# Responses to City of Hamilton Interrogatories

This page intentionally left blank

**C of H 1. Exhibit 7, Tab 1, Schedule 1, p. 2 ff.**

**Background:**

**Horizon is proposing a new Large Use 2 (“LU(2)”) customer class, consisting of four customers. The prefiled evidence states that “these customers are served by dedicated feeders, and do not participate in the use of the pooled assets, because of their size.” The prefiled evidence further states that “this rate class does not attract allocation of the shared primary or secondary asset pools”. Finally, the prefiled evidence indicates that the introduction of the LU(2) customer class and the removal of costs related to assets these customers do not use reduces the costs allocated to these customers by nearly $4 million per year.**

**(a) What proportion, if any, of the common or system costs of Horizon will be allocated to the LU(2) customer class if Horizon’s proposal is accepted?**

**(b) Has the cost allocation methodology underlying the creation of the LU(2) customer class, namely that the class should bear the costs only of those assets it directly uses, been accepted by the Ontario Energy Board (“Board” or “OEB”) for use by any other LDC? If so, please provide copies of the Board decisions or reports in which that approval is found.**

**Is the street light rate class bearing only those costs of the assets it directly uses?**

**(c) How has the nearly $4 million reduction in costs of the LU(2) customer class been allocated among other customer classes? If so, which classes and in what amounts?**

**Response:**

(a) The Board-approved cost allocation methodology allocates a proportion of all common or system costs to each rate class for which they have cost responsibility as determined by the cost causality principle[1]. As a result of the direct allocation to this class, the LU (2) class pays 100% of the costs of the dedicated distribution facilities that they use (they “cause” 100% of the costs of the dedicated facilities) and they do not pay a share of the cost of the remaining distribution facilities that are used only by other customers. Most of the costs, other than these distribution facilities costs, are common costs that are

[1] See, for example, National Association of Regulatory Utility Commissioners, (January 1992) Electric Utility Cost Allocation Manual. As stated at page 12.

*Cost studies are therefore used by regulators for the following purposes:*
*To attribute costs to different categories of customers based on how those customers cause costs to be incurred ..*

"caused by" and allocated to all classes. In 2015, the costs allocated to the LU (2) class consist of $399,055 of common costs and $33,167 of directly allocated costs which total $432,222 or 0.36% of Horizon Utilities' total 2015 revenue requirement.

b) Yes. For example, in Hydro One Networks Inc.'s ("Hydro One") 2010-2011 Electricity Distribution Rate Application (EB-2009-0096), Hydro One used a combination of direct allocation and customized allocators that exclude allocation of pooled costs to the Sub Transmission ("ST") and Distributed Generation ("Dgen") rate classes which do not use the assets that contribute to the pooled costs. This proposal was accepted by the OEB in its April 9, 2010 Decision with Reasons (see C of H 1_Attch 1_Dec_Reasons_HONI_20100409) at section 8.1. In this case, the model used was filed September 28, 2009, under the name HONI_APPL_Model_20090926 and is available on the Board's web drawer[2].

More generally, it may be noted that the Board-approved cost allocation model includes tab I9-Direct Allocation which is explicitly intended to accommodate the direct allocation of dedicated facilities and any other costs that are caused by a single rate class (as described on the "Instructions" Tab of the Cost Allocation Model under the heading "Worksheet I9 Direct Allocation). This tab was used for the direct allocation of costs to the LU (2) class. While the most recent cost allocation models of all distributors are not on the public record, it is Horizon Utilities' understanding that other distributors with customers served with dedicated facilities (e.g., Enwin Utilities Limited) would have rates that are established on the basis of directly allocated costs of dedicated facilities. This approach complies with the methodology detailed in the *Electricity Utility Cost Allocation Manual* (January 1992) (the "Manual") published by the National Association of Regulatory Utility Commissioners ("NARUC"). In Chapter 6: Classification and Allocation of Distribution Plant of the Manual, it states that "Direct assignment or 'exclusive use' costs are assigned directly to the customer class or group which exclusively uses such facilities. The remaining costs are then classified to the respective cost components." (page 88)

[2] The CA model can be downloaded as part of the ZIP at this link: http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/151227/view/

c) Please see Horizon Utilities' response to Interrogatory 7-Energy Probe-48.

This page intentionally left blank

# C of H 1_Attch 1_Dec_Reasons_HONI_20100409

This page intentionally left blank

**Ontario Energy Board** **Commission de l'énergie de l'Ontario**

# EB-2009-0096

**IN THE MATTER OF AN APPLICATION BY**

# HYDRO ONE NETWORKS INC.

**2010 and 2011 DISTRIBUTION RATES**

## DECISION WITH REASONS

April 9, 2010

## TABLE OF CONTENTS

**<u>Appendices</u>**

**EB-2009-0096**

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

**AND IN THE MATTER OF** an application by Hydro One Networks Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges for 2010 and 2011.

**BEFORE:** Pamela Nowina
Presiding Member

Cynthia Chaplin
Vice Chair

Paul Sommerville
Member

# DECISION WITH REASONS

## April 9, 2010

# 1. BACKGROUND

On July 13, 2009 Hydro One Networks Inc. (“Hydro One”) filed an application for 2010 and 2011 distribution rates, including its Green Energy Plan. The Board assigned file number EB-2009-0096 to the application and issued an approved issues list on September 22, 2009.

Further procedural details are found in Appendix 1.

## 1.1 SETTLEMENT CONFERENCE

The Board convened a settlement conference on November 18, 2009. While no settlement was achieved, a document filed by the parties identified those issues that would not be subject to cross examination in the hearing and would be dealt with only in final argument. The document filed as a result of the settlement discussion is attached as Appendix 2.

## 1.2 ORAL DECISION ON COST OF CAPITAL SUBMISSIONS

On December 15, 2009, the Board issued an oral decision on submissions from parties regarding the Report of the Board on Cost of Capital for Ontario’s Regulated Utilities, EB-2009-0084, issued on December 11, 2009. A copy of this decision is attached as Appendix 3.

## 1.3 DECISION ON MOTION

On January 12th, 2010 the Board heard a motion by the Consumers Council of Canada, seeking an order from the Board requiring Hydro One to publish an amended notice of application in the proceeding. The motion alleged that there were certain defects in the original Notice, which was published in various newspapers across the province in August 2009. The motion was denied on January 14, 2010. A copy of this decision is attached as Appendix 4.

## 1.4 PARTIAL DECISION

On February 18, 2010 the Board issued a partial decision on Issue 9.3, which dealt with whether Hydro One’s methodology for allocating Green Energy Plan O&M and capital costs between the Ontario Power Authority (OPA) (Global Adjustment Mechanism) and Hydro One was appropriate.

In a separate but related matter, on September 25, 2009, the Board initiated a consultation process (EB-2009-0349) to address how the Board should, in accordance with the requirements of Ontario Regulation 330/09, determine the direct benefits that accrue to the consumers of a distributor when that distributor has incurred costs to make an eligible investment in its distribution system to accommodate a renewable energy generation facility. These are costs that would generally be included in a Green Energy Plan. As a consequence of the determination of the direct benefits, the cost allocation between provincial ratepayers and the ratepayers of the individual distributor making the investment will be determined.

The Board issued its February 18, 2010 partial decision on this issue to provide Hydro One and other parties the information they need to participate fully in the Board's EB-2009-0349 policy initiative.

In that decision, the Board approved the methodology proposed by Hydro One in this rates proceeding for the allocation of Green Energy Plan costs for rate setting purposes on a provisional basis. More information on this is contained in the section on the Green Energy Plan.

The partial decision is attached as Appendix 5.

### 1.5 THE HEARING, SUBMISSIONS AND EVIDENCE

The oral hearing for this proceeding took place in December 2009 and January 2010, concluding with Hydro One's oral Argument-in-Chief on January 14, 2010. Board staff and intervenor written submissions were submitted on February 1, 2010 and February 8, 2010 respectively. The Board received submissions from School Energy Coalition (SEC), Pollution Probe, Consumers Council of Canada ("CCC"), Canadian Manufacturers and Exporters ("CME"), Association of Major Power Consumers of Ontario ("AMPCO"), Energy Probe Research Foundation ("Energy Probe"), Society of Energy Professionals ("Society"), Rogers Cable Communications ("Rogers"), Electrical Contractors Association of Ontario ("ECAO"), Green Energy Coalition ("GEC"), Vulnerable Energy Consumers' Coalition ("VECC"), Power Workers Union ("PWU"), Hopper Foundry ("Hopper") and Board staff.

Hydro One submitted its reply argument on February 12, 2010. Copies of the evidence, exhibits, arguments and transcripts of the proceeding are available for review at the Board's offices or at the Board website, www.oeb.gov.on.ca.

During the proceeding, confidential treatment was provided for a number of documents. These documents are filed at the Board's offices, but not on the public record.

The Board considered the full record of the proceeding but has summarized the record only to the extent necessary to provide context to its findings.

## 2. LOAD FORECAST

Hydro One's load forecast for 2010, including the impact of Conservation and Demand Management ("CDM"), is 38,306 GWh of electricity delivered to 1,196,000 distribution customers. CDM and the economic downturn are the major influences on the 2010 forecast resulting in a 4.3 percent decrease in electricity consumption from 2008 with a slight increase of 1.3 percent over 2008 customer count.

For 2011 the forecast features a continuing decrease in electricity load to 38,049 GWh but customer numbers growing to 1,204,000 (a .07 percent increase). Hydro One has demonstrated that its load forecast has tracked actual results in a consistent manner (within one standard deviation) over the past several years.

Hydro One indicated that while some macroeconomic inputs had changed since the last forecast was produced, these changes were of a minor nature and that the forecast would not be updated.

In the last distribution rates proceeding, the Board directed Hydro One to come forward in its next rates case with a detailed proposal to incorporate the impacts of CDM into its load forecast, both those attributable to its own actions and those not attributable to the Company's actions.[1] In the current proceeding Hydro One was unable to provide a new proposal for incorporating CDM into the load forecast. Hydro One did inform the Board and intervenors that a consulting study had been commissioned but that the results were not available until early 2010. Hydro One did file a "Net Load Impact of Conservation and Demand Management" report[2].

### BOARD FINDINGS

The Board approves the load forecast as filed. Hydro One has a very sophisticated and capable load forecasting methodology. It has been approved in at least two previous Board decisions, and no intervener specifically challenged the company's forecast per se.

[1] EB-2007-0681 Decision with Reasons, December 18, 2008, p. 8
[2] Exhibit H/Tab12/Sch2/Attachment 1

One area of concern which is shared by a number of parties and which also concerns the Board, is the absence of a proven rationale for the recognition of CDM outcomes into the load forecast.

As noted above, the Board's previous decision directed the applicant to produce a study, the purpose of which was to provide such a rationale. That study has not been produced for the purposes of this proceeding, and the deficiency in methodology with respect to CDM continues.

<u>The Net Load Impact Analysis of Conservation and Demand Management</u> report referenced above was produced by Hydro One staff and was intended to inform the preparation of its load forecast. While this report is of some assistance in assessing the influence of CDM in developing the load forecast, it expressly does not replace the anticipated contribution of the study Hydro One was directed by the Board to produce in EB-2007-0681.

The Board's concern is rooted in the fact that very substantial sums of money have been and are to be expended on CDM programs by this applicant, and indeed by virtually every other local distribution company in the province. The development of a methodology to appropriately incorporate the effects of these programs is an important regulatory milestone. While there is a belief that these programs are having the desired effect of reducing the use of electricity in general or at peak times, there is currently no reliable methodology which allows the Board to make a reliable or objective assessment of the efficiency or effectiveness of these programs.

The Board's direction to Hydro One to develop such a methodology was intended to be one step in developing a more satisfactory approach to the reflection of CDM programs into load forecast, and the efficacy of those programs.

The Board now restates its direction to the company to produce the study originally called for, for distribution to the Board, and the interveners of record in this proceeding, in connection with its next cost of service application.

Several intervenors urged the Board to adopt a mechanism which would track the differences between Hydro One's forecast of CDM effects and the actual CDM volumes realized.

This proposal is fuelled in part by the significant growth in the company's forecast for CDM in each of 2010 and 2011. For 2010 the impact of CDM, as forecast by the company, will increase very substantially over previous periods to 5.8% of total load. In 2011 the impact grows to 7%. If these forecasts are inaccurate there is a risk that ratepayers will have been overburdened.

Hydro One's forecast of CDM effects is derived primitively compared to the sophistication of its methodology for all other elements of its load forecast. In effect, it takes estimates from the OPA, which are themselves subject to considerable uncertainty, and applies them proportionately to its service area. This methodology is not one which inspires confidence in its outcome. Hydro One itself recognizes that this is a deficiency in its overall load forecasting methodology.

In light of the circumstances, the Board considers it appropriate to require the company to track the differences between its CDM forecast volumes and those which can be reasonably demonstrated to have been effected, using the best verification methods available at the time, akin to a Lost Revenue Adjustment Mechanism (“LRAM”). The Board notes that LRAM is a voluntary mechanism, and that Hydro One is not the only distributor to have not applied to the Board for LRAM recovery. However, the Board is concerned that Hydro One’s method of forecasting CDM effects may result in an inappropriate level of over-recovery from ratepayers, and believes that a retrospective adjustment may be necessary and appropriate. When used properly, an LRAM decreases the incentive for distributors to over-forecast CDM effects in their load forecast, since there is a retrospective mechanism to compensate for any unforecasted lost revenues. This helps to stabilize the impact on ratepayers.

This approach was proposed by several intervenors, most notably GEC, but resisted by Hydro One. The company’s resistance is based on its concern that the necessary utility-specific CDM program results are not currently available. There is an element of circularity in this line of argument. The Board considers it important for Hydro One to develop the requisite tools to establish the effects of CDM programs within its franchise area, as many other distributors have done. The requirement to track these effects is an important step in that process. The completion of the study is another.

## 3. OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

The table below summarizes the Operations, Maintenance and Administration ("OM&A") costs proposed by Hydro One for the two test years and includes the percentage change from the prior year. The OM&A level approved in the last cost of service rate application for 2008 rates was $466 million. The 2010 test year amount requested by Hydro One is 20.2% higher than the approved 2008 level. Hydro One identified three key drivers for the increased spending: vegetation management, PCB regulations, and work related to the Green Energy Plan. The direct costs of the Green Energy Plan are not included in the table and are addressed separately in this decision. The table does include the indirect costs related to the Green Energy Plan, which Hydro One estimated to be $10 to $15 million.

**OM&A Expenditures, 2008 – 2011**
**($ million, including % variance from prior year)**

| Category | 2008 Actual | 2009 Bridge | 2010 Test | 2011 Test |
|---|---|---|---|---|
| **Sustaining** | **284.5** 4.4% | **296.4** 4.2% | **318.5** 7.5% | **340.5** 6.9% |
| **Development** | **8.0** 90.4% | **14.5** 81.2% | **21.7** 49.6% | **21.9** 0.9% |
| **Operations** | **12.4** -0.2% | **12.5** 0.8% | **16.7** 33.6% | **17.6** 5.4% |
| **Customer Care** | **99.3** 2.3% | **106.7** 7.4% | **106.3** -0.4% | **102.4** -3.7% |
| **Shared Services & Other** | **62.9** -31.5% | **92.4** 46.9% | **92.1** -0.3% | **88.1** -4.3% |
| **Tax other than Income Tax** | **4.3** | **4.6** | **4.7** | **4.8** |
| **Total** | **471.3** -3.1% | **527.1** 11.8% | **560.0** 6.2% | **575.2** 2.7% |

Hydro One maintained that year-over-year comparisons of OM&A costs should include the 2009 bridge year, because that was an Incentive Rate Mechanism ("IRM") rate adjustment year and any cost increases above the adjustment level were borne by the company. Hydro One submitted that many OM&A cost increases took place in 2009 and that this is evidence of the company's commitment to, and the necessity for, these programs.

Hydro One stressed the importance of the vegetation management program and explained the need to move to a shorter cycle to reduce unit costs and outages. It highlighted increased spending from $118 million in 2008 to $136 million in 2009, as an example of a bridge year increase that showed Hydro One’s commitment to that program. Hydro One also highlighted lines and maintenance programs which are not discretionary and are a response to higher regulatory standards, principally for PCB regulations.

The following areas were addressed in the submissions:

- Overall OM&A Spending
- Compensation
- Vegetation Management

## 3.1 OVERALL OM&A SPENDING

PWU supported the proposed level of expenditures and cited the twin requirements of new government-mandated initiatives and the need to maintain an aging system. In PWU’s view, reducing costs now would lead inevitably to even higher costs in the future.

Board staff and intervenors identified a number of factors which in their view showed that the OM&A cost increases are excessive: lower inflation and cost escalation factors; trend analysis; benchmark results; and specific spending items.

Board staff and most intervenors noted that updated evidence indicated lower overall inflation and lower distribution cost escalation than in the original application. VECC submitted that based on these updates OM&A is overstated by at least $9.4 million in 2010 and $7.0 million in 2011.

CME submitted that Hydro One’s budget should be assessed through three trends or “indicators of reasonableness”: total OM&A spending; OM&A cost per customer; and OM&A costs per circuit km. CME noted that OM&A costs have increased by 18.8% between 2008 and 2010 and by 44% between from 2006 and 2011. CME pointed to the

Board's decision in Hydro One's prior distribution rates case which specifically mentioned that past spending is a useful guide in assessing spending proposals. CME noted that OM&A cost per customer has grown by 16% between 2008 and 2010 and by 37% between 2006 and 2011, and that OM&A cost per circuit km has grown by 16% between 2008 and 2010 and by 35% between 2006 and 2011.

Hydro One agreed that historical spending levels are useful information for the Board but submitted that basing future expenditures only on historical norms ignores the reasons and evidence behind the changes. Hydro One argued that it had filed extensive evidence justifying the proposed spending increases and that arbitrary reductions without reference to the evidence should be rejected. With respect to the cost per customer and cost per circuit km trends, Hydro One responded that these measures were not meaningful because the cost increases are due to increased workload, not customer or wire additions. Hydro One cited the PCB regulations and increasing vegetation management spending as independent of either the customer numbers or circuit kilometres.

Board staff and intervenors also pointed to various benchmark results. Board staff submitted that the benchmarking results show that Hydro One has the highest distribution substation O&M expense per installed MVA, and was ranked in the middle-of-the-pack for substation O&M expense per asset. SEC also pointed to benchmarking results which show that Hydro One's OM&A cost per customer in 2010 is $459.50, which is more than double that of many large and complex Ontario utilities. In CCC's view, Hydro One has demonstrated very little in terms of productivity gains because work programs are increasing by 33% and total head is increasing by 37%.

Intervenors were also concerned that Hydro One was not exercising sufficient control over spending increases. SEC acknowledged some key cost drivers, such as PCB regulations, vegetation management needs and the Green Energy Plan spending, but submitted that when customers are being asked to absorb significant cost increases as a result of such key cost drivers, keeping cost increases in other areas to approximately the rate of inflation is a reasonable cost containment measure. SEC submitted that "…companies in a competitive environment facing key cost drivers in certain areas would work to ensure that other areas of spending are either held constant or held to minimal year over increases. Hydro One has done none of that."[3]

[3] SEC Final Argument, p. 17

CCC argued that in light of the pressure related to the Green Energy Plan and related projects, more discretionary projects should have been deferred or scaled back. CCC argued, for example, that the $3 million in 2010 and $4 million in 2011 associated with the head office and GTA space requirements should be viewed as discretionary and should be deferred.

CCC and CME both submitted that Hydro One should be held to a 3% inflationary increase relative to the 2008 Board approved level. CCC estimated this would result in a reduction of about $66 million in each of the test years. SEC recommended an overall OM&A reduction of $18.1 million in 2010.

Board staff recommended a reduction of $33 million in the overall OM&A budget for 2010. The reduction was defined as the half-way point between a 3% inflation scenario and the original OM&A budget. Board staff submitted it was inappropriate to micro-manage Hydro One's activities and recommended that Hydro One should reduce OM&A costs in areas it determines most appropriate. CME agreed with this approach.

Hydro One disagreed with the proposals by Board staff and intervenors to cut OM&A costs based on envelope or index-linked reductions. Hydro One maintained that there was no meaningful criticism or analysis of the underlying causes of the proposed increases and reiterated that the shareholder has borne significant cost increases during the IRM period as a result of the increased work programs, thereby demonstrating that the increased work is necessary. Hydro One maintained that if OM&A is reduced, less work will be accomplished and the performance of the distribution system will be affected.

## BOARD FINDINGS

The Board finds that Hydro One's OM&A budget is excessive. Inflation and cost escalation factors are now lower than originally forecast and therefore the budgets are now over-stated on that measure. Second, and more importantly, the various trend measures demonstrate that Hydro One has had limited success in controlling expenditure increases. The Board agrees with Hydro One that these various trends are imperfect measures of reasonableness, but the measures are indicators. Hydro One emphasized that the expenditure increases are not driven by customer numbers or expansion in the circuit kilometres, but by increased workload particularly in the areas of vegetation management, PCB management, and Green Energy Plan related work.

However, if significant incremental work is required in particular areas, then it is the responsibility of the company to manage that in a way that ensures that growth in cost per customer is kept within reasonable levels to ensure ongoing customer affordability. The Board concludes that Hydro One has not been sufficiently successful in controlling the overall growth in spending. The benchmarking results also support the conclusion that Hydro One could and should do better in managing its growth in spending.

In the past, the Board has used different techniques to determine the allowed OM&A. In some cases a detailed line by line examination has resulted in an equally detailed funding prescription from the Board. In other cases the Board has provided the applicant with an overall envelope of funding. In such cases the Board does not stipulate an approved amount of spending for any particular category of spending, but rather leaves to the applicant the freedom to apply that spending according to its own prioritization.

In the Board's view, given Hydro One’s capabilities and its complexity, it would not be appropriate to micromanage the utility’s operations through a line by line authorization of spending; rather the Board should set an overall envelope and leave the specific allocation of the available funds to Hydro One’s judgment and prioritization. In the following two sections of this decision, the Board will provide its observations and findings with respect to compensation and vegetation management. The company should take the Board’s guidance on these subjects into account in arriving at its prioritization.

In arriving at the quantum of the envelope approved for OM&A the Board has taken a number of factors into account:

First is the totality of the evidence developed throughout the case. Through the detailed examination which takes place the Board achieves an understanding of the key drivers of utility operations and cost structures. This process also gives the Board the opportunity to assess the overall implications of the company’s rate proposals for its customers and includes the opportunity for a variety of interests to express their particular concerns respecting the applicant's rate proposal and operational plans. This is a key element in arriving at a balanced and fair rate decision. The Board’s consideration of the specific elements of the application as developed in the evidentiary portion is reflected in our observations and findings under compensation and vegetation management.

Second, the Board has considered the recent rate history of the distribution business. Over the last number of years Hydro One has applied for and received significant increases in the delivery portion of its electricity rates. Since 2004, Hydro One's delivery rates have increased significantly. Between 2004 and 2009 rates for the R1 Class have increased about 28%, whereas inflation has run at about 9%. The increase between 2007 and 2009 has also significantly outpaced inflation. As a result, Hydro One's revenues have exceeded inflation materially. That is not to say that the previous rate decisions have been inordinately generous. Over this period the company has been able to demonstrate a need to improve its customer information systems, maintain its physical plant, and generally manage its operations according to the revenue requirements approved. But the fact remains that customers have experienced increases in the delivery portion of their rates over this period that have significantly outstripped the general inflationary pressure within the economy.

Third, some of these rate increases combined with a recognized need to rationalize and harmonize the rate classes associated with acquired utilities have led to very significant increases in delivery charges for some customers. These increases have been of such a nature that they have been subject to rate mitigation measures, which are continuing.

Fourth, the Board must take into account the overall increase and prospect of further increases in the commodity portion of the bill. While these charges are outside of the control of the applicant, they are no less real for customers. In giving effect to the Board's objective to protect the interests of consumers the Board cannot ignore the overall impacts on customers.

The evidence also reveals another factor that has implications in determining the appropriate quantum of the conventional operations funding envelope. The Province, as part of a global phenomenon, has experienced a significant contraction in economic activity. The resulting demand reductions have two important implications. First, to the extent businesses have curtailed electricity demand or ceased operations, the per unit cost to be covered in delivery charges by the remaining customers will increase. This has an inherently inflationary effect on delivery charges. Second, both companies and individuals are experiencing material challenges in carrying added costs for the delivery of electricity.

Hydro One has maintained that the increases in 2009 borne by the shareholder demonstrate that the expenditures are necessary. In the Board's view, if a company spends more than the amount embedded in rates (whether for a test year or an IRM year), it is not determinative of whether the amounts are reasonable and prudent; nor does it establish the appropriate base for future levels. Management and shareholders make expenditure decisions for a variety of reasons, and the Board must still determine whether the test year forecasts are appropriate in light of all the evidence. Considering all the factors identified above, and in particular the conclusion that Hydro One has not sufficiently controlled its growth in spending, the Board finds that the appropriate quantum of the envelope to accommodate conventional operations should be derived from the year which was most recently examined and approved by the Board. In 2008, the approved level of expenditure was $466 million and the actual level of expenditure was $471 million. These figures are sufficiently close that the Board will derive the allowed level for 2010 and 2011 using the 2008 actual level.

To this initial 2008 level, the Board will apply an annual increase of 5% to derive an allowed OM&A for 2010 of $520 million. For 2011 the Board will apply an increase factor of 3% for an allowed OM&A of $535 million. The escalation factor for 2010 is higher than the rate of inflation. The Board adopts this approach in recognition that the company has statutory obligations, other than those associated with the *Green Energy and Green Economy Act, 2009 (*GEA), which it must meet, and the fact that it is preparing itself for an operating environment that is turbulent and to some extent unknown. The escalation factor for 2011 is lower, although still higher than forecast inflation, to reflect that Hydro One itself proposed an even lower level of increase between 2010 and 2011. The Board notes that the approved spending levels are well in excess of the Minimum Level of spending (as explained in the capital expenditure section of this decision) of $476 million for 2010 and $483 million for 2011.

The Board recognizes that accommodating these levels of spending, which are significantly less than that applied for, will require the company to engage in a thoughtful reconsideration of its spending priorities. The Board concludes, however, that given the overall pressures operating within this environment, which are highlighted above, this is the right time for such a recalibration.

## 3.2 COMPENSATION

Hydro One's total compensation (for the distribution and transmission businesses) is forecast to grow from $566 million in 2008 to $849 million in 2010 and to $934 million by 2011. Headcount is forecast to increase from 6,547 in 2008 to 9,552 in 2010 and to 10,245 in 2011. Hydro One referred to the Mercer/Oliver Wyman Compensation Cost

Benchmarking study (“the Mercer study”) filed in the last transmission case (EB-2008-0272). The Mercer study concluded that on a weighted average basis for the positions reviewed, Hydro One’s compensation was approximately 17% above the market median. In the transmission proceeding, the Board disallowed $4 million in compensation costs. Hydro One estimated that the comparable reduction for the distribution business would be $9 million.

Hydro One noted that the Mercer study results were largely driven by the PWU represented employees. Hydro One submitted that because it is currently under a labour contract with the PWU it was not practical to expect it to negotiate a reduction in absolute wage levels and benefits through the collective bargaining process, at least not without a work stoppage. Hydro One maintained that it has demonstrated it is attempting to control labour costs while at the same time making a concerted effort to improve efficiency in the utilization of its labour resources.

Hydro One filed evidence comparing wages in 1999 and 2009 for the Ontario Hydro successor companies: Hydro One, Bruce Power and OPG. Hydro One also included the IESO in the comparisons showing the Society positions. Hydro One claimed that this comparative information demonstrated that it did have success in reducing compensation costs between 1999 and 2009 compared to the other companies.

Intervenors representing Hydro One’s unionized staff supported the company’s position. The Society cited the competitive pressures in attracting and retaining skilled staff, the efficiency benefits of a healthy collective bargaining relationship, and Hydro One’s prudent use of internal staff and contractors. PWU submitted that the conclusions of the Board in the transmission case should not be applied in this case because the decision was flawed. PWU also highlighted the demographic challenges faced by Hydro One, the challenges faced by others in the industry, the increased volume of work, and the shortage of skilled labour. PWU maintained that the evidence showed that Hydro One has achieved smaller increases than other comparable companies and that Hydro One is maintaining wage escalation at competitive levels.

Board staff and intervenors representing ratepayers all argued that the compensation levels were excessive. Board staff, CCC, SEC and VECC each argued that the transmission decision remained applicable and that the compensation costs should be reduced by $9 million as a result. CCC and VECC took the position that Hydro One had not provided any significant new evidence which would justify a departure from the Board’s decision in the transmission application. CME submitted that the Board should reduce compensation costs by at least $9 million but also indicated that the Board would be justified in reducing compensation by up to $29 million, CME's estimate of the impact of bringing costs to the market median determined in the Mercer study.

Board staff submitted that the tables that compare Hydro One to its related Ontario Hydro successor companies appeared to show that it has made some progress in controlling wages, but do not refute the conclusions made by the Board in the transmission case. Board staff maintained that the argument that high wages are required for attracting highly skilled staff does not explain why non-skilled wages were shown to be substantially higher as well. Board staff argued that more progress was required in those areas.

Energy Probe made similar submissions but rather than adopting the $9 million impact identified by Hydro One, Energy Probe estimated that the appropriate comparable reduction would be $16.5 million. Energy Probe also argued there should be two additional adjustments: a further 10% reduction for overtime on the basis that overtime represents about 10% of the total budget; and a reduction of $12 million in capitalized labour costs.

Energy Probe noted that the Management Compensation Plan (MCP) wage increases are in excess of inflation for 2006 to 2009 and submitted that the Board should set a zero percentage increase for MCP staff in 2010 and 2011. In Energy Probe's view, increases for MCP staff are not warranted in an economic slowdown and the evidence showed that turnover rates were not unusually high. Energy Probe estimated these reductions would reduce the compensation budget by $1.35 million in 2010 and $1.39 million in 2011.

A number of intervenors also took issue with the overall staffing level and the rate of increase. Board staff pointed out that staffing has continued to grow every year since 2006, that attrition is not a problem (besides retirements, very few employees leave of their own accord) and that witnesses acknowledged that hiring qualified workers is generally not an issue except for a few specific areas.

VECC submitted that the staff increase of 37% relative to the work program increase of 33% did not show any increases in productivity. SEC also noted the 47% increase in Head Office/GTA headcount between 2008 and 2011, and compared that with the increase in customer numbers of only 4%. SEC recommended that the Board deny increases in headcount that exceed the increases in customer count. Energy Probe questioned whether the staff increases were even achievable.

Hydro One maintained that in this proceeding it had attempted to provide additional and more meaningful evidence to demonstrate its bargaining achievements. Hydro One noted that in response to the Mercer study it had provided additional evidence comparing Hydro One to a more appropriate and relevant peer group: its successor companies, Bruce Power and OPG. Hydro One maintained that these are Hydro One's main competitors for labour resources and that Hydro One has achieved more success in controlling wage increases across virtually all wage classifications. In Hydro One's view, these achievements should be considered rather than simply focusing on current wage and benefit levels.

Hydro One acknowledged that it fully understands the Board's message in the earlier transmission decision but maintained that little can be done to address the issue in the short term because collective bargaining agreements are in place until 2011 for PWU and 2013 for the Society. Hydro One assured the Board that it would continue with its best efforts to address the Board's concerns through the means available to it.

## BOARD FINDINGS

In the last transmission decision the Board stated:

> "The Board concludes that it is appropriate to disallow some compensation costs because these costs are substantially above those of other comparable companies and the company has failed to demonstrate that productivity levels offset this situation."[4]

The Board also stated:

> "Hydro One's evidence is that the revenue requirement would be $13 million less if it were based on the median compensation level from the Mercer Study…The Board has already indicated that while the full level of compensation has not been justified, Hydro One has made strides in controlling these costs. The Board will disallow $4 million in each of the test years; this level of adjustment goes some

[4] EB-2008-0272 Decision with Reasons, May 28, 2008, p. 30

> way toward aligning Hydro One's costs with other comparable companies."[5]

The Board concludes that a comparable reduction is warranted for the distribution business. Hydro One has shown (for the categories presented) that it has controlled wage escalation better than some of the other Ontario Hydro successor companies. However, compensation costs remain excessive in comparison to market indicators. The evidence indicates that Hydro One's main competition for labour comes from within Ontario and the Board regulates most of those other entities. It would be unacceptable for the Board to, in effect, fuel that wage competition by incorporating ever rising wage levels (over and above market related levels) into rates. Hydro One has indicated that a reduction of $9 million would be comparable to the Board's finding in the transmission decision. The Board has already established an overall OM&A envelope and will not order this as a specific reduction. However, the Board would observe that compensation costs, including growth in headcount, are one of the areas in which Hydro One must take further action to control expenditure increases.

## 3.3 VEGETATION MANAGEMENT

Hydro One's vegetation management program manages clearances to energized equipment to maintain reliability, manage safety hazards posed by trees, manage plant species to permit maintenance and restoration of power, and minimize environmental, ecological and social impacts. Vegetation management accounts for about 40% of the Sustaining budget in 2010. In 2008, actual spending was $118 million, increasing to $136 million in 2009, dropping slightly to $133 million in 2010 and growing to $145 million in 2011.

Hydro One's evidence indicated that the 2010 and 2011 spending requirements are based on continuing to reduce the vegetation management cycle so that a 7-year cycle can begin in 2011. Line clearing accomplishments in 2007 and 2008 were performed at about an 8-year cycle. Hydro One's evidence was that a reduction to a 7-year cycle would require a 14% increase in expenditures in 2010 and a 24% increase in 2011 in comparison to the 2007 and 2008 period.

PWU supported the proposal and submitted that the increased spending is required, will improve Hydro One's performance, and will control costs in the long-term.

[5] EB-2008-0272 Decision with Reasons, May 28, 2008, p. 31

AMPCO, VECC, CME, and SEC all argued that the vegetation management costs should be reduced by maintaining an 8-year cycle rather than moving to a 7-year cycle. Two primary reasons were cited: the need to control spending at this time and a lack of strong evidence supporting the benefits of moving to a 7-year cycle. Intervenors were also of the view that the activity was not being conducted as efficiently as possible.

AMPCO submitted that the evidence does not show improved reliability even though there have been increases in vegetation management spending since 2006. AMPCO accepted that there may be some benefits from moving to a 7-year cycle, but submitted that Hydro One had not provided sufficient evidence to support a decision to move beyond an 8-year cycle at this time. AMPCO urged the Board to direct Hydro One to continue on the 8-year cycle and provide evidence in its next application as to whether its projections of improved service quality are being realized. SEC also recommended staying with the 8-year cycle until evidence is provided that a shorter cycle is warranted and the benefits to ratepayers are determined.

VECC submitted that Hydro One is focusing too much on labour hours and not enough on overall cost efficiency and that an overall cost efficiency focus could lead to achieving more than an 8-year cycle for the same level of expenditure. In AMPCO's view, the Vegetation Management Study shows that the actual per unit cost for Hydro One to treat a tree was more than double that of other utilities. AMPCO submitted that the Board should direct Hydro One to undertake a study to determine whether it is prudent and cost effective to continue to execute their vegetation management program in-house.

Hydro One responded that its evidence, including the Vegetation Management Study, supported the move to a 7-year cycle. Hydro One maintained that the benefits of a shorter cycle do not seem to be in doubt and that reducing these costs in the short term would lead to increased costs in the longer term.

## BOARD FINDINGS

The Board concludes that this is an area where spending deferrals or reductions may well be warranted. The analysis suggests that there are net benefits from moving to a 7-year cycle. However, the actual benefits of moving to an 8-year cycle have yet to be demonstrated on Hydro One's system. The Board understands the lag involved between increased spending levels for vegetation management and reduced future expenditures on trouble calls, but it would be appropriate to perform some analysis of actual results at the 8-year cycle before embarking on the significant expense associated with moving to the 7-year cycle.

The evidence also suggests that Hydro One's efficiency level for this activity could be enhanced whatever the cycle length. The significant expenditures associated with moving to the 7-year cycle should be supported by a thorough demonstration that Hydro One has investigated all potential efficiency improvements for this work, for example, greater outsourcing.

The evidence indicates that if Hydro One were to maintain spending at the 8-year cycle level, OM&A could be reduced by about $17 million in 2010 and $28 million in 2011. The Board has already established an overall OM&A envelope and will not order a specific incremental reduction for this item. However, vegetation management is one of the areas where expenditure reductions should be achievable.

## 4. RATE BASE AND CAPITAL EXPENDITURES

Hydro One's forecast distribution rate base for 2010 and 2011 is $4,836 million and $5,146 million, respectively. For 2010, the proposed rate base is 13.9% higher than the approved rate base for 2008 of $4,247 million.

Historical and forecast capital expenditure levels are summarized by major cost category in the table below. The table includes the percentage change from the previous year. Hydro One also proposed significant additional capital expenditures for its Green Energy Plan. The direct costs for the Green Energy Plan are not included in the table, but indirect costs, in the form of capitalized overheads estimated at $10 million to $15 million, are included. The Green Energy Plan is addressed separately in this decision; the rest of the capital expenditure program is addressed in this section.

**Capital Expenditures, 2006 – 2011**
**($ million, including % variance from prior year)**

| Category | 2006 Actual | 2007 Actual | 2008 Actual | 2009 Bridge | 2010 Test | 2011 Test |
|---|---|---|---|---|---|---|
| **Sustaining** | **172.2** | **146.9**<br>-14.7% | **170.7**<br>16.2% | **176.5**<br>3.4% | **185.8**<br>5.3% | **202.5**<br>9.0% |
| **Development**[6] | **146.8** | **154.2**<br>5.0% | **153.2**<br>-0.6% | **167.9**<br>9.6% | **189.2**<br>12.7% | **219.0**<br>15.8% |
| **Operations** | **2.1** | **2.0**<br>-4.8% | **0.9**<br>-55.0% | **2.4**<br>166.7% | **8.1**<br>237.5% | **11.2**<br>38.3% |
| **Shared Services and Other** | **57.4** | **96.8**<br>68.6% | **110.6**<br>14.3% | **103.5**<br>-6.4% | **164.8**<br>59.2% | **110.8**<br>-32.8% |
| **Total** | **378.5** | **399.9**<br>5.6% | **435.3**<br>8.8% | **450.5**<br>3.5% | **547.9**<br>21.6% | **543.5**<br>-0.8% |

Hydro One provided evidence on its planning process which can be broadly divided into four steps:

[6] Hydro One Reply Submission, page 34 (excludes GE Plan Expenditures in the test years)

1. Asset planners determine a list of investments for the various investment categories based on the assumption that no constraints exist. After a series of challenges the list of investments is finalized.

2. This list undergoes a prioritization process resulting in a portfolio of individual investments that together make up a preliminary Investment Plan.

3. The preliminary Investment Plan is reviewed by senior management who may further modify it based on various considerations.

4. The end result is a prioritized Investment Plan proposal, which is recommended to the Hydro One Board of Directors for approval as part of the Corporation's business plan.

Hydro One's prioritization process considers risk mitigation against the dimensions of a set of business values to select the proposed levels of investment. The process incorporates a probability/severity-of-outcome risk matrix to determine the impact ratings for each business value. The Probability scale ranges from Remote to Very Likely and the Severity of Outcome scale ranges from Minor to Worst Case. The accomplishment levels are established and evaluated for a period of five years. The lowest level of investment is referred to as Minimum Level. Minimum Levels of investment are those required to avoid unacceptable risk within the five-year planning period.

The following issues are addressed in this chapter:

- Overall Capital Expenditures
- Distribution System Code Interpretation
- Allowance for Funds Used During Construction
- Working Capital Allowance

## 4.1 OVERALL CAPITAL EXPENDITURES

Capital expenditures, excluding the direct Green Energy Plan expenditures, are forecast to increase by 22% between 2009 and 2010. The level in 2011 is projected to be slightly lower than in 2010, but still 21% higher than 2009. The arguments generally focused on the overall level of the proposed capital expenditures.

Hydro One argued that aside from the Green Energy Plan investments the capital budget has not increased considerably and that the increases are primarily driven by Green Energy Plan related activity. PWU supported the capital expenditure budget and noted that if Hydro One does not undertake increased sustaining work now and into the future, the system will be left with a population of assets that is too old and in very poor condition. PWU submitted that replacing assets under those circumstances could be prohibitively costly.

Board staff noted that Minimum Level funding by definition is intended to mitigate unacceptable risk and questioned whether certain capital programs could be deferred in light of the significant increases proposed in the application. Board staff also noted the significant decline in the cost escalators as updated since the initial application.

CME submitted that the Board should reduce Hydro One's budget to the Minimum Level. VECC submitted that the Board should reduce the work plan by limiting capital expenditures to near the Minimum Level. VECC proposed a 10% reduction to the 2010 capital budget and 5% reduction to the 2011 budget. VECC argued that as Minimum Level spending culminates in unacceptable risk after 5 years, it is appropriate for Hydro One to be restricted to Minimum Level spending for the two test years as a rate impact mitigation measure.

VECC also submitted that before the capital budget is reduced to near Minimum Level, it should first be adjusted for the reduction in the cost escalator for construction. VECC noted that the cost escalator had been significantly reduced from applied-for levels and estimated the impact would be a reduction of 2% to the budget.

SEC argued that Hydro One should prioritize its capital expenditures within an overall envelope, including the Green Energy Plan. SEC submitted that the distribution capital budget should be $460 million in 2010.

CCC submitted that spending should be capped at $415.5 million in 2010. This level is the average for the period 2006 through 2009. CCC proposed that the level for 2011 be set at $423.8 million which is a 2% increase over the level proposed for 2010. CCC also submitted that there should be an asymmetric variance account to capture any underspending.

Hydro One responded that the proposed work plan is based on asset condition information and no party challenged that information. In Hydro One's view, arguments that call for a reduction to the work plan are inconsistent given the uncontested asset condition information. Hydro One also noted that while there was an overall decrease in system demand, the evidence demonstrated that there are pockets of the Province where demand is increasing and Hydro One is obligated to respond to new customer connections.

## BOARD FINDINGS

The Board concludes that in light of the significant increased expenditures associated with the Green Energy Plan, there should be significant efforts to contain spending in other areas of the distribution business. The Board acknowledges that spending at the Minimum Level may not be appropriate over the longer term, but it is appropriate to consider limiting spending to this level during this period of accelerated Green Energy Plan expenditures. The Minimum Level for 2010 is $487 million and for 2011 it is $505 million. However, this analysis was driven off a base level of spending which included the portion of the Green Energy Plan spending which is proposed to be recovered directly from Hydro One's ratepayers. As a result, since Green Energy Plan spending is considered separately in this decision, the Minimum Level for the rest of the distribution business is likely somewhat lower than these levels. In addition, it is also clear that inflation and cost escalation factors are lower than the levels incorporated into the Minimum Level budget.

