68 days were determined. Taking this information into account, a dollar-weighted expense lead time of 27.93 days was determined for Great West Life – Medical, Dental and Vision medical coverage.

Great West Life – Health Care Spending Account

HUC pays for employee Health Care Spending accounts in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.23 days and an average payment lead time of 37.90 days were determined. Taking this information into account, a dollar-weighted expense lead time of 53.13 days was determined for Great West Life – Medical, Dental and Vision medical coverage.

Group Life & Long Term Disability Insurance

HUC pays for employee Group Life & Long Term Disability Insurance in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.25 days and an average payment lead time of 12.~~06~~11 days were determined. Taking this information into account, a dollar-weighted expense lead time of 27.~~31~~36 days was determined for Group Life & Long Term Disability Insurance.

Workplace Safety & Insurance Board

HUC pays for employee Workplace Safety & Insurance Board payments in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.23 days and an average payment lead time of 14.08 days were determined. Taking this information into account, a dollar-weighted expense lead time of 29.30 days was determined for Workplace Safety & Insurance Board payments.

Pensions (OMERS)

HUC pays for employee Pensions, also known as Ontario Municipal Employees Retirement System ("OMERS") payments in arrears for the prior month. Based on HUC's benefits data for 2012, an average service lead time of 15.23 days and an average payment lead time of 27.86 days were determined. Taking this information into account, a dollar-weighted expense lead time of 43.09 days was determined for Pensions (OMERS) payments.

OM&A Expenses

For the purpose of the distribution lead-lag study, OM&A expenses were considered to consist of payments made by HUC to its vendors in the following categories:

1. P Card;
2. Contract Labour;
3. Vehicles;
4. Computer Maintenance;
5. Software;
6. Cellphone & Pager;
7. Wireless;
8. Freight, Postage & Delivery;
9. Consulting;
10. Tree Trimming;
11. Outside Services; and,
12. Property Taxes.

Expense lead times were calculated individually for each of the items listed above and then dollar-weighted to derive a composite expense lead time of 1.23 days for OM&A expenses. A summary of the dollar-weighted expense lead time is provided in Table 8 below.

Table 8: Summary of OM&A Expenses

Description	Amounts ($M)	Weighting Factor %	Lead Time	Weighted Lead Time
Credit Card	$0.30	2.86%	44.21	1.27
Contract Labour	$0.21	2.02%	29.30	0.59
Vehicles	$0.02	0.16%	31.65	0.05
Computer Maintenance	$0.63	6.03%	(357.55)	(21.57)
Software	$2.42	23.23%	15.21	3.53
Cell & Pager	$0.29	2.76%	29.45	0.81
Wireless	$0.23	2.22%	31.84	0.71
Freight / Postage / Delivery	$0.11	1.09%	33.31	0.36
Consulting Services	$2.37	22.75%	33.03	7.52
Tree Trimming	$0.55	5.27%	33.71	1.78
Outside Services	$2.62	25.11%	31.76	7.98
Property Taxes	$0.68	6.47%	(27.66)	(1.79)
Total	**$10.43**	**100.00%**		**1.23**

P Card

During 2012, HUC used Credit Cards for a variety of services procured by its employees. Based on HUC's Credit Card expense data for 2012, an average service lead time of 15.24 days and an average payment lead time of 28.97 days were determined. Taking this information into account, a dollar-weighted expense lead time of 44.21 days was determined for Credit Card expenses.

Contract Labour

During 2012, HUC procured Contract Labour for a variety of services required for distribution services. Based on HUC's Contract Labour data for 2012, an average service lead time of 15.26 days and an average payment lead time of 14.03 days were determined. Taking this information into account, a dollar-weighted expense lead time of 29.30 days was determined for Contract Labour.

Vehicles

During 2012, HUC expensed Vehicles for a variety of services required for distribution services. Based on HUC's Vehicle spending data for 2012, an average service lead time of 15.38 days and an average payment lead time of 16.27 days were determined. Taking this information into account, a dollar-weighted expense lead time of 31.65 days was determined for Vehicle expenses.

Computer Maintenance

During 2012, HUC procured services from multiple vendors for Computer Maintenance agreements. Based on HUC's Computer Maintenance Procurement data for 2012, an average service lead time of 373.61 –days and an average payment lead time of (731.16) days were determined. Taking this information into account, a dollar-weighted expense lead time of (357.55) days were determined for Computer Maintenance.

Software

During 2012, HUC procured licenses from multiple vendors for computer Software. Based on HUC's Software Procurement data for 2012, an average service lead time of 23.93 days and an average payment lead time of (8.71) days were determined. Taking this information into account, a dollar-weighted expense lead time of 15.21 days was determined for Software expenses.

Cellphone & Pager

During 2012, HUC expensed Cellphone & Pager use for a variety of services required for distribution services. Based on HUC's Cellphone & Pager data for 2012, an average service lead time of 15.25 days and an average payment lead time of 14.20 days were determined. Taking this information into account, a dollar-weighted expense lead time of 29.45 days was determined for Cellphone & Pager expenses.

Wireless Services

During 2012, HUC expensed Wireless Services for a variety of services required for distribution services. Based on HUC's Wireless Services data for 2012, an average service lead time of 15.28 days and an average payment lead time of 16.55 days were determined. Taking this information into account, a dollar-weighted expense lead time of 31.84 days was determined for Wireless expenses.

Freight / Postage / Delivery

During 2012, HUC expensed Freight / Postage / Delivery services for a variety of activities required for distribution services. Based on HUC's Freight / Postage / Delivery data for 2012, an average service lead time of 15.25 days and an average payment lead time of 18.06 days were determined. Taking this

information into account, a dollar-weighted expense lead time of 33.31 days was determined for Freight / Postage / Delivery expenses.

Consulting Services

During 2012, HUC procured Consulting Services required for a variety of activities related to distribution services. Based on HUC's Consulting Services data for 2012, an average service lead time of 15.23 days and an average payment lead time of 17.79 days were determined. Taking this information into account, a dollar-weighted expense lead time of 33.03 days was determined for Consulting Services.

Tree Trimming

During 2012, HUC expensed Tree Trimming services required for distribution services. Based on HUC's Tree Trimming spending data for 2012, an average service lead time of 15.17 days and an average payment lead time of 18.53 days were determined. Taking this information into account, a dollar-weighted expense lead time of 33.71 days was determined for Tree Trimming expenses.

Outside Services

During 2012, HUC procured Outside Services for a variety of activities required for distribution services. Based on HUC's Outside Services data for 2012, an average service lead time of 15.28 days and an average payment lead time of 16.48 days were determined. Taking this information into account, a dollar-weighted expense lead time of 31.76 days was determined for Outside Services.

Property Taxes

During 2012, HUC paid property tax payments to the following municipalities:

1. City of Hamilton; and,
2. City of St. Catharines.

Based on HUC's Property Tax data for 2012, an average service lead time of 183.00 days and an average payment lead (lag) time of (210.66) days were determined. Since property taxes are an annual expense, services were rendered on an annual basis, with (27.~~76~~66) days resulting as the ~~service~~expense lead time associated with property taxes.

Payments in Lieu of Taxes

HUC makes payments in lieu of taxes ("PILs") in monthly installments to the relevant taxing authorities. In 2012, HUC made (12) payments for each month of the year. Based on HUC's PILs data for 2012, an average service lead time of ~~15.21~~183.00 days and an average payment lead (lag) time of (~~0.25~~168.50) days were determined. Taking this information into account, a dollar-weighted expense lead time of 14.~~96~~50 days was determined for PILs.

Debt Retirement Charge

HUC makes a Debt Retirement Charge in monthly installments to the Ontario Electricity Finance Corporation. The payment for the current charge month is made during the middle of the following month. Based on HUC's Debt Retirement Charge data for 2012, an average service lead time of 15.26 days and an average payment lead time of 10.34 days were determined. Taking this information into account, a dollar-weighted expense lead time of 25.59 days was determined for Debt Retirement Charge.

Interest Expense

HUC has two outstanding debt issuances which incur interest expenses. Based on HUC's Interest Expense data for 2012, an average service lead time of 91.50 days and an average payment lead (lag) time of (158.65) days were determined. Taking this information into account, a dollar-weighted expense lead (lag) time of (67.15) days were determined for Interest Expense.

Harmonized Sales Tax

The expense lead (lag) times associated with the following items that attract HST were considered in this study:

1. Customer Revenues including Cost of Power;
2. Cost of Power expenses; and
3. OM&A Expenses.

Effective July 1, 2010, the Ontario government implemented the harmonization of the Provincial Sales Tax with the Federal Goods and Service Tax into a single Harmonized Sales Tax. Given this is a known and measurable change forward looking; the WCA was calculated using the HST rate of 13.00%. Note that the statutory approach described at the outset was used to determine the expense lead times associated with HUC's remittances and disbursements of HST (i.e., both remittances and collections are generally on the last day of the month following the date of the applicable invoice)
A summary of the expense lead (lag) times associated with each of the above items is provided in Table 10 and Table 10 below.

Table 9:_ HST Working Capital Factor

HST Category	HST Lead/Lag Days	Working Capital Factor	Working Capital Factor (Leap Year)
HST Rate	13%	13%	13%
Revenues [inc. COP] Lead Days	(~~21.08~~23.12)	~~5.77%~~(6.33%)	~~5.76%~~(6.32%)
Cost of Power Lead Days	43.73	11.98%	11.95%
OM&A Lead Days	2.55	0.70%	0.70%

Table 10: Summary of Expense Lead Times Associated With HST

HST Category	2014	2015	2016	2017	2018	2019
Revenues [incl. COP]	$622,203,415	$638,342,404	$664,944,611	$688,586,511	$711,468,938	$734,283,591
HST Rate	13.00%	13.00%	13.00%	13.00%	13.00%	13.00%
~~Revenues [incl. COP]~~	~~$622,203,415~~	~~$638,342,404~~	~~$664,944,611~~	~~$688,586,511~~	~~$711,468,938~~	~~$734,283,591~~
Cost of Power	$514,946,434	$520,720,617	$542,171,542	$562,422,662	$583,269,859	$602,042,446
OM&A	$30,783,301	$29,728,985	$29,849,980	$30,659,445	$31,709,813	$33,108,690
Revenues [incl. COP]	- $~~4,671,108~~5,123,216	- $~~4,792,269~~5,256,105	- $~~4,978,342~~5,460,188	- $5,~~169,470~~669,814	- $5,~~341,257~~858,228	- $~~5,512,535~~6,046,083

Cost of Power	$8,020,726	$8,110,664	$8,421,707	$8,760,209	$9,084,921	$9,377,320
OM&A	$28,011	$27,052	$27,088	$27,899	$28,854	$30,127
Total	**$~~3,377,630~~2,925,521**	**$~~3,345,447~~2,881,611**	**$~~3,470,453~~2,988,607**	**$3,~~618,637~~118,293**	**$3,~~772,519~~255,548**	**$3,~~894,913~~361,364**

Section V: HUC's Working Capital Allowance

Using the results described under the discussion of revenue lags and expense leads, and applying them to HUC's distribution expenses for 2014-2019, the weighted average WCA was determined to be 12.~~7~~0% of HUC's distribution OM&A expenses (including Cost of Power) for each of the test years 2014-2019. A summary of HUC's WCA for individual 2014-2019 years is provided in the subsequent tables below. These tables include HST amounts which have been derived from Table 10 above.

Table 11: Summary of Working Capital Allowance - 2014

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	~~69.34~~67.30	32.86	~~36.48~~34.44	~~10.0~~9.4%	$514,946,434	$~~51,463,007~~48,584,754
OM&A Expenses[4]	~~69.34~~67.30	7.30	~~62.04~~60.00	~~17.0~~16.4%	$64,986,015	$~~11,046,321~~10,683,086
PILs	~~69.34~~67.30	14.50	~~54.84~~52.80	~~15.0~~14.5%	$555,146	$~~83,406~~80,303
Debt Retirement Charge	~~69.34~~67.30	25.59	~~43.74~~41.70	~~12.0~~11.4%	$32,180,619	$3,~~856,729~~676,858
Interest Expense	~~69.34~~67.30	(67.15)	~~136.49~~134.45	~~37.4~~36.8%	$9,519,067	$3,~~559,569~~506,363
Sub-Total					**$622,187,281**	**$~~70,009,032~~66,531,364**
HST						$~~3,377,630~~2,925,521
Total						**$~~73,386,661~~69,456,886**
WCA as a % of OM&A (incl. Cost of Power)						**12.~~7~~0%**

[4] Includes Payroll and Benefits

Table 12–: Summary of Working Capital Allowance - 2015

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	69.3467.30	32.86	36.4834.44	10.09.4%	$520,720,617	$52,040,07049,129,543
OM&A Expenses[5]	69.3467.30	7.30	62.0460.00	17.016.4%	$64,479,807	$10,960,275599,871
PILs	69.3467.30	14.50	54.8452.80	15.014.5%	$2,874,217	$431,828415,763
Debt Retirement Charge	69.3467.30	25.59	43.7441.70	12.011.4%	$31,854,423	$3,817,636639,588
Interest Expense	69.3467.30	(67.15)	136.49134.45	37.436.8%	$9,831,640	$3,676,453621,500
Sub-Total					**$629,760,705**	**$70,926,26267,406,264**
HST						$3,345,4472,881,611
Total						**$74,271,70970,287,875**
WCA as a % of OM&A (incl. Cost of Power)						**12.70%**

Table 13–: Summary of Working Capital Allowance - 2016

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	69.3467.30	32.86	36.4834.44	10.09.4%	$542,171,542	$54,035,80151,013,656
OM&A Expenses[6]	69.3467.30	7.30	62.0460.00	17.016.4%	$65,940,947	$11,178,01510,810,450
PILs	69.3467.30	14.50	54.8452.80	15.014.4%	$4,252,792	$637,202613,496
Debt Retirement Charge	69.3467.30	25.59	43.7441.70	12.011.4%	$31,531,534	$3,768,614592,852
Interest Expense	69.3467.30	(67.15)	136.49134.45	37.336.7%	$10,204,633	$3,805,504748,622
Sub-Total					**$654,101,448**	**$73,425,13669,779,077**
HST						$3,470,4532,988,607
Total						**$76,895,58972,767,684**
WCA as a % of OM&A (incl. Cost of Power)						**12.60%**

[5] Includes Payroll and Benefits
[6] Includes Payroll and Benefits

Table 14—: Summary of Working Capital Allowance - 2017

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	~~69.34~~67.30	32.86	~~36.48~~34.44	~~10.0~~9.4%	$562,422,662	$~~56,207,712~~53,064,095
OM&A Expenses[7]	~~69.34~~67.30	7.30	~~62.04~~60.00	~~17.0~~16.4%	$67,692,855	$11,~~506,429~~128,065
PILs	~~69.34~~67.30	14.50	~~54.84~~52.80	~~15.0~~14.5%	$4,496,240	$~~675,524~~650,392
Debt Retirement Charge	~~69.34~~67.30	25.59	~~43.74~~41.70	~~12.0~~11.4%	$31,211,917	$3,~~740,634~~566,177
Interest Expense	~~69.34~~67.30	(67.15)	~~136.49~~134.45	~~37.4~~36.8%	$10,624,086	$3,~~972,781~~913,398
Sub-Total					**$676,447,760**	**$~~76,103,080~~72,322,128**
HST						$3,~~618,637~~118,293
Total						**$~~79,721,717~~75,440,421**
WCA as a % of OM&A (incl. Cost of Power)						**12.~~7~~0%**

[7] Includes Payroll and Benefits

Table 15—: Summary of Working Capital Allowance - 2018

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	69.3467.30	32.86	36.4834.44	10.09.4%	$583,269,859	$58,291,15155,031,010
OM&A Expenses[8]	69.3467.30	7.30	62.0460.00	17.016.4%	$69,773,217	$11,860,049470,057
PILs	69.3467.30	14.50	54.8452.80	15.014.5%	$3,925,141	$589,721567,781
Debt Retirement Charge	69.3467.30	25.59	43.7441.70	12.011.4%	$30,895,541	$3,702,717530,029
Interest Expense	69.3467.30	(67.15)	136.49134.45	37.436.8%	$11,632,105	$4,349,720284,704
Sub-Total					**$699,495,863**	**$78,793,35974,883,581**
HST						$3,772,519255,548
Total						**$82,565,87878,139,129**
WCA as a % of OM&A (incl. Cost of Power)						**12.60%**

Table 16—: Summary of Working Capital Allowance - 2019

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Amounts ($M)	Working Capital Allowance ($M)
Cost of Power	69.3467.30	32.86	36.4834.44	10.09.4%	$602,042,446	$60,167,25756,802,187
OM&A Expenses[9]	69.3467.30	7.30	62.0460.00	17.016.4%	$72,228,903	$12,277,46611,873,749
PILs	69.3467.30	14.50	54.8452.80	15.014.5%	$4,021,290	$604,166581,690
Debt Retirement Charge	69.3467.30	25.59	43.7441.70	12.011.4%	$30,582,371	$3,665,185494,247
Interest Expense	69.3467.30	(67.15)	136.49134.45	37.436.8%	$12,600,791	$4,711,952641,521
Sub-Total					**$721,475,801**	**$81,426,02677,393,394**
HST						$3,894,913361,364
Total						**$85,320,93980,754,758**
WCA as a % of OM&A (incl. Cost of Power)						**12.70%**

[8] Includes Payroll and Benefits
[9] Includes Payroll and Benefits

2-Staff-23a_Attch 3_Service Lag Revised Table

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Service Lag Derivation	# Days	# Months	Mid-Point Service Lag
	A	B	C = A / B / 2
Monthly Service Lag	366	12	15.25
Bi-Monthly Sevice Lag	366	6	30.5

				SERVICE LAG						
DISTRIBUTION REVENUES	Year:	2012		Weighting Factors						
Rate Classification	Monthly	Bi Monthly	Total	Monthly	Monthly Service Lag		Bi Monthly	Bi-Monthly Service Lag		Weighted Lag
Residential	$ 1,985,015	$ 60,046,695	$ 62,031,710	2.0%	15.25	0.31	61.79%	30.50	18.84	19.16
General Service < 50	$ 10,496,135	$ 2,180,356	$ 12,676,491	10.8%	15.25	1.65	2.24%	30.50	0.68	2.33
General Service > 50	$ 14,435,421		$ 14,435,421	14.9%	15.25	2.27	0.00%	30.50	-	2.27
Large Users	$ 5,422,396		$ 5,422,396	5.6%	15.25	0.85	0.00%	30.50	-	0.85
Unmetered and Scattered	$ 498,067	$ 2,000	$ 500,067	0.5%	15.25	0.08	0.00%	30.50	0.00	0.08
Sentinel	$ 22,165	$ 15,788	$ 37,953	0.0%	15.25	0.00	0.02%	30.50	0.00	0.01
Streetlights	$ 2,081,032		$ 2,081,032	2.1%	15.25	0.33	0.00%	30.50	-	0.33
	$ 34,940,230	**$ 62,244,840**	**$ 97,185,070**							**25.02**

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3-Staff-24 Volumetric Forecasts

Reference:

1. Exhibit 3 Tab 1 Schedule 2 – Load Forecast and Methodology

Preamble:

Horizon adopted Itron Inc.'s MetrixND software ("MetrixND") as its forecasting tool. Through the use of it Horizon has developed separate models that forecast sales by rate class for the period 2014 – 2019. The determinants of the forecasts differ by rate class and it appears that not all determinants have been specified in the referenced Exhibit,

Board staff, in the tables below, have summarized the determinants reported in the reference for the residential and general service classes:

Residential

	Variable	Coefficient	Standard Error	Std Error (%)
1	mSales.Days	4,407,151.37	538,274.72	12.2%
2	mLight.Hlight	(117,856.05)	10,215.84	8.7%
3	mWthr.CCD18	547,729.00	20,609.45	3.8%
4	mWthr.HDD13	25,113.00	3,848.92	15.3%
5	mEcon.RPDI	3.20	1.05	32.8%
6	mEcon.RPD_Trend	0.05	0.02	40.0%
7	mEcon.ResPrice_Idx	(12,143,705.14)	6,119,129.53	50.4%
8	mBin.Mar07	19,564,657.63	4,884,320.72	25.0%
9	mBin.Sep07	(24,564,657.63)	5,880,419.37	23.9%
10	mBin.Apr12	(25,093,959.11)	4,580,260.39	18.3%
11	MA(1)	1.16	0.09	7.8%

General Service < 50 kW

	Variable	Coefficient	Standard Error	Std Error (%)
1	mSales.Days	1,484,544.46	245,603.52	16.5%
2	mLight.Hlight	(11,718.41)	6,752.59	57.6%
3	mWthr.CCD18	19,004.03	2,626.60	13.8%
4	mWthr.HDD13	86,209.39	5,289.92	6.1%
5	Economics.GDP	572.94	364.80	63.7%
6	mEcon.GDP_Trend	(10.43)	5.40	51.8%
7	mBin.Aug	(3,632,113.83)	1,117,797.47	30.8%
8	mBin.Oct	(7,161,667.39)	918,311.71	12.8%
9	mBin May10	(5,060,823.39)	1,932,348.71	38.2%
10	mBin Sep10	(6,230,309.02)	2,031,713.58	32.6%
11	mBin Apr11	(3,608,083.73)	1,944,720.61	53.9%
12	mBin.Sep11	(7,172,301.87)	1,979,593.75	27.6%
13	mBin.Aug13	6,408,470.00	2,080,658.32	32.5%
14	Sm|GSSales.LagDep(1)	(17.00)	0.06	0.4%

General Service < 50 kW

	Variable	Coefficient	Standard Error	Std Error (%)
1	mSales.Days	3,439,591.00	579,358.87	16.8%
3	mWthr.CCD18	47,394.00	3,676.52	7.8%
4	mWthr.HDD13	166,834.00	9,553.02	5.7%
5	mBin.Oct	(5,896,385.00)	1,903,406.22	32.3%
6	mBin.Yr2009Plus	(9,047,212.00)	1,805,346.06	20.0%
7	mBin.Mar09	(6,383,665.00)	4,531,391.15	71.0%
8	mBin.Sep12	(26,183,117.00)	4,422,823.96	16.9%
9	Economics.GDP	2,126.00	876.16	41.2%
10	mEcon.GDP_Trend	(14.00)	19.96	142.6%

a. Please confirm whether or not the reported determinants and their parameters are correct.

b. Please state why there is no constant.

c. Please provide the constant and its related statistical parameters.

It is a fact of the mathematics that by increasing the number of determinants will result in a stronger R2. Board staff is concerned that Horizon might be seeking a high R2 through

the inclusion of additional determinants of questionable value, based on the accuracy represented by the Standard Error of the determinants.

d. Please provide a forecast for each class for 2014 – 2019 with only the determinants with a Standard Error less than 30%. Please also include the constant when reporting the results.

e. Please explain the specific purpose of each binary variable.

f. Please comment on the residuals for both; the models proposed by Horizon, and the models requested by Board staff.

Horizon has modelled Hamilton and St. Catherines as one market, although it is known that Niagara Escarpment provides a micro climate to St. Catherines which differs along the shoreline from the weather on top of the escarpment. This would suggest different balance points for determining the degree days.

g. Did Horizon investigate differences in degree days between the two markets?

h. Please explain how the balance points were determined.

Horizon has used binary determinants for each of the months to forecast Sentinel Lights and Unmetered Scattered Loads. It then includes a trend variable that is negative.

i. Has Horizon performed a reasonableness check, given expected growth/loss of connections, as well as conservation retrofits to the loads?

Horizon has provided the following model for Street Lighting:

Street Lighting

1	CONST	119.03	2.36	2.0%
2	Mlight.Hlight	(0.15)	0.01	6.7%
3	mBin.Dec	6.35	1.68	26.5%
4	mBin.June	(4.90)	1.98	40.4%
5	MA(1)	(0.43)	0.12	27.9%

j. Please explain determinants 2 – 5.

k. Please remove determinants 3 and 4, and include a trend variable and recast the forecast for 2014 – 2019.

l. Please perform a reasonableness check on the outcomes of Horizon's forecast for Street Lighting and for Board staff's. Base the check on expected changes in connections and inclusion of conservation measures over the forecast period.

Response:

a) Horizon Utilities has calculated the Std Error % in Tables 1 – 3 below and confirms that they are correct. There was a transposition error in the GS < 50 kW and GS > 50 kW weather variables and the GS < 50 kW Lag Dependent variable as provided by Board Staff.

Table 1: Residential Sales Forecast Standard Error %

Variable:	Coefficient	Standard Error	Std Error (%)
mSales.Days	4,407,151.37	538,274.72	12.2%
mLight.HLight	(117,856.05)	10,215.84	8.7%
mWthr.CDD18	547,729.00	20,609.45	3.8%
mWthr.HDD13	25,113.75	3,848.92	15.3%
mEcon.RPDI	3.20	1.05	32.9%
mEcon.RPDI_Trend	(0.05)	0.02	39.6%
mEcon.ResPrice_Idx	(12,143,705.14)	6,119,129.53	50.4%
mBin.Mar07	19,552,566.15	4,884,320.72	25.0%
mBin.Sep07	(24,564,657.63)	5,880,419.37	23.9%
mBin.Apr12	(25,093,959.11)	4,580,260.39	18.3%
MA(1)	(1.16)	0.09	7.4%

Table 2: GS < 50 kW Sales Forecast Standard Error %

Variable:	Coefficient	Standard Error	Std Error (%)
mSales.Days	1,484,544.46	245,603.52	16.5%
mLight.HLight	(11,718.41)	6,752.59	57.6%
mWthr.HDD10	19,004.03	2,626.60	13.8%
mWthr.CDD15	86,209.39	5,289.92	6.1%
Economics.GDP	572.94	364.80	63.7%
mEcon.GDP_Trend	(10.43)	5.40	51.8%
mBin.Aug	(3,632,113.83)	1,117,797.47	30.8%
mBin.Oct	(7,161,667.39)	918,311.71	12.8%
mBin.May10	(5,060,823.39)	1,932,348.71	38.2%
mBin.Sep10	(6,230,309.02)	2,031,713.58	32.6%
mBin.Apr11	(3,608,083.73)	1,944,720.61	53.9%
mBin.Sep11	(7,172,301.87)	1,979,593.75	27.6%
mBin.Aug13	6,408,470.23	2,080,658.32	32.5%
SmlGSSales.LagDep(1)	(0.17)	0.06	34.9%

Table 3: GS > 50 kW Sales Forecast Standard Error %

Variable:	Coefficient	Standard Error	Std Error (%)
mSales.Days	3,439,591	579,358.87	16.8%
mWthr.HDD10	47,394	3,676.42	7.8%
mWthr.CDD15	166,834	9,553.02	5.7%
mBin.Oct	(5,876,385)	1,903,406.22	32.4%
mBin.Yr2009Plus	(9,047,212)	1,805,346.06	20.0%
mBin.Mar09	(6,383,665)	4,531,391.15	71.0%
mBin.Sep12	(26,183,117)	4,422,823.96	16.9%
Economics.GDP	2,126	876.16	41.2%
mEcon.GDP_Trend	(14)	19.96	143.9%

b) There is no constant because the variable mSales.Days acts as a constant. Like a constant, if there were no weather or other model variables the predicted value would equal the number of days in the month times the coefficient associated with the variable.

c) As stated in Horizon Utilities' response to b) above, the variable mSales.Days acts as a constant. The variable mSales.Days and its related statistical parameters have been provided in Tables 3-9, 3-11, and 3-15 in Exhibit 3, Tab 1, Schedule 2.

d) In Table 4 below, Horizon Utilities has provided a kWh forecast by rate class using only the determinants with a Standard Error of less than 30% as calculated in Tables 1 through 3. Horizon Utilities has provided the resulting model statistics for the Residential, GS<50 kW, GS >50 kW, USL, Sentinel Lighting and Street Lighting customer classes in Tables 5 through 10.

Table 4: Revised Load Forecast using only variables with <30% Standard Error

Year	Residential	GS < 50 kW	GS > 50 kW	USL	Sentinel	Street Lighting	Total
2014	1,649,969,250	593,083,206	1,845,478,075	11,551,895	455,814	39,766,330	4,140,304,570
2015	1,637,680,419	589,739,112	1,833,750,094	11,321,163	437,397	39,721,683	4,112,649,868
2016	1,638,321,484	590,104,303	1,823,486,508	11,090,430	418,980	39,625,271	4,103,046,976
2017	1,630,970,007	587,836,732	1,803,410,106	10,859,697	400,564	39,678,337	4,073,155,444
2018	1,627,930,994	586,990,245	1,788,155,070	10,628,965	382,147	39,656,393	4,053,743,814
2019	1,624,929,136	586,143,758	1,772,900,034	10,398,232	363,731	39,637,229	4,034,372,120

Table 5: Revised Residential Sales Forecast Model Statistics

Statistic:	Value
Adjusted R-Squared	0.856
Mean Absolute Percentage Error (MAPE)	3.83%
Durbin-Watson Statistic	2.042

Variable:	Coefficient	Standard Error	T-Statistic	P-Value
mSales.Days	5,300,382.58	188,607.26	28.10	0.00%
mLight.HLight	(111,469.09)	13,919.07	(8.01)	0.00%
mWthr.CDD18	528,459.24	22,497.91	23.49	0.00%
mWthr.HDD13	25,888.01	4,471.78	5.79	0.00%
mBin.Mar07	10,810,309.40	6,493,812.91	1.67	10.01%
mBin.Sep07	(14,897,965.15)	6,311,895.04	(2.36)	2.08%
mBin.Apr12	(22,765,221.13)	6,362,324.06	(3.58)	0.06%
MA(1)	(0.46)	0.11	(4.12)	0.01%

Table 6: Revised GS < 50 kW Sales Forecast Model Statistics

Statistic:	Value
Adjusted R-Squared	0.794
Mean Absolute Percentage Error (MAPE)	3.95%
Durbin-Watson Statistic	1.967

Variable:	Coefficient	Standard Error	T-Statistic	P-Value
mSales.Days	1,417,660.66	22,108.00	64.12	0.00%
mWthr.HDD10	21,019.86	2,136.20	9.84	0.00%
mWthr.CDD15	71,406.97	5,559.77	12.84	0.00%
mBin.Oct	(5,845,383.06)	1,095,118.28	(5.34)	0.00%
mBin.Sep11	(6,622,088.05)	2,556,541.61	(2.59)	1.14%

Table 7: Revised GS > 50 kW Sales Forecast Model Statistics

Statistic:	Value
Adjusted R-Squared	0.858
Mean Absolute Percentage Error (MAPE)	2.36%
Durbin-Watson Statistic	2.359

Variable:	Coefficient	Standard Error	T-Statistic	P-Value
mSales.Days	4,821,365	46,389.67	103.93	0.00%
mWthr.HDD10	52,772	3,767.47	14.01	0.00%
mWthr.CDD15	179,209	9,822.27	18.25	0.00%
mBin.Yr2009Plus	(9,901,350)	1,161,048.60	(8.53)	0.00%
mBin.Sep12	(23,733,927)	4,868,453.09	(4.88)	0.00%

Table 8: Revised USL Sales Forecast Model Statistics

Statistic:	Value
Adjusted R-Squared	0.694
Mean Absolute Percentage Error (MAPE)	5.98%
Durbin-Watson Statistic	2.322

Variable:	Coefficient	Standard Error	T-Statistic	P-Value
mBin.Jan	1,184,290	53,315.47	22.21	0.00%
mBin.Feb	1,137,564	53,680.44	21.19	0.00%
mBin.Mar	1,143,152	54,046.89	21.15	0.00%
mBin.Apr	1,114,019	54,414.79	20.47	0.00%
mBin.May	1,070,620	54,784.12	19.54	0.00%
mBin.June	1,319,604	55,154.84	23.93	0.00%
mBin.Jul	1,394,760	55,526.94	25.12	0.00%
mBin.Aug	1,172,229	55,900.37	20.97	0.00%
mBin.Sep	989,188	56,275.12	17.58	0.00%
mBin.Oct	1,062,904	56,651.15	18.76	0.00%
mBin.Nov	1,260,559	57,028.45	22.10	0.00%
mBin.Dec	1,366,045	57,406.98	23.80	0.00%
mBin.TrendVar	(19,228)	5,543.27	(3.47)	0.10%

Table 9: Revised Sentinel Lighting Sales Forecast Model Statistics

Statistic:	Value
Adjusted R-Squared	0.836
Mean Absolute Percentage Error (MAPE)	5.39%
Durbin-Watson Statistic	2.628

Variable:	Coefficient	Standard Error	T-Statistic	P-Value
mBin.Jan	61,952.21	1,967.08	31.50	0.00%
mBin.Feb	47,388.10	1,882.88	25.17	0.00%
mBin.Mar	56,670.28	1,894.40	29.92	0.00%
mBin.Apr	46,341.44	1,978.24	23.43	0.00%
mBin.May	60,811.00	1,989.47	30.57	0.00%
mBin.June	54,042.28	2,149.23	25.15	0.00%
mBin.Jul	70,163.77	2,160.36	32.48	0.00%
mBin.Aug	51,764.75	1,952.95	26.51	0.00%
mBin.Sep	51,664.50	1,964.83	26.30	0.00%
mBin.Oct	45,087.25	1,976.77	22.81	0.00%
mBin.Nov	64,974.43	1,988.77	32.67	0.00%
mBin.Dec	57,512.18	2,000.82	28.74	0.00%
mBin.Jan09	(16,904.01)	3,714.92	(4.55)	0.00%
mBin.TrendVar	(1,534.72)	190.37	(8.06)	0.00%

Table 10: Revised Street Lighting Sales Forecast Model Statistics

Statistic:	Value
Adjusted R-Squared	0.909
Mean Absolute Percentage Error (MAPE)	3.83%
Durbin-Watson Statistic	2.042

Variable:	Coefficient	Standard Error	T-Statistic	P-Value
CONST	121.98	2.17	56.30	0.00%
mLight.HLight	(0.16)	0.01	(28.18)	0.00%
mBin.Dec	5.54	1.70	3.26	0.18%
MA(1)	(0.41)	0.13	(3.30)	0.16%

e) In a regression model, a binary variable takes on a value of 1 or 0. In a monthly sales forecast model, binaries are often used to account for a monthly or seasonal pattern that is not accounted for by the other model variables or used to reduce the impact that an outlier (a specific month) has on the estimated model coefficients. There are binary variables included in each month for the USL and Sentinel Lighting rate classes. The use of these binary variables allows the model to replicate monthly patterns in kWh consumption for these classes.

The Residential, GS < 50 kW and GS > 50 kW sales models contain various binary variables that were identified by comparing model residuals (actual consumption minus. forecast consumption for the actual consumption period 2008-2013). Large residuals where identified, where an event has occurred that had an effect on consumption that needs to be neutralized in the regression equation. The Residential binaries are to account for abnormal swings in weather, while the GS < 50 kW and GS > 50 kW binaries are to account for abnormal swings in weather in addition to further account for economic conditions.

Horizon Utilities has provided Table 11 below, which shows the monthly binary variables used in the Residential, GS<50 kW, GS>50 kW, USL, Sentinel and Street Lighting forecasts, all of which were used to account for monthly or seasonal patterns that were not accounted for by the other model variables.

1 **Table 11: Binary Variables used in the Load Forecast models**

Variable	Binary Variable Description
Residential	
mBin.Mar07	A binary variable for the month of March, and the year 2007
mBin.Sep07	A binary variable for the month of September, and the year 2007
mBin.Apr12	A binary variable for the month of April, and the year 2012
GS < 50 kW	
mBin.Aug	A binary variable for the month of August
mBin.Oct	A binary variable for the month of October
mBin.May10	A binary variable for the month of May, and the year 2010
mBin.Sep10	A binary variable for the month of September, and the year 2010
mBin.Apr11	A binary variable for the month of April, and the year 2011
mBin.Sep11	A binary variable for the month of September, and the year 2011
mBin.Aug13	A binary variable for the month of August, and the year 2013
GS > 50 kW	
mBin.Oct	A binary variable for the month of October
mBin.Yr2009Plus	A binary variable for the year 2009 and onwards
mBin.Mar09	A binary variable for the month of March, and the year 2009
mBin.Sep12	A binary variable for the month of September, and the year 2012
USL	
mBin.Jan	A binary variable for the month of January
mBin.Feb	A binary variable for the month of February
mBin.Mar	A binary variable for the month of March
mBin.Apr	A binary variable for the month of April
mBin.May	A binary variable for the month of May
mBin.June	A binary variable for the month of June
mBin.Jul	A binary variable for the month of July
mBin.Aug	A binary variable for the month of August
mBin.Sep	A binary variable for the month of September
mBin.Oct	A binary variable for the month of October
mBin.Nov	A binary variable for the month of November
mBin.Dec	A binary variable for the month of December
mBin.May11	A binary variable for the month of May, and the year 2011
mBin.TrendVar	A binary variable for the trend in sales
Sentinel	
mBin.Jan	A binary variable for the month of January
mBin.Feb	A binary variable for the month of February
mBin.Mar	A binary variable for the month of March
mBin.Apr	A binary variable for the month of April
mBin.May	A binary variable for the month of May
mBin.June	A binary variable for the month of June
mBin.Jul	A binary variable for the month of July
mBin.Aug	A binary variable for the month of August
mBin.Sep	A binary variable for the month of September
mBin.Oct	A binary variable for the month of October
mBin.Nov	A binary variable for the month of November
mBin.Dec	A binary variable for the month of December
mBin.Jan09	A binary variable for the month of January, and the year 2009
mBin.TrendVar	A binary variable for the trend in sales
Street Lighting	
mBin.Dec	A binary variable for the month of December
mBin.June	A binary variable for the month of June

2

f) Horizon Utilities has provided a comparison table below, Table 12, which calculates two class specific load forecasts using the variables as filed in Exhibit 3 and variables provided by Board Staff in the preamble. Horizon Utilities observes that the difference between the two methodologies provides a range of 0.05% to 0.48% reduction in total kWhs. In Table 13, below, Horizon Utilities has displayed the difference in the Adjusted R squared, Mean Absolute Percentage Error, and the Durban Watson Statistic of the two scenarios and observes that the original statistics used for the load forecast are statistically stronger.

Table 12: Load Forecast Comparison

Revised load forecast per Board Staff requirements

Year	Residential	GS < 50 kW	GS > 50 kW	USL	Sentinel	Street Lighting	Total
2014	1,649,969,250	593,083,206	1,845,478,075	11,551,895	455,814	39,766,330	4,140,304,570
2015	1,637,680,419	589,739,112	1,833,750,094	11,321,163	437,397	39,721,683	4,112,649,868
2016	1,638,321,484	590,104,303	1,823,486,508	11,090,430	418,980	39,625,271	4,103,046,976
2017	1,630,970,007	587,836,732	1,803,410,106	10,859,697	400,564	39,678,337	4,073,155,444
2018	1,627,930,994	586,990,245	1,788,155,070	10,628,965	382,147	39,656,393	4,053,743,814
2019	1,624,929,136	586,143,758	1,772,900,034	10,398,232	363,731	39,637,229	4,034,372,120

Horizon Utilities class specific load forecast per Exhibit 3

Year	Residential	GS < 50 kW	GS > 50 kW	USL	Sentinel	Street Lighting	Total
2014	1,630,039,291	589,101,097	1,862,301,069	11,620,990	455,814	39,744,804	4,133,263,066
2015	1,617,715,605	586,002,830	1,857,864,416	11,397,660	437,397	39,694,810	4,113,112,718
2016	1,615,569,770	585,648,636	1,852,830,462	11,174,331	418,980	39,602,538	4,105,244,716
2017	1,608,117,860	583,142,939	1,841,172,846	10,951,001	400,564	39,651,553	4,083,436,763
2018	1,604,991,612	581,558,617	1,831,925,238	10,727,671	382,147	39,629,670	4,069,214,956
2019	1,600,739,130	579,899,038	1,822,597,172	10,504,342	363,731	39,610,413	4,053,713,826

Variance

Year	Residential	GS < 50 kW	GS > 50 kW	USL	Sentinel	Street Lighting	Total
2014	19,929,959	3,982,108	-16,822,994	-69,095	0	21,526	7,041,504
2015	19,964,814	3,736,282	-24,114,321	-76,498	0	26,873	-462,851
2016	22,751,714	4,455,667	-29,343,954	-83,901	0	22,733	-2,197,740
2017	22,852,147	4,693,793	-37,762,739	-91,304	0	26,783	-10,281,319
2018	22,939,381	5,431,628	-43,770,168	-98,707	0	26,724	-15,471,142
2019	24,190,005	6,244,720	-49,697,137	-106,110	0	26,816	-19,341,706

% Variance

Year	Residential	GS < 50 kW	GS > 50 kW	USL	Sentinel	Street Lighting	Total
2014	1.21%	0.67%	-0.91%	-0.60%	0.00%	0.05%	0.17%
2015	1.22%	0.63%	-1.32%	-0.68%	0.00%	0.07%	-0.01%
2016	1.39%	0.76%	-1.61%	-0.76%	0.00%	0.06%	-0.05%
2017	1.40%	0.80%	-2.09%	-0.84%	0.00%	0.07%	-0.25%
2018	1.41%	0.93%	-2.45%	-0.93%	0.00%	0.07%	-0.38%
2019	1.49%	1.07%	-2.80%	-1.02%	0.00%	0.07%	-0.48%

Table 13: Model Statistic Comparison

Statistic	Residential as Filed	Residential Revised
Adjusted R Squared	0.899	0.856
MAPE	2.96%	3.83%
Durban Watson	1.671	2.042
Statistic	GS < 50 as Filed	GS < 50 Revised
Adjusted R Squared	0.885	0.794
MAPE	2.72%	3.95%
Durban Watson	1.953	1.967
Statistic	GS > 50 as Filed	GS > 50 Revised
Adjusted R Squared	0.885	0.858
MAPE	2.09%	2.36%
Durban Watson	1.931	2.359
Statistic	USL as Filed	USL Revised
Adjusted R Squared	0.734	0.694
MAPE	5.41%	5.98%
Durban Watson	2.453	2.322
Statistic	Sentinel Lighting as Filed	Sentinel Lighting Revised
Adjusted R Squared	0.836	0.836
MAPE	5.39%	5.39%
Durban Watson	2.628	2.628
Statistic	Street Lighting as Filed	Street Lighting Revised
Adjusted R Squared	0.916	0.909
MAPE	3.51%	3.83%
Durban Watson	2.049	2.042

g) Horizon Utilities did not investigate differences in degree days between the two markets. In the 2011 CoS Application, Horizon Utilities used monthly weather data from the Hamilton Airport and a weather station in the St. Catharines vicinity from 2003 to 2009. In order to provide a 20 year average weather normalized data set, Horizon Utilities was limited to the use of the Hamilton Airport data, as the St. Catharines data was not available for the full historical period. Horizon Utilities believes that the weather data from the Hamilton Airport reasonably estimates the weather conditions across the service area for the purpose of load forecasting.

h) The degree-day breakpoints were determined by comparing model statistics for HDD and CDD variables with different temperature breakpoints. In the General Service models, it was discovered that a slightly better model fit could be achieved using a CDD and HDD with lower bases.

i) Horizon Utilities has performed a reasonableness check, given the expected loss of connections for the Unmetered Scattered Loads class is 8 connections per year, and the Sentinel Lighting connections is expected to decrease by 6 connections on average per year. Horizon Utilities has not received any formal applications for conservation retrofits to the Sentinel Lights and Unmetered Scattered Loads but has used the trend variable to capture the historical yearly change in connections.

j) The following is Horizon Utilities' explanation of the Street Lighting determinants 2-5 as provided in the preamble.