In the OM&A section of this decision the Board has laid out in detail the basis for its envelope approach. The Board will adopt the same approach for capital expenditures for the same reasons. The Board acknowledges that there are areas of work driven by asset condition (for example, wood pole replacement) and regulatory obligations (for example, customer connections). However, given the very significant expenditure plans associated with connecting renewable generation and implementing smart grid technologies, it is incumbent upon Hydro One to manage and prioritize the balance of its expenditures in order to moderate the overall impact on customers. This may involve reducing the level of work. For example, the budget for Transport and Work Equipment, though driven by the Green Energy Plan, is likely over-stated given more realistic estimates of the magnitude and timing of that program. Prioritizing may also lead to the deferment of certain projects. The large increases in expenditures in the area of Facilities and Real Estate suggest this may be an area where project deferrals are in order. However, as with OM&A, the Board will not make project-specific reductions or disallowances; in the Board's view it is appropriate for Hydro One to make those decisions.

The Board finds that capital expenditures for 2010 and 2011 will be reduced to $500 million in each year. This level remains above the Minimum Level and represents a significant increase over historical levels. Given the significant reduction from the proposed level, the Board concludes that a variance account is not required. As indicated above, the Green Energy Plan is addressed separately in this decision.

## 4.2 DISTRIBUTION SYSTEM CODE

During the proceeding VECC's counsel raised two issues with respect to Hydro One's interpretation of certain sections of the Distribution System Code ("DSC"). The first dealt with the types of activities that were considered "enhancements" versus "expansions" for the purpose of applying the cost recovery provisions of the DSC to load and non-renewable generation customers. The second issue dealt with Hydro One's interpretation of section 3.3.4 of the DSC which addressed the implementation period for changes to the DSC.

Hydro One provided a list of the types of investment activities it considers to be "enhancements" as opposed to "expansions" for the purpose of applying the cost recovery provisions of the DSC. At the hearing, Counsel for VECC noted that three activities on the list of enhancement activities (increasing the size of distribution station transformers, re-conductoring lines and modifications to voltage regulating equipment) are categorized as expansion activities in section 3.2.30 of the DSC. Hydro One clarified its position and indicated that its categorization of what is enhancement and what is expansion varies depending upon whether the activity arises as a result of the connection of a particular customer or group of customers or whether the activity is part of its overall distribution system plan. Hydro One noted that if the Board finds that the activities it has interpreted to be enhancements are in fact expansions, the impact would be a reduction of $2 million per year to the connections budget.

VECC submitted that the DSC clearly lays out the definition of enhancement and expansion activities and that Hydro One should align its approach with the DSC. VECC however acknowledged that under the DSC the cost recovery treatment for certain activities changes depending on whether they are in or out of a distributor's system plan and this may have the same effect as Hydro One's approach.

The second issue deals with the effective date for the DSC changes in cost recovery as they are applied to new non-renewable generators and load connections. Sections 3.3.3 and 3.3.4 of the DSC state:

> 3.3.3 Subject to section 3.3.4, the distributor shall bear the cost of constructing an enhancement or making a renewable enabling improvement, and therefore shall not charge:
>
> (a) a customer a capital contribution to construct an enhancement; or
>
> (b) a customer that is connecting a renewable energy generation facility a capital contribution to make a renewable enabling improvement.
>
> 3.3.4 Section 3.3.3(a) shall not apply to a distributor until the distributor's rates are set based on a cost of service application for the first time following the 2010 rate year.

VECC submitted that the wording of the DSC is clear and the changes should not be applied in the current application.

Hydro One did not address this issue in reply.

## BOARD FINDINGS

The Board is satisfied with Hydro One's explanation of how it operationalizes the provisions in the DSC related to enhancements and expansions as they relate to load customers and non-renewable generation. The Board has previously recognized that there may be some overlap between enhancements and expansions, but the Board is satisfied on Hydro One's evidence that it addresses the issue on a consistent basis.

With respect to the timing of implementation, the Board will accept Hydro One's interpretation because the application addresses the impacts of the new provisions adequately. It may well be that other distributors have interpreted the provision differently and have not adjusted their 2010 applications to incorporate that change. That too may be acceptable in the circumstances of that distributor.

## 4.3 ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

The Allowance for Funds Used During Construction ("AFUDC", also referred to Construction Work in Progress or CWIP) is $22.3 million in 2010 and $27.1 million in 2011. The AFUDC rate is 6.4% in 2010 and 7.7% in 2011.

No party was opposed to Hydro One's overall approach to establishing the AFUDC rates. Energy Probe however submitted that consistent with the approach used to update the cost of capital components, Hydro One should update its test year AFUDC rates based on September 2009 information. The AFUDC rates based on September 2009 forecasts are considerably lower than the rates included in the application. The updated AFUDC rate for 2010 would be 5.23% and for 2011 would be 5.73%.

Hydro One maintained that the original amounts were appropriate and noted that it did not intend to or support revising the AFUDC rates.

### BOARD FINDINGS

The Board finds that it would not be appropriate to update the AFUDC rate for more current information. All test year forecasts are underpinned by assumptions for economic factors which may vary as time passes as the test year approaches or as the test year begins. The Board has traditionally resisted selective updates because in order to be consistent the entire application would need to be updated. When the Board updates the return on equity and the deemed debt rates, it does so for purposes of the overall cost of capital in accordance with the deemed capital structure, and for only that purpose. No adjustment will be made to the AFUDC.

## 4.4 WORKING CAPITAL ALLOWANCE

The working capital allowance for 2010 is $300.7 million (or 11.7% of 2010 OM&A and cost of power expenses) and $305.4 million in 2011 (or 11.9% of 2011 OM&A and cost of power expenses).

The determination of working capital relies on a lead-lag study and is based on the forecast of OM&A expenses, cost of power, capital and income taxes, the net lead-lag days and materials and inventory. Hydro One proposed to continue the methodology originally approved by the Board in 2005 and reviewed in subsequent proceedings. In

2009, Hydro One retained Navigant Consulting Inc. to conduct a lead-lag study. The results of that update were used to estimate the test year working capital requirements.

No party objected to the results of the lead-lag study or the methodology used to determine the working capital requirements. VECC and Energy Probe however raised concerns with certain assumptions used to determine the cost of power and the impact on the revenue lag of the planned migration of 140,000 customers from bi-monthly billing to monthly billing.

To determine the cost of power Hydro One has used a weighted average commodity price of $61.70 per MWh, based on prices in the Board's April 2009 Regulated Price Plan (RPP) Report. Hydro One also calculated the cost of power based on prices in the Board's October RPP Report which is a weighted average price of $61.12 per MWh. This change would reduce the cost of power by $15 million and the cash working capital by $1.5 million per year. Hydro One has relied on the historical RPP/non-RPP customer split of 69%/31% to estimate the weighted average commodity price. However, Hydro One recalculated the commodity price based on a forecast split of 65%/35% and the Board's October 2009 RPP Report, and this would further reduce the weighted average commodity price to $60.99 per MWh.

Energy Probe and VECC argued that the allowance should be based on the cost of power in the Board's October 2009 RPP Report. They argued the Board's standard practice was to require the working capital allowance to be updated for the most recent RPP Report (typically October or April depending on the timing of the Decision) and that there is no reason why Hydro One should be treated differently. Energy Probe further argued that Hydro One should use the forecast split between RPP and non-RPP customers to calculate the weighted average price and noted that this further reduces the working capital requirement by approximately $400,000 in 2010 and $1.9 million in 2011.

Starting in 2010 Hydro One will begin the migration of 140,000 customers from bi-monthly billing to monthly billing. This migration is expected to be completed by mid 2011 and will reduce the revenue lag by 1.96 days from 69.99 days for those customers. Hydro One estimated this change will reduce the working capital requirement by approximately $13 million per year when the full year impact of the migration occurs in 2012.

Energy Probe and VECC argued that a portion of the full year reduction in working capital should be reflected in the test year estimates given that the migration begins in 2010. VECC submitted that based on the timing of the migration approximately 85%-90% of the full year impact will be realized by 2011 and therefore the 2011 working capital should be reduced by $11 million. Energy Probe submitted that the working capital should be reduced by $4.3 million in 2010 and by $11.9 million in 2011.

Hydro One submitted that the working capital inputs are appropriate and argued that the impact of the updates is relatively small and is offset by other impacts. With respect to the movement of customers, Hydro One submitted that it will be considered after 2011.

## BOARD FINDINGS

The Board has consistently incorporated the most current available Board approved commodity price for purposes of determining the working capital allowance in cost of service decisions. The Board concludes that a similar approach is appropriate here and therefore directs Hydro One to use the cost of power in the October 2009 RPP report and to use its forecast split between RPP and non-RPP customers (65%/35%). The Board will also make an adjustment to recognize the impact of the shift from bi-monthly to monthly billing. As this will largely be completed within 2011, the Board will reduce the allowance for that year by $11 million, as estimated by VECC, but no reduction will be made for 2010.

# 5. GREEN ENERGY PLAN

Hydro One filed its Green Energy Plan in response to certain provisions of the *GEA.* The plan covers the five year period from 2010 to 2014 and includes the incorporation of renewable energy generation, development of a Smart Grid and promotion of energy conservation.

Using the Board's *Guidelines: Deemed Condition of Licence: Distribution System Planning – G-2009-0087,* issued on June 16, 2009 (the "Guidelines"), Hydro One presented the O&M and capital expenditures related to renewable generation under the categories of Connection, Expansion and Renewable Enabling Improvements ("REI"). Hydro One's Green Energy Plan is summarized in the table below.

**Green Energy Plan Summary, 2010 – 2014**
**($ million)**

| | 2010 | | 2011 | | 2012 – 2014 | |
|---|---|---|---|---|---|---|
| **Category** | **O&M** | **Capital** | **O&M** | **Capital** | **O&M** | **Capital** |
| **Renewable Generation** | 3 | 168 | 3 | 296 | 10 | 930 |
| **Smart Grid** | 10 | 30 | 10 | 62 | 45 | 250 |
| **Energy Conservation** | >20 | - | >20 | - | >60 | - |
| **Total Plan Costs** | >33 | 198 | >33 | 358 | >115 | 1,180 |
| | | | | | | |
| **Less Generator Funded Costs** | - | 13 | - | 27 | - | 40 |
| **Less External Funding** | >20 | 139 | >20 | 236 | >60 | 780 |
| | | | | | | |
| **Net Costs to Hydro One** | 13 | 46 | 13 | 95 | 55 | 360 |

With respect to cost recovery, Hydro One has assumed that the revenue requirement associated with a significant portion of the capital investments contained in the plan will be recovered through an external funding mechanism that recovers the required revenue from all electricity consumers in Ontario. The cost responsibility proposals for the Connections, Expansion and REI investments were developed in accordance with the proposed Distribution System Code ("DSC") amendments issued by the Board on June 5, 2009 and subsequently updated on September 11, 2009. The DSC amendments were finalized on October 21, 2009, after the filing and update of Hydro One's Green Energy Plan.

Hydro One sought two specific approvals with respect to its Green Energy Plan:

- That the Board accept the five year plan as fulfilling Hydro One's obligation to put forward a Green Energy Plan pursuant to the GEA, and
- That the Board specifically approve the levels of spending set out in the plan for the years 2010 and 2011 for rate-making purposes.

The total capital costs for 2010 and 2011 are $556 million, over 84% of which are related to renewable generation connection. The balance is related to the Smart Grid program. Hydro One intends to reapply in 2011 with an updated plan for approval of expenditures in future years.

The Board will address the following issues:

- Overall Assessment of the Green Energy Plan
- Express Feeders
- Remaining Renewable Generation Expenditures
- Smart Grid Expenditures
- Conservation and Demand Management (CDM)

## 5.1 OVERALL ASSESSMENT OF THE GREEN ENERGY PLAN

Hydro One outlined its view of how the Board should review and approve the Green Energy Plan as follows:

> "The review of Hydro One's Plan should be consistent with the review normally done in a Cost of Service application in terms of testing the evidence. In addition, the Board must satisfy itself with respect to the plan's support of the Board's objectives under the *Green Energy and Green Economy Act, 2009* to promote electricity conservation and demand management and renewable energy generation, and facilitate the implementation of a smart grid. Hydro One submits its Green Energy Plan has met these objectives by bringing forward a set of investments that will allow Hydro One to proceed with expanding and enabling the distribution system to accommodate increased renewable generation and to further develop the smart grid to support this objective as well as promote and expand energy conservation in the province. As stated in the Green Energy Plan, Hydro One is currently not submitting an updated set of CDM programs until the issues noted in the plan are resolved. Once the processes to address these issues are

> completed, Hydro One Distribution will be in a position to assemble a portfolio of CDM programs for the Board's review and approval."[7]

Intervenors generally agreed with this view of how the Board should assess the plan, although they disagreed as to the conclusion the Board should reach.

Board staff submitted that the Green Energy Plan meets the objectives in the GEA, to the extent that those objectives can be identified in section 70(2.1) of the OEB Act. Board staff also noted that as yet there is no "obligation" for Hydro One to put forward a Green Energy Plan. The obligation to prepare and file plans arises when the Board mandates such filing, and as yet the Board has not done so.

Board staff submitted that Hydro One's Plan may not meet the Board's filing guidelines in two ways: the absence of a section providing a current assessment of the capacity of the system to accommodate the connection of renewable generation, and a failure to provide sufficient detail to enable the Board to carry out its mandate to evaluate the plan. Most intervenors made similar submissions.

Intervenors generally were of the view that expenditures proposed in the plan should not be approved, but that a funding adder/deferral account approach could be used, albeit at a reduced level, with prudence being considered later. Intervenors noted the uncertainty of the renewable generation forecast and the lack of specificity in the plans. CME submitted that the requested expenditure levels were excessive in light of overall rate impacts and affordability considerations and proposed that funding be allowed at the 67% level.

Hydro One was not opposed to a rate rider/variance account approach (i.e. assuming the prudence of the expenditures had been approved), but emphasized the need to approximate the cash flow that would result if the expenditures were included directly in the revenue requirement.

## BOARD FINDINGS

In assessing Hydro One's Green Energy Plan, the Board must reconcile the Board's objectives to protect the interest of consumers with respect to prices and reliability, to promote economic efficiency, to promote conservation and demand management, to facilitate the implementation of a smart grid, and to promote generation from renewable

[7] Exhibit H-9-52

energy sources consistent with the policy of the Government of Ontario. The policy articulated in the Board's guidelines on distribution planning provides guidance to this consideration. The Guidelines include the expectation that an applicant will bring forward a plan to support a request for material funds to develop and implement green energy initiatives. Hydro One has made such a request and therefore it is appropriate for the company to have filed a plan. However, the timing was not ideal for Hydro One. The specific requirements for additional capacity to connect renewable generation were in the early stage of development when Hydro One submitted its application, and continue to develop at the time of this decision. While Hydro One cannot be faulted for not bringing forward a more detailed plan, the lack of specifics in the test years does provide significant difficulty for the Board.

While the Board accepts that Hydro One's plan has addressed the objectives of the *GEA*, in level of detail it falls short of the expectations of the Board's filing guidelines. This detail is important because if the Board approves the Green Energy Plan, there are three significant impacts.

The most immediate and obvious impact of approval of part or all of the Plan is that the spending for approved projects will be recovered from ratepayers (both Hydro One ratepayers and provincial ratepayers). According to the Board's guidelines, once approved in a plan, the need, selection, and budget of a project will not be revisited in subsequent proceedings except in regard to material deviations. Second, approval of all or part of a plan would also result in changes in cost responsibility in accordance with the DSC and regulations. Specifically, costs would be shifted from generators to ratepayers (both local and provincial) pursuant to sections 3.2.5A and 3.2.5.B of the DSC, section 79.1(4)(c) of the Act and section 1(2) of O. Reg. 330/09. Third, under the Act, a distributor can be required to expand or reinforce its system, or make Smart Grid investments, in accordance with an approved plan (section 70(2.1)3 of the Act). This was of particular concern to VECC.

The Board concludes that it cannot approve all the 2010 and 2011 expenditures in the Green Energy Plan. The Board will approve the expenditures for Smart Grid, and subject to material conditions, the expenditures associated with the six express feeders as described at Exhibit D2/Tab 2/Schedule 3/Reference D29. No other aspect of the Green Energy Plan is approved. The Board will, however, provide a funding mechanism for a portion of the projected Renewable Generation expenditures that are not being approved at this time. Funds are to be recovered from both local and provincial ratepayers. The Board will establish a process whereby the prudence of these funded expenditures can be tested at the appropriate time. In the interim the Board will facilitate the operation of the rate protection provisions of the legislation and the regulations.

Hydro One has indicated that costs indirectly related to the Green Energy Plan are embedded in Hydro One's Capital and O&M forecasts. These costs are in addition to the amounts filed as Green Energy Plan and explicitly dealt with in this section of the decision. In future proceedings, the Board directs Hydro One to identify in its evidence the total cost of its Green Energy Plan – direct and indirect. It is important that the full impact of the plan is known both for the Board's consideration and for transparency of communication.

## 5.2 EXPRESS FEEDERS

Hydro One provided evidence regarding the planned construction of six express feeders that are expected to be approximately 25 km long and connect to a new, as yet unsited transmission station in southwest Ontario. These feeders are expected to be constructed in 2011, with a route that will be finalized after connection applications related to the OPA's FIT program are received. The aggregate cost of these assets is estimated to be $34.7 million, accommodating no less than 240 MW of generation capacity. However, Hydro One has indicated that these assets will not be constructed until Hydro One has sufficient assurance that the feeders are fully subscribed at least to the level identified in the plan.

### BOARD FINDINGS

The Board approves as prudent the proposed capital expenditures related to the express feeders, provided that construction does not commence until a time mandated by the Board. The revenue requirement amounts for each test year related to the feeders will be recovered by way of a rate rider and external funding. A variance account will be used for the purpose of tracking the difference between the forecast and actual expenditures for future disposition.

The Board is mindful that the deemed condition of licence set out in section 70(2.1)3(i) of the Act requires a distributor to expand or reinforce its system in accordance with an approved plan or as otherwise mandated by the Board.

Given the current uncertainty regarding the total demand for and location of the feeders, the Board does not wish its approval to result in a requirement that Hydro One expand or reinforce its system prematurely. The Board is therefore directing that the construction of the express feeders be deferred. Hydro One shall inform the Board when it has sufficient information regarding requests for connection underpinning the need for each feeder and the location of each feeder. The Board will then determine when and confirm how this expansion of Hydro One's distribution system should occur, which the Board may do with or without a hearing. However, the Board does authorize Hydro One to begin the necessary development and pre-construction work associated with the express feeders.

The revenue requirement amounts for each test year related to the express feeders will be split between Hydro One's ratepayers and provincial ratepayers. In its partial decision in this application, dated February 18, 2010, the Board provisionally approved, for rate setting purposes, the methodology proposed by Hydro One for the allocation of eligible investment costs in Hydro One's Green Energy Plan between Hydro One ratepayers and provincial ratepayers. The allocation methodology and the resulting responsibility for eligible investment costs for 2010 and 2011 will be subject to later revision to reflect the Board's final policy determination in EB-2009-0349. If the result of the Board's policy is to change the allocation that has been provisionally approved, Hydro One will be required to recalculate the assignment of costs, and implement a debit or credit to each ratepayer group.

## 5.3 REMAINING RENEWABLE GENERATION EXPENDITURES

Hydro One proposes to connect 3,500 MW of renewable generation to its system by the end of 2011. The capital required to connect this level of generation is projected to be $464 million over two years for connections, expansions and REI. The capital expenditures by cost responsibility category are summarized below:

**Renewable Generation Capital Expenditures, 2010 and 2011**
**($ millions)**

| | Connection | | Expansion | | REI | | Total | |
|---|---|---|---|---|---|---|---|---|
| | 2010 | 2011 | 2010 | 2011 | 2010 | 2011 | 2010 | 2011 |
| **Generator Funded** | 13 | 27 | 0 | 0 | 0 | 0 | 13 | 27 |
| **Externally Funded** | 0 | 0 | 60 | 118 | 79 | 118 | 139 | 236 |
| **Hydro One Ratepayer Funded** | 0 | 0 | 12 | 25 | 4 | 8 | 16 | 34 |
| **Total Capital** | 13 | 27 | 72 | 143 | 83 | 127 | 168 | 296 |

One of the key assumptions in the capital budget is the expected number of renewable generation connections. Hydro One has assumed that a majority of these new connections will be from the Feed-in Tariff ("FIT") program. However, when Hydro One's capital expenditure forecast was developed, the actual results of the FIT program were not definitively known.

Hydro One also proposed that the renewable generation capital assets developed under the Green Energy Plan be depreciated on a straight line basis over a 20 year period. Hydro One argued that a 20-year depreciation period is appropriate because it equals the length of the underlying electricity contracts between the OPA and the renewable generators. Hydro One claimed that there is no guarantee that the assets will be used and useful beyond the life of those contracts and that the service life should match the period of time for which there is a benefit for provincial ratepayers. Board staff argued that the assets will still be used and useful when the initial contracts expire and notes that Hydro One has not provided any rationale for why this is not the case.

The intervenors generally submitted that the amount of additional capacity needed and the timing of renewable generation connections are very uncertain. In addition, CCC questioned Hydro One's capability to complete the work plan by 2011 in any event, given the significant level of expenditures for the overall capital program.

## BOARD FINDINGS

With the exception of the proposal to construct the express feeders, the Board will not approve as prudent the expenditures for renewable generation at this time. In the Board's view, the proposal is deficient due to the unsubstantiated magnitude of the forecast connections, and therefore total expenditures, and the lack of specificity as to projects to be undertaken.

Hydro One has provided little conclusive evidence regarding the timing and extent of renewable generation connections. The OPA's FIT program is in its very early stages and the most recent public information from the OPA suggests capacity renewable generation connections at 50% to 75% of Hydro One's estimate. While the Board recognizes that this is very preliminary information, there is little else to indicate the overall capacity required in 2010 and 2011. The Board also shares the concern expressed by CCC that Hydro One may not have the capability to complete such an ambitious program in any event.

Hydro One agreed that the Board's review of the plan should be consistent with the review normally done in a cost of service application in terms of testing the evidence. The level of detail for renewable generation expenditures, however, did not allow such a review to be conducted. The actual projects, their location and the specific needs to be addressed by each project were not set out in the Green Energy Plan.

The Board notes that considerable uncertainty remains regarding all the proposed green energy projects, despite Hydro One's efforts to work with all available information. The Board concludes that it is necessary to have greater detail and specificity regarding the projects to be undertaken before a finding of prudence and approval of the remaining expenditures can be made. In the past, expansion costs to serve a generator would be paid for by the generator and ratepayers faced minimum risk if the forecast was inaccurate. In today's environment for renewable generation, if the Board approves the expenditures, ratepayers are at risk for the entire cost of the expansions. It is therefore particularly important to have confidence that the investments become used and useful. In addition, given the still uncertain take-up and location of FIT generation, the Board is reluctant to make a finding which under section 70(2.1)3 of the Act, might require Hydro One to build the facilities approved in the plan even if it became unnecessary to do so.

Although the Board will not approve these renewable generation expenditures on the basis of the record in this application, the Board understands that Hydro One will likely need to undertake work in this area during 2010 and 2011 and should therefore have funding to undertake that work. The Board concludes that funding adders and deferral accounts should be used to support Hydro One's work, while managing the risk to ratepayers and Hydro One.

The Board finds that funding will be provided for 67% of the remaining capital and OM&A expenditures for renewable generation connection for 2010 and 2011. In the Board's view, this represents a more probable level of activity for 2010 and 2011. Actual expenditures will be captured in deferral accounts which will be subject to a prudence review and cleared as part of Hydro One's next distribution rate case. This clearance will be symmetrical. That is, if Hydro One has spent less than the amount collected through the funding adder, the difference will be returned to ratepayers, in addition to any costs found to be imprudently incurred. If Hydro One has prudently spent more than the amount collected through the funding adder, Hydro One will collect the difference through future rates.

Rate protection as prescribed under section 79.1 of the Act will apply to allow collection of a portion of the costs from provincial ratepayers, consistent with the allocation proposed by Hydro One. As explained in the previous section, this allocation is provisional and will be revisited once the Board's policy is determined through the EB-2009-0397 process.

Section 79.1(2) of the Act reads as follows:

> **Distributor entitled for compensation for lost revenue**
> (2) A distributor is entitled to be compensated for lost revenue resulting from the rate reduction provided under subsection (1) that is associated with costs that have been approved by the Board and incurred by the distributor to make an eligible investment referred to in subsection (1).

In making an order permitting collection of amounts from provincial ratepayers in this case prior to a prudence review, the Board has taken a purposive approach to section 79.1 of the Act, using a regulatory approach that is consistent with the manner in which the Board sets rates in the normal course as well as one that will further the Board's objective of promoting the use and generation of electricity from renewable energy sources.

Under the Board's rate setting regime, rates are set based on a forecast of the revenue that will be required by the distributor in the test year. Rates are therefore largely set on the basis of costs that have not yet been incurred. In exercising its other powers under the Act, the Board should do so in a manner consistent with how the Board carries out its mandate to set just and reasonable rates under section 78 of the Act. In some instances in the past the Board has permitted the collection of funds from ratepayers, subject to a subsequent prudence review. This enables the utility to have a source of funding, while protecting ratepayer interests.

The Board, for the reasons cited above, cannot make a finding of prudence with respect to the remaining proposed expenditures for renewable generation connection in Hydro One's plan. However, when viewed in light of the way in which the Board sets rates, the Board is of the view that in the circumstances of this application, costs can be specifically approved for collection under section 79.1 even if not yet approved as prudent.

The Board is of the view that, ultimately, the liability of provincial ratepayers for the rate protection referred to in section 79.1 of the Act is limited to costs that have been determined by the Board to have been prudently incurred (net of any direct benefits). As such, where collection from provincial ratepayers is provided for by the Board on a provisional basis, it will be important to ensure that an appropriate mechanism is in place to allow for any necessary reconciliation. In this case, the Board has provided for a reconciliation between costs actually spent and costs prudently incurred, as well as between amounts provisionally collected from provincial ratepayers and costs that are determined to be their responsibility once the Board's policy on the calculation of direct benefits is finalized.

The Board's Guidelines created two deferral accounts for the recording of renewable connection expenditures: account 1531 for capital costs and account 1532 for OM&A costs. Hydro One should use these accounts to record actual expenditures related to renewable energy generation connections. In addition, in its *Filing Requirements for Distribution System Plans*, released March 25, 2010, the Board approved two deferral accounts for the recording of amounts collected through Green Energy Act related funding adders. Account 1533 should be used to record amounts collected through the funding adder. It will be necessary to use sub-accounts to separate collection from Hydro One ratepayers and provincial ratepayers (i.e. payments from the IESO).

Under the provisions of the DSC, if expansion and REI costs have not been previously approved by the Board, then any amounts over $90,000 per MW are the responsibility of the generator. If a plan or the specific expenditures are approved (found prudent) the cost responsibility for those expenditures shifts from the renewable generator to ratepayers. The Board understands, therefore, that its approval of a plan, or expenditures within a plan, has significant ramifications for renewable generators as well as ratepayers. The DSC does contemplate approval of expansion and REI work outside the context of a five year Green Energy Plan. When sufficient detail becomes available to allow Hydro One to demonstrate the prudence of the remaining renewable connection expenditures for the test period, Hydro One may apply for a determination of prudence and collection of those expenditures through a rate rider.

Depreciation for Renewable Generation Investments

The Board does not accept Hydro One's proposal to use a 20-year depreciation period at this time. The Board agrees with Board staff that Hydro One did not provide sufficient evidence to support a deviation from the standard treatment for depreciation. However, it would be appropriate for Hydro One to bring further evidence supporting its request for a shortened depreciation period when the Board considers the prudence of the expenditures. Until such a case is made and decided upon, Hydro One will use the normal depreciation periods for the assets in the plan, including the Express Feeders.

## 5.4 SMART GRID

Hydro One plans to spend $30 million in 2010 and $62 million in 2011 on Smart Grid capital investments. Hydro One proposes that the investments be included in rate base for the test years, arguing that the investments are necessary, used and useful, and sufficiently well defined to be included as part of its rate base. Smart Grid O&M costs of $10 million for each of 2010 and 2011 are also included in the Green Energy Plan.

The Smart Grid expenditure projection was developed following a three step process. The first step was to focus on integrating renewable energy generation, CDM, and system automation. Second, Hydro One formulated plans to utilize pilots to investigate new innovative technologies. The final step is the implementation of pilot projects. The capital expenditures on the smart grid program are summarized below:

**Smart Grid Capital Expenditures, 2010 and 2011**
**($ million)**

| | 2010 | 2011 |
|---|---|---|
| Energy Storage | 2 | 2 |
| Smart Zone Pilot | 13 | 42 |
| PHEV Trials | 1 | 1 |
| Distribution System Innovation | 5 | 5 |
| Facilities/System Upgrades | 7 | 10 |
| Technology Work (GIS) | 3 | 3 |
| **Total Smart Grid Capital** | **30** | **62** |

As shown above, a significant portion of the investments is related to the Smart Zone pilot project. The main objective of this project is to innovate, test and prove new and emerging technologies. Hydro One issued an RFP in 2009 related to research and development and other development work that will be undertaken in the Smart Zone pilot. The results are yet to be finalized.

In cross examination, the witnesses confirmed that until the RFP process is completed, the final costs may vary. However, Hydro One acknowledged that the final costs may vary, but argued that the estimates have been developed in a prudent manner and that the final costs will reflect the forecast.

Board staff argued that Smart Grid costs were of higher risk because of developing requirements for distribution grids and quickly evolving technology. Staff suggested the use of a rate adder and deferral account with a subsequent review for prudence.

CCC and CME both objected to the Smart Grid costs. CME argued that the total plan costs should be reduced by 67%, including the Smart Grid costs. CCC submitted that Hydro One's costs were uncertain since its RFP process was not finalized. CCC also argued that Hydro One had not met the Smart Grid guidelines because the company had not entered into joint participation agreements and that part of the RFP was for research and development. Hydro One responded that the forecast is reliable and maintained that the work does not include research and development but rather technical studies.

## BOARD FINDINGS

Hydro One's Smart Grid plan includes many of the activities indentified in the Board's filing guidelines regarding smart grid. Generally, the Board finds that the activities identified in Hydro One's Smart Grid plan are consistent with the filing guidelines. Other than the submissions of CCC that Hydro One had not entered in a joint participation agreement and that the activities included research and development (which is prohibited under the guidelines), no party argued that the activities were inconsistent with the Board's guidelines. Parties were most concerned with the uncertainty of the costs.

Although the Board encourages utilities to jointly participate in Smart Grid studies, the Board accepts that Hydro One is uniquely positioned to move forward at this time with Smart Grid activities. The Board encourages Hydro One to share the results of its programs with other utilities where applicable.

The Board accepts Hydro One's evidence that the activities do not include research and development as contemplated in the Board's guidelines. The Board agrees with Hydro One that the RFP in question is very detailed and that Hydro One has the expertise to accurately forecast the cost.

Regarding Board staff's concern that Smart Grid functions are quickly evolving, the Board notes that it is the need to understand these changes which drives the requirement for Smart Grid studies. The development of renewable generation is dependent to a significant degree on technical enhancements to the system - smart grid capabilities. Given the unique role of Hydro One in the province, and the need to develop these capabilities, the Board considers it prudent to approve the Smart Grid aspects of the Green Energy Plan.

Therefore, the Board concludes that the costs as budgeted are prudent, and should be recovered in rates.

While the Board accepts that the cost forecast for the Smart Zone pilot is reasonable, the Board is concerned that the funds may well not be spent in the 2010 and 2011, because the RFP has not yet been finalized. Given this uncertainty regarding the timing of this significant portion of the Smart Grid budget, the Board directs that Smart Grid costs will be recovered through a rate rider, and will be subject to further review, not for prudence, but to determine if the amounts were actually spent in the period. Therefore, the difference between amounts collected and actual expenditures are to be recorded in a variance account which can be cleared at Hydro One's next distribution rate proceeding.

## 5.5 CONSERVATION AND DEMAND MANAGEMENT (CDM)

Hydro One included CDM in its Green Energy Plan but indicated that it was seeking only minimal rate funding as it awaits the setting of CDM targets for each distributor and OPA funding for CDM initiatives. Hydro One indicated that it has engaged a consultant to propose a portfolio of programs suitable for Hydro One's service territory and the customer end uses within it, when the CDM targets are established. Hydro One budgeted $1 million for CDM in the application and indicated that $20 million is the current level of OPA-funded CDM activity.

Pollution Probe and GEC focused on CDM and the related LRAM issue in this proceeding. The LRAM issue is dealt with in the Load Forecast section of this decision. Pollution Probe recommended that specific CDM programs be expanded, including the Hydro One Peaksaver, Electricity Retrofit Incentive and the Double Return Programs.

GEC expressed disappointment that Hydro One had not focused enough effort on load reduction in its Green Energy Plan. GEC noted that the legislative and policy framework anticipates a continued coordinating and planning role for the OPA and target-setting by the Board in response to Ministerial direction, but submitted that the delays in that process should not slow progress by individual distributors with their existing programs given that the Board has explicitly authorized distributors to apply for rate funding to address gaps in provincial programs. GEC noted that Hydro One had agreed to a Green Energy Plan variance account and that CDM spending variances could be captured in such an account. GEC concluded that the Board should direct Hydro One to accelerate its existing programs in the 2010 and 2011 and track its costs in the Green Energy Plan variance account.

### BOARD FINDINGS

The Board recognizes the important role that CDM has in meeting the government's policy objectives and providing customers with a means to reduce their bills. However, the Board will not direct Hydro One to expand its CDM programs as suggested by GEC and Pollution Probe. Hydro One is appropriately waiting for further direction from the government (through regulation or directive), the Board and the OPA on the appropriate targets for CDM. The OPA is developing programs that are widely applicable which will be available to Hydro One.

The Board approves the CDM spending as proposed by Hydro One.

## 5.6 SUMMARY OF BOARD FINDINGS IN THIS SECTION

**Renewable Generation Expenditures - Express Feeders:**

- Capital expenditures approved.
- Development and pre-construction work can proceed.
- Construction deferred awaiting further information from Hydro One and direction from the Board.
- Costs to be recovered through a rate rider, with a variance account to track the difference between actual expenditures and amounts collected through the rate rider.
- Rate protection as prescribed under section 79.1 of the Act will apply to allow collection of a portion of the costs from provincial ratepayers consistent with the allocation proposed by Hydro One. If application of the Board's policy regarding the determination of direct benefits would alter this allocation, Hydro One will be required to recalculate the assignment of costs, and implement a debit or credit to each ratepayer group.

**Renewable Generation Expenditures – Remainder:**

- Expenditures not approved as prudent at this time.
- 67% of applied-for expenditures to be collected through a funding adder.
- Amounts collected through the funding adder are to be recorded in Account 1533, using sub-accounts to separate amounts collected from Hydro One ratepayers and from provincial ratepayers.
- Actual expenditures are to be recorded in account 1531 for capital costs and account 1532 for OM&A costs.
- Rate protection as prescribed under section 79.1 of the Act will apply to allow collection of a portion of the costs from provincial ratepayers consistent with the allocation proposed by Hydro One. If application of the Board's policy regarding the determination of direct benefits would alter this allocation, Hydro One will be

required to recalculate the assignment of costs, and implement a debit or credit to each ratepayer group.

**Smart Grid:**

- Proposed expenditures approved.
- Costs to be recovered through a rate rider, with a variance account to track the difference between actual expenditures and amounts collected through the rate rider.

**CDM:**

- Spending as proposed by Hydro One approved.
- Costs to be recovered through the OPA and in rates.

## 6. COST OF CAPITAL

The table below summarizes the proposed capital structure and cost of capital for the two test years as reflected in Hydro One's original filing:

**Capital Structure & Cost of Capital**
**2010 and 2011**

| | 2010 | | | | 2011 | | | |
|---|---|---|---|---|---|---|---|---|
| **Deemed** | **$M** | **%** | **Cost Rate (%)** | **Return ($M)** | **$M** | **%** | **Cost Rate (%)** | **Return ($M)** |
| **Long-term Debt** | 2,707.9 | 56.0% | 5.72% | 154.8 | 2,881.6 | 56.0% | 5.72% | 164.7 |
| **Short term Debt** | 193.4 | 4.0% | 1.19% | 2.3 | 205.8 | 4.0% | 2.76% | 5.7 |
| **Common Equity** | 1,934.2 | 40% | 8.11% | 156.9 | 2,058.3 | 40.0% | 9.09% | 187.1 |
| **Total** | **4,835.6** | **100.0%** | **6.49%** | **314.0** | **5,145.7** | **100.0%** | **6.95%** | **357.4** |

Hydro One's deemed amount of short-term debt is fixed at 4% of rate base, as part of its deemed capital structure, and is based on the three-month bankers' acceptance rate plus a fixed spread of 25 basis points based on the then prevailing Cost of Capital policy. Short term variable rate debt, which pays interest based on the bankers' acceptance rate, has been included as part of the deemed short term debt amount of 4%.

Hydro One's long term debt rate (56% of rate base) is calculated as the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2010 and 2011. As Hydro One Distribution has a market determined cost of debt, the weighted average long term debt rate is also applied to any notional debt that is required to match the actual amount of long term debt to the deemed amount of long term debt. This approach is consistent with the Board's EB-2008-0272 Decision.

With respect to Return on Equity ("ROE"), in its original evidentiary filing, Hydro One proposed an ROE of 8.11% for the 2010 test year and 9.09% for the 2011 test year per the Board's formulaic approach in Appendix B of the then prevailing Cost of Capital methodology developed in EB-2006-0088/EB-2006-0089, issued December 20, 2006.

## BOARD FINDINGS

This aspect of the application was not controversial until the Board issued its cost of capital report in EB-2009-0084[8] (the "Report"). The Report had the effect of amending the Guideline the Board uses to establish the applicable cost of capital parameter which is applied to rate base, and which provides the stipulated return on equity to the utility.

In its initial filing, and throughout the proceeding, the applicant had indicated that it would rely upon and apply the prevailing Board approved Guideline for the derivation of the return on equity, which with the issuance of the Board Report on December 11, 2009 became the Revised Guideline.

Early in 2009 the Board embarked on what evolved into a comprehensive review of its cost of capital methodology. All of the parties in the instant case participated in one degree or another in this consultation on cost of capital.

The Board's review culminated in its report of December 11, 2009. That report changed the method used by the Board in developing the cost of capital parameter component of rates. It is unnecessary for the purposes of this decision to discuss in any detail how that methodology was amended as a result of the Board's consultation, but the end result is a material increase in return for the utility.

As documented in the Board's letter of February 24, 2010, the revised methodology increases the 2010 ROE from 8.11% to 9.85%, and the short-term debt rates were established at 2.07%.

The Report was issued in the middle of the oral portion of this proceeding, and immediately caused concern among a number of the intervenors representing ratepayer interests. For its part, the applicant indicated that it would hold to its abiding position that the Board-approved methodology, as amended by the Revised Guideline, should be applied to its application without deviation.

[8] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084, December 11, 2009

Prior to the release of the Report the cost of capital issue did not attract significant interest from any party through the interrogatory process or otherwise.

The first attack on the company's position by the ratepayer-oriented intervenors took the form of submissions which sought to require the production by Hydro One of additional evidence to justify the application of the amended approach to its case.

On December 15, 2009, after hearing argument from all parties, the Board issued its oral decision. In denying the relief sought by parties, the Board recognized that its report of December 11, 2009 specifically addressed the question of challenges to the applicability of the Guideline, or any part of the Guideline in any given rate case.

Put simply, the Board found that its Report contemplated circumstances where intervenors may want to challenge the application of the Revised Guidelines to a particular applicant in a particular case. In such cases the Report made it incumbent upon intervenors to lead evidence supporting that point of view. In its oral decision, the Board cautioned intervenors that the Board would not entertain, in the context of this case, a re-consideration of the Revised Guideline per se. The Board did indicate that it would entertain a challenge to the applicability of the Guideline or any portion of it to Hydro One in this case, provided that challenge was supported by evidence. The Board invited the intervenors challenging the application of the Guideline in this case to file evidence on the point. A few days later, the intervenors informed the Board that they did not wish to file evidence in this case on this issue. [9]

CCC filed a motion on January 12, 2010, which sought a re-publication of the notice of application in this case so as to include as part of the notice, the rate implications associated with the application of the Revised Guideline. Their contention was that the change brought about by the amendment of the Revised Guideline was of such materiality that the original notice failed to adequately inform the public of the implications of the application and therefore had to be replaced by a revised notice which did.

After considering the submissions of all parties, Board denied that motion. A copy of the Board's decision on that motion is appended to this Decision.

[9] Tr. Vol. 8, p. 2&3

The challenge to the application of the Board's Revised Guideline on cost of capital appears in the arguments filed by the ratepayer-oriented intervenors in this case.

CME, in an argument that was adopted by a number of other intervenors, challenged the application of any cost of capital parameter for this applicant. In its view, which as noted was adopted by a number of other intervenors, this applicant, because of its ownership structure ought not to be subject to any return on equity. CME argued that Hydro One, as an entity that is owned and directed by the province itself does not raise capital conventionally, and is not subject to the business risks associated with independent, privately owned and operated entities. In effect, CME contends, the utility is supported through taxation, and to reward it with any return on equity would be a form of double recovery.

For its part, CCC argued that because of the ownership of the utility by the province and its role within the infrastructure of the province, it operates essentially in a risk-free environment, and any return on equity should be no greater than the cost of debt actually experienced in the market.

Other intervenors suggested that, because Hydro One does not raise equity based capital in equity markets, that portion of the Guideline that provides for 50 basis points in “transaction costs” as part of the return on equity should be excluded. The argument is that these are costs that are not experienced by Hydro One and therefore should not form part of its cost of capital.

A further argument was made respecting the application of the short-term debt rate to the working capital allowance portion of rate base. Essentially this argument contends that the assets to which the working capital allowance typically relate ought to be subject to the prevailing short-term interest rate.  This approach is not consistent with the Board's Revised Guideline, or the previous December 20, 2006 Report of the Board. The Board established in the December 20, 2006 Report of the Board that there would be a 4% short term debt capitalization in the deemed capital structure, and this was continued in the Revised Guideline.  Under the Board’s policy to the extent the working capital allowance exceeds 4% of rate base, it will attract the long-term debt cost.

The fact is that none of these arguments seeking to displace all of, or portions of, the Revised Guideline on cost of capital is supported by any evidence whatsoever. Whatever the relative merit of any of these arguments may be, in order to prevail they must be underpinned with persuasive evidence, which has been subjected to the usual testing processes. This is a basic tenet of law; in order to succeed an argument must be founded on evidence properly before the decision maker.

The Revised Guideline is clear on its face: parties wishing to challenge the application of the Guideline in whole or in part to any given utility have an obligation to file evidence supporting their point of view. That burden properly rests with the party seeking to displace the operation of the Guideline. Argument, unsupported by evidence, is not the appropriate vehicle for advancing these positions.

In this proceeding the intervenors seeking to challenge the application of the Guideline explicitly chose not to file evidence on these issues. They also did not reference any aspects of the evidence already on the record.