- Mlight.Hlight – is a variable that displays monthly hours of light
- mBin.Dec – is a binary variable for the month of December
- mBin.June – is a binary variable for the month of June
- MA (1) – is a moving average variable

k) Horizon Utilities has removed the mBin.Dec and mBin.June variables, and included a trend variable. The following Tables 14 and 15 provide the model statistics and the revised Street Lighting kWh load forecast.

Table 14: Street Lighting Model Statistics

Statistic:	Value
Adjusted R-Squared	0.895
Mean Absolute Percentage Error (MAPE)	4.18%
Durbin-Watson Statistic	1.876

Variable:	Coefficient	Standard Error	T-Statistic	P-Value
CONST	126.46	2.20	57.42	0.00%
mLight.HLight	(0.17)	0.01	(32.57)	0.00%
mBin.TrendVar	(0.06)	0.16	(0.38)	70.25%
MA(1)	(0.42)	0.12	(3.33)	0.15%

Table 15: Street Lighting (kWh) Forecast

Year	Street Light (kWh)
2014	39,535,641
2015	39,538,277
2016	39,400,003
2017	39,420,246
2018	39,361,004
2019	39,304,748

l) A comparison between Horizon Utilities' Street Lighting forecast as originally filed in Exhibit 3, Tab 1, Schedule 2 and a Street Lighting forecast using Board Staff's recommended variables is provided in Table 16 below. Horizon Utilities observes that the removal of the mBin.June and mBin.December variables and the addition of the mBin.TrendVar variable reduce the Street Lighting kWh forecast by 0.5% in the 2014 Bridge Year and 0.8% in the 2019 Test Year. Horizon Utilities has provided an analysis in Table 17, on the two Street Lighting forecast methodologies and the impact on kWh/device. There is a slight decline of 8 kWh per device by using Board Staff's variables which is reasonable.

Table 16: Street Lighting kWh Forecast Comparison

Year	Revised Variables Street Light (kWh)	As Filed Street Light (kWh)	Variance	% Variance
2014	39,535,641	39,744,804	(209,164)	(0.5)%
2015	39,538,277	39,694,810	(156,533)	(0.4)%
2016	39,400,003	39,602,538	(202,535)	(0.5)%
2017	39,420,246	39,651,553	(231,307)	(0.6)%
2018	39,361,004	39,629,670	(268,666)	(0.7)%
2019	39,304,748	39,610,413	(305,665)	(0.8)%

Table 17: Street Lighting kWh/Device

Year	As Filed Street Light (kWh)	Forecasted Street Light Connections	kWh/Device
2014	39,744,804	52,412	758
2015	39,694,810	52,384	758
2016	39,602,538	52,356	756
2017	39,651,553	52,328	758
2018	39,629,670	52,300	758
2019	39,610,413	52,273	758
Year	**Revised Variables Street Light (kWh)**	**Forecasted Street Light Connections**	**kWh/Device**
2014	39,535,641	52,412	754
2015	39,538,277	52,384	755
2016	39,400,003	52,356	753
2017	39,420,246	52,328	753
2018	39,361,004	52,300	753
2019	39,304,748	52,273	752

3-Staff-25 Other Revenues – Interest Income

Reference:

1. Exhibit 3 Tab 3 Schedule 2

Preamble:

Horizon has provided the following report on actual and proposed interest and dividend income:

Account 4405 - Interest and Dividend Income

		2011 Actual	2012 Actual	2013 Actual	Bridge Year	Test Year	Test Year	Test Year	Test Year	Test Year
Reporting Basis		CGAAP	MIFRS	MIFRS	2014	2015	2016	2017	2018	2019
Short-term Investment Interest		$148,554	$497,557	$320,332	$101,001	$0	$0	$0	$70,098	$82,265
Bank Deposit Interest										
Miscellaneous Interest Revenue										
etc.										
Total		$ 148,554	$ 497,557	$ 320,332	$ 101,001	$ -	$ -	$ -	$ 70,098	$ 82,265

Please explain the year-over-year variances for Short-term Investment Interest.

Response:

The table provided above is an incorrect reproduction of Table 3-41. The correct version appears below as Table 1:

Table 1: Interest and Dividend Income

Account 4405 - Interest and Dividend Income

	2011 Actual	2012 Actual	2013 Actual	2014 Budget	2015 Budget	2016 Budget	2017 Budget	2018 Budget	2019 Budget
Bank Deposit Interest	$ 3,994	$ 204,994	$ 293,793	$ 104,099	$ -	$ -	$ -	$ 70,098	$ 82,265
Interest Income on Regulatory Deferral/Variance Acct Balances	$ 139,803	$ 292,563	$ 26,539						
Inter-company interest income	$ 4,757	$ -							
Total	**$ 148,554**	**$ 497,557**	**$ 320,332**	**$ 104,099**	**$ -**	**$ -**	**$ -**	**$ 70,098**	**$ 82,265**

Bank Deposit interest is directly related to actual or projected balances for cash and cash equivalents. Horizon Utilities issued $150 million in new long-term debt in July 2012, while existing long-term debt of $116 million was retired. The net increase of $34 million in long-term debt increased the balance of cash and cash equivalents, which in turn increased interest income in 2012. The increase in interest income in 2013 is due to a higher average balance of cash and cash equivalents over the full year.

Interest income is expected to decrease in 2014 as a result of declining cash balances from 2013, as no new long-term debt issuance is planned. Average cash and cash equivalents are expected to reach a zero balance by the end of 2014, with no new long-term debt expected to be issued through the end of 2017. A new long-term debt issuance of $50 million is anticipated

in mid-2018. The increase in interest income in 2019 is due to a higher average balance of cash and cash equivalents over the full year.

Horizon Utilities does not agree that interest income should be included as a revenue offset; particularly where the corresponding cash balances are effectively supported by borrowings in anticipation of identified future investment requirements. Such interest income should be viewed a component of cost of capital and, more specifically, the deemed debt allowance. Borrowings, particularly long-term, are undertaken in large discreet amounts to provide for cost effective yields and some opportunity for advanced financing of future investments.

Additionally, interest income on credit facility balances may arise when balances are positive for part of a month but negative for the remainder; or positive in one month but negative in the next. Such interest income should be considered net of related interest expense as repatriating one as a revenue offset while including the other as part of the cost of debt allowance is not consistent and punitive to the financial capacity of the utility.

Interest on temporary cash balances that are effectively financed by borrowings in support of current and future investments should be treated as a component of interest expense and not included in revenue offsets. Horizon Utilities clearly has a rising requirement in forecast capital expenditure. It is punitive to the financial capacity of the utility and its shareholders to repatriate interest on surplus cash balances created by prudent borrowing decisions in anticipation of future utility investment needs that have corresponding interest costs.

In summary, interest income should only be considered as a revenue offset where the underlying cash is truly surplus to the current or forecast needs of the utility i.e., it is not a source of financing for utility needs.

4-Staff-26 Workforce & Compensation

References:

1. **Appendix 2-K Employee Costs**
2. **Exhibit 4 Tab 4 Schedule 2**
3. **Exhibit 4 Tab 4 Appendix 4-3 – Workforce Labour Strategy and Plan**
4. **Exhibit 4 Tab 4 Appendix 4-6.2 – Mercer Letters**

Preamble:

Horizon filed an updated Workforce Labour Strategy and Plan ("WLSP") at Reference 3. This plan is an update to the WLSP filed in Horizon's last cost of service application EB-2010-0131. At page 3 of Reference 3, Horizon states that it had identified that additional trades and technical staff would be required to undertake these asset renewal projects. Horizon states that based on the plan, it hired an additional 13 Apprentices: Construction and Maintenance (6), Network Operations (6) and Customer Connections (1). The Board in EB-2010-0131 approved 349.1 FTEs as indicated in Reference 1. In Reference 2, Horizon has detailed additional new positions that it states it requires.

In Reference 4, Mercer describes the scope of the work Mercer has performed for Horizon as of October 28, 2013 in regards to executive and non-executive compensation for fiscal 2012 and 2013.

a. Both WLSP's identified the need to hire more management and executive employees. The Board approved 67.0 FTE's for management and executive for the 2011 rate year, while the actual was 62.8, 4.2 FTE's less. In 2013, based on actuals, Horizon had only raised the count to 66.0. Horizon is now requesting 77. Horizon itself has identified in its WLSP the challenges arising from attrition, retirements, and labour market forces. Please explain how Horizon will increase to 77 FTE's and maintain that level over the 2015 – 2019 CIR period?

b. Horizon has estimated that it will have hired the required FTEs to have a compliment of 77 management and executive FTEs by the end of 2014, an increase of 11.3 FTEs over 2013 actuals. Please provide a status report which includes dates hired and expected to be hired, and any downward adjustments to the 77 FTEs due to attrition, retirements, and labour market forces that may be required.

c. Both WLSP's identified the need to hire more non-management (union and non-union) employees. The Board approved 282.1 FTE's for non-management for the 2011 rate year, while the actual was 265.0, 17.1 FTE's less. In 2013, based on actuals, Horizon had only raised the count to 268.9, which is 13.2 less than approved. Horizon estimates that the FTE for non-management will be 277.5 which is still 4.6 FTE less than the 2011 board approved level. Horizon is now requesting 270.8 for 2015, tapering to 267.3 in 2017 and remaining there until 2019. Horizon itself has identified in its WLSP the challenges arising from attrition, retirements, and labour market forces. Horizon has also undertaken through the RRFE continuous improvements. Given the difficulties in hiring and maintaining 100% FTE capacity that Horizon has stated and shown in its FTE counts,

please explain how Horizon will manage at the proposed levels for the 2015 – 2019 Custom IR term?

d. Horizon has estimated that it will a compliment of 277.5 non-management FTEs by the end of 2014, an increase of 8.6 FTEs over 2013 actuals. Please provide a status report which includes dates hired and expected to be hired, and any downward adjustments to the 277.5 FTEs due to attrition, retirements, and labour market forces that may be required.

e. On page 6, Table 2 and Table 3 of the WLSP Horizon provides retirement and attrition rates. Will the FTE levels shown in Reference 1 be less than planned due to these retirements and attritions?

f. Please provide the undertakings by Hayes described in the letter dated October 28, 2013 in Reference 4.

Response:

a. Horizon Utilities is actively recruiting vacant positions at the management level and anticipates permanently filling these positions in 2014. Through workforce planning, Horizon Utilities has identified the required management and executive workforce to deliver business results and meet customer expectations. Horizon Utilities utilizes contract resources to temporarily fill vacant positions in order to meet organizational and customer demands pending a permanent hire.

Horizon Utilities has implemented a number of initiatives since 2011 to further enhance the ability to efficiently fill vacant positions. One initiative, as outlined in Exhibit 4, Tab 3, Schedule 3, p.14, describes new technology platforms and solutions implemented in 2012. Horizon Utilities also hired an additional Human Resources Generalist in 2013 to meet increasing organizational demands, including recruitment and retention through positive employee/labour relations.

b. As referenced in Exhibit 4, Tab 4, Schedule 2, p.13, the Management workforce consists of an additional 11.3 FTE compared to 2013 that is attributed to filling positions and/or vacancies carried over to 2014, and the hiring of new positions in 2014. Horizon Utilities expects the full complement of FTEs to be filled in 2014.

Table 1 provides a status update of Management vacancies as of December 31, 2013 as well as additional new positions in 2014. To date, all of the vacant positions as of December 31, 2013 as well as the new positions in 2014 have been permanently filled.

Horizon Utilities does not expect any downward adjustments to the 77 FTE. The utilization of contract resources to fill vacant permanent positions on a temporary basis allows Horizon Utilities to operate at or near full capacity pending a permanent hire.

Table 1: Dates of Hire

Job Title	Status	Date of Hire
Supervisor Customer Connections (Metering)	Filled	28-Jan-14
Manager, Outside Contractors	Filled	28-Jan-14
Manager, Lines	Filled	4-Feb-14
Manager, Health and Safety	Filled	2-May-14
Supervisor, Underground	Filled	9-Jan-14
Supervisor, Engineering Systems	Filled	13-May-14
Supervisor, Engineering Design	Filled	2-Jun-14
Manager, Engineering Systems and Asset Records	Filled	25-Mar-14

c. Through workforce planning, Horizon Utilities has identified the required non-management workforce to deliver business results and meet customer expectations from 2015 through 2019, factoring in expected FTE reductions as a result of productivity achievements. Horizon Utilities will use a multi-pronged approach to managing FTE levels including: proactive recruitment for anticipated retirements; hiring of apprentices to sustain a proficient and competent workforce; and the utilization of contract resources to fill vacant positions on a temporary basis.

d. As referenced in Exhibit 4, Tab 4, Schedule 2, p.13, the Management workforce consists of an additional 8.6 FTE compared to 2013. This is attributed to filling positions and/or vacancies carried over to 2014, and the hiring of new positions in 2014. Horizon Utilities expects the full complement of FTEs to be filled in 2014.

Table 2 provides a status update of Non-Management vacancies as of December 31, 2013 as well as additional new positions in 2014. To date, all of the vacant positions as of December 31, 2013 as well as the new positions in 2014 have been permanently filled with the exception of two positions which are backfilled by contract resources. Horizon Utilities does not anticipate any downward adjustments to the 277.5 FTE and it is anticipated that all positions will be permanently filled in 2014.

Table 2: Dates of Hire

Job Title	Status	Date of Hire
Engineering Records Clerk	Filled	18-Feb-14
Electical Safety Specialist	Contractor	
Distribution Engineer	Backfill	
Engineering Records Coordinator	Filled	11-Feb-14
GIS Developer	Filled	11-Feb-14
GIS Developer	Filled	25-Feb-14
Engineering Technician	Filled	9-Sep-13
Engineering Technician	Filled	9-Sep-13

e. Horizon Utilities considers all information pertaining to retirements and attrition when conducting its workforce planning. Based on the forecast of retirement and attrition rates detailed in Workforce Labour Strategy and Plan, Exhibit 4, Tab 4, Appendix 4-3, ongoing monitoring of retirements and attrition levels, and utilizing the strategies outlined in the response to parts (a) and (c), Horizon Utilities strives to minimize the impact of any unplanned attrition or retirements through the utilization of contract resources.

f. There are five items related to this question:

   a. The MEARIE Management Salary Survey of Local Distribution Companies (including a 2013 Addendum);
   b. A Mercer 2012 CEO Compensation Analysis pertaining to Horizon Utilities' CEO;
   c. A Mercer 2012 Executive Compensation Review addressing all Horizon Utilities executives with the exception of the CEO;
   d. A Mercer 2013 Compensation Cost Benchmarking Study sponsored by Hydro One Networks Inc. but reflecting information related to Horizon Utilities; and
   e. A Short Term Incentive Pay Design Survey.

Item (a) is being filed on the public record in this proceeding as 4-Staff-26f_Attch_1. For the reasons set out in Horizon Utilities' correspondence relating to its confidential filings, items (b), (c) and (d) are being filed in confidence and Horizon Utilities will be delivering copies in confidence to those of the parties' counsel and/or consultants who have executed the Board's form of Declaration and Undertaking with respect to confidentiality, subject to Horizon Utilities' right to object to the Board's acceptance of a Declaration and Undertaking from any person, with the following exceptions. Because certain information in those documents constitutes personal information and/or is not relevant to this proceeding, Horizon Utilities is not prepared to disclose that information in any

manner, whether publicly or in confidence, notwithstanding that individuals may have executed the Board's form of Declaration and Undertaking with respect to confidentiality.

Finally, with respect to item (e), Horizon Utilities was not a sponsor of the survey – it simply provided information to Mercer. Horizon Utilities has no authorization from the sponsors of the survey to release it in any form, and will not do so. Horizon Utilities expects to have submissions on confidentiality in the event that it is ordered to release the document.

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4-Staff-26f_attch_1_MEARIE Management Salary Survey and Addendum_(July 2013)

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The MEARIE Group

2013 Management Salary Survey Of Local Distribution Companies

SURVEY REPORT

July 2013

SURVEY ADMINISTRATOR: HAY GROUP LIMITED

Table of Contents

Section

Appendices

1. Introduction

The MEARIE Group is pleased to present this report of the 2013 Management Salary Survey of Local Distribution Companies (LDCs).

In today's competitive talent market, LDCs are challenged with establishing and maintaining competitive, yet affordable, compensation programs and policies. The MEARIE Group established the Management Salary Survey of Ontario's Local Distribution Companies to assist LDCs in understanding the competitive landscape and to support your efforts to develop pay practices that attract, motivate and retain high quality, high performing employees.

The survey was updated in 2012 through the combined efforts of The MEARIE Group's *HR Information Solutions* team, outside consultants and representatives of our members, all working together to ensure that the Survey continues to meet the evolving needs of member LDCs.

The Survey has been further enhanced for 2013 through our partnership with Hay Group, a globally renowned compensation consulting firm. Drawing on their expertise and experience in developing and managing salary surveys across all sectors of the economy and in numerous countries around the world. The 2013 survey includes:

- Geographic, Number of Employees, Number of Customer and Revenue size reporting.
- Fifty (50) benchmark descriptions, supported by the Hay Group job evaluation methodology for improved reporting and greater ability to identify the impact of organization size and structure.
- Continued reporting of "total cash compensation" to provide greater depth of information regarding market pay practices.
- An overview of local distribution company market trends and compensation projections for 2014 budget planning.
- MS Excel survey reporting including versions of position salary tables by All Organizations, Geography, Revenue and Customers to support those organizations that wish to conduct further analysis of the results and to assist in transferring survey results into internal reporting.

The survey includes two presentation documents and Excel data tables in formats as follows:

- PDF Documents:
  - Survey Report Executive Summary containing a complete analysis and a data summary of all the positions.
  - Survey Report addendum which includes a complete analysis of each position, presented on one page.
- Excel Documents which are provided for easy data export and printable to one legal sized page, showing LDC Survey data by:
  - All Organizations
  - Region
  - Customer Base
  - Revenue
  - Number of Employees

We would like to thank you for your participation. As a result of the strong response, we are able to provide you with an informative and detailed survey that will help you in the support of your organization's compensation programs.

Confidentiality

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the Management Salary Survey, as well as Hay Group Limited (survey administrators) and The MEARIE Group.

All of the information collected through this survey has been treated with the utmost confidentiality. All data was submitted by way of password-protected files, and is stored on devices with restricted, password-controlled, access.

Data has been reported on an aggregate basis only, and in such a way as to ensure that individual participant data cannot be identified/attributed. Standards for minimum number of data, as documented in Appendix D to this report, have been strictly enforced to ensure confidentiality. Neither Hay Group nor The MEARIE Group will release or disclose to any other person whatsoever any information pertaining to any individual LDC participant.

The data on which this report is based was provided by the LDCs who participated in the survey. While every effort has been made to "clean" the data received – using analytical tools to identify anomalies and contacting participants where data was incomplete or unclear – the data has not been independently verified. Neither Hay Group nor The MEARIE Group is responsible for the accuracy of the data submitted, nor any conclusions, decisions or actions made or taken based on the results reported herein.

Survey results are being reported only to those LDCs who participated in the survey and provided comprehensive data. The survey includes the following:

- Survey Report in PDF format
- Survey Report Addendum Position Reports in PDF format
- LDC Survey data by All Organizations in Excel format
- LDC Survey data by Region in Excel format
- LDC Survey data by Customer Base in Excel format
- LDC Survey data by Revenue in Excel format
- LDC Survey data by Number of Employees in Excel format

All participants must consider this information as strictly confidential. The results of the Management Salary Survey will not be disclosed/sold to or shared with organizations that have not participated in the survey, whether by MEARIE Group or Hay Group or survey participants. **Participants may not share the survey report/results with non-participant LDCs or any entity under any circumstances.**

The obligations of confidentiality set out in this policy are subject to the requirements of applicable law. However, LDCs may not disclose the existence or results of the Management Salary Survey to any regulatory body (or other person) unless compelled by law to do so, and if an LDC is compelled by law to make such a disclosure, it will give The MEARIE Group as much notice in advance as possible of the disclosure and the reasons the disclosure is legally required. In such circumstances, the LDC will take such steps as The MEARIE Group reasonably requests, or will co-operate with respect to any steps The MEARIE Group reasonably wishes to take, to contest or limit the scope of the disclosure.

2. Survey Overview

Survey Benchmark Positions

The survey covers 50 benchmark positions representing a cross-section of the functions within member organizations. The benchmark positions were reviewed in 2012 by a working group of LDC sector Human Resources professionals. Job profiles for each benchmark job were developed and reviewed by the consultants and the HR group.

Senior Management	0000	President & CEO
	0001	Chief Operating Officer (COO)
	0002	Head of Operations and/or Engineering
	0003	CFO / Head of Finance
	0004	Head of Customer Service
	0005	Head of Regulatory Affairs
	0006	Head of Human Resources
Administration	1000	Executive Assistant
	1001	Administrative Assistant
Engineering	2000	Director Engineering
	2001	Engineering Manager and/or Distribution Engineer
	2002	Project Engineer
	2003	Supervisor Engineering
Operations	2500	Director Operations
	2501	Manager Operations
	2502	Manager Control Centre
	2503	Supervisor Control Centre
	2504	Supervisor Protection and Control
	2505	Supervisor Station Maintenance
	2506	Line Supervisor
	2507	Manager Meter Department
	2508	Supervisor Meter Department

Supply Chain / Procurement	3000	Director Supply Chain Management
	3001	Manager Procurement and/or Inventory and/or Facilities and/or Fleet
	3002	Supervisor Stores / Inventory / Warehouse
Accounting / Finance	4000	Controller or Director Finance
	4001	Manager Accounting
	4002	Manager Risk Management
	4003	Supervisor Accounting
	4004	Financial or Business Analyst
	4005	Accountant
Customer Service	5000	Director Customer Service
	5001	Manager Customer Service and/or Billing
	5002	Supervisor Customer Service and/or Billing and/or Collections
Communications	5500	Director Communications
	5501	Manager Communications
Regulatory Affairs	6000	Director Regulatory Affairs
	6001	Manager Regulatory Affairs
	6002	Regulatory Accountant
Conservation / Demand	7000	Settlement or Rate Analyst
	7001	Director or Officer, Conservation and Demand Management
	7002	Manager Conservation & Demand / Marketing
Information Systems	8000	Director Information Systems
	8001	Manager Information Systems and/or Security
	8002	Systems / Program Administrator or Applications / Systems Support Professional
Human Resources	9000	Human Resources Manager
	9001	Human Resources Generalist
	9002	Human Resources Coordinator
	9003	Payroll
	9004	Manager, Health & Safety

Participants

All organizations in the LDC sector in Ontario were invited to participate in the survey. The following fifty (50) organizations submitted data:

- Bluewater Power Distribution Corporation
- Brant County Power Inc.
- Brantford Power Inc.
- Burlington Hydro Inc.
- Cambridge and North Dumfries Hydro Inc.
- Collus PowerStream Corp
- E.L.K. Energy Inc.
- Enersource Corporation
- Entegrus Inc.
- EnWin Utilities Ltd.
- Essex Power
- Festival Hydro Inc.
- Fort Frances Power Corporation
- Greater Sudbury Utilities
- Grimsby Power Incorporated
- Guelph Hydro Electric Systems Inc.
- Haldimand County Hydro Inc.
- Halton Hills Hydro Inc.
- Horizon Utilities Corporation
- Hydro Ottawa Limited
- Innisfil Hydro Distribution Systems Limited
- Kenora Hydro Electric Corporation Ltd
- Kitchener-Wilmot Hydro Inc.
- Lakeland Holding Ltd
- London Hydro Inc.
- Midland Power Utility Corporation
- Milton Hydro Distribution Inc
- Newmarket-Tay Power Dist. Ltd.
- Niagara Peninsula Energy Inc.
- North Bay Hydro Distribution Limited
- Northern Ontario Wires Inc.
- Oakville Hydro
- Orangeville Hydro Limited
- Orillia Power Distribution Corporation
- Oshawa PUC Networks, Inc.
- Ottawa River Power Corporation
- Parry Sound Power
- Peterborough Utilities Group
- PowerStream Inc.
- PUC Services Inc.
- Renfrew Hydro Inc.
- Sioux Lookout Hydro Inc.
- Thunder Bay Hydro Electricity Distribution Inc.
- Utilities Kingston / Kingston Hydro
- Veridian Connections Inc.
- Wasaga Resource Services
- Waterloo North Hydro Inc.
- Welland Hydro-Electric System Corp.
- Westario Power Inc.
- Woodstock Hydro Services Inc.

Participant Group Profile

All participants provided information regarding their organizational profile. The statistical references for the profile of the organizations are as follows:

Note that the figures reported below are as provided by the participating organizations. Hay Group and MEARIE Group have not independently verified or confirmed the values, especially with regard to whether the values reflect only the LDC business or include other business ventures.

Statistic	P25	P50	P75	Average *
Annual Operating Budget ($ millions)	3.9	7.8	16.7	18.73
Number of Employees (full time equivalent)	30	51	121	104
Number of Customers	11,825	27,826	51,921	52,769
Gross Revenue ($ millions, less the cost of power)	7.6	59.4	113.6	103.64

*Analyst's note: "average" values are near or above the 75th percentile for several data elements, indicating that there are a small number of organizations that are significantly larger than the rest of the population.

All organizations (50) noted that the fiscal year ends December 31st.

3. Salary Administration

Salary Range Adjustments – 2013 & 2014

The most common month for adjusting salary ranges is January (approximately 70% of reporting organizations) followed by April (approximately 12% of reporting organizations).

Survey participants report adjusting their salary ranges in 2013 by an overall average of 2.6%.

Survey participants report planning to adjust salary ranges in 2014 by an overall average of 2.6%.

The salary range adjustments by employee level and overall are noted in the table below:

Year	CEO	Executive	Director	Management	Professional / Technical	Admin.	Overall
2013	2.9	2.7	2.6	2.6	2.6	2.6	**2.6**
2014	3.2	2.6	2.4	2.4	2.4	2.4	**2.6**

Base Salary Increases – 2013 & 2014

The most common timing for adjusting salaries is January (approximately 64% of reporting organizations grant annual salary increases in that month) followed by April (11 %) and “anniversary date of hire” (9%).

Survey participants report adjusting actual salaries in 2013 by an overall average of 2.7%.

For 2014, survey participants reported projected average salary increases of 2.7%.

The base salary adjustments by employee level are noted in the table below.

Year	CEO	Executive	Director	Management	Professional / Technical	Admin.	Overall
2013	2.7	2.6	2.8	2.7	2.8	2.9	**2.7**
2014	2.9	2.6	2.5	2.7	2.6	2.6	**2.7**

Incentive Programs

A majority of organizations (32 of 50 or 64%) indicated that they offer short term incentive pay opportunities to at least some portion of their employees.

Twenty-two organizations provided information about their incentive plans.

a. Employee participation in short term incentive (STI) plans:
   - Nine (9) of the organizations indicated that all employee groups participated in STI.
   - Six (6) organizations had at least one STI plan that applied to employees from Administration through Management but may not include senior management and executive (i.e. senior officers covered by a separate plan).
   - The data indicates that five (5) organizations have STI plans for designated senior management and/or executives that do not extend to management and non-management staff.

b. Weighting of performance factors (corporate versus individual versus team/department performance) in the determination of individual bonus payments:
   - The average plan mix, by employee level, is provided in the table below. (Totals may not equal 100% due to rounding).

Performance Factor	CEO	Executive	Director	Management	Professional / Technical	Admin.
Corporate	64.7 %	48.5 %	45.3 %	37.7 %	43.1 %	39.7 %
Team / Department	0.0 %	7.1 %	4.7 %	7.5 %	3.1 %	3.3 %
Individual	35.3 %	44.4 %	50.0 %	54.8 %	53.8 %	57.0 %

Incentive Programs
(continued)

Threshold Bonus Payouts

Formulaic or "target based" bonus programs typically do not pay out until a minimum level of performance (corporate, team and/or individual) has been achieved (i.e., if the threshold performance is not achieved, there is no pay out). Once this threshold performance has been achieved, incentive plans will pay out a minimum level of bonuses; pay out levels typically then increase as performance / results increase, up to a "target" bonus rate when performance goals have been "met".

Twelve (12) of the 32 organizations with incentive plans reported that they define minimum levels of performance required before any bonuses are generated. The typical bonus rate at the threshold performance is set at 50% of "target" bonus.

Maximum Bonus

Bonus programs are often designed such that there is a maximum level of payout. For example: if a position has a 10% bonus and the maximum payout is 200%, or 2x, then the maximum amount the employee can achieve regardless of performance, is 20% of their current base salary.

The average maximum bonus is provided by employee level in the table below, though the typical bonus pay maximum is 100% of target.

Maximum Bonus Payout %	CEO (n = 10)	Executive (n = 11)	Director (n = 11)	Management (n = 11)	Professional / Technical (n = 9)	Admin. (n = 9)
Average	122 %	126 %	123 %	121 %	131 %	132 %

In the broader market, it is more common to find higher maximum bonus levels (as a % of target) at higher levels of the organization, to reflect the greater influence on organizational performance that more senior roles are perceived to have.

Special (Project) Bonuses

Organizations were asked if they provide any project bonuses for participation in key / special projects, paid on successful achievement of specific milestones and/or on completion of the project, separate and distinct from annual incentive plans.

No organizations reported providing such bonuses.

4. Benefit Policies

Car Benefit

The majority of organizations (34 of 50 or 68%) provide a car benefit to some level of employee.

The tables below summarize the value of car benefits, by position, where provided. An asterisk (*) indicates insufficient data to report:

		Company Owned Car (Value)	Monthly Lease Payment	Car Allowance
CEO	P75	*	*	900
	P50	45,375	*	600
	P25	*	*	520
	Average	37,625	864	779
	Number	4	3	27
Executive / VP	P75	*	*	750
	P50	*	*	505
	P25	*	*	338
	Average	44,983	800	554
	Number	3	3	16
Sr. Management / Director	P75	*	*	548
	P50	*	*	500
	P25	*	*	350
	Average	31,667	*	448
	Number	3	0	10

Eight (8) organizations reported providing a car benefit to specified positions below Senior Management. Specifically, six (6) organizations provide use of a company-owned vehicle and two (2) provide an allowance where the incumbent is required to be available for off-hours call-in, such as operations supervisors, line superintendents, engineers and meter supervisors.

Mileage

The market statistics for mileage rates provided to employees as reimbursement for personal vehicle use are detailed in the table below.

N = 49	Mileage Reimbursement (¢ per km)
P75	53
P50	52
P25	48
Average	51

The most frequently reported mileage rate (8 organizations) is 53 cents per kilometer; the next most frequent reported rates are 52 cents per kilometer and 47 cents per kilometer (7 organizations).

Perquisites

Club Memberships – Fitness

Twenty (20) organizations reported providing a subsidy for fitness club fees or providing a fitness facility on site. The typical policy is to provide a reimbursement of a fixed percentage (either 50 or 100%) up to a maximum amount per year. For eighteen (18) organizations, the same policy and maximum reimbursement applies regardless of job level; for three (3) organizations, executives participate in a Discretionary Spending Plan that includes fitness, and so are not included in the reporting.

	Maximum Reimbursement per year
P75	$ 288
P50	$ 200
P25	$ 150
Average	$ 221

Club Memberships – Social

None of the organizations reported having a separate policy / program for reimbursement of social club fees.

Perquisites (cont'd)

Health Spending Account

Eight (8) organizations reported providing a Health Spending Account (i.e. discretionary spending within a defined range of services / benefits).

Of the eight organizations, two (2) provide this perquisite to senior officers only while six (6) provide an HSA at all levels. Of those six, three (3) provide the same funding for all jobs levels while three (3) differentiate by job level.

	CEO	Executive	Director	Management	Professional / Technical
P75	2,000	2,000	*	*	*
P50	1,050	1,050	750	400	400
P25	488	413	*	*	*
Average	1,506	1494	657	508	504
Number	8	8	7	6	6

2nd Opinion Medical Advice

Only two (2) organizations in the survey reported having a separate policy / program for this benefit.

Personal Financial / Legal Counseling

Three (3) organizations reported that financial and legal counseling is available via their Employee Assistance Program, which is provided to all employees.

One (1) organization reported that financial counseling is available as part of a Discretionary Spending Account provided to executives.

Perquisites (cont'd)

Executive Medical Plan

Four (4) organizations reported providing enhanced medical coverage for executive levels only. Two (2) organizations reported a maximum dollar value while two organizations reported that a specified group of test/procedures are available (without advising a dollar value).

Personal Computer / Cell Phone / Internet

Fourteen (14) organizations provided information regarding policies and practices related to computers and internet.

The most common policies/practices are:

- Low / no interest rate loans to purchase computer equipment for personal / home office use
- Provision of laptops for particular levels of employee, in addition to office desktop, to allow for mobile work (note: may be a perquisite if personal use of computer is allowed, but not a perquisite if for business use only)
- Reimbursement for cell phone and/or home internet connection for selected employees (either full reimbursement or 50% reimbursement were both provided in the market place)
- Cash allowance intended to coverage cell phone and/or internet service

The value of these benefits varies dramatically by level within organizations and between organizations; the data does not lend itself to reporting of the value of typical practices. Excluding monthly cell phone allowances, the range of allowances / loans provided is in the range of $600 - $4,000.

Other Perquisites

Other programs / practices reported, by less than four (4) organizations, include:

- Discretionary spending accounts (executive levels only)
- Reimbursement of dues / fees for professional associations such as Engineers (P.Eng) and Accountants (CGA/CMA/CA)
- Provision of an Employee Assistance Program

Perquisites (cont'd)

Enhanced Life Insurance Coverage for Senior Officers

Organizations were asked if, for senior level jobs, there was additional, employer paid, life insurance coverage. For example, if the typical life insurance plan was 1.5x employee salary, was this enhanced to above 1.5x to some greater number such as 2x, or even 3x, for senior level jobs.

Nineteen (19) organizations provided information about their basic / standard life insurance coverage where the typical coverage is 2x annual salary (average coverage of 1.8x). Though for five (5) organizations, there is supplemental coverage for senior roles typically at 3x annual salary (average coverage of 2.4x).

Vacation Entitlement

Organizations provided the number of years of service required by various levels of employee in order to be entitled to a certain number of weeks vacation.

The following table below details the range, average and typical (i.e., most common) number of years of service required per weeks of entitlement.

Several organizations noted that for executive level jobs, vacations are typically negotiated versus following a schedule for entitlement.

	2 weeks	3 weeks	4 weeks	5 weeks	6 weeks +
CEO					
Range	N/A	1 – 6	1 – 11	1 – 18	1 – 27
Average	1	2.5	6.0	12.9	19.4
Typical	1	1	9	17	25
Executive / VP Level					
Range	N/A	1 – 6	1 – 11	1 – 18	12 – 27
Average	1.0	2.4	6.2	14.0	22.4
Typical	1	9	9	17	25
Director Level					
Range	N/A	1 – 6	1 – 11	1 – 18	15 – 27
Average	1	2.3	6.6	14.4	22.3
Typical	1	1	9	17	25
Manager Level					
Range	N/A	1 – 6	1 – 14	8 – 18	15 – 27
Average	1	2.3	7.5	14.7	22.4
Typical	1	1	9	15	25
Professional Level					
Range	N/A	1 – 6	1 – 11	8 – 18	15 – 27
Average	1	2.6	7.8	15.3	23.1
Typical	1	3	9	17	25

Unused Vacation

Organizations provided information about their policies and practices with regard to vacation time that was not fully utilized in the year in which it was earned.

Policy Regarding Carry Over	Number	%
Unused vacation entitlement at year end is paid out (vacation pay adjustment) – no carry over.	3	6%
Any/All unused vacation entitlement may be carried-over with no restrictions.	9	19%
Unused vacation entitlement may be carried over, subject to maximum total accumulated balance.	11	23%
A maximum amount of unused vacation may be carried over.	24	51%
Total	47	100%

Maximum Number of Days to Carry Over	Number
No limit	9
One Year's Entitlement	3
75% of One Year's Entitlement	1
3 or more weeks	3
2 weeks	13
1 week	13
No information provided	8
Total	50

Note: Some organizations reported variations to the above policies such as:

- Differences by job level, such as more senior officers may carry over a greater number of days
- Differences by vacation eligibility, such as carrying over 10 days if eligible for up to 3 weeks' vacation but 20 days if eligible for 4 weeks' vacation
- Exception policies where workload or special projects caused the employee to be unable to fully utilize vacation time, or where carry forward beyond standard policy is regularly allowed but must be approved by senior management
- Cash out policies where some vacation time may be paid out instead of being carried over

Time Limit for Utilizing Carried-Over Vacation Time	Number
No limit	9
One Year	17
Six Months	17
Total	43

Educational Assistance / Reimbursement

Half of the participating organizations (25) provided details with regards to education assistance / reimbursement policies ranging from eligibility criteria to pay back provisions. There are a wide variety of types of programs and reimbursement rates. Key highlights are provided below:

- Nineteen (19) organizations stated that there is a policy for education assistance / reimbursement; though typically there are limiters such as (1) education or training courses must be job related and (2) are subject to managerial approval
- Six (6) organizations stated that there is no formal policy, however, approval for educational assistance or reimbursement happens regularly and is on a case by case basis.
- Nine (9) organizations provided an annual reimbursement maximum, the average is $4,100 and the median is $2,000.
- Four (4) organizations provided a lifetime reimbursement maximum, the average is $21,400 and the median is $22,500.
- Payback provisions were provided by fourteen (14) organizations. The average time to not trigger any pay back provision is 2.7 years, the median is 2.5 years. The range of time is generally between 1 - 5 years and seven (7) organizations noted they have some form of partial payment plan for leaving within a designated time period after completion of education. For example, if 4 years for no repayment, if the employee leaves in 2 years, they will be asked for 50% pay back.

5. Benchmark Position Survey Results

Survey Results

This section reports the information collected in aggregate values for each benchmark position. The values reported in this table reflect "all Ontario" data in that the data for all organizations matching to the position are included (regardless of size and geographic location).

Additional summaries, on a job by job basis, are provided in the accompanying "Addendum".

Detailed analysis, with expanded statistical data (i.e., including P25 and P75 data points) as well as analysis of survey results by geographic region, by customer base and by revenue, are reported in Excel files accompanying this report.