It should also be noted that an attack on the application of the Revised Guideline in the context of a particular rate proceeding, such as this one, does not involve a re-consideration of the Revised Guideline per se. As has been determined in this case in our ruling of December 15, 2009, the Board will not entertain such a re-consideration of the Guideline. What the Board can consider is whether the Guideline or some portion of it ought not to apply to a given utility in the context of a specific cost of service proceeding. In order to succeed, that challenge must be supported by properly introduced evidence. It is for the challenging party to decide what evidence it believes is appropriate to bring, but it may well go beyond a simple assertion respecting transaction costs or the nature of the assets typically funded through the working capital allowance.

For these reasons, the Board finds that the Revised Guideline will be applied to the applicant. This includes implementation of the updated cost of capital parameters, which were issued on February 24, 2010. It also means that the company's cost of long term debt must be updated to reflect the actual debt costs associated with the actual debt instruments used by the company in 2009. In its oral evidence, the company had suggested that such an update would not be undertaken. The Board considers that approach to be inconsistent with the Revised Guideline, which expresses the Board's intention to rely on the actual costs for long term debt, when they are known.

The Cost of Capital parameters will be updated for the purpose of establishing 2011 rates. The Board will rely on September, 2010 data for purposes of deriving the ROE and short-term debt rate. The Board will issue a letter containing the necessary values to allow Hydro One to develop a Draft Rate Order, to be effective January 1, 2011.

Hydro One will be required to provide an updated cost of long-term debt, based on actual debt issued. The Board expects this process to be mechanistic in nature; no further evidence will be heard at that point.

# 7. DEFERRAL AND VARIANCE ACCOUNTS

Hydro One is requesting disposition of certain deferral/variance account balances as at December 31, 2009. The principal balances and interest in these accounts are forecast beyond December 31, 2008 audited balances. The accounts for which disposition is requested including the balances, are summarized in the table below:

**Deferral & Variance Account Balances**
**2008 and 2009**[10]

| Account Number | Description | Balance at December 31, 2008 ($ millions) | Balance at December 31, 2009 ($ millions) |
|---|---|---|---|
| 1518/1548 | RCVA | (1.7) | (1.9) |
| 1555 and 1556 | Smart Meter Minimum Functionality Under-recovery Jan. 1 to Dec. 31, 2008 | .9 | .9 |
| 1555 and 1556 | Smart Meter Exceeding Minimum Functionality Under-Recovery between Jan. 1 to Dec. 31, 2008 | 1.1 | 1.1 |
| 1580 | RSVA Wholesale Market Services | (11.4) | (18.7) |
| 1584 | RSVA Tx Network & Tx Network Aggregation | (14.0) | (7.2) |
| 1586 | RSVA Tx Connection & Tx Connection Aggregation | (2.9) | .8 |
| | | | |
| 1588 Sub-account Global Adjustment | RSVA Provincial Benefit | 5.5 | 19.6 |
| | | | |
| 1550 | RSVA Low Voltage | 1.9 | 2.6 |
| 1590 | Regulatory Asset Recovery Phase 1 | (18.7) | (23.0) |
| | | | |
| | **Total Requested for Disposition** | **(39.3)** | **(25.8)** |

Hydro One is proposing to refund the total regulatory asset balance of $(25.8) million, or $(12.9) million per year, starting January 1, 2010 over a two year period, with the assumption that new distribution rates would be effective on January 1, 2010.

Submissions on the clearance of existing accounts focused on whether audited or unaudited account balances should be used, whether the disposition period should be 1 or 2 years, whether the variance in the distribution system losses should be specifically

[10] Exhibit F1/Tab1/Sch1 and Exhibit H/Tab1/Sch110

reflected in account 1588, and whether a separate rate rider should be established for non-RPP customers when disposing of the 1588 Global Adjustment account.

## 7.1 AUDITED VS UNAUDITED BALANCES

Board staff pointed out that it was not common practice in the electricity sector to dispose of forecast principal balances for deferral and variance accounts but also acknowledged that the Board had disposed of forecast balances in the past. Intervenors had varying views on this issue. VECC and Energy Probe agreed only audited balances with forecast interest should be considered for disposal. CCC and CME submitted that the Hydro One proposal was appropriate as long as the balances are ultimately trued up when the audit process is complete.

In reply argument, Hydro One noted that the 2009 audited results will be available when the final rate order is implemented.

### BOARD FINDINGS

While acknowledging that past Board decisions have at times varied on the disposition of audited or non-audited balances for deferral and variance accounts, in this case, the Board will order that only audited amounts will be cleared. Hydro One has indicated that audited values will be available for 2009 in time for the issuance of the rate order for this proceeding. Board approves the clearance of 2009 audited balances and directs Hydro One to prepare the draft rate order for Board's approval on that basis.

## 7.2 ONE OR TWO YEAR DISPOSITION

Board staff advocated disposition of the accounts over one year rather than the proposed two year period, to mitigate the rate impacts of the application. CCC and CME agreed with this approach. Energy Probe advocated that the amount for recovery should be equally split between 2010 and 2011, which would mean a higher rebate in 2010 if the rates were implemented later in the year. AMPCO advocated for disposition from May 1, 2010 to December 31, 2011.

In reply argument, Hydro One submitted that a principled approach should be followed that is consistent with past practice, and that disposition over the two test years has an overall rate smoothing effect for both test years. If disposed of in only the first year, the 2010 rate impact would be lower but 2011 would be higher.

**BOARD FINDINGS**

As new distribution rates will not be in place until May, the Board orders the balances to be recovered over the time period remaining from implementation to December 31, 2011. If the entire balance were returned in 2010, the rate increase for 2011 would in effect be even higher. The Board finds that the proposed approach of disposing the balances over both test years is preferred.

## 7.3 ACCOUNT 1588 DISTRIBUTION SYSTEM LOSSES

Board staff submitted that Hydro One is excluding the variance relating to distribution system losses from account 1588 RSVA – Power and submitted that there is a difference between the cost of actual line losses and what is collected in rates. Board staff took the position that Hydro One should reflect this difference in account 1588. Board staff submitted that this is a calculated number that does not require special meters and noted that other LDCs are able to calculate line loss variances in account 1588. Board staff also submitted that Hydro One does identify the kWh line losses and reports the same to the Board under Reporting and Record Keeping Requirements (RRR) 2.1.5. An analysis of RRR 2.1.5 filings from 2005 to 2008 was presented by Board staff at the oral hearing. This chart showed that on average, Hydro One’s losses from 2005 to 2008 have been approximately 6.8% of the wholesale kWh purchased. The Hydro One witness suggested that distribution system loss, expressed as a percent of retail kWh would be 7.3%[11]. However, this is still a significant difference from Hydro One’s currently approved loss factors.

Board staff also submitted that the difference between the dollar value of the actual losses and the dollar value of losses recovered in billings should be booked in account 1588.

Hydro One responded that given its unique and complex distribution system, it has different loss factors for each rate class while other LDCs have one uniform approved loss factor. So the comparison of actual losses to the approved losses requires an allocation of actual losses to each rate class. Hydro One maintained that the accuracy

[11] Exhibit K10.1 and Tr. Vol. 10, p. 81

of this allocation negates the benefit of any comparison. The only way to provide a meaningful comparison is to track actual losses which would require a significant investment to install meters to record actual sales compared with electricity purchases. Hydro One submitted that the cost of doing so would be greater than the gains that may be achieved. Hydro One also referred to the Board's EB-2005-0378 decision where the Board agreed with Hydro One's submissions on this issue.

## BOARD FINDINGS

It is important that Hydro One calculate and report to the Board the difference between the cost of actual line losses and the amounts recovered from ratepayers. These amounts could have a material impact on ratepayers. The Board understands that Hydro One's calculation of cost and revenue is more involved than any other distributor, and that with the several deemed loss factors in Hydro One's tariff, there is the likelihood of inaccuracies that are different in nature from other distributors. However, this differential is tracked by other distributors and the Board is of the view that Hydro One should attempt to do so as well, or should demonstrate more clearly to the Board why such an approach is impractical.

The Board directs Hydro One to track the dollar value of variances between the Board approved losses recovered in rates, and actual line losses, commencing January 1, 2010. The Board expects that the information related to wholesale purchases, as well as line losses recovered in rates, are currently available to Hydro One through its wholesale meters, and its billing systems. The Board further expects that Hydro One can obtain the dollar value of recoveries of losses in rates from its billing system; and can convert the kWh information of actual line losses (which are measured and reported to the Board under RRR 2.1.5) to dollar values, although other approaches, such as the allocation method identified by Hydro One, may be appropriate. Hydro One is directed to bring this analysis to its next cost of service proceeding so that this issue may be further examined.

## 7.4 SEPARATE RATE RIDER FOR NON-RPP CUSTOMERS FOR RECOVERY OF 1588 SUB-ACCOUNT GLOBAL ADJUSTMENT

With regard to the amounts in the Global Adjustment account, Board staff submitted that Hydro One should establish a separate rate rider for disposition of account 1588, sub-account Global Adjustment. The rate rider should apply prospectively to non-RPP customers, and would exclude the MUSH sector and other designated customers that were on RPP. Energy Probe supported Board staff's position. Hydro One did not address this issue in its reply submissions.

### BOARD FINDINGS

Although Hydro One did not respond to the proposal for a separate rate rider, many other distributors are able to determine a separate rate rider and therefore the Board will direct Hydro One to develop a separate rate rider for these non-RPP amounts, for disposition of the Global Adjustment to non-RPP customers only, excluding the MUSH sector and other designated customers that were on RPP.

With regard to the disposition of Deferral and Variance account balances, for accounting purposes, the respective balance in each of the accounts shall be transferred to Account 1595 Disposition and Recovery of Regulatory Balances Control Account, as soon as possible, and certainly no later than June 30, 2010 so that the Reporting and Record Keeping Requirements (RRR) data reported in the second quarter of 2010 reflects these adjustments.

## 7.5 NEW ACCOUNTS REQUESTED

Hydro One is requesting Board approval for five new deferral accounts. These are the Pension Cost Differential Account, OEB Cost Differential Account, Impact of Changes in International Financial Reporting Standards (IFRS), Fixed Charge for Micro-Generators, and Bill Impact Mitigation Account. The specific accounts are described below:

### Pension Cost Differential Account

In this account, Hydro One proposes to track the difference between the actual pension costs booked using the actuarial assessment provided by Mercer, and the estimated pension costs used in this filing. Hydro One would use Account 1508 Other Regulatory Assets; Sub Account Pension Contributions to record pension cost differentials.

Of those intervenors that commented on the Pension Cost Differential Account, VECC and Energy Probe supported approval. SEC and AMPCO argued against the approval of this account. SEC advocated that Hydro One provide more information to the Board after the pension evaluation is complete, detailing potential impacts and how this should be addressed.

In reply, Hydro One reiterated that this account was appropriate and would cover the impact of any changes in pension contributions on Hydro One's OM&A that cannot reasonably be predicted in advance of the completion of the updated valuation.

**BOARD FINDINGS**

The Board finds that the proposal is reasonable and approves the Pension Cost Differential Account. The Board accepts that the impact of the actuarial assessment could be significant and notes that the issues identified by SEC and AMPCO can be addressed at the time of disposition.

**OEB Cost Differential Account**

In this account, Hydro One is seeking to track the difference between approved and actual costs for 2010 and 2011 with respect to the Board's cost assessments, intervenor cost awards and costs associated with Board-initiated studies. Hydro One would use Account 1508 Other Regulatory Assets: Sub Account OEB Costs to record these amounts.

Board staff noted that Hydro One had previously requested this account in EB-2007-0681, but the request was denied and the Board did not allowed a similar request by Toronto Hydro. In the last Hydro One transmission proceeding (EB-2008-0272), a variance account was allowed but exclusively for variances in the Board's costs assessments. Staff submitted that the account should continue to be approved for Board cost assessments only.

VECC, CCC, SEC, CME, AMPCO and Energy Probe all agreed with this submission. CCC submitted that Hydro One should not be afforded what would effectively be a pass-through of intervenor cost awards and cost associated with Board-initiated studies. Hydro One did not address this account in its reply submission.

## BOARD FINDINGS

The Board concurs with Board staff and the intervenors. The extended coverage sought by Hydro One is not available to other distributors, and no compelling reason has been provided for why Hydro One should be treated differently.

The Board approves this account on the basis that it be used for the Board cost assessments only.

### Impact for Changes in IFRS Account

In this account, Hydro One proposes to track the difference between costs in the current revenue requirement and any difference in revenue requirement directly attributable to changes which may arise in IFRS standards between now and the conclusion of the test period. The application has been filed based on IFRS standards as they are reflected in the publications of the relevant accounting authorities. It is possible that IFRS standards may change during the test period, and this proposed account is designed to capture the revenue requirement consequences of any such changes.

Board staff pointed out that the creation of such an account has been specifically considered by the Board and rejected (EB-2008-0408, Report of the Board, Transition to International Financial Reporting Standards, July 28, 2009) and submitted that such an account should not be approved in this case. VECC, CCC, SEC, CME, AMPCO and Energy Probe all submitted that the proposal should be denied.

Energy Probe noted that Hydro One has included IFRS transition administration related costs in approved rates and submitted that the Board should require Hydro One to track any difference between the amount included in rates and the actual transition costs in the variance account set out in Section 8.2 of the EB-2008-0408 Report. Hydro One has not explicitly identified the amount included in revenue requirement in this proceeding.

Hydro One responded that the nature of the requested IFRS account was misunderstood by Board staff and intervenors. Hydro One maintained that the requested account would conform to Board policy and would not include revenue requirement impacts arising from changes in the timing of the recognition of expenses, as specifically excluded from the deferral account in the Board's EB-2009-0408 Report which is effective from January 1, 2011. Hydro One submitted that it requires the account to address changes in IFRS or its interpretations that could not be predicted arising between the date of its application in this proceeding and January 1, 2011.

Hydro One stated that its application for 2011 rates, while based on Canadian Generally Accepted Accounting Principles (GAAP), contemplated eventual adoption of IFRS as it was known at the date of application, including the International Accounting Standards Board (IASB)'s exposure draft on accounting for rate regulated activities. Hydro One stated that adoption of IFRS, in its then expected form, would not have a material impact on its reported cash flows. Hydro One also stated that the impact of IASB approved changes or interpretations between the date of Hydro One's application in this proceeding and the date of adoption on January 1, 2011, should be provided for through the mechanism of the proposed account.

## BOARD FINDINGS

In its EB-2008-0408 Report, the Board stated that it will:

> "…require(s) distributors to specifically identify financial differences and any revenue requirement impacts that result from adoption of modified IFRS requirements in the distributor's first cost of service application after adoption. Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified."[12]

The Report also noted that:

> "There was general agreement among participants that rate mitigation mechanisms currently used by the Board, such as deferral accounts and rate riders, could be used to reduce any impacts resulting from IFRS-related costs that the Board permits to be recovered through rates." [13]

In addition, the Report stated in Appendix 2:

> "Rate impacts (from adopting IFRS policies) should be considered in aggregate to determine the significance of the cumulative effect. Distributors must provide specific

[12] EB-2008-0408, Report of the Board, p. 25
[13] EB-2008-0408, Report of the Board, p. 25

> information regarding the individual cost drivers making up the aggregate impact."[14]

The Board will approve the creation of the IFRS deferral account to capture the aggregate impact on the 2011 revenue requirement resulting from any changes to existing IFRS standards and changes in the interpretation of such standards. The granting of this account is, in part, in recognition of the fact that this application by Hydro One covers a two year period.

The account is to permit Hydro One to record, for future disposition of revenue requirement, impacts due to changes in IFRS that arise before the next Hydro One cost of service proceeding. It is to provide for mitigation, should it be appropriate, when considering the impact of transition to IFRS in aggregate, as contemplated in Section 7.0 of the EB-2008-0408 Report.

Approval of this account does not indicate approval of any particular regulatory accounting practice. When considering disposition of the account at the next cost of service application after adoption of IFRS, the Board will address the extent to which entries can be directly linked to changes to the IFRS standards which were used for purposes of the current application, as well as the usual parameters such as prudence, materiality, alternatives considered and other management actions taken by Hydro One to mitigate any material aggregate impact.

### Fixed Charge for Micro-Generators

This account is intended to record revenue collected from the new fixed meter charge that will be applied to micro-generators. This revenue will be tracked in a variance account to be refunded in the future to customers. Hydro One would be using Account 1508 Other Regulatory Assets: Sub Account Fixed Charge for Micro-Generators to record these amounts.

## BOARD FINDINGS

The Board notes that the Fixed Charge for Micro-Generators Account was supported by all parties. The Board approves the account.

[14] EB-2008-0408, Report of the Board, Appendix 2

## Bill Impact Mitigation Account

This account will record any revenue forgone and any incremental costs associated with implementing any additional mitigation measures that might be required as a result of completing the rate harmonization process. Hydro One intends to use Account 1508 Other Regulatory Assets; Sub Account Bill Impact Mitigation to record these variances.

The Bill Impact Mitigation Account received detailed submissions from two parties: AMPCO and VECC. VECC pointed out that the purpose of this account is to record any revenue foregone or incremental costs required as a result of completing the harmonization process. VECC questioned the need for such an account as Hydro One has stated that it is not proposing to forego revenue as means of mitigating the impact of harmonization. Also, Hydro One had a similar account approved for 2008 rates but has not recorded any costs in the account. Furthermore, now that the harmonization is underway, VECC did not understand what additional costs could be incurred. VECC submitted that, unless Hydro One is being asked to forego revenues as a means of mitigating the impact of harmonization, this request should be denied.

AMPCO submitted that mitigation should be viewed in the context of the need to mitigate overall bill impacts for all customers first and for specific groups only afterwards. If this is done, AMPCO could support a specific bill impact mitigation account as proposed. AMPCO continued that, at the same time, if the total bill impact across all customer groups remains high, AMPCO could not support this approach, as it inevitably generates cross-class subsidies when the account is cleared across all customer groups.

Hydro One did not comment on this account in its reply argument.

## BOARD FINDINGS

The Board finds that it is appropriate for Hydro One to record rate mitigation amounts in a formally constituted Rate Mitigation Account to complete the rate harmonization process, especially as the increase in revenue requirement as a result of updates in this case has increased the potential need for rate mitigation. The Board therefore approves creation of this account.

## Deferral Account for Harmonized Sales Tax ("HST")

The provincial sales tax ("PST") and goods and services tax ("GST") will be harmonized effective July 1, 2010 pursuant to Bill 218 which received Royal Assent on December 15, 2009. Unlike the GST, the PST is currently included as an OM&A expense and is also included in capital expenditures. When GST and PST are harmonized, Hydro One will realize a reduction in OM&A expense and capital expenditure that has not been reflected in the current application.

Hydro One did not include any forecast of the impact of HST but indicated that it would track the PST savings and that the estimated savings would be tracked in deferral account 1592.

## BOARD FINDINGS

The Board finds that Hydro One's proposal is acceptable. This approach is consistent with the approach which has been adopted by the Board for other distributors.

## Green Energy Plan Accounts

Please refer to the Green Energy Plan section of this decision.

# 8. COST ALLOCATION AND RATE DESIGN

The following issues are addressed in this section of the decision:

- Cost Allocation
- Density Criteria and Study
- Revenue to Cost Ratios
- Hopper Foundry
- Unmetered Scattered Load
- Milton LV Assets
- Harmonization and Impact Mitigation

## 8.1 COST ALLOCATION - GENERAL

VECC submitted that the Hydro One cost allocation methodology raises concerns in a number of areas, including:

- direct allocation of certain costs
- allocation of administrative and general expenses
- allocation of revenue from miscellaneous charges
- assumptions underlying the Minimum System customer and demand costs.

It did not suggest that the Board should reject the cost allocation as filed in 2010, but submitted that Hydro One should modify its methodology or address the matter with its next cost of service application.

### BOARD FINDINGS

The Board finds that the cost allocation study is sufficient for 2010 and 2011 rates. No concerns were raised by the parties, and Hydro One's methodology has been reviewed and approved in a number of prior proceedings. VECC has identified several issues which it submits have yet to be addressed by Hydro One. The Board concludes that these matters should be reviewed in the course of Hydro One's work to consider potential improvements to its cost allocation methodology as a normal part of its evolution and directs Hydro One to address these issues in the pre-filed evidence at its next cost of service application.

## 8.2 DENSITY CRITERIA AND STUDY

Hydro One provided a Study on Density Criteria in response to the Board direction in EB-2007-0681 to analyze the relationship between density and cost allocation; to review the customer class demarcation in order to assess if it reflects cost causation; and to develop alternative considerations regarding density weightings. The Board directed Hydro One to:

> "…..provide a more detailed analysis on the relationship between density and cost allocation to the Board. This should consider whether the number of Residential and General Service customer classes in the new class structure is adequate, and whether the customer class demarcations approved in this Decision offer the best reflection of cost causation. The study should include consideration of alternative density weightings, with descriptions and criteria for comparing alternatives. Comparisons with the costs of distributors similar in size and location to Acquired Distributors would also be useful. The Board requires that Hydro One submit this information in its next cost of service application."[15]

The report filed by Hydro One was prepared by John Todd of Elenchus Research Associates. Hydro One acknowledged that the report is not in full compliance with the Board's direction. Hydro One submitted that the report is the first step of a staged approach, and was achieved over a relatively brief period of time. A focus of the report is the methodology (or methodologies) that could be employed in the subsequent stage(s) of the analysis.

SEC filed evidence on density based classes and rates by Dr. C.K. Woo, of Energy and Environmental Economics Inc.

Both experts agreed that where urban/rural distinctions are found, it is more usual to base them on municipal boundaries than on the density characteristics of the distribution system.

[15] EB-2007-0681, Decision with Reasons, December 18, 2008, p. 31

SEC submitted that customers in the service areas acquired by Hydro One have been assigned to pre-existing classes without appropriate cost allocation. Many of these service areas are small clusters of relatively high density that may be less costly to serve than the legacy area with which they have been grouped. SEC made three recommendations:

- Hydro One should be directed to complete a proper study of the relationship between density and cost of service as soon as possible, and should do so on a cooperative basis.
- Until the study is reviewed any further harmonization should be halted.
- The cost of the study should be borne by Hydro One as it was already included in the 2008 cost of service.

AMPCO submitted that SEC's evidence, which suggests that Hydro One should develop a rate structure based on municipal boundaries, is illogical and unpersuasive. However, AMPCO was also of the view that Hydro One had not responded adequately to the Board's direction and should be required to provide a more detailed analysis on the relationship between density and cost allocation.

CME and Board staff argued that the Board should direct Hydro One to comply with the previous direction. Board staff suggested that Hydro One should take responsibility for determining the most appropriate methodology but that analysis of sample data or the engineering study method (or a combination) would be appropriate.

CCC submitted that further study was warranted, but should not be undertaken until completion of the harmonization process. VECC also submitted that Hydro One should be directed to comply with the previous direction. Specifically, VECC stated:

> "Thus, VECC submits that the first step is to establish a methodology that reasonably captures the cost causation implications of density and then test whether there are urban/rural splits other than the one currently used by Hydro One Networks that better reflect the cost differences that arise due to density. Indeed, VECC submits that this is precisely what the Board directed Hydro One Networks to do in its EB-2007-0681 Decision, To this end, VECC also submits that the use of a couple of simple methodologies (including Hydro One Network's current approach based on

> customers per kilometer of feeder) would be a good starting point."[16]

Pending the completion of the analysis, VECC submitted that Hydro One should maintain the existing approach to reflecting density in its cost allocation methodology and not change the treatment of seasonal customers.

Hydro One responded by requesting further guidance from the Board. Hydro One maintained that a full study of the relationship between density and costs would be "extremely costly and is not certain to provide information which is better than the current density definitions used by Hydro One." Hydro One also maintained that it should be permitted to continue with the harmonization and that it should be permitted to change the density weighting factors for its Seasonal customers.

## BOARD FINDINGS

The Board will direct Hydro One to comply with the Board's prior direction regarding this issue. Hydro One has not requested to be released from the prior direction and the rationale for the work still exists. There has been no change, nor any evidence, to suggest that the study is no longer relevant or necessary.

The Board will not specify at this point the precise methodology or approach Hydro One is to use. A variety of approaches were discussed in the testimony of the experts and it is not clear at this point if there is one single best approach. The Board concludes that there is merit in pursuing a variety of approaches, at least to some extent, to assist in determining the preferred approach. The Board expects Hydro One to work cooperatively with the parties but leaves it to Hydro One's discretion to determine how best to conduct the study taking into consideration timing, feasibility and cost. The Board recognizes there are concerns about the costs involved, particularly if there are full cost allocation studies done involving alternative customer classifications and density weighting factors. The Board expects Hydro One to manage the project efficiently and recognizes that it may be appropriate to compare scenarios that are not as completely developed as Hydro One's main cost allocation study.

The Board will not stop the harmonization process. This program was already examined and approved in a prior proceeding, and although the work on density has not

[16] VECC Final Argument, p. 41

been completed there is no evidence to suggest the harmonization is inappropriate. However, the Board finds that Hydro One will not be permitted to change the density weighting factor for Seasonal customers at this time. This represents a further change beyond what has already been approved, which may not be adequately supported. On balance, the Board finds that it is more appropriate to wait for further analysis in this area.

## 8.3 REVENUE TO COST RATIOS

Hydro One proposed downward changes to its rate design to achieve a ratio of 1.15 for the Seasonal customer class, a ratio of 1.20 for the UGSe class, a ratio of 1.00 for Distributed Generation, and a corresponding upward change to 0.89 for the GSd class. It also proposed small upward shifts to Streetlights and Sentinel Lights. Hydro One's existing and proposed revenue to cost ratios are presented in the table below.

**Revenue to Cost Ratios**
**2010 and 2011**

| | | | |
|---|---|---|---|
| **Class** | **Status Quo Ratios** | **Proposed Ratios** | **Target Range** |
| UR | 1.09 | 1.09 | 0.85 – 1.15 |
| R1 | 0.92 | 0.92 | 0.85 – 1.15 |
| R2 | 1.02 | 1.02 | 0.85 – 1.15 |
| Seasonal | 1.16 | 1.15 | |
| UGSe | 1.21 | 1.20 | 0.8 – 1.2 |
| UGSd | 1.25 | 1.25 | 0.8 – 1.8 |
| GSe | 1.07 | 1.07 | 0.8 – 1.2 |
| GSd | 0.88 | 0.89 | 0.8 – 1.8 |
| ST | 1.01 | 1.01 | 0.85 – 1.15 |
| DG | 1.35 | 1.00 | |
| Streetlights | 0.68 | 0.70 | 0.7 – 1.2 |
| Sentinel Lights | 0.67 | 0.70 | 0.7 – 1.2 |

VECC submitted that the increase for the GSd class was inappropriate and that the ratio for Distributed Generation need not be set to 1.00, but should be set to 1.15.

**BOARD FINDINGS**

The Board finds that the proposed adjustments to the revenue to cost ratios are appropriate. Specifically, the Board will accept the increase to the General Service demand ratio to .89 and the reduction in the DG ratio to 1.00. The Board has indicated in various decisions that distributors are not obligated to adjust ratios closer to 1.00 once a class is within the Board's target range but may do so if adequately supported with evidence. The Board finds that Hydro One has adequately supported its proposal in this case.

## 8.4 HOPPER FOUNDRY

Hopper Foundry ("Hopper") has paid for its electricity distribution services on a time-of-use ("TOU") rate structure since 1981 as a customer of Forest PUC. In 1992, the company received a grant under Ontario Hydro's Load Shifting Program to facilitate the shift of production to off-peak hours, including installation of a larger melting furnace. In Hydro One's previous cost-of-service application (EB-2007-0681), the Board ordered Hydro One to continue with the existing TOU rate structure until April 30, 2010. The Board noted that the two-year extension would enable Hopper Foundry to explore its options and to take steps in preparation for paying an ordinary approved distribution rate.

The Board heard evidence and arguments on three options for Hopper Foundry:

- Hopper Foundry suggested that it could remain on the status quo TOU rate structure,
- In the normal course, Hopper Foundry would be assigned to the General Service Demand-billed class ("GSd") in Forest.
- Hydro One suggested that the qualification for the Sub Transmission (ST) class could be extended to include Hopper Foundry and 13 other customers.

Board staff supported the second alternative, but recommended that the rate should be designed to limit the bill impact and suggested that a fourth alternative would be to design a succession of rates to enable a smooth transition from the status quo toward rates approved for the demand-billed General Class. Board staff also submitted that, as part of this approach, Hydro One should be directed to provide a more detailed analysis of its rate classes and costs, to determine whether an additional rate class might be developed that would be consistent with cost allocation principles and yet more favourable to Hopper and similar customers. Hopper and CME supported this recommendation.

Hopper argued that it should be permitted to stay on its TOU rate. In its view, "this would recognize Hopper's historic legacy position of having worked with Hydro One and its predecessor, Ontario Hydro, since 1981 to use the majority of our power off-peak." The resulting shortfall for Hydro One would be $60,000. In the alternative, Hopper submitted that it would be fair for it to be classified in the ST class, but ideally it should continue to benefit from time of use rate by being billed for demand based on on-peak energy demand.

The difference between the current rate and the GSd rate in terms of total bill impact was estimated at approximately 153%, but Mr. Roger testified that a more up-to-date calculation would yield an estimated impact of 190%. Hopper suggested that it would likely go out of business if it were required to pay GSd rates. As for the ST class alternative, Hopper would have a higher bill, with an impact of approximately 22%, but as a group the other customers that meet the same voltage and size criteria would have lower bills. The result would be an overall shortfall to Hydro One of approximately $1 million. AMPCO submitted that Hopper should be included in the ST class.

CME submitted that it would be inappropriate to place Hopper Foundry in the GSd class because Hydro One is not in a position to meet the peak demand 24 hours a day and Hopper itself would be liable for the costs of any corrective action. CME further argued that Hopper's willingness to operate off-peak is conservation behaviour that should be promoted. SEC and CME supported continuing with the special rate structure on a grandfathered basis.

## BOARD FINDINGS

The Board finds that assigning Hopper to the GSd rate would result in pronounced rate shock and would not adequately recognize the historical context of the situation. The Board concludes that of the options discussed during the proceeding, grandfathering Hopper's current TOU rate would recognize the unique characteristics of Hopper and its rate history with minimal adverse impacts on other ratepayers. The Board will direct Hydro One to grandfather the TOU rate structure for Hopper and will permit Hydro One to recover the revenue shortfall from ratepayers. If there is a material change in the circumstances related to this issue, then it should be brought to the Board at that time.

## 8.5 UNMETERED SCATTERED LOAD (USL)

Hydro One considers USL to be a sub-class of its General Service energy-billed (“GSe”) class, and charges each USL connection at the monthly service charge of an ordinary load customer in that class less a credit that reflects the meter cost savings. This rate structure was approved most recently by the Board in the EB-2007-0681 decision.

Rogers Cable noted that the USL customers constitute a very small proportion of the class and as a result their cost characteristics are swamped by the costs of serving the other customers. Rogers Cable submitted that the load and cost characteristics of USL customers are unlike the typical metered customer in the class. It maintained that the Board’s approval of the current rate structure was granted with the note that the Board had insufficient information in the record of that case to evaluate an alternative rate structure. Rogers Cable noted that Hydro One did not produce information on what the revenue to cost ratio would be for the USL customers in response to an interrogatory in EB-2007-0681 and that the same situation has occurred in the current proceeding.

Rogers Cable noted that the monthly service charge for each unmetered connection is 28 times higher than the corresponding charge per connection for Streetlighting. Rogers Cable noted that Hydro One agreed that it could produce revenue to cost ratio for the USL customers as part of its next cost of service application and requested that the Board direct Hydro One to do so.

Hydro One responded that requiring it to provide evidence on the revenue to cost ratio of USL customers would in effect require it to create a separate class for USL.

## BOARD FINDINGS

The Board directs Hydro One to prepare evidence on the revenue to cost ratio for USL customers for its next cost of service application. There is evidence to suggest that such an investigation is warranted, in particular the magnitude of the difference in charges between USL and Streetlighting customers, and Hydro One has offered no reason why such work would be inappropriate. Hydro One has indicated that performing the analysis would have the effect of creating a separate class for USL. This may well be warranted; the Board would note that many distributors have a separate rate class for USL customers.

## 8.6 MILTON LV ASSETS

The Board indicated in its previous decision (EB-2007-0681) that Hydro One should sell to Milton Hydro certain LV assets that are used to serve Milton Hydro, thereby eliminating the issue of whether Milton Hydro is being charged a fair rate. Further, the Board stated that if the sale did not occur before May 2010, then Hydro One should bring forward evidence that could be used to construct a specific rate for Milton Hydro's circumstances.

Hydro One submitted that a rate could be designed for customers whose circumstances are similar to Milton Hydro's by using line-length as the charge determinant rather than billing demand. However, Hydro One also submitted evidence that it has made a proposal to Milton Hydro for the sale of LV facilities, but as of October 19, 2009 was still waiting for a response. There was no further evidence provided and there were no submissions on this issue.

### BOARD FINDINGS

The Board's direction remains outstanding. Hydro One has not developed a specific rate for Milton Hydro's circumstances; nor has a sale been completed. Hydro One made a sale proposal to Milton in October, but is evidently still waiting for a response. The Board directs that if a sale is not completed in advance of the next cost of service proceeding Hydro One will come forward at that proceeding with a proposed resolution of this issue.

## 8.7 HARMONIZATION AND IMPACT MITIGATION

Hydro One proposed to continue the mitigation plan approved in the previous cost-of-service application (EB-2007-0681). The guideline used by Hydro One is to limit the impact of changes in delivery cost to 10%, calculated as a percentage of the total bill of an average customer in any given class.

Board staff noted that the rate design for 2008 included mitigation for small customers that would have a bill impact greater than 15% and further noted that Hydro One had requested continuation of the deferral account associated with this mitigation.

The increase in the revenue requirement is larger than had been assumed earlier, which leaves less room under the 10% constraint for the increases that would achieve harmonization. As a result, the expected end point of the harmonization process has become 2012 for some Acquired Distributors, rather than 2011 as in the earlier rate design.

CCC supported Hydro One's proposal to continue to move from the existing approved rates to 2010 rates following the harmonization plan.

VECC also supported the continued harmonization plan, but expressed concern that the rate mitigation plan does not take adequate account of other changes to customers' total bills. VECC submitted that the Board cannot determine whether total bill impacts are reasonable without further information about the other components of the bill, but maintained that there was sufficient information available to conclude that the impact for the majority of customers will be greater than 10%. VECC concluded that without this information the Board cannot determine whether the bill mitigation plan is appropriate or that the bill impacts are reasonable.

## BOARD FINDINGS

The Board approves the continuation of the harmonization and associated mitigation plan previously approved, including the mitigation process for small customers faced with bill impacts of 15% or more. The Board recognizes that the period for implementation will likely be extended by one year for some Acquired Distributors. The Board finds that this is acceptable under the circumstances because it is consistent with the underlying principles of the harmonization process. The Board will not adjust the rate impact mitigation plan to take account of bill impacts arising from other non-distribution factors. While these are important aspects of customers' total bills, the Board finds that it would be inappropriate to defer the collection of Hydro One's revenue requirement, or institute other means of distribution rate mitigation, to address these other cost pressures at this time. The Board will continue to examine options for rate impact mitigation and affordability.

## 8.8 OTHER MATTERS

The Board notes Hydro One's proposal to derive Retail Transmission Service rates using the Uniform Transmission Rates approved for January 1, 2010. The Board accepts this approach.

The Board also notes that it has recently approved a microFIT rate. Hydro One is directed to incorporate this rate into its Draft Rate Order.

Hydro One also requested a number of changes to Specific Service Charges as shown in Exhibit G2/Tab4/Schedule1, page 19. The Board approves these charges as shown in this exhibit.

# 9. COMMUNICATION OF DECISION

On January 14, 2010, the Board issued its decision on the motion filed by the CCC seeking an order from the Board requiring Hydro One to publish an amended Notice of Application. In making its decision the Board also added:

> "Although the motion is denied, the discussion which has taken place in the course of intervenor submissions has heightened the Board's awareness of the importance of clear communication of its final decision in this rates proceeding. The Board will seek to ensure that ratepayers understand the elements that drive rate changes resulting from this case and will also seek to ensure that, as much as possible, these changes are put into context for ratepayers.
>
> So in that regard, the Board asks that parties include in their final arguments any proposals they may have that would assist the Board in designing appropriate, transparent communication of the final decision of this proceeding."[17]

Although the Board's direction requested submissions on the communication of the final decision in this proceeding, parties also made submissions on possible changes to notices in proceedings.

The Board received submissions from CCC, CME and SEC.

## 9.1 NOTICE

CCC, CME and SEC each made substantial comment on possible improvements to the notice of application.

CCC submitted that this case has highlighted need to alter the way in which notice is provided to ratepayers of proposed rate changes. CCC recognized that communicating relevant and useful information to ratepayers is difficult for a complex application. However, in CCC's view, ratepayers deserve to be given notice of pending changes not only with respect to distribution rates, but also with respect to all elements of their bills.

CME submitted that the Board should adopt an integrated total price and bill impact approach when providing the public with advance notice of the relief being requested by

[17] Tr. Vol. 11, p. 11

an applicant. CME recommended modifications to the Filing Requirements in its 2006 Rate Handbook and the Draft Filing Requirements pertaining to Green Energy Plans to require utilities to provide the integrated multi-year price and bill impact information.

SEC submitted that there is a need for more transparency in communications from the Board and the utilities to the public and for the Board to have information on the real total bill impacts when it is making decisions. SEC suggested that utilities should be required to present a total price and bill impact analysis of their spending plans over a five year planning horizon and include an estimate, on a rolling five year basis, of all elements of the total price and bill received by electricity consumers. SEC urged the Board to develop a method that delivers the "transparent mechanism" sought by CME, test it internally to see how it can work, and subject it to a consultation process to get input from stakeholders from all points of view.

Hydro One responded that many of the factors that affect the customer bills are external to Hydro One, outside of its control and beyond its ability to forecast. Hydro One submitted that the proposal made by intervenors will result in a fundamental change to the methodology of assessing rate impacts and would require the Board to provide forecasts to the utilities on many portions of the customer's bill.

**BOARD FINDINGS**

The issue of notice was already determined in this proceeding in the Board's decision on CCC's motion. The Board will not make a further finding on notice other than to observe that the Board continually seeks to improve the transparency and clarity of its communications. The parties have articulated some interesting ideas for improvement in notices, some which may be achievable and some not. The Board will consider these submissions going forward.

## 9.2 COMMUNICATION OF DECISION AND RATE ORDER

CCC submitted that Hydro One should provide more information to its customers about the final approved rates than it has in the past. CCC noted that past practice has consisted largely of Hydro One informing its customers that the Board has approved a rate increase and submitted that at a minimum Hydro One should be directed to provide the following in its notice to customers:

1. Hydro One applied to the Ontario Energy Board for a rate increase for 2010 and 2011;

2. The rate increases are due, in part, to cost increases related to the implementation of the *Green Energy and Green Economy Act, 2009*, the installation of smart meters, and a higher common equity return;

3. The average distribution rate impacts and bill impacts are X, but the actual impact for customers will depend upon usage;

4. Other components of the bill are also rising, so ultimately, assuming usage levels stay the same, the bill will increase further due to those impacts;

5. Those impacts include the cost of the electricity itself, which is paid through the Provincial Benefit Charge or the Regulated Pricing Plan charge on the bill, the introduction of the Harmonized Sales Tax, the introduction of the Government's Special Purpose Fund Charge (when approved);

6. Hydro One will be introducing time-of use rates in 2010, which will impact the bill. It may be higher or lower depending upon the ability to use electricity at off-peak times.

CME submitted that the Board should adopt an integrated total price and bill impact approach when notifying the public of the results of its decisions.

CME urged the Board to report the results of its decision in this case and its likely impact on total bills in a manner that does not assume that all other elements of the bill, other than Hydro One's distribution charges, will remain constant, and recommended that the communications include an estimate of the total bill impact including impacts beyond those related to the application.

CME suggested that it should be assumed that increases in the other components of the bill will be in the same order of magnitude as the combined percentage increase in the bill that flows from the distribution revenue requirement the Board approves for Hydro One in this case, and from the portion of the Transmission revenue requirement for 2010 that will be paid by Hydro One distribution customers.

Hydro One responded that the communication of the final decision could contain a clear statement that the Board's decision is only in relation to Hydro One's current distribution rate application for rates in 2010 and 2011 and that the total overall bill of Hydro One's customers will be influenced, higher or lower, by factors that are external to the present distribution rate application. Hydro One also submitted that the Board may wish to provide information about the *Green Energy and Green Economy Act, 2009* and any approval of Hydro One's Green Energy Plan.

## BOARD FINDINGS

The Board found the submissions of parties helpful and believes that the communication of this decision in Hydro One's customer rate notices, particularly regarding the factors driving rate changes and the context of the rate changes, must be carefully crafted. It is the responsibility of the Board and the applicant to ensure that ratepayers receive clear, transparent information.

All parties who made submissions commented that the communication must clearly inform ratepayers that the rate increase resulting from this decision is only one component of a many-faceted customer bill and that other components will also change during the rate period. The Board concurs. The Board agrees with the statement of SEC that "A bill analysis of 30% of the total bill, while holding other elements constant, is not a "total" bill analysis. It is a "partial bill" analysis". Hydro One's customer rate notices must be clear on this point. However, the Board does not agree with CME that the applicant or the Board should attempt to quantify the bill changes that are likely to occur as a result of these other components; to do so would be speculative and could confuse things further.

The Board approves the customer rate notices of gas distributors and finds that it is also appropriate to require the same kind of approval in the case of Hydro One. Hydro One shall submit draft customer rate notices to the Board for approval before the notices are sent to customers. The Board found the submissions of CCC most helpful. The Board directs Hydro One to include the items below in its customer rate notices:

- That Hydro One applied to the Ontario Energy Board for a rate increase for 2010 and 2011;
- That those rate impacts are due, in part, to cost increases related to higher costs for compensation, various work programs, capital costs for physical infrastructure and systems, implementation of the GEA, and a higher cost of capital;

- That the average distribution rate impacts and bill impacts are X, but the actual impact for customers will depend upon usage; bill impacts should be shown as an average % of the distribution component of the bill and an average actual dollar amount for residential customers and GS<50 customers;
- That other components of the bill may also rise, so ultimately, assuming a customer's usage levels stay the same, the bill may increase further due to those impacts;
- That those impacts include the cost of the electricity itself, the introduction of the Harmonized Sales Tax, the introduction of the Government's Special Purpose Fund Charge (when approved);
- That Hydro One will be introducing time-of use rates in 2010, which will impact a customer's bill. It may be higher or lower depending upon the customer's ability to use electricity at off-peak times.

These points are in addition to any other information that Hydro One commonly includes in its billing notices, such as contact information, etc.