All Organizations

				COMPENSATION DESIGN						ACTUAL COMPENSATION				
Survey Benchmark Job	Sample Statistics		Hay Points	Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
0000 President & CEO	46	46	1242	146,300	174,200	182,500	20%	189,000	220,300	169,100	182,900	19%	180,800	216,600
0001 Chief Operating Officer (COO)	15	15	904	135,100	165,500	175,000	20%	206,800	204,500	165,500	167,800	19%	170,100	200,100
0002 Head of Operations / Engineering	30	38	839	108,100	125,800	139,800	15%	131,700	142,600	126,500	130,600	9%	135,300	143,300
0003 CFO / Head of Finance	44	44	818	109,800	134,800	138,500	17%	137,900	160,300	133,000	139,100	11%	138,000	156,600
0004 Head of Customer Service	20	20	818	102,100	125,600	130,200	20%	132,600	146,000	129,200	129,000	19%	134,200	144,700
0005 Head of Regulatory Affairs	9	9	954	125,900	146,800	161,500	20%	176,200	163,700	143,200	139,500	17%	170,700	165,000
0006 Head of Human Resources	16	16	751	109,300	129,200	129,200	20%	139,800	146,300	125,400	127,900	14%	135,000	141,000
1000 Executive Assistant	35	54	245	56,800	67,100	74,500	5%	70,100	72,200	69,000	71,000	5%	72,100	73,500
1001 Administrative Assistant	18	27	198	51,700	61,400	63,600	4%	62,400	62,700	61,800	61,400	2%	62,500	62,900
2000 Director Engineering	17	17	732	102,500	123,700	124,600	13%	131,500	137,100	124,200	124,500	7%	128,500	134,300
2001 Engineering Manager	29	37	588	87,700	103,200	110,200	7%	108,200	109,700	103,000	104,100	5%	105,300	108,200
2002 Project Engineer	13	33	479	75,600	94,200	103,600	9%	98,400	97,700	94,200	91,000	8%	95,800	94,300
2003 Supervisor Engineering	20	29	421	78,800	92,600	97,500	7%	95,500	98,900	93,200	92,100	7%	97,000	95,600
2500 Director Operations	13	14	732	104,600	125,000	132,300	15%	132,000	137,000	120,400	124,600	9%	131,200	138,100
2501 Manager Operations	28	36	516	88,900	104,600	111,900	7%	111,400	111,200	105,200	104,500	5%	110,200	109,400
2502 Manager Control Centre	7	7	539	91,000	109,700	116,700	10%	121,400	122,700	109,700	111,700	11%	120,700	123,100
2503 Supervisor Control Centre	15	16	429	80,900	94,100	101,300	9%	98,400	99,300	94,400	96,300	7%	98,300	99,900
2504 Supervisor Protection and Control	5	5	466	89,600	93,000	105,800	*	98,400	107,700	96,000	100,000	*	96,000	107,300
2505 Supervisor Station Maintenance	11	13	421	79,200	94,100	105,800	10%	99,700	103,500	94,500	98,000	7%	99,100	102,900
2506 Line Supervisor	36	124	366	77,700	92,700	98,000	5%	93,500	95,800	94,400	93,700	5%	95,900	96,200
2507 Manager Meter Department	14	14	551	90,700	111,100	116,700	9%	121,400	118,600	105,800	106,600	10%	115,400	114,700
2508 Supervisor Meter Department	15	18	406	78,800	92,600	92,600	5%	95,500	97,000	91,700	93,100	6%	97,100	96,900

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

All Organizations

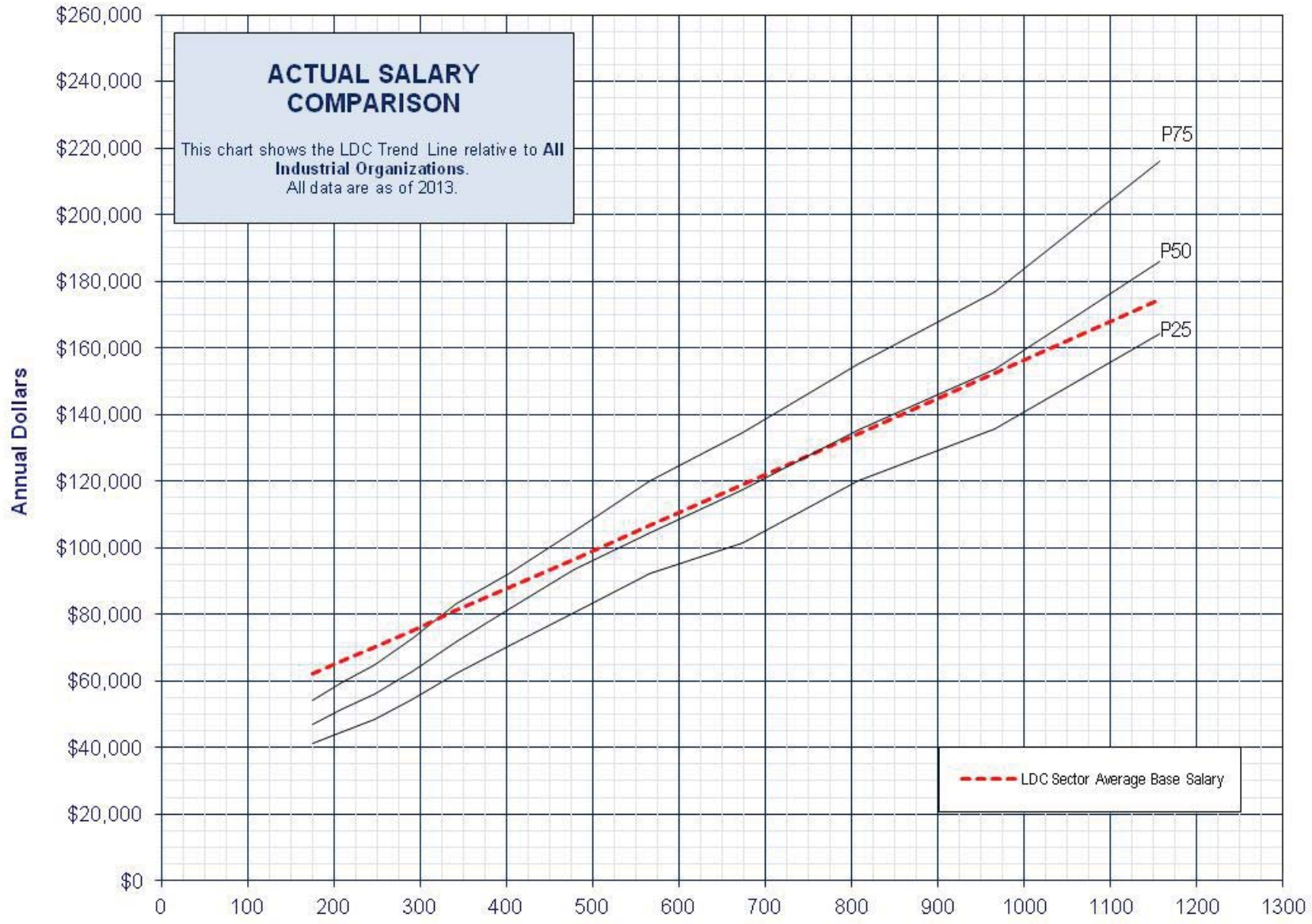
Survey Benchmark Job	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
3000 Director Supply Chain Management	3	3		*	*	*	*	*	144,300	*	133,600	*	*	156,600
3001 Manager Procurement/Inventory	19	21	451	80,200	93,600	105,400	8%	98,300	100,000	93,100	94,400	7%	97,700	99,500
3002 Supervisor Stores/Inventory	11	12	342	67,900	81,400	92,600	6%	83,800	86,300	81,400	83,600	5%	83,800	86,900
4000 Controller or Director Finance	17	18	588	90,000	106,800	124,800	13%	113,800	127,200	109,700	115,800	8%	118,100	127,800
4001 Manager Accounting	23	24	479	79,200	97,300	111,900	8%	103,200	105,400	98,300	99,000	6%	102,800	102,900
4002 Manager Risk Management	4	4	655	103,300	125,000	129,700	*	139,700	137,500	115,400	118,100	*	126,100	129,800
4003 Supervisor Accounting	13	16	353	70,000	85,300	93,200	5%	87,800	87,700	85,100	84,200	5%	89,600	87,200
4004 Financial or Business Analyst	18	25	342	67,900	79,500	86,700	5%	83,800	85,900	80,900	78,900	4%	83,600	82,600
4005 Accountant	13	25	332	63,000	77,100	84,000	5%	78,800	78,800	72,900	72,700	5%	75,600	74,600
5000 Director Customer Service	7	7	702	108,400	135,400	149,000	15%	155,600	145,300	128,500	125,900	14%	148,300	142,000
5001 Manager Customer Service	27	30	479	79,400	91,100	102,200	10%	97,800	98,400	90,700	91,900	6%	95,000	96,000
5002 Supervisor Customer Service	27	45	353	67,800	82,000	86,000	5%	83,700	84,300	78,800	79,900	4%	78,800	82,800
5500 Director Communications	7	7	677	108,400	135,100	149,000	15%	150,800	147,700	131,200	126,400	13%	141,700	142,800
5501 Manager Communications	11	11	393	75,200	90,600	99,600	9%	99,300	98,700	90,600	91,800	9%	95,600	98,000
6000 Director Regulatory Affairs	9	9	702	104,600	127,900	150,400	15%	147,100	148,500	137,800	131,500	16%	147,800	148,500
6001 Manager Regulatory Affairs	22	24	459	77,300	91,900	96,600	8%	94,600	94,500	91,500	92,000	7%	95,800	95,300
6002 Regulatory Accountant	14	17	337	67,900	79,600	94,300	7%	83,800	86,100	81,200	81,700	7%	82,700	84,900
7000 Settlement or Rate Analyst	15	17	342	70,700	85,900	92,300	5%	88,500	88,500	85,900	83,500	5%	85,900	86,200
7001 Director/Officer, Conservation	10	10	739	102,600	121,100	129,800	15%	136,300	139,900	118,200	120,600	17%	135,500	138,700
7002 Manager Conservation & Demand	21	23	393	72,100	85,500	88,300	9%	88,900	92,400	85,200	85,900	8%	88,800	90,500
8000 Director Information Systems	20	20	739	103,400	127,100	127,300	15%	138,300	137,300	125,200	124,300	14%	131,100	136,100
8001 Manager Information Systems	16	23	525	81,700	97,700	100,700	10%	104,000	105,900	97,600	99,500	8%	101,400	105,900

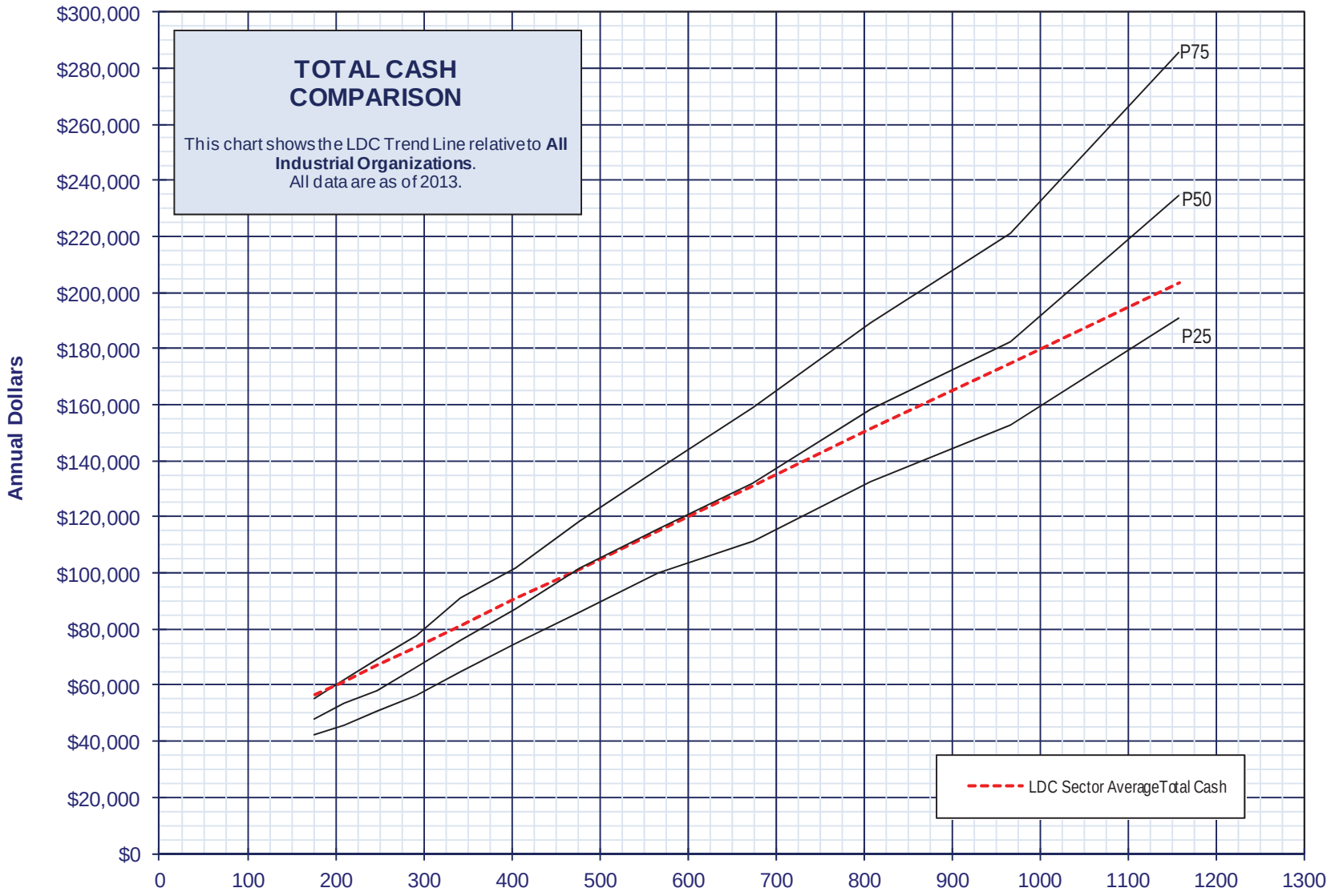
Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

All Organizations

Survey Benchmark Job	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
8002 Systems/Program Administrator	22	35	332	67,300	78,900	85,500	5%	79,800	81,600	80,900	78,200	5%	83,700	80,800
9000 Human Resources Manager	11	11	479	87,600	103,100	110,600	9%	114,700	110,400	100,700	100,200	5%	105,000	106,800
9001 Human Resources Generalist	17	22	323	65,100	77,700	81,900	5%	78,800	83,200	81,400	78,700	4%	81,400	81,600
9002 Human Resources Coordinator	11	15	233	57,100	67,100	77,200	5%	69,800	73,500	65,200	65,400	7%	66,200	68,100
9003 Payroll	17	18	245	56,800	67,900	73,800	5%	69,300	71,900	67,100	71,000	3%	69,500	72,900
9004 Manager, Health & Safety	22	24	479	80,900	92,600	98,900	6%	94,100	99,300	95,800	95,300	5%	96,700	99,000

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).





APPENDICES

A. Survey Methodology

A brief profile was developed for each benchmark position. These profiles were incorporated into a survey package and distributed to each participant along with a data submission spreadsheet requesting data on survey benchmark positions, as well as the organization's profile and selected salary administration & benefits policies.

Participants matched their jobs to the profiles and provided data for each position, where applicable. For each position where an organization submitted more than one match, the data were aggregated and an average figure was used for that organization. By using this methodology, all organizations carry equal weighting, and no one single organization excessively influences the market statistics by virtue of the size of its employee population.

Once the completed surveys were returned to Hay Group, participants were contacted for data verification as necessary. Hay Group also initiated a number of follow-up actions to clarify information provided by the participants. All of the matches submitted by the participants were reviewed by Hay Group to determine their appropriateness versus the job profiles and the market. If deemed inappropriate, the matches, or outlier data, were removed from the survey results.

Where possible, organization charts or details regarding reporting relationships were provided to Hay Group to enable understanding of the roles. From the job match information, plus a review of organization charts and other contextual information provided, Hay Group has estimated at which Hay Reference Level each organizations' roles fall to facilitate point-based comparisons.

B. Definitions – Compensation Elements

Salary Range

Minimum	The lowest salary/rate that the organization is prepared to pay for an incumbent in the position. May be the starting salary for inexperienced/non-qualified hire.
Job Rate / Control Point	Typically the midpoint of the salary range, intended to reflect the salary the organization is prepared to pay for sustained competent performance by a fully trained / qualified incumbent.
Maximum	The highest point in the salary range (or step progression). Note: might be the same as "job rate".

Short Term Incentive	*Short Term Incentive (STI) refers to any incentive arrangement designed to reward an individual for performance/results achieved over a performance cycle/period of up to one year.*
Target	Target bonus is the level of award (either a % of salary or a fixed dollar amount) that an employee in this position would expect to receive if all corporate, team and individual performance goals are "met" (as planned). This rate/amount is often communicated to employees as part of the incentive/bonus plan design, e.g. "the target bonus for jobs in grade/band 6 is 8% of salary".
Discretionary	Discretionary plans have no target bonus rate and pay out at the end of the year at the discretion of executive/board.
Current Salary	The amount paid for work performed on a regular, ongoing basis. Does not include variable bonus or incentive payments, sales commissions, shift premiums, or overtime payments.
Actual STI (Paid)	*Total of all STI awards paid to the incumbent(s) for performance/results over the latest completed fiscal year.* May be paid during the year or after year end. (Note: recorded and reported on an annual basis)

C. Definitions – Statistical Elements

Market data are reported using the following statistics:

	Definition	Reporting Requirement (# of Observations Necessary to Report)
P90	90th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 10% of the observations would fall above the 90th percentile and 90% would fall below	**11**
P75	75th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 25% of the observations would fall above this value and 75% would fall below	**7**
P50	50th percentile, also referred to as "median" If all observations were sorted and listed from highest/largest to lowest/smallest, 50% of the observations would fall above this value and 50% would fall below	**4**
P25	25th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 75% of the observations would fall above this value and 25% would fall below	**7**
P10	10th percentile If all observations were sorted and listed from highest/largest to lowest/smallest, 90% of the observations would fall above this value and 10% would fall below	**11**
Average	The arithmetic mean of all values, calculated by adding up all of the values and dividing by the number of observations	**3**

D. Benchmark Position Profiles

Job Title	Description
President & CEO	Directs the development of short and long term strategic plans, operational objectives, policies, budgets and operating plans for the organization, as approved by the Board of Directors. Establishes an organization hierarchy and delegates limits of authority to subordinate executives regarding policies, contractual commitments, expenditures and human resource matters. Represents the organization to the financial community, industry groups, government and regulatory agencies and the general public.
Chief Operating Officer (COO)	Highest ranking operations position. Reporting to the President/CEO, directs the operational elements of the organization, could include operations & engineering, customer services, metering and information technology. Develops the short and long term strategic plans, directs the development of operational objectives, policies, budgets for his/her areas of accountability. The position reports directly to the President/CEO.
Head of Operations and/or Engineering	Highest ranking operations/engineering position. Reporting to COO or President. Directs both the operations and engineering functions. Develops the short and long term strategic plans, formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Establishes clear controls, objectives and measures to ensure safe and appropriate delivery of power and power related services. Evaluates the feasibility of new or revised systems or procedures and oversees operations and engineering to ensure compliance with established standards.
CFO / Head of Finance	Highest ranking financially-oriented position within the company. Reporting to the President &CEO, this strategic role plans directs and controls the organization's overall financial plans, policies and accounting practices and relationships with lending institutions, shareholders and the financial community in mid to large organizations. Provides advice and guidance for the Board of Directors on financial matters. May direct such functions as finance, general accounting, tax, payroll, customer billing, regulatory affairs, and information systems and may be responsible for Administration functions. Normally possesses a CA, CMA or CGA designation.
Head of Customer Service	The highest-ranking customer service position in the utility. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the development, implementation and integration of all customer service related activities to achieve a competitive advantage through customer driven initiatives and strategies. Directs and oversees the implementation of customer service standards, policies and procedures; manages and coordinates budgets.
Head of Regulatory Affairs	Represents the organization on quality and regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Keeps abreast of on-going developments in regulatory practices affecting electrical distribution utilities. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO). Generally reports to President & CEO or a senior executive.
Head of Human Resources	The highest-ranking human resources position in the organization. Provides direction, support and alignment of organization-wide Human Resources practices and systems with the business in terms of mission, vision and the strategic imperatives. Ensures that existing needs and future demands of internal customers are met through a cost effective and efficient HR services. Directs HR management and staff in the development and implementation of Human Resources strategy, policies and programs covering employment, negotiations & labour relations, training, compensation, organization development, performance management, benefits and may include health & safety. Provides coaching and counsel to the executive and Board of Directors.

Administration

Executive Assistant	Performs advanced, diversified and confidential administrative duties requiring broad knowledge of organizational policies and practices. Initiates and prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. In some cases, may have responsibility for routine HR and administrative services. Records, prepares and distributes minutes of meetings, including Board of Director minutes. Reports to the President & CEO and may provide support to other executives.
Administrative Assistant	Performs advanced, diversified and confidential administrative duties for executives and/or senior management, requiring broad and comprehensive experience and knowledge of organizational policies and practices. Prepares correspondence, reports, either routine or non-routine. Screens telephone calls and visitors and resolves routine and complex inquiries. Schedules appointments, meetings and travel itineraries. Reports to a senior executive or executive team.

Engineering

Director Engineering	Plans and directs the overall engineering activities and engineering staff of the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes. Coordinates the creation, development, design and improvement of the organization's projects and products in conformance with established programs and objectives. Oversees plans, resources and budgets of the department aligned with business strategy.
Engineering Manager and/or Distribution Engineer	Supervises and directs the work of an engineering division such as distribution, line design, transmission planning, distribution planning and/or civil engineering. Responsible for engineering work involving a wide scope of assignments. Handles personnel coordination and issues of the division, prepares estimates, specifications and designs, including the supervision, planning and scheduling of work within the division – Requires a P. Eng. OR Supervises engineering technicians or service technicians. Directs and coordinates the activities, schedules and projects of the construction and maintenance group of those involved with the distribution of electrical power from transformer substations, construction and maintenance of distribution systems. Consults with other department management on plant design, construction and maintenance. Prepares monthly operating reports, budget estimates, and work and materials specifications. Reviews and approves material requisitions, work authorizations and drawings for facilities. Requires a P. Eng.
Project Engineer	Non-supervisory position. Directs and coordinates activities related to utility engineering project work, such as smart grid systems, renewables, large utility projects, asset renewal, etc. Requires a P. Eng.
Supervisor Engineering	Supervises a small technical work group which may include CAD operators and/or engineering technicians. Coordinates the development and maintenance of engineering and construction standards and systems (GIS, AM/FM, CAD). Organizes, stores and maintains the integrity of hard copy file records, digital formats and mapping standards. Normally requires a C.E.T. or A.Sc. T. Typically reports to an engineering manager.

Operations

Director Operations	NOT the head of function. Plans and directs all operations functions (no engineering responsibility), of the utility. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Evaluates the feasibility of new or revised systems or procedures and oversees operations to ensure compliance with established standards.
Manager Operations	NOT the head of function. Supervises, co-ordinates, directs, schedules and controls the construction, maintenance and personnel of the division, including budgets, transportation, equipment and material requirements and fleet management. Division responsibilities include construction, maintenance and repair of all overhead transmission, overhead and underground distribution and may include coordination of tree trimming for geographical area assigned to the division. In smaller utilities, a professional engineer may fill this role.
Manager Control Centre	Supervises, co-ordinates, directs, schedules and controls the control centre and technical staff. Provides leadership in the planning and coordination of the control centre relative to safety, reliability and control of the distribution system. Is responsible for budgets, and the direct operations of the control centre approving system outages, switching and maintenance requirements to maintain and improve system reliability.
Supervisor Control Centre	Directs and supervises control centre technical staff. Provides planning and coordination of control centre scheduling and maintenance required for the safe, reliable operation and control of the distribution system, including the authorization of the operation of system devices, equipment and control access to electrical plant and substations. Approves and coordinates system outages and switching as required for maintenance and system reliability. Oversees power interruptions and emergencies with dispatch staff to affect corrective measures for isolation, emergency repairs and restoration purposes. Monitors feeder load profiles.
Supervisor Protection and Control	Responsible for the management of all Protection & Controls activities related to the installation, maintenance and commissioning of: Protective Relaying Schemes and Station Automation Systems; SCADA System, Visual Display System and Remote Terminal Units; Operations Ethernet and system-wide Area Communications Networks; Distribution Automation Systems, Sectionalizing Devices and Remote Supervisory Controlled Devices. Prepares and administers reports, budgets, Policies and Procedures, record keeping systems.
Supervisor Station Maintenance	Responsible for the planning, coordinating both maintenance and installation of substations, as well as ensuring reliability of the underground plant, through testing and troubleshooting. Supervises, coordinates and schedules the activities of Station Maintenance Electricians and Protection and Control Technicians, Reviews work assignments, daily logs, reports and orders. Co-ordinate crews and plan jobs, assigns work per shift, long-term work and shift coverage to ensure the smooth flow of routine work and that all shifts are covered.
Line Supervisor	Coordinates and directs the lead journey person and/or crews in the construction and maintenance of distribution lines and equipment (overhead and/or underground). Works with lead journey person to develop plans and schedules required in directing and assigning a crew or crews of skilled trade staff in performing construction, maintenance and operation of the distribution system lines in a safe and efficient manner. Supervises and coordinates subcontractors engaged in planning and executing work procedures, interpreting specifications and managing construction.
Manager Meter Department	Supervises the overall operations of the Meter department, prepares budgets, directs the purchase and maintenance of equipment and technology related to the department. Provides direction on the supervision of meter staff, the assignment of work and productivity of staff. Supervises the work related to interactions with electronic meter programming and interaction with/or the operation of the MV90 or similar data collection systems.

Supervisor Meter Department	Responsible for overall operation of the Meter department, including operations, budgeting and supervision of meter technicians or other operations staff. Assigns, monitors and inspects the daily work and productivity of the staff in metering operations to ensure timely delivery of services, maintenance of equipment and identification of issues. Develops work plans for the department that include supervising meter re-verification, new meter installs, record maintenance and monitoring of meter maintenance, damage, reporting and theft issues. Ensures compliance with technical standards for equipment. Responsible for electronic meter programming and interaction with/operation of an MV90 or similar data collection system.

Supply Chain / Procurement

Director Supply Chain Management	Responsible for the overall operation of the Procurement, Inventory, Fleet and/or Facilities programs and initiatives in the organization. Formulates and implements plans, budgets, policies and procedures to facilitate and improve processes and establishes clear controls, objectives and measures to ensure safe and appropriate delivery of services and clarity of roles and responsibilities. Oversees the establishment of user service level agreements, and provides contract management expertise and acts as a resource for contract negotiation, review and approval. Directs the effective capital acquisition and maintenance of the corporate fleet and/or directs the effective maintenance and capital investment of the organizations facilities and assets.
Manager Procurement and/or Inventory and/or Facilities and/or Fleet	Responsible for all purchasing and/or inventory and/or facilities and/or fleet for all areas of the utility. Negotiates vendor agreements and manages the tender process. May also be responsible for stores and inventory control in the warehouse. Is responsible for budgets, policies and procedures and directs the work of the purchasing or buyers and/or stores and/or facilities and/or fleet personnel. Works with the organization in setting partnership relationships to understand and meet the needs of the organization, its operations and risk associated with the effective and efficient operations of the company.
Supervisor Stores/Inventory/ Warehouse	Supervises inventory control, records and stores operation. Orders material to maintain on-hand quantities with procurements approval. Responsible for testing safety equipment, i.e., hoses, blankets, gloves, etc., small tool and equipment repair and reconditioning. Assists procurement department in the sale of obsolete equipment and material.

Accounting / Finance

Controller or Director Finance	NOT the head of function. Responsible for all financial reporting, accounting and record keeping functions. Directs the establishment and maintenance of the organization's accounting and finance principles, practices and procedures for the maintenance of its fiscal records and the preparation of its financial reports. Directs general and property accounting, cost accounting and budgetary control. Appraises operating results in terms of costs, budgets, operating policies, trends and increased profit opportunities. Reports to a CFO/VP Finance.
Manager Accounting	Manages the general accounting functions and the preparation of reports and statistics reflecting earnings, profits, cash balances and other financial results. Formulates and administers approved accounting practices throughout the organization to ensure that financial and operating reports accurately reflect the condition of the business and provide reliable information. Reports to Controller/Director Finance or CFO/VP Finance.
Manager Risk Management	Responsible for risk management activities including cash flow management, credit facilities management, insurance and support for credit and collection policies throughout the corporation. May be responsible for ensuring that cash liquidity risk is managed in an appropriate fashion such that bank account balances are sufficient to meet operational, capital expenditures and debt servicing requirements while minimizing short-term borrowings or surplus investing. Provides leadership in the developing new and refining existing risk management policies to respond to changes in risk tolerances and business conditions and as financial risks are better understood in accordance with industry best practices. Reports to Head of Finance or COO or CEO.

Supervisor Accounting	Coordinates activities of the payable/receivable clerks. Supervises accounts payable and receivable transactions, entries and trial balances; responsible for the accuracy of all journal entries and reconciliation of invoices; updates credit department on account status.
Financial or Business Analyst	Conducts analysis of information for budgeting, investment and financial forecasts; applies principles of accounting to analyze past and present financial operations; estimates future revenues and expenditures; prepares budgets; develops and maintains budgeting systems; processes and prepares business transactions and reports, reconciles ledgers and sub-ledgers, cash flow projections, entry of source documents. Holds a financial designation, either CA, CMA or CGA.
Accountant	Supports the organization decisions through financial information and relevant analysis. Ensures the integrity between the CS work order systems and general ledger system is maintained. Initiate corrective measures when discrepancies occur between the systems. Collects and combines information for the decision making process by management, including financial statements and special projects as assigned (e.g. preparation of rate submission supplemental information).

Customer Service

Director Customer Service	NOT the head of function. Provides direction for all departmental activities, services and practices, including customer care/call centre, billing, credit and collections. Accountable for the implementation and integration of all customer service related activities. Oversees the implementation of customer service standards, policies and procedures; manages budgets; manages activities of CS managers and/or supervisory staff.
Manager Customer Service and/or Billing	NOT the head of function. Manages a team of customer service and/or billing representatives in providing information, receiving and responding to customer inquiries, complaints or requests. Develops and maintains customer information systems, processes and procedures including billing, credit, deposits and collections. Liaises with representatives of other organizations and customer groups to share information and resolve administrative, organizational and technical problems. Responds to elevated customer complaints. This function may also be responsible for coordinating meter installation/maintenance, residential electric service connections, and service calls.
Supervisor Customer Service and/or Billing and/or Collections	Supervises customer service representatives (billing clerks and/or collections clerks) and coordinates customer service programs within the framework of established customer service policies. Schedules and organizes staff to accommodate anticipated workflow from bill inquiries, delinquent accounts, re-connections and disconnections, customer deposits, etc. Recommends corrective steps to address customer issues and refers unique issues to manager for response.

Regulatory Affairs

Director Regulatory Affairs	NOT the head of function. Supports the VP or may represent the organization on regulatory matters before government agencies and conformity assessment bodies including providing of evidence, regulatory filings, supporting analyses, position papers, interrogatory responses, etc. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Is responsible for or supports the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).
Manager Regulatory Affairs	NOT the head of function. Manages the organization's regulatory staff, programs and activities to ensure compliance. Assists the organization on quality and regulatory matters before government agencies, providing research and analyses. Ensures that regulatory information is disseminated throughout the organization in a timely and effective manner. Coordinates the filing of written communications and regulatory submissions to government agencies (OEB) and conformity assessment bodies (IMO).

Regulatory Accountant	Ensures that the accounting activities for regulatory financial reporting are in compliance with all Ontario Energy Board (OEB) policies and guidelines. Act as a key resource to provide expert advice and recommendations in the implantation of all OEB, OPA and IESO codes and regulations in order to ensure corporate compliance. Track and reconcile all OEB accounts, including business rationale for changes in balances, cost side of accounts subject to prudency review (i.e. conservation, smart meters) and the cost side of Ontario Power Authority (OPA) programs.

Conservation / Demand

Settlement or Rate Analyst	Responsible for recording, creating, analyzing, processing and reconciling metering data. Operates and administers an MV-90 or similar data collection system, downloading, validating, editing, estimating and processing interval meter-related information. Has in-depth understanding of commercial billing practices, the IMO and the OEB's Retail Settlement Code. Analyses rates using rate sensitivity models and develops appropriate rate structures, using the specific models.
Director or Officer, Conservation and Demand Management	This position is responsible for planning, coordinating, evaluating and delivering energy and water conservation and demand management programs. Develops plans for programs in accordance with the OEB's conservation and demand management code to ensure achievement of OEB mandated energy consumption and demand conservation targets.
Manager Conservation & Demand/Marketing	Responsible for managing the development and implementation of CDM initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's Conservation and Demand Management (CDM) programs. Marketing communication plans may include, but are not limited to advertising, media conferences, program launch events, workshops, event displays. Liaising with, as needed, senior marketing and/or communications personnel representing organizations and groups involved in conservation and sustainability including, but not limited to, the Ontario Power Authority (OPA), the Ontario Energy Board (OEB), Ministry of Energy, municipal and regional governments, etc.

Information Systems / Technology

Director Information Systems	Accountable for operations and alignment of the Information and Telecommunication Systems with the business in terms of organization objectives and imperatives. Ensures that existing needs and future demands of internal and external customers are met through a cost effective and efficient information and telecommunication infrastructure. Oversees IS management in areas of computer operations, systems planning, design, security, programming and telecommunications. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, strategy, budgets and resource requirements. Typically reports to President & CEO, or CFO.
Manager Information Systems and/or Security	Manages and directs staff in areas of computer operations, systems planning, design, security, programming and telecommunications. Develops and maintains systems standards and procedures and assigns work to department staff. Reviews and evaluates project feasibility and needs based upon management's and business requirements and priorities. Develops departmental plans, project plans, budgets and resource requirements.
Systems/Program Administrator or Applications/Systems Support Professional	Responsible for maintenance of software systems including system analysis, programming and design, updates and changes. Makes a preliminary study of new applications and recommendations to implement them, including hardware and software. Troubleshoots and corrects problems in existing programs, other than normal problems, usually caused by changes of software or hardware.

Human Resources

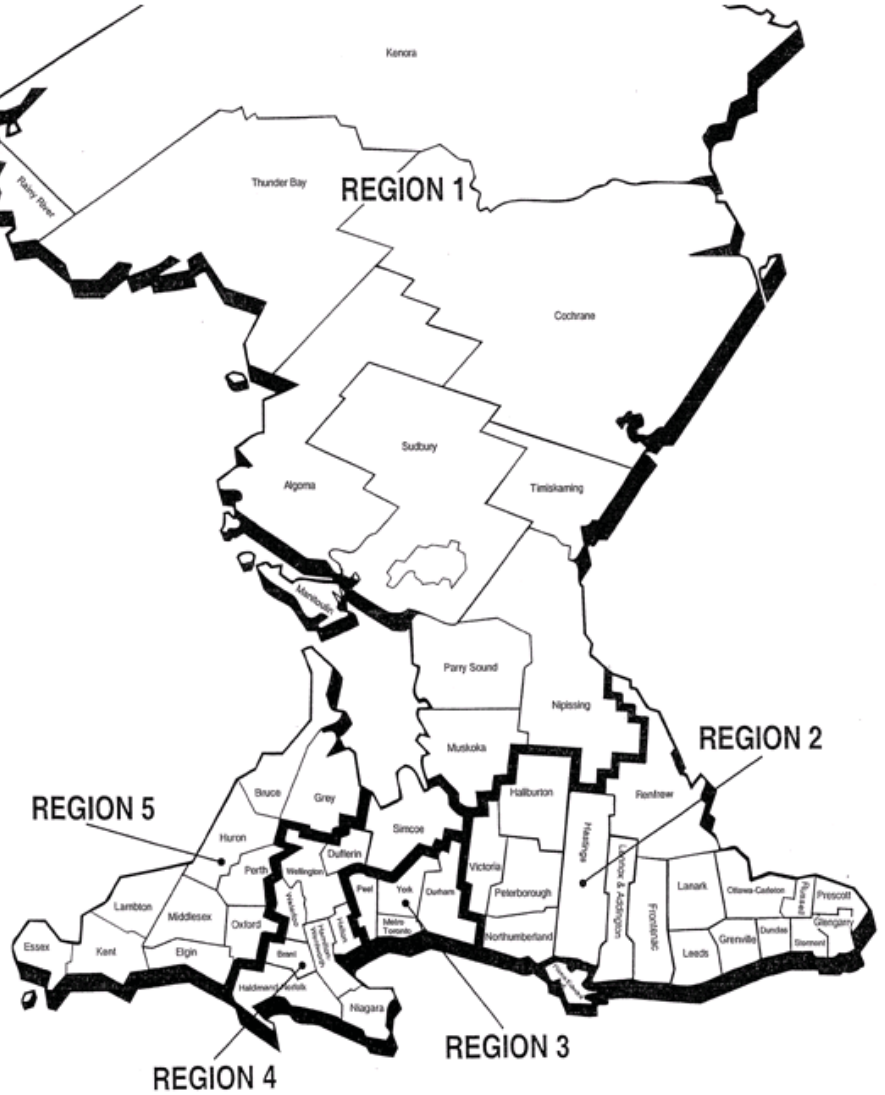
Human Resources Manager	NOT the head of function. Develops and implements human resources programs, including compensation, benefits, recruitment, performance management, labour relations/negotiations, training and development, assists in policy development, HR planning, record keeping or payroll etc. May supervise a team of HR professionals or support staff. Reports to a senior HR professional (Director or VP or equivalent).
Human Resources Generalist	Assists in the development and implementation of human resources policies and programs by providing support and guidance to managers and employees in the areas of compensation, labour relations, employee relations, performance management, benefits, recruitment, training and HRIS systems. Acts as a business partner to the organization in the areas of human capital. May assist in the preparation of negotiations.
Human Resources Coordinator	Administrative support to one or more functional areas of HR and/or Safety. Processes, coordinates and enters into a HRIS or other system, a variety of documents including employment applications, benefits, compensation and payroll changes and confidential employee information. Responds to routine employment questions and distributes and maintains manuals and employee program communications.
Payroll	Performs the payroll coordination and administration. Maintains the organizations internal or external payroll system. Prepares monthly requisitions for WSIB, Employee Health Tax, Receiver General, OMERS Pension and Union Dues. Administers employee pension program and provides pension calculation estimates as requested. Reconciles monthly payroll for year-end finance procedures. Prepares annual T4's and T4A's and OMERS Pension and responds to inquiries from employees and pensioners regarding the pension plan.
Manager, Health & Safety	Accountable for the development and implementation of occupational health, safety and environmental programs, including training, maintenance of safe working conditions, investigation and reporting of workplace accidents. Also identifies areas of potential risk and makes recommendations to reduce or eliminate potential accident or health hazards in compliance with government regulations.

Communications

Director Communications	Directs the development, management and execution of internal and external corporate communications strategies for the company, and marketing and public relations initiatives. Acts as the Chief Spokesperson for the organization. Leads the management and development of the corporate brand and identity. Oversees the development, production and distribution of corporate publications including, but not limited to, the annual report, customer newsletters, information brochures, bill inserts, CDM/Green marketing materials, employee newsletters and media releases. Directs the development and management of the company's external (corporate internet site) and internal (corporate intranet site) web presence and strategy. Oversees the management and execution of internal and external corporate events as well as community-relations activities such as sponsorship and donation programs.
Manager Communications	Responsible for managing the development and implementation of all customer communications initiatives as well as the marketing communications expertise and support required for the successful delivery of the company's CDM and customer communications materials/systems. Communication materials may include, but are not limited to, customer newsletters, information brochures, bill form design, employee intranet, LCD information monitors, and website communications. Working in conjunction with Regulatory Affairs, develop materials or other communication methods to communicate regulatory changes/issues that may directly impact the customer. Manages event planning for internal and external company events.

E. Regions

The map below identifies the 5 regions that will be used for reporting on a geographic basis.



The MEARIE Group

2013 Management Salary Survey Of Local Distribution Companies

Addendum – Position Reports

July 2013

SURVEY ADMINISTRATOR: HAY GROUP LIMITED

The MEARIE Group
2013 Management Salary Survey
of Local Distribution Companies

Code: 0000

Model Job Title: President & CEO

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	46	46	1242	146,300	174,200	182,500	20%	189,000	220,300	169,100	182,900	19%	180,800	216,600
Geography: Region 1	9	9	904	124,700	124,300	156,200	*	132,200	143,400	124,400	134,700	*	128,100	139,000
Geography: Region 2	4	4	1643	168,700	218,300	226,100	*	251,400	236,200	206,700	217,600	*	236,500	268,000
Geography: Region 3	5	5	1708	207,200	250,200	287,700	50%	375,200	373,700	238,900	260,800	49%	328,700	389,700
Geography: Region 4	17	17	1192	137,300	170,000	171,600	15%	179,100	205,000	168,000	181,300	15%	177,700	203,500
Geography: Region 5	11	11	1090	146,800	176,900	199,700	28%	221,400	217,100	175,000	176,600	28%	220,000	202,900
Revenue: Up to $20 Million	16	16	904	109,400	138,800	144,100	10%	150,100	151,100	134,400	140,000	10%	141,900	147,800
Revenue: $20 to $50 Million	6	6	1166	188,800	199,800	208,200	*	231,700	231,900	169,000	179,300	*	169,000	193,900
Revenue: $50 to $100 Million	7	7	1090	133,100	166,200	199,400	16%	202,000	201,500	163,400	168,900	14%	189,000	193,600
Revenue: $100 to $200 Million	11	11	1486	168,200	183,000	195,800	25%	226,700	247,900	193,100	201,300	24%	223,800	242,600
Revenue: $200 Million +	6	6	2044	207,200	246,900	300,000	40%	339,500	357,000	267,600	283,200	40%	409,100	402,000
Customers: Up to 19,999	17	17	904	109,400	131,900	144,100	10%	141,100	144,400	132,900	136,600	10%	135,900	142,300
Customers: 20,000 to 39,999	12	12	1141	143,300	179,300	199,400	17%	195,500	202,200	169,200	173,800	16%	184,500	193,900
Customers: 40,000 to 99,999	11	11	1486	170,000	192,700	197,900	28%	226,700	243,200	193,100	199,700	28%	220,000	236,000
Customers: 100,000 +	6	6	2128	223,600	273,100	312,900	38%	375,800	391,800	298,100	301,100	38%	447,200	436,800
Employees: Less than 21	10	10	904	90,900	119,700	117,000	10%	120,700	124,800	119,700	121,300	10%	122,600	125,700
Employees: 21 to 50	12	12	1065	143,300	168,000	185,000	10%	179,100	183,000	163,100	162,400	10%	168,900	178,100
Employees: 51 to 100	6	6	1191	133,100	177,000	160,100	17%	205,600	213,900	175,300	180,600	17%	195,100	201,200
Employees: 101 to 200	12	12	1486	180,100	187,800	195,800	28%	210,100	235,600	194,200	196,600	23%	207,900	228,400
Employees: More than 200	6	6	2128	223,600	273,100	312,900	38%	375,800	391,800	298,100	301,100	38%	447,200	436,800

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

The MEARIE Group
2013 Management Salary Survey
of Local Distribution Companies

Code: 0001

Model Job Title: Chief Operating Officer (COO)

				COMPENSATION DESIGN						ACTIUAL COMPENSATION				
Market Segment	Sample Statistics		Hay Points	Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	15	15	904	135,100	165,500	175,000	20%	206,800	204,500	165,500	167,800	19%	170,100	200,100
Geography: Region 1	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	4	4	1263	181,200	213,000	239,400	33%	287,100	264,500	198,500	198,500	38%	277,000	268,300
Geography: Region 4	3	3		*	*	*	*	*	187,400	*	154,100	*	*	183,400
Geography: Region 5	4	4	904	140,400	157,200	165,800	14%	178,200	184,000	138,300	143,900	*	155,000	152,200
Revenue: Up to $20 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	5	5	839	119,000	139,500	156,700	7%	150,900	154,000	137,400	143,500	*	162,400	152,000
Revenue: $100 to $200 Million	4	4	972	143,000	178,200	200,800	*	213,800	214,100	156,400	156,400	*	185,300	188,000
Revenue: $200 Million +	3	3		*	*	*	*	*	285,700	*	233,200	*	*	319,700
Customers: Up to 19,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	5	5	839	119,000	139,500	156,700	7%	150,900	154,000	137,400	143,500	*	162,400	152,000
Customers: 40,000 to 99,999	6	6	972	155,900	178,200	189,400	25%	213,800	217,100	167,400	162,000	24%	190,500	191,300
Customers: 100,000 +	3	3		*	*	*	*	*	285,700	*	233,200	*	*	319,700
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	5	5	839	125,800	139,500	156,700	8%	146,500	157,100	133,200	138,500	*	139,800	146,600
Employees: 51 to 100	3	3		*	*	*	*	*	183,300	*	155,100	*	*	177,500
Employees: 101 to 200	4	4	1040	163,600	175,400	184,600	*	222,900	218,700	169,200	164,800	*	197,900	194,300
Employees: More than 200	3	3		*	*	*	*	*	285,700	*	233,200	*	*	319,700

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

The MEARIE Group
2013 Management Salary Survey
of Local Distribution Companies

HayGroup®

Code: 0002

Model Job Title: Head of Operations and/or Engineering

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	30	38	839	108,100	125,800	139,800	15%	131,700	142,600	126,500	130,600	9%	135,300	143,300
Geography: Region 1	3	3		*	*	*	*	*	133,700	*	128,500	*	*	132,000
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	4	6	1040	*	*	*	22%	*	203,700	162,300	162,700	25%	202,700	200,000
Geography: Region 4	14	19	732	97,800	115,700	123,500	9%	120,600	125,500	111,700	120,600	8%	114,800	126,600
Geography: Region 5	7	8	732	100,400	122,600	135,000	15%	133,900	149,800	121,900	131,800	9%	133,900	144,900
Revenue: Up to $20 Million	11	12	732	90,000	109,600	118,100	8%	114,600	113,900	109,100	106,400	7%	113,600	110,600
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	4	5	717	99,300	125,100	135,100	*	132,900	130,700	123,000	120,300	*	130,800	127,200
Revenue: $100 to $200 Million	7	10	1040	120,000	131,300	143,200	22%	138,300	157,400	141,000	145,400	20%	146,400	161,500
Revenue: $200 Million +	6	9	1068	130,900	159,000	172,300	20%	190,800	188,100	161,000	162,100	24%	194,200	193,400
Customers: Up to 19,999	10	11	615	92,500	111,800	113,900	8%	114,800	113,900	107,200	107,000	8%	113,000	110,800
Customers: 20,000 to 39,999	8	9	786	101,300	127,600	144,900	9%	132,900	139,100	123,000	128,000	7%	130,800	135,100
Customers: 40,000 to 99,999	6	10	1040	117,100	130,900	140,100	*	131,700	133,800	140,500	137,000	*	143,500	146,100
Customers: 100,000 +	6	8	1068	137,700	172,000	180,500	23%	210,800	202,400	176,600	167,300	24%	218,300	205,700
Employees: Less than 21	5	6	594	89,100	104,800	104,800	*	105,000	110,500	102,400	100,400	*	109,700	105,200
Employees: 21 to 50	8	8	732	99,300	116,600	127,400	6%	121,300	122,500	116,200	115,900	6%	118,200	119,700
Employees: 51 to 100	3	4		*	*	*	*	*	*	*	118,000	*	*	132,200
Employees: 101 to 200	8	12	1040	116,700	132,500	144,500	15%	140,300	147,800	143,200	141,500	9%	144,800	148,200
Employees: More than 200	6	8	1068	137,700	172,000	180,500	23%	210,800	202,400	176,600	167,300	24%	218,300	205,700

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

The MEARIE Group
2013 Management Salary Survey
of Local Distribution Companies

Code: 0003

Model Job Title: CFO / Head of Finance

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	44	44	818	109,800	134,800	138,500	17%	137,900	160,300	133,000	139,100	11%	138,000	156,600
Geography: Region 1	6	6	648	103,900	124,300	138,200	*	124,300	121,800	118,300	115,300	*	118,300	117,000
Geography: Region 2	4	4	986	110,000	141,000	146,200	*	155,400	162,700	133,700	137,200	*	144,200	165,000
Geography: Region 3	5	5	994	161,700	202,200	232,500	30%	283,000	247,100	184,000	189,700	33%	244,100	251,300
Geography: Region 4	19	19	805	108,600	122,700	137,500	13%	133,100	146,100	125,100	135,900	10%	130,800	146,400
Geography: Region 5	10	10	766	104,000	130,000	138,600	20%	156,000	162,000	123,700	134,800	15%	138,400	148,900
Revenue: Up to $20 Million	14	14	591	94,800	111,900	114,800	9%	115,100	112,000	107,200	106,300	8%	111,900	110,100
Revenue: $20 to $50 Million	6	6	657	135,300	156,800	156,800	*	185,600	179,800	127,900	136,500	*	130,900	144,800
Revenue: $50 to $100 Million	7	7	702	98,100	135,000	137,400	11%	141,800	148,000	131,300	131,200	7%	137,800	141,100
Revenue: $100 to $200 Million	11	11	994	133,200	141,900	149,600	20%	156,000	181,600	144,200	158,300	23%	153,700	180,500
Revenue: $200 Million +	6	6	1358	145,700	188,100	210,300	30%	248,300	234,900	196,800	191,900	39%	262,400	250,900
Customers: Up to 19,999	15	15	571	95,000	108,900	109,800	8%	114,000	109,700	104,800	103,300	7%	109,700	106,000
Customers: 20,000 to 39,999	12	12	754	101,900	136,200	140,200	10%	143,000	145,200	136,800	133,700	9%	144,400	142,300
Customers: 40,000 to 99,999	11	11	994	140,000	141,900	151,900	23%	156,000	181,400	151,900	157,100	25%	156,000	176,000
Customers: 100,000 +	6	6	1388	162,200	208,800	249,300	30%	279,100	261,000	218,300	206,300	34%	295,300	276,000
Employees: Less than 21	8	8	571	85,000	100,500	100,500	*	100,500	98,600	96,800	95,300	*	101,400	98,200
Employees: 21 to 50	11	11	677	100,700	117,800	135,400	8%	123,400	131,600	114,200	118,500	7%	120,000	125,300
Employees: 51 to 100	7	7	805	115,300	137,400	144,200	13%	144,200	159,500	144,200	148,200	9%	157,600	160,700
Employees: 101 to 200	12	12	1017	122,300	139,300	144,800	20%	154,200	170,100	138,500	148,200	15%	151,300	162,000
Employees: More than 200	6	6	1388	162,200	208,800	249,300	30%	279,100	261,000	218,300	206,300	34%	295,300	276,000

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 0004

Model Job Title: Head of Customer Service

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	20	20	818	102,100	125,600	130,200	20%	132,600	146,000	129,200	129,000	19%	134,200	144,700
Geography: Region 1	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	3		*	*	*	*	*	210,000	*	160,800	*	*	211,200
Geography: Region 4	8	8	803	99,600	115,200	126,400	*	121,000	135,500	120,800	129,100	*	126,400	138,700
Geography: Region 5	5	5	611	90,300	112,800	112,800	15%	132,200	127,100	112,800	111,700	*	129,000	119,200
Revenue: Up to $20 Million	4	4	690	91,000	110,100	118,000	*	110,100	107,000	110,100	102,900	*	110,100	105,600
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	3	3		*	*	*	*	*	108,500	*	99,200	*	*	105,000
Revenue: $100 to $200 Million	7	7	864	122,300	133,000	140,100	20%	135,400	163,300	140,100	141,100	20%	140,100	163,700
Revenue: $200 Million +	4	4	994	114,900	143,600	164,800	*	172,200	170,700	139,300	146,900	*	171,400	177,300
Customers: Up to 19,999	3	3		*	*	*	*	*	107,300	*	101,800	*	*	105,500
Customers: 20,000 to 39,999	6	6	644	89,300	106,200	117,000	10%	114,200	119,400	105,000	110,400	7%	108,800	115,800
Customers: 40,000 to 99,999	7	7	864	122,900	133,000	140,100	20%	135,400	159,900	140,100	140,500	*	140,100	156,300
Customers: 100,000 +	4	4	994	120,900	152,800	173,700	23%	187,000	190,600	155,100	157,300	23%	191,100	197,200
Employees: Less than 21	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	4	4	542	79,300	99,200	115,200	*	102,900	99,900	99,700	97,100	*	102,900	98,700
Employees: 51 to 100	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	9	9	864	103,900	130,900	133,000	18%	133,000	147,800	133,000	131,400	11%	135,400	143,500
Employees: More than 200	4	4	994	120,900	152,800	173,700	23%	187,000	190,600	155,100	157,300	23%	191,100	197,200

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

The MEARIE Group
2013 Management Salary Survey
of Local Distribution Companies

Code: 0005

Model Job Title: Head of Regulatory Affairs

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	9	9	954	125,900	146,800	161,500	20%	176,200	163,700	143,200	139,500	17%	170,700	165,000
Geography: Region 1	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	3		*	*	*	*	*	185,900	*	156,900	*	*	190,500
Geography: Region 4	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 5	3	3		*	*	*	*	*	154,600	*	139,600	*	*	156,200
Revenue: Up to $20 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	3	3		*	*	*	*	*	169,400	*	150,500	*	*	177,600
Revenue: $200 Million +	4	4	954	129,000	147,500	166,800	20%	177,000	180,600	143,400	153,600	23%	174,500	187,500
Customers: Up to 19,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 100,000 +	5	5	954	130,500	148,100	170,400	20%	177,800	186,200	143,500	156,800	24%	178,400	192,300
Employees: Less than 21	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: More than 200	5	5	954	130,500	148,100	170,400	20%	177,800	186,200	143,500	156,800	24%	178,400	192,300

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 0006

Model Job Title: Head of Human Resources

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	16	16	751	109,300	129,200	129,200	20%	139,800	146,300	125,400	127,900	14%	135,000	141,000
Geography: Region 1	3	3		*	*	*	*	*	117,400	*	118,700	*	*	120,200
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	3		*	*	*	*	*	164,300	*	139,500	*	*	145,100
Geography: Region 4	4	4	721	111,100	123,200	126,600	*	141,700	145,700	126,600	125,600	*	149,200	147,200
Geography: Region 5	4	4	815	106,500	124,100	124,100	*	145,500	140,100	124,100	124,200	*	138,100	134,400
Revenue: Up to $20 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	4	4	701	111,800	122,800	130,000	*	139,900	142,800	124,300	126,400	*	126,900	139,800
Revenue: $50 to $100 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	6	6	815	102,300	122,900	123,800	*	134,200	138,800	123,800	127,800	*	134,200	140,900
Revenue: $200 Million +	4	4	828	122,700	148,100	162,900	18%	174,300	180,800	150,400	146,800	*	150,400	163,600
Customers: Up to 19,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	3	3		*	*	*	*	*	131,300	*	115,800	*	*	125,900
Customers: 40,000 to 99,999	6	6	830	107,600	122,900	123,800	*	134,200	136,500	123,800	125,100	*	134,200	137,000
Customers: 100,000 +	5	5	954	130,500	160,700	176,800	20%	192,900	186,200	160,700	150,800	*	160,700	172,400
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	9	9	800	91,700	112,800	114,600	18%	133,000	134,700	114,600	122,000	11%	133,000	133,300
Employees: More than 200	5	5	954	130,500	160,700	176,800	20%	192,900	186,200	160,700	150,800	*	160,700	172,400

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

The MEARIE Group
2013 Management Salary Survey
of Local Distribution Companies

Code: 1000

Model Job Title: Executive Assistant

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	35	54	245	56,800	67,100	74,500	5%	70,100	72,200	69,000	71,000	5%	72,100	73,500
Geography: Region 1	4	4	242	54,700	66,000	68,000	*	66,000	65,600	67,800	65,100	*	67,800	66,600
Geography: Region 2	3	12		*	*	*	*	*	72,400	*	70,900	*	*	72,400
Geography: Region 3	6	7	245	63,500	79,200	79,400	7%	83,400	81,700	77,600	75,200	6%	81,200	79,300
Geography: Region 4	14	19	245	54,300	66,700	73,400	5%	67,600	70,500	68,200	71,000	4%	69,600	72,800
Geography: Region 5	8	12	245	55,200	66,900	78,400	6%	70,900	72,500	67,900	70,800	7%	72,900	74,100
Revenue: Up to $20 Million	7	7	245	50,000	65,000	72,800	6%	65,000	70,400	67,100	71,100	5%	69,000	73,700
Revenue: $20 to $50 Million	3	5		*	*	*	*	*	74,600	*	72,600	*	*	75,200
Revenue: $50 to $100 Million	7	7	245	59,000	73,000	75,000	5%	76,600	73,700	73,300	72,000	4%	75,100	74,000
Revenue: $100 to $200 Million	12	15	245	57,100	66,900	72,400	5%	69,800	68,700	67,800	68,200	4%	69,600	69,900
Revenue: $200 Million +	6	20	245	62,400	74,100	79,100	10%	78,500	77,900	77,900	74,700	9%	80,000	79,000
Customers: Up to 19,999	5	5	245	50,000	66,300	67,100	*	67,100	74,600	67,100	74,400	*	69,000	77,400
Customers: 20,000 to 39,999	12	12	242	55,700	69,000	73,100	5%	71,700	70,100	69,100	69,100	4%	73,000	70,900
Customers: 40,000 to 99,999	12	14	245	57,600	66,900	74,000	5%	68,900	69,900	69,400	70,600	3%	71,100	72,300
Customers: 100,000 +	6	23	245	60,000	75,000	80,000	10%	78,600	78,700	73,000	72,900	9%	78,700	77,800
Employees: Less than 21	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	7	7	245	53,600	67,100	79,600	*	67,100	74,800	67,100	74,000	*	70,000	76,500
Employees: 51 to 100	8	8	201	54,700	64,400	73,000	5%	67,600	68,700	73,000	70,500	4%	74,400	72,300
Employees: 101 to 200	12	14	245	57,700	68,300	72,300	3%	70,500	70,900	69,000	70,300	3%	71,200	71,900
Employees: More than 200	6	23	245	60,000	75,000	80,000	10%	78,600	78,700	73,000	72,900	9%	78,700	77,800

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 1001

Model Job Title: Administrative Assistant

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	18	27	198	51,700	61,400	63,600	4%	62,400	62,700	61,800	61,400	2%	62,500	62,900
Geography: Region 1	4	7	206	46,600	59,600	62,100	*	59,600	60,600	59,400	60,000	*	59,400	60,700
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	6		*	*	*	*	*	75,500	*	69,200	*	*	75,500
Geography: Region 4	6	9	169	52,100	58,100	63,100	*	58,500	57,800	59,500	58,400	*	60,000	58,500
Geography: Region 5	3	3		*	*	*	*	*	62,500	*	61,100	*	*	62,300
Revenue: Up to $20 Million	5	5	169	47,700	56,800	58,900	*	56,800	56,200	56,700	55,600	*	56,800	55,800
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	5	9	208	49,800	61,100	62,500	*	62,500	61,600	61,800	61,000	*	61,800	61,500
Revenue: $200 Million +	5	10	169	57,500	65,600	70,300	*	70,300	70,000	64,500	67,500	*	69,500	71,300
Customers: Up to 19,999	5	5	169	47,700	56,800	58,900	*	56,800	56,200	56,700	55,600	*	56,800	55,800
Customers: 20,000 to 39,999	3	3		*	*	*	*	*	63,100	*	61,100	*	*	62,700
Customers: 40,000 to 99,999	6	12	203	51,700	61,400	63,500	*	62,400	61,100	61,800	61,900	*	62,900	62,300
Customers: 100,000 +	4	7	184	57,900	66,000	74,500	*	71,600	73,000	65,000	68,300	*	69,900	73,000
Employees: Less than 21	3	3		*	*	*	*	*	55,300	*	55,000	*	*	55,000
Employees: 21 to 50	3	3		*	*	*	*	*	59,500	*	58,200	*	*	59,000
Employees: 51 to 100	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	8	14	203	49,600	60,700	62,900	2%	61,900	61,600	61,800	61,600	2%	62,300	62,400
Employees: More than 200	4	7	184	57,900	66,000	74,500	*	71,600	73,000	65,000	68,300	*	69,900	73,000

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 2000

Model Job Title: Director Engineering

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	17	17	732	102,500	123,700	124,600	13%	131,500	137,100	124,200	124,500	7%	128,500	134,300
Geography: Region 1	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	3	3		*	*	*	*	*	136,800	*	125,200	*	*	139,000
Geography: Region 3	3	3		*	*	*	*	*	*	*	132,600	*	*	152,400
Geography: Region 4	7	7	732	105,600	118,700	124,200	*	118,700	131,300	124,200	122,700	*	125,400	129,400
Geography: Region 5	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: Up to $20 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	3	3		*	*	*	*	*	146,100	*	125,900	*	*	137,400
Revenue: $50 to $100 Million	3	3		*	*	*	*	*	137,500	*	127,100	*	*	131,600
Revenue: $100 to $200 Million	6	6	702	104,600	118,700	120,400	*	118,700	130,500	119,500	121,400	*	121,000	130,100
Revenue: $200 Million +	4	4	865	104,600	126,500	144,300	*	143,300	145,200	132,900	134,800	*	149,100	151,400
Customers: Up to 19,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	5	5	594	94,900	123,100	123,100	6%	131,200	132,600	123,100	124,600	4%	128,500	128,400
Customers: 40,000 to 99,999	7	7	702	105,100	119,100	124,800	15%	128,400	132,700	124,200	122,200	12%	125,400	130,900
Customers: 100,000 +	4	4	840	109,500	136,900	164,300	18%	160,500	156,200	137,200	136,900	17%	164,000	158,900
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	4	4	648	*	*	*	*	*	138,700	121,800	125,800	*	126,500	130,500
Employees: 101 to 200	8	8	729	102,500	118,600	123,700	15%	123,400	130,400	123,700	121,900	6%	126,900	129,500
Employees: More than 200	4	4	840	109,500	136,900	164,300	18%	160,500	156,200	137,200	136,900	17%	164,000	158,900

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 2001

Model Job Title: Engineering Manager and/or Distribution Engineer

				COMPENSATION DESIGN						ACTIUAL COMPENSATION				
Market Segment	Sample Statistics		Hay Points	Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	29	37	588	87,700	103,200	110,200	7%	108,200	109,700	103,000	104,100	5%	105,300	108,200
Geography: Region 1	4	4	552	92,900	101,600	107,300	*	101,600	104,400	101,700	103,200	*	101,700	104,300
Geography: Region 2	3	3		*	*	*	*	*	113,900	*	105,100	*	*	107,400
Geography: Region 3	5	6	551	101,000	121,500	121,500	10%	132,000	131,800	121,500	114,900	9%	126,500	125,600
Geography: Region 4	10	10	542	86,000	97,300	108,000	8%	97,300	102,800	102,000	101,800	7%	102,000	104,900
Geography: Region 5	7	14	611	84,300	102,800	103,000	5%	108,200	105,000	101,400	99,800	4%	104,400	103,200
Revenue: Up to $20 Million	3	3		*	*	*	*	*	88,300	*	87,700	*	*	89,000
Revenue: $20 to $50 Million	2	3		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	8	8	516	87,400	108,300	115,500	5%	113,100	110,500	104,800	104,100	4%	107,400	106,700
Revenue: $100 to $200 Million	10	10	600	88,600	103,100	110,800	9%	106,400	107,500	102,900	105,500	8%	108,900	110,200
Revenue: $200 Million +	6	13	677	94,500	114,100	122,000	13%	128,000	124,000	105,600	112,100	*	113,800	118,900
Customers: Up to 19,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	11	11	516	84,900	103,000	106,800	5%	108,200	106,900	103,000	102,000	4%	103,400	104,900
Customers: 40,000 to 99,999	10	11	588	88,600	101,500	109,900	9%	103,900	105,000	101,500	103,300	8%	104,900	106,600
Customers: 100,000 +	6	13	667	94,700	114,300	132,600	10%	129,000	129,200	114,500	115,400	10%	128,200	124,300
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	6	6	496	79,600	96,500	98,900	*	96,500	98,500	94,500	94,500	*	95,200	95,800
Employees: 51 to 100	6	6	506	89,800	111,200	115,500	5%	119,600	111,000	112,300	106,200	5%	116,800	110,900
Employees: 101 to 200	11	12	611	85,800	100,200	106,800	7%	103,200	104,500	100,200	102,100	4%	104,400	104,800
Employees: More than 200	6	13	667	94,700	114,300	132,600	10%	129,000	129,200	114,500	115,400	10%	128,200	124,300

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 2002

Model Job Title: Project Engineer

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	13	33	479	75,600	94,200	103,600	9%	98,400	97,700	94,200	91,000	8%	95,800	94,300
Geography: Region 1	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	15		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	4		*	*	*	*	*	109,300	*	95,400	*	*	103,700
Geography: Region 4	5	11	417	70,300	81,100	86,900	*	81,100	83,900	80,700	81,500	*	80,700	83,000
Geography: Region 5	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: Up to $20 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	1	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	5	11	417	75,200	94,000	100,000	*	98,400	94,300	88,600	86,800	*	95,800	89,500
Revenue: $200 Million +	4	17	448	80,200	94,300	108,500	*	99,100	101,300	94,300	97,700	*	98,300	102,400
Customers: Up to 19,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	1	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	6	7	448	75,700	94,700	98,700	*	97,900	94,000	91,400	88,500	*	91,400	90,500
Customers: 100,000 +	4	22	448	80,200	94,300	113,100	*	103,300	106,800	94,300	98,500	*	99,000	105,000
Employees: Less than 21	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	1	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	6	7	448	75,700	94,700	98,700	*	97,900	94,000	91,400	88,500	*	91,400	90,500
Employees: More than 200	4	22	448	80,200	94,300	113,100	*	103,300	106,800	94,300	98,500	*	99,000	105,000

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

The MEARIE Group
2013 Management Salary Survey
of Local Distribution Companies

Code: 2003

Model Job Title: Supervisor Engineering

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	20	29	421	78,800	92,600	97,500	7%	95,500	98,900	93,200	92,100	7%	97,000	95,600
Geography: Region 1	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	3	3		*	*	*	*	*	113,500	*	99,200	*	*	101,100
Geography: Region 3	4	6	427	*	*	*	9%	*	111,400	94,000	96,300	7%	100,800	103,200
Geography: Region 4	9	16	421	76,800	92,300	96,000	6%	95,300	94,000	92,200	90,500	6%	95,300	93,600
Geography: Region 5	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: Up to $20 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	3		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	4	4	414	73,800	90,700	95,700	*	94,000	96,000	87,900	88,300	*	89,100	90,300
Revenue: $100 to $200 Million	9	11	421	77,800	92,100	96,800	8%	93,400	95,400	93,700	92,500	7%	97,900	95,800
Revenue: $200 Million +	5	10	432	85,800	101,000	105,800	13%	111,100	110,800	94,900	97,300	*	99,900	101,800
Customers: Up to 19,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	5	5	421	73,900	92,300	95,300	*	95,300	95,900	88,600	89,700	*	91,000	91,300
Customers: 40,000 to 99,999	9	15	421	77,800	91,400	97,000	7%	91,400	92,100	92,600	92,000	5%	96,100	94,600
Customers: 100,000 +	5	8	451	85,800	103,500	111,100	10%	112,100	116,000	96,600	97,600	9%	102,500	104,000
Employees: Less than 21	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	5	6	421	77,800	94,400	102,900	6%	99,900	102,800	93,700	95,400	5%	96,100	99,400
Employees: 101 to 200	7	12	479	76,800	91,200	96,000	*	91,200	91,100	92,600	92,600	*	96,000	94,100
Employees: More than 200	5	8	451	85,800	103,500	111,100	10%	112,100	116,000	96,600	97,600	9%	102,500	104,000

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

The MEARIE Group
2013 Management Salary Survey
of Local Distribution Companies

Code: 2500

Model Job Title: Director Operations

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	13	14	732	104,600	125,000	132,300	15%	132,000	137,000	120,400	124,600	9%	131,200	138,100
Geography: Region 1	1	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	4	4	732	102,800	122,800	132,600	15%	141,200	144,000	114,800	123,700	20%	147,900	151,200
Geography: Region 4	4	4	732	107,900	125,800	126,600	*	135,700	135,900	126,600	128,500	*	138,300	138,600
Geography: Region 5	3	3		*	*	*	*	*	141,700	*	126,800	*	*	133,400
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	6	7	732	101,200	116,800	126,300	*	120,300	128,000	115,500	118,800	*	116,900	130,500
Revenue: $200 Million +	3	3		*	*	*	*	*	151,000	*	135,000	*	*	155,100
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	3	3		*	*	*	*	*	120,700	*	114,700	*	*	118,800
Customers: 40,000 to 99,999	6	7	732	105,100	122,900	132,600	15%	136,200	134,400	119,400	120,300	12%	133,800	134,800
Customers: 100,000 +	4	4	852	109,000	136,400	150,100	15%	149,500	153,100	141,600	138,300	14%	152,400	157,700
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	3	3		*	*	*	*	*	120,700	*	114,700	*	*	118,800
Employees: 101 to 200	5	6	732	105,600	130,800	132,900	*	150,400	136,900	120,400	122,800	*	147,200	139,100
Employees: More than 200	4	4	852	109,000	136,400	150,100	15%	149,500	153,100	141,600	138,300	14%	152,400	157,700

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 2501

Model Job Title: Manager Operations

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	28	36	516	88,900	104,600	111,900	7%	111,400	111,200	105,200	104,500	5%	110,200	109,400
Geography: Region 1	5	5	516	82,800	102,100	111,500	*	102,100	101,200	93,200	98,000	*	93,200	99,700
Geography: Region 2	3	7		*	*	*	*	*	116,700	*	109,800	*	*	116,600
Geography: Region 3	5	7	571	97,800	117,900	126,400	8%	128,100	133,200	116,700	115,900	10%	124,100	126,400
Geography: Region 4	8	10	516	88,200	99,300	110,300	10%	99,700	106,000	102,000	103,000	8%	104,800	106,800
Geography: Region 5	7	7	516	83,200	101,100	110,400	5%	106,700	107,300	100,700	100,500	5%	102,300	104,000
Revenue: Up to $20 Million	6	6	500	81,600	91,700	100,800	*	96,000	97,300	94,500	94,800	*	96,300	96,800
Revenue: $20 to $50 Million	3	3		*	*	*	*	*	*	*	101,400	*	*	104,500
Revenue: $50 to $100 Million	7	7	516	84,900	104,600	111,900	5%	109,300	109,000	102,000	103,500	5%	106,800	107,300
Revenue: $100 to $200 Million	8	9	583	91,000	111,900	114,600	9%	118,000	113,700	105,700	106,900	7%	115,600	112,900
Revenue: $200 Million +	4	11	732	92,000	115,000	126,400	*	125,400	125,900	115,000	118,500	*	126,700	128,500
Customers: Up to 19,999	7	7	516	81,600	91,700	100,800	*	96,000	97,300	95,100	94,800	*	96,000	96,500
Customers: 20,000 to 39,999	9	9	516	84,900	106,100	111,900	5%	111,400	110,800	105,600	105,100	4%	109,300	109,000
Customers: 40,000 to 99,999	8	9	594	89,600	100,200	111,100	10%	103,200	109,700	105,600	106,100	5%	111,200	110,700
Customers: 100,000 +	4	11	624	92,200	115,200	136,300	10%	125,400	132,000	115,000	117,000	11%	126,700	130,200
Employees: Less than 21	4	4	516	*	*	*	*	*	*	91,700	89,700	*	94,000	92,300
Employees: 21 to 50	8	8	516	82,600	98,500	109,000	5%	100,300	101,800	97,900	99,200	4%	101,000	101,300
Employees: 51 to 100	4	4	583	*	*	*	6%	*	121,100	112,100	112,300	5%	119,900	118,800
Employees: 101 to 200	8	9	594	89,500	103,900	111,500	7%	112,000	111,300	107,000	107,100	4%	112,100	110,800
Employees: More than 200	4	11	624	92,200	115,200	136,300	10%	125,400	132,000	115,000	117,000	11%	126,700	130,200

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 2502

Model Job Title: Manager Control Centre

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	7	7	539	91,000	109,700	116,700	10%	121,400	122,700	109,700	111,700	11%	120,700	123,100
Geography: Region 1	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	3		*	*	*	*	*	122,700	*	109,400	*	*	121,200
Geography: Region 4	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 5	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $200 Million +	4	4	524	93,100	111,500	118,700	13%	123,700	126,400	114,800	112,000	11%	127,200	124,300
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 100,000 +	5	5	539	92,900	113,400	120,600	10%	125,200	126,100	118,000	113,200	11%	130,400	125,500
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: More than 200	5	5	539	92,900	113,400	120,600	10%	125,200	126,100	118,000	113,200	11%	130,400	125,500

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 2503

Model Job Title: Supervisor Control Centre

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	15	16	429	80,900	94,100	101,300	9%	98,400	99,300	94,400	96,300	7%	98,300	99,900
Geography: Region 1	3	3		*	*	*	*	*	95,400	*	95,400	*	*	95,400
Geography: Region 2	2	3		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	3		*	*	*	*	*	109,400	*	103,400	*	*	111,300
Geography: Region 4	4	4	436	81,100	93,200	104,100	*	97,900	98,400	93,800	92,800	*	98,500	97,600
Geography: Region 5	3	3		*	*	*	*	*	98,800	*	94,900	*	*	97,700
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	7	7	466	79,900	93,400	101,300	9%	98,400	97,800	94,100	94,200	9%	100,000	98,600
Revenue: $200 Million +	5	6	429	84,600	96,300	105,800	*	96,300	102,700	96,300	100,700	*	96,300	104,100
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	3	3		*	*	*	*	*	97,600	*	95,000	*	*	97,000
Customers: 40,000 to 99,999	7	7	406	80,900	92,000	99,600	*	94,100	94,900	93,400	93,100	*	96,900	96,100
Customers: 100,000 +	5	6	466	82,800	103,500	113,100	*	111,100	106,600	98,500	101,600	*	108,300	106,900
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	8	8	414	80,400	91,600	96,000	6%	93,600	94,100	94,100	94,100	5%	97,600	96,300
Employees: More than 200	5	6	466	82,800	103,500	113,100	*	111,100	106,600	98,500	101,600	*	108,300	106,900

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 2504

Model Job Title: Supervisor Protection and Control

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	5	5	466	89,600	93,000	105,800	*	98,400	107,700	96,000	100,000	*	96,000	107,300
Geography: Region 1	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	3		*	*	*	*	*	118,800	*	105,000	*	*	117,100
Geography: Region 4	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 5	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $200 Million +	3	3		*	*	*	*	*	117,000	*	108,000	*	*	118,100
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	3	3		*	*	*	*	*	93,500	*	90,700	*	*	92,700
Customers: 100,000 +	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	3	3		*	*	*	*	*	93,500	*	90,700	*	*	92,700
Employees: More than 200	2	2		*	*	*	*	*	*	*	*	*	*	*

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 2505

Model Job Title: Supervisor Station Maintenance

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	11	13	421	79,200	94,100	105,800	10%	99,700	103,500	94,500	98,000	7%	99,100	102,900
Geography: Region 1	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	1	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	4		*	*	*	*	*	124,600	*	113,000	*	*	124,200
Geography: Region 4	3	3		*	*	*	*	*	97,400	*	92,500	*	*	96,900
Geography: Region 5	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	4	4	421	79,300	93,700	105,500	*	97,200	96,600	93,300	92,900	*	96,800	96,200
Revenue: $200 Million +	5	7	479	84,600	105,800	113,400	*	111,100	112,200	105,800	105,200	*	112,400	111,900
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	4	4	414	79,300	91,200	96,500	*	92,900	94,400	91,600	91,100	*	91,600	93,500
Customers: 100,000 +	6	8	473	80,100	100,100	113,100	9%	105,700	110,200	100,100	103,100	8%	106,000	109,800
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	4	4	387	77,200	91,600	94,500	*	92,900	93,700	91,600	90,900	*	91,600	92,700
Employees: More than 200	6	8	473	80,100	100,100	113,100	9%	105,700	110,200	100,100	103,100	8%	106,000	109,800

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 2506

Model Job Title: Line Supervisor

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	36	124	366	77,700	92,700	98,000	5%	93,500	95,800	94,400	93,700	5%	95,900	96,200
Geography: Region 1	6	12	394	79,700	94,100	94,900	*	94,100	95,200	94,300	95,400	*	95,900	96,000
Geography: Region 2	3	17		*	*	*	*	*	96,500	*	93,100	*	*	95,100
Geography: Region 3	6	28	366	85,800	104,300	105,800	7%	111,100	109,500	100,900	99,900	8%	108,400	106,600
Geography: Region 4	12	45	366	78,100	90,200	98,300	5%	90,200	92,900	94,200	92,000	4%	96,300	93,700
Geography: Region 5	9	22	366	75,000	92,100	97,000	8%	92,100	92,300	92,600	91,100	4%	92,600	93,200
Revenue: Up to $20 Million	6	7	421	76,200	90,100	98,400	*	90,100	91,100	93,400	93,500	*	93,900	93,700
Revenue: $20 to $50 Million	5	14	353	77,100	92,400	95,900	*	93,800	94,800	94,600	92,300	*	95,500	94,400
Revenue: $50 to $100 Million	7	11	366	74,600	92,800	100,300	5%	92,800	97,900	93,100	92,600	3%	93,100	94,300
Revenue: $100 to $200 Million	12	43	366	77,900	92,000	97,300	7%	94,100	94,000	94,400	93,100	7%	98,400	96,200
Revenue: $200 Million +	6	49	421	85,100	96,000	101,600	*	102,800	102,300	96,000	97,700	*	102,800	102,500
Customers: Up to 19,999	7	7	421	78,200	92,400	97,600	*	92,400	92,600	94,100	93,900	*	95,100	94,100
Customers: 20,000 to 39,999	11	19	366	74,500	92,800	98,000	5%	92,800	95,900	93,100	92,100	3%	93,100	93,700
Customers: 40,000 to 99,999	12	47	366	78,800	91,500	97,300	7%	91,800	92,900	93,900	92,900	5%	97,100	95,800
Customers: 100,000 +	6	51	421	80,100	96,000	109,300	9%	106,000	104,300	96,000	98,200	8%	106,500	104,200
Employees: Less than 21	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	9	12	366	74,600	86,400	99,100	*	88,900	88,600	91,400	91,300	*	91,400	92,100
Employees: 51 to 100	7	12	366	80,900	95,700	100,600	5%	102,800	99,700	94,300	92,300	5%	100,000	94,900
Employees: 101 to 200	12	47	386	78,300	91,800	96,300	5%	93,100	94,500	94,800	93,800	4%	98,000	96,300
Employees: More than 200	6	51	421	80,100	96,000	109,300	9%	106,000	104,300	96,000	98,200	8%	106,500	104,200

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 2507

Model Job Title: Manager Meter Department

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	14	14	551	90,700	111,100	116,700	9%	121,400	118,600	105,800	106,600	10%	115,400	114,700
Geography: Region 1	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	5	5	551	93,200	116,500	124,700	12%	128,100	129,100	106,400	111,000	11%	122,000	123,100
Geography: Region 4	3	3		*	*	*	*	*	109,800	*	99,200	*	*	106,200
Geography: Region 5	4	4	555	87,300	107,000	107,000	*	112,600	111,000	104,300	104,400	*	108,800	108,000
Revenue: Up to $20 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	6	6	545	91,000	113,800	132,300	9%	121,900	120,300	105,400	105,700	8%	114,000	113,900
Revenue: $200 Million +	5	5	677	92,900	113,400	116,700	15%	126,000	127,300	111,200	111,900	11%	123,400	123,800
Customers: Up to 19,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	3	3		*	*	*	*	*	107,900	*	103,500	*	*	107,200
Customers: 40,000 to 99,999	4	4	561	*	*	*	9%	*	122,300	106,200	107,300	7%	116,200	115,400
Customers: 100,000 +	6	6	614	92,000	113,600	124,700	13%	125,000	126,700	108,400	110,300	11%	122,700	122,000
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	3	3		*	*	*	*	*	103,200	*	99,900	*	*	101,700
Employees: 51 to 100	3	3		*	*	*	*	*	*	*	107,100	*	*	114,000
Employees: 101 to 200	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: More than 200	6	6	614	92,000	113,600	124,700	13%	125,000	126,700	108,400	110,300	11%	122,700	122,000

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 2508

Model Job Title: Supervisor Meter Department

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	15	18	406	78,800	92,600	92,600	5%	95,500	97,000	91,700	93,100	6%	97,100	96,900
Geography: Region 1	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	5		*	*	*	*	*	108,700	*	99,600	*	*	108,500
Geography: Region 4	7	8	406	78,800	88,800	92,000	*	88,800	93,200	91,100	91,000	*	93,400	93,300
Geography: Region 5	3	3		*	*	*	*	*	91,700	*	88,400	*	*	91,400
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	3	3		*	*	*	*	*	101,000	*	92,500	*	*	95,100
Revenue: $100 to $200 Million	4	5	473	76,000	89,300	92,300	*	93,000	93,100	91,900	90,800	*	96,300	94,500
Revenue: $200 Million +	6	8	400	82,100	92,500	98,800	*	99,300	99,700	94,400	96,100	*	100,100	100,500
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	3	3		*	*	*	*	*	101,000	*	92,500	*	*	95,100
Customers: 40,000 to 99,999	6	6	436	77,800	87,400	91,900	*	87,500	90,300	92,200	90,600	*	93,000	93,200
Customers: 100,000 +	6	9	400	77,600	94,300	108,400	9%	102,500	101,700	94,100	96,000	8%	100,800	101,600
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	3	3		*	*	*	*	*	101,000	*	92,500	*	*	95,100
Employees: 101 to 200	6	6	436	77,800	87,400	91,900	*	87,500	90,300	92,200	90,600	*	93,000	93,200
Employees: More than 200	6	9	400	77,600	94,300	108,400	9%	102,500	101,700	94,100	96,000	8%	100,800	101,600

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 3000

Model Job Title: Director Supply Chain Management

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	3	3		*	*	*	*	*	144,300	*	133,600	*	*	156,600
Geography: Region 1	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 4	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 5	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $200 Million +	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 100,000 +	3	3		*	*	*	*	*	144,300	*	133,600	*	*	156,600
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: More than 200	3	3		*	*	*	*	*	144,300	*	133,600	*	*	156,600

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 3001

Model Job Title: Manager Procurement and/or Inventory and/or Facilities and/or Fleet

				COMPENSATION DESIGN						ACTIUAL COMPENSATION				
Market Segment	Sample Statistics		Hay Points	Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	19	21	451	80,200	93,600	105,400	8%	98,300	100,000	93,100	94,400	7%	97,700	99,500
Geography: Region 1	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	3	3		*	*	*	*	*	109,100	*	103,500	*	*	110,200
Geography: Region 3	5	7	551	93,100	107,600	111,200	8%	121,000	116,600	103,800	102,400	9%	118,900	112,200
Geography: Region 4	5	5	421	80,700	93,400	105,300	*	94,800	95,700	92,000	93,500	*	99,500	97,200
Geography: Region 5	5	5	382	70,200	84,600	87,500	*	84,600	88,600	84,600	83,600	*	84,600	85,600
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	4	4	388	75,000	89,200	93,000	*	91,300	88,100	88,800	84,400	*	90,900	86,400
Revenue: $100 to $200 Million	9	9	406	76,500	89,000	98,900	7%	92,100	93,100	91,200	89,200	6%	92,000	93,100
Revenue: $200 Million +	5	7	551	92,900	109,700	116,700	10%	121,400	117,700	109,700	110,600	10%	119,400	120,600
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	5	5	382	70,200	84,600	87,500	*	84,600	86,300	84,600	82,600	*	84,600	84,700
Customers: 40,000 to 99,999	9	9	479	79,400	92,700	105,500	7%	96,500	95,300	92,000	92,900	5%	94,800	95,900
Customers: 100,000 +	5	7	551	92,900	109,700	120,600	10%	121,400	121,300	109,700	108,900	10%	119,400	120,900
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	3	3		*	*	*	*	*	83,000	*	80,900	*	*	81,800
Employees: 51 to 100	3	3		*	*	*	*	*	*	*	96,000	*	*	102,000
Employees: 101 to 200	8	8	436	76,700	89,000	96,200	6%	90,400	92,300	88,600	89,800	4%	91,100	91,900
Employees: More than 200	5	7	551	92,900	109,700	120,600	10%	121,400	121,300	109,700	108,900	10%	119,400	120,900

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 3002

Model Job Title: Supervisor Stores/Inventory/Warehouse

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	11	12	342	67,900	81,400	92,600	6%	83,800	86,300	81,400	83,600	5%	83,800	86,900
Geography: Region 1	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	1	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	3		*	*	*	*	*	92,700	*	86,900	*	*	92,100
Geography: Region 4	3	3		*	*	*	*	*	87,500	*	87,400	*	*	90,300
Geography: Region 5	3	3		*	*	*	*	*	86,100	*	83,200	*	*	86,000
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	3	3		*	*	*	*	*	81,600	*	81,200	*	*	84,000
Revenue: $50 to $100 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	3	3		*	*	*	*	*	91,700	*	82,300	*	*	87,200
Revenue: $200 Million +	5	6	342	67,200	81,400	94,500	*	81,400	86,000	84,000	85,900	*	84,000	88,500
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	5	5	342	67,900	78,300	90,100	5%	83,800	86,300	84,000	85,300	4%	84,000	88,300
Customers: 100,000 +	5	6	353	68,400	84,000	97,100	*	91,300	89,100	81,400	84,900	*	83,800	88,400
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	6	6	309	67,600	77,000	87,000	5%	80,300	84,000	79,800	82,600	4%	81,000	85,600
Employees: More than 200	5	6	353	68,400	84,000	97,100	*	91,300	89,100	81,400	84,900	*	83,800	88,400

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 4000

Model Job Title: Controller or Director Finance

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	17	18	588	90,000	106,800	124,800	13%	113,800	127,200	109,700	115,800	8%	118,100	127,800
Geography: Region 1	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	4	5	690	*	*	*	15%	*	178,400	119,000	131,600	19%	135,900	157,600
Geography: Region 4	6	6	570	84,800	98,900	116,700	*	99,900	106,200	107,100	104,900	*	109,600	111,000
Geography: Region 5	3	3		*	*	*	*	*	122,700	*	115,300	*	*	120,500
Revenue: Up to $20 Million	3	3		*	*	*	*	*	86,600	*	89,900	*	*	91,600
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	7	7	588	91,000	108,600	127,600	10%	117,300	124,000	112,500	113,500	9%	121,800	123,000
Revenue: $200 Million +	3	4		*	*	*	*	*	184,000	*	153,200	*	*	191,000
Customers: Up to 19,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	4	4	531	78,200	98,500	109,900	*	103,400	103,900	105,200	104,100	*	110,000	107,800
Customers: 40,000 to 99,999	7	7	588	91,000	108,600	127,600	10%	117,300	125,200	112,500	113,900	8%	121,800	121,700
Customers: 100,000 +	4	5	909	110,000	137,100	164,300	18%	161,800	177,200	143,100	148,600	22%	172,700	182,300
Employees: Less than 21	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	3	3		*	*	*	*	*	101,500	*	103,000	*	*	104,800
Employees: 51 to 100	4	4	551	*	*	*	8%	*	110,000	111,500	111,200	6%	118,300	118,600
Employees: 101 to 200	5	5	588	91,700	108,400	108,400	*	116,000	126,500	105,100	112,000	*	112,900	118,900
Employees: More than 200	4	5	909	110,000	137,100	164,300	18%	161,800	177,200	143,100	148,600	22%	172,700	182,300