## 10. IMPLEMENTATION DATE

Hydro One originally requested a change to its rate implementation date to January 1, 2010 from the customary May 1 date. Hydro One's rationale was that the earlier rate implementation date would facilitate the incorporation of the new Hydro One Sub-Transmission (ST) rates by other LDCs into their own rates that would usually take effect on May 1. The new implementation date would also align Hydro One's financial year with its rate year. Evidence filed before the Cost of Capital update indicated that this change would increase Hydro One's revenue by $44 million in 2010.

Hydro One has subsequently indicated that it would not pursue the January 1, 2010 date but would accept an implementation date as soon as possible in 2010 upon the completion of the proceeding. It was still requesting that 2011 rates be implemented on January 1, 2011. Hydro One did not apply to the Board for interim rates as of January 1, 2010.

A number of intervenors argued that the Hydro One's proposal was premature, especially in light of the Board's consultation on the issue.

### BOARD FINDINGS

The Board finds that Hydro One's proposal to change the effective date for its 2011 rates from May 1, to January 1 is reasonable, and approves it.

The Board notes that one of the reasons cited by Hydro One for the implementation of the effective date change, which was to allow other Local Distribution Companies to incorporate Hydro One's approved rates as input to their rates, may in the future, not be as compelling, given that a number of other distributors may desire for a January 1st rate implementation date going forward. A Board policy consultation to address the issue of aligning rate years with fiscal years for electricity distributors has been initiated (EB-2010-0423).

The Board considers that Hydro One, as the largest transmitter and distributor in the Province may well realize efficiencies in aligning its rate year with its fiscal year.

## 11. RATE IMPLEMENTATION

The Board has made findings in this decision which change the 2010 and 2011 revenue requirement and therefore change the distribution rates from those proposed by Hydro One. In filing its draft Rate Order, it is the Board's expectation that Hydro One file detailed supporting material, including all relevant calculations showing the impact of this decision on the Hydro One 2010 and 2011 revenue requirement, the allocation of the approved revenue requirement to the classes and the determination of the final rates for 2010. (Final rates for 2011 will be determined when the cost of capital parameters for 2011 are published by the Board later in 2010.) Supporting documentation shall include, but not be limited to, filing a completed version of the Revenue Requirement Work Form excel spreadsheet (or a similar document), which can be found on the Board's website. Hydro One should also show detailed calculations of the revised retail transmission service rates and variance account rate riders reflecting this decision.

Hydro One applied for rates effective January 1, 2010. The Board approves a May 1 effective date and notes that there is sufficient time to implement the rates on May 1, 2010 as well. In the same manner, the recovery of external funding from all provincial ratepayers for Green Energy Plan initiatives shall also be effective May 1, 2010. Further, the Board has made numerous findings throughout this Decision which would change the as-filed revenue requirement claimed by Hydro One and would also necessitate certain rate riders and rate adders. These are to be properly reflected in a Draft Rate Order incorporating an effective and implementation date of May 1, 2010 for the new rates.

In addition, this decision also approves the recovery of external funding from all provincial ratepayers for Green Energy Plan initiatives. Accordingly, Hydro One should also propose annual external funding amounts for 2010 and 2011 based on the specifics in this decision. These funding quantities should include separate amounts related to the Express Feeder expenditures and the remaining Renewable Generation expenditures. Hydro One should include calculations detailing exactly how these amounts were determined.

The Board orders that Hydro One will implement rate riders on its Service Charges and Distribution Volumetric Rates from the implementation date to December 31, 2011.

If any specific matter has not been dealt with for purposes of drafting the Rate Order to implement the new rates or dispose of the deferral/variance accounts, the Company shall clearly identify these in its filing.

A Rate Order will be issued after the steps set out below are completed.

1. The company shall file with the Board, and shall also forward to intervenors, a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, by April 16, 2010.
2. Intervenors may file with the Board and forward to the company responses to the company's Draft Rate Order by April 23, 2010.
3. The company shall file with the Board and forward to intervenors responses to any comments on its Draft Rate Order and a revised Draft Rate Order by April 27, 2010.

A cost awards decision will be issued after the steps set out below are completed:

1. Intervenors eligible for cost awards shall file with the Board and forward to the company their respective cost claims no later than April 30, 2010.

2. The company may file with the Board and forward to intervenors eligible for cost awards any objections to the claimed costs by May 7, 2010.

3. Intervenors, whose cost claims have been objected to, may file with the Board and forward to the company any responses to any objections for cost claims by May 14, 2010.

The company shall pay the Board's costs of and incidental to, this proceeding upon receipt of the Board's invoice.

**DATED** at Toronto, April 9, 2010

**ONTARIO ENERGY BOARD**

*Original Signed By*

______________________________

**Pamela Nowina**
Presiding Member

*Original Signed By*

**Cynthia Chaplin**
Vice- Chair

*Original Signed By*

**Paul Sommerville**
Member

**C of H 2. Exhibit 7, Tab 1, Schedule 1, p. 3**

**Background:**

**In its prefiled evidence, Horizon states that "…there is concern that, absent the proposed rate class, some of these customers may choose to make related investments to directly connect to Hydro One, leaving Horizon Utilities with stranded assets, and significantly less volume throughput."**

**(a) Please provide copies of records of all discussions and meetings, including email and written correspondence, between the members of the LU(2) customer class and Horizon with respect to their rates.**

**(b) Please provide copies of all presentations made by Horizon to its senior management and/or its board of directors with respect to the proposed rates for the LU(2) customer class.**

**(c) Have any of the members of the proposed LU(2) customer class threatened to leave Horizon's system to directly connect to Hydro One? If so, please indicate when the threat was made, by whom it was made, and the circumstances in which it was made.**

**(d) To Horizon's knowledge, has Hydro One indicated whether it would permit the direct connection to its system by the members of the proposed LU(2) customer class?**

**Response:**

a) Horizon Utilities is not at liberty to share records of confidential discussions that it has had with its customers. Such discussions are customer-specific and contain information of a competitive and commercially sensitive nature that cannot be disclosed. Under the terms of its Electricity Distributor Licence, Horizon Utilities shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator. Additionally, Horizon Utilities shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed for certain purposes as set out in its Licence. Horizon Utilities is also bound by the provisions of the *Affiliate Relationships Code for Electricity Distributors and Transmitters*, which prohibits the disclosure of confidential information to affiliates without the consent of the consumer. Horizon Utilities does not have the proposed LU (2) customers' consent to the release of the requested information.

b) Horizon Utilities has included the following presentations that it has made to its senior management and Board of Directors regarding the introduction of the LU (2) Class:

- C of H 2_Attch 1_CARD Presentation Aug 6 2013
- C of H 2_Attch 2_CARD Horizon Presentation Updated (2013_05_01)
- C of H 2_Attch 3_Bill Impacts Presentation- 11'26'2013
- C of H 2_Attch 4_Bill Impacts Table- 11'26'2013
- C of H 2_Attch 5_Bill Impacts - EMT Review 11'06'2013
- C of H 2_Attch 6_Bill Impacts - EMT Review Target Area Comparison

Please note that Slide 3 of Attachment 1 and Slide 6 of Attachment 2 have been altered for the purpose of responding to this question. Those slides contain graphs setting out Large Use customer demand, and each line represents a Large Use customer. In their original versions, the customer names were shown on the graphs. Horizon Utilities is not prepared to disclose its Large Use customers' names or specify the individual customers to which the load information relates (this is commercially sensitive customer information) and, accordingly, the names have been replaced with letters. The presentations are otherwise unchanged.

c) Please see Horizon Utilities' response to part (a) above. Communications between individual customers and Horizon Utilities are confidential and cannot be disclosed.

d) Horizon Utilities has no knowledge of discussions between proposed LU (2) customers and Hydro One.

# C of H 2_Attch 1_CARD Presentation Aug 6 2013

This page intentionally left blank

# Recommendation on Cost Allocation

August 2013

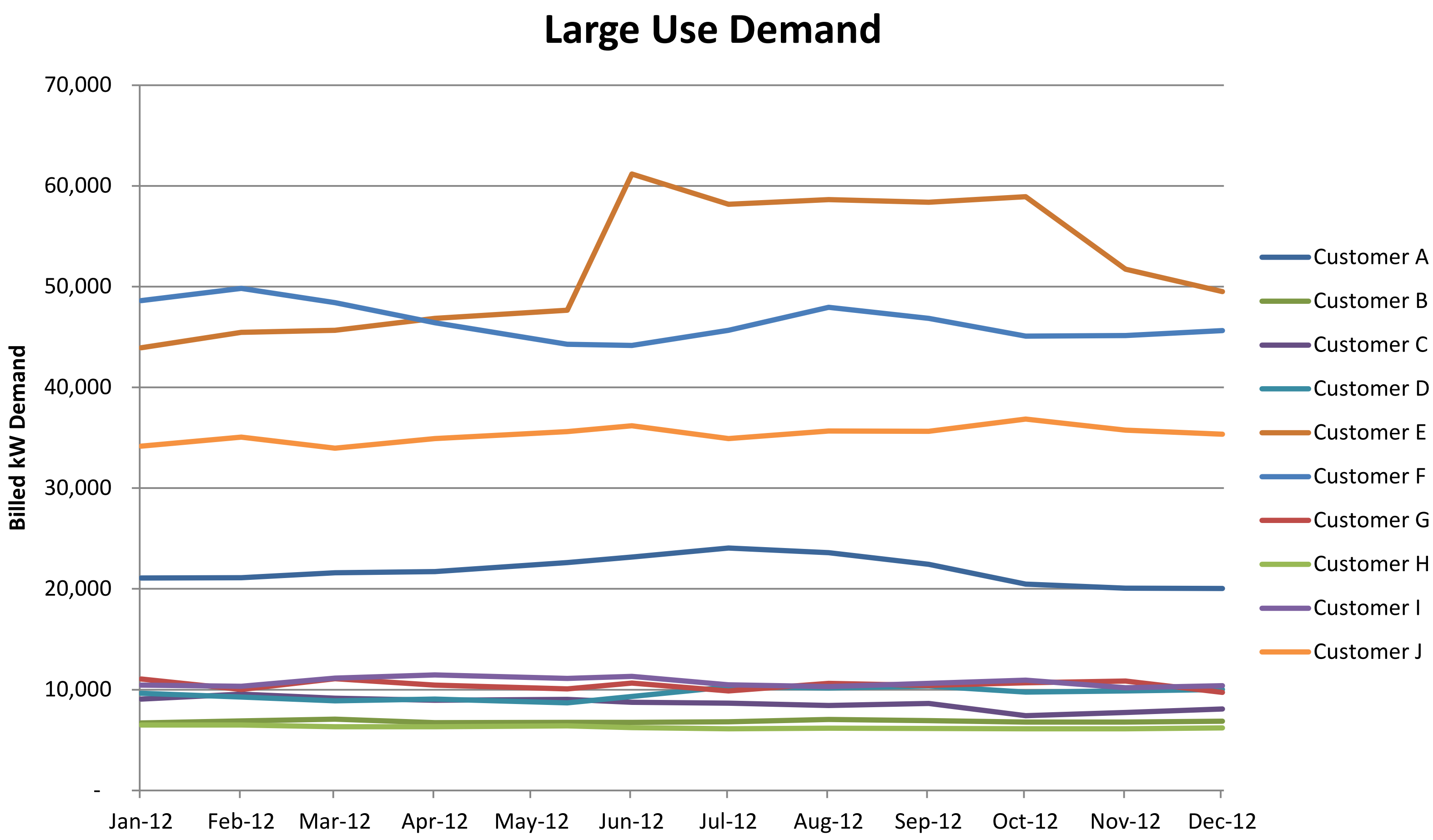
## Summary of Recommendations Approved

- Approval in principle with the split of the Large Use class as of May 1, 2013 EMT meeting into:
  - Large User GS>5 MW – 15 MW
  - Super User GS>15 MW – with Dedicated Assets

- Direct Assignment of Costs of dedicated assets at Net Book Value for Super User class

- Retain the existing definition of GS > 50 kW:
  - One class 50 kW – 4999 kW

# Super User and Large User Demand



# Objectives revisited

- Review cost allocation process to address comments of OEB in the 2011 Cost of Service Application Decision
- Respond to customer requests to review Cost Allocation
- Consider strategic issues within Horizon Utilities’ service area
- Smooth rate transitions at the class boundaries
- Mitigate the shareholder’s risk

# Development of the Baseline

2011 OEB Approved Model

→ Updated by Loading into the 2013 OEB Model

→ Updated to 2015 Forecast and 2013 Rates

→ Updated Primary/ Secondary Asset Split

→ 2015 Baseline

# Baseline: Revenue Requirement and Revenue to Cost Ratios

| Customer Classes | Approved 2011 CoS All numbers in 000's | | 2013 OEB Model (2011 data) | | 2015 Forecast with 2013 OEB model | | 2015 Forecast with 2013 OEB model and update to P/S assets | | OEB Target Range |
|---|---|---|---|---|---|---|---|---|---|
| Residential | $58,034 | 108% | $58,166 | 108% | $66,358 | 108% | $67,541 | 107% | 85-115% |
| GS < 50 | $11,949 | 103% | $12,547 | 97% | $14,456 | 97% | $14,513 | 97% | 80-120% |
| GS > 50 | $20,102 | 84% | $20,861 | 81% | $24,109 | 86% | $23,776 | 87% | 80-120% |
| Large Use | $8,067 | 85% | $6,843 | 101% | $7,786 | 88% | $6,973 | 98% | 85-115% |
| Street Light | $2,964 | 75% | $2,718 | 83% | $2,959 | 84% | $2,971 | 84% | 70-120% |
| Sentinel | $57 | 80% | $52 | 88% | $57 | 89% | $57 | 89% | 80-120% |
| USL | $534 | 108% | $505 | 111% | $570 | 108% | $575 | 107% | 80-120% |
| Standby | $640 | 80% | $654 | 80% | $1,030 | 56% | $920 | 62% | 80-120% |
| Total Rev. | $102,347 | | $102,347 | | $117,326 | | $117,326 | | |

# Baseline: Rate and Bill Impacts

| | Fixed Charge | | Variable Charge | | Distribution Rate Impact | | Total Monthly Bill Impact | |
|---|---|---|---|---|---|---|---|---|
| | 2014 | 2015 Baseline | 2014 | 2015 Baseline | $ change | % change | $ change | % change |
| Residential | $14.83 | $15.76 | $0.0147 | $0.0156 | $1.65 | 6.2% | $1.68 | 1.6% |
| GS < 50 | $33.02 | $35.18 | $0.0087 | $0.0093 | $3.36 | 6.7% | $3.42 | 1.3% |
| GS > 50 | $301.07 | $320.77 | $2.1100 | $2.2481 | $42.88 | 6.5% | $48.45 | 0.6% |
| Large Use | $23,245 | $24,766 | $1.3963 | $1.4877 | $2,036 | 6.5% | $2,300 | 0.5% |
| Street Light | $2.37 | $2.53 | $6.3414 | $6.7564 | $0.24 | 6.7% | $0.27 | 2.3% |
| Sentinel | $4.54 | $4.84 | $12.4807 | $13.2974 | $0.46 | 6.6% | $0.52 | 3.4% |
| USL | $9.35 | $9.88 | $0.0146 | $0.0154 | $0.65 | 5.6% | $0.73 | 2.6% |
| Standby | - | - | $2.5221 | $3.5334 | $3,354 | 40.1% | $3,790 | 3.9% |

# Direct Assignment at Book Value - Revenue Requirement and Revenue to Cost Ratios

<table>
<tr><th></th><th colspan="2">2015 Baseline</th><th>RR Share</th><th colspan="2">Direct Assignment at Book Value</th><th>RR Share</th><th>Target Range</th></tr>
<tr><td>Residential</td><td>$67,541</td><td>106%</td><td>57.6%</td><td>$69,010</td><td>104%</td><td>58.8%</td><td>85-115%</td></tr>
<tr><td>GS < 50</td><td>$14,513</td><td>97%</td><td>12.4%</td><td>$15,137</td><td>93%</td><td>12.9%</td><td>80-120%</td></tr>
<tr><td>GS > 50</td><td>$23,776</td><td>87%</td><td>20.3%</td><td>$25,847</td><td>80%</td><td>22.0%</td><td>80-120%</td></tr>
<tr><td>Large Use</td><td rowspan="2">$6,973</td><td rowspan="2">98%</td><td rowspan="2">5.9%</td><td>$2,428</td><td>138%</td><td>2.1%</td><td>85-115%</td></tr>
<tr><td>Super Use</td><td>$260</td><td>1399%</td><td>0.2%</td><td>85-115%</td></tr>
<tr><td>Street Light</td><td>$2,971</td><td>84%</td><td>2.5%</td><td>$2,971</td><td>84%</td><td>2.5%</td><td>70-120%</td></tr>
<tr><td>Sentinel</td><td>$57</td><td>89%</td><td>0.0%</td><td>$57</td><td>89%</td><td>0.0%</td><td>80-120%</td></tr>
<tr><td>USL</td><td>$575</td><td>107%</td><td>0.5%</td><td>$578</td><td>106%</td><td>0.5%</td><td>80-120%</td></tr>
<tr><td>Standby</td><td>$920</td><td>62%</td><td>0.8%</td><td>$1,037</td><td>56%</td><td>0.9%</td><td>80-120%</td></tr>
<tr><td></td><td>$117,326</td><td></td><td>100%</td><td>$117,326</td><td></td><td>100%</td><td></td></tr>
</table>

# Direct Assignment at Book Value – Rate and Bill Impacts

| | Fixed Charge | | Variable Charge | | Direct Assignment Adjusted Revenue to Cost Ratios | Distribution Rate Impact | | Monthly Total Bill Impact | |
|---|---|---|---|---|---|---|---|---|---|
| | 2015 Baseline | Direct Assignment | 2015 Baseline | Scenario 1 | | $ change | % change | $ change | % change |
| Residential | $15.76 | $16.54 | $0.0156 | $0.0164 | 108% | $1.42 | 5.0% | $1.44 | 1.2% |
| GS < 50 | $35.18 | $36.83 | $0.0093 | $0.0097 | 96% | $2.45 | 4.6% | $2.50 | 0.9% |
| GS > 50 | $320.77 | $338.21 | $2.2481 | $2.3409 | 83% | $33.03 | 4.7% | $37.32 | 0.4% |
| Large Use | $24,766 | $14,610 | $1.4877 | $2.3324 | 115% | ($5,402) | (16.3%) | ($6,104) | (1.3%) |
| Super Use | $24,766 | $3,184 | $1.4877 | $0.0851 | 115% | ($68,738) | (91.9%) | ($77,674) | (2.9%) |
| Street Light | $2.53 | $2.64 | $6.7564 | $7.0731 | 87% | $0.17 | 4.5% | $0.20 | 1.5% |
| Sentinel | $4.84 | $5.06 | $13.2974 | $13.9208 | 92% | $0.34 | 4.6% | $0.39 | 2.3% |
| USL | $9.88 | $10.43 | $0.0154 | $0.0163 | 110% | $0.68 | 5.6% | $0.77 | 2.4% |
| Standby | - | - | $3.5334 | $3.5334 | 71% | - | - | - | - |

# Realignment of Revenues

| | Customer Count | 2015 Baseline | Dedicated assets | $ Difference | % Share of reallocated revenue responsibility |
|---|---|---|---|---|---|
| Residential | 214,658 | 67,541 | 69,010 | 1,469 | 34.27% |
| GS<50 | 17,931 | 14,513 | 15,137 | 624 | 14.60% |
| GS>50 | 2,279 | 23,776 | 25,848 | 2,072 | 48.33% |
| Large Use | 8 | 6,973 | 2,428 | (4,285) | -100.00% |
| Super Use | 4 | | 260 | | |
| Street Light | 52,000 | 2,971 | 2,971 | - | 0.00% |
| Sentinel | | 57 | 57 | - | 0.00% |
| USL | | 575 | 578 | 3 | 0.07% |
| Standby | | 920 | 1,037 | 117 | 2.73% |
| Total revenue | | 117,326 | 117,326 | - | 0% |

# C of H 2_Attch 2_CARD Horizon Presentation Updated (2013_05_01)

This page intentionally left blank

# Cost Allocation and Rate Design EMT Presentation

May 1, 2013

# Outline

1. Background on the Project
2. Options Considered
   - Breaking up the Existing Large Use Customer Class
   - Breaking up the Existing GS > 50 kW Class
3. Development of the Baseline
4. Scenarios Evaluated
5. Risk Matrix
6. Summary of Recommendations

# Objectives

- Review cost allocation process to address comments of OEB in the 2011 Cost of Service Application Decision
- Respond to customer requests to review Cost Allocation
- Consider strategic issues within Horizon Utilities' service area
- Smooth rate transitions at the class boundaries
- Mitigate the shareholder's risk

**Outcome:**

- **Decision needed from EMT as to which rate class(es) should be created**



horizon UTILITIES Looking beyond...

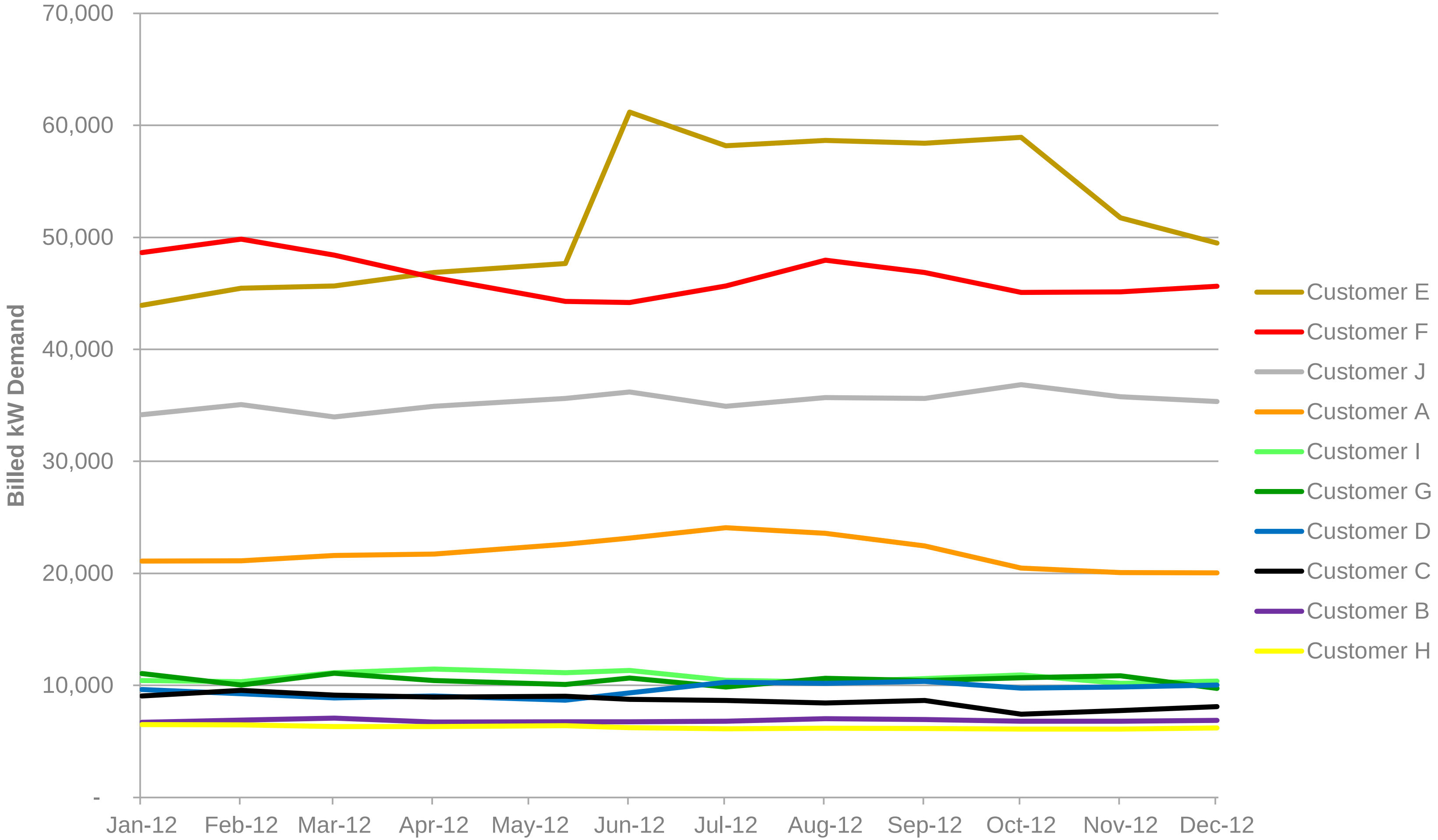
# Background on Cost Allocation

- Cost Allocation is the process of dividing cost responsibility on the basis of cost causation
- Rates are expected to fall within the range around costs
- Cost Allocation is NOT Rate Design
- Baseline Scenario established with 2013 Cost Allocation Model and 2015 Forecasted Revenue and Costs
- All scenarios compared to Baseline Scenario
- Sample rates are presented for discussion purposes only
- Bill impacts are monthly totals

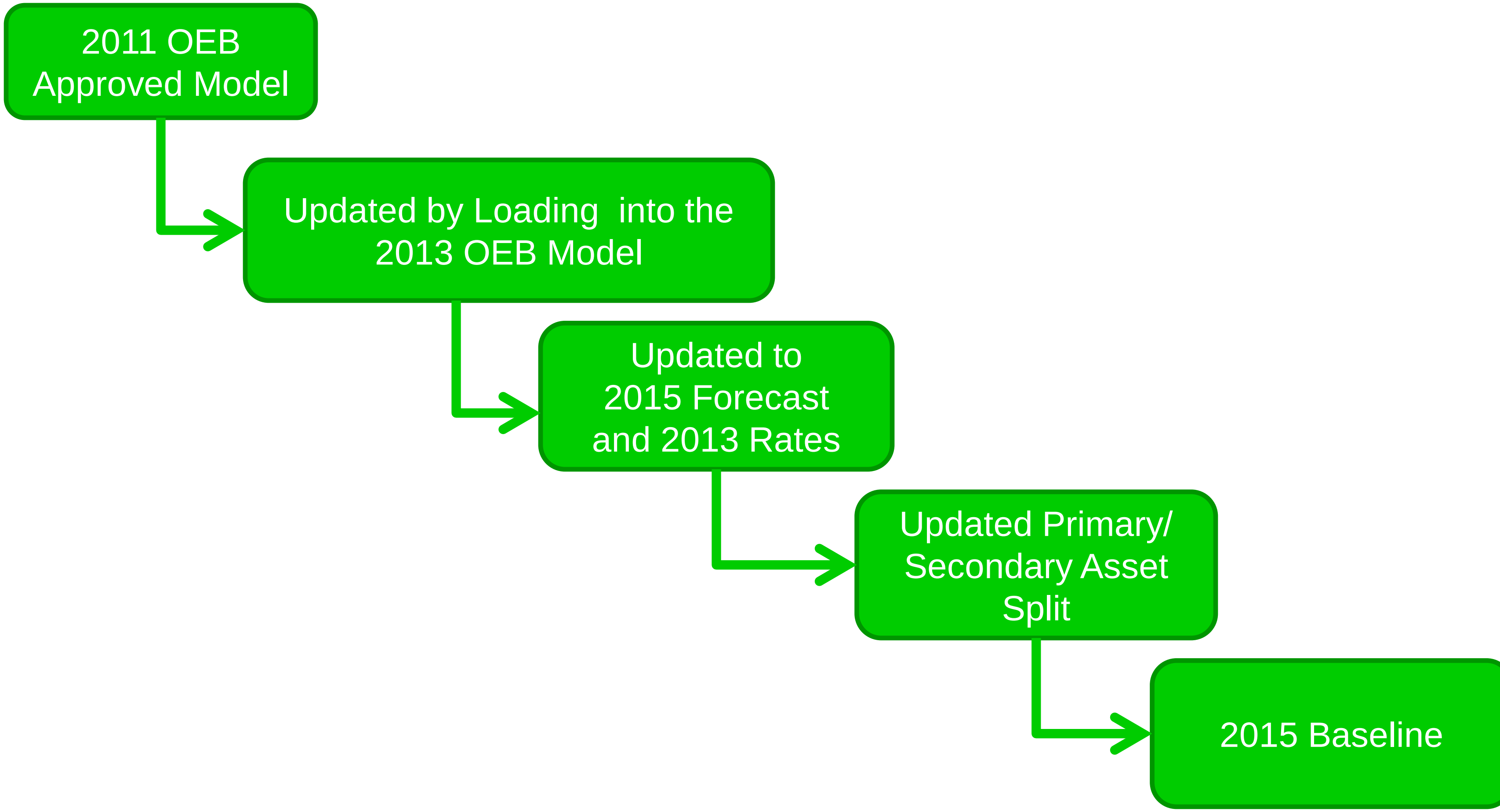
# Approach to New Customer Class within Large Use

- Looked at different options to define the Super User Class
  - Sub-Transmission Class (Rejected)
  - Dedicated Assets (Pursued – Below)
  - Level of Demand (Pursued – Below)
- Options for allocating costs to the Super User Class
  - Dedicated assets
    - Valued at Book Value (Pursued – Scenario 1)
    - Valued at 100% Replacement Cost (Pursued – Scenario 2)
    - Valued at 50% Replacement Cost (Pursued – Scenario 3)
  - Level of Demand
    - More defined allocation: Asset accounts, identified at the most granular level permitted by accounting, are allocated among all classes that may participate in the use of those accounts. (Pursued – Scenario 4)

# Large Use Customers – Demand



# Development of the Baseline



# Baseline: Revenue Requirement and Revenue to Cost Ratios

| Customer Classes | Approved 2011 CoS All numbers in 000's | | 2013 OEB Model (2011 data) | | 2015 Forecast with 2013 OEB model | | 2015 Forecast with 2013 OEB model and update to P/S assets | | OEB Target Range |
|---|---|---|---|---|---|---|---|---|---|
| Residential | $58,034 | 108% | $58,166 | 108% | $66,358 | 108% | $67,541 | 107% | 85-115% |
| GS < 50 | $11,949 | 103% | $12,547 | 97% | $14,456 | 97% | $14,513 | 97% | 80-120% |
| GS > 50 | $20,102 | 84% | $20,861 | 81% | $24,109 | 86% | $23,776 | 87% | 80-120% |
| Large Use | $8,067 | 85% | $6,843 | 101% | $7,786 | 88% | $6,973 | 98% | 85-115% |
| Street Light | $2,964 | 75% | $2,718 | 83% | $2,959 | 84% | $2,971 | 84% | 70-120% |
| Sentinel | $57 | 80% | $52 | 88% | $57 | 89% | $57 | 89% | 80-120% |
| USL | $534 | 108% | $505 | 111% | $570 | 108% | $575 | 107% | 80-120% |
| Standby | $640 | 80% | $654 | 80% | $1,030 | 56% | $920 | 62% | 80-120% |
| Total Rev. | $102,347 | | $102,347 | | $117,326 | | $117,326 | | |

# Baseline: Rate and Bill Impacts

| | Fixed Charge | | Variable Charge | | Total Monthly Bill Impact | |
|---|---|---|---|---|---|---|
| | 2013 | 2015 Baseline | 2013 | 2015 Baseline | $ change | % change |
| Residential | $14.69 | $15.70 | $0.0146 | $0.0157 | $2.00 | 1.9% |
| GS < 50 | $32.70 | $35.23 | $0.0086 | $0.0093 | $3.99 | 1.6% |
| GS > 50 | $298.15 | $321.20 | $2.0897 | $2.2512 | $51.01 | 0.7% |
| Large Use | $23,109.37 | $24,859.64 | $1.3830 | $1.4791 | $2,423.99 | 0.6% |
| Street Light | $2.35 | $2.53 | $6.2800 | $6.7654 | $0.28 | 2.7% |
| Sentinel | $4.50 | $4.85 | $12.3597 | $13.3151 | $0.55 | 4.0% |
| USL | $9.26 | $9.87 | $0.0145 | $0.0155 | $0.77 | 3.1% |
| Standby | - | - | $2.4952 | $3.5334 | $3,502.12 | 3.7% |

# Scenario 1: Direct Assignment at Book Value - Revenue Requirement and Revenue to Cost Ratios

| | 2015 Baseline | | Scenario 1 | | Target Range |
|---|---|---|---|---|---|
| Residential | $67,541 | 107% | $69,010 | 104% | 85-115% |
| GS < 50 | $14,513 | 97% | $15,139 | 93% | 80-120% |
| GS > 50 | $23,776 | 87% | $25,847 | 80% | 80-120% |
| Large Use | $6,973 | 98% | $2,428 | 137% | 85-115% |
| Super Use | | | $260 | 1398% | 85-115% |
| Street Light | $2,971 | 84% | $2,969 | 84% | 70-120% |
| Sentinel | $57 | 89% | $57 | 89% | 80-120% |
| USL | $575 | 107% | $578 | 106% | 80-120% |
| Standby | $920 | 62% | $1,037 | 56% | 80-120% |
| | $117,326 | | $117,326 | | |



horizon UTILITIES Looking beyond...

# Scenario 1: Direct Assignment at Book Value – Rate and Bill Impacts

| | Fixed Charge | | Variable Charge | | Scenario 1 Adjusted Revenue to Cost Ratios | Scenario 1 - Monthly Total Bill Impact | |
|---|---|---|---|---|---|---|---|
| | 2015 Baseline | Scenario 1 | 2015 Baseline | Scenario 1 | | $ change | % change |
| Residential | $15.70 | $15.99 | $0.0157 | $0.0159 | 104% | $0.46 | 0.4% |
| GS < 50 | $35.23 | $35.58 | $0.0093 | $0.0094 | 93% | $0.56 | 0.2% |
| GS > 50 | $321.20 | $379.11 | $2.2512 | $2.5925 | 92% | $117.20 | 1.4% |
| Large Use | $24,859.64 | $14,608.56 | $1.4791 | $2.3326 | 115% | ($5,539.63) | (1.2%) |
| Super Use | $24,859.64 | $3,183.99 | $1.4791 | $0.0851 | 115% | ($69,707.97) | (2.7%) |
| Street Light | $2.53 | $2.81 | $6.7654 | $7.5185 | 92% | $0.44 | 3.8% |
| Sentinel | $4.85 | $5.06 | $13.3151 | $13.8902 | 92% | $0.22 | 1.4% |
| USL | $9.87 | $10.08 | $0.0155 | $0.0158 | 107% | $0.26 | 0.9% |
| Standby | - | - | $3.5334 | $4.6111 | 92% | $3,635.50 | 3.7% |

# Scenario 2: Direct Assignment at 100% Replacement Cost - Revenue Requirement and Revenue to Cost Ratios

| | 2015 Baseline | | Scenario 2 | | Target Range |
|---|---|---|---|---|---|
| Residential | $67,541 | 107% | $68,669 | 105% | 85-115% |
| GS < 50 | $14,513 | 97% | $15,063 | 93% | 80-120% |
| GS > 50 | $23,776 | 87% | $25,701 | 81% | 80-120% |
| Large Use | $6,973 | 98% | $2,407 | 139% | 85-115% |
| Super Use | | | $874 | 415% | 85-115% |
| Street Light | $2,971 | 84% | $2,951 | 84% | 70-120% |
| Sentinel | $57 | 89% | $57 | 90% | 80-120% |
| USL | $575 | 107% | $575 | 107% | 80-120% |
| Standby | $920 | 62% | $1,028 | 56% | 80-120% |
| | $117,326 | | $117,326 | | |

# Scenario 2: Direct Assignment at 100% Replacement Cost – Rate and Bill Impacts

| | Fixed Charge | | Variable Charge | | Scenario 2 Adjusted Revenue to Cost Ratios | Scenario 2 - Monthly Total Bill Impact | |
|---|---|---|---|---|---|---|---|
| | 2015 Baseline | Scenario 2 | 2015 Baseline | Scenario 2 | | $ change | % change |
| Residential | $15.70 | $15.99 | $0.0157 | $0.0159 | 105% | $0.46 | 0.4% |
| GS < 50 | $35.23 | $35.58 | $0.0093 | $0.0094 | 94% | $0.56 | 0.2% |
| GS > 50 | 321.20 | $369.50 | $2.2512 | $2.5328 | 90% | $97.23 | 1.2% |
| Large Use | $24,859.64 | $14,479.55 | $1.4791 | $2.3120 | 115% | ($5,788.76) | (1.3%) |
| Super Use | $24,859.64 | $10,939.92 | $1.4791 | $0.2924 | 115% | ($54,732.16) | (2.1%) |
| Street Light | $2.53 | $2.73 | $6.7654 | $7.2999 | 90% | $0.31 | 2.7% |
| Sentinel | $4.85 | $4.90 | $13.3151 | $13.4493 | 90% | $0.08 | 0.5% |
| USL | $9.87 | $10.08 | $0.0155 | $0.0158 | 107% | $0.26 | 0.9% |
| Standby | - | - | $3.5334 | $4.4648 | 90% | $3,141.97 | 3.2% |



horizon UTILITIES Looking beyond...

# Scenario 3: Direct Assignment at 50% Replacement Cost – Revenue Requirement and Revenue to Cost Ratios

| | 2015 Baseline | | Scenario 3 | | Target Range |
|---|---|---|---|---|---|
| Residential | $67,541 | 107% | $68,843 | 104% | 85-115% |
| GS < 50 | $14,513 | 97% | $15,102 | 93% | 80-120% |
| GS > 50 | $23,776 | 87% | $25,775 | 81% | 80-120% |
| Large Use | $6,973 | 98% | $2,418 | 138% | 85-115% |
| Super Use | | | $562 | 646% | 85-115% |
| Street Light | $2,971 | 84% | $2,960 | 84% | 70-120% |
| Sentinel | $57 | 89% | $57 | 89% | 80-120% |
| USL | $575 | 107% | $577 | 107% | 80-120% |
| Standby | $920 | 62% | $1,033 | 56% | 80-120% |
| | $117,326 | | $117,326 | | |

# Scenario 3: Direct Assignment at 50% Replacement Cost – Rate and Bill Impacts

| | Fixed Charge | | Variable Charge | | Scenario 3 Adjusted Revenue to Cost Ratios | Scenario 3 - Monthly Total Bill Impact | |
|---|---|---|---|---|---|---|---|
| | 2015 Baseline | Scenario 3 | 2015 Baseline | Scenario 3 | | $ change | % change |
| Residential | $15.70 | $15.99 | $0.0157 | $0.0159 | 105% | $0.46 | 0.3% |
| GS < 50 | $35.23 | $35.58 | $0.0093 | $0.0094 | 93% | $0.56 | 0.2% |
| GS > 50 | $321.20 | $374.40 | $2.2512 | $2.5632 | 91% | $107.41 | 1.3% |
| Large Use | $24,859.64 | $14,544.99 | $1.4791 | $2.3225 | 115% | ($5,662.10) | (1.3%) |
| Super Use | $24,859.64 | $6,996.97 | $1.4791 | $0.1870 | 115% | ($62,345.99) | (2.1%) |
| Street Light | $2.53 | $2.77 | $6.7654 | $7.4093 | 91% | $0.38 | 2.7% |
| Sentinel | $4.85 | $4.98 | $13.3151 | $13.6885 | 91% | $0.09 | 0.5% |
| USL | $9.87 | $10.08 | $0.0155 | $0.0158 | 107% | $0.26 | 0.5% |
| Standby | - | - | $3.5334 | $4.5380 | 91% | $3,388.90 | 3.2% |

# Scenario 4: More Defined Allocation to Super User - Revenue Requirement and Revenue to Cost Ratios

| | 2015 Baseline | | Scenario 4 | | Target Range |
|---|---|---|---|---|---|
| Residential | $67,541 | 107% | $66,138 | 108% | 85-115% |
| GS < 50 | $14,513 | 97% | $15,048 | 93% | 80-120% |
| GS > 50 | $23,776 | 87% | $26,438 | 79% | 80-120% |
| Large Use | $6,973 | 98% | $2,579 | 130% | 85-115% |
| Super Use | | | $2,850 | 129% | 85-115% |
| Street Light | $2,971 | 84% | $2,585 | 95% | 70-120% |
| Sentinel | $57 | 89% | $50 | 101% | 80-120% |
| USL | $575 | 107% | $531 | 115% | 80-120% |
| Standby | $920 | 62% | $1,106 | 53% | 80-120% |
| | $117,326 | | $117,326 | | |

# Scenario 4 : More Defined Allocation to Super User - Rate and Bill Impacts

| | Fixed Charge | | Variable Charge | | Scenario 4 Adjusted Revenue to Cost Ratios | Scenario 4 - Monthly Total Bill Impact | |
|---|---|---|---|---|---|---|---|
| | 2015 Baseline | Scenario 4 | 2015 Baseline | Scenario 4 | | $ change | % change |
| Residential | $15.70 | $15.99 | $0.0157 | $0.0159 | 109% | $0.46 | 0.3% |
| GS < 50 | $35.23 | $35.58 | $0.0093 | $0.0094 | 94% | $0.56 | 0.3% |
| GS > 50 | $321.20 | $332.81 | $2.2512 | $2.3049 | 80% | $20.98 | 0.4% |
| Large Use | $24,859.64 | $15,482.33 | $1.4791 | $2.4721 | 115% | ($3,852.46) | (0.9%) |
| Super Use | $24,859.64 | $23,109.37 | $1.4791 | $1.3132 | 115% | ($7,544.03) | (0.3%) |
| Street Light | $2.53 | $2.56 | $6.7654 | $6.8336 | 96% | $0.04 | 0.3% |
| Sentinel | $4.85 | $4.90 | $13.3151 | $13.4493 | 101% | $0.08 | 0.5% |
| USL | $9.87 | $10.08 | $0.0155 | $0.0158 | 115% | $0.6 | 0.9% |
| Standby | - | - | $3.5334 | $4.2267 | 80% | $2,338.76 | 2.4% |



horizon® UTILITIES Looking beyond...

# Risk Matrix

| | Scenarios | Shareholders | Other Customers | Large Users | Super Users |
|---|---|---|---|---|---|
| | 2015 Baseline | • SU direct connect to HONI<br>• Potential loss of revenue between Cost of Service ("CoS") applications<br>• Negative impact to ROE | • No impact - until next rebasing and then rates would be higher | • Still have high rates; rates will be higher after next rebasing | • Go to direct connect during IRM - capital outlay, timing |
| 1 | Book Value | • Risk Free to Shareholders - but may not be approved as other classes will oppose, and rates may be perceived as preferential. | • Absorb higher costs;<br>• rates will go up - but given the larger number of customers, impact not as great Total bill impact between 0.2% and 3.8% | • Slightly lower rates - due to elimination of within-class cross-subsidy (-1.2%) | • Significantly lower rates |
| 2 | 100 % Replacement Value | • Low probability of bypass, but not completely risk free | • Absorb higher costs<br>• rates will go up - but larger number of customers, impact not as great, total bill impact between 0.2% and 3.2% | • Slightly lower rates than Scenario 1 (-1.3%) | • Lower rates though not as low as Scenario 1 |
| 3 | 50% Replacement Value | • Mitigating "Risk Free" value<br>• Better than Baseline<br>• Reflects average depreciation of an asset pool | • Absorb higher costs<br>• Rates will go up but given the larger number of customers, the impact is small,<br>• Impact will be better than Baseline and Scenario 1 | • Slightly lower rates (-1.3%)<br>• Better than Baseline | • Mitigating "Risk Free" value<br>• Better than Baseline and Scenario 2 |
| 4 | Refined allocation of SU assets | • SU would still have a financial incentive to go direct connect (bypass)<br>• Similar to Baseline – adjustment to rates not significant | • Small impact until next rebasing and then rates would be higher | • Small impact but will have high rates - rates will be higher at next rebasing year | • Go to direct connect during IRM - capital outlay, timing<br>• Similar to Baseline – adjustments to rates not significant |



horizon UTILITIES Looking beyond...