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 4001

Model Job Title: Manager Accounting

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	23	24	479	79,200	97,300	111,900	8%	103,200	105,400	98,300	99,000	6%	102,800	102,900
Geography: Region 1	3	3		*	*	*	*	*	98,400	*	100,600	*	*	100,600
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	5	5	479	97,200	115,700	115,700	8%	129,000	124,000	107,900	107,600	7%	124,400	117,000
Geography: Region 4	7	7	479	79,200	94,000	105,300	*	94,800	100,300	90,700	94,700	*	90,700	96,900
Geography: Region 5	6	7	479	77,900	97,300	97,300	8%	105,100	103,200	96,800	95,300	6%	102,300	100,000
Revenue: Up to $20 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	3	4		*	*	*	*	*	*	*	102,500	*	*	107,500
Revenue: $50 to $100 Million	5	5	479	88,900	104,600	118,700	5%	109,300	108,600	98,900	100,000	4%	106,400	103,300
Revenue: $100 to $200 Million	8	8	443	75,200	89,000	97,300	8%	89,000	93,000	91,500	92,100	*	92,900	94,200
Revenue: $200 Million +	6	6	515	88,800	105,600	114,100	12%	113,900	117,000	105,400	106,800	9%	113,700	114,200
Customers: Up to 19,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	6	6	479	84,000	101,800	115,300	5%	108,100	104,800	98,600	97,600	4%	103,200	100,400
Customers: 40,000 to 99,999	9	10	551	81,700	96,000	102,100	8%	99,000	97,900	97,300	95,200	5%	102,800	98,700
Customers: 100,000 +	6	6	479	85,200	105,600	114,100	10%	114,500	118,300	105,400	108,400	9%	113,700	115,800
Employees: Less than 21	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	4	4	436	78,100	94,800	107,200	*	98,800	99,900	94,800	98,600	*	99,100	101,600
Employees: 51 to 100	4	4	436	*	*	*	*	*	99,300	92,700	92,600	*	94,700	95,400
Employees: 101 to 200	8	9	570	85,500	98,800	107,700	9%	104,100	100,700	97,800	96,100	5%	101,400	99,100
Employees: More than 200	6	6	479	85,200	105,600	114,100	10%	114,500	118,300	105,400	108,400	9%	113,700	115,800

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 4002

Model Job Title: Manager Risk Management

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	4	4	655	103,300	125,000	129,700	*	139,700	137,500	115,400	118,100	*	126,100	129,800
Geography: Region 1	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 4	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 5	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $200 Million +	3	3		*	*	*	*	*	132,200	*	117,500	*	*	129,700
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 100,000 +	3	3		*	*	*	*	*	132,200	*	117,500	*	*	129,700
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: More than 200	3	3		*	*	*	*	*	132,200	*	117,500	*	*	129,700

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 4003

Model Job Title: Supervisor Accounting

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	13	16	353	70,000	85,300	93,200	5%	87,800	87,700	85,100	84,200	5%	89,600	87,200
Geography: Region 1	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	2	3		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 4	6	7	353	70,000	82,500	89,700	*	82,700	80,700	82,500	81,000	*	85,200	82,500
Geography: Region 5	3	4		*	*	*	*	*	*	*	77,900	*	*	79,800
Revenue: Up to $20 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	4	4	363	*	*	*	*	*	90,600	84,800	84,800	*	87,300	86,900
Revenue: $50 to $100 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	2	3		*	*	*	*	*	*	*	*	*	*	*
Revenue: $200 Million +	4	6	368	76,300	91,300	96,000	*	100,300	97,900	88,400	91,100	*	97,200	97,400
Customers: Up to 19,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	3	3		*	*	*	*	*	77,300	*	76,100	*	*	77,300
Customers: 40,000 to 99,999	3	4		*	*	*	*	*	86,100	*	87,500	*	*	89,100
Customers: 100,000 +	5	7	353	68,400	85,500	97,500	6%	90,800	96,500	85,500	90,000	7%	90,800	96,100
Employees: Less than 21	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	4	5	383	75,400	89,300	93,500	*	90,700	89,500	93,500	89,400	*	95,300	91,500
Employees: More than 200	5	7	353	68,400	85,500	97,500	6%	90,800	96,500	85,500	90,000	7%	90,800	96,100

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 4004

Model Job Title: Financial or Business Analyst

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	18	25	342	67,900	79,500	86,700	5%	83,800	85,900	80,900	78,900	4%	83,600	82,600
Geography: Region 1	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	5	10	372	77,600	86,000	93,600	7%	96,800	94,900	85,000	82,100	7%	90,400	88,400
Geography: Region 4	7	7	333	68,400	78,000	86,700	5%	80,000	84,400	78,000	76,500	4%	80,000	79,500
Geography: Region 5	3	5		*	*	*	*	*	78,500	*	79,100	*	*	81,100
Revenue: Up to $20 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	3	4		*	*	*	*	*	78,700	*	75,600	*	*	78,400
Revenue: $50 to $100 Million	3	3		*	*	*	*	*	97,100	*	86,300	*	*	89,200
Revenue: $100 to $200 Million	7	8	342	64,500	78,200	85,800	5%	79,900	80,200	80,600	76,900	5%	82,900	79,700
Revenue: $200 Million +	3	8		*	*	*	*	*	98,500	*	87,600	*	*	96,100
Customers: Up to 19,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	6	6	348	65,600	81,300	81,300	5%	84,600	85,800	77,600	79,700	3%	80,300	81,900
Customers: 40,000 to 99,999	6	8	337	67,900	78,000	86,700	4%	78,000	80,400	79,300	77,400	5%	81,200	79,900
Customers: 100,000 +	4	9	353	77,600	86,800	97,100	9%	96,800	96,700	86,000	86,000	9%	93,700	94,500
Employees: Less than 21	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	4	4	358	*	*	*	*	*	88,300	79,500	79,900	*	83,500	82,700
Employees: 101 to 200	7	8	342	67,900	78,300	86,700	3%	81,800	82,200	78,000	77,500	3%	78,000	79,500
Employees: More than 200	4	9	353	77,600	86,800	97,100	9%	96,800	96,700	86,000	86,000	9%	93,700	94,500

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 4005

Model Job Title: Accountant

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	13	25	332	63,000	77,100	84,000	5%	78,800	78,800	72,900	72,700	5%	75,600	74,600
Geography: Region 1	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	3	8		*	*	*	*	*	80,300	*	76,000	*	*	77,600
Geography: Region 3	2	4		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 4	5	7	332	67,200	75,600	89,600	*	75,600	78,900	75,600	72,200	*	75,600	74,200
Geography: Region 5	3	6		*	*	*	*	*	73,200	*	72,800	*	*	73,400
Revenue: Up to $20 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	5	8	282	59,300	73,000	79,600	*	76,600	75,700	66,300	69,500	*	66,300	71,200
Revenue: $100 to $200 Million	3	6		*	*	*	*	*	84,500	*	75,900	*	*	80,300
Revenue: $200 Million +	3	9		*	*	*	*	*	76,100	*	75,200	*	*	75,200
Customers: Up to 19,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	7	11	332	59,300	73,000	79,600	5%	76,600	75,500	66,300	69,300	5%	66,300	71,200
Customers: 40,000 to 99,999	3	5		*	*	*	*	*	83,200	*	74,100	*	*	77,800
Customers: 100,000 +	2	8		*	*	*	*	*	*	*	*	*	*	*
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	5	8	282	59,300	73,000	81,500	5%	76,600	77,500	63,100	66,700	5%	66,300	70,100
Employees: 101 to 200	4	7	332	65,800	77,700	86,700	*	81,600	81,100	78,400	76,900	*	79,300	78,800
Employees: More than 200	2	8		*	*	*	*	*	*	*	*	*	*	*

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 5000

Model Job Title: Director Customer Service

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	7	7	702	108,400	135,400	149,000	15%	155,600	145,300	128,500	125,900	14%	148,300	142,000
Geography: Region 1	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 4	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 5	3	3		*	*	*	*	*	123,700	*	113,700	*	*	118,800
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $200 Million +	4	4	754	108,600	135,800	153,300	18%	159,400	151,600	135,200	130,700	17%	161,500	151,100
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 100,000 +	5	5	805	108,900	136,100	157,600	15%	155,800	152,400	135,000	130,300	15%	161,300	150,500
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: More than 200	5	5	805	108,900	136,100	157,600	15%	155,800	152,400	135,000	130,300	15%	161,300	150,500

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 5001

Model Job Title: Manager Customer Service and/or Billing

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	27	30	479	79,400	91,100	102,200	10%	97,800	98,400	90,700	91,900	6%	95,000	96,000
Geography: Region 1	6	6	436	81,000	91,100	101,300	*	91,100	90,100	82,600	84,800	*	82,600	86,100
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	6	8	515	92,900	105,500	118,800	10%	121,400	120,600	105,100	108,900	9%	114,600	118,000
Geography: Region 4	10	11	412	71,400	87,100	92,700	10%	87,100	88,100	88,000	84,400	6%	90,400	86,800
Geography: Region 5	3	3		*	*	*	*	*	100,100	*	93,700	*	*	96,800
Revenue: Up to $20 Million	6	6	405	61,500	72,500	82,700	*	74,400	76,100	73,400	76,400	*	73,400	77,600
Revenue: $20 to $50 Million	4	4	534	*	*	*	*	*	114,300	95,100	92,600	*	99,400	95,900
Revenue: $50 to $100 Million	4	4	436	80,500	94,200	97,600	*	98,100	96,600	89,000	90,500	*	91,500	92,600
Revenue: $100 to $200 Million	8	9	481	79,400	91,100	102,200	9%	97,800	96,500	93,300	93,000	8%	98,600	97,100
Revenue: $200 Million +	5	7	571	92,900	113,400	129,100	13%	123,100	119,900	99,200	109,300	10%	112,700	119,000
Customers: Up to 19,999	6	6	393	63,000	70,000	77,000	*	70,000	75,600	70,900	72,600	*	70,900	73,100
Customers: 20,000 to 39,999	7	7	466	77,500	90,000	100,800	5%	95,000	95,300	90,000	93,000	4%	95,000	95,400
Customers: 40,000 to 99,999	9	9	496	80,200	92,300	104,900	10%	98,000	98,100	93,100	93,600	5%	96,700	97,100
Customers: 100,000 +	5	8	571	92,900	113,400	129,100	10%	123,100	126,200	99,200	110,400	11%	112,700	122,200
Employees: Less than 21	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	7	7	393	73,900	89,500	91,800	*	89,500	89,300	87,500	82,600	*	87,500	83,100
Employees: 51 to 100	5	5	406	72,100	87,400	95,400	6%	90,500	89,400	90,000	93,500	5%	95,000	97,700
Employees: 101 to 200	8	8	496	82,000	99,200	106,800	9%	107,500	101,000	94,700	94,600	4%	100,200	97,600
Employees: More than 200	5	8	571	92,900	113,400	129,100	10%	123,100	126,200	99,200	110,400	11%	112,700	122,200

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 5002

Model Job Title: Supervisor Customer Service and/or Billing and/or Collections

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	27	45	353	67,800	82,000	86,000	5%	83,700	84,300	78,800	79,900	4%	78,800	82,800
Geography: Region 1	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	3		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	5	9	393	78,600	94,500	101,400	7%	103,000	106,300	90,500	90,600	7%	103,700	97,800
Geography: Region 4	11	20	342	67,200	78,000	84,000	6%	78,000	78,400	74,700	74,300	4%	76,200	76,300
Geography: Region 5	7	11	353	70,600	81,400	83,700	5%	81,400	83,900	83,700	82,600	3%	85,500	84,700
Revenue: Up to $20 Million	3	3		*	*	*	*	*	65,400	*	67,000	*	*	68,400
Revenue: $20 to $50 Million	4	8	353	71,800	84,000	84,500	*	86,500	84,600	81,800	81,100	*	82,800	83,100
Revenue: $50 to $100 Million	4	5	287	61,800	77,900	80,000	*	78,900	77,200	73,500	71,800	*	75,600	72,900
Revenue: $100 to $200 Million	10	16	353	70,600	85,500	92,600	7%	87,300	87,400	78,800	80,500	6%	80,100	83,800
Revenue: $200 Million +	6	13	348	72,400	85,900	92,500	*	91,600	93,700	87,300	90,000	*	93,900	94,900
Customers: Up to 19,999	3	3		*	*	*	*	*	71,500	*	73,100	*	*	74,600
Customers: 20,000 to 39,999	7	8	291	61,000	76,200	77,500	5%	78,200	76,100	72,800	72,300	3%	75,200	73,700
Customers: 40,000 to 99,999	11	20	353	72,600	84,000	92,300	5%	86,500	86,800	83,700	82,400	3%	84,000	85,100
Customers: 100,000 +	6	14	353	73,000	88,000	95,800	9%	96,400	96,300	84,600	87,700	8%	91,200	93,400
Employees: Less than 21	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	5	5	291	63,600	76,000	80,000	*	76,000	73,900	80,000	77,800	*	80,000	78,700
Employees: 51 to 100	4	5	317	*	*	*	*	*	83,000	76,200	73,900	*	78,700	77,200
Employees: 101 to 200	11	20	353	69,400	83,700	85,200	5%	86,000	84,300	78,000	80,200	4%	78,100	82,400
Employees: More than 200	6	14	353	73,000	88,000	95,800	9%	96,400	96,300	84,600	87,700	8%	91,200	93,400

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 5500

Model Job Title: Director Communications

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	7	7	677	108,400	135,100	149,000	15%	150,800	147,700	131,200	126,400	13%	141,700	142,800
Geography: Region 1	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 4	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 5	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $200 Million +	4	4	830	108,600	135,800	153,300	18%	159,300	157,300	138,600	134,300	12%	155,000	150,600
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 100,000 +	5	5	830	108,400	135,400	150,200	15%	155,800	154,400	134,000	130,900	13%	141,700	146,800
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: More than 200	5	5	830	108,400	135,400	150,200	15%	155,800	154,400	134,000	130,900	13%	141,700	146,800

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 5501

Model Job Title: Manager Communications

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	11	11	393	75,200	90,600	99,600	9%	99,300	98,700	90,600	91,800	9%	95,600	98,000
Geography: Region 1	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 4	3	3		*	*	*	*	*	94,700	*	90,200	*	*	97,600
Geography: Region 5	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: Up to $20 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	4	4	393	73,000	91,000	100,300	*	99,100	93,600	87,600	87,000	*	95,600	93,200
Revenue: $200 Million +	3	3		*	*	*	*	*	114,500	*	104,100	*	*	114,500
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	3	3		*	*	*	*	*	89,400	*	86,300	*	*	90,200
Customers: 40,000 to 99,999	4	4	393	75,100	89,500	94,000	*	97,400	92,800	89,500	88,000	*	93,300	92,100
Customers: 100,000 +	4	4	436	83,100	103,700	114,800	10%	113,000	111,600	98,300	99,800	10%	108,000	109,700
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	3	3		*	*	*	*	*	90,400	*	85,100	*	*	90,700
Employees: 101 to 200	4	4	393	71,300	89,500	91,700	*	97,400	92,000	89,500	88,900	*	93,300	91,700
Employees: More than 200	4	4	436	83,100	103,700	114,800	10%	113,000	111,600	98,300	99,800	10%	108,000	109,700

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 6000

Model Job Title: Director Regulatory Affairs

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	9	9	702	104,600	127,900	150,400	15%	147,100	148,500	137,800	131,500	16%	147,800	148,500
Geography: Region 1	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 4	5	5	654	102,300	125,200	150,200	15%	144,700	143,700	137,800	131,200	14%	147,800	144,700
Geography: Region 5	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	4	4	690	101,200	126,500	150,300	*	145,900	140,200	125,300	125,300	*	144,500	140,300
Revenue: $200 Million +	3	3		*	*	*	*	*	155,800	*	138,500	*	*	160,300
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	3	3		*	*	*	*	*	146,500	*	124,700	*	*	145,200
Customers: 100,000 +	4	4	830	104,600	130,700	153,900	18%	154,700	153,000	140,600	138,300	16%	165,600	160,100
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	3	3		*	*	*	*	*	144,000	*	131,500	*	*	139,100
Employees: 101 to 200	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: More than 200	4	4	830	104,600	130,700	153,900	18%	154,700	153,000	140,600	138,300	16%	165,600	160,100

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 6001

Model Job Title: Manager Regulatory Affairs

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	22	24	459	77,300	91,900	96,600	8%	94,600	94,500	91,500	92,000	7%	95,800	95,300
Geography: Region 1	3	3		*	*	*	*	*	78,100	*	76,200	*	*	76,200
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	4	4	479	86,800	102,200	113,900	10%	111,900	112,800	102,300	102,400	9%	110,800	111,700
Geography: Region 4	9	11	438	77,100	90,700	95,200	8%	90,700	91,600	90,500	90,200	*	90,500	92,200
Geography: Region 5	4	4	443	77,200	94,600	94,600	*	96,900	93,900	94,600	91,400	*	96,300	94,900
Revenue: Up to $20 Million	6	6	373	67,000	79,100	89,000	*	80,300	81,200	83,700	83,200	*	83,700	83,700
Revenue: $20 to $50 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	3	3		*	*	*	*	*	91,700	*	88,600	*	*	89,700
Revenue: $100 to $200 Million	8	10	459	80,300	94,800	97,600	9%	101,000	98,500	97,600	93,800	7%	101,400	98,400
Revenue: $200 Million +	5	5	479	84,200	94,800	111,100	*	101,300	105,500	101,000	101,700	*	109,700	107,500
Customers: Up to 19,999	4	4	373	71,200	83,700	87,700	*	84,900	84,300	83,700	83,800	*	83,700	83,800
Customers: 20,000 to 39,999	6	6	412	71,800	86,200	95,600	*	88,500	87,000	91,400	87,000	*	93,100	88,600
Customers: 40,000 to 99,999	7	7	479	82,700	94,800	97,900	9%	94,800	96,100	97,300	92,800	7%	97,900	96,500
Customers: 100,000 +	5	7	479	82,800	101,000	113,400	10%	111,100	109,200	101,000	103,500	9%	109,700	110,700
Employees: Less than 21	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	7	7	393	70,600	80,200	95,000	*	81,400	84,800	88,300	85,600	*	88,300	86,000
Employees: 51 to 100	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	7	7	551	79,800	93,800	97,900	7%	96,900	96,600	94,800	93,200	6%	97,900	96,500
Employees: More than 200	5	7	479	82,800	101,000	113,400	10%	111,100	109,200	101,000	103,500	9%	109,700	110,700

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 6002

Model Job Title: Regulatory Accountant

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	14	17	337	67,900	79,600	94,300	7%	83,800	86,100	81,200	81,700	7%	82,700	84,900
Geography: Region 1	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	5	7	393	82,100	97,000	101,400	7%	104,100	103,400	88,400	88,300	7%	94,200	95,600
Geography: Region 4	3	3		*	*	*	*	*	79,700	*	76,300	*	*	78,800
Geography: Region 5	3	4		*	*	*	*	*	76,700	*	78,000	*	*	78,500
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	6	7	368	69,700	82,000	92,000	*	85,900	83,500	81,200	79,400	*	83,600	82,000
Revenue: $200 Million +	6	8	337	71,300	83,600	95,900	*	88,000	90,900	81,100	84,600	*	84,000	89,200
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	8	9	328	67,900	78,300	90,100	7%	83,800	79,600	78,100	77,300	6%	78,800	79,500
Customers: 100,000 +	5	7	342	79,500	88,400	97,200	*	97,200	96,500	88,400	88,100	*	94,200	93,700
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	6	7	305	65,300	76,900	82,800	*	80,300	77,900	72,800	75,800	*	73,500	76,700
Employees: More than 200	5	7	342	79,500	88,400	97,200	*	97,200	96,500	88,400	88,100	*	94,200	93,700

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 7000

Model Job Title: Settlement or Rate Analyst

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	15	17	342	70,700	85,900	92,300	5%	88,500	88,500	85,900	83,500	5%	85,900	86,200
Geography: Region 1	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	4	6	346	77,600	89,200	93,600	8%	96,100	95,700	89,200	87,800	8%	95,500	94,500
Geography: Region 4	5	5	342	66,300	82,000	85,900	*	82,000	82,800	78,700	79,700	*	78,700	80,600
Geography: Region 5	3	3		*	*	*	*	*	81,700	*	81,100	*	*	81,500
Revenue: Up to $20 Million	3	3		*	*	*	*	*	80,300	*	78,400	*	*	78,700
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	3	3		*	*	*	*	*	99,700	*	87,900	*	*	92,100
Revenue: $100 to $200 Million	3	3		*	*	*	*	*	81,500	*	81,200	*	*	81,200
Revenue: $200 Million +	4	6	315	74,300	84,500	95,800	*	92,900	91,600	83,600	85,000	*	89,500	90,500
Customers: Up to 19,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	6	6	400	72,900	91,200	93,600	5%	96,000	94,400	86,800	87,200	5%	90,600	90,000
Customers: 40,000 to 99,999	3	3		*	*	*	*	*	78,400	*	77,800	*	*	78,200
Customers: 100,000 +	4	6	315	74,300	84,500	95,800	*	92,900	91,600	83,600	85,000	*	89,500	90,500
Employees: Less than 21	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	4	4	374	74,400	91,200	91,200	*	96,000	96,200	86,800	87,400	*	90,600	90,500
Employees: 101 to 200	4	4	327	69,300	82,000	83,200	*	82,600	83,800	81,600	82,100	*	82,300	83,400
Employees: More than 200	4	6	315	74,300	84,500	95,800	*	92,900	91,600	83,600	85,000	*	89,500	90,500

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 7001

Model Job Title: Director or Officer, Conservation and Demand Management

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	10	10	739	102,600	121,100	129,800	15%	136,300	139,900	118,200	120,600	17%	135,500	138,700
Geography: Region 1	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 4	3	3		*	*	*	*	*	131,900	*	119,900	*	*	139,800
Geography: Region 5	3	3		*	*	*	*	*	129,600	*	115,500	*	*	125,200
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	3	3		*	*	*	*	*	125,000	*	112,300	*	*	125,200
Revenue: $200 Million +	3	3		*	*	*	*	*	174,800	*	139,800	*	*	169,300
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	4	4	766	98,300	114,700	120,600	*	134,500	130,700	114,700	117,400	*	127,800	134,400
Customers: 100,000 +	4	4	775	110,500	138,200	158,200	18%	161,700	166,600	131,700	134,700	19%	164,800	161,300
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	4	4	766	98,300	114,700	120,600	*	134,500	130,700	114,700	117,400	*	127,800	134,400
Employees: More than 200	4	4	775	110,500	138,200	158,200	18%	161,700	166,600	131,700	134,700	19%	164,800	161,300

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 7002

Model Job Title: Manager Conservation & Demand/Marketing

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	21	23	393	72,100	85,500	88,300	9%	88,900	92,400	85,200	85,900	8%	88,800	90,500
Geography: Region 1	5	5	342	65,700	81,200	81,200	*	83,400	83,200	77,300	76,800	*	77,300	77,500
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	3		*	*	*	*	*	123,600	*	110,300	*	*	124,100
Geography: Region 4	6	8	400	66,600	77,700	89,600	*	77,700	79,300	79,300	80,000	*	81,200	82,100
Geography: Region 5	5	5	342	65,400	81,800	84,900	7%	88,300	87,600	81,800	81,000	5%	88,100	85,000
Revenue: Up to $20 Million	4	4	368	59,200	69,600	78,900	*	71,200	69,400	69,300	68,700	*	69,300	69,700
Revenue: $20 to $50 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	7	9	342	66,500	81,800	84,900	7%	82,300	85,000	81,800	82,700	5%	82,300	85,300
Revenue: $200 Million +	6	6	524	84,200	99,200	108,900	10%	110,200	113,800	101,000	104,800	12%	109,300	115,800
Customers: Up to 19,999	3	3		*	*	*	*	*	*	*	60,000	*	*	60,000
Customers: 20,000 to 39,999	6	6	393	62,400	79,200	86,500	5%	82,400	85,200	80,800	81,600	5%	84,400	83,700
Customers: 40,000 to 99,999	6	6	374	69,800	82,100	88,200	*	84,900	84,000	82,100	83,900	*	85,200	85,200
Customers: 100,000 +	6	8	492	83,100	101,900	116,800	10%	112,000	116,400	102,400	105,200	11%	111,400	117,800
Employees: Less than 21	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	4	4	363	*	*	*	*	*	82,500	70,900	72,400	*	71,900	72,900
Employees: 51 to 100	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	7	7	393	66,500	82,300	85,200	*	87,500	84,500	82,300	84,800	*	88,100	86,300
Employees: More than 200	6	8	492	83,100	101,900	116,800	10%	112,000	116,400	102,400	105,200	11%	111,400	117,800

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 8000

Model Job Title: Director Information Systems

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	20	20	739	103,400	127,100	127,300	15%	138,300	137,300	125,200	124,300	14%	131,100	136,100
Geography: Region 1	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	5	5	677	104,600	130,800	150,400	15%	150,400	148,900	125,000	130,300	15%	133,100	149,600
Geography: Region 4	7	7	702	102,300	126,200	126,200	15%	130,700	125,800	125,500	121,600	15%	130,700	131,500
Geography: Region 5	4	4	803	100,300	122,700	122,700	15%	138,300	139,300	120,200	120,400	*	120,200	122,800
Revenue: Up to $20 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	3	3		*	*	*	*	*	141,600	*	119,400	*	*	128,700
Revenue: $50 to $100 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	8	8	690	103,400	128,200	129,600	15%	138,300	134,500	125,200	122,800	11%	131,900	130,200
Revenue: $200 Million +	6	6	892	107,000	130,100	141,500	20%	151,900	154,400	134,300	140,300	20%	148,600	161,200
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	6	6	607	92,900	118,400	118,400	7%	123,400	117,800	118,400	111,900	6%	121,900	117,900
Customers: 40,000 to 99,999	8	8	766	101,300	119,500	125,800	15%	140,300	133,300	124,300	118,800	*	124,400	124,800
Customers: 100,000 +	6	6	847	111,600	140,500	161,400	18%	165,500	162,100	145,800	144,100	17%	169,300	169,100
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	4	4	578	86,200	104,700	115,700	*	108,600	110,800	106,900	106,500	*	111,600	113,100
Employees: 101 to 200	10	10	754	102,500	119,500	125,800	15%	138,300	133,000	124,300	119,500	7%	124,400	125,400
Employees: More than 200	6	6	847	111,600	140,500	161,400	18%	165,500	162,100	145,800	144,100	17%	169,300	169,100

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 8001

Model Job Title: Manager Information Systems and/or Security

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	16	23	525	81,700	97,700	100,700	10%	104,000	105,900	97,600	99,500	8%	101,400	105,900
Geography: Region 1	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	3	3		*	*	*	*	*	108,100	*	99,500	*	*	106,300
Geography: Region 3	3	3		*	*	*	*	*	131,000	*	119,200	*	*	134,700
Geography: Region 4	4	9	498	83,900	97,500	102,200	*	99,000	95,500	100,300	92,600	*	102,200	95,300
Geography: Region 5	5	7	534	77,900	97,300	97,300	9%	105,100	100,700	96,900	92,800	6%	101,500	97,600
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	4	4	443	78,200	94,900	97,500	*	97,000	91,900	93,600	86,900	*	96,800	88,800
Revenue: $100 to $200 Million	7	12	496	81,000	92,000	101,300	8%	98,400	97,600	97,900	96,300	7%	101,300	100,300
Revenue: $200 Million +	4	6	677	99,500	117,000	134,400	13%	131,600	132,000	115,900	117,300	12%	129,500	132,800
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	5	5	479	78,900	96,900	98,000	*	97,000	94,800	93,800	90,800	*	96,900	92,300
Customers: 40,000 to 99,999	6	7	515	79,400	91,800	99,600	8%	95,000	96,400	97,600	94,300	6%	99,900	97,900
Customers: 100,000 +	5	11	677	90,700	113,400	132,700	10%	124,500	128,300	111,300	114,400	12%	124,100	129,000
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	3	3		*	*	*	*	*	93,300	*	87,800	*	*	89,300
Employees: 101 to 200	6	7	543	80,000	92,400	100,300	8%	97,700	99,700	97,600	97,100	6%	99,900	100,700
Employees: More than 200	5	11	677	90,700	113,400	132,700	10%	124,500	128,300	111,300	114,400	12%	124,100	129,000

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 8002

Model Job Title: Systems/Program Administrator or Applications/Systems Support Professional

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	22	35	332	67,300	78,900	85,500	5%	79,800	81,600	80,900	78,200	5%	83,700	80,800
Geography: Region 1	3	3		*	*	*	*	*	*	*	72,800	*	*	74,100
Geography: Region 2	2	7		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	5	10	323	73,400	82,500	86,500	6%	90,700	85,500	79,200	77,600	6%	86,400	83,200
Geography: Region 4	9	12	332	67,400	75,600	84,000	4%	75,600	78,600	84,000	80,100	4%	88,300	81,800
Geography: Region 5	3	3		*	*	*	*	*	81,100	*	79,700	*	*	81,900
Revenue: Up to $20 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	4	4	373	*	*	*	*	*	93,000	87,900	82,700	*	91,200	85,400
Revenue: $50 to $100 Million	3	8		*	*	*	*	*	81,900	*	70,500	*	*	72,600
Revenue: $100 to $200 Million	9	12	323	63,800	71,600	77,100	5%	71,600	73,800	74,000	74,200	5%	77,700	76,000
Revenue: $200 Million +	5	10	323	71,300	79,200	87,200	*	87,200	87,600	84,000	84,700	*	86,400	88,900
Customers: Up to 19,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	6	11	337	61,400	81,100	81,100	5%	84,400	80,600	77,000	74,500	4%	79,900	76,600
Customers: 40,000 to 99,999	9	9	323	67,300	73,700	78,800	4%	73,700	76,900	78,400	78,900	4%	78,400	80,600
Customers: 100,000 +	5	13	332	71,300	85,500	94,500	9%	91,500	90,700	82,100	84,300	8%	88,300	89,800
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	3	3		*	*	*	*	*	*	*	69,800	*	*	70,800
Employees: 51 to 100	5	10	282	57,100	79,200	79,200	*	81,400	78,800	72,800	70,900	*	76,400	73,000
Employees: 101 to 200	9	9	342	67,200	77,000	79,200	4%	78,400	79,300	84,000	81,600	4%	84,000	83,500
Employees: More than 200	5	13	332	71,300	85,500	94,500	9%	91,500	90,700	82,100	84,300	8%	88,300	89,800

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 9000

Model Job Title: Human Resources Manager

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	11	11	479	87,600	103,100	110,600	9%	114,700	110,400	100,700	100,200	5%	105,000	106,800
Geography: Region 1	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	3	3		*	*	*	*	*	*	*	105,700	*	*	111,500
Geography: Region 4	3	3		*	*	*	*	*	92,800	*	91,500	*	*	94,900
Geography: Region 5	3	3		*	*	*	*	*	103,600	*	95,400	*	*	98,700
Revenue: Up to $20 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $200 Million +	5	5	551	93,300	111,100	116,700	9%	120,600	121,000	111,100	107,600	*	116,600	117,200
Customers: Up to 19,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	2	2		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	4	4	515	*	*	*	*	*	103,500	97,800	96,800	*	102,400	101,700
Customers: 100,000 +	4	4	614	96,000	113,900	118,700	9%	123,300	131,000	113,900	114,200	*	122,900	126,300
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	3	3		*	*	*	*	*	*	*	102,300	*	*	108,900
Employees: 101 to 200	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: More than 200	4	4	614	96,000	113,900	118,700	9%	123,300	131,000	113,900	114,200	*	122,900	126,300

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 9001

Model Job Title: Human Resources Generalist

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	17	22	323	65,100	77,700	81,900	5%	78,800	83,200	81,400	78,700	4%	81,400	81,600
Geography: Region 1	2	2		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	3	3		*	*	*	*	*	77,800	*	75,200	*	*	76,700
Geography: Region 3	4	4	377	78,500	90,200	101,500	9%	99,900	102,000	88,300	92,500	8%	99,000	101,400
Geography: Region 4	5	7	307	62,200	76,600	81,900	*	76,600	77,600	74,200	73,900	*	77,300	75,300
Geography: Region 5	3	6		*	*	*	*	*	80,500	*	78,500	*	*	79,300
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	2	5		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	3	3		*	*	*	*	*	73,600	*	66,100	*	*	67,600
Revenue: $100 to $200 Million	7	9	323	66,500	77,300	81,900	6%	77,300	80,800	77,300	77,300	4%	77,300	79,000
Revenue: $200 Million +	5	5	342	77,500	88,100	94,500	*	97,200	93,900	88,100	90,200	*	96,100	96,100
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	5	7	289	59,800	73,000	77,500	*	76,600	75,600	71,700	70,700	*	72,900	71,900
Customers: 40,000 to 99,999	6	9	333	69,200	76,900	80,800	4%	76,900	80,500	79,600	76,500	3%	79,600	78,400
Customers: 100,000 +	6	6	342	71,300	84,700	93,900	9%	90,100	92,100	87,800	87,600	8%	91,800	93,000
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	3	4		*	*	*	*	*	77,700	*	70,100	*	*	71,800
Employees: 101 to 200	7	11	323	66,500	76,600	77,500	3%	77,300	80,300	77,300	77,500	2%	77,700	79,200
Employees: More than 200	6	6	342	71,300	84,700	93,900	9%	90,100	92,100	87,800	87,600	8%	91,800	93,000

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 9002

Model Job Title: Human Resources Coordinator

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	11	15	233	57,100	67,100	77,200	5%	69,800	73,500	65,200	65,400	7%	66,200	68,100
Geography: Region 1	1	1		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	4	8	254	63,600	78,900	80,000	9%	83,600	83,400	70,300	69,800	8%	75,800	74,500
Geography: Region 4	3	3		*	*	*	*	*	70,900	*	62,800	*	*	66,000
Geography: Region 5	3	3		*	*	*	*	*	66,600	*	63,000	*	*	63,600
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	6	9	245	55,400	64,800	73,600	6%	66,200	71,500	63,900	64,100	4%	64,400	66,100
Revenue: $200 Million +	4	5	239	63,600	75,000	78,600	8%	80,600	79,100	70,300	68,500	*	75,800	72,900
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 40,000 to 99,999	5	8	282	57,100	67,100	77,200	6%	69,800	73,900	65,200	67,000	*	66,200	68,800
Customers: 100,000 +	5	6	233	63,500	70,700	77,700	5%	77,700	75,500	70,000	66,400	8%	74,800	70,600
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	3	6		*	*	*	*	*	69,900	*	62,900	*	*	63,200
Employees: More than 200	5	6	233	63,500	70,700	77,700	5%	77,700	75,500	70,000	66,400	8%	74,800	70,600

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 9003

Model Job Title: Payroll

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	17	18	245	56,800	67,900	73,800	5%	69,300	71,900	67,100	71,000	3%	69,500	72,900
Geography: Region 1	0	0		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 2	2	3		*	*	*	*	*	*	*	*	*	*	*
Geography: Region 3	4	4	273	*	*	*	8%	*	87,200	78,100	81,500	8%	83,000	87,200
Geography: Region 4	6	6	242	55,500	67,900	75,600	*	68,400	67,600	65,300	67,700	*	66,900	68,500
Geography: Region 5	5	5	275	57,100	70,200	71,700	*	70,200	71,200	70,200	69,800	*	70,200	70,500
Revenue: Up to $20 Million	2	2		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $50 to $100 Million	1	1		*	*	*	*	*	*	*	*	*	*	*
Revenue: $100 to $200 Million	7	7	238	55,100	66,400	69,500	5%	67,700	66,600	65,600	67,100	3%	67,600	68,200
Revenue: $200 Million +	6	7	242	59,300	69,500	74,700	*	70,200	77,700	71,600	75,800	*	73,300	79,100
Customers: Up to 19,999	1	1		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	4	4	244	53,500	66,900	68,700	*	66,900	67,200	64,800	65,400	*	64,800	66,200
Customers: 40,000 to 99,999	6	6	260	57,100	67,100	76,500	*	68,900	68,300	71,800	71,200	*	72,000	72,100
Customers: 100,000 +	6	7	238	57,000	70,400	75,900	8%	72,000	78,500	67,900	73,900	8%	69,800	77,700
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	3	3		*	*	*	*	*	68,900	*	68,600	*	*	69,300
Employees: 51 to 100	2	2		*	*	*	*	*	*	*	*	*	*	*
Employees: 101 to 200	6	6	224	56,700	64,800	69,500	*	65,000	67,800	66,200	68,100	*	67,500	69,000
Employees: More than 200	6	7	238	57,000	70,400	75,900	8%	72,000	78,500	67,900	73,900	8%	69,800	77,700

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

Code: 9004

Model Job Title: Manager, Health & Safety

Market Segment	Sample Statistics		Hay Points	COMPENSATION DESIGN						ACTIUAL COMPENSATION				
				Salary Range Minimum	Job Rate / Control Point / Policy	Salary Range Maximum	Target % (where eligible)	Total Cash Design		Actual Base Salary		Actual Bonus % (where received)	Actual Total Cash	
	Orgs	Incs	P50	P50	P50	P50	P50	P50	AVG	P50	AVG	P50	P50	AVG
All Organizations	22	24	479	80,900	92,600	98,900	6%	94,100	99,300	95,800	95,300	5%	96,700	99,000
Geography: Region 1	3	3		*	*	*	*	*	100,400	*	99,600	*	*	101,100
Geography: Region 2	3	3		*	*	*	*	*	105,700	*	95,800	*	*	101,700
Geography: Region 3	5	7	551	91,700	107,700	116,800	9%	116,600	119,100	105,800	107,100	9%	113,400	117,000
Geography: Region 4	6	6	445	78,200	88,300	98,100	*	88,300	90,100	92,200	92,000	*	93,100	92,500
Geography: Region 5	5	5	406	74,100	90,600	92,600	*	92,600	89,800	90,600	84,400	*	92,600	86,100
Revenue: Up to $20 Million	0	0		*	*	*	*	*	*	*	*	*	*	*
Revenue: $20 to $50 Million	3	3		*	*	*	*	*	101,900	*	98,100	*	*	101,600
Revenue: $50 to $100 Million	3	3		*	*	*	*	*	90,700	*	80,800	*	*	82,700
Revenue: $100 to $200 Million	10	10	479	79,200	91,100	94,100	8%	91,100	92,900	93,400	92,900	*	93,400	94,600
Revenue: $200 Million +	6	8	551	87,700	107,700	110,300	10%	115,900	111,800	107,700	105,000	9%	116,300	113,200
Customers: Up to 19,999	0	0		*	*	*	*	*	*	*	*	*	*	*
Customers: 20,000 to 39,999	6	6	373	69,400	84,700	92,400	5%	86,800	93,600	83,500	86,300	4%	85,100	88,600
Customers: 40,000 to 99,999	10	10	479	79,200	91,100	97,200	6%	92,600	91,600	94,700	93,300	4%	95,200	95,300
Customers: 100,000 +	6	8	517	87,700	107,700	117,700	10%	117,800	116,400	109,800	107,500	9%	116,300	115,700
Employees: Less than 21	0	0		*	*	*	*	*	*	*	*	*	*	*
Employees: 21 to 50	1	1		*	*	*	*	*	*	*	*	*	*	*
Employees: 51 to 100	3	3		*	*	*	*	*	*	*	96,200	*	*	99,500
Employees: 101 to 200	12	12	406	79,000	90,900	95,600	5%	91,900	92,800	93,400	91,400	4%	93,700	93,400
Employees: More than 200	6	8	517	87,700	107,700	117,700	10%	117,800	116,400	109,800	107,500	9%	116,300	115,700

Minimum data requirements for information diclosure are: 3 for average, 4 for P50, 7 for P25 / P75. If insufficient data, this is indicated by the asterisks (*).

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End of Report

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4-Staff-27 Post-employment Benefits Other Than OMERs Pension

Reference:

1. Exhibit 4 Tab4 Appendix4-4.3 – Eckler Letter March 21, 2013
2. Exhibit 4 Tab 4 Schedule 2
3. Exhibit 6 Tab 2 Schedule 1 Impact on Employee Benefits

Preamble:

Horizon Utilities has engaged Eckler Ltd. ("Eckler") consultants and actuaries to assist in the development of the overall actuarial assumptions in determining the post-employment benefit cost including financial assumptions based on market expectations at the end of the reporting period. Reference 1 is a letter from Eckler regarding "2019 Cost of Service Application – Post-Retirement Benefits – Update for 2013 actual results".

a. Horizon will have recovered from ratepayers in excess of $4 million more than the cash benefit payments from 2012 to the end of 2019. Board staff prepared the table below based on Reference 1 Appendix A to compare accrual accounting benefits expense proposed for recovery and the amounts paid or to be paid through 2019.

	2012	2013	2014	2015	2016	2017	2018	2019	Total
1 Benefit expense	1,459,400	1,533,800	1,521,300	1,565,400	1,613,000	1,664,700	1,719,900	1,779,100	12,856,600
2 Benefits paid	1,084,810	1,109,200	1,118,900	1,099,200	1,101,000	1,099,500	1,116,200	1,116,200	8,845,010
3 Excess recovered	374,590	424,600	402,400	466,200	512,000	565,200	603,700	662,900	4,011,590

i. Please confirm that the amounts and the totals set out in the table above are correct and make any corrections required.
ii. What does Horizon plan to do with the excess funds recovered?
iii. Has Horizon created a trust fund into which the recoveries from ratepayers will be deposited to cover the future benefit payments? Is Horizon familiar with the FERC policy on irrevocable trusts when a utility recovers post-employment benefits using accrual accounting rather than cash payments? Board staff has provided FERC61_19921228-0154(10071367).tif for Horizon's assistance.
iv. Does Horizon consider it prudent to establish an irrevocable trust to protect money recovered from ratepayers, in some cases decades, in advance of the need to make the cash payments to retirees? Please discuss Horizon's opinion fully.

b. Board staff has prepared the table below to compare the benefit costs shown in Table 4-56 of Reference 2 with the benefit expense provided in Reference 1. Table 4-56 indicates that post-retirement benefits are included in the line "Life, Health, LTD". The Eckler Ltd. evidence provided as at December 31, 2011 indicates that its actuarial valuation includes the same items.