# Objectives revisited

- Review cost allocation process to address comments of OEB in the 2011 Cost of Service Application Decision
- Respond to customer requests to review Cost Allocation
- Consider strategic issues within Horizon Utilities’ service area
- Smooth rate transitions at the class boundaries
- Mitigate the shareholder’s risk

# Summary - Recommendations

- Move forward with the split of the Large User group into:
  - Large User GS>5 MW – 19.9 MW
  - Super User GS>20 MW
- Direct Assignment of 100% of Replacement Cost to the Super User class (Scenario 2)

- Retain the existing definition of GS > 50 kW:
  - One class 50 kW – 4999 kW

# C of H 2_Attch 3_Bill Impacts Presentation- 11'26'2013

This page intentionally left blank

# CoS Scenario Bill Impacts

**Nov 26 2013**

# 2015 Distribution Revenue Breakdown

| | Scenario 1 (No LU (2) Class) | | | Scenario 2 (Introduce LU (2) in 2015) | | |
|---|---|---|---|---|---|---|
| | $MM | | % | $MM | | % |
| Residential | $ | 66.87 | 59.3% | $ | 69.25 | 61.4% |
| GS < 50 kW | $ | 13.66 | 12.1% | $ | 13.66 | 12.1% |
| GS >50 to 4999 kW | $ | 21.56 | 19.1% | $ | 23.66 | 21.0% |
| LU (1) | $ | 3.10 | 2.8% | $ | 2.07 | 1.8% |
| LU (2) | $ | 4.11 | 3.6% | $ | 0.38 | 0.3% |
| Other | $ | 3.45 | 3.1% | $ | 3.71 | 3.3% |
| TOTAL | $ | 112.75 | 100.0% | $ | 112.74 | 100.0% |



horizon UTILITIES Looking beyond...

# 2015 Revenue to Cost Ratios

| | Scenario 1 (No LU (2) Class) | | Scenario 2 (Introduce LU (2) in 2015) | |
|---|---|---|---|---|
| | **Per CA Model** | **Rate Design** | **Per CA Model** | **Rate Design** |
| **Residential** | 110.8% | 107.2% | 105.1% | 105.1% |
| **GS < 50 kW** | 103.8% | 103.8% | 96.3% | 96.3% |
| **GS >50 to 4999 kW** | 70.7% | 80.0% | 72.4% | 89.5% |
| **LU (1)** | 103.6% | 103.6% | 168.7% | 115.0% |
| **LU (2)** | NA | NA | 1202.7% | 115.0% |



horizon UTILITIES Looking beyond...

# Bill Impacts: Scenario Comparisons

# Scenario 1: No LU (2) Class

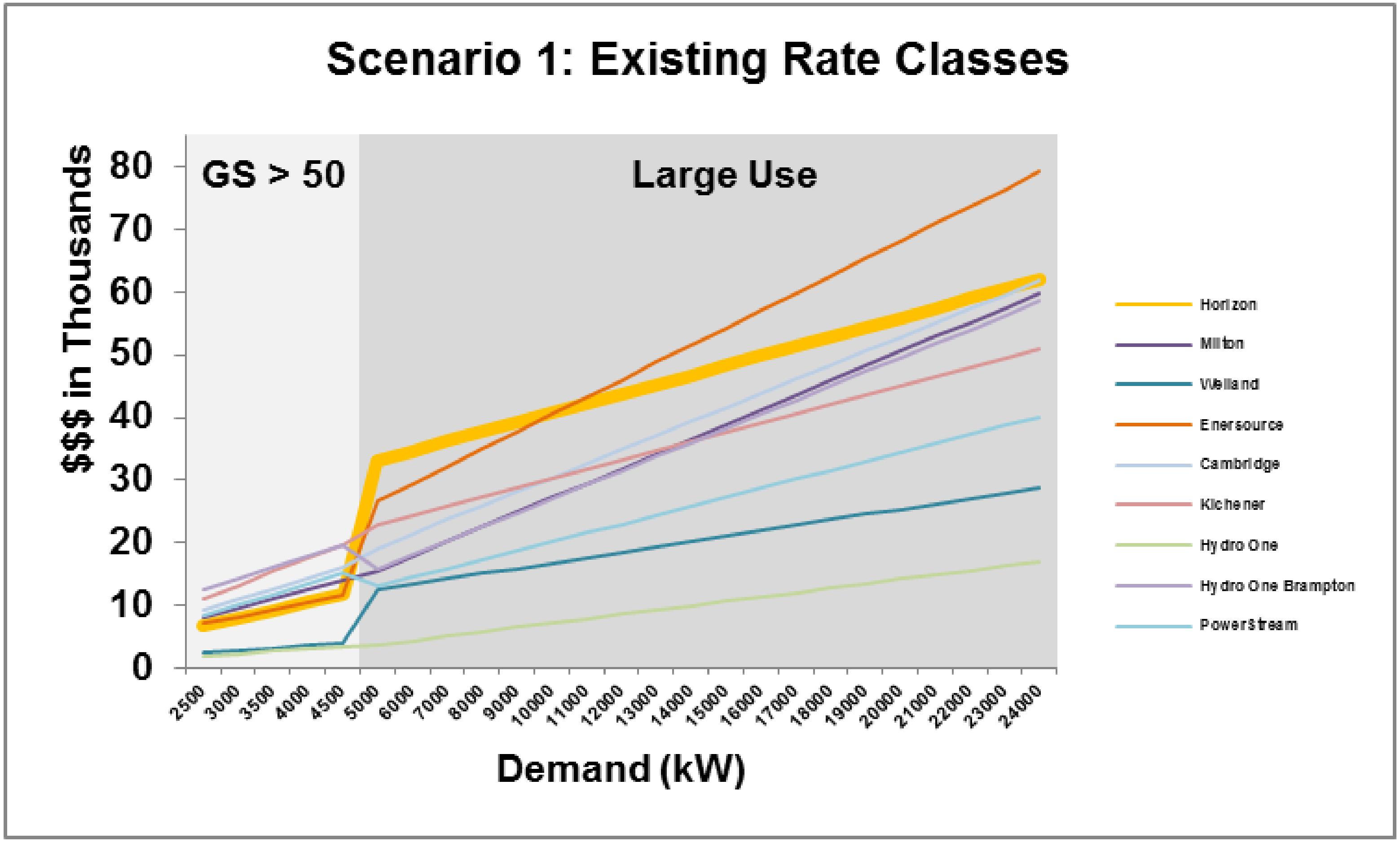
| Distribution Bill Impacts | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | |
| | | | $ | % | $ | % | $ | % | $ | % | $ | % |
| Residential | kWh | 800 | $ 1.60 | 6.00% | $ 0.95 | 3.36% | $ 0.69 | 2.36% | $ 0.32 | 1.07% | $ 0.88 | 2.91% |
| GS< 50kW | kWh | 2,000 | $ 4.80 | 9.52% | $ 2.19 | 3.97% | $ 0.49 | 0.85% | $ 0.59 | 1.02% | $ 1.79 | 3.06% |
| GS > 50 kW | kW | 250 | $ 188.49 | 22.77% | $ 47.85 | 4.71% | $ 19.99 | 1.88% | $ 11.55 | 1.07% | $ 31.16 | 2.84% |
| LU (1) | kW | 5,000 | $ 2,919.50 | 9.64% | $ 1,270.48 | 3.83% | $ (761.54) | (2.21)% | $ 386.36 | 1.15% | $1,043.02 | 3.06% |
| LU (1) | kW | 10,000 | $ 3,584.50 | 9.64% | $ 1,559.98 | 3.83% | $ (935.04) | (2.21)% | $ 474.36 | 1.15% | $1,280.52 | 3.06% |
| LU (1) | kW | 20,000 | $ 4,914.50 | 9.64% | $ 2,138.98 | 3.83% | $(1,282.04) | (2.21)% | $ 650.36 | 1.15% | $1,755.52 | 3.06% |
| Table excludes the impact of HST (13%) and OCEB (10%) | | | | | | | | | | | | |

| Total Bill Impacts (Excluding HST and OCEB) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | |
| | | | $ | % | $ | % | $ | % | $ | % | $ | % |
| Residential | kWh | 800 | $ 2.34 | 2.06% | $ 1.15 | 0.99% | $ 1.02 | 0.88% | $ 0.74 | 0.63% | $ 0.34 | 0.29% |
| GS< 50kW | kWh | 2,000 | $ 6.35 | 2.42% | $ 2.70 | 1.00% | $ 1.11 | 0.41% | $ 1.42 | 0.52% | $ 1.63 | 0.59% |
| GS > 50 kW | kW | 2,500 | $ 628.66 | 5.23% | $ (46.73) | (0.37)% | $ 52.17 | 0.41% | $ 43.70 | 0.35% | $ 63.33 | 0.50% |
| LU (1) | kW | 5,000 | $ 9,057.57 | 3.15% | $ 382.48 | 0.13% | $ (25.54) | (0.01)% | $1,122.86 | 0.38% | $1,779.02 | 0.60% |
| LU (1) | kW | 10,000 | $ 15,860.68 | 2.87% | $ (216.02) | (0.04)% | $ 536.96 | 0.09% | $1,947.36 | 0.34% | $2,752.52 | 0.48% |
| LU (1) | kW | 20,000 | $ 29,466.90 | 2.73% | $ (1,413.02) | (0.13)% | $ 1,661.96 | 0.15% | $3,596.36 | 0.32% | $4,699.52 | 0.42% |
| Table excudes the impact of HST (13%) and OCEB (10%) | | | | | | | | | | | | |



horizon UTILITIES Looking beyond...

# Scenario 1: Rate Curve Competitiveness for 2015



# Scenario 2: Introduce LU (2) in 2015

**Distribution Bill Impacts**

| Customer Class | Billing Units | Average Monthly Volume | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | $ | % | $ | % | $ | % | $ | % | $ | % |
| Residential | kWh | 800 | $ 2.56 | 9.60% | $ 1.12 | 3.83% | $ 0.68 | 2.24% | $ 0.34 | 1.10% | $ 0.92 | 2.93% |
| GS< 50kW | kWh | 2,000 | $ 4.80 | 9.52% | $ 2.24 | 4.06% | $ 1.20 | 2.09% | $ 0.60 | 1.02% | $ 1.77 | 2.99% |
| GS > 50 kW | kW | 250 | $ 280.24 | 33.85% | $ 40.81 | 3.68% | $ 22.67 | 1.97% | $ 11.42 | 0.97% | $ 33.07 | 2.80% |
| LU (1) | kW | 5,000 | $ (8,092.07) | (26.73)% | $ (761.49) | (3.43)% | $ 452.13 | 2.11% | $ 227.73 | 1.04% | $ 659.15 | 2.98% |
| LU (1) | kW | 10,000 | $ (9,935.57) | (26.73)% | $ (934.99) | (3.43)% | $ 555.13 | 2.11% | $ 279.73 | 1.04% | $ 809.15 | 2.98% |
| LU (2) | kW | 20,000 | $ (45,778.23) | (89.83)% | $ 2,928.51 | 56.51% | $ 171.80 | 2.12% | $ 85.51 | 1.03% | $ 249.01 | 2.98% |

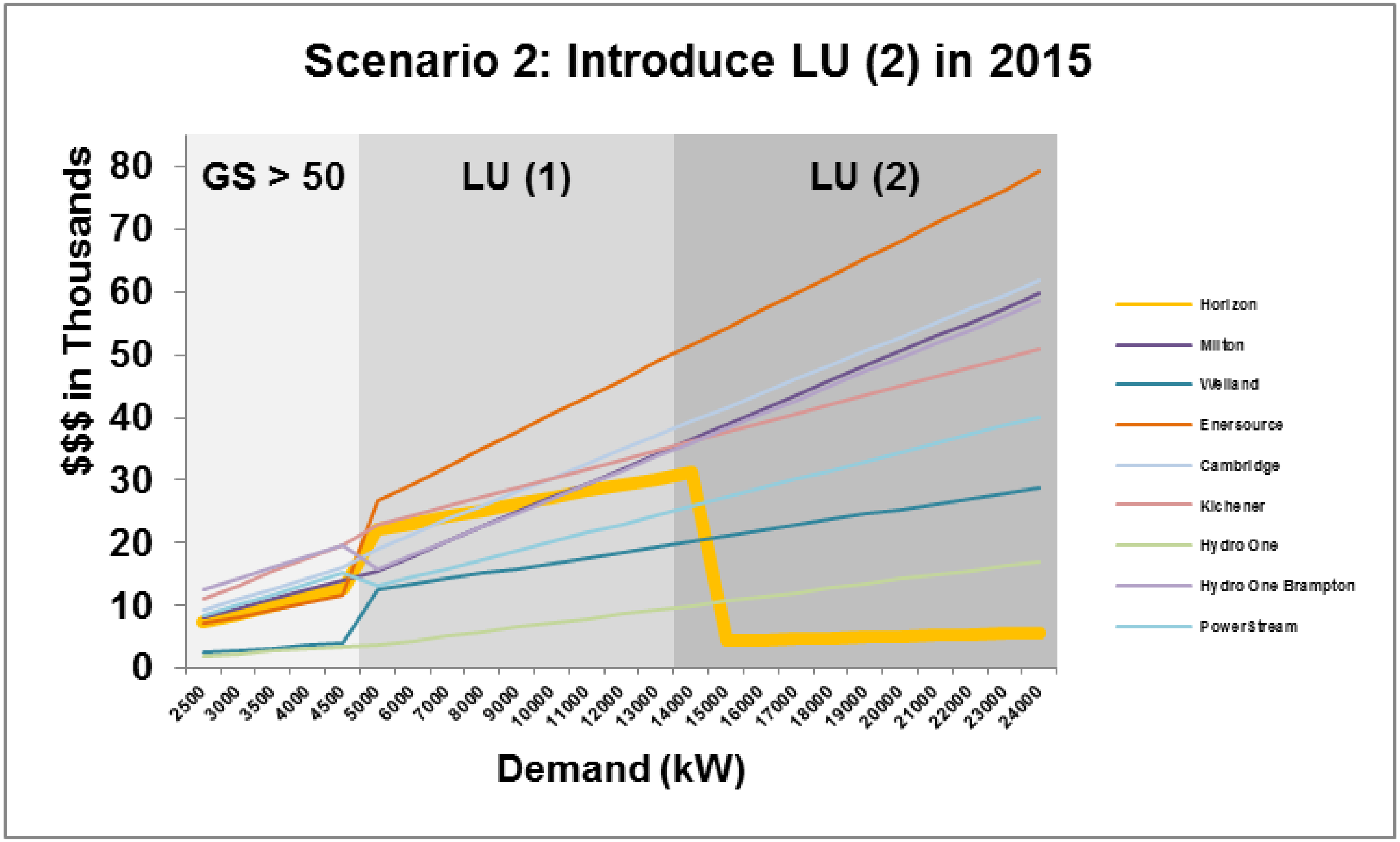
Table excludes the impact of HST (13%) and OCEB (10%)

**Total Bill Impacts (Excluding HST and OCEB)**

| Customer Class | Billing Units | Average Monthly Volume | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | $ | % | $ | % | $ | % | $ | % | $ | % |
| Residential | kWh | 800 | $ 3.30 | 2.91% | $ 1.32 | 1.13% | $ 1.01 | 0.86% | $ 0.76 | 0.64% | $ 0.38 | 0.32% |
| GS< 50kW | kWh | 2,000 | $ 6.35 | 2.42% | $ 2.75 | 1.02% | $ 1.82 | 0.67% | $ 1.43 | 0.52% | $ 1.61 | 0.58% |
| GS > 50 kW | kW | 250 | $ 720.41 | 6.00% | $ (53.77) | (0.42)% | $ 54.85 | 0.43% | $ 43.57 | 0.34% | $ 65.25 | 0.51% |
| LU (1) | kW | 5,000 | $ (1,954.00) | (0.68)% | $ (1,649.49) | (0.58)% | $ 1,188.13 | 0.42% | $ 964.23 | 0.34% | $ 1,395.15 | 0.49% |
| LU (1) | kW | 10,000 | $ 2,340.61 | 0.42% | $ (2,710.99) | (0.49)% | $ 2,027.13 | 0.37% | $ 1,752.73 | 0.32% | $ 2,281.15 | 0.41% |
| LU (2) | kW | 20,000 | $ (21,225.83) | (1.96)% | $ (623.49) | (0.06)% | $ 3,115.80 | 0.29% | $ 3,031.51 | 0.29% | $ 3,193.01 | 0.30% |

Table excudes the impact of HST (13%) and OCEB (10%)

# Scenario 2: Rate Curve Competitiveness for 2015



# C of H 2_Attch 4_Bill Impacts Table- 11'26'2013

This page intentionally left blank

# Bill Impacts: 11'26'2013

| Distribution Bill Impacts | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | |
| | | | $ | % | $ | % | $ | % | $ | % | $ | % |
| Residential | kWh | 800 | $ 2.56 | 9.60% | $ 1.12 | 3.83% | $ 0.68 | 2.24% | $ 0.34 | 1.10% | $ 0.92 | 2.93% |
| GS< 50kW | kWh | 2,000 | $ 4.80 | 9.52% | $ 2.24 | 4.06% | $ 1.20 | 2.09% | $ 0.60 | 1.02% | $ 1.77 | 2.99% |
| GS > 50 kW | kW | 250 | $ 280.24 | 33.85% | $ 40.81 | 3.68% | $ 22.67 | 1.97% | $ 11.42 | 0.97% | $ 33.07 | 2.80% |
| LU (1) | kW | 5,000 | $ (8,092.07) | (26.73)% | $ (761.49) | (3.43)% | $ 452.13 | 2.11% | $ 227.73 | 1.04% | $ 659.15 | 2.98% |
| LU (1) | kW | 10,000 | $ (9,935.57) | (26.73)% | $ (934.99) | (3.43)% | $ 555.13 | 2.11% | $ 279.73 | 1.04% | $ 809.15 | 2.98% |
| LU (2) | kW | 20,000 | $ (45,778.23) | (89.83)% | $ 2,928.51 | 56.51% | $ 171.80 | 2.12% | $ 85.51 | 1.03% | $ 249.01 | 2.98% |
| Table excludes the impact of HST (13%) and OCEB (10%) | | | | | | | | | | | | |

| Distribution Bill and Horizon Variance Account Rider Bill Impacts | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | |
| | | | $ | % | $ | % | $ | % | $ | % | $ | % |
| Residential | kWh | 800 | $ 4.14 | 15.97% | $ 1.07 | 3.56% | $ 0.68 | 2.18% | $ 0.34 | 1.07% | $ 0.13 | 0.40% |
| GS< 50kW | kWh | 2,000 | $ 8.76 | 18.49% | $ 2.12 | 3.78% | $ 1.20 | 2.06% | $ 0.60 | 1.01% | $ 0.98 | 1.64% |
| GS > 50 kW | kW | 250 | $ 667.15 | 117.53% | $ (85.94) | (6.96)% | $ 22.67 | 1.97% | $ 11.42 | 0.97% | $ 33.07 | 2.80% |
| LU (1) | kW | 5,000 | $ (3,299.96) | (12.18)% | $ (2,385.49) | (10.02)% | $ 452.13 | 2.11% | $ 227.73 | 1.04% | $ 659.15 | 2.98% |
| LU (1) | kW | 10,000 | $ (351.35) | (1.14)% | $ (4,182.99) | (13.72)% | $ 555.13 | 2.11% | $ 279.73 | 1.04% | $ 809.15 | 2.98% |
| LU (2) | kW | 20,000 | $ (26,609.79) | (69.50)% | $ (3,567.49) | (30.55)% | $ 171.80 | 2.12% | $ 85.51 | 1.03% | $ 249.01 | 2.98% |
| Table excludes the impact of HST (13%) and OCEB (10%) | | | | | | | | | | | | |

| Total Bill Impacts (Excluding HST and OCEB) | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Customer Class | Billing Units | Average Monthly Volume | 2015 | | 2016 | | 2017 | | 2018 | | 2019 | |
| | | | $ | % | $ | % | $ | % | $ | % | $ | % |
| Residential | kWh | 800 | $ 3.30 | 2.91% | $ 1.32 | 1.13% | $ 1.01 | 0.86% | $ 0.76 | 0.64% | $ 0.38 | 0.32% |
| GS< 50kW | kWh | 2,000 | $ 6.35 | 2.42% | $ 2.75 | 1.02% | $ 1.82 | 0.67% | $ 1.43 | 0.52% | $ 1.61 | 0.58% |
| GS > 50 kW | kW | 250 | $ 720.41 | 6.00% | $ (53.77) | (0.42)% | $ 54.85 | 0.43% | $ 43.57 | 0.34% | $ 65.25 | 0.51% |
| LU (1) | kW | 5,000 | $ (1,954.00) | (0.68)% | $ (1,649.49) | (0.58)% | $ 1,188.13 | 0.42% | $ 964.23 | 0.34% | $ 1,395.15 | 0.49% |
| LU (1) | kW | 10,000 | $ 2,340.61 | 0.42% | $ (2,710.99) | (0.49)% | $ 2,027.13 | 0.37% | $ 1,752.73 | 0.32% | $ 2,281.15 | 0.41% |
| LU (2) | kW | 20,000 | $ (21,225.83) | (1.96)% | $ (623.49) | (0.06)% | $ 3,115.80 | 0.29% | $ 3,031.51 | 0.29% | $ 3,193.01 | 0.30% |
| Table excudes the impact of HST (13%) and OCEB (10%) | | | | | | | | | | | | |

This page intentionally left blank

# C of H 2_Attch 5_Bill Impacts - EMT Review 11'06'2013

This page intentionally left blank

# CoS Scenario Bill Impacts

**Nov 6 2013**

# Overview of Scenarios

**Scenario 1**: **Existing Rate Classes with 2015 – 2019 Revenue Requirement (No LU (2) Class)**

- **Pros**: Revenue to cost ratios for all classes sit within the OEB prescribed range
- **Cons:** Does not include the introduction of the LU (2) Class, which leaves an exposure of $4MM if those 4 customers migrate to direct connect

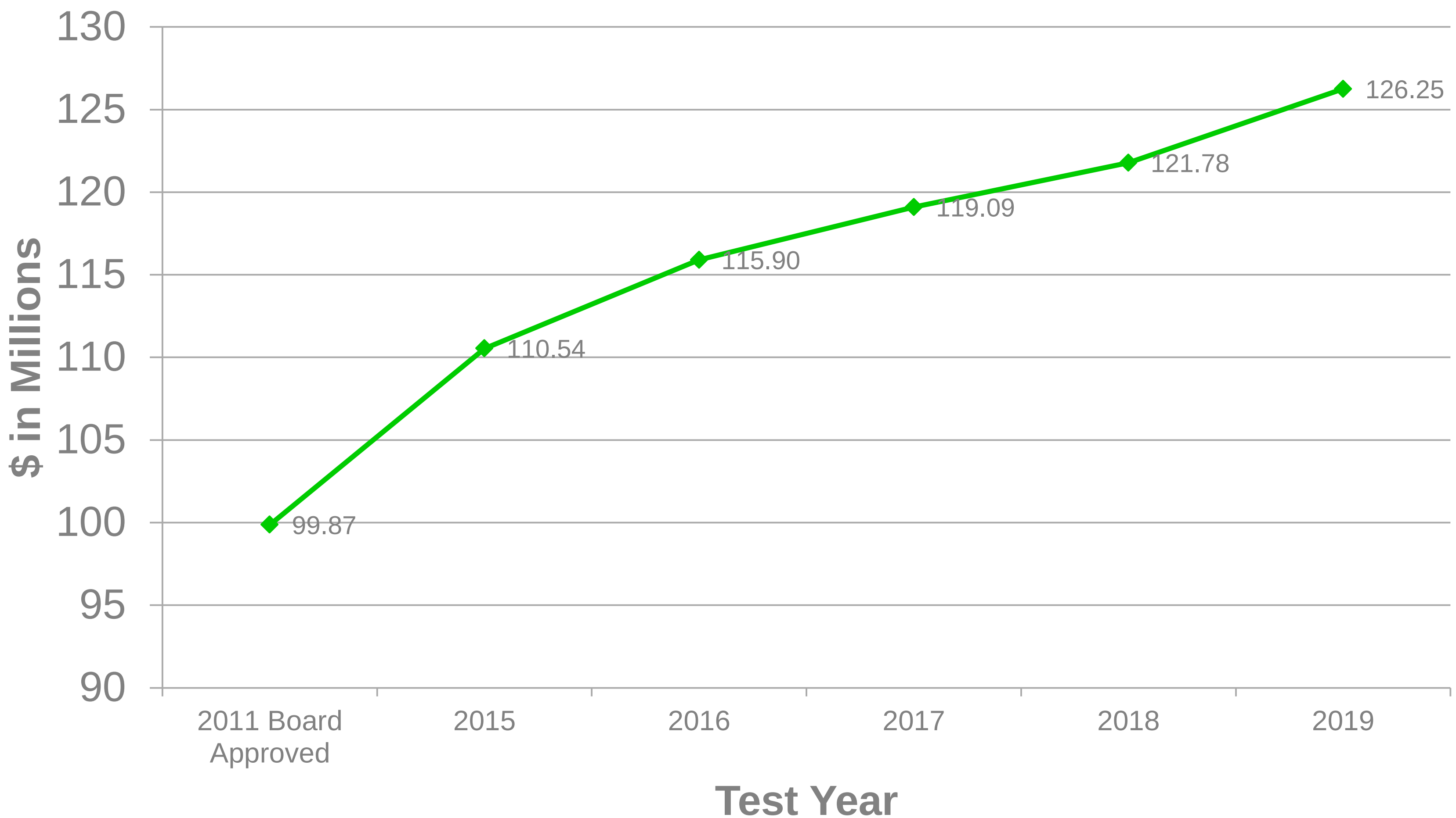
**Scenario 2: Introduction of LU (2) Class in 2015**

- **Pros:** Recognizes the cost causality of the LU (2) Class
- **Cons:** The remaining rate classes see a larger increase in their 2015 rates (predominantly the GS > 50 kW Class)

**Scenario 3: LU (2) Class introduced over 5 years**

- **Pros:** Mitigates rate shock and follows OEB principles of rate mitigation
- **Cons:** Does not immediately reflect the cost causality of the LU (2) Class

# Increase in Distribution Revenue Requirement



# 2015 Distribution Revenue Breakdown

| | Scenario 1 (No LU (2) Class) | | Scenario 2 (LU (2) Class in 2015) | | Scenario 3 (LU (2) Class over 5 Years) | |
|---|---|---|---|---|---|---|
| | $ (MM) | % | $ (MM) | % | $ (MM) | % |
| **Residential** | $67.5 | 61.0% | $67.9 | 61.5% | $67.9 | 61.5% |
| **GS < 50 kW** | $13.4 | 12.1% | $13.4 | 12.1% | $13.4 | 12.1% |
| **GS > 50 kW** | $19.3 | 17.4% | $23.0 | 20.8% | $20.2 | 18.3% |
| **LU (1)** | $3.0 | 2.7% | $2.0 | 1.8% | $2.0 | 1.8% |
| **LU (2)** | $4.0 | 3.6% | $0.4 | 0.34% | $3.4 | 3.0% |
| **Other** | $3.3 | 3.2% | $3.8 | 3.46% | $3.6 | 3.3% |
| **Total** | **$110.5** | **100.0%** | **$110.5** | **100%** | **$110.5** | **100%** |

# 2015 Revenue to Cost Ratios

| | OEB Approved Ranges | Scenario 1 (No LU (2) Class) | | Scenario 2 (LU (2) Class in 2015) | | Scenario 3 (LU (2) Class over 5 Years) | |
|---|---|---|---|---|---|---|---|
| | | Per CA Model | Rate Design | Per CA Model | Rate Design | Per CA Model | Rate Design |
| **Residential** | 85% - 115% | 107.39% | 106.58% | 101.94% | 101.94% | 101.94% | 101.94% |
| **GS < 50 kW** | 80% - 120% | 104.98% | 104.98% | 98.00% | 98% | 98.00% | 98% |
| **GS > 50 kW** | 80% - 120% | 76.89% | 80.00% | 78.80% | 96.84% | 78.80% | 85.59% |
| **LU (1)** | 85% - 115% | 157.12% | 104.06% | 169.98% | 115.00% | 169.98% | 115.00% |
| **LU (2)** | 85% - 115% | N/A | N/A | 1187.46% | 115.00% | 1187.46% | 989.57% |

# Bill Impacts: Scenario Comparisons

# Scenario 1: No LU (2) Class

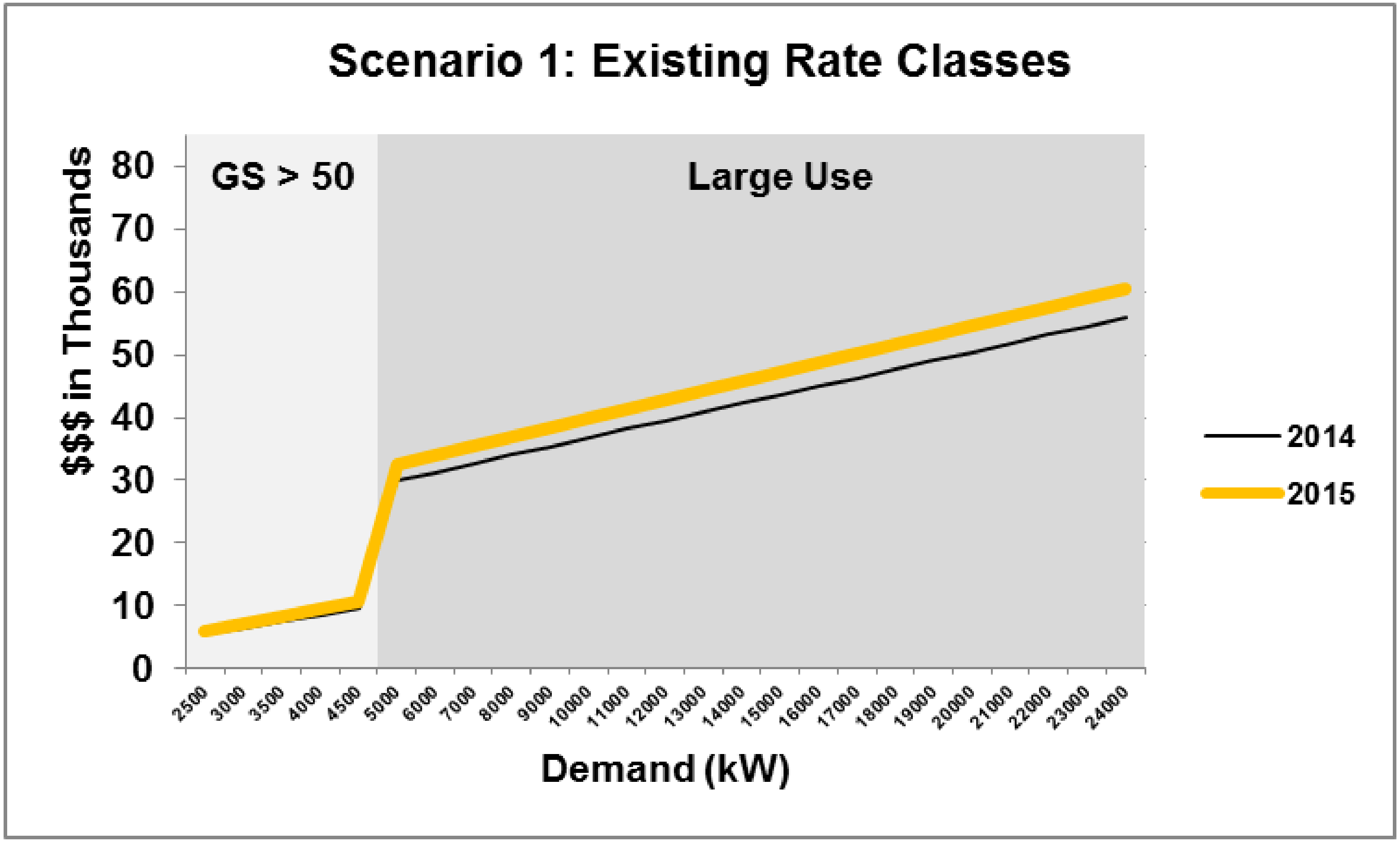
| Scenario 1 | | | Distribution Bill Impacts | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2015 vs 2014 | | 2016 vs 2015 | | 2017 vs 2018 | | 2018 vs 2017 | | 2019 vs 2018 | |
| | | | $$$ | % | $$$ | % | $$$ | % | $$$ | % | $$$ | % |
| **Residential** | kWh | 800 | $ 2.06 | 7.79% | $ 1.11 | 3.89% | $ 0.70 | 2.36% | $ 0.53 | 1.75% | $ 0.94 | 3.05% |
| **GS< 50kW** | kWh | 2000 | $ 4.14 | 8.30% | $ 2.32 | 4.30% | $ 1.25 | 2.22% | $ 1.05 | 1.82% | $ 1.81 | 3.09% |
| **GS 50 to 4,999 kW** | kW | 250 | $ 96.45 | 11.78% | $ 46.45 | 5.07% | $ 20.20 | 2.10% | $ 15.54 | 1.58% | $ 28.84 | 2.89% |
| **Large Use** | kW | 5000 | $ 2,501.72 | 8.35% | $ 1,382.48 | 4.26% | $ 770.46 | 2.28% | $ 592.81 | 1.71% | $ 1,099.71 | 3.12% |
| **Large Use** | kW | 10000 | $ 3,071.72 | 8.35% | $ 1,697.48 | 4.26% | $ 945.96 | 2.28% | $ 727.81 | 1.71% | $ 1,350.21 | 3.12% |
| **Large Use** | kW | 20000 | $ 4,211.72 | 8.35% | $ 2,327.48 | 4.26% | $ 1,296.96 | 2.28% | $ 997.81 | 1.71% | $ 1,851.21 | 3.12% |
| **Street Lighting** | KW | 2500 | $ 1,314.20 | 8.35% | $ 726.11 | 4.26% | $ 404.81 | 2.28% | $ 311.55 | 1.71% | $ 577.84 | 3.12% |

| Scenario 1 | | | Total Bill Impacts | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2015 vs 2014 | | 2016 vs 2015 | | 2017 vs 2018 | | 2018 vs 2017 | | 2019 vs 2018 | |
| | | | $$$ | % | $$$ | % | $$$ | % | $$$ | % | $$$ | % |
| **Residential** | kWh | 800 | $ 3.07 | 2.81% | $ 1.25 | 1.77% | $ 1.05 | 0.92% | $ 0.96 | 0.83% | $ 0.41 | 0.35% |
| **GS< 50kW** | kWh | 2000 | $ 6.35 | 2.52% | $ 4.52 | 1.75% | $ 1.91 | 0.72% | $ 1.91 | 0.72% | $ 1.67 | 0.63% |
| **GS 50 to 4,999 kW** | kW | 250 | $ 355.97 | 2.86% | $ 150.05 | 1.17% | $ 53.27 | 0.41% | $ 48.50 | 0.37% | $ 62.05 | 0.48% |
| **Large Use** | kW | 5000 | $ 6,312.29 | 2.28% | $ 2,977.27 | 1.05% | $ 1,532.07 | 0.53% | $ 1,351.91 | 0.47% | $ 1,866.92 | 0.64% |
| **Large Use** | kW | 10000 | $ 10,660.06 | 2.01% | $ 4,868.90 | 0.90% | $ 2,459.07 | 0.45% | $ 2,238.22 | 0.41% | $ 2,870.19 | 0.52% |
| **Large Use** | kW | 20000 | $ 19,355.59 | 1.86% | $ 8,652.18 | 0.82% | $ 4,313.06 | 0.40% | $ 4,010.85 | 0.37% | $ 4,876.73 | 0.45% |
| **Street Lighting** | KW | 2500 | $ 3,820.45 | 3.16% | $ 1,682.56 | 1.35% | $ 668.99 | 0.53% | $ 574.14 | 0.45% | $ 844.45 | 0.66% |

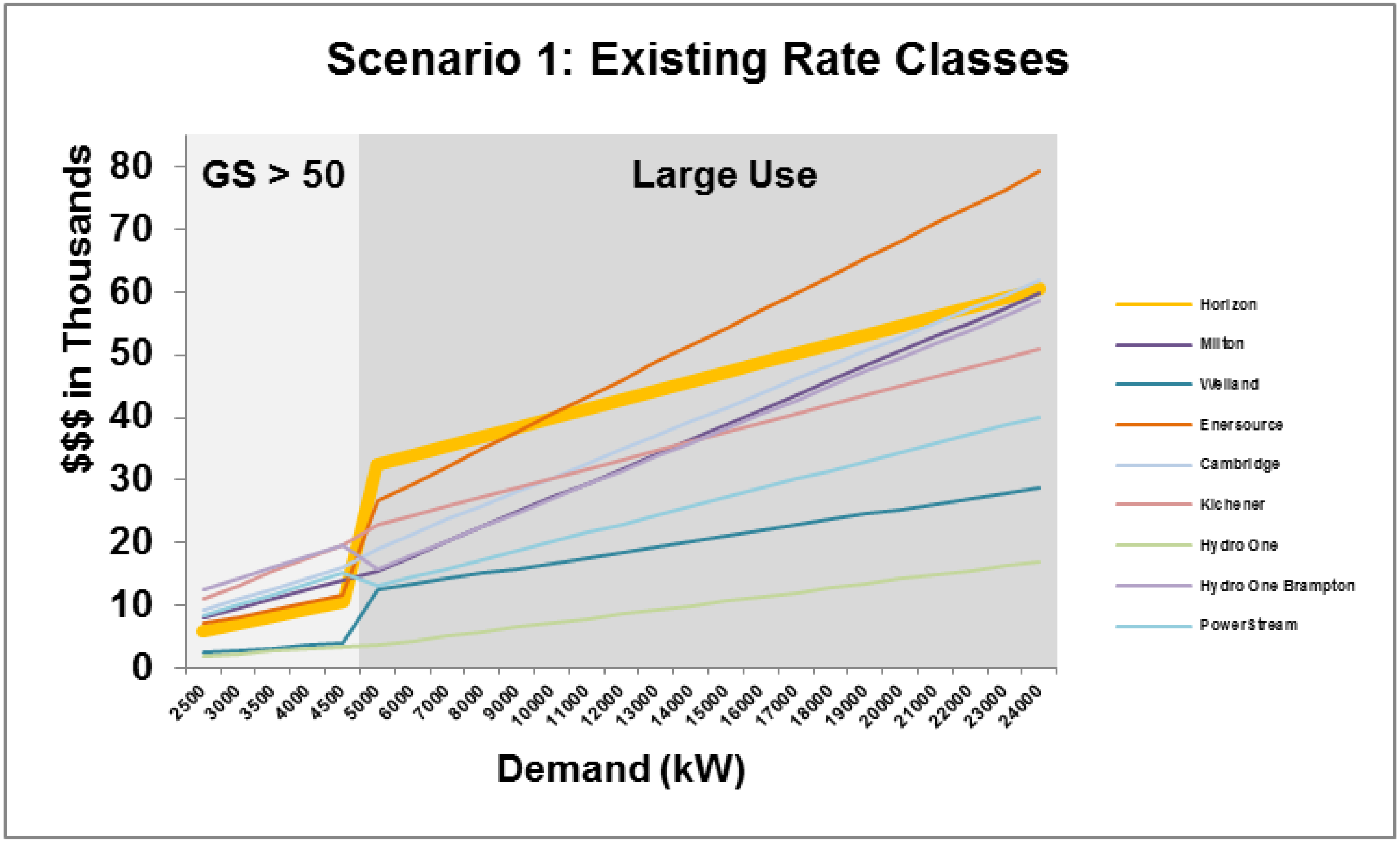


horizon UTILITIES Looking beyond...