Comparison of the cost of Life, Health & LTD programs on Reference 2 page 18 and the Eckler. benefit expense evidence in Reference 1 is provided in the following table:

	2011	2012	2013	2014	2015	2016	2017	2018	2019	Total
1 Benefit programs	3,347,772	3,620,459	3,877,825	4,047,765	4,102,656	4,206,158	4,402,001	4,532,495	4,674,684	36,811,815
2 Benefit expense	1,430,800	1,459,400	1,533,800	1,521,300	1,565,400	1,613,000	1,664,700	1,719,900	1,779,100	14,287,400
3 Difference	1,916,972	2,161,059	2,344,025	2,526,465	2,537,256	2,593,158	2,737,301	2,812,595	2,895,584	22,524,415

i. Please confirm that the amounts and the totals are correct and make any corrections required.
ii. Please explain fully why the benefit expense forecast by Eckler Ltd. for Horizon is materially lower than the Life, Health and LTD costs sought for recovery in Table 4-56.

c. At Reference 3 page 5, Horizon has recognized a cumulative loss related to the actuarial valuation of $2,117,012 on conversion to IFRS. Horizon has not requested any recovery for these amounts in this application. Please explain fully why Horizon is not requesting recovery of this amount.

Response:

a (i) Please refer to the updated table below for the correct amounts and totals as filed in Exhibit 4 Table 4-120.

Updated Table 4-120

Description	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year	Total
Benefit expense per Table 4-120 (2013-2019)	$1,307,406	$1,492,641	$1,354,288	$1,393,120	$1,435,091	$1,480,649	$1,529,345	$1,529,345	$11,521,885
Benefits paid per Table 4-120 (2013-2019)	$1,119,500	$1,076,254	$1,108,900	$1,118,400	$1,098,500	$1,100,000	$1,098,200	$1,098,200	$ 8,817,954
Difference	$ 187,906	$ 416,387	$ 245,388	$ 274,720	$ 336,591	$ 380,649	$ 431,145	$ 431,145	$ 2,703,931

The table above represents the benefits expensed and premiums on an accrual basis in accordance with IFRS.

(ii) Please refer to the table below which provides an analysis of actual funds recovered based on the Board's decision in the 2011 Cost of Service Application (EB-2010-0131) compared to the amounts actually expensed from 2011 to 2014.

Table 1: Funds Recovered

Description	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	Total
Post-employment benefit expense recovered	$1,304,611	$1,304,611	$1,304,611	$1,304,611	$5,218,444
Post-employment benefit expense per Table 4-120 (2013-2019)	$ 976,865	$1,307,406	$1,492,641	$1,354,288	$5,131,200
Difference	$ 327,746	$ (2,795)	$ (188,030)	$ (49,677)	$ 87,244

Horizon Utilities expects to use the funds recovered for the current employees' portion of the future benefits expensed.

(iii) Horizon Utilities does not concur with the Board staff's position that excess funds have been recovered. Post-retirement benefits are recorded on an accrual basis; the accounting practice has not changed since the last Board Decision.

On December 23, 2008, the Board initiated a consultation (EB-2008-0408) to receive input from experts and stakeholders to assist the Board in making regulatory policy regarding the transition to IFRS. Horizon Utilities was a participant in the consultation.

A report was issued by the Board on July 28, 2009 entitled *Transition to International Financial Reporting Standards*. In this report, Board staff did not propose a change to the Board's approach to pension and other post-employment benefit costs. For electricity distributors, the current practice approved by the Board would continue for pensions and employee future benefit costs.

The Board issued a revised Accounting Procedures Handbook ("APH") in December 2011; the revisions were effective January 1, 2012. The Board advised electricity distributors to use the APH in conjunction with the CICA Handbook Part I – International Financial Reporting Standards to determine appropriate accounting policies and practices, giving due regard for the need to comply with applicable Board decisions or orders.

Article 510 of the APH provides additional guidance in regard to the first-time adoption of IFRS. Included in Article 510 is guidance with respect to post-employment benefits. Horizon Utilities is following this guidance where applicable.

Article 470 of the APH sets out, in considerable detail, the regulatory accounting procedures or requirements for employee benefits. Post-employment benefits are considered in Article 470. Horizon Utilities has followed the regulatory accounting procedures and requirements. As stated in Article 470, accounting for a defined benefit plan requires the use of actuarial assumptions to make reliable estimates of the benefit that employees have earned in return for their service in the current and prior periods. The entity underwrites the actuarial and investment risks associated with the plan; the expense recognized for a defined benefit plan is not necessarily the amount of the cash contribution due for the period. There may be periods where the cash contribution is in excess of the expensed recognized. Furthermore, rate payers are not responsible for the full liability amount as most of this has already been recovered from ratepayers.

Horizon Utilities does not believe it is prudent to establish an irrevocable trust as the tax vehicles to fund PEB are not tax efficient in Canada. Trusts are generally taxable at the highest marginal tax applicable to individuals, which is 49.53% for 2014. Additionally, there is no legislative or financial reporting requirement to do so.

(iv) Please see Horizon Utilities' response to iii) above. Additionally, Horizon Utilities does not believe it is necessarily prudent to do so. Horizon Utilities is a highly credit-rated regulated electricity distributor in Ontario with considerable liquidity and financial flexibility to make payments to retirees as they come due. In Horizon Utilities' view, it is highly unlikely that Horizon Utilities or a successor corporation would become insolvent or unable to make such payments. The surpluses referenced above, or conditions under which surpluses may accrue, can easily turn to deficits in circumstances where benefit accruals exceed benefit payments; as has been the case with respect to pensions in North America. The lack of access to any surplus deposited in trusts in these circumstances creates a practical cash flow issue with respect to funding the plan since employers effectively over-fund the plan. Horizon Utilities believes the present approach is prudent and balanced between employees and employers with due regard for going concern risks within the sector. Furthermore, the design of the post-retirement benefit plan is determined by the employer through collective bargaining for unionized employees and policy review for non-union employees. Benefits changes may be contemplated by Horizon Utilities depending on the financial circumstances of the Utility and/or current economics of the sector.

b (i) Please refer to the table below for the updated comparison of total benefit programs versus post-employment benefit expense:

Table 2: Total Benefit Programs vs Post-Employment Benefit

Description	2011 Actuals	2012 Actuals	2013 Actuals	2014 Bridge Year	2015 Test Year	2016 Test Year	2017 Test Year	2018 Test Year	2019 Test Year	Total
Benefit programs per Table 4-56	$3,347,772	$3,620,459	$3,877,825	$4,047,765	$4,102,656	$4,206,158	$4,402,001	$4,532,495	$ 4,674,684	$ 36,811,815
Post-employment benefit expense per Table 4-120 (2013-2019)	$ 976,865	$1,307,406	$1,492,641	$1,354,288	$1,393,120	$1,435,091	$1,480,649	$1,529,345	$ 1,529,345	$ 12,498,750
Difference	$2,370,907	$2,313,053	$2,385,184	$2,693,477	$2,709,536	$2,771,067	$2,921,352	$3,003,150	$ 3,145,339	$ 24,313,065

(ii) Benefit programs included in Table 4-56 include both the cost of the post-retirement benefits which represent the future costs of benefits for retired employees and the Life, Health and LTD premiums for all active employees.

(c) Under IFRS, actuarial gains and losses resulting from changes in actuarial assumptions and experience adjustments (the effects of differences between the previous actuarial assumptions

and what has actually occurred), are recorded in the financial statements in the current year as Other Comprehensive Income ("OCI"). Horizon Utilities has not requested any recovery of the amounts charged to OCI on transition to IFRS in the Application as it is expected that future differences resulting from these actuarial gains and losses will also be recorded in this account. Differences between accrued expenses and actual expenses will be recognized as expense in the year of payment. This is consistent with the regulatory treatment under Canadian Generally Accepted Accounting Principles ("CGAAP"), with the exception of the amortization of these gains and losses; which were formerly recovered from ratepayers.

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4-Staff-28 Depreciation

Reference:

1. Appendix 2-CA
2. Exhibit 4 Tab 5 Appendix 4-9 – Useful Lives of Assets
3. RRWF – 2015
4. Appendix 2-CA 2015

Preamble:

Board staff is interested in whether the proposed new lives based on Reference 2 (the "Kinectrics Report") are reasonable considering the average condition that the assets are in now. Board staff is also interested in how Horizon manages its assets.

a. In footnote 4 of Reference 1 it states that the opening asset balance depreciation should be based on the remaining life of the asset. Please provide a schedule of the remaining life by account that was determined by management.

Typically when a line is replaced, the assets are retired, and not put back into service. Horizon has some accounts that may be retired when a line is retired, but have a Typical Useful Life that is not equal to the remainder of the set off assets being replaced (poles, cables, conduits).

b. Account 1839 Overhead Conductors and Devices – Primary: Are these supported by concrete poles and towers?

c. Account 1844 Underground Conductors primary PILC – Are these conductors directly buried? If they are in conduits, should the depreciation be based on an economic life conduits based on the life of the conduit rather than setting the depreciation rate based on the Typical Useful Life?

d. Please confirm that Horizon has all sets of assets that are retired together with their remaining lives aligned and are appropriately depreciated.

Board staff has noticed a discrepancy between Reference 3 and Reference 4 for the 2015 depreciation expenses.

e. Please explain, review and correct.

Response:

a. The remaining life by account upon transition to IFRS as determined by management is provided in Exhibit 4, Tab 4, Schedule 1, Table 4-80-Appendix 2-CB.

b. Account 1839 - Overhead Conductors and Devices: these assets are supported by either concrete or wood poles.

c. Account 1844 – Underground Conductors Primary PILC: the majority of these conductors are installed in conduits. Underground Conductors Primary PILC is a separate component of property, plant and equipment ("PP&E"), and is accounted for separately in accordance with IFRS. Depreciation expense for this component should be determined by the corresponding estimated useful life for this component in accordance with IFRS. These conductors can be installed in and removed from conduits, which are also separate components of PP&E under IFRS. IFRS requires that each significant component of PP&E be depreciated separately. Horizon Utilities revised its accounting policy to address the component accounting requirements of IFRS, as fully described in Exhibit 4, Tab 5, Schedule 2 of the Application.

d. Horizon Utilities confirms that for components of PP&E which would be removed from service coincidently, the depreciable lives as determined by management are aligned and such components are depreciated appropriately. A summary of depreciable lives by component is provided in Table 4-75, Exhibit 4, Tab 5, Schedule 2 of the Application. The majority of distribution system PP&E components have an estimated useful life of 40 years.

e. The depreciation expense in Reference 3 (RRWF – 2015) is $24,970,618. The depreciation expense in Reference 4 (Appendix 2-CE 2015 per Appendix 2-BA Fixed Assets) is $23,383,544. Horizon Utilities provided a reconciliation of these two amounts in Table 2-28 on page 2 of Exhibit 2, Tab 3, Schedule 3. Table 2-28 is provided below for reference. The depreciation expense in Reference 3 includes losses on derecognition which are not included in the depreciation expense in Reference 4. Horizon Utilities is required to reclassify gains and losses on disposals as depreciation expense for regulatory reporting and filing purposes as identified on page 41 in the Report of the Board Transition to International Financial Reporting Standards (EB-2008-0408) issued July 28, 2009. These gains and losses are not included in the continuity statements. As such, both amounts are correct and Horizon Utilities believes that a correction is not required. A more detailed description is provided on page 1 of Exhibit 2, Tab 3, Schedule 3.

Table 2-28 - Reconciliation of Depreciation on Continuities to Depreciation Expense

Description	2011 Actual CGAAP	2012 Actual MIFRS	2013 Actual MIFRS	2014 Bridge Year MIFRS	2015 Test Year MIFRS	2016 Test Year MIFRS	2017 Test Year MIFRS	2018 Test Year MIFRS	2019 Test Year MIFRS
Total Depreciation on Continuties	**$ 27,720,934**	**$18,191,399**	**$19,299,511**	**$21,023,720**	**$23,383,544**	**$24,201,320**	**$24,161,257**	**$23,437,190**	**$23,877,061**
Deduct:									
Fleet/Stores Depreciation Allocated to Capital	$ (1,331,522)								
Add: (Gain)/Loss on Derecognition:									
Cost	$0	$2,027,707	$1,793,609	$1,773,488	$2,089,496	$3,825,068	$3,017,473	$3,318,009	$4,597,818
Accumulated Depreciation	$0	($150,765)	($156,463)	($133,043)	($187,423)	($1,085,758)	($344,159)	($430,511)	($1,426,748)
Proceeds	$0	($443,492)	($518,695)	($267,360)	($315,000)	($453,006)	($454,896)	($500,203)	($557,460)
(Gain)/Loss on Derecognition of PP&E	**$0**	**$1,433,449**	**$1,118,452**	**$1,373,086**	**$1,587,074**	**$2,286,304**	**$2,218,419**	**$2,387,296**	**$2,613,609**
Total Depreciation Expense	**$ 26,389,412**	**$ 19,624,849**	**$ 20,417,963**	**$ 22,396,806**	**$ 24,970,618**	**$ 26,487,624**	**$ 26,379,676**	**$ 25,824,486**	**$ 26,490,670**

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4-Staff-29 Shared Services

References:

1. Exhibit 4 Tab 4 Schedule 3
2. Exhibit 4 Tab 4 Appendix 4-6.1 – Transfer Pricing Study
3. Exhibit 2 Tab 6 Schedule 1

Preamble:

Horizon is a member of a group of affiliated businesses that perform services for each other. Stratsolver Corporation was retained to perform the Transfer Pricing Study filed at Reference 2.

Assets

At Reference 2, it states that the OEB prescribed cost of capital in effect October 31, 2013 is used to derive a markup that is applied to the Customer Care – Electricity Distribution Operations ("CC-EDO") direct operating costs which apply solely to assets in the customer care line of business.

a. Please state the assets that are employed that underpin the markup.

b. Who owns the assets?

c. How is the asset allocated in the CC-EDO relationship?

d. Customer Care bills for other affiliates. How is the billing system allocated between the billing services that Customer Care provides?

Allocators

At Reference 1, Horizon lists the allocators by service offering. Each allocator is based on an operating statistic – number of transactions, time spent, etc.

e. Healthy Workplace and Safety is allocated on the number of claims. Board staff views this as an insurance policy, and so you don't pay by claims, but by an annual premium. Why isn't this service allocated on employee count, since it covers all employees?

f. How are the executive times determined?

g. What is the period upon which these allocators are determined? That is, are they based on the most resent 12 month, full year, average of x years, or forecasted?

Fee Transaction Increases over 2014 – 2019

In Reference 2, it states that the CC-EDO is the greater management fee and is expected to increase from $8.1 million in 2014 to $9.1 million in 2019. This $1.1 million increase is and average annual increase of 2.5%. The total annual management fee between EDO and Affiliates is expected to increase $9.9 million to $11.2 million. This $1.3 million increase is an average annual increase of 1.2%.

h. Horizon has pointed out that postage costs are increasing. However, Horizon is also embarking on e-services for billing and payment. Please state any productivity gains that are built into these fees. Please state you assumptions and identify any sharing of gains or losses that Horizon may be planning.

i. Please identify any action that Horizon has taken to ensure that Horizon Holdings Inc. has undertaken for continuous improvements in order to provide benefits to EDO.

Response:

a. The assets referred to in the Transfer Pricing Study that are subject to markup consist of billing software and furniture.

b. The assets identified in the response to a) above are owned by the unregulated Customer Care division of Horizon Utilities Corporation.

c. The assets identified in the response to a) above are assigned to the Customer Care ("CC") division and therefore are not included in the rate base which is comprised exclusively of Electricity Distribution Operations ("EDO") assets. The markup in the CC-EDO management fee provides Customer Care with a return on capital for the share of the assets used in EDO.

d. Customer Care provides billing services to one affiliate – the water billing for the City of Hamilton (most Hamilton residents receive a single bill for both electricity and water). The proportion of number of customer accounts is the allocator for the billing system. As identified in footnote (2) to Table 3.1.2 in the Transfer Pricing Study, this allocator results in 68.9% of the costs in Customer Care allocated to EDO.

e. The use of the number of claims as an allocator for Healthy Workplace and Safety produces an appropriate allocation for this service. Employee counts would be less appropriate, in that there can be a wide range of risk levels associated with different employee positions. Using the number of claims, rather than employee counts, takes into consideration the variation in risk levels associated with different entities and the nature of their staffing complement.

f. Executive Oversight and Support Services provided by Horizon Holdings Inc. to EDO are based on estimates of the time allocation for three individual employees. Other services that include an Executive component are based on proxies of time as documented in the Transfer Pricing Study. In the case of services provided by EDO to Customer Care and to Conservation and Demand Management ("CDM"), the proportion of full-time equivalent employees ("FTE") was used. The cost of services provided by EDO to Solar Sunbelt General Partnership ("SSGP"), in which Horizon Utilities holds a 99.9% interest, are allocated based on a proportion of total operating costs.

g. Allocator values were determined on the basis of the most recent complete year of actual results (2012) at the time the Transfer Pricing Study was being prepared, with the exception of number of customer accounts for water billing where a three-year historical average (2010-2012) was used.

h. The financial projections for postage costs assume annual growth of 1.5%. Horizon Utilities expects that increased customer enrollment in e-services, and specifically e-billing, will be required to contain costs, to the extent actual Canada Post price increases exceed this level. Horizon Utilities is not proposing any sharing of gains or losses arising from actual Canada Post postage cost increases or from the actual customer enrollment rate for e-billing services. Horizon Utilities' budgeted postage expenditures assuming that the current billing schedule is maintained, which is principally bi-monthly billing for residential customers.

i. Horizon Holdings Inc. has undertaken actions for continuous improvement to mitigate cost increases of its own operations and increase value to EDO. Horizon Holdings Inc. will continue to retain a minimal level of staffing; use consulting services; and, in some cases, contract employees to contain costs and maintain flexibility. Horizon Holdings Inc. will continue to increase value for EDO through projects it conceives and forwards to Horizon Utilities for implementation, such as the Smart Growth Connection Program that encourages infill commercial development to increase customer revenue from existing assets.

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6-Staff-30 Deferred Taxes

Reference:

1. Exhibit 6 Tab 2 Schedule 1

Preamble:

On pages 19 – 21 of the Reference, Horizon discussed the impact of IFRS on PILs and regulatory and accounting rates of return. Horizon has asked the Board to comment on the fair return standard in light of the Board's policy to allow only current income tax PILs to be recovered in distribution rates and not to allow deferred taxes to be recovered. Horizon has expressed its concern that material differences between externally reported net income (on an accounting basis which includes deferred taxes) and allowed net income calculated on a regulatory basis (which excludes deferred taxes) may be viewed negatively by lenders and rating agencies.

In Board staff's view, should the Board wish to comment on Horizon's question, Staff request the following information may be helpful:

a. Please state whether or not Horizon recover more PILs than it paid from 2000 up to the date of the current application? Please provide a table that shows total income tax, Ontario capital tax and Large Corporation Tax recoveries by year from ratepayers since 2000 and the amounts actually paid to the Ministry of Finance Corporations Tax Branch, and the net difference between collections from ratepayers and payments made.

b. Please confirm that the balance approved for disposition and recovery was a debit or recovery from customers of $3,323,866 over a 14 month term in Horizon's PILs 1562 disposition case (EB-2012-0005).

c. In the Board's Cost of Capital proceeding EB-2009-0084, did Horizon make submissions regarding the fair return standard and the inclusion of deferred taxes in rates? If the answer is no, why did Horizon not raise the issue in that proceeding? If the answer is yes, please file Horizon's submission and discuss its submission in the context of its current request in this proceeding.

d. Please confirm that Horizon does not have a regulatory asset for deferred taxes on its balance sheet?

e. Please confirm that Horizon voluntarily adopted IFRS in advance of the requirement set by the CICA, now CPA Canada, of January 1, 2015?

f. Please explain whether Horizon is of the view that given its position on deferred taxes now, that it may not have prudently assessed its current and future exposures when it adopted IFRS early.

g. Please confirm Horizon's understanding that when the majority of Ontario electricity distributors adopt IFRS on January 1, 2015, they will be able to recognize regulatory assets and liabilities on their balance sheets.

h. Please provide Horizon's view as to whether the distributors that adopt IFRS on January 1, 2015 have the same issues with respect to deferred taxes now faced by Horizon?

i. Please provide Horizon's view as to whether the distributors that adopted US GAAP, rather than IFRS, have the same issues with respect to deferred taxes now faced by Horizon?

j. Did Horizon make submissions in the RRFE process development regarding deferred taxes and the fair return standard? If not, please explain fully why Horizon did not make submissions. If yes, please file the submission and discuss how the circumstances today are similar or different than they were in 2012.

Response:

a. Horizon Utilities provides the table requested as Table 1 below:

Table 1: Horizon Utilities' Differences Between PILs Recovered and Ministry Liability on a Regulatory Basis

Year	Former HHI	Former SCHI	Taxes Recovered From Ratepayers (1)	Former HHI	Former SCHI	Ministry Taxes Paid On Regulatory Basis (2)	Difference
2000	-	-	-	-	-	-	-
2001	2,470,670	636,144	3,106,814	2,470,670	636,144	3,106,814	-
2002	9,107,869	2,586,341	11,694,210	9,107,869	2,586,341	11,694,210	-
2003	11,153,083	3,135,688	14,288,771	11,153,083	3,135,688	14,288,771	-
2004	8,562,884	2,290,946	10,853,830	8,562,884	2,290,946	10,853,830	-
2005	7,521,035	2,156,656	9,677,691	7,521,035	2,156,656	9,677,691	-
2006			10,402,946			9,718,191	684,755
2007			9,613,518			8,667,190	946,328
2008			7,642,605			6,724,833	917,772
2009			6,657,149			6,139,250	517,899
2010			6,657,149			6,000,796	656,353
2011			5,982,449			6,202,926	(220,476)
2012			4,725,771			6,657,007	(1,931,235)
2013			5,646,880			5,552,946	93,934
Total			106,949,784			105,284,455	1,665,329

Notes:
1. - Horizon Utilities made an application to dispose of Deferred Payments In Lieu Account 1562 (EB-2012-0005). The taxes recovered from ratepayers in years 2001 through April 2006 are in respect of those years based on the Board Decision in EB-2012-0005. Recoveries were effectively settled at these amounts through the disposition of AC1562.
   - 2006 -2013 amounts are derived from OEB Approved PILs plus IRM adjustments where applicable.
   - 2011 and 2012 recoveries are reported net of amounts approved for settlement of principal balances in AC 1592.
   - 2012 and 2013 recoveries are reported net of amounts shared with customers through IRM process.

2. - Since the Board approved amounts in 1) in EB-2012-0005 for purposes of 2001 to April 30, 2006, Horizon Utilities has used such amounts as Ministry Taxes Paid adjusted on a regulatory basis. Regulatory taxes payable were effectively recognized at these amounts through settlement of AC1562.
   - May - Dec 2006 amounts are derived from prorated annual OEB Trial Balance PILs and prorated Capital Taxes paid.
   - 2007 - 2013 amounts are derived from OEB Trial Balances.

As Board Staff is aware, the Board's ability to set rates was limited from November 11, 2002 until January 1, 2005 when the Ontario Energy Board Act, 1998 (the "Act") was amended by the *Energy Pricing, Conservation and Supply Act*, 2002, S.O. 2002, c.23 ("Bill 210"). Pursuant to section 79, the Board was restrained from accepting applications, commencing a proceeding on its own motion, and issuing orders to change rates under section 78 without leave of the Minister of Energy. The rates of the predecessors of Horizon Utilities during this period included PILs proxy amounts for both 2002 and the last three months of 2001. The recovery of 2001 PILs amounts was expected to be removed in 2003 when the final third tranche of the allowable return on equity (Market Adjusted Revenue Requirement or "MARR"adjustment) was to be implemented.

However, during the period rates were frozen under Bill 210, Horizon Utilities, including its predecessors, continued to track PILs variances in Account 1562 – Deferred PILs. These amounts represented: i) differences between PILs amounts included in rates and collections from customers; and ii) actual PILs paid to the Ministry of Finance and the PILs proxy calculations. The Board reviewed the prudence of these amounts in Horizon Utilities' PILs Application (EB-2012-0005) and issued its Decision on October 4 2012. Horizon Utilities demonstrated that, excluding carrying charges, it under recovered PILs for the period October 1, 2001 to April 30, 2006 in the amount of $2,039,038. Therefore, in the above table, Horizon Utilities does not recognize any differences between amounts recovered from customers and amounts paid to the Ministry of Finance computed on a "regulatory basis" to April 30, 2006.

Subsequent to April 2006, the taxes recovered from ratepayers are calculated using Board Approved recovery amounts for each year, net of amounts returned to customers in 2011 and 2012 as either recorded in Account 1592 - PILs and Tax Variance for 2006 and Subsequent Years or the Shared Tax Savings Adjustments approved in the 2012 and 2013 IRM adjustments. The difference computed in Table 1 is partially explained by the sharing of tax savings as a result of declining corporate tax rates.

Horizon Utilities submits that this interrogatory is not relevant to the reference in the Application. Horizon Utilities is not seeking additional recovery from its customers with respect to the issue identified in Exhibit 6, Tab T2, Schedule 1. The intent of this discussion is to create awareness; which may precipitate further direction from the Board.

Please also refer to 6-VECC-48 which provides a full analysis of this issue including Horizon Utilities' statement thereon that: *"Horizon Utilities suggests that its resolution requires further study and may be outside the scope of this Application."*

The fundamental issue is not driven by a conversion to IFRS. Such issue arises from the use of a cash taxes basis of recovery from customers (rather than an accounting basis) and the inconsistency of such with the accounting basis otherwise used to recover distributor costs from customers. The adoption of IFRS has exacerbated this issue for reasons discussed in Horizon Utilities'' response to Interrogatory 6-VECC-48. Other distributors may experience this issue where they have adopted longer depreciable asset lives as a result of depreciation studies irrespective of their adoption of IFRS or US GAAP.

b. Horizon Utilities confirms that approval was received for the recovery of $3,323,866 over a 14-month term (November 1, 2012 to December 31, 2013) in respect of Horizon Utilities' application for the disposition of Account 1562 Deferred Payments in Lieu ("PILS") of Taxes (EB-2012-0005). This amount was comprised of principal PILs amounts of $2,039,038 and carrying charges of $1,284,828. The principal PILs amounts represented the difference between PILs collected from customers and PILs amounts included in rates for the period from October 2001 through April 2006.

c. Horizon Utilities made a submission in the Board's Cost of Capital proceeding (EB-2009-0084) on October 30, 2009 as a member of the Coalition of Large Distributors ("CLD"). A copy of that submission is provided as 6-Staff-30c_Attch 1_CLD Submission. At that time Horizon Utilities was preparing for the implementation of IFRS and not all of the impacts of regulatory accounting on external reporting were fully determined by the industry and the accounting bodies. As a result, Horizon Utilities did not make comment on the effect of deferred income taxes on returns reported externally. However, the submission stressed the need for recognition of fair returns to attract new capital. As illustrated in Table 6-13 in Exhibit 6, Tab 2, Schedule 1, under IFRS, the use of a cash taxes basis of recovery in the determination of rates results in external returns below allowable rates of return for regulatory purposes under the conditions described in 6-VECC-48.

d. Horizon Utilities confirms that it does not recognize deferred taxes on its regulatory balance sheet.

e. The Canadian Accounting Standards Board ("AcSB") adopted a strategic plan that required publicly accountable enterprises to adopt IFRS in place of Canadian GAAP for

fiscal years beginning on or after January 1, 2011. In October 2010, the AcSB approved the incorporation of a one year optional deferral into Part 1 of the Canadian Institute of Chartered Accountants ("CICA") Handbook for qualifying entities with activities subject to rate regulation. Part 1 of the CICA Handbook specified that first-time adoption was mandatory for annual financial statements relating to annual periods beginning on or after January 1, 2012. Horizon Utilities prudently planned the transition to IFRS and made the necessary changes to its systems and processes to implement IFRS on January 1, 2012.

f. Horizon Utilities is not of this view. As explained in c), this issue has always existed in rate-making policy but is exacerbated by the adoption of longer depreciable asset lives under IFRS or otherwise. Such issue has existed since the Board resolved its original PILs Proxy methodology. The former Hamilton Hydro Inc., continuing within Horizon Utilities, made Board Staff aware of this issue at that time. As described in 6-VECC-48, this issue is not a cash issue for a utility provided that the future tax assets or liabilities are ultimately settled with customers as the underlying accounting/ tax timing differences reverse into cash taxes payable. However, this issue will result in accounting based returns that do not align with regulated returns since such are determined on clearly different bases as corresponding to the determination of tax expense; irrespective of the financial reporting basis adopted.

g. Horizon Utilities is unaware of the number of Ontario electricity distributors that will adopt IFRS on January 1, 2015. It is Horizon Utilities' understanding that the International Accounting Standards Board ("IASB") issued an interim standard – IFRS 14 Regulatory Deferral Accounts in January 2014. The interim standard is effective for financial reporting periods beginning after January 1, 2016, although early adoption is permitted. The interim standard will permit first-time adopters of IFRS to continue using previous GAAP to account for regulatory deferral account balances (the recognition or derecognition of regulatory assets/ liabilities is not relevant to the issue Horizon Utilities has articulated depending on the position taken by distributors with respect to such items for tax purposes. Horizon Utilities provided analysis in 6-VECC-48 that demonstrates the issue with respect to differences in depreciation for accounting and tax purposes).

Horizon Utilities is unaware of the number of Ontario electricity distributors that will be able to recognize regulatory assets and liabilities on their balance sheets effective for financial reporting periods beginning after January 1, 2015. It is Horizon Utilities' understanding that the IASB has not committed to issuing a comprehensive standard on rate-regulated activities that will permit qualifying entities to recognize regulatory assets and liabilities on their balance sheets in the future. The IASB has yet to complete its comprehensive project in this area. The use of this standard is irrelevant to the issue articulated in response to this interrogatory and 6-VECC-48.

h. Please refer to 6-VECC-48. These issues have existed for all distributors since the implementation of rate-making methodology for PILs; irrespective of their basis for financial reporting. The magnitude of the issue will be exacerbated where distributors adopt longer depreciable asset lives as a consequence of: i) the adoption of IFRS; or ii) evidence based on studies or otherwise.

i. Please refer to the response in h).

j. No. Please refer to the responses in a) through i).

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October 30, 2009

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge St., Suite 2700
Toronto, ON, M4P 1E4

Dear Ms. Walli:

RE: Cost of Capital in Current Economic and Financial Market Conditions
Board File No.: EB-2009-0084

Please find attached the submission of the Coalition of Large Distributors (the "CLD"), listed below, with respect to the above-captioned proceeding.

If you have any questions, please contact Paula Conboy at 905-532-4526.

Yours truly,

(Original signed on behalf of the CLD by)

Paula Conboy
Attach.

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Cost of Capital in Current Economic and Financial Market Conditions
Board File No.: EB-2009-0084

Submission by the Coalition of Large Distributors
October 26, 2009

Introduction and Context

These are the comments of the Coalition of Large Distributors (the "CLD"), in respect to the above-noted consultation. The CLD consists of Enersource Hydro Mississauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited, and Veridian Connections Inc.

The Ontario Energy Board's (the "Board" or the OEB") review of its approach to the Cost of Capital is timely; in fact, it is urgently required. Ontario's energy infrastructure requires renewal and expansion. The IPSP estimates a required $60 billion investment in the electricity system to the year 2027 (2007 CDN$). This figure does not include investment in the electricity or gas distribution systems. To put this figure in some context, the current rate regulated invested capital is approximately $30 billion.[1]

Ontario's infrastructure expansion and renewal is part of a broader continental and international demand for energy infrastructure investment. The Edison Electric Institute projects an infrastructure investment requirement of $900 billion by 2025 in the United States.[2] This is only a portion of the International Energy Agency's estimate of a required $26.3 trillion investment in energy infrastructure world wide by 2030.[3]

The OEB is the only provincial agency charged with the responsibility to ensure that Ontario will attract its share of rate regulated investment in a competitive global market. The result of this process will demonstrate the Board's appreciation of the challenge ahead of it, and the credibility of its approach to meeting that challenge.

The *status quo* is not a credible approach to meet that challenge. Simply put, Ontario has not kept up with competing jurisdictions when it comes to attracting new capital. Other jurisdictions, particularly in the United States, provide much more competitive returns and an investment environment marked by less regulatory risk than Ontario. American jurisdictions have been averaging approved returns in the range of between 11 and 12% as a baseline, with premiums for investments facilitating renewable power. As recently as April 10, 2009, the U.S. Federal Energy Regulatory Commission approved regulatory approval for the Green Power Express Transmission Project. This approval consisted of an approved ROE of 12.38 percent;

[1] Transcript, September 22, p. 106.
[2] David K. Owens, Executive Vice President, Edison Electric Institute, "30 Years of Energy Information and Analysis", April 7, 2008. http://www.eia.doe.gov/conf_pdfs/Monday/owens.pdf
[3] Nobuo Tanaka, Executive Director, International Energy Agency, "Meeting the Investment Challenge" March, 2009. http://www.iea.org/speech/2009/Tanaka/cera_week.pdf

recovery of development costs; 100% CWIP in rate base; and a deemed capital structure of 60% equity and 40% debt.[4]

The OEB's currently approved ROE of 8.01 for electric distributors that were rebased for the 2009 test year (with an equity thickness of 40%) is simply not competitive and will not succeed in attracting energy infrastructure investment to the province.

The OEB's approved ROE results from a formula created by the NEB; the NEB has now rejected that formula because it fails to take into account international competition for capital investment. The NEB expressed its views on this formula (initially determined in the 1994 Decision (RH-2-94)) in the TQM Decision as follows:[5]

> "*In the Board's view, one of the most significant changes since 1994 is the increased globalization of financial markets which translates into a higher level of competition for capital. When taken together, the Board is of the view that these changes cast doubt on some of the fundamentals underlying the RH-2-94 Formula as it relates to TQM.*"

More recently, the NEB confirmed that the formula should no longer apply to determine the rate of return for *any* regulated utility.[6]

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[4] FERC Order on Transmission Rate Incentives and Formula Rate Proposal (April 10, 2009). The materials and opinions on how American utilities are an appropriate proxy group are thoroughly canvassed in Concentric's Final Written Comments, and will not be repeated here. However, it is worth noting in this regard that Dr. Booth – the sole outlier on this issue - made no mention of the fact that American regulators have, in addition to granting higher rates of return than the OEB, have been using a number of alternative measures to remove regulatory risk in infrastructure investment. Some of these alternative mechanisms (including prior approval and recovery of CWIP in rate base, are described in the NRRI Report prepared by Scott Hempling and Scott H. Strauss, *Pre-Approval Commitments: When and Under What Conditions should Regulators Commit Ratepayer Dollars to Utility-Proposed Capital Projects* (November, 2008). See also: FERC Order No. 679. Dr. Booth's comments apparently did not take these developments into account when he asserted that, under American regulatory practice, "Expenditures [are] not pre-approved as they are in Canada" (See Dr. Booth's Slide Deck entitled "Cost of Capital").
In the same materials, Dr. Booth makes much of the fact that Ontario uses deferral accounts more than in the United States. However, reliance on deferral accounts is a source of risk. As the Board recently stated, "As the Board has articulated in numerous documents, the recording of costs in a Board approved deferral account is not a guarantee of recovery." (Hydro One 2009 and 2010 Transmission Revenue Requirement and Rates, Decision With Reasons (EB-2009-0272), at p. 59. This risk is increasing as the size of deferral accounts have been growing dramatically. For example, the total amount held in deferral accounts reflecting the cost of global adjustments has increased considerably between 2008-2009. By way of magnitude, balances in the GA variance accounts for CLD members have increased in the range of 125% to as much as 592% from December 31, 2008 to September 30, 2009. Collectively, the CLD members are holding $184 million as of September 30, 2009, a 236% increase since December 31, 2008.

[5] National Energy Board, Reasons for Decision, Trans Quebec & Maritimes Pipeline Inc. RH-1-2008 (March, 2009), at p. 16 (Emphasis Added).

[6] The NEB's Letter Decision on the review of RH-2-94 stated: "The Board notes that since 1994, there have been considerable changes in financial and economic circumstances. Based on these considerations, the Board is of the view that there is a doubt as to the ongoing correctness of the RH-2-94 Decision." Review of the Multi-Pipeline Cost of Capital Decision (RH-2-94), Letter Decision (October 8, 2009), at p. 2.

If the OEB continues to rely on its current approach, the province will be in the position of competing for international capital using an approach that has been rejected by its original creator *for the very reason that it fails to effectively take into account global competition for capital*. This is a tenuous position in which to leave the province.

The following submissions provide a prescription to prevent this situation. It is organized as follows. First, it addresses the policy framework for the Board's review. Second, it addresses what the Board can do in the short and long term to improve its approach to cost of capital.

In addition to these submissions, the CLD, along with Enbridge Gas Distribution and Hydro One have retained Concentric Energy Advisors ("Concentric") to provide the Board with its expert research and analysis on whether the Board's current approach continues to meet the fair return standard, and whether re-calibration and modification of the formula is warranted after a dozen years in operation. Concentric has provided Final Written Comments on this matter. These comments are supported and endorsed by the CLD; they are not repeated in these submissions.

1. Policy Framework

The CLD submits that the appropriate framework for this review was provided by the Chair in his closing statement. He emphasized that "it is essential that the Board's cost of capital policy has accurately as possible determined the opportunity cost of capital for monies invested in utility works, with the ultimate objective being facilitating efficient investment in the sector."[7]

The Chair's focus on opportunity costs of capital is helpful because it sheds light on two important issues for the policy framework for this process. First, it provides context for what is measured by the tests in the "fair return standard", and in particular, the capital attraction test. Second, it confirms that the Board's approach is to use tools of *economic efficiency* to meet capital requirements. This is important because it relates to the issue of whether public or private ownership is a relevant consideration.

Each of these points will be addressed in turn.

Capital Attraction and the Fair Return Standard

There are three main tests to determine whether the fair return standard is met: comparable investments; financial integrity and capital attraction. Each of these tests must be passed. The CLD submits that Concentric's Written Comments demonstrate that the Board's current approach fails to meet any of these tests.

These submissions focus on one component of the "fair return standard" i.e., the capital attraction test. As Bonbright observes, among the components of the fair

[7] Transcript, October 6, 2009, p. 154.

return standard, "a high place, perhaps even first place, must be given to that of capital-attracting efficiency."[8]

It is helpful to clarify what the standard of capital attraction comprises. This is necessary because some participants in this and other proceedings have tended to use the term "capital attraction" to have a different meaning than its conventional understanding. Specifically, the term "capital attraction" has been used to measure whether a utility is capable of meeting service quality and reliability obligations. This description of capital attraction can be called the "Mandatory Investment Test."[9]

A more conventional approach to capital attraction in regulatory economics looks not at the question of whether obligations can be met, but whether the rate is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital. This can be called the "Opportunity Cost Test."

The CLD submits that the Board should not follow the Mandatory Investment Test. The problems with this test are well known. In an influential Report prepared by Karen Taylor and Michael McGowan, the authors noted that regulators have defended proposed ROEs on the grounds that utilities "are still investing in system assets." Ms. Taylor and Mr. McGowan acknowledged that this was true, but added the following observation:

> "Utilities will likely continue to invest in rate base despite an unsatisfactory ROE for a number of reasons: (1) requirement to be the supplier or supply of last resort and fulfil the obligation to serve; (2) maintain the safe and reliable operation of the utility; and (3) remain in compliance with a governing licence. *It should not be presumed that continued investment is an acquiescence that the allowed ROE adequately meets the fair return standard.*"[10]

Further, the fact that capital is available does not address whether its cost is accurately reflected in the Board's approved return on equity. In a functioning capital market, the demand for long-term capital and the supply of long-term capital will typically be in equilibrium. This does not necessarily imply that the equilibrium is on some hypothetical "optimal" frontier. It merely demonstrates that capital is available at a price. The issue in this review is to determine whether the price is appropriate.

Indeed, following the approach of the Mandatory Investment Test is not really applying the standard of capital attraction. To the contrary, setting a rate that is only sufficient to meet incremental capital investments necessary to meet obligations is a form of expropriation, namely, the expropriation of sunk assets. To use an

[8] Bonbright, Danielsen and Kamerschen, *Principles of Public Utility Rates* (1988), (Bonbright) at p. 203.
[9] See, for example, VECC's cross-examination of Concentric Energy Advisors, Transcript, Sept. 22, pp. 82-88)
[10] Karen Taylor and Michael McGowan, Pipelines & Utilities, "2007 ROE Preview – The Ugly get Uglier and is there Trouble Brewing in Ontario." BMO Capital Markets, June 27, 2006

extreme case to demonstrate the point, Holburn provides the example of where the regulator allows no return (as opposed to an inadequate return) on sunk assets:[11]

> "Expropriation of the firm's sunk assets, however, does not mean that the government takes over the operation of the company, but rather, that it sets operating conditions that just compensate for the firm's operating costs and the return on its non-specific assets. Such returns will provide sufficient ex-post incentives for the firm to operate, but not to invest."
>
> ...
>
> "The company will be willing to continue operating because its return from operating will exceed its return from shutting down and deploying its assets elsewhere. On the other hand, the firm will have little incentive to invest new capital as it will not be able to obtain a return."

The same principles apply in the case of an inadequate return. In either case, the fact that a utility continues to meet its regulatory obligations and is not driven to bankruptcy is not evidence that the capital attraction standard has been met. To the contrary, maintaining rates at a level that continues operation but is inadequate to attract new capital investment can be considered confiscatory. The capital attraction standard is universally held to be *higher than* a rate that is merely non-confiscatory. As the United States Supreme Court put it, "The mere fact that a rate is nonconfiscatory does not indicate that it must be deemed just and reasonable."[12]

The appropriate approach towards the capital attraction standard is the Opportunity Cost Test. As Bonbright observes, "most public utility companies, in order to render good service, must be able repeatedly to attract new capital from investors who are free to commit their funds to any alternative investments including the purchase of stocks in unregulated enterprises."[13] Thus, although a rate base is comprised of existing capital investments, the *return* on that capital bears on the fairness standard because "existing, captive investments are fairly compensated if permitted to receive whatever rates of return would currently induce free investments."[14]

The Opportunity Cost Test is also more relevant to the needs of the province, because it looks to whether the rate of return will be successful in attracting new capital investment for energy infrastructure in Ontario. This necessarily involves comparing Ontario's ROE to ROEs in competing jurisdictions with due consideration for environmental differences such as jurisdictional maturity, market participant size and liquidity risks, etc. The evidence is that, with consideration for jurisdictional differences and similarities, Ontario's ROE is considerably lower than other jurisdictions, and that difference is not accounted for by increased risk in other jurisdictions.

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[11] G. Holburn and P. Spiller, "Institutional or Structural: Lessons from International Electricity Sector Reforms" in *The Economics of Contracts: Theories and Applications* (Cambridge, 2002).
[12] *Banton v. Belt Line Ry. Corp.* 268 U.S. 413, 422-423, quoted in Charles Phillips, *The Regulation of Public Utilities* (1993), at p. 380.
[13] Bonbright, at p. 209.
[14] Bonbright, at p. 207.