# Scenario 1: Rate Curve for 2015



# Scenario 1: Rate Curve Competitiveness for 2015




Distribution Charges at 4,999 kW: $11,878
Distribution Charges at 5,000 kW: $32,454

# Scenario 2: Introduce LU (2) Class in 2015

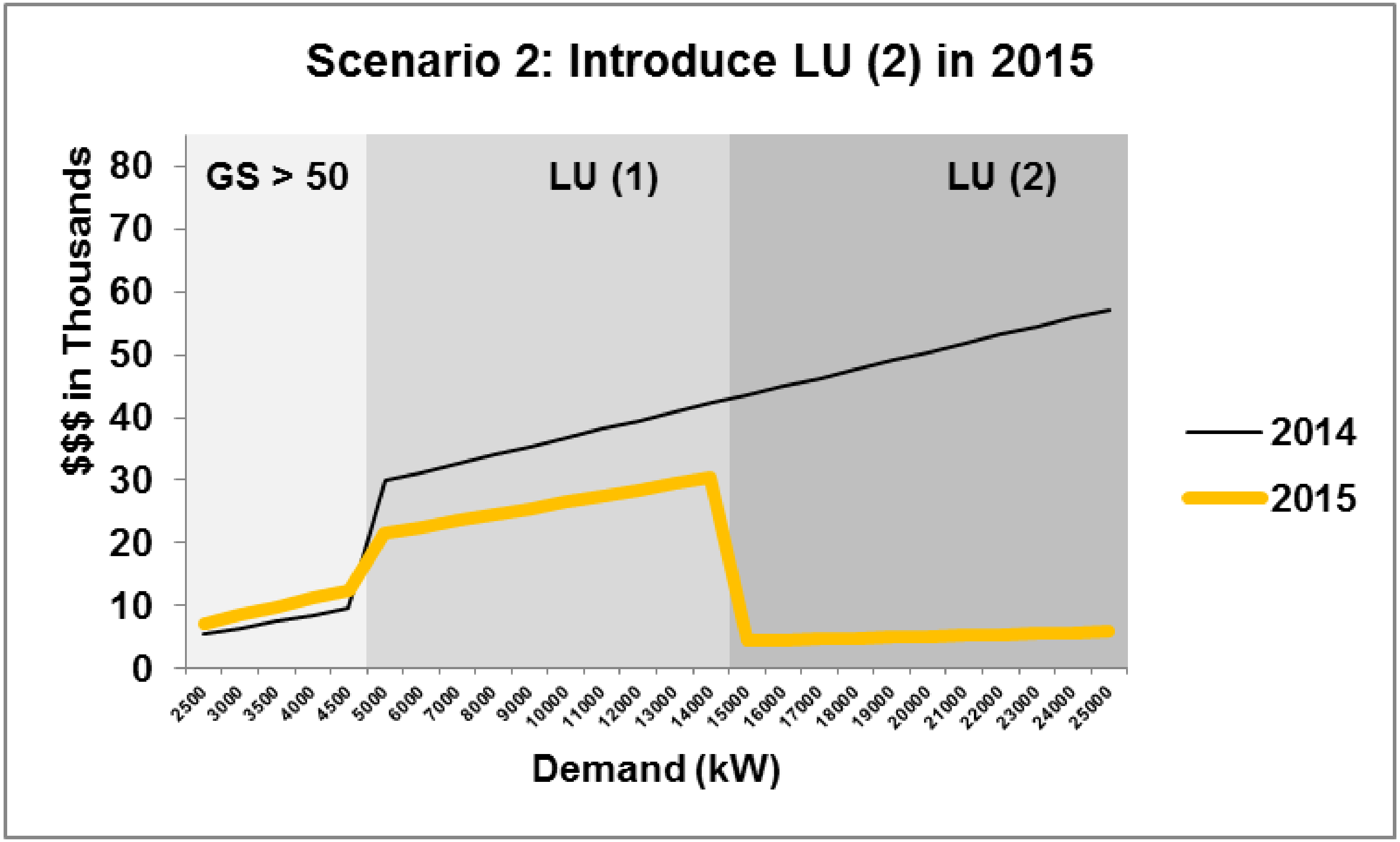
| Scenario 2 | | | Distribution Bill Impacts | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2015 vs 2014 | | 2016 vs 2015 | | 2017 vs 2018 | | 2018 vs 2017 | | 2019 vs 2018 | |
| | | | $$$ | % | $$$ | % | $$$ | % | $$$ | % | $$$ | % |
| **Residential** | kWh | 800 | $ 2.22 | 8.40% | $ 1.26 | 4.40% | $ 0.70 | 2.34% | $ 0.54 | 1.76% | $ 0.95 | 3.05% |
| **GS< 50kW** | kWh | 2000 | $ 4.21 | 8.44% | $ 2.36 | 4.36% | $ 1.25 | 2.22% | $ 1.07 | 1.86% | $ 1.83 | 3.11% |
| **GS 50 to 4,999 kW** | kW | 250 | $ 258.47 | 31.56% | $ 43.93 | 4.08% | $ 23.93 | 2.13% | $ 18.88 | 1.65% | $ 34.61 | 2.97% |
| **LU (1)** | kW | 5000 | $ (8,379.67) | (27.98)% | $ (1,096.09) | (5.08)% | $ 468.09 | 2.29% | $ 369.31 | 1.76% | $ 676.79 | 3.18% |
| **LU (1)** | kW | 10000 | $ (10,288.67) | (27.98)% | $ (1,345.59) | (5.08)% | $ 574.59 | 2.29% | $ 453.31 | 1.76% | $ 830.79 | 3.17% |
| **LU (2)** | kW | 20000 | $ (45,255.77) | (89.75)% | $ 2,841.94 | 55.01% | $ 184.02 | 2.30% | $ 144.29 | 1.76% | $ 265.47 | 3.18% |
| **Street Lighting** | KW | 2500 | $ 2,637.40 | 16.76% | $ 804.87 | 4.38% | $ 438.57 | 2.29% | $ 346.05 | 1.76% | $ 634.10 | 3.18% |

| Scenario 2 | | | Total Bill Impacts | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2015 vs 2014 | | 2016 vs 2015 | | 2017 vs 2018 | | 2018 vs 2017 | | 2019 vs 2018 | |
| | | | $$$ | % | $$$ | % | $$$ | % | $$$ | % | $$$ | % |
| **Residential** | kWh | 800 | $ 3.24 | 2.96% | $ 1.11 | 1.91% | $ 1.05 | 0.92% | $ 0.97 | 0.84% | $ 0.42 | 0.36% |
| **GS< 50kW** | kWh | 2000 | $ 6.42 | 2.55% | $ 4.56 | 1.77% | $ 1.91 | 0.72% | $ 1.93 | 0.73% | $ 1.69 | 0.63% |
| **GS 50 to 4,999 kW** | kW | 250 | $ 520.74 | 4.18% | $ 147.49 | 1.14% | $ 57.06 | 0.44% | $ 51.89 | 0.39% | $ 67.92 | 0.51% |
| **LU (1)** | kW | 5000 | $ (2,138.54) | (0.77)% | $ (2,159.05) | (0.78)% | $ 1,224.56 | 0.45% | $ 1,124.61 | 0.41% | $ 688.30 | 0.25% |
| **LU (1)** | kW | 10000 | $ 2,303.64 | 0.43% | $ (3,457.11) | (0.65)% | $ 2,081.38 | 0.39% | $ 1,959.06 | 0.37% | $ 844.91 | 0.16% |
| **LU (2)** | kW | 20000 | $ (30,952.85) | (2.98)% | $ 9,175.39 | 0.91% | $ 3,181.20 | 0.31% | $ 3,142.82 | 0.31% | $ 3,264.03 | 0.32% |
| **Street Lighting** | KW | 2500 | $ 5,316.30 | 4.32% | $ 1,846.67 | 1.44% | $ 773.24 | 0.59% | $ 678.90 | 0.52% | $ 972.09 | 0.74% |

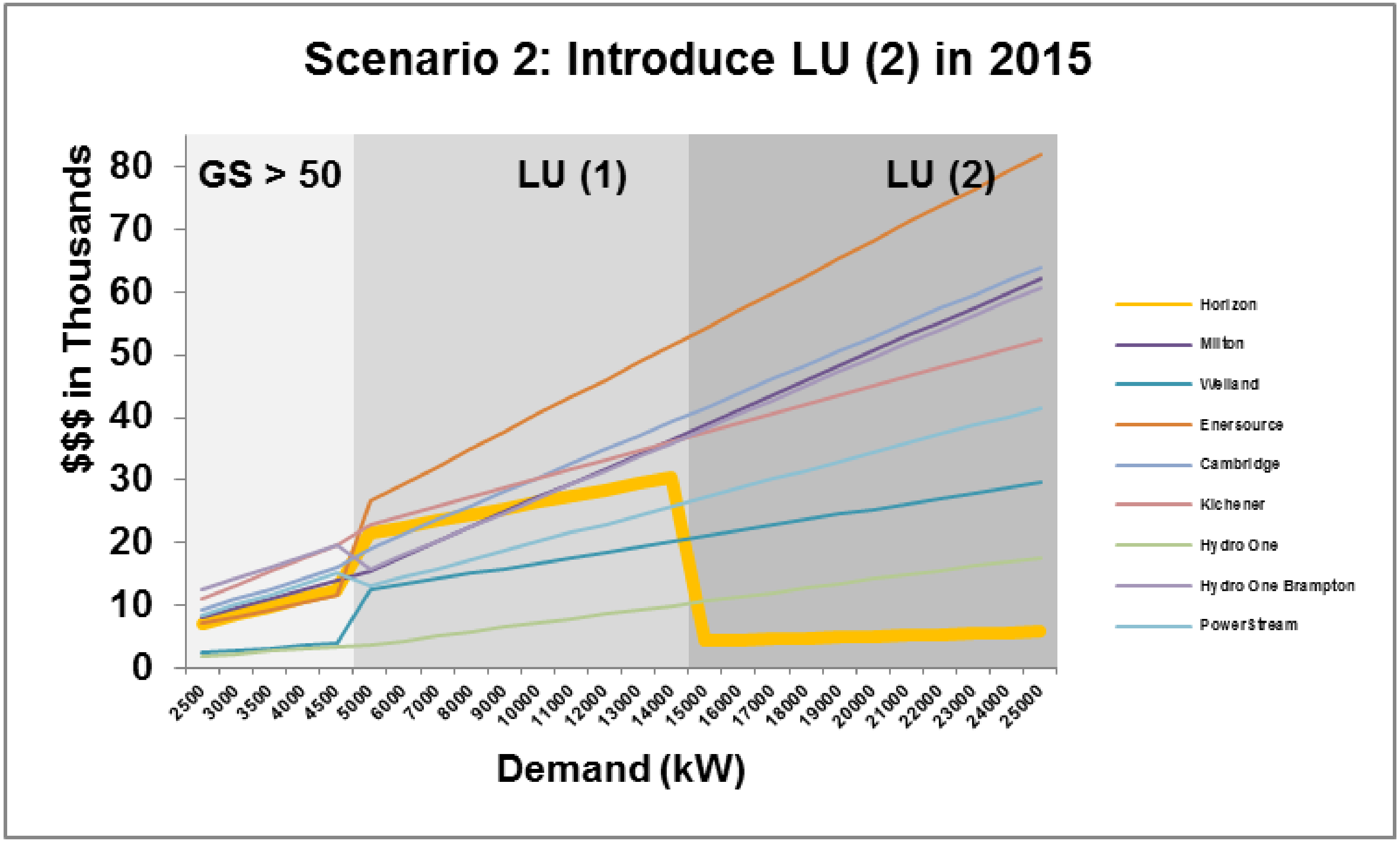


horizon UTILITIES Looking beyond...

# Scenario 2: Rate Curve for 2015

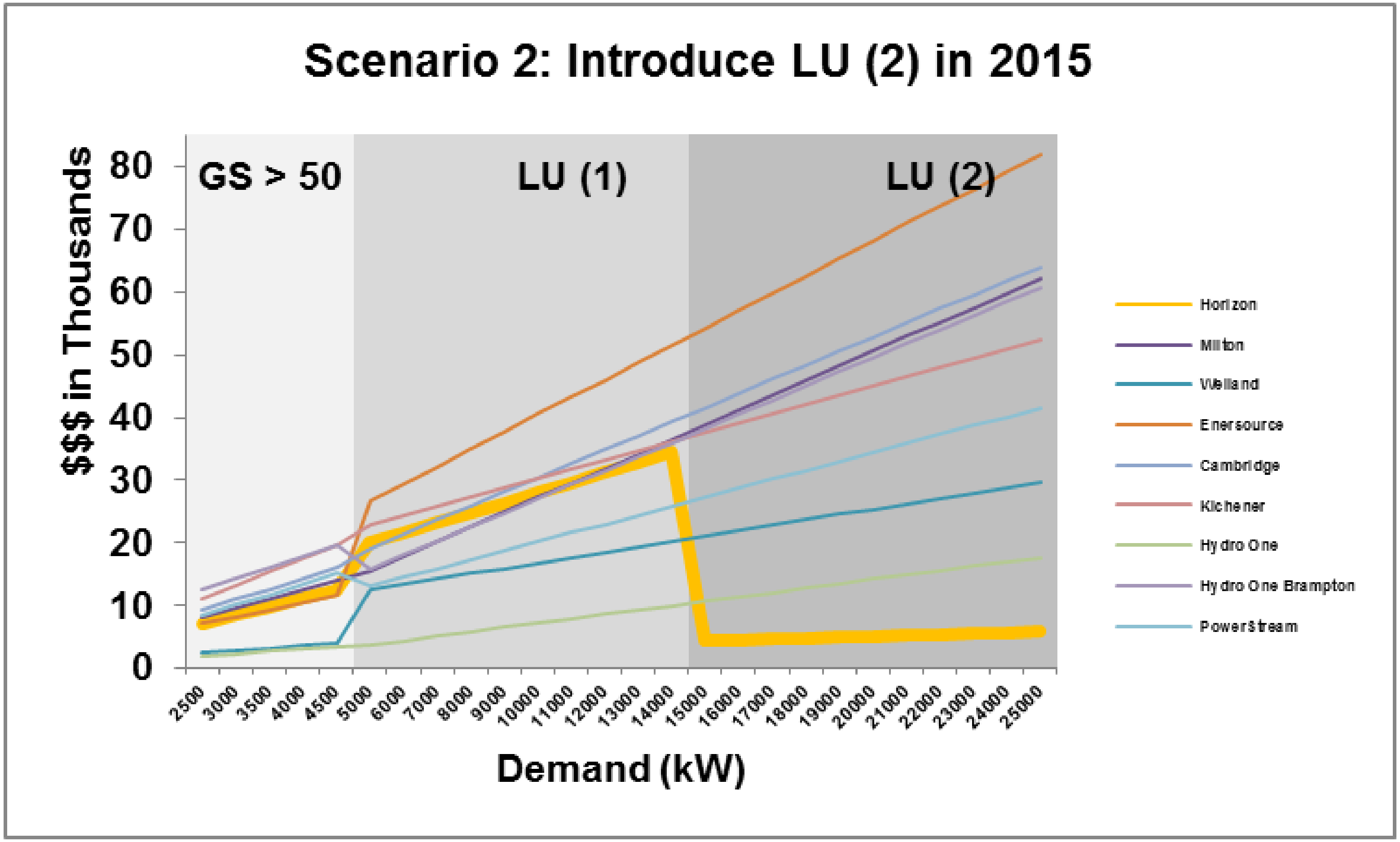


# Scenario 2: Rate Curve Competitiveness for 2015
## (with 70/30 Fixed Variable Split for LU (1) Class)



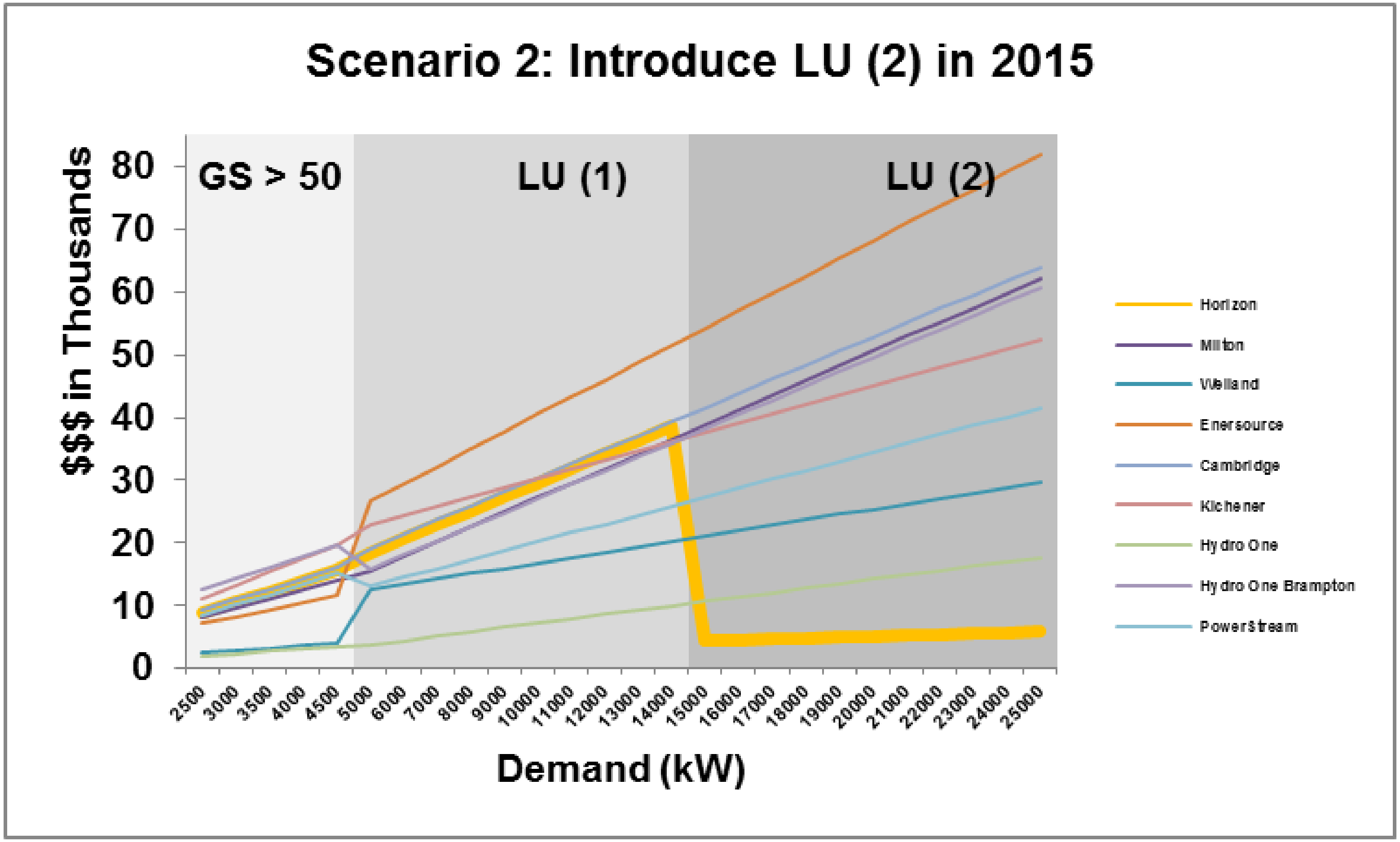

Distribution Charges at 4,999 kW: $12,533
Distribution Charges at 5,000 kW: $21,573

# Scenario 2A: Rate Curve Competitiveness for 2015
## (with 50/50 Fixed Variable Split for LU (1) Class)




Distribution Charges at 4,999 kW: $12,533
Distribution Charges at 5,000 kW: $20,032

# Scenario 2B: Rate Curve Competitiveness for 2015
## (with 30/70 Fixed Variable Split for LU (1) and GS > 50 kW Classes)




Distribution Charges at 4,999 kW: $15,729
Distribution Charges at 5,000 kW: $18,443

# Scenario 3: Introduce LU (2) Class over 5 years

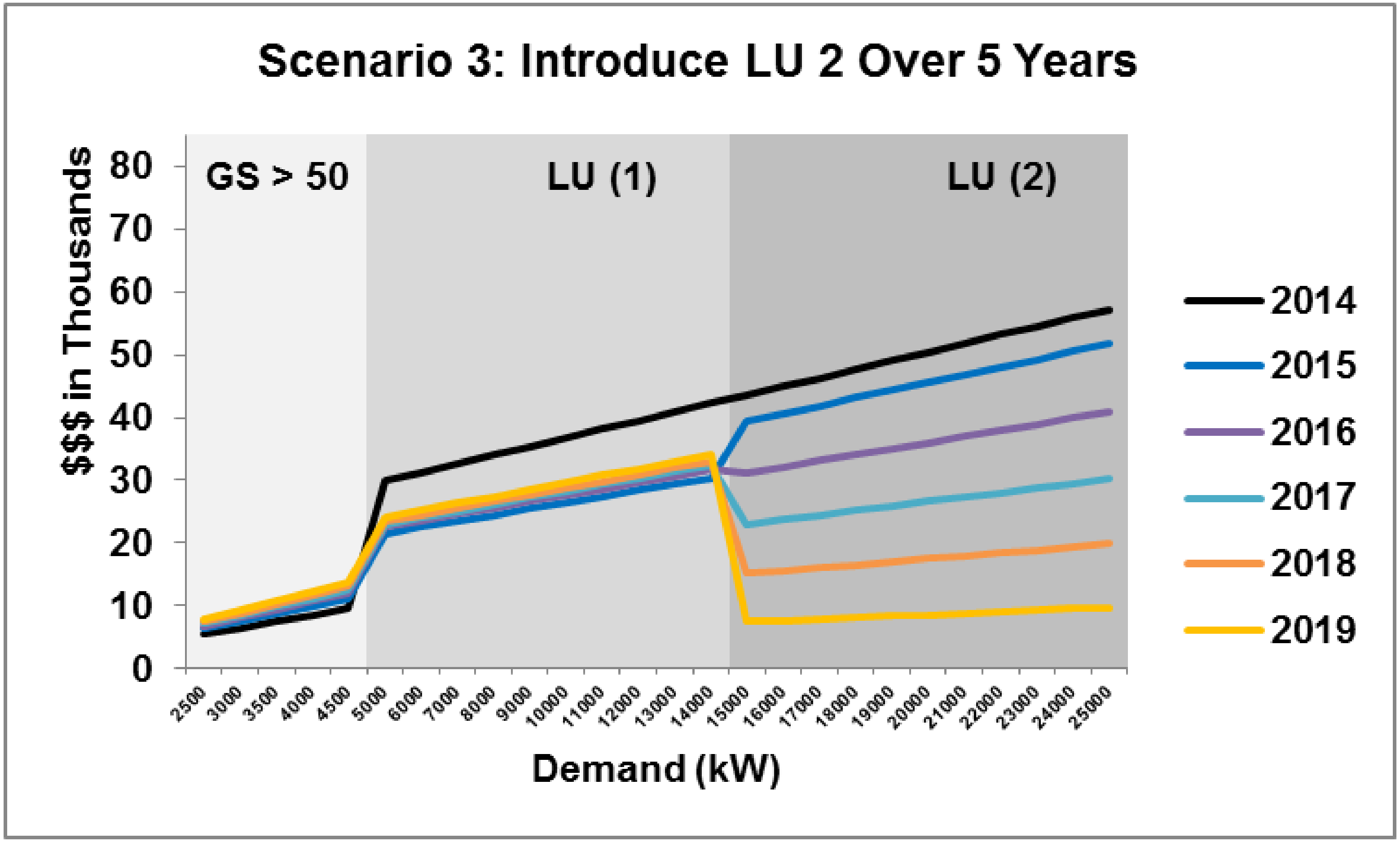
| Scenario 3 | | | Distribution Bill Impacts | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2015 vs 2014 | | 2016 vs 2015 | | 2017 vs 2018 | | 2018 vs 2017 | | 2019 vs 2018 | |
| | | | $$$ | % | $$$ | % | $$$ | % | $$$ | % | $$$ | % |
| **Residential** | kWh | 800 | $ 2.22 | 8.40% | $ 1.26 | 4.40% | $ 0.70 | 2.34% | $ 0.54 | 1.76% | $ 0.95 | 3.05% |
| **GS< 50kW** | kWh | 2000 | $ 4.21 | 8.44% | $ 2.35 | 4.35% | $ 1.24 | 2.20% | $ 1.06 | 1.84% | $ 2.16 | 3.68% |
| **GS 50 to 4,999 kW** | kW | 250 | $ 136.94 | 16.72% | $ 75.71 | 7.92% | $ 50.47 | 4.89% | $ 45.02 | 4.16% | $ 58.24 | 5.17% |
| **LU (1)** | kW | 5000 | $ (8,379.67) | (27.98)% | $ 940.11 | 4.36% | $ 508.48 | 2.26% | $ 399.42 | 1.73% | $ 737.94 | 3.15% |
| **LU (1)** | kW | 10000 | $ (10,288.67) | (27.98)% | $ 1,154.11 | 4.36% | $ 624.48 | 2.26% | $ 490.42 | 1.74% | $ 905.94 | 3.15% |
| **LU (2)** | kW | 20000 | $ (4,836.15) | (9.59)% | $ (9,550.90) | (20.95)% | $ (9,403.77) | (26.10)% | $ (9,123.13) | (34.26)% | $ (8,883.07) | (50.74)% |
| **Street Lighting** | KW | 2500 | $ 1,345.20 | 8.55% | $ 744.36 | 4.36% | $ 1,131.17 | 6.35% | $ 982.65 | 5.18% | $ 1,272.44 | 6.38% |

| Scenario 3 | | | Total Bill Impacts | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | 2015 vs 2014 | | 2016 vs 2015 | | 2017 vs 2018 | | 2018 vs 2017 | | 2019 vs 2018 | |
| | | | $$$ | % | $$$ | % | $$$ | % | $$$ | % | $$$ | % |
| **Residential** | kWh | 800 | $ 3.24 | 2.96% | $ 1.11 | 1.91% | $ 1.05 | 0.92% | $ 0.97 | 0.84% | $ 0.42 | 0.36% |
| **GS< 50kW** | kWh | 2000 | $ 6.42 | 2.55% | $ 4.55 | 1.76% | $ 1.90 | 0.72% | $ 1.92 | 0.73% | $ 2.03 | 0.76% |
| **GS 50 to 4,999 kW** | kW | 250 | $ 397.15 | 3.19% | $ 179.80 | 1.40% | $ 84.05 | 0.65% | $ 78.48 | 0.60% | $ 91.95 | 0.70% |
| **LU (1)** | kW | 5000 | $ (2,138.54) | (0.77)% | $ (88.23) | (0.03)% | $ 1,265.64 | 0.46% | $ 1,155.23 | 0.42% | $ 750.48 | 0.27% |
| **LU (1)** | kW | 10000 | $ 2,303.64 | 0.43% | $ (914.91) | (0.17)% | $ 2,132.12 | 0.40% | $ 1,996.80 | 0.37% | $ 921.34 | 0.17% |
| **LU (2)** | kW | 20000 | $ 10,153.91 | 0.98% | $ (3,428.13) | (0.33)% | $ (6,569.59) | (0.63)% | $ (6,282.14) | (0.60)% | $ (6,040.03) | (0.58)% |
| **Street Lighting** | KW | 2500 | $ 4,002.14 | 3.25% | $ 1,785.13 | 1.40% | $ 1,477.62 | 1.15% | $ 1,326.32 | 1.02% | $ 1,621.29 | 1.23% |

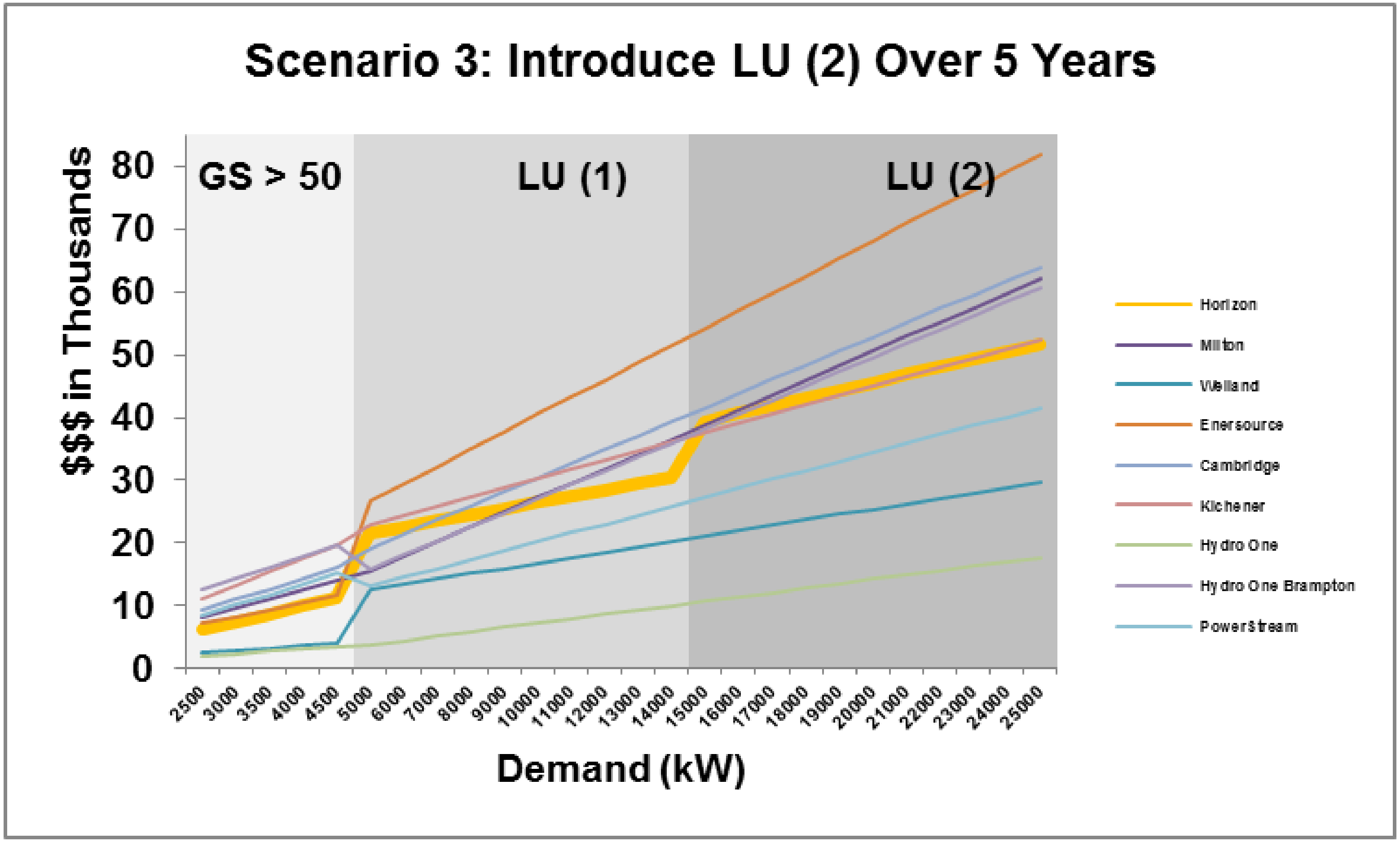


horizon UTILITIES Looking beyond...

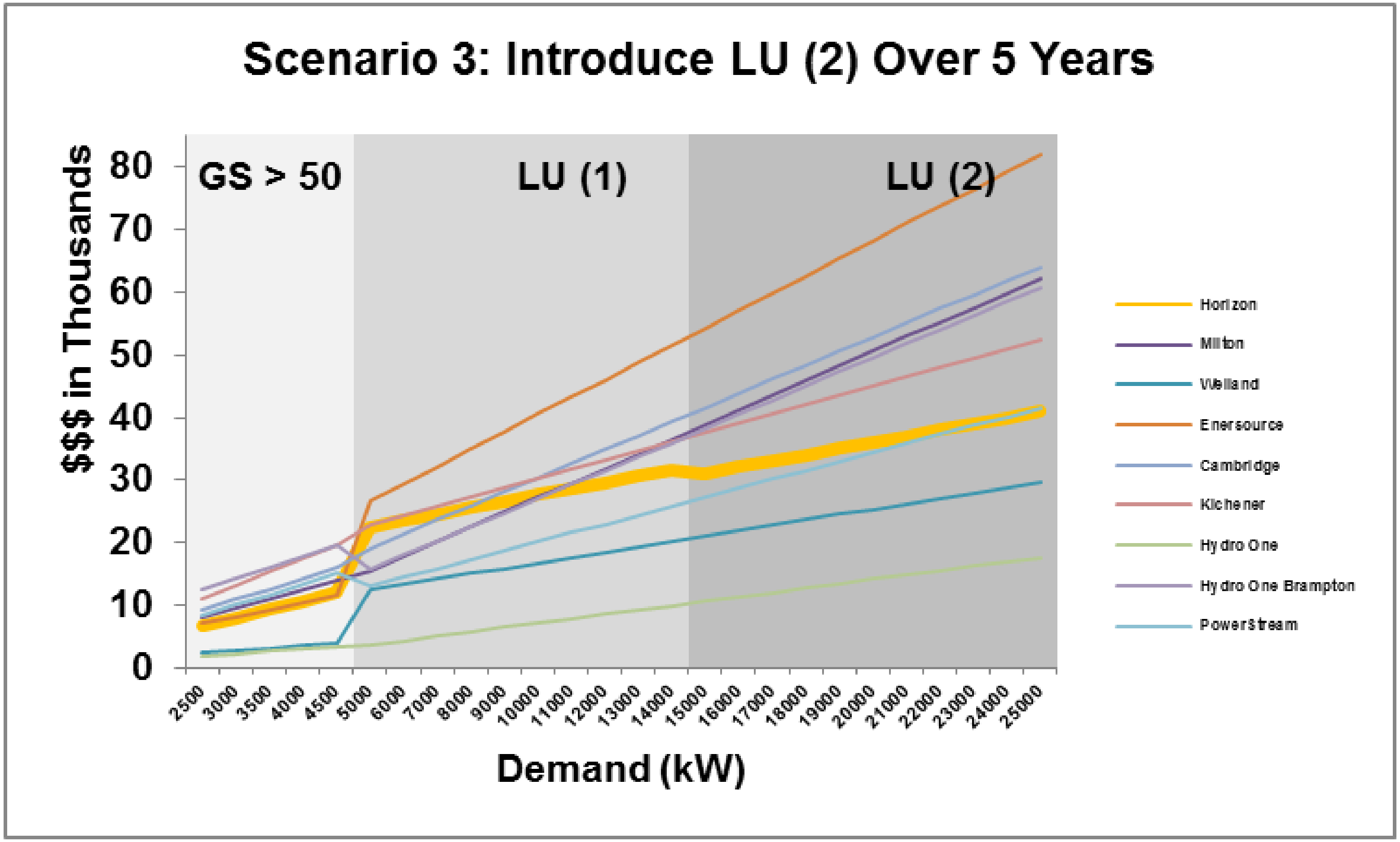
# Scenario 3: Rate Curve for 2015 - 2019



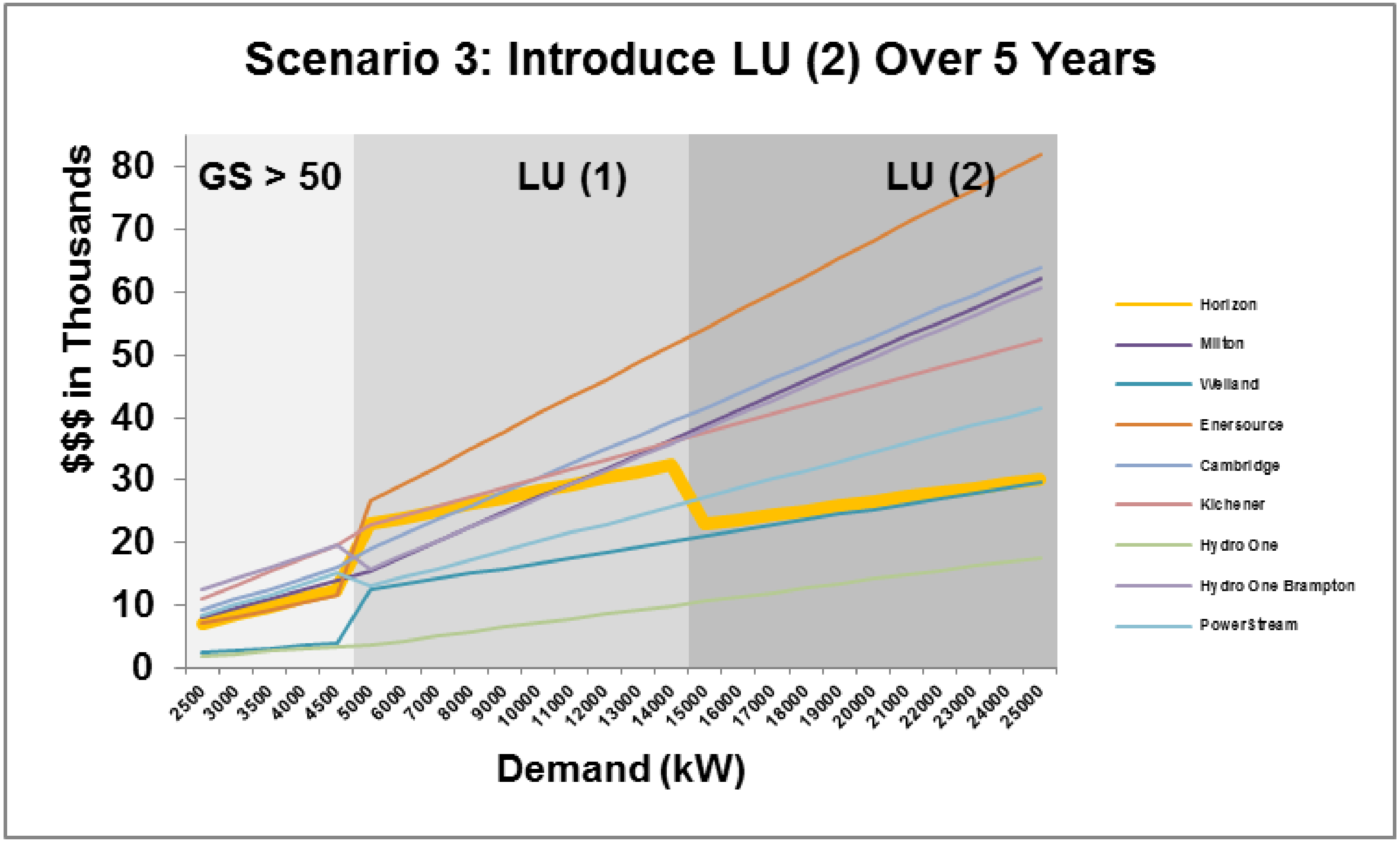
# Scenario 3: Rate Curve Competitiveness for 2015



# Scenario 3: Rate Curve Competitiveness for 2016



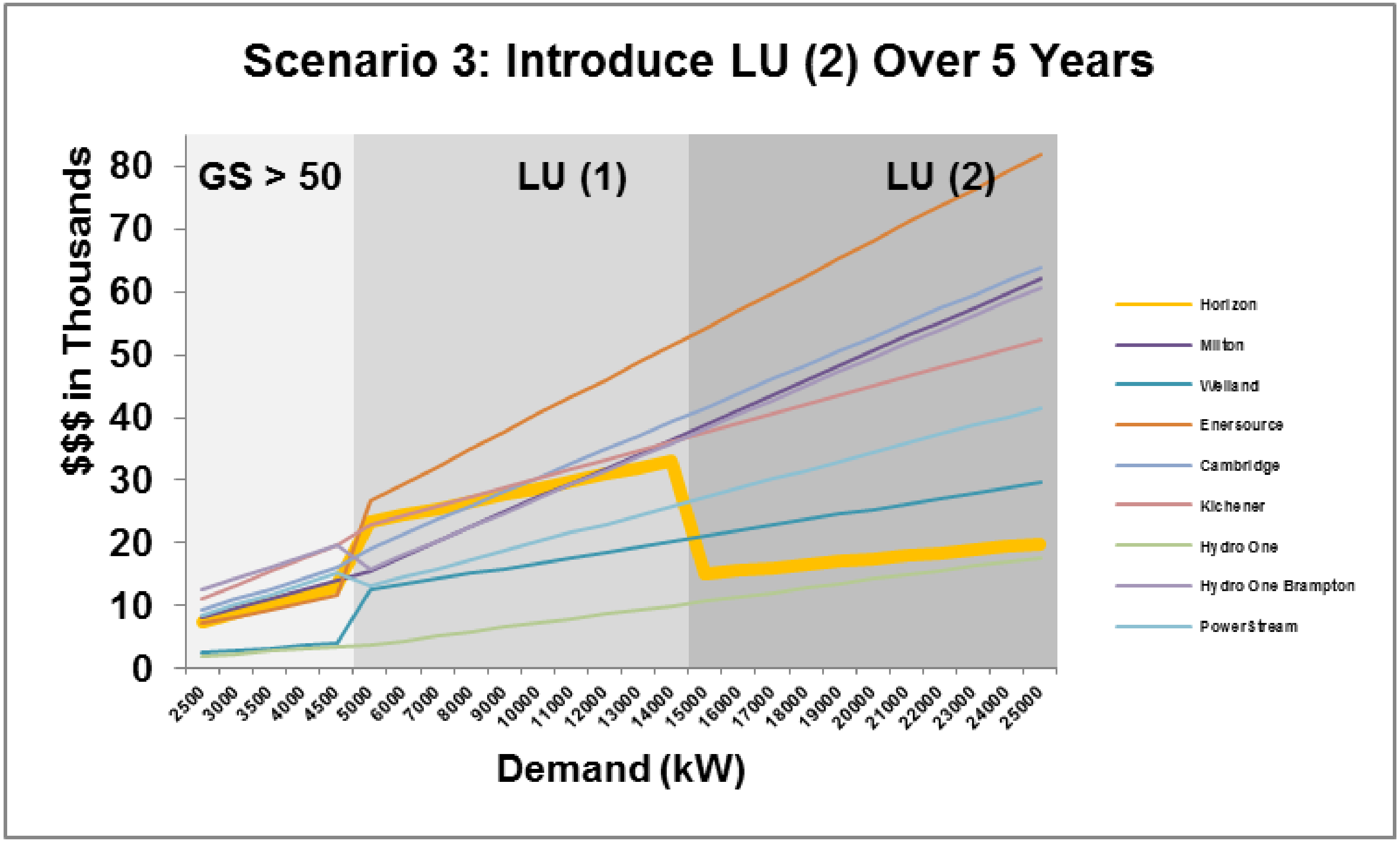
# Scenario 3: Rate Curve Competitiveness for 2017



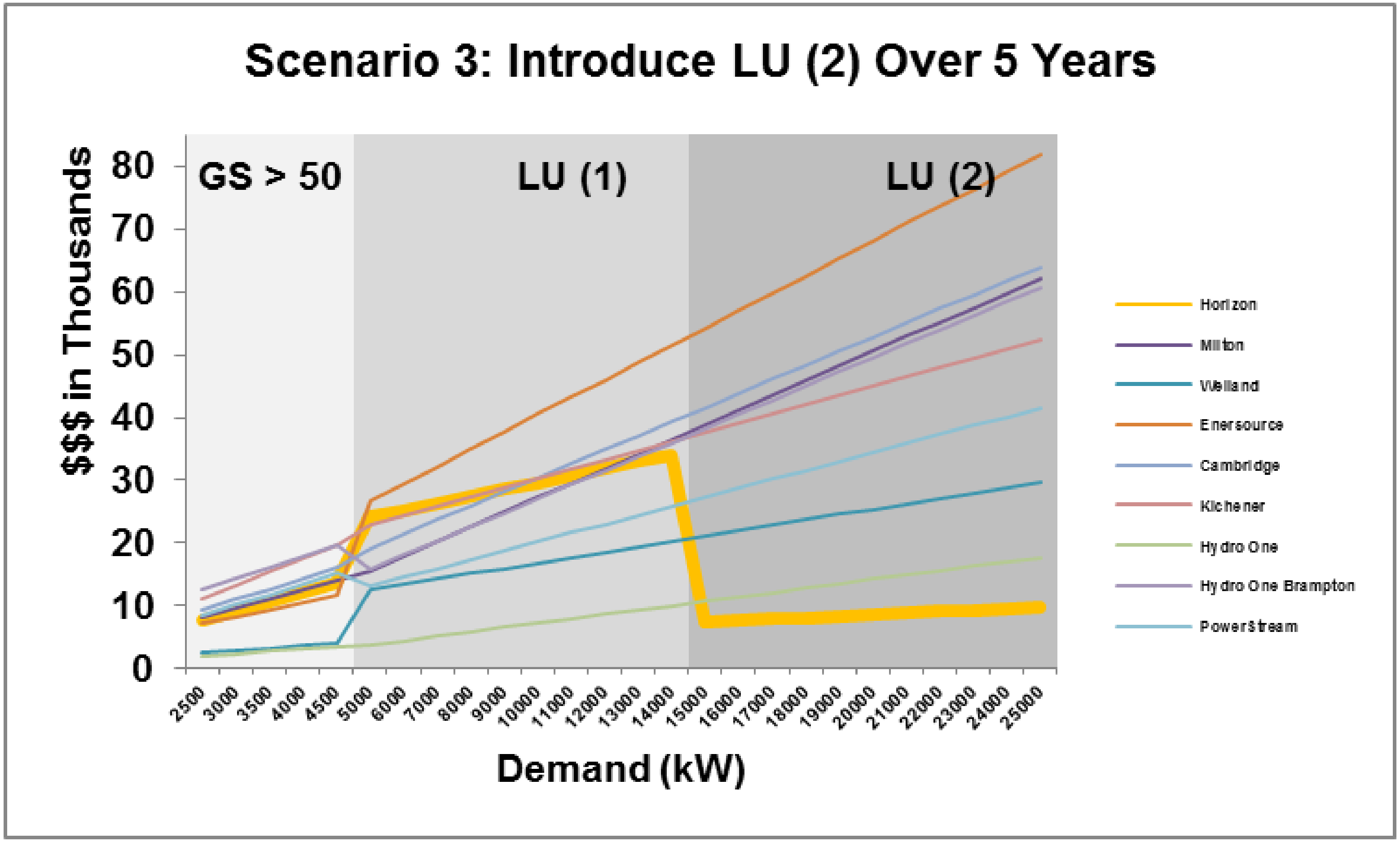



horizon UTILITIES Looking beyond...

# Scenario 3: Rate Curve Competitiveness for 2018



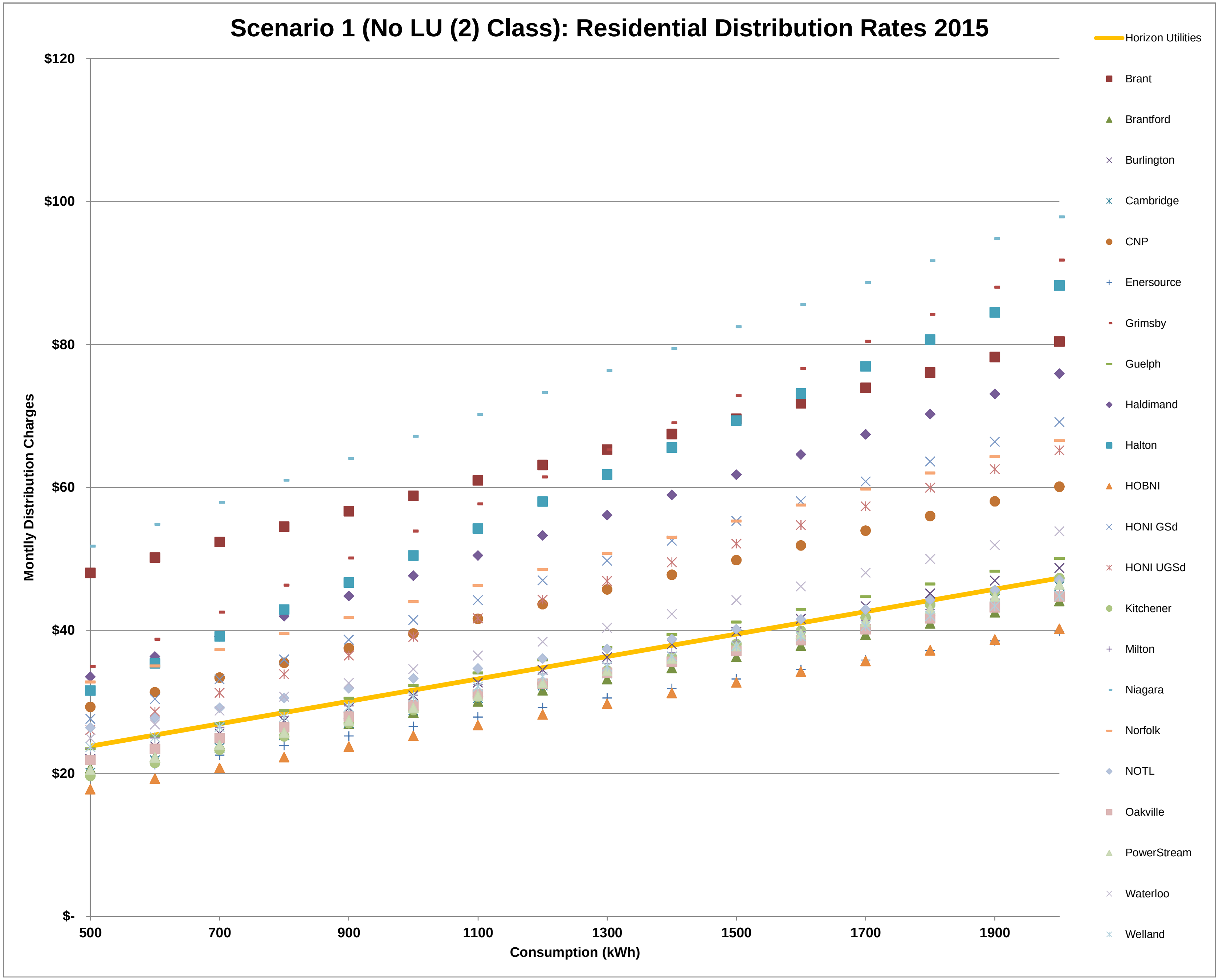
# Scenario 3: Rate Curve Competitiveness for 2019



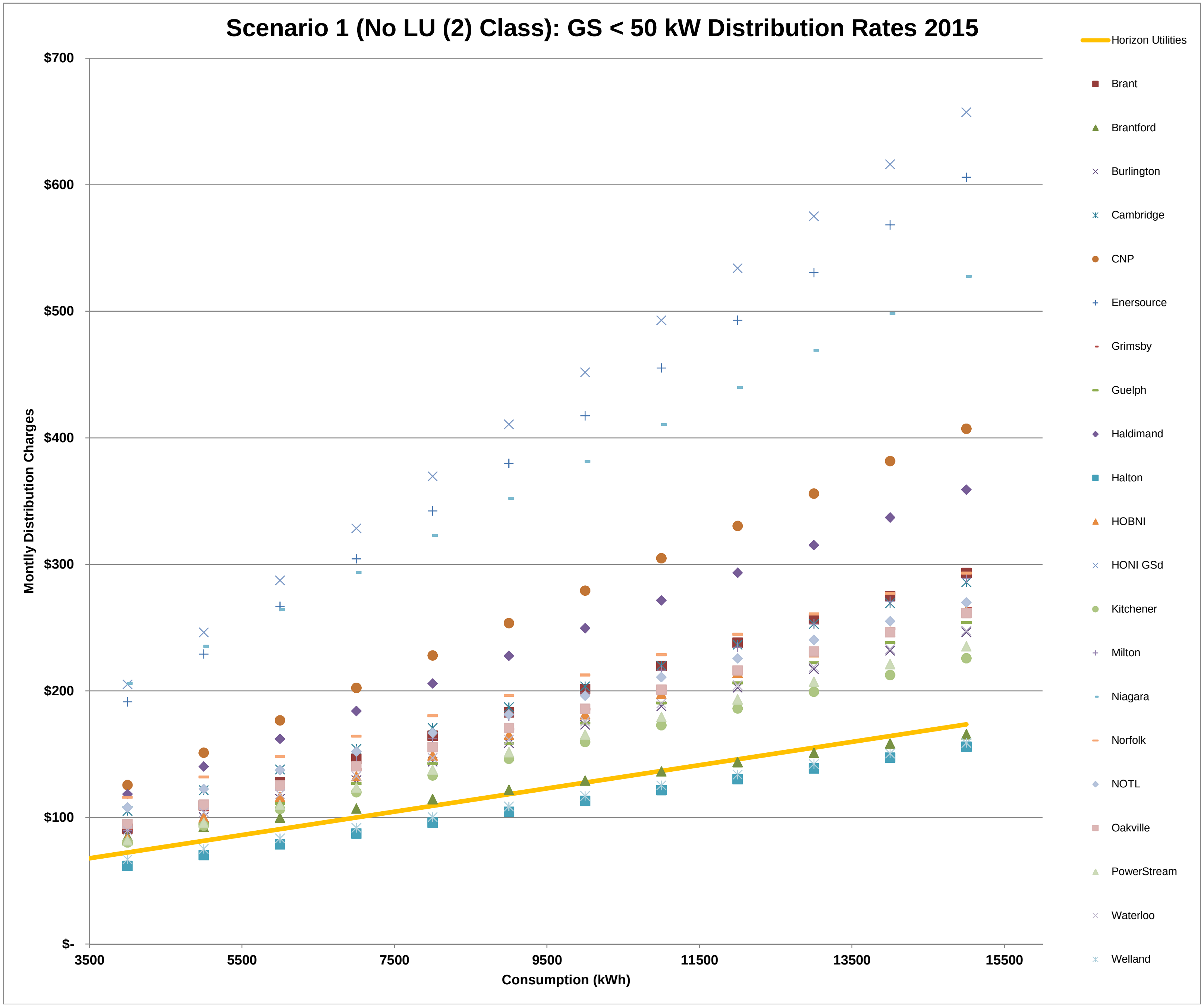
This page intentionally left blank

# C of H 2_Attch 6_Bill Impacts - EMT Review Target Area Comparison

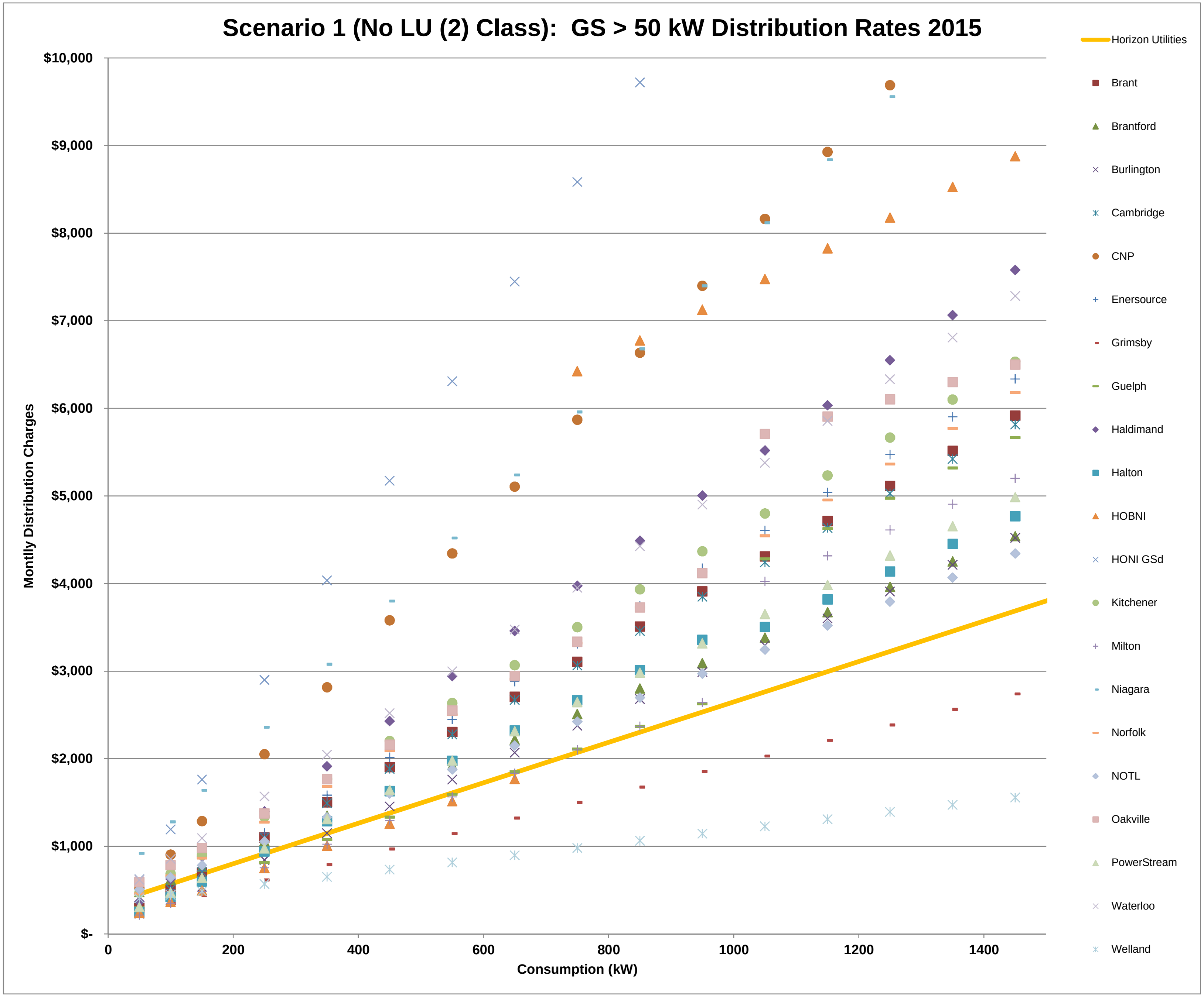
This page intentionally left blank



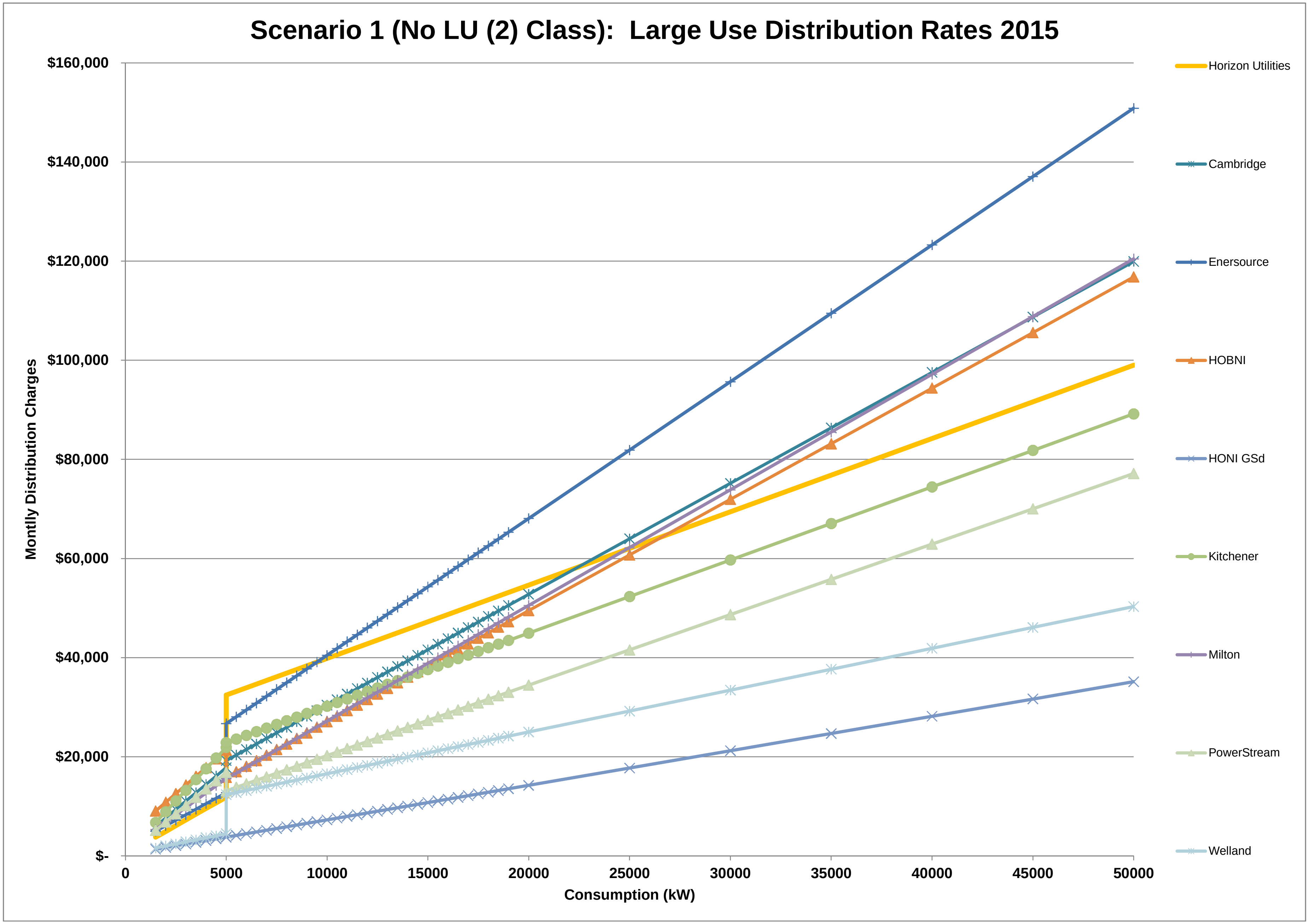
Scenario 1 (No LU (2) Class): Residential Distribution Rates 2015
Montlly Distribution Charges
$120
$100
$80
$60
$40
$20
$-
500
700
900
1100
1300
1500
1700
1900
Consumption (kWh)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
HONI UGSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland



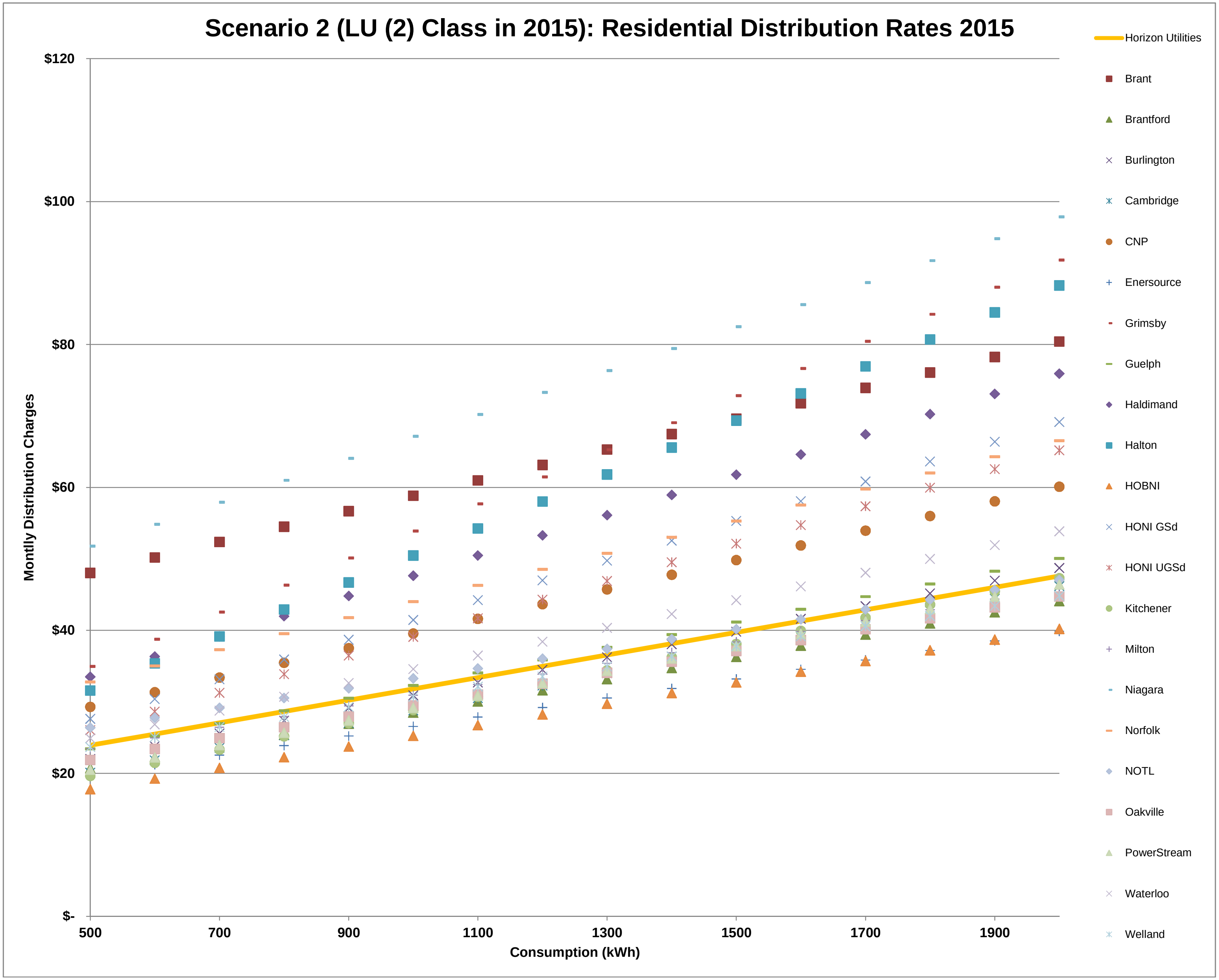
Scenario 1 (No LU (2) Class): GS < 50 kW Distribution Rates 2015
Montlly Distribution Charges
Consumption (kWh)
$700
$600
$500
$400
$300
$200
$100
$-
3500
5500
7500
9500
11500
13500
15500
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland



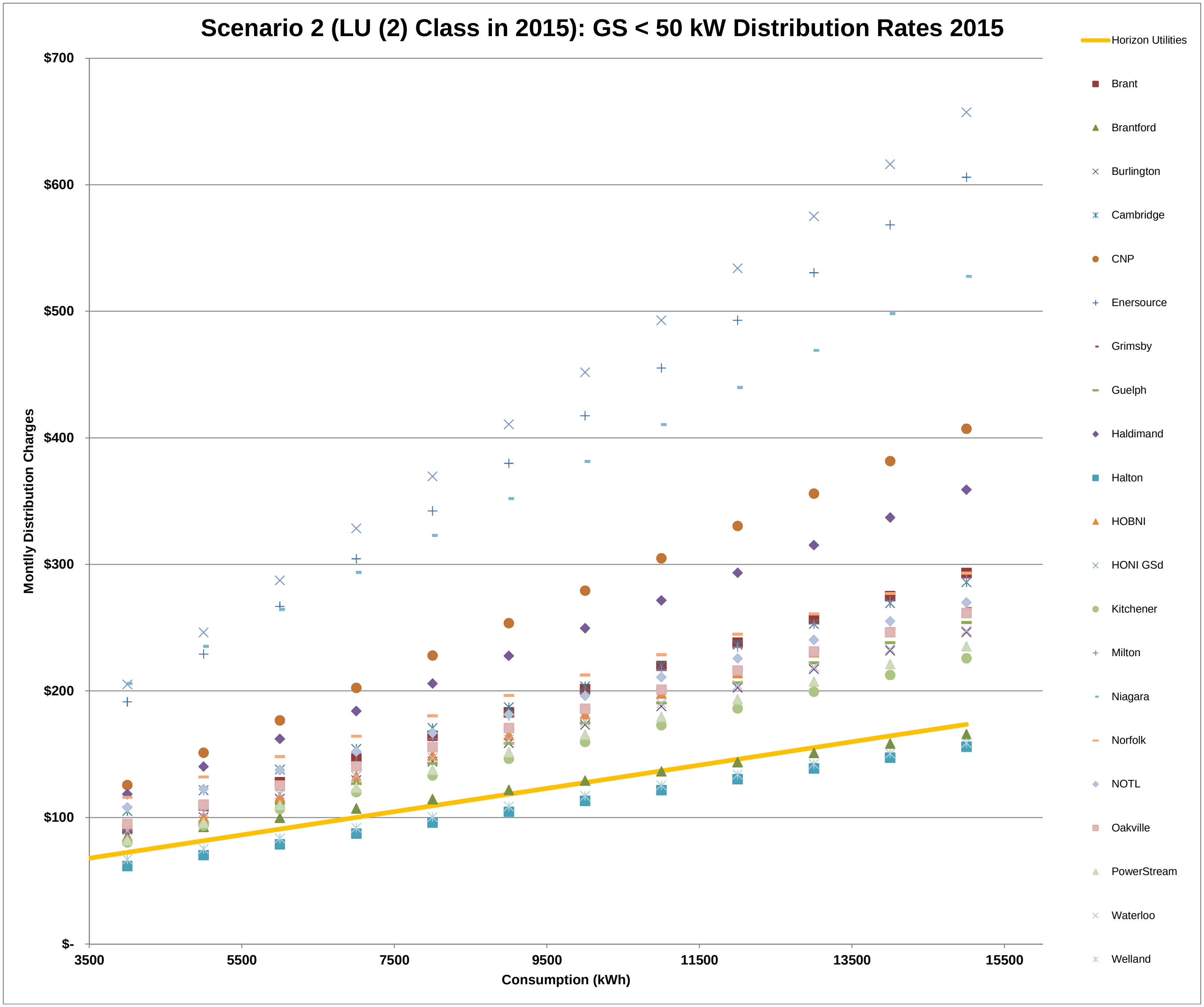
Scenario 1 (No LU (2) Class): GS > 50 kW Distribution Rates 2015
Montly Distribution Charges
$10,000
$9,000
$8,000
$7,000
$6,000
$5,000
$4,000
$3,000
$2,000
$1,000
$-
0
200
400
600
800
1000
1200
1400
Consumption (kW)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland

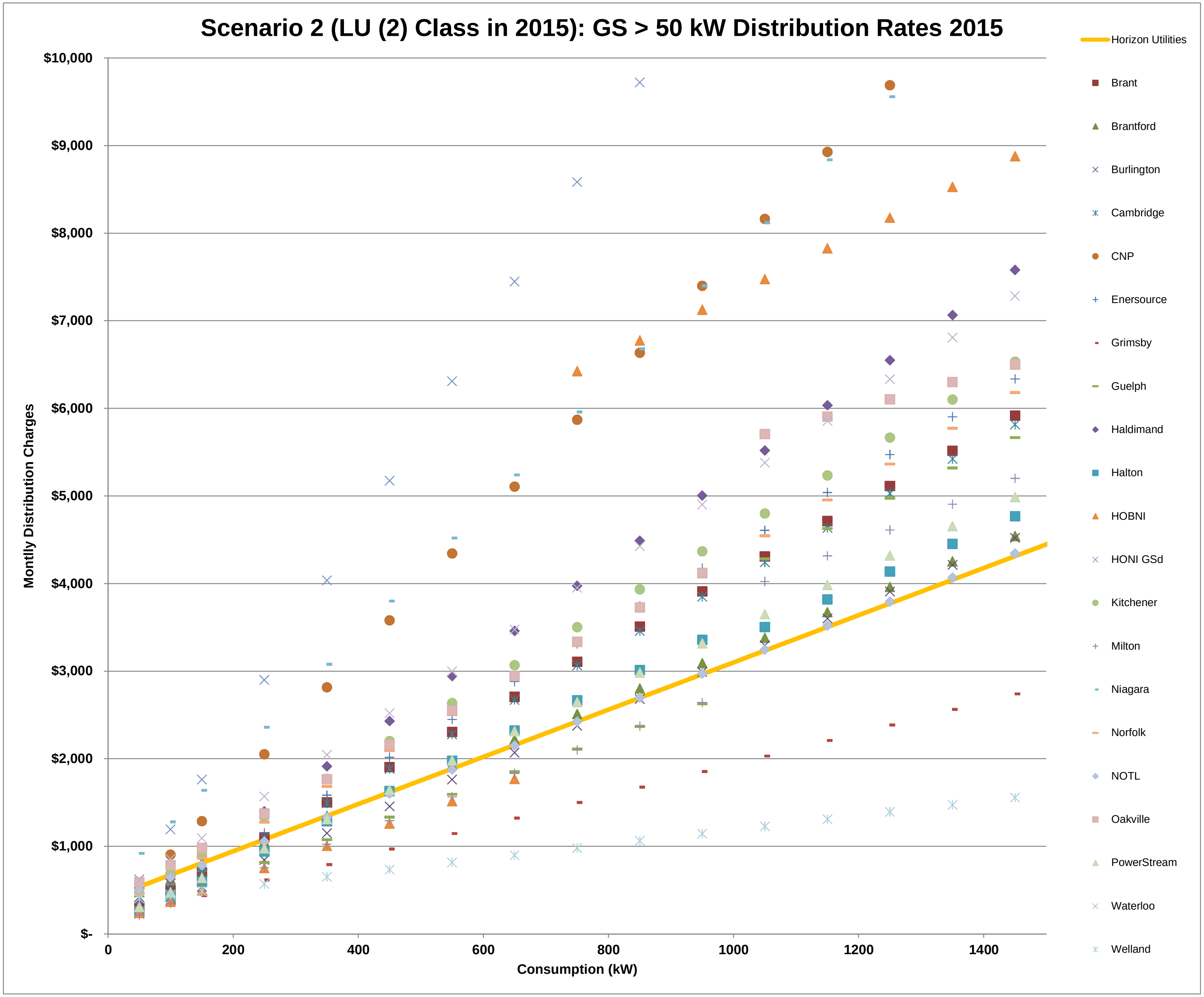


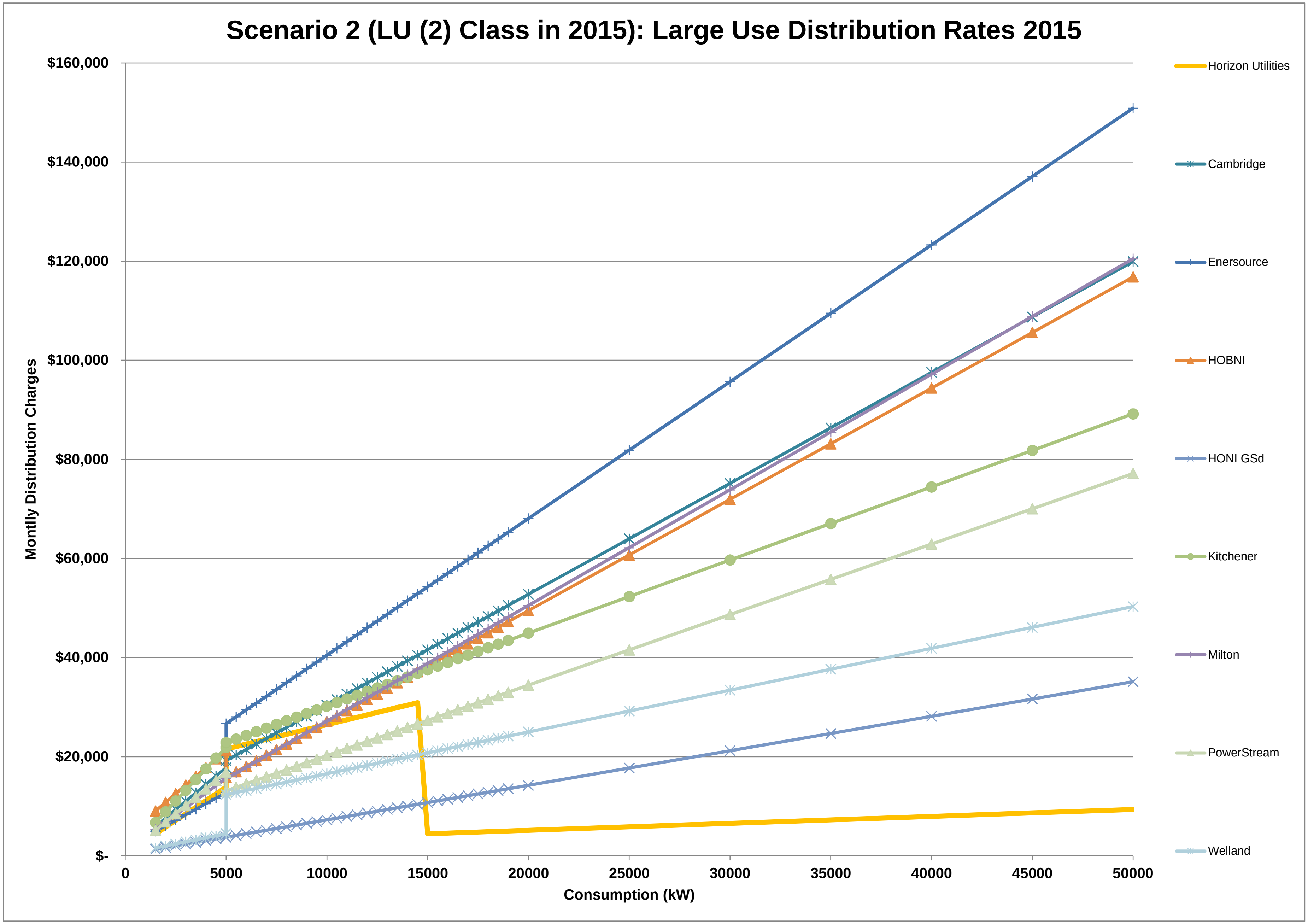
Scenario 1 (No LU (2) Class): Large Use Distribution Rates 2015
Montlly Distribution Charges
$160,000
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$-
0
5000
10000
15000
20000
25000
30000
35000
40000
45000
50000
Consumption (kW)
Horizon Utilities
Cambridge
Enersource
HOBNI
HONI GSd
Kitchener
Milton
PowerStream
Welland



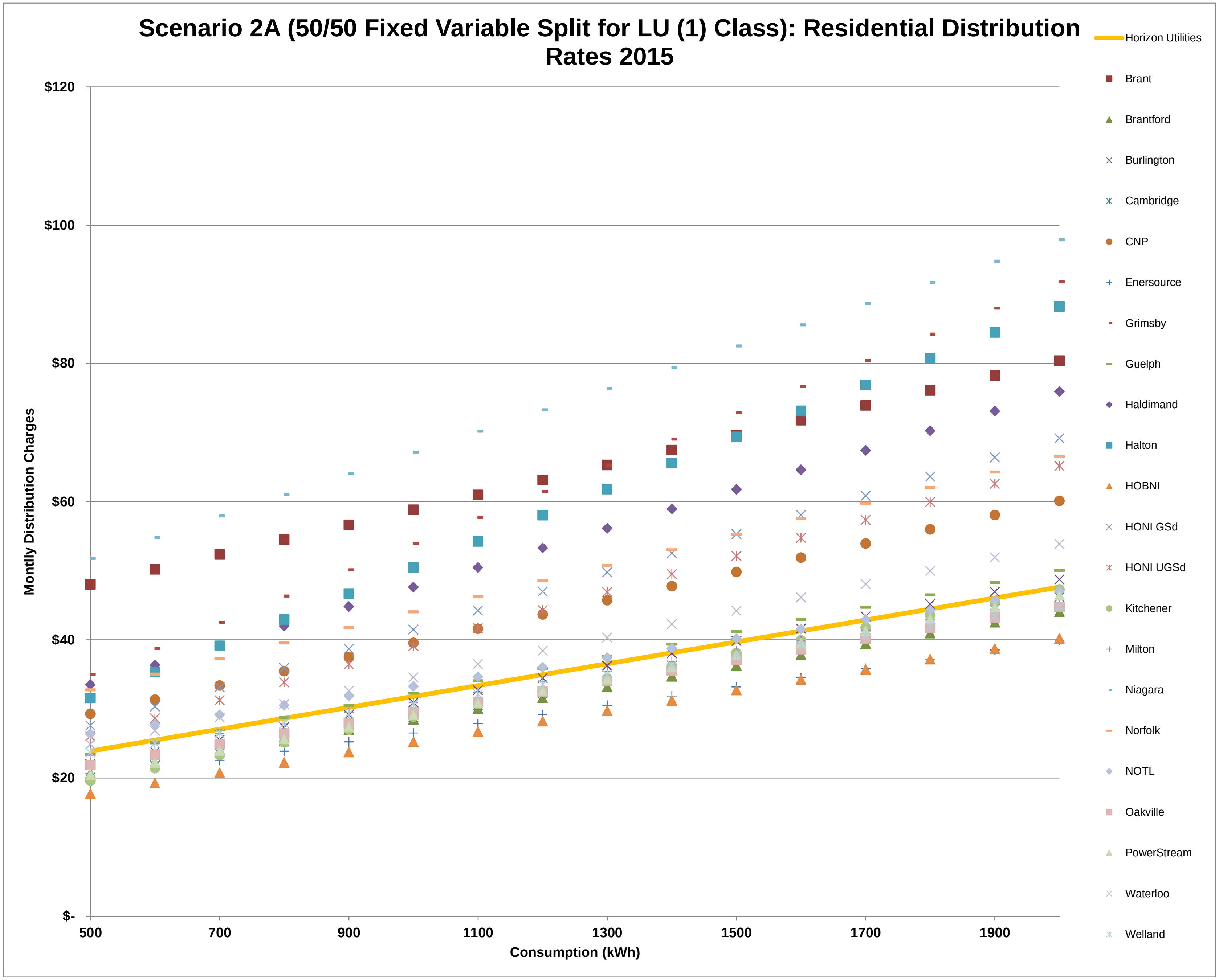
Scenario 2 (LU (2) Class in 2015): Residential Distribution Rates 2015
Montlly Distribution Charges
$120
$100
$80
$60
$40
$20
$-
500
700
900
1100
1300
1500
1700
1900
Consumption (kWh)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
HONI UGSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland


Scenario 2 (LU (2) Class in 2015): GS < 50 kW Distribution Rates 2015
$700
$600
$500
$400
$300
$200
$100
$-
Montly Distribution Charges
3500
5500
7500
9500
11500
13500
15500
Consumption (kWh)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland

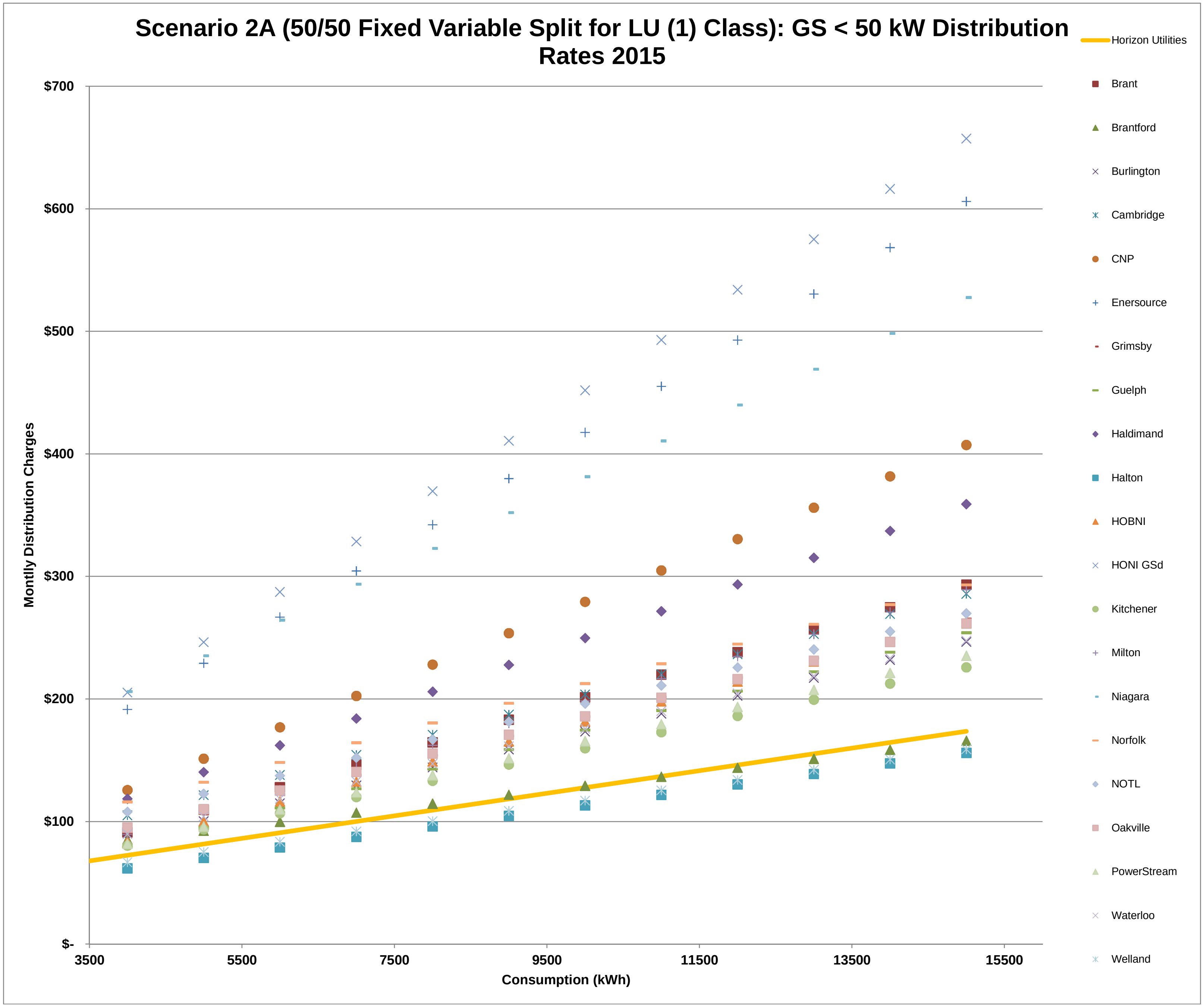

Scenario 2 (LU (2) Class in 2015): GS > 50 kW Distribution Rates 2015
Montlly Distribution Charges
$10,000
$9,000
$8,000
$7,000
$6,000
$5,000
$4,000
$3,000
$2,000
$1,000
$-
0
200
400
600
800
1000
1200
1400
Consumption (kW)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland



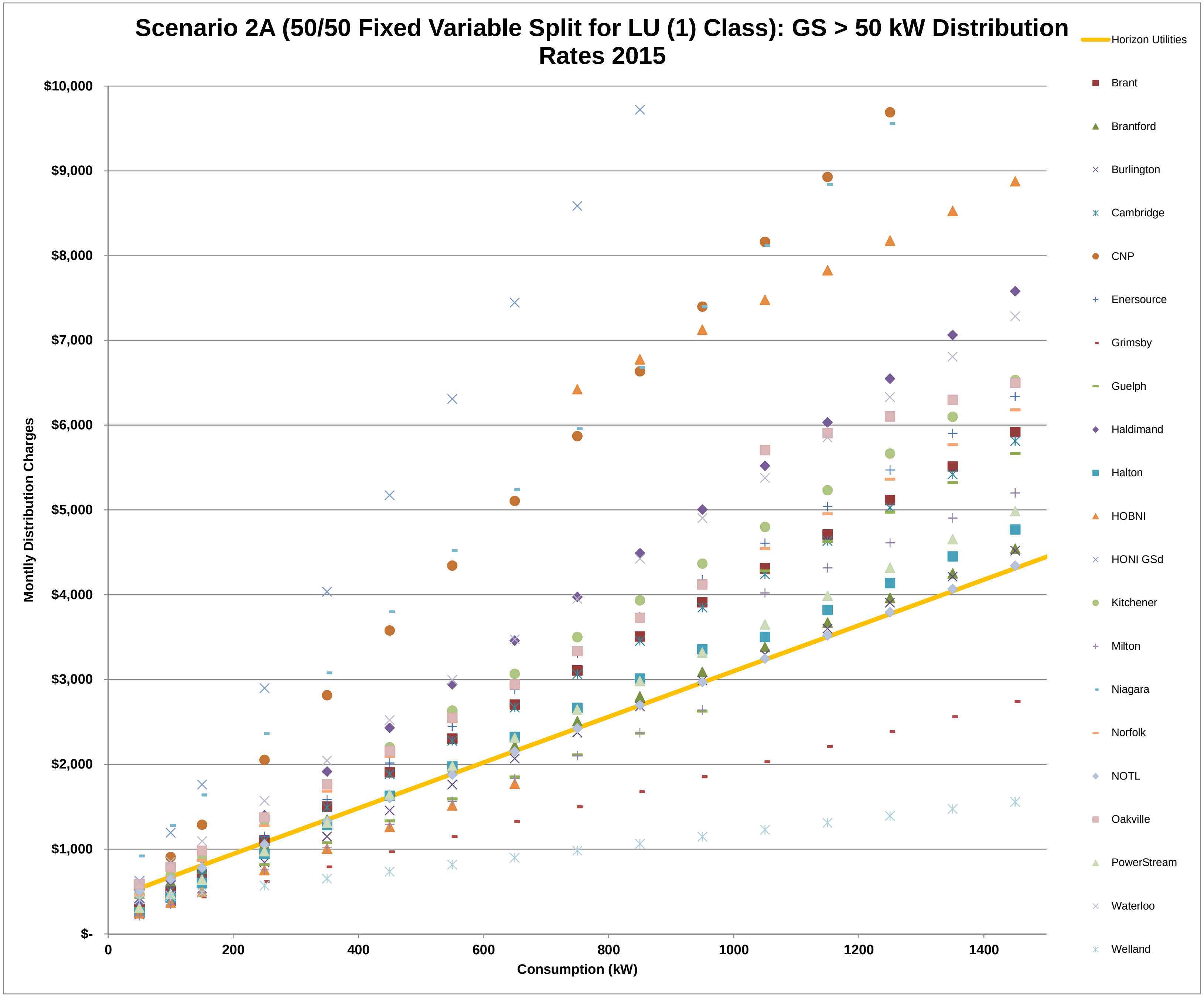
Scenario 2 (LU (2) Class in 2015): Large Use Distribution Rates 2015
Montlly Distribution Charges
Consumption (kW)
$160,000
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$-
0
5000
10000
15000
20000
25000
30000
35000
40000
45000
50000
Horizon Utilities
Cambridge
Enersource
HOBNI
HONI GSd
Kitchener
Milton
PowerStream
Welland