To the contrary, empirical research demonstrates that Ontario is one of the riskiest jurisdictions in which to invest in energy infrastructure. Surveys of energy investors with experience in Ontario and other jurisdictions indicate that Ontario has relatively high regulatory risk resulting from ongoing political involvement in the electricity sector. In particular, one recent independent academic work conducted a survey of investors in the Ontario energy market to obtain their views of the relative regulatory risks of investing in Ontario as opposed to other jurisdictions. It came to the following conclusion:[15]

> "In contrast to operational and regulatory policy issues, the assessment of the regulatory governance regime in Ontario was considerably less favourable. The bottom-ranked three factors were all governance aspects. Each rated less favourably than other jurisdictions. Firms with experience in Ontario … further scored these dimensions lower than those without experience in the province …suggesting that perceptions of the regulatory environment may have deteriorated after physical investments or financial commitments have been made."

It should be noted that the survey addressed investment in renewable power. However, the revenues for renewable power contracts are guaranteed by the Ontario Power Authority in the sense that there is guaranteed recourse to the market for revenues. Thus, the risk profile of an OPA contract is not unlike the risk profile for investments in regulated infrastructure. It is also worth observing that the OPA's FIT program uses an assumed rate of return of 11-12%.[16]

The Relevance of Public Ownership

During the consultation, the Vice Chair, Ms. Nowina asked, whether it was appropriate that "government-owned utilities and investor-owned utilities should receive the same cost of equity capital."[17] This notion has been raised in other processes as well. For example, in its comments on the Staff Discussion Paper on the Regulatory Treatment of Infrastructure Investment, the CME and others suggested that the Board should not apply economic principles of public utility regulation where those principles were developed for utilities that are "privately owned companies which are not subject to Government direction to invest more capital."[18] The CLD appreciates this issue being raised so that it can be expressly addressed.

In the CLD's submission, discounting a rate of return entitlement for publicly owned utilities should not be entertained. Such an approach is unlawful, inconsistent with government policy, and uneconomic.

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[15] G. Holburn, K. Lui, and C. Morand, *Policy Risk and Private Investment in Wind Power: Survey Evidence from Ontario, (*University of Western Ontario, Monograph), September 8, 2009, p. 12.
[16] OPA Presentation on Proposed Feed In Tariff Program, Revised Rules, Draft Contract and Revised Price Schedule, May 12, 2009.
[17] Transcript, September 22, p. 29.
[18] CME Submissions in EB-2009-0152, July 7, 2009, p. 4.

With respect to legal entitlements, all rate regulated utilities are entitled to a fair return; this is an inherent component of a just and reasonable rate.[19] The Board is not granted the discretion to reduce that return based on the identity of the shareholder. This discretion would have to be expressly authorized in legislation.

As well as being inconsistent with legislation, such an approach would be inconsistent with government policy. The last time that the government formally addressed the returns available to publicly owned utilities was in the context of its June 7, 2000 Directive to the OEB. That Directive required the OEB, when setting rates, to "give primacy to the objective 'to protect the interests of consumers with respect to prices and the reliability and quality of electricity service." The Board addressed the impact of the Directive on distributors' entitlement to a commercial rate of return as follows:[20]

> "The Board does not interpret the Directive as a move away from the commercial orientation of municipally-owned utilities as set out in the White Paper and in the legislation. The Board does not view the Minister's Directive to mean that there should be no return on capital. Nor does the Board believe that the Directive instructs the Board to set rates that are not just and reasonable, and thus impair its role as a regulator.
>
> On the contrary, the Board is of the view that in the new commercial setting, the best way to protect consumers with respect to prices, and the reliability and quality of service, is to facilitate the establishment and maintenance of a financially viable electricity distribution sector. *It is fundamental for a viable electricity distribution sector in a commercial setting to have opportunities for earning a market rate of return.*"

The CLD is not aware of any change in government policy that would authorize the Board to depart from its understanding of its role in setting just and reasonable rates for publicly owned utilities.

From an economic perspective, not including a commercial cost of capital in a utility rate is inefficient. Capital has a cost. If the Board does not attribute a cost to capital, or attributes less than its full cost, that cost is not eliminated, it is transferred to utility shareholders. Transferring this cost is inefficient because it distorts the comparability of economic trade-offs between capital resources (investments in generation, transmission and distribution) and between capital and operating expenditures. For this reason, even a governmental decision to make a "pure" publicly funded capital expenditure, such as a highway or bridge, is evaluated using an economic analysis that incorporates an imputed cost of capital.[21]

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[19] See, for example, *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186; *Re Union Gas Ltd. and Ontario Energy Board* (1983), 43 O.R. (2d) 489 (Div. Ct.); *British Columbia Electric Railway Co. v. Public Utilities Commission of British Columbia*, [1960] S.C.R. 837; and *TransCanada Pipelines Ltd. v. National Energy Board*, 2004 FCA, 149.

[20] RP-2000-0069, p. 9 (Decisions with Reasons, September 29, 2000)

[21] See for example, Treasury Board of Canada Secretariat, Canadian Cost Benefit Analysis Guide: Regulatory Proposals.

Finally, an approach that sets a rate of return based on the assumption that publicly owned entities do not require a profit to invest in infrastructure risks becoming a self-fulfilling prophecy. If the Board entertains such an approach, it is virtually *guaranteeing* that private investment will not come to Ontario. Again, as Holburn and Spiller point out, where a low rate of return results in expropriation of sunk costs, "private utilities will not undertake investments in the first place. Thus, government direct intervention may become the default mode of operation."

2. Short Term and Long Term Fixes to the Current Approach

The Board's current measure of the cost of capital is set out in its December 20, 2006 Report. The legal status of the Report is to provide some guidance on how the Board intends to approach the cost of capital. It was not produced on the basis of a formal hearing and is not binding on the Board. There is therefore no reason to grant it a privileged status such that it can only be adjusted or set aside on the basis of a full hearing. If the approach has flawed assumptions, and CLD submits that it does, then there is no reason for the Board to keep following it. Further, if on the basis of information provided by participants the Board is persuaded that there is a superior approach that results in a rate that is more just and reasonable, and the CLD submits that its proposed approach is far superior, then the Board should follow the superior approach.

The current approach is inadequate both with respect to the cost of debt and the cost of equity.

With respect to the cost of debt, long term debt is passed through at actual costs.[22] The short term debt rate is based on a technically flawed assumption. Specifically, short term debt is set at a deemed cost of a 90 day bankers acceptance rate plus 25 basis points. The same calculation is applied for variance and deferral accounts. The consequence is that the current approved rate under this formula is .55 percent. Distributors borrow short term rate at a rate which is three to five times that amount.[23] This demonstrates that the 25 basis point spread embedded in this rate is inappropriate.

A 25 basis point spread above the 90 day bankers' acceptance rate is a rate that is available to major finance company borrowers, not distributors. A way to remedy this technical deficiency would be for the Board to survey Schedule I banks for a more realistic spread to apply to LDCs.

With respect to the cost of equity, CLD's submission is that, in the short term, effective for the 2010 rate year and for annual adjustments thereafter, the Board should apply the results from Concentric's cost of capital study detailed at Part III of its Written Comments.

However, the Board should be careful that it does not only follow the results of any formula, including the formula proposed by the CLD. Avoiding this result involves two actions: first, regularly testing the outcome of any formula by reference to

[22] Transcript, October 6, p. 148.
[23] Transcript, October 6, pp. 147-149.

empirical data on the cost of capital; and second, allowing utilities to apply for a cost of capital on an evidentiary basis. Each will be addressed in turn.

With respect to the need for regular testing, it almost goes without saying that all formulas become dated and should be constantly re-evaluated to ensure that the information produced by that formula is the best information available to determine a just and reasonable rate. The CLD proposes that the Board adopt a methodology that allows for the systematic testing of the operation of the formula. This methodology allows the Board flexibility to depart from the formula when and if the formula leads to anomalous results.

The CLD submits that the tests proposed by Concentric and those proposed by Dr. Vander Weide are helpful in this regard.

Dr. Vander Weide suggested six tests that can be used to evaluate whether the Board approved rate of return meets the fair return standard. Each of these tests involve measuring the Board approved rate with empirical evidence of the real cost of capital. The evidence for each of these tests is as follows:[24]

> 1. Evidence on Experienced Equity Risk Premiums on Investments in Canadian Utility Stocks.
>
> 2. Evidence on Recent Allowed Rates of Return on Equity for U.S. Utilities.
>
> 3. Evidence on the Sensitivity of the Forward-looking Required Equity Risk Premium on Utility Stocks to Changes in Interest Rates.
>
> 4. Evidence on the Sensitivity of the Allowed Equity Risk Premium for U.S. Utilities to Changes in Interest Rates.
>
> 5. Evidence on the Relative Risk of Returns on Canadian Utility Stocks Compared to the Canadian Market Index.
>
> 6. Evidence on Whether the Board's ROE formula Produces Lower Results in a Period of Increased Risk and Uncertainty in the Economic and Capital Markets

The CLD proposes that the Board maintain clear and sufficient data that would allow the regular testing of any formulaic result by reference to these criteria and conduct regular testing of its results by reference to the criteria proposed by Concentric or by Dr. Vander Weide.

With respect to utility applications, there is no reason in law or practice why a utility cannot apply for an ROE based on its actual cost of capital. Although the CLD appreciates that the Board, for administrative purposes, would prefer to use a default formulaic approach, that approach should only be a default and not purport to be an actual determination of a utility's cost of capital. A utility should be able to apply for a cost of capital based on evidence. Such an application should not presumptively apply an ROE formula. Rather, the evaluation of an appropriate cost

[24] Appendix A to Responses to Questions Raised at Issues Discussion at Stakeholder Conference, James H. Vander Weide, Ph. D.

of capital should be based on the evidence provided and based on an appropriate cost of capital for a well run, efficient and economically sized utility.

Conclusion

This review has provided the Board with important information on how its current approach to the cost of capital is working in the real world. It is a world marked by unprecedented demand for energy infrastructure investment. Other jurisdictions have aggressively pursued this investment. The information provided in this review makes it clear that the current approach will not result in the Board successfully ensuring that capital investment is attracted to Ontario in an economically efficient manner.

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7-Staff-31 Direct Allocations

References:

1. Exhibit 7 Tab 1 Schedule 1
2. Worksheet I9 – Direct Allocation

Preamble:

In Reference 1, Horizon points to the direct allocation of PILs, debt and equity to the new LU(2) class. In Reference 2, Account 1840 U/G Conduit and Account 1845 UG Conduit and Devices are assigned to this new class.

a. What basis was used to develop these costs (categorization & assignment)?
b. Please describe why the method was chosen.

Response:

a. The methodology for Account 1840 U/G Conduit and Account 1845 UG Conduit and Devices is explained at Exhibit 7, Tab 1, Schedule 2, Appendix 7.1, section 3.1.6:

> Through examination of the assets required by the Large Use (2) class, it was determined that 100% of the customers in this rate class were served exclusively by dedicated conductors, and nearly exclusively by dedicated conduit. Furthermore, it was established that under current design practices, if the conductors and conduit were to be replaced, these assets would be fully dedicated to the Large Use (2) class, and if a new customer qualified for the Large Use (2), that customer would also be served from dedicated assets. As such, the Large Use (2) customers do not participate in use of the pooled assets in accounts 1830, 1835, 1840, and 1845.

With respect to PILs, debt, and equity, Worksheet I9 - Direct Allocation calculates the amount of PILs, debt, and equity associated with the directly allocated assets included in rate base to allocate on the basis of direct allocation. This amount is used by the model in assigning PILs, debt, and equity associated with the directly allocated assets.

b. This method was chosen in order to better reflect cost causation. In this case, where assets or costs are dedicated to the service of one rate class, it is appropriate to directly allocate the assets or costs to that rate class so that other rate classes are not responsible for assets they do not use. At the same time, since the LU (2) rate class

does not participate in the use of the pooled assets in accounts 1830, 1835, 1840, and 1845, it is appropriate that it not be allocated a share of the pooled costs.

8-Staff-32 Fixed – Variable Split

References:

1. Exhibit 8 Tab 1 Schedule 2
2. Worksheet O2 – Fixed Charge
3. Report of the Board EB-2007-0667 Application of Cost Allocation for Electricity Distributors, November 28, 2007

Preamble:

Board staff has developed the following table based on the proposed fixed rates from Reference 1 and the ceiling for fixed rates in Reference 2. The rates highlighted in Orange are above the ceiling.

Fixed Rate Compared to the Ceiling

	2011 per App.		2015		2016		2017		2018		2019	
	Ceiling	Rate	Ceiling	Rate	Ceiling	Rate	Ceiling	Rate	Ceiling	Rate	Ceiling	Rate
10 Res	13.81	14.71	13.69	16.38	14.43	17.13	14.69	17.49	14.80	17.74	14.94	18.25
11 GS<50	21.05	33.87	19.28	41.33	20.67	43.26	20.93	44.28	20.97	44.91	21.13	46.20
12 GS 50-4,999	122.54	332.50	88.24	376.90	100.57	394.61	100.92	404.56	98.99	410.35	99.01	422.19
13 Standby												
14 LU(1)	722.23	26,699.15	1,229.24	17,835.83	1,546.90	18,655.46	1,554.31	19,042.30	1,513.72	19,314.38	1,504.94	19,868.86
15 LU(2)			2,299.20	3,015.85	2,397.90	3,598.73	2,444.74	4,784.55	2,419.00	4,856.33	2,432.71	4,995.75
16 Sent	9.92	5.34	10.48	5.69	11.04	5.95	11.33	6.09	11.40	6.19	11.67	6.36
17 Street	9.85	2.98	7.01	2.97	7.42	3.11	7.51	3.19	7.63	3.23	7.87	3.33
18 USL	10.28	10.95	7.56	9.54	7.95	9.73	8.13	9.93	8.18	10.04	8.21	10.32

In Reference 3, the Board stated:

"In the interim, the Board does not expect distributors to make changes to the MSC that result in a charge that is greater than the ceiling as defined in the Methodology for the MSC. Distributors that are currently above this value are not required to make changes to their current MSC to bring it to or below this level at this time."

It is apparent that not only are the rates moving further above the ceiling for the residential and general service classes, but, in splitting the Large User class which was below the ceiling, Horizon has set the two new offspring rates with fixed charges above the ceiling.

a. Why has Horizon, in general, continued to increase the gap between the ceiling and the fixed rate?

b. What impeded Horizon from setting the new Large User classes at or below the ceiling?

Response:

a. Horizon Utilities has applied for fixed and variable distribution rates that maintain the existing Board-approved fixed/variable split for each rate class. This fixed/variable split was approved in Horizon Utilities' 2011 Cost of Service application (EB-2010-0131). The Board-approved fixed charge was higher than the ceiling at that time. In the Application, Horizon Utilities has continued the existing fixed/variable split to maintain the Board-approved fixed/variable split, which results in the the higher fixed charges. Horizon Utilities therefore believes its proposal is appropriate.

Horizon Utilities' proposal is further substantiated by the Board's current proposal *o*n revenue decoupling, currently in the consultation phase. In the Board's *Draft Report of the Board on Rate Design for Electricity Distributors* (EB-2012-0410, issued March 31, 2014) the Board states:

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

The Board's Draft Report made specific proposals under three options for the small volume classes (Residential, GS>50). All three options are based on 100% recovery of the revenue requirement through fixed charges. For the remaining classes, the Board noted that it will deal with such classes once certain demand measurement matters are addressed. Horizon Utilities' proposed fixed charges are closer to the Board's contemplated 100% solution for the small customer classes and are consistent with the Board's principle and contemplation for the remaining classes. Horizon Utilities' proposed fixed charges are therefore more appropriate than the charges that would flow from the old MSC approach. Notably, Horizon Utilities' proposed fixed rates will lessen the customer impact in the event a 100% fixed charge, or at least a higher fixed charge than currently, rate design solution is implemented.

b. As noted in a) Horizon Utilities maintained the existing fixed/variable split for each customer class as approved in the 2011 Cost of Service application (EB-2010-0131). Tables 8-3 and 8-4 from Exhibit 8, Tab 1, Schedule 2 show the current and proposed fixed/variable split. As discussed at Exhibit 8, Tab 1, Schedule 2, Page 2, Horizon Utilities has proposed a fixed/variable split for the LU (1) and LU (2) class that is

consistent with that which was approved in the 2011 Application for the LU class. For these reason and for the other reasons noted in a) with regard to Board's statements and contemplation around fixed charges for the larger customer classes, Horizon Utilities believes its proposals are appropriate.

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8-Staff-33 Bill Impacts

Reference:

1. Exhibit 8 Tab 4 Schedule 1
2. Exhibit 2 Appendix 2-4 Appendix A Innovative Customer Consultation Report
3. Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012

Preamble:

Board staff has reviewed the rate impacts for 2015 – 2019 found in Reference 1. For prescribed Residential and General Service <50 KW the impacts are as indicated in the following table developed by Board staff.

Rate Impacts

	2015		2016		2017		2018		2019	
	$	%	$	%	$	%	$	%	$	%
Distribution Only (Subtotal A)										
Residential @ 800 kWh	1.08	3.8	1.38	4.7	0.60	2.0	0.41	1.3	0.91	3.8
GS<50 kW @ 2,000 kWh	10.96	20.1	0.83	1.3	1.62	2.5	1.03	1.5	1.89	20.1

Board staff also developed the following table for the two new Large User Classes in Reference 1.

Rate Impacts

	2015		2016		2017		2018		2019	
	$	%	$	%	$	%	$	%	$	%
Distribution Only										
LU(1) @12.5 MW	- 9,817	-24.2%	1,707	5.6%	672	2.1%	473	1.4%	963	2.9%
LU(2) @ 15 MW	- 38,407	-87.4%	1,237	22.3%	2,236	33.0%	135	1.5%	262	2.9%
LU(2) @ 20 MW	- 44,422	-87.4%	1,455	22.8%	2,585	33.0%	156	1.5%	303	2.9%

In Reference 2, some of Horizon's key account customers (3 of the 9 surveyed) preferred no rate increases and believed the rate change is unreasonable and opposed it.

In Reference 3, the Board wants distributors to appropriately pace its investments.

a. Given the impacts for the remaining years why is Horizon not proposing mitigation measures for GS<50 20.1% in 2015?

b. After large decreases in 2015, the Large User class has significant increases. Why has Horizon not proposed rate mitigation, particularly in light of some of its Key Account customer comments?

c. What capital investments or OM&A programs could be deferred or reduced or spread out that would assist in keeping the increases in the early years down?

Response:

a. When evaluating the need for rate mitigation strategies, Horizon Utilities has considered the rate increases on a total bill basis, consistent with the Board's Chapter 2 Filing Requirements section 2.11.12.1. For the GS < 50 kW class specifically, as shown in Table 8-43 of Exhibit 8, Tab 4, Schedule 1, the total bill increase in 2015 is 5.88% which is well below levels that would warrant rate mitigation according to Board policies and practices. Horizon Utilities did not propose rate mitigation, as a result.

b. The increases in 2016 and 2017 for the Large Use class are the result of capital work to be completed on a transformer station that is a dedicated asset that is directly allocated to the LU (2) class. The LU (2) customers are aware that because they are served using dedicated assets that are directly allocated to them, all costs associated with those dedicated assets (such as the work stated above), will be fully incorporated into their distribution rates.

Furthermore, while the proposed increases to LU (2) rates in 2016 and 2017 are large as compared to the prior year's rates as filed, compared to the existing 2014 rates this class still experiences a rate decrease. Table 1 below provides the distribution bill impacts for the LU (2) class comparing each subsequent rate year to the 2014 existing Large Use rates.

Table 1: LU (2) Distribution Rate Bill Impacts Compared to 2014 Existing Rates

	LU (2) @ 20 MW	LU (2) @ 15 MW
2015 DX Revenues at Existing 2014 Rates	$ 50,960	$ 44,064
2015 DX Revenues at Proposed 2015 Rates	$ 6,574	$ 5,684
2015 DX Bill increase (%)	-87.10%	-87.10%
2016 DX Revenues at Existing 2014 Rates	$ 50,960	$ 44,064
2016 DX Revenues at Proposed 2016 Rates	$ 7,845	$ 6,783
2016 DX Bill increase (%)	-84.61%	-84.61%
2017 DX Revenues at Existing 2014 Rates	$ 50,960	$ 44,064
2017 DX Revenues at Proposed 2017 Rates	$ 10,431	$ 9,154
2017 DX Bill increase (%)	-79.53%	-79.23%
2018 DX Revenues at Existing 2014 Rates	$ 50,960	$ 44,064
2018 DX Revenues at Proposed 2018 Rates	$ 10,586	$ 9,154
2018 DX Bill increase (%)	-79.23%	-79.23%
2019 DX Revenues at Existing 2014 Rates	$ 50,960	$ 44,064
2019 DX Revenues at Proposed 2019 Rates	$ 10,890	$ 9,416
2019 DX Bill increase (%)	-78.63%	-78.63%

c. Horizon Utilities has submitted a comprehensive capital plan that outlines the needs of the business to best safely and reliably serve its customer base. As summarized in Exhibit 1, Tab 2, Schedule 6, Page 9:

The major drivers of Horizon Utilities' Distribution System Plan are the necessary renewal investments in: the distribution system; buildings and related underlying systems and processes; and the Smart Meter implementation. A significant portion of Horizon Utilities' asset infrastructure is now largely due for renewal. Horizon Utilities has been able to extend the life of this equipment through careful management and prudent investments focused on the long term stewardship of these assets. However, the health of a significant portion of these assets is degrading and must be replaced along a carefully managed timeframe in a manner that balances distribution system risks and customer rate impacts. Building infrastructure systems are at or nearing end of life, resulting in: poor equipment performance; increased risk of system failure; poor work environments for employees; and increased health and safety risks.

Horizon Utilities has paced its capital program, as identified in Exhibit 2 Appendix 2-4 Section 3.1 Summary of Capital Expenditure Plan, compared to the recommendation provided by Kinectrics in its ACA.

Regarding OM&A expenditures, in Exhibit 1, Tab 2, Schedule 6, page 27, Horizon Utilities notes:

There is urgency to step up OM&A in 2014 and 2015 to address the non-controllable, regulatory, and managed cost drivers that will affect Horizon Utilities in those years and thereafter. The rationale and justification for such managed growth is articulated in the Application and corresponds to themes such as: support for urgent and rising distribution renewal investment and ongoing medium-term growth in maintenance programs; delivery of customer value through information technology investments to enhance distribution system management and monitoring and timely customer access and response; and to provide functional and sustainable office and operating centre work environments.

Overall, the Application already incorporates pacing of capital expenditures and OM&A to best serve the immediate and long-term needs of its customers. Additionally, the Application articulates a sequencing of expenditure with respect to certain programs. Consequently, Horizon Utilities does not recommend any further deferral or reduction of expenditures as rate mitigation.

9-Staff-34 Depreciation

References:

1. **Appendix 2-EA Account 1575 – IFRS-CGAAP Transitional PP&E Amounts**
2. **Exhibit 6 Tab 2 Schedule 1, Table 6-10 and Table 6-7**
3. **Exhibit 1 Tab 5 Audited Financial Statements for 2011**

Preamble:

Board staff notes that the evidence provided under Appendix 2-EA with respect to additions and depreciation is not consistent with evidence under Table 6-10, Table 6-7, and Horizon's audited financial statements.

The discrepancies noted between the evidence provided under Appendix 2-EA and that under Table 6-10 is detailed in the two Tables below.

CGAAP

	Appendix 2-EA	Table 6-10	Difference
Net Additions	10,739,863	39,840,632	29,100,769
Net Depreciation	1,379,834	-27,720,934	-29,100,768

MIFRS

	Appendix 2-EA	Table 6-10	Difference
Additions	28,938,504	30,500,974	1,562,470
Derecognition		-1,512,181	-1,512,181
Net Depreciation	-16,079,487	-16,129,776	-50,289

a. Please explain the differences noted above between Appendix 2-EA and Table 6-10.

b. According to Table 6-7, indirect costs which were permitted to be capitalized under CGAAP are not capitalized under IFRS. However, per Appendix 2-EA, net additions are lower under CGAAP for 2011 than under IFRS. Please explain.

c. In Appendix 2-EA, the depreciation amount is a positive number. Appendix 2-EA row for net depreciation under both, CGAAP and MIFRS reads: "Net Depreciation (amounts should be negative)". Please explain why the depreciation is a positive number in 2011 under CGAAP.

d. Note 1 at the bottom of Table 6-10 states: "CGAAP depreciation excludes impact of CGAAP write-off of assets at end-of-life of $29,100,768". Please provide reasons for such a large (approximately 10% of the Opening Net Book Value) write-off in 2011. Where has Horizon recorded the write-off?

e. The depreciation expense in Appendix 2-EA does not match the 2011 audited financial statements of Horizon. Depreciation expense for 2011 in Consolidated Statement of Income and Retained Earnings for Horizon is shown as $28,371,000. Please provide reasons for this amount to be different from the one used for calculating Account 1575 in Appendix 2-EA under CGAAP.

Response:

a. CGAAP Net Additions: The Net Additions amount in Appendix 2-EA consists of capital additions of $39,840,632 less the asset cost of fully depreciated assets derecognized in the year of $29,100,768, for a Net Additions amount of $10,739,863. Table 6-10 shows the amount of Additions only of $39,840,632, without netting the amount of derecognized assets. The difference of $29,100,768 is the asset cost of fully depreciated assets derecognized under CGAAP in 2011.

CGAAP Net Depreciation: The Net Depreciation amount in Appendix 2-EA consists of depreciation of $27,720,934 less the accumulated depreciation value of fully depreciated assets derecognized in the year of $29,100,768, for a net amount of $1,379,834. Table 6-10 shows the amount of Depreciation only of $27,720,934, excluding the impact of the write-off of assets at end-of-life under CGAAP. The difference of $29,100,768 is the accumulated depreciation value of fully depreciated assets derecognized under CGAAP in 2011.

In Table 6-10 the derecognition of assets is shown on a separate line following Additions and Depreciation, where the asset value ($29,100,768) and accumulated depreciation value ($29,100,768) of fully depreciated assets at end-of-life are netted to zero.

A comparison of the change in opening to closing Net PP&E for 2011 under CGAAP between Appendix 2-EA and Table 6-10 is illustrated in the table below. There is no impact to net PP&E.

Table 1: Net PP&E 2011 CGAAP

2011 CGAAP	Appendix 2-EA	Table 6-10	Difference
Additions	$ 39,840,632	**$ 39,840,632**	$ -
Asset Value Derecognition	$ (29,100,768)		$ 29,100,768
Net Additions	**$ 10,739,863**		
Depreciation	$ (27,720,934)	**$ (27,720,934)**	$ -
Acc Deprec Value Derecognition	$ 29,100,768		$ (29,100,768)
Net Depreciation	**$ 1,379,834**		
Asset Value Derecognition		$ 29,100,768	$ 29,100,768
Acc Deprec Value Derecognition		$ (29,100,768)	$ (29,100,768)
Derecognition of Assets (Net of Depreciation)		**$ -**	
Change in Opening and Closing Net PP&E	$ 12,119,698	$ 12,119,698	$ -

MIFRS Additions: The Net Additions amount in Appendix 2-EA consists of capital additions of $39,840,632 less the burden adjustment of $9,339,658 from the IFRS conversion (as identified on page 9 of Exhibit 6 Tab 2 Schedule 1) and the gross cost of assets derecognized in the year of $1,562,469, for a net amount of $28,938,504. Table 6-10 shows the amount of Additions of $39,840,632 less the burden adjustment of $9,339,658 upon IFRS conversion, of $30,500,974, excluding the amount of derecognized assets. The difference of $1,562,469 is the cost of assets derecognized under MIFRS in 2011.

MIFRS Derecognition: In Appendix 2-EA the asset and accumulated depreciation amounts of derecognized assets are netted against additions and depreciation. In Table 6-10 the MIFRS derecognition of assets is shown as a separate line following Additions and Depreciation, where the asset value ($1,562,469) and accumulated depreciation value ($50,288) are netted to $1,512,181.

MIFRS Net Depreciation: The Net Depreciation amount in Appendix 2-EA of $16,079,487 consists of depreciation on capital assets of $16,257,673 less the depreciation on the burden adjustment from IFRS conversion of $127,897 and the accumulated depreciation value of assets derecognized in the year of $50,288. The Depreciation amount of $16,129,776 in Table 6-10 consists of the same amounts of depreciation ($16,257,673) less the depreciation on the burden adjustment from IFRS conversion ($127,897), excluding the impact of derecognized assets. The difference of $50,288 is the accumulated depreciation value of assets derecognized under MIFRS in 2011 and is included in the Derecognition of

Assets amount of $1,512,181 in Table 6-10, which is equal to gross assets of $1,562,469 less accumulated depreciation of $50,288.

A comparison of the change in opening to closing Net PP&E for 2011 under MIFRS between Appendix 2-EA and Table 6-10 is illustrated in the table below. There is no impact to net PP&E.

Table 2: Net PP&E 2011 MIFRS

2011 MIFRS	Appendix 2-EA	Table 6-10	Difference
Additions without IFRS Burden Adjmt	$ 39,840,632	$ 39,840,632	$ -
IFRS Conversion Burden Adjustment	$ (9,339,658)	$ (9,339,658)	$ -
Additions		**$ 30,500,974**	
Asset Value Derecognition	$ (1,562,469)		$ 1,562,469
Net Additions	**$ 28,938,504**		
Asset Value Derecognition		$ (1,562,469)	$ (1,562,469)
Acc Deprec Value Derecognition		$ 50,288	$ 50,288
Derecognition of Assets (Net of Depreciation)		**$ (1,512,181)**	
Depreciation without IFRS Burden Adjmt	$ (16,257,673)	$ (16,257,673)	$ -
IFRS Conversion Burden Adjustment	$ 127,897	$ 127,897	$ -
Depreciation		**$ (16,129,776)**	
Acc Deprec Value Derecognition	$ 50,288		$ (50,288)
Net Depreciation	**$ (16,079,487)**		
Change in Opening and Closing Net PP&E	$ 12,859,017	$ 12,859,017	$ -

b. 2011 Net Additions under CGAAP of $10,739,863 were lower than Net Additions under MIFRS of $28,938,504 by $18,198,641. This difference is attributed to two changes in accounting policy during the conversion from CGAAP to IFRS: indirect costs and derecognition of assets, which are further explained in Exhibit 6, Tab 2, Schedule 1. Indirect costs which were not permitted to be capitalized under IFRS caused Net Additions under IFRS to be lower than Net Additions under CGAAP by $9,339,658. Offsetting this reduction was the impact of the change in policy for derecognition of assets. Under CGAAP for rate regulated entities using a pooled approach to fixed asset recognition, PP&E assets were removed at the end of their depreciable lives, and for 2011 this amount was $29,100,768. Under IFRS, an item of PP&E is derecognized when it is disposed of or when no future economic benefits are expected from its continued use or retention, and for 2011 this amount was $1,562,469. This difference in the asset value of derecognized assets of

$27,538,299 offsets the impact of the burden adjustment, and results in additions under MIFRS greater than under CGAAP. This difference is summarized in the table below.

Table 3: Net Additions CGAAP vs MIFRS

Appendix 2-EA	2011 CGAAP	2011 MIFRS	Difference
Additions without IFRS Burden Adjmt	$ 39,840,632	$ 39,840,632	$ -
IFRS Conversion Burden Adjustment		$ (9,339,658)	$ (9,339,658)
Asset Value Derecognition	$ (29,100,768)	$ (1,562,469)	$ 27,538,299
Net Additions	**$ 10,739,863**	**$ 28,938,504**	**$ 18,198,641**

c. In Appendix 2-EA the Net Depreciation for 2011 under CGAAP is a positive amount of $1,379,834, although the row reads that "amounts should be negative". This Net Depreciation amount consists of depreciation of $27,720,934 which is netted against the asset value of fully depreciated assets of $29,100,768 that had reached end-of-life in 2011. Since the value of the end-of-life assets is greater than the depreciation for the year, the amount is positive. The composition of Net Depreciation is summarized in the table below. Please refer to response (d) for further information concerning the amount of fully depreciated assets that had reached end-of-life in 2011.

Table 4: 2011 CGAAP Net Depreciation

2011 CGAAP	Appendix 2-EA
Depreciation	$ (27,720,934)
Acc Deprec Value of Derecognized Assets	$ 29,100,768
Net Depreciation	**$ 1,379,834**

d. Under CGAAP for rate regulated entities, PP&E assets were written off at the end of their depreciable lives. Horizon recorded the write-off of fully depreciated assets for 2011 of $29,100,768 by reducing the asset and accumulated depreciation values by the same amount. As these assets were fully depreciated, there was no charge or credit to income from this write-off.

The amount of the write-off of fully depreciated assets in 2011 was largely due to a change in the useful lives of assets implemented in 1986 under the authority of Ontario Hydro. The remaining useful lives of a substantial number of assets were changed in 1986 to 25 years, which resulted in these assets reaching their end-of-life in 2011.

e. Depreciation expense of $28,371,000 in the audited financial statements of Horizon Utilities is different from the Net Depreciation amount of $1,379,834 in Appendix 2-EA for several reasons. The $28,371,000 amount from the audited financial statements includes Non Wires activities of $155,000, and a Regulatory Deferral and Variance Account Adjustment of $1,826,000 related to smart meters. After these adjustments, the depreciation expense included in this application is $26,390,000. This reconciliation is shown in Exhibit 1, Tab 5, Appendix 1.11.1 2011 Audited Financial Statements Reconciled to Regulatory Financial Results.

The Net Depreciation amount in Appendix 2-EA of $1,379,834 is the change in accumulated depreciation for 2011 which consists of the increase in accumulated depreciation from depreciation expense ($27,720,934), reduced by the value of fully depreciated derecognized assets ($29,100,768). The depreciation expense of $27,720,934 is further reduced by the amount of fleet and stores equipment depreciation under CGAAP that was allocated to capital and not included in depreciation expense ($1,331,522), resulting in depreciation expense for 2011 CGAAP of $26,389,412 as identified in Exhibit 4, Tab 1, Schedule 1, Table 4-5.

The table below illustrates how these amounts reconcile.

Table 5: Reconciliation

Financial Statements		**Depreciation Expense**
Horizon Utilities Depreciation Expense		**$ 28,371,000**
Non Wires activities		$ (155,000)
Regulatory Deferral & Variance Account Adjustments		$ (1,826,000)
Regulatory Statements Depreciation Expense		$ 26,390,000
Appendix 2-EA	**Change in Accumulated Depreciation**	**Depreciation Expense**
Net Depreciation	**$ 1,379,834**	
Acc Deprec Value of Derecognized Assets	$ (29,100,768)	
Depreciation Expense offset in Accumulated Depreciation	$ (27,720,934)	$ 27,720,934
Fleet & Stores Capitalized Depreciation		$ (1,331,522)
Regulatory Statements Depreciation Expense		$ 26,389,412

9-Staff-35 RRR Reconciliation

References:

1. **Appendix 2-BA1 Fixed Assets Continuity Schedule for 2011**
2. **Horizon's RRR 2.1.7 filing 2011, published in the 2011 Yearbook**

Preamble:

Board staff notes a difference in reported PP&E and Depreciation between the Application and Horizon's RRR filing.

Please explain the discrepancy between the two.

	2-BA1	Yearbook	Difference
Gross PP&E	642,704,976	670,042,169	-27,337,193
Depreciation expens	27,720,934	26,389,412	1,331,522

Response:

Gross PP&E: The Gross PP&E amount of $642,704,976 recorded in the fixed asset continuity schedule in 2011 ("2-BA1") reported under CGAAP is $27,337,193 lower than the Gross PP&E amount reported in the 2011 Yearbook. The Gross PP&E amount of $642,704,976 in 2-BA1 is before Work-In-Progress ("WIP") of $8,414,355. The Gross PP&E amount reported in the 2011 Yearbook includes WIP of $8,414,355 and Goodwill of $18,922,839 related to an acquisition made prior to 2011. The latter amount is recorded in "2060 – Electric Plant Acquisition Adjustment" and should not be and is not included in 2-BA1. A reconciliation of the Gross PP&E amounts is identified in the table below.

Table 1: Gross PP&E Amounts

Description	Amount
Gross PP&E per 2-BA1 excluding WIP	**$642,704,976**
WIP	$8,414,355
Gross PP&E per 2-BA1 including WIP	**$651,119,331**
2060 – Electric Plant Acquisition Adjustment (Goodwill)	$18,922,839
Gross PP&E per 2011 Yearbook	**$670,042,169**

Depreciation Expense: The depreciation of $27,720,934 recorded on the fixed asset continuity schedule in 2011 reported under CGAAP is $1,331,522 higher than the depreciation expense recorded on the income statement of $26,389,412, as identified in Table 2-28 on page 2 of Exhibit 2, Tab 3, Schedule 3. Table 2-28 is provided as reference below. Depreciation on fleet and stores equipment reported under CGAAP was allocated to capital and was not recorded as a charge or credit to income. A detailed explanation is provided on page 1 of Exhibit 2, Tab 3, Schedule 3.

Table 2-28 - Reconciliation of Depreciation on Continuities to Depreciation Expense

Description	2011 Actual CGAAP	2012 Actual MIFRS	2013 Actual MIFRS	2014 Bridge Year MIFRS	2015 Test Year MIFRS	2016 Test Year MIFRS	2017 Test Year MIFRS	2018 Test Year MIFRS	2019 Test Year MIFRS
Total Depreciation on Continuties	**$ 27,720,934**	**$18,191,399**	**$19,299,511**	**$21,023,720**	**$23,383,544**	**$24,201,320**	**$24,161,257**	**$23,437,190**	**$23,877,061**
Deduct:									
Fleet/Stores Depreciation Allocated to Capital	$ (1,331,522)								
Add: (Gain)/Loss on Derecognition:									
Cost	$0	$2,027,707	$1,793,609	$1,773,488	$2,089,496	$3,825,068	$3,017,473	$3,318,009	$4,597,818
Accumulated Depreciation	$0	($150,765)	($156,463)	($133,043)	($187,423)	($1,085,758)	($344,159)	($430,511)	($1,426,748)
Proceeds	$0	($443,492)	($518,695)	($267,360)	($315,000)	($453,006)	($454,896)	($500,203)	($557,460)
(Gain)/Loss on Derecognition of PP&E	**$0**	**$1,433,449**	**$1,118,452**	**$1,373,086**	**$1,587,074**	**$2,286,304**	**$2,218,419**	**$2,387,296**	**$2,613,609**
Total Depreciation Expense	**$ 26,389,412**	**$ 19,624,849**	**$ 20,417,963**	**$ 22,396,806**	**$ 24,970,618**	**$ 26,487,624**	**$ 26,379,676**	**$ 25,824,486**	**$ 26,490,670**

9-Staff-36 Account 1575 – IFRS-CGAAP Transitional PP&E Amounts

References:

1. Appendix 2-EA Account 1575 – IFRS-CGAAP Transitional PP&E Amounts
2. Horizon's RRR 2.1.7 filings for 2010 and 2011, published in the respective Yearbooks

Preamble:

Board staff notes that the balances for Net PP&E and Depreciation Expense amount used in the calculation of Appendix 2-EA do not agree to the RRR 2.1.7 filings for 2010 and 2011, and as published in the respective yearbooks.

Using the 2010 Closing Net PP&E for the Opening Net PP&E for 2011, and Depreciation Expense as reported to the Board for 2011, please recalculate the account balance for Account 1575.

Response:

Horizon Utilities agrees that the balances for Net PP&E and Depreciation Expense amount used in the calculation of Appendix 2-EA do not agree to the RRR 2.1.7 filings for 2010 and 2011, and as published in the respective yearbooks. However, the Net PP&E and Depreciation Expense amounts submitted in the RRR 2.1.7 filings for 2010 and 2011 include amounts which should not be used for the calculation of Appendix 2-EA. Horizon Utilities has provided a reconciliation of the balances below.

Net PP&E for 2010 and 2011: As identified in Board Interrogatory 9-Staff-35, the net PP&E amount reported in the Yearbooks includes Work-in-Progress ("WIP") and Goodwill amount of $18,922,839 related to an acquisition made prior to 2011. WIP is not included in the calculation of Appendix 2-EA as it is not a part of rate base. The Goodwill amount of $18,922,839 is recorded in "2060 – Electric Plant Acquisition Adjustment" and should not be and is not included in the calculation of Appendix 2-EA. A reconciliation of the net PP&E amounts is identified in the table below.

Table 1: Reconciliation of Net PP&E

Description	2010	2011
Closing Net PP&E - 1575	**$ 304,878,268**	**$ 316,997,965**
Work-in-Progress	$ 9,157,146	$ 8,414,355
Goodwill	$ 18,922,839	$ 18,922,839
Closing Net PP&E - Yearbook	**$ 332,958,253**	**$ 344,335,159**

Horizon Utilities has not recalculated the account balance for 1575 for any net PP&E differences as it believes it has used the correct net PP&E amounts in the calculation of Appendix 2-EA as previously submitted in Table 9-14 Appendix 2-EA Account 1575 – IFRS-CGAAP Transitional PP&E Amounts on page 2 of Exhibit 9, Tab 2, Schedule 2.

2011 Depreciation Expense: As identified in Board Interrogatory 9-Staff-35, the depreciation recorded on the fixed asset continuity schedule in 2011 reported under CGAAP (and used for the calculation of Appendix 2-EA) is $1,331,522 higher than the depreciation expense recorded on the income statement (and submitted in the 2.1.7 RRR filings) of $26,389,412. Depreciation on fleet and stores equipment reported under CGAAP was allocated to capital and was not recorded as a charge or credit to income. It should be included as part of the calculation of Appendix 2-EA as it is a part of rate base but does not appear on the income statement.

In addition to the above difference, Appendix 2-EA includes a reduction of $29,100,768 to gross assets and accumulated depreciation to reflect the write-off of fully depreciated assets for 2011 as identified in Board Staff Interrogatory 9-Staff-34. This amount could have been excluded from the calculation of Appendix 2-EA, however it would have had a zero net effect on Net Book Value and as a result had no impact to the calculation of Appendix 2-EA. A reconciliation of the net PP&E amounts is identified in the table below.

Table 2: Reconciliation of Net PP&E

Description	Net Additions	Net Depreciation
2011 Yearbook	**$ 39,840,632**	**$ 26,389,412**
Add Back Capitalized Depreciation on Fleet and Stores Equipment	$ -	$ 1,331,522
2011 Fixed Asset Continuity Statements - 2-BA1	**$ 39,840,632**	**$ 27,720,934**
Disposals	$ (29,100,768)	$ (29,100,768)
Net PP&E 1575	**$ 10,739,863**	**$ (1,379,834)**

Horizon Utilities has recalculated the account balance for 1575 using the Net Additions and Net Depreciation before the impact of the write-off of fully depreciated assets. The net depreciation used for the calculation of Appendix 2-EA is $27,720,934 which includes capitalized depreciation for fleet and stores equipment. The write-off of fully depreciated assets has a zero net effect on Net Book Value and as such, there is no impact to the calculation of Appendix 2-EA as identified in the table below.

Table 3: Impact on 2-EA

	2011 Rebasing Year	2012	2013	2014	2015 Rebasing Year	2016 Rebasing Year	2017 Rebasing Year	2018 Rebasing Year	2019 Rebasing Year
Reporting Basis	**CGAAP**	**IRM**	**IRM**	**IRM**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Forecast vs. Actual Used in Rebasing Year	**Forecast**	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**	**Forecast**
		$	$	$	$	$	$	$	$
PP&E Values under CGAAP									
Opening net PP&E - Note 1	304,878,268	316,997,965	365,070,186	382,168,427					
Net Additions - Note 4	39,840,632	79,043,474	48,352,195	51,959,529					
Net Depreciation (amounts should be negative) - Note 4	-27,720,934	-30,971,254	-31,253,954	-33,363,213					
Closing net PP&E (1)	316,997,965	365,070,186	382,168,427	400,764,743					
PP&E Values under MIFRS (Starts from 2011, the transition year)									
Opening net PP&E - Note 1	304,878,268	317,737,285	366,100,384	383,071,763					
Net Additions - Note 4	28,938,504	68,229,924	36,114,427	38,018,561					
Net Depreciation (amounts should be negative) - Note 4	-16,079,487	-19,866,824	-19,143,048	-20,890,677					
Closing net PP&E (2)	317,737,285	366,100,384	383,071,763	400,199,647					
Difference in Closing net PP&E, CGAAP vs. MIFRS	-739,320	-1,030,199	-903,337	565,095					

Effect on Deferral and Variance Account Rate Riders			
Closing balance in deferral account	565,095	**WACC**	5.77%
Return on Rate Base Associated with deferred PP&E balance at WACC - Note 2	32,619	**# of years of rate rider disposition period**	1
Amount included in Deferral and Variance Account Rate Rider Calculation	597,715		

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9-Staff-37 Fixed Asset Continuity

References:

1. Appendix 2-BA1, Fixed Asset Continuity Schedule – CGAAP 2011
2. Appendix 2-BA2, Fixed Asset Continuity Schedules for 2012, 2013, 2014, 2015

Preamble:

On page 12 of Article 510 of the APH effective January 1, 2012 it states: "Therefore, while a distributor electing the rate-regulated deemed cost exemption must record an adjusting entry in the USoA at the changeover date to reflect the fact that accumulated depreciation was set to nil under MIFRS at the transition date, the historical previous Canadian GAAP gross amounts must be maintained until the first rebasing under MIFRS" [Emphasis added]. Horizon has not fully maintained the gross amounts in this first rebasing application under MIFRS. Horizon included fixed asset continuity schedules for 2011 CGAAP on a gross basis and 2012 to 2015 MIFRS on a net basis.

a. Please explain why Horizon has not provided 2012 to 2015 fixed asset schedules on a gross basis.

b. For the 2012 to 2015 fixed asset schedules provided on a net basis, has Horizon ensured that the depreciation expense and net book value would be the same as that on a gross basis? Please explain and provide supporting analysis.

Response:

a. Horizon Utilities has not provided 2012 to 2015 fixed asset continuity schedules on a gross basis because the continuity schedules prepared on this basis result in the same Net Book Value ("NBV") as the continuity schedules provided in the application. There is an equal and offsetting impact to gross assets and accumulated depreciation as a result of electing the deemed cost exemption and setting accumulated depreciation to nil under MIFRS at the transition date. Rate Base is calculated based on average NBV and as such there is no impact to rate base of maintaining the gross amounts of assets and accumulated depreciation as compared to providing them on a MIFRS (net) basis.

b. Horizon Utilities has ensured that the depreciation expense and net book value calculated for the 2012 to 2015 fixed asset schedules are the same as that on a gross basis. Furthermore, the depreciation expense and net book value calculated for the 2012 to 2015 fixed asset schedules have to be the same as that on a gross basis, due to the nature of the calculation for both scenarios.

The depreciation expense provided on a net basis is calculated by taking the gross asset amount (= to NBV at date of IFRS transition) of each asset divided by the remaining useful life.

The depreciation expense provided on a gross basis is derived by the same calculation (NBV at date of IFRS transition of each asset divided by the remaining useful life). On conversion to IFRS, Horizon Utilities established a new level of componentization and corresponding new useful lives. Due to the change in useful lives, and subsequently the change in remaining useful lives, the gross asset amount could not be used to calculate future depreciation expense. The only way to accurately calculate future depreciation expense on a gross basis is to use the NBV of each asset at the date of IFRS transition divided by the remaining useful life. As such the depreciation expense and net book value on a net basis are equal to depreciation expense and net book value on a gross basis.

9-Staff-38 Account 1588 – RSVA Power, and Account 1589 – RSVA Global Adjustment

Reference:

1. Exhibit 9 Tab 1 Scheduled 7

Preamble:

Horizon has indicated that it made adjustments to its previously approved balances for Account 1588 – RSVA Power, and Account 1589 – RSVA Global Adjustment. This adjustment impacted these two accounts as follows:

Description	USoA	2013 Original Balance [1]	Cumulative Adjustment	2013 Restated Balance
RSVA - Power	1588	$406,117	($4,728,759)	($4,322,642)
RSVA - Global Adjustment	1589	($4,936,309)	$4,728,759	($207,550)
Total		**($4,530,192)**	**$0**	**($4,530,192)**

[1] The rules relating to the calculation and billing of the GA are set out in a regulation under the Electricity Act, 1998 (O. Reg. 429/04). Under that regulation Class A consumers (large consumers whose peak demand in a month is more than 5 MW) are charged based on their consumption during the 5 peak hours in a "base period".

a. Please confirm that when prorating charge type 146 to non-RPP customers, Horizon excluded allocation of charge type 146 to Class A consumers who pay their full amount based on their peak demand on a monthly basis.

b. Please describe how the split was calculated for Class A for 2012 and 2013, which Horizon has since corrected.

c. Please provide supporting documentation on the adjustments made to Account 1588 and Account 1589 for 2012 and 2013.

d. Please provide the adjustment amount that relates to what was already approved by the Board for disposition in Horizon's 2014 proceeding.

Response:

a. Horizon Utilities confirms that when pro-rating the Class B global adjustment on the IESO invoice to RPP and non-RPP customers it excluded allocation of the Class B global adjustment to Class A customers.

However, to clarify part a. of the Board's question, for 2012 and 2013 there is no charge type 146 on the IESO invoice. The charge type 146 on the IESO invoice was in effect prior to 2012 and included the Class A and Class B global adjustment. For 2012 and

2013, the years to which the adjustment relates, the global adjustment on the IESO invoice appears as two charge types:

1. Charge Type 147 – Class A Global Adjustment Settlement Amount
2. Charge Type 148 – Class B Global Adjustment Settlement Amount

The adjustment that Horizon Utilities made to the allocation of the Class B Global Adjustment as identified in Exhibit 9, Tab 1, Schedule 7 was to adjust the allocation of the Class B global adjustment (Charge Type 148) to RPP and non-RPP customers. It did not affect Class A customers.

b. The split between RPP and non-RPP customers was not and did not need to be calculated for Class A customers for 2012 and 2013. The Class A global adjustment on the IESO invoice is a separate line item under charge code 147. All of Horizon Utilities' Class A customers are non-RPP customers. As such, 100% of the Class A global adjustment is allocated to non-RPP customers. Horizon Utilities did not need to and has not corrected the global adjustment allocation for Class A customers. The adjustment identified in Exhibit 9, Tab 1, Schedule 7 was related to the allocation of the Class B global adjustment only.

c. Horizon Utilities has provided supporting documentation for the adjustments made to Account 1588 and Account 1589 for 2012 and 2013 in the live excel filed as "9-Staff-38c_Attch 1_GA Adjustment".

d. The adjustment amount that relates to what was already approved by the Board for disposition in Horizon Utilities' 2014 proceeding (the adjustment relating to 2012) is identified in the table below.

Table 1: Approved Amounts

Description	USoA	Cumulative Adjustment
RSVA - Power	1588	($3,274,512)
RSVA - Global Adjustment	1589	$3,274,512
Total		**$0**

9-Staff-39 Account 1592 PILs

References:

1. Exhibit 9 Tab 2 Schedule 1
2. Table 9-11 – Account 1592 PILs and Tax Variances for 2006 and Subsequent Years

Preamble:

According to Horizon, the balance for disposition is a debit amount of $19,885 as of December 31, 2013 and comprises the difference between the projected interest in 2011 approved for disposition and the actual interest recorded in 2011.

a. The amount disposed in the 2011 proceeding was a credit amount. Please explain how a debit amount was calculated for carrying charges on a credit amount.

b. The amount per Table 9-11 does not match to the amount used for the rate rider calculation. Please explain and adjust as appropriate.

c. Why does Horizon believe that this account is different from other accounts as carrying charges are forecasted and disposed of in the same manner for all accounts? That is, the amounts disposed of should be the latest audited balances, and carrying charges should be projected to the beginning of the test year.

Response:

a. The balance for disposition in Account 1592 PILs is a debit amount of $19,885. Horizon Utilities' statement that the balance comprises the difference between the projected interest in 2011 approved for disposition and the actual interest recorded in 2011 is incorrect and was an unintentional error. The balance of $19,885 comprises the cumulative principal difference arising from the difference in the actual tax rate (26.50%) and approved tax rate (26.05%) used for the tax savings rate rider approved in Horizon Utilities' 2012 IRM Application (EB-2011-0172).

The tax savings were based on a tax rate of 26.05%. However, Horizon Utilities' actual tax rate was 26.50%, and as such the tax savings should have been calculated based on 26.50% not 26.05%.

In summary, the $19,885 debit balance in Account 1592 is a principal adjustment not an amount calculated for carrying charges.

Horizon Utilities provides a calculation of the carrying charges in Account 1592 below.

Table 1: Carrying Charges

Date	Opening Principal	Principal Adjustment	Principal Disposition	Closing Principal	Carrying Charges
Jan-11	($1,017,174.96)		$0.00	($1,017,174.96)	($1,246.04)
Feb-11	($1,017,174.96)		$0.00	($1,017,174.96)	($1,246.04)
Mar-11	($1,017,174.96)		$0.00	($1,017,174.96)	($1,246.04)
Apr-11	($1,017,174.96)		$0.00	($1,017,174.96)	($1,246.04)
May-11	($1,017,174.96)		$0.00	($1,017,174.96)	($1,246.04)
Jun-11	($1,017,174.96)		$0.00	($1,017,174.96)	($1,246.04)
Jul-11	($1,017,174.96)		$0.00	($1,017,174.96)	($1,246.04)
Aug-11	($1,017,174.96)		$1,017,174.96	$0.00	($1,246.04)
2011	($1,017,174.96)		$1,017,174.96	$0.00	($9,968.32)
2012	$0.00	$19,885.39	$0.00	$19,885.39	$131.76
2013	$19,885.39	$0.00	$0.00	$19,885.39	$292.32
TOTAL				**$19,885.39**	**($9,544.24)**

b. Table 9-11 shows an amount of $19,885 which is the principal adjustment related to the tax savings rider as described in part a. above. The rate rider calculation identified in Table 9-22 on page 2 of Exhibit 9, Tab 6, Schedule 1 and in Table 9-25 on page 2 of Exhibit 9, Tab 6, Schedule 4 uses the same principal balance of $19,885 in the rate rider calculation. Carrying charges to the beginning of the Test Year are also included in the rate rider calculation as identified in the table below.

Table 2: Amount Used for Rate Rider

Description	Amount
Principal Balance as of December 31, 2013 = Amount in Table 9-11	$19,885
Carrying Charges to December 31, 2013	$(9,544)
Sub-total December 31, 2013 Balance	**$10,341**
Projected Carrying Charges to December 31, 2014	$292
Total Amount Used for Rate Rider Calculation	**$10,634**

Horizon Utilities does not believe that an adjustment is necessary as the principal amount identified in Table 9-11 of $19,885 is consistent with the principal amount used in the rate rider calculation identified in Tables 9-22 and 9-25.

c. Horizon Utilities does not believe that Account 1592 is different from other accounts. The amount proposed for disposition is the latest 2013 audited balance, and carrying charges

have been projected to the beginning of the test year as identified in the table provided above in part b.

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9-Staff-40 Account 2405 – Other Regulatory Liabilities and Credits

Reference:

1. Exhibit 9 Tab 1 Schedule 5

Preamble:

Horizon has stated that this account was previously used to recover the overpayment of Low Voltage Charges from Hydro One for 2003 to 2008 and to recognize the liability to ratepayers as a result of the conversion related to HST. The amount proposed for disposition is a credit of $220,000.

Board staff notes that the APH requires the distributors to use Account 1592 for the savings related to HST.

a. Please explain the reasons for using a different account than the one provided in the APH for this purpose.

b. Please provide a breakdown of the components in this account and their respective dollar values.

Response:

a. The APH FAQs for December 2010 stated that "Sub-account HST/OVAT Input Tax Credits (ITCs)" be used to record the ITC savings from the elimination of the Provincial Sales Tax and the implementation of the HST on July 1, 2010. It also stated that the offsetting entry be recorded to a new sub-account, a contra account within Account 1592 "HST/OVAT Contra Account". Horizon Utilities did record the ITC savings in the correct accounts which had a zero net effect on reporting for regulatory reporting purposes.

In addition to the entries to 1592 described above, Horizon Utilities made an entry on a CGAAP basis in December, 2010 to reduce distribution revenue and recognize the liability owing to ratepayers, which represented 50% of the tax savings related to the HST implementation. The liability owing to ratepayers was recorded in Account 2405 – Other Regulatory Liabilities and Credits.

Upon subsequent review of the APH FAQs for December 2010, Horizon Utilities should have reversed the entry to Account 2405 for regulatory purposes and reported only the balance in Account 1592 "Sub-account HST/OVAT Input Tax Credits (ITCs)" for disposition. Although Account 2405 was used to record the liability owing to ratepayers, there is no change to the amount requested for disposition.

b. The credit of $220,000 in Account 2405 – Other Regulatory Liabilities and Credits represents the liability owing to ratepayers as a result of the harmonization of HST effective July 1, 2010. The credit of $220,000 represents 50% of the tax savings realized from July, 2010 to December 2010 due to HST harmonization. No carrying charges are included in this amount. There are no amounts related to the overpayment of Low Voltage Charges from Hydro One for 2003 to 2008 in Account 2405.

9-Staff-41 Account 1592 Harmonized Sales Tax Deferral Account

Reference:

1. Exhibit 9 Tab 2 Schedule 2

Preamble:

Horizon has stated that it has recorded the savings arising from the elimination of the PST and implementation of HST in Account 1592, and that these balances were disposed of Horizon's 2011 rate proceeding. The remaining balance of $19,885 proposed for disposition in the current application is the difference between the projected interest in 2011 approved for disposition and the actual interest recorded in 2011.

Board staff notes that the Board approved disposition of Horizon's Group 1 and Group 2 balances as of December 31, 2009 in Horizon's rate proceeding EB-2010-0131. Board staff notes that the approved disposition did not include any amounts related to the savings due to HST harmonization as the PST and GST were not harmonized until July1, 2010. There have been no Group 2 dispositions since EB-2010-0131 for Horizon.

a. Using the December 2010 FAQs for electricity distributors, please calculate the amounts refundable to customers for HST ITC savings. Please provide this calculation and other supporting documentation as necessary.

b. Please review the accounting entries in Account 1592 as the savings should result in a credit balance. That is, amounts refundable to customers. Horizon is currently showing a debit balance of $19,885 in this account.

c. Please adjust and provide the allocation of balances and rate rider calculations as necessary.

d. Please file the necessary documentation to indicate whether or not the impact of the HST and associated ITCs on capital and operating costs was reflected in Horizon's 2011 revenue requirement. If the impact was not included in the 2011 revenue requirement, please calculate the savings from July 1, 2010 to December 31, 2014.

Response:

The statement on page 1 in Exhibit 9, Tab 2, Schedule 2 that Horizon Utilities disposed of the balances related to the savings arising from the implementation of HST in Horizon Utilities' 2011 Cost of Service Application (EB-2010-0131) is incorrect. Horizon Utilities did not dispose of these balances in its Cost of Service Application EB-2010-0131.

a. Horizon Utilities calculated the amounts refundable to customers for HST ITC savings in December 2010 using the December 2010 FAQs for electricity distributors. The amount

calculated of $220,000 was recorded in Account 2405 – Other Regulatory Liabilities and Credits. An explanation of why Horizon Utilities used this account is provided in the response to Interrogatory 9-Staff-40a. Horizon Utilities has provided supporting calculations in 9-Staff-41a_Attch_HST Implementation Calculation.

b. The debit principal balance in 1592 of $19,885 relates to a tax savings rate rider as identified in Interrogatory Response 9-Staff-39a. The liability owing to ratepayers of $220,000 as a result of the implementation of HST has been recorded in Account 2405 as identified in Interrogatory Response 9-Staff-40.

c. The amounts requested for disposition both for the tax savings rate rider and the liability owing to ratepayers as a result of the implementation of HST are both correct. (The latter has been recorded in Account 2405 instead of Account 1592). As such, there is no adjustment to the rate rider calculations required.

d. Horizon Utilities confirms that the impact of the HST and associated ITCs on capital and operating costs was reflected in Horizon's 2011 revenue requirement. Horizon Utilities confirmed in Board Staff Interrogatory #57 from its 2011 CoS Application (EB-2010-0131) the following: "(a) Horizon Utilities' 2011 Test Year OM&A expenditures were budgeted on the basis that they exclude HST. In the preparation of the 2011 budget, direction was provided to the preparers of the 2011 departmental budgets to exclude HST from the amounts budgeted. In light of this approach to the preparation of the 2011 budget, the OM&A expenditures for 2011 inherently reflect any incremental ITC impact arising from the implementation of the HST... (b) Consistent with the response to (a) above, the budget for the 2011 Test Year capital expenditures was prepared on the basis that HST and/or PST was excluded from the amounts budgeted."

9-Staff-42 Account 1508 – IFRS Transition Costs

References:

1. Exhibit 9 Tab 3 Schedule 1
2. Table 9-13 – Account 1508 – IFRS Transition Costs

Preamble:

Board staff notes that Appendix 2-U of the filing requirements provided as Table 9-13 shows no amounts in row "Amounts, if any, included in previous Board approved rates (amounts should be negative)" except for the deferred account balance for $565,914 approved for disposition in EB-2010-0131.

a. Did Horizon have any one-time IFRS transition costs embedded in its rates from 2011 to 2014 (not including the amount disposed through a rate rider)? If so, how much?

b. Please recalculate the amount for disposition net of the amounts embedded in Horizon's ongoing rates from 2011 to 2014.

Response:

a. Horizon Utilities does not have any one-time IFRS transition costs embedded in its rates from 2011 to 2014. Horizon Utilities confirms that all transition costs specifically related to the implementation of IFRS, including information technology, project management, and other professional service fees to complete the balance of the implementation project, were recorded in Account 1508 – IFRS Transition Costs. The Board approved the disposition of the balance in this account at December 31, 2009 (including carrying charges) of $565,914 in the 2011 Cost of Service Application (EB-2010-0131). The balance included in this Application for disposition represents costs related to the transition incurred since January 1, 2010. None of these costs were embedded in Horizon Utilities' rates.

b. Not applicable - See response to (a) above.

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9-Staff-43 Account 1533 Renewable Generation Connection Funding Adder Deferral Account.

References:

1. Exhibit 9 Tab 1 Schedule 1

Preamble:

Horizon is requesting to clear a credit of $306,546 in its Account 1533 – Renewable Connection Funding Adder Deferral Account.

a. Are there any offsetting costs in Account 1531 and Account 1532?

b. Please identify any direction to clear this account that Horizon might have received.

c. What does Horizon have to clear this account now?

Response:

a. There are no offsetting costs in Account 1531 and Account 1532.

b. Horizon Utilities has not received any direction to clear account 1533 – Renewable Connection Funding Adder Deferral Account. However as stated in the Accounting Procedures Handbook, Article 490, *"At the time of rebasing, all account balances will be reviewed and should be disposed of, unless otherwise justified by the distributor or as required by a specific Board decision or guideline*". Accordingly, Horizon Utilities is requesting that the balance in the account at December 31, 2013 be cleared in the current Application.

c. Please see response to b. above.

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9-Staff-44 Retail Cost Variance Accounts 1518 and 1548

Reference:

a. Exhibit 9 Tab 4 Schedule 1

Preamble:

Board staff compared the amounts disposed of in Horizon's last two cost of service proceedings to the current one, as follows:

Account	EB-2007-0697	EB-2010-0131	EB-2014-0002
1518	-75,179	301,545	601,108
1548	51,981	59,160	-41,823

a. Please explain the reasons for the trends noted above.

b. How have the costs of providing the retailer related services increased?

c. Board staff notes that the EB-2010-0131 proceeding would have had 3 years of balances accumulated in these accounts, and the current proceeding has 4 years. The amount recoverable has doubled over this time. Please provide the number of retailer customers and transactions causing the increase in the amounts recoverable compared to prior balance dispositions.

Response:

a. The number of customers with retailers has declined significantly since 2008. The main drivers of retailer revenue are variable and calculated on a per customer basis or a per service transaction request basis. The costs of providing retailer related services have also declined. However, a significant portion of these costs are fixed, such as the fixed portion of the software license and maintenance fee and the costs associated with billing staff and regulatory staff. As such, the decline in retailer revenue is only partly offset by the decline in costs associated with retailer related services which are not fully recovered by Horizon Utilities.

b. The costs of providing retailer related services have not increased as identified in Horizon Utilities' response to part a) above.

c. Horizon Utilities has provided the number of retailer customer and transactions in Table 1 below. The decline in the number of retailer customer and transactions has caused an

increase in the amounts recoverable in that the corresponding decline in revenue is only partly offset by a decline in the costs of providing retailer related services.

Table 1: Number of Retailers, Customers, and Transaction Requests

Year	# of retailers	# of customers	# service transaction requests
2008	32	52,105	5,741
2009	34	41,201	4,607
2010	36	37,079	2,233
2011	40	29,096	1,407
2012	42	24,555	1,500
2013	38	21,531	1,665

9-Staff-45 Account 1555 Smart Meters Smart Meter Capital

References:

1. **Exhibit 9 Tab 7 Schedule 1**
2. **Smart Meter Model**

Preamble:

Horizon sought Board approval in its 2011 Smart Meter Prudence Application ("SMPA") (EB-2011-0417) for the disposition and recovery of costs related to Smart Meter deployment accumulated to December 31, 2011, offset by Smart Meter Funding Adder ("SMFA") revenues collected from May 1, 2006 to April 30, 2012. The Board approved the disposition for recovery of the aforementioned costs for Smart Meter deployment and operation.

The Board recognized that at the end of 2011, Horizon Utilities had 297 hard to reach ("HTR") Residential customer locations and 4,305 GS < 50 kW legacy customer locations remaining without a Smart Meter. Horizon is now applying to include these HTR and legacy installations in its 2015 opening rate base, and dispose of the balances in Account 1555.

Unit costs

Board staff has developed the following table:

	Count	$	Unit	EB-2011-0417
Res	297	103,330	347.91	98.79
GS<50	4,305	2,128,134	494.34	161.05 to 722.41
	4,602	2,231,464	484.89	

It is apparent that the costs to complete the installation of smart meters are higher per unit compared to the costs previously cleared.

a. Please provide the break-out of costs into:

i. Meters;
ii. Ancillary components; and
iii. Labour.

Please provide an explanation of the higher component costs compared to the costs from the Smart Meter Prudence Review.

Cost Allocation

b. Please provide Smart Meter Models and rate rider derivations for each customer class.

Response:

a. Horizon Utilities provides the following break out of the current Smart Meter costs by customer classification for 2014 in Table 1 below:

Table 1: 2014 Smart Meter Component Costs per Device

Breakdown of 2014 Smart Meter component costs, per device		
	Residential (Hard to Reach program)	**GS < 50 kW**
Smart Meters	n/a	$307 to $644
Ancillary Devices, if required	$45 to $214	$123 to $140
Labour	$180 to $240	n/a
Total	$225 to $454	$307 to $784

As identified in Exhibit 9, Tab 7, Schedule 1, Page 4 and 5, capital expenditures related to the procurement for the residential conversions were previously approved in Horizon Utilities' 2011 Smart Meter Prudence Application ('SMPA") (EB-2011-0417). For the GS <50 kW customers, the costs reported are for metering equipment only; the labour component is included in the distribution expenditures as the work is being completed as part of the recertification program.

As identified in Exhibit 9, Tab 7, Schedule 1, Page 3, Horizon Utilities' costs related to meter procurement have increased by approximately 18% primarily due to the disqualification for production volume pricing benefits. Since the completion of the mass deployment of Smart Meters in 2009, Horizon Utilities is no longer purchasing meters in volumes of sufficient size to qualify for production volume pricing benefits.

A secondary driver for increased costs related to Smart Meters for the GS< 50 kW customer class is the procurement of Smart Meters to address the conversion of the 600-Volt Delta-meter locations. The 600-Volt Delta meters are currently the most expensive Smart Meter option for the GS < 50 kW class at $644 per meter. This meter type was not available from the vendor until mid-2012. The delay of this meter purchase, followed by its required procurement to support more than 30% of the

outstanding GS <50 class customers, increased Horizon Utilities expenditures as compared to historical costs.

The Board references a per meter cost as low as $161.05 from the expenditures submitted in the SMPA (EB-2011-0417). This expenditure relates to a single-phase General Service Smart Meter. The single-phase meters were converted early in Horizon Utilities' implementation plan; the outstanding Smart Meters are all the three-phase meter type that are more costly.

Ancillary device expenditures, typically Instrument Transformers, have also increased by an average of $30 per device since the submission of Horizon Utilities' SMPA.

Labour costs per meter for the residential class have increased due to the need to address the HTR escalation program for residential customer locations as compared to expenditures during mass deployment. Each successful HTR Smart Meter conversion requires a Horizon Utilities staff resource for custom communications and customer follow-up. The HTR meter locations are primarily inside the customer premises, requiring additional time to access the building and complete the work. The Horizon Utilities HTR conversion plan is provided in Exhibit 9, Tab 7, Schedule 1, Page 2.

b. As discussed in Exhibit 9, Tab 7, Schedule 1, Horizon Utilities is seeking approval to transfer the balance of the capital costs for the Smart Meter program recorded in Account 1555 to opening capital costs in 2015. As a result there is no rate rider required in the disposition of Account 1555. Horizon Utilities has calculated the revenue requirement associated with Smart Meter investments in the 2012 – 2014 timeframe in a manner that is consistent with the approach used in the Smart Meter Prudence Application (EB-2011-0417) for investments in Smart Meters prior to 2012.

Horizon Utilities is also seeking approval for a rate rider to recover the revenue requirement on these investments for the above referenced period. Table 9-29 in Exhibit 9, Tab 7, Schedule 1 summarizes the revenue requirement inputs and allocation to the Residential and GS < 50 kW rate classes. Detailed calculations of the revenue requirement are in the Board's Smart Meter Model in Exhibit 9, Tab 7, Appendix 9-2. The rate rider derivations for each customer class are provided in Table 9-30 in Exhibit 9, Tab 7, Schedule 1.

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9-Staff-46 Request for A variance Account for Stand-by Power Revenues

References:

1. **Exhibit 9 Tab 1 Schedule 6**
2. **Exhibit 3 Tab 1 Schedule 3**
3. **Decision and Order EB-2010-0131**

Preamble:

At Reference 1, Horizon has requested the establishment of a deferral account to track any incremental revenues earned on generation activities in the LU (1) and LU (2) customer classes over and above that which is approved in the load forecast in this application.

In Reference 2, Horizon has forecast the loads of its LU (1) and LU (2) customers.

In Reference 3, the Board denied Horizon's request to track in a subaccount of account 1572 – Extraordinary Event Losses any distribution revenues related to demand above the revised load forecast for the two specific Large Use customers.

In both instances, EB-2010-0131 and this current Application, Horizon is proposing to collect only excess revenues and not losses. In EB-2010-0131, the Board denied Horizon's proposal stating:

"The Board finds that the asymmetric return profile to the utility, 100% of the downside risk and 50% of the upside benefit, and the limited coverage of the account as it applies to only two of Horizon's 12 Large Use customers, to be problematic."

Please detail any significant differences between Horizon's EB-2010-0131 proposal and this one.

Response:

Upon further review of the Board's Decision in Horizon Utilities'' 2011 Cost of Service Application (EB-2010-0131), Horizon Utilities respectfully withdraws its request for a deferral account to address any variance in the Stand-By Power revenues.

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9-Staff-47 LRAMVA

Reference:

1. Exhibit 9, Tab 5, Schedule 1

Preamble:

Table 9-19 on page 3 of the reference Horizon calculates the 2011 LRAMVA amounts for the 8 months of 2011. Table 9-20 on page three calculates the full year impact for 2012.

a. Please expand Table 9-19 and include all the initiatives under each of the customer classes and the corresponding energy and peak demand savings for each initiative that have contributed to Horizon's LRAMVA claim for 2011.

b. At column (B) of Table 2-20, Horizon indicates it has relied on the 2012 OPA Q3 Results to determine the LRAMVA eligible savings in 2012. Please discuss why Horizon has not relied on the 2012 OPA Final Results when determine its 2012 LRAMVA amount.

c. Please expand table 9-20 and include all the initiatives included under each of the customer classes and the corresponding energy and peak demand savings for each initiative that have contributed to Horizon's LRAMVA claim for 2012.

d. Please update Table 9-20 using the 2012 OPA Final Results.

Response:

a) Horizon Utilities provides an expanded Table 9-19 below which includes all of the CDM initiatives for each of the customer classes and the corresponding energy and peak demand savings that each initiative has contributed to Horizon Utilities' LRAMVA claim for 2011. Horizon Utilities made minor adjustments to the customer classes as per OPA's final verified results. This has resulted in a slight adjustment to the LRAMVA of $110. Horizon Utilities has also included the updated Table 9-19 for the LRAMVA.

Expanded Table 9-19

Horizon Utilities
2011 OPA Results Eligible for the LRAMVA Allocated to Customer Class

FROM TABLE 3A OF THE OPA REPORT - issued Q1 of 2014

OPA Program Category:	#	Initiative	Unit	2011 Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)	2011 Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)	kW by Customer Class: Residential	GS<50	GS>50	Large User	TOTAL	kWh by Customer Class: Residential	GS<50	GS>50	Large User	TOTAL
Consumer	1	Appliance Retirement	Appliances	172	1,238,865	172	0	0	0	**172**	1,238,865	0	0	0	**1,238,865**
Consumer	2	Appliance Exchange	Appliances	18	21,438	18	0	0	0	**18**	21,438	0	0	0	**21,438**
Consumer	3	HVAC Incentives	Equipment	1,693	3,070,047	1,693	0	0	0	**1,693**	3,070,047	0	0	0	**3,070,047**
Consumer	4	Conservation Instant Coupon Booklet	Coupons	50	810,293	50	0	0	0	**50**	810,293	0	0	0	**810,293**
Consumer	5	Bi-Annual Retailer Event	Coupons	68	1,188,091	68	0	0	0	**68**	1,188,091	0	0	0	**1,188,091**
Consumer	6	Retailer Co-op	Items	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Consumer	7	Residential Demand Response*	Devices	1,093	2,830	*EXCLUDE FROM LRAMVA*				**0**	*EXCLUDE FROM LRAMVA*				**0**
Consumer	8	Residential New Construction	Houses	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Business	9	Retrofit	Projects	857	4,805,916	0	0	473	384	**857**	0	0	2,342,267	2,463,649	**4,805,916**
Business	10	Direct Install Lighting	Projects	661	1,693,346	0	661	0	0	**661**	0	1,693,346	0	0	**1,693,346**
Business	11	Building Commissioning	Buildings	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Business	12	New Construction	Buildings	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Business	13	Energy Audit	Audits	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Business	14	Small Commercial Demand Response*	Devices	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Business	15	Demand Response 3*	Facilities	536	20,936	*EXCLUDE FROM LRAMVA*				**0**	*EXCLUDE FROM LRAMVA*				**0**
Industrial	16	Process & System Upgrades	Projects	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Industrial	17	Monitoring & Targeting	Projects	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Industrial	18	Energy Manager	Managers	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Industrial	19	Retrofit	Projects	70	402,527	0	0	39	31	**70**	0	0	196,180	206,347	**402,527**
Industrial	20	Demand Response 3*	Facilities	3,498	205,346	*EXCLUDE FROM LRAMVA*				**0**	*EXCLUDE FROM LRAMVA*				**0**
Home Assistance	21	Home Assistance Program	Projects	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Pre-2011 Programs completed in 2011	22	Electricity Retrofit Incentive Program	Projects	3,066	17,700,219	0	0	1,692	1,374	**3,066**	0	0	8,626,583	9,073,636	**17,700,219**
Pre-2011 Programs completed in 2011	23	High Performance New Construction	Projects	242	1,244,589	0	0	242	0	**242**	0	0	1,244,589	0	**1,244,589**
Pre-2011 Programs completed in 2011	24	Toronto Comprehensive	Projects	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Pre-2011 Programs completed in 2011	25	Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	**0**	0	0	0	0	**0**
Pre-2011 Programs completed in 2011	26	LDC Custom Programs	Projects	0	0	0	0	0	0	**0**	0	0	0	0	**0**
		OPA-Contracted LDC Portfolio Total		**12,024**	**32,404,443**	**2,001**	**661**	**2,446**	**1,789**	**6,897**	**6,328,734**	**1,693,346**	**12,409,619**	**11,743,632**	**32,175,331**
			CHECK	1	-1										
		*TOTAL *EXCLUDE FROM LRAMVA**		*5,127*	*229,112*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
		OPA Results - Eligible for LRAMVA		**6,897**	**32,175,331**	**2,001**	**661**	**2,446**	**1,789**	**6,897**	**6,328,734**	**1,693,346**	**12,409,619**	**11,743,632**	**32,175,331**
			CHECK							0					0
		Adjustment to verified results			8 months	1,334	441	1,630	1,193	4,598	4,219,156	1,128,897	8,273,079	7,829,088	21,450,221
				193	2,151,259										
	9	Retrofit - adjustment (advised Q2 - 2013)	Projects	193	2,151,259	-293	28	458	0	**193**	-445,907	60,847	2,536,319	0	**2,151,259**
		Adjustment to verified results			8 months	-195	18	306	-	129	(297,271)	40,564	1,690,879	-	1,434,173
		Adjusted verified results				1,139	459	1,936	1,193	4,727	3,921,885	1,169,462	9,963,959	7,829,088	22,884,393

Updated Table 9-19

BASED ON EIGHT MONTHS (May 1 - December 31, 2011): Period which aligns with 2011 CoS Effective Rates									
	2011 OEB Approved CDM Incld in Load Forecast (A)		2011 OPA Results Eligible for LRAMVA (B)		2011 Variances OPA Results Eligible for LRAMVA / OEB Approved CDM Incld in Load Forecast (B - A)		2011 OEB Approved Distribution Rates		**2011 LRAMVA**
Customer Class:	kW	kWh	kW	kWh	kW	kWh	$ / kW	$ / kWh	**$**
Residential	0	8,383,777	0	3,921,885		(4,461,893)		$ 0.0142	**$ (63,359)**
GS<50	0	2,928,876	0	1,169,462		(1,759,415)		$ 0.0084	**$ (14,779)**
GS>50	1,693	7,448,680	1,936	0	243	(7,448,680)	$ 2.0341		**$ 5,938**
Large User	0	0	1,193	0	1,193		$ 1.3359		**$ 19,122**
TOTAL	**1,693**	**18,761,333**	**3,129**	**5,091,346**	**1,436**	**(13,669,987)**			**$ (53,078)**

b) The LRAMVA eligible savings in 2012 submitted in the Application were based on an estimate of the 2012 OPA results for year-end. Horizon Utilities inadvertently failed to update Table 9-20 when the 2012 OPA results were available. Horizon Utilities provides an updated Table 9-20 in part (d) based on OPA 2012 final and verified results. The impact of this update is a decrease to the LRAMVA of $22,717.

c) Horizon Utilities provides an expanded Table 9-20 below which includes all of the initiatives for each of the customer classes and the corresponding energy and peak demand savings that each initiative has contributed to Horizon Utilities' LRAMVA for 2012. The expanded Table 9-20 is based on the OPA 2012 final and verified results.

Expanded Table 9-20

Horizon Utilities
2012 OPA results Verified

FROM TABLE 3A OF THE OPA REPORT - issued Q1 of 2014

OPA Program Category:	#	Initiative	Unit	2012 final kW	2012 final kwhs	kW by Customer Class: Residential	GS<50	GS>50	Large User	TOTAL	kWh by Customer Class: Residential	GS<50	GS>50	Large User	TOTAL
Consumer	1	Appliance Retirement	Appliances	96	669,778	96	0	0	0	**96**	669,778	0	0	0	**669,778**
Consumer	2	Appliance Exchange	Appliances	19	33,812	19	0	0	0	**19**	33,812	0	0	0	**33,812**
Consumer	3	HVAC Incentives	Equipment	1,091	1,843,136	1,091	0	0	0	**1,091**	1,843,136	0	0	0	**1,843,136**
Consumer	4	Conservation Instant Coupon Booklet	Coupons	9	56,527	9	0	0	0	**9**	56,527	0	0	0	**56,527**
Consumer	5	Bi-Annual Retailer Event	Coupons	60	1,082,743	60	0	0	0	**60**	1,082,743	0	0	0	**1,082,743**
Consumer	6	Retailer Co-op	Items			0	0	0	0	**0**	0	0	0	0	**0**
Consumer	7	Residential Demand Response*	Devices			*EXCLUDE FROM LRAMVA*				**0**	*EXCLUDE FROM LRAMVA*				**0**
Consumer	8	Residential New Construction	Houses			0	0	0	0	**0**	0	0	0	0	**0**
Business	9	Retrofit	Projects	1,659	9,600,471	0	0	1,659		**1,659**	0	0	9,600,471		**9,600,471**
Business	10	Direct Install Lighting	Projects	550	1,875,038	0	550	0	0	**550**	0	1,875,038	0	0	**1,875,038**
Business	11	Building Commissioning	Buildings			0	0	0	0	**0**	0	0	0	0	**0**
Business	12	New Construction	Buildings	0	1,331	0	0	0	0	**0**	0	0	1,331	0	**1,331**
Business	13	Energy Audit	Audits	16	75,529	0	0	16	0	**16**	0	0	75,529	0	**75,529**
Business	14	Small Commercial Demand Response*	Devices			0	0	0	0	**0**	0	0	0	0	**0**
Business	15	Demand Response 3*	Facilities			*EXCLUDE FROM LRAMVA*				**0**	*EXCLUDE FROM LRAMVA*				**0**
Industrial	16	Process & System Upgrades	Projects			0	0	0	0	**0**	0	0	0	0	**0**
Industrial	17	Monitoring & Targeting	Projects			0	0	0	0	**0**	0	0	0	0	**0**
Industrial	18	Energy Manager	Managers	60	479,921	0	0	60	0	**60**	0	0	479,921	0	**479,921**
Industrial	19	Retrofit	Projects	0		0	0	0	0	**0**	0	0	0	0	**0**
Industrial	20	Demand Response 3*	Facilities			*EXCLUDE FROM LRAMVA*				**0**	*EXCLUDE FROM LRAMVA*				**0**
Home Assistance	21	Home Assistance Program	Projects	24	286,839	24	0	0	0	**24**	286,839	0	0	0	**286,839**
Pre-2011 Programs completed in 2011	22	Electricity Retrofit Incentive Program	Projects			0	0	0	0	**0**	0	0	0	0	**0**
Pre-2011 Programs completed in 2011	23	High Performance New Construction	Projects	146	582,164	0	0	146	0	**146**	0	0	582,164	0	**582,164**
Pre-2011 Programs completed in 2011	24	Toronto Comprehensive	Projects			0	0	0	0	**0**	0	0	0	0	**0**
Pre-2011 Programs completed in 2011	25	Multifamily Energy Efficiency Rebates	Projects			0	0	0	0	**0**	0	0	0	0	**0**
Pre-2011 Programs completed in 2011	26	LDC Custom Programs	Projects			0	0	0	0	**0**	0	0	0	0	**0**
OPA-Contracted LDC Portfolio Total				**3,730**	**16,587,289**	**1,299**	**550**	**1,881**	**0**	3,730	**3,972,835**	**1,875,038**	**10,739,416**	**0**	16,587,289
CHECK chk															
*TOTAL *EXCLUDE FROM LRAMVA**						*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*
OPA Results - Eligible for LRAMVA						**1,299**	**550**	**1,881**	**0**	3,730	**3,972,835**	**1,875,038**	**10,739,416**	**0**	16,587,289

(d) Horizon Utilities provides an updated Table 9-20 below using the 2012 OPA final and verified results.

Updated Table 9-20

Final Verified Results - corrected for CoS - July 8, 2014

Customer Class	2011 OEB Approved CDM Incld in Load Forecast (A)		2012 OPA Verified Results - Eligible for LRAMVA (B)		2012 Variances Verified Results for Dec 31, 2012 Eligible for LRAMVA / OEB Approved CDM Incld in Load Forecast (B - A)		2012 OEB Approved Distribution Rates		**2012 LRAMVA**
	kW	kWh	kW	kWh	kW	kWh	$ / kW	$ / kWh	**$**
Residential		12,575,666		3,972,835		(8,602,831)		$ 0.0143	**$ (123,020)**
GS<50		4,393,315		1,875,038		(2,518,277)		$ 0.0084	**$ (21,154)**
GS>50	2,539	11,173,019	1,881		(658)	(11,173,019)	$ 2.046		**$ (16,154)**
Large User					-	-	$ 1.344		**$ -**
TOTAL	2,539	28,142,000	1,881	5,847,873	(658)	(22,294,127)			**$ (160,328)**