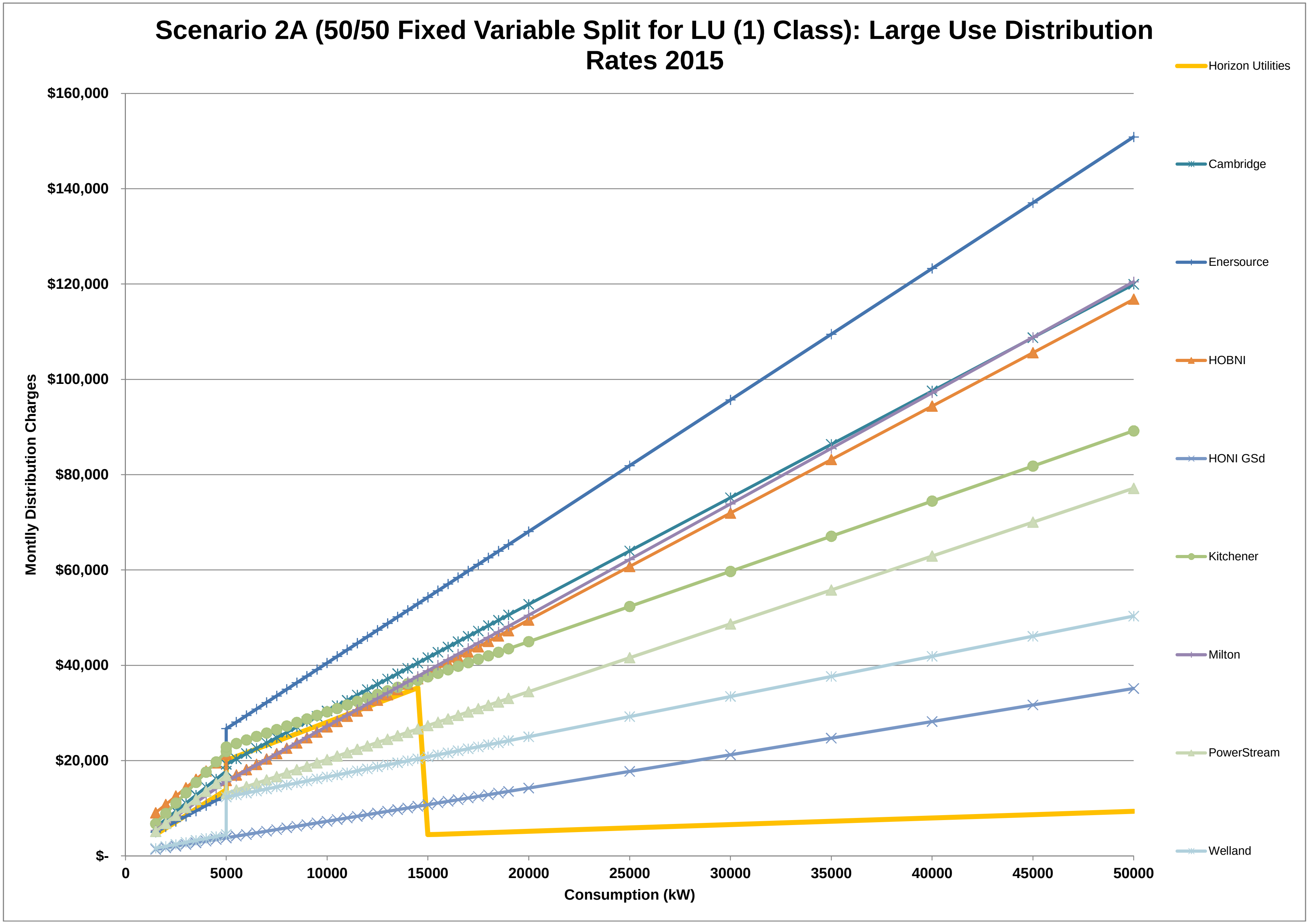


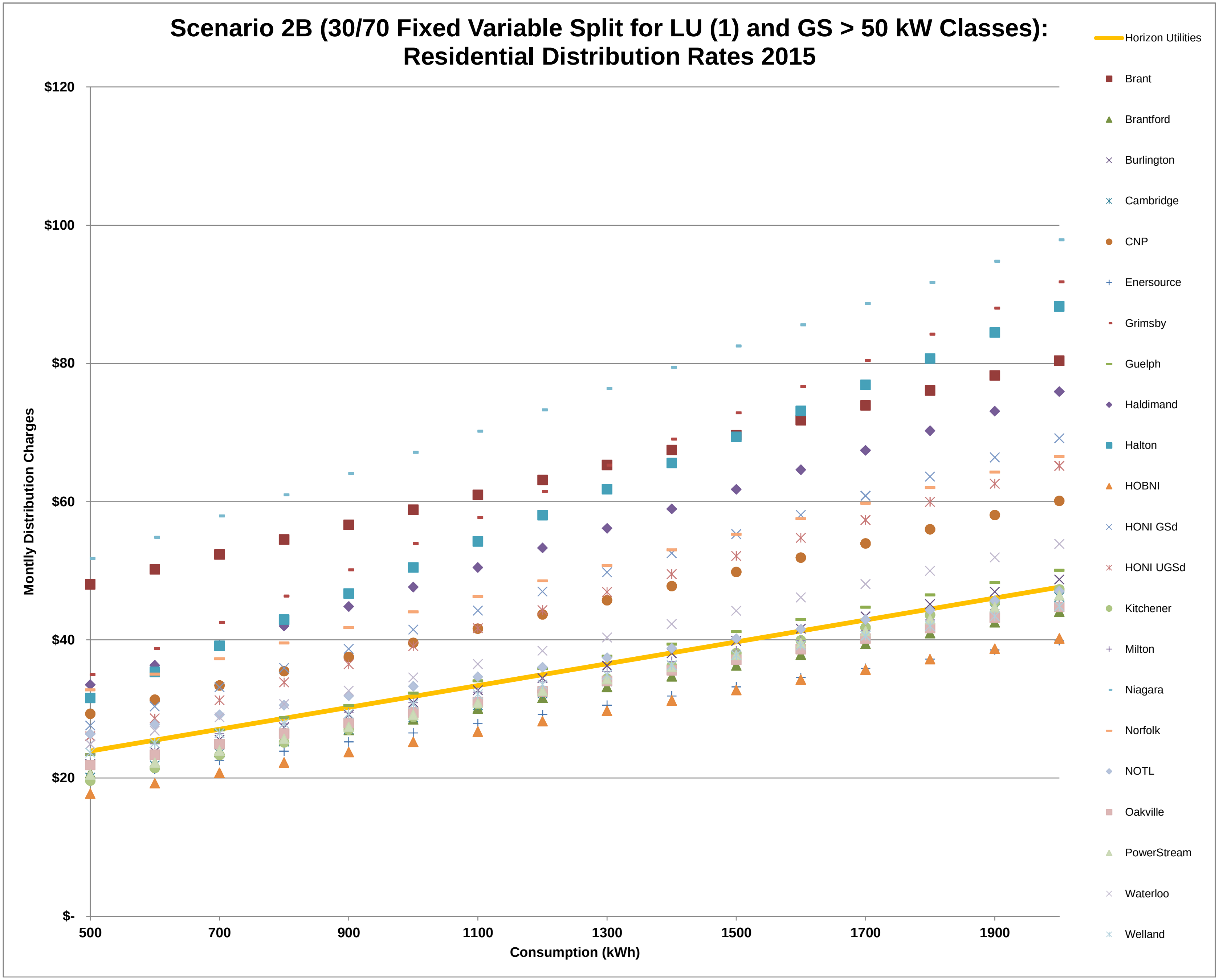
Scenario 2A (50/50 Fixed Variable Split for LU (1) Class): Residential Distribution Rates 2015
Montly Distribution Charges
$120
$100
$80
$60
$40
$20
$-
500
700
900
1100
1300
1500
1700
1900
Consumption (kWh)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
HONI UGSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland



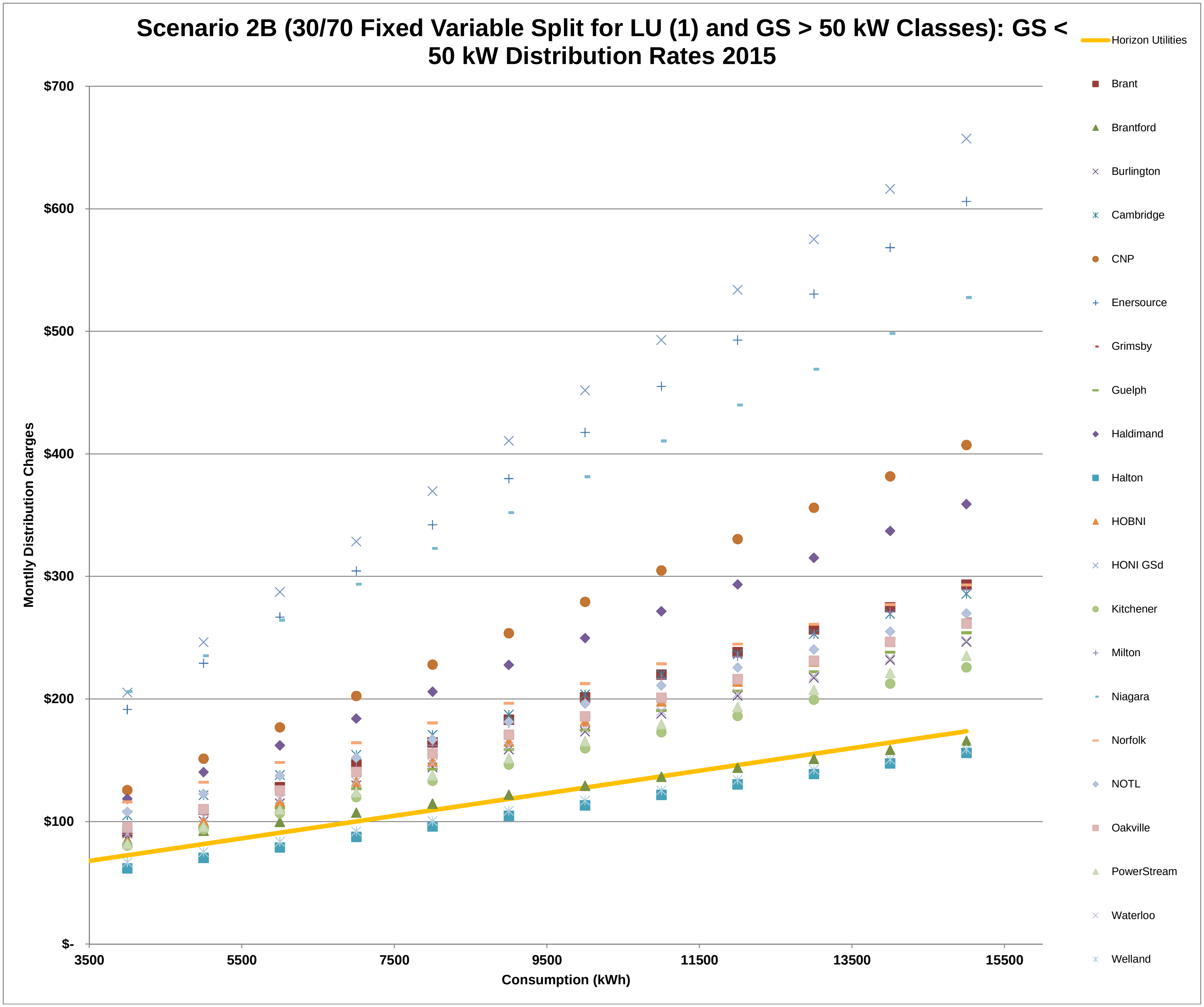
Scenario 2A (50/50 Fixed Variable Split for LU (1) Class): GS < 50 kW Distribution Rates 2015
Montly Distribution Charges
$700
$600
$500
$400
$300
$200
$100
$-
3500
5500
7500
9500
11500
13500
15500
Consumption (kWh)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland

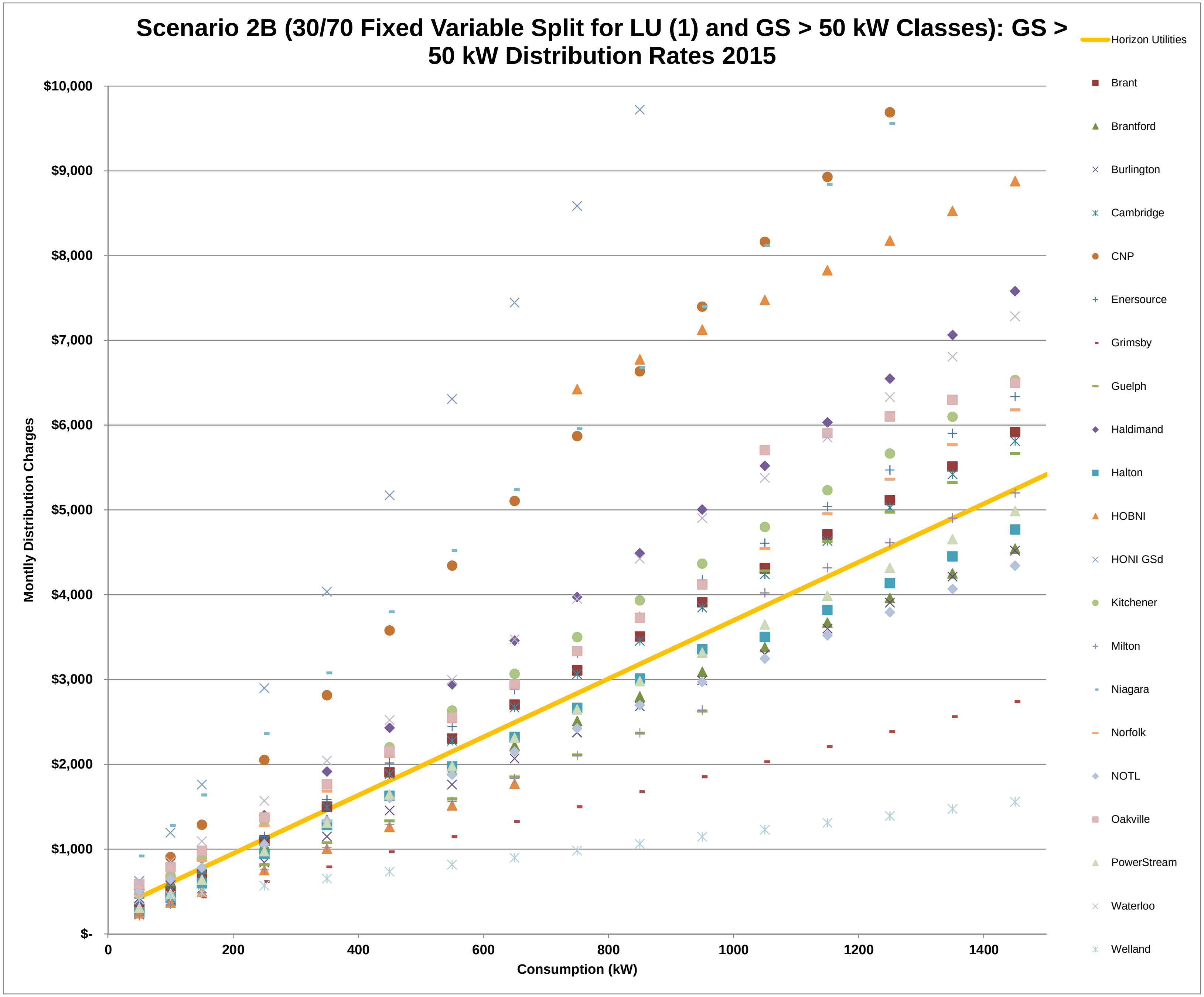

Scenario 2A (50/50 Fixed Variable Split for LU (1) Class): GS > 50 kW Distribution Rates 2015
Montlly Distribution Charges
$10,000
$9,000
$8,000
$7,000
$6,000
$5,000
$4,000
$3,000
$2,000
$1,000
$-
0
200
400
600
800
1000
1200
1400
Consumption (kW)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland

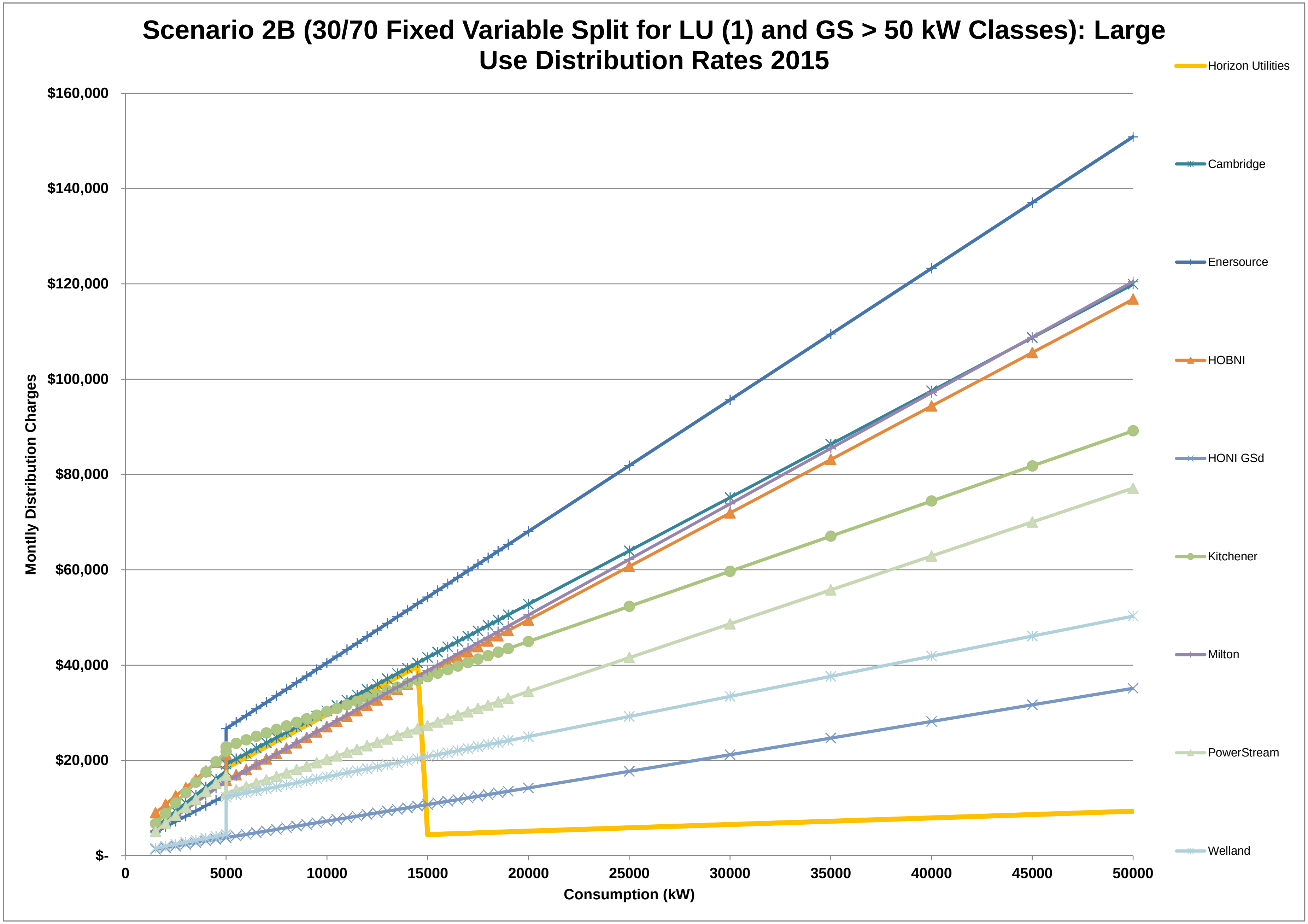

Scenario 2A (50/50 Fixed Variable Split for LU (1) Class): Large Use Distribution Rates 2015
Montlly Distribution Charges
$160,000
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$-
0
5000
10000
15000
20000
25000
30000
35000
40000
45000
50000
Consumption (kW)
Horizon Utilities
Cambridge
Enersource
HOBNI
HONI GSd
Kitchener
Milton
PowerStream
Welland



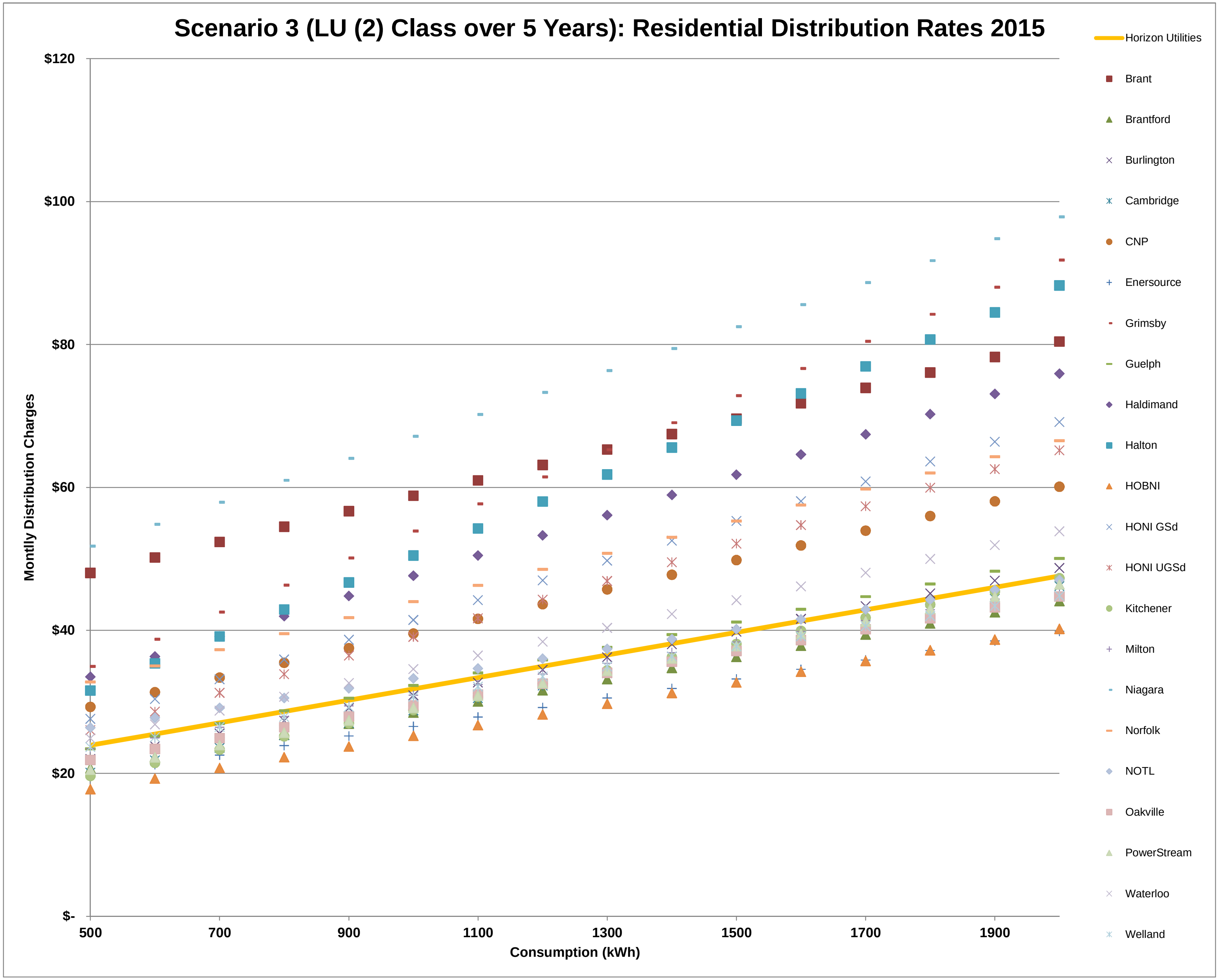
Scenario 2B (30/70 Fixed Variable Split for LU (1) and GS > 50 kW Classes):
Residential Distribution Rates 2015
Montly Distribution Charges
$120
$100
$80
$60
$40
$20
$-
500
700
900
1100
1300
1500
1700
1900
Consumption (kWh)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
HONI UGSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland

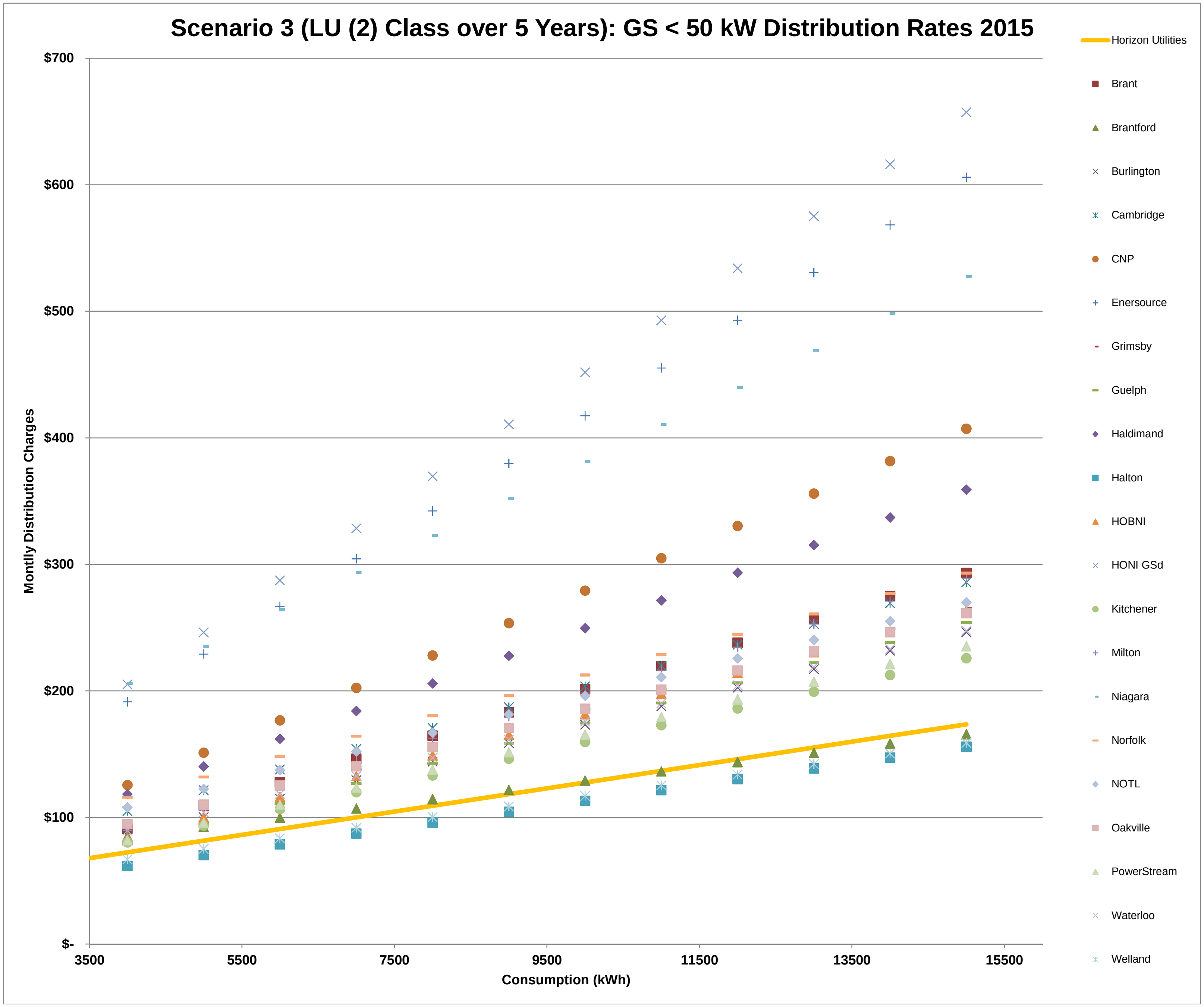

Scenario 2B (30/70 Fixed Variable Split for LU (1) and GS > 50 kW Classes): GS < 50 kW Distribution Rates 2015
$700
$600
$500
$400
$300
$200
$100
$-
Montly Distribution Charges
3500
5500
7500
9500
11500
13500
15500
Consumption (kWh)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland

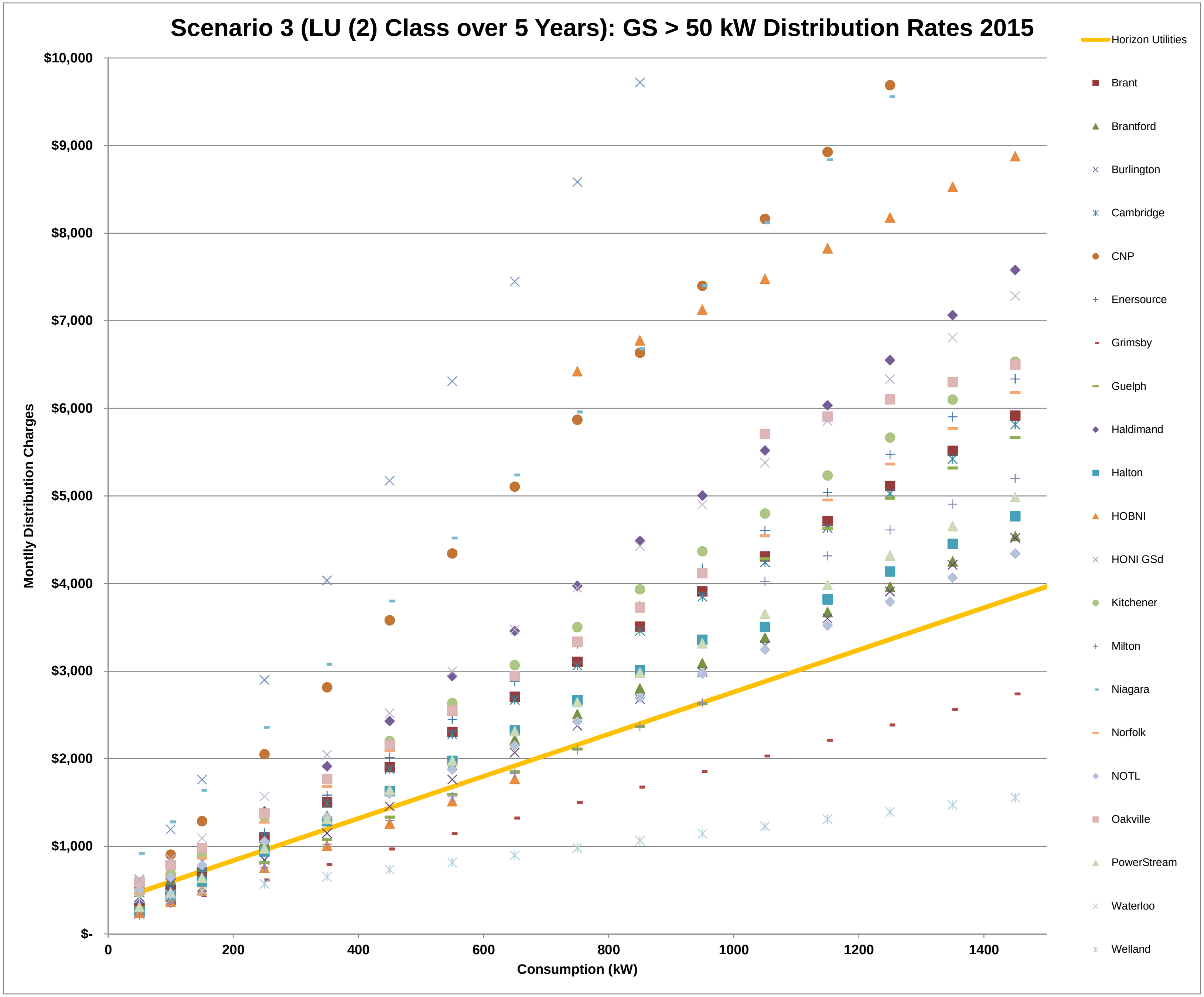

Scenario 2B (30/70 Fixed Variable Split for LU (1) and GS > 50 kW Classes): GS > 50 kW Distribution Rates 2015
Montlly Distribution Charges
$10,000
$9,000
$8,000
$7,000
$6,000
$5,000
$4,000
$3,000
$2,000
$1,000
$-
0
200
400
600
800
1000
1200
1400
Consumption (kW)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland

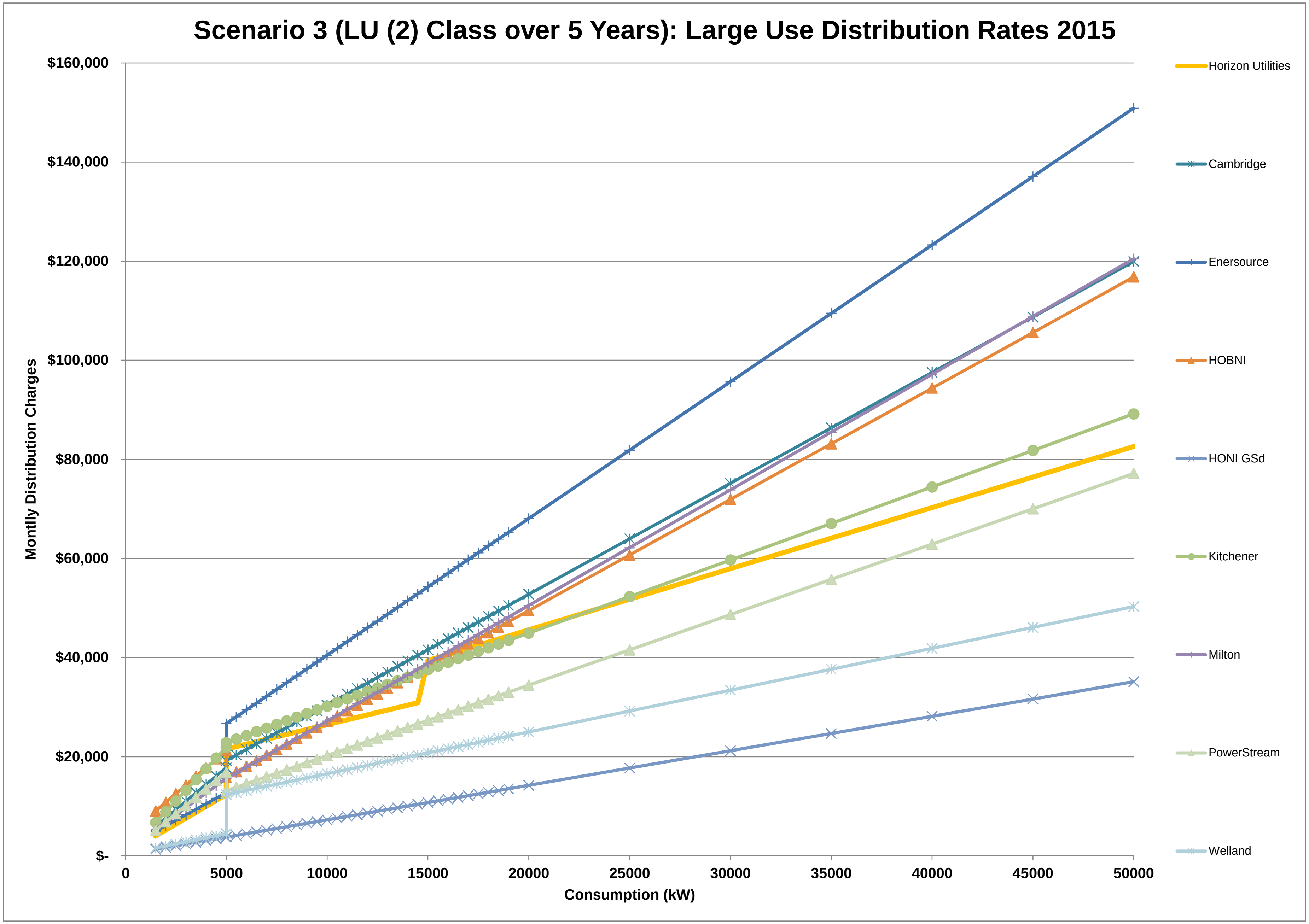


Scenario 2B (30/70 Fixed Variable Split for LU (1) and GS > 50 kW Classes): Large Use Distribution Rates 2015
$160,000
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$-
Montly Distribution Charges
0
5000
10000
15000
20000
25000
30000
35000
40000
45000
50000
Consumption (kW)
Horizon Utilities
Cambridge
Enersource
HOBNI
HONI GSd
Kitchener
Milton
PowerStream
Welland


Scenario 3 (LU (2) Class over 5 Years): Residential Distribution Rates 2015
Montly Distribution Charges
$120
$100
$80
$60
$40
$20
$-
500
700
900
1100
1300
1500
1700
1900
Consumption (kWh)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
HONI UGSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland


Scenario 3 (LU (2) Class over 5 Years): GS < 50 kW Distribution Rates 2015
Montly Distribution Charges
$700
$600
$500
$400
$300
$200
$100
$-
3500
5500
7500
9500
11500
13500
15500
Consumption (kWh)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland


Scenario 3 (LU (2) Class over 5 Years): GS > 50 kW Distribution Rates 2015
Montly Distribution Charges
$10,000
$9,000
$8,000
$7,000
$6,000
$5,000
$4,000
$3,000
$2,000
$1,000
$-
0
200
400
600
800
1000
1200
1400
Consumption (kW)
Horizon Utilities
Brant
Brantford
Burlington
Cambridge
CNP
Enersource
Grimsby
Guelph
Haldimand
Halton
HOBNI
HONI GSd
Kitchener
Milton
Niagara
Norfolk
NOTL
Oakville
PowerStream
Waterloo
Welland



Scenario 3 (LU (2) Class over 5 Years): Large Use Distribution Rates 2015
Montlly Distribution Charges
$160,000
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$-
0
5000
10000
15000
20000
25000
30000
35000
40000
45000
50000
Consumption (kW)
Horizon Utilities
Cambridge
Enersource
HOBNI
HONI GSd
Kitchener
Milton
PowerStream
Welland

**C of H 3. Exhibit 7, Tab 1, Schedule 1, p. 4**

**Background:**

**In its prefiled evidence, Horizon states that "The 2015-2019 connections (unmetered) for the Street Lighting class are calculated using a ratio of 1.3141 Devices : 1 Connection."**

**(a) What are the definitions Horizon uses for "devices", "connections" and "daisy chains"?**

**(b) What is the basis for the definitions for "devices", "connections", and "daisy chains" which Horizon uses?**

**(c) Have the definitions of "devices", "connections", and "daisy chains" used by Horizon been approved by the Board? If so, in what OEB report or decision?**

**(d) Has Horizon compared its ratio of devices to connections with the ratio used by comparable LDCs? If so, what is the comparison? If not, why not?**

**Response:**

a) Horizon Utilities does not have standardized corporate definitions for devices and connections. The term connection generally refers to a distinct customer connection which, for all classes other than Street Lighting and USL, refers to a meter connection. For the Street Light and USL rate classes, Horizon Utilities, like many other distributors, have used the terms device and connection interchangeably. In essence, each device was deemed to be a connection.

Since the introduction of the OEB's cost allocation model for the 2006 Cost Allocation Information Filings, the industry has recognized that street lights are commonly served using a daisy chain configuration. The daisy chain configuration is defined as a serial connection from one light to another, where failure of one light means all lights downstream of the failed light will not work. For purposes of the cost allocation model, a distinction was drawn between devices (i.e., individual lights) and connections (with daisy chained lights being treated as a single connection). For the Street Light class, this definition of a connection served as a means of improving the comparability of the causal costs of a residential connection as compared to a street light connection. In essence, the daisy chain ratio serves as a weighting factor for street light devices. The appropriateness of this approach to achieving equity within the cost allocation model is to be reviewed by an OEB policy process in the near future.

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

c) The terms identified in the interrogatory have not been been reviewed or approved by the OEB. In the Report of the Board - Review on the Board's Cost Allocation Policy for Unmetered Loads (EB-2012-0383), the Board shared that definitions for account, connection, customer, and device (as they relate to unmetered loads) will be added to the instructions for the Cost Allocation model as recommended in the Report by Elenchus Research Associates - Review of Cost Allocation Policy for Unmetered Loads (EB-2012-0383) ("CA Report"). The definitions as recommended in the CAReport are as follows:

**Account**: An account is a record of financial transactions over a period of time related to an arrangement between a customer and the local electrical utility company for the purposes of distributing electrical power to that customer.

An account may be a single customer and represent a single connection to the LDC's system as is the case with a typical residential customer. An account can also represent many "customers" as would be the case for a Retail Store with aggregated billing. Alternatively an account could have many connections as is generally the case with the Street Lights of a municipality.

**Connection**: A Connection is the physical link between the device and wire which are owned by the utility's customer and the utility's distribution system. A single connection may have one device attached to it or it may have multiple devices attached, in what is sometimes called a "daisy chain" arrangement. Usually multiple connections are utilized in order to serve an Unmetered Load customer.

The term connection also applies in the case of metered loads and refers to physical link where a load is connected to the utility's distribution system.

**Customer**: In the Board's Cost Allocation Model as currently constructed each customer is considered to have a service drop (which may be owned by the LDC or the customer) and, if not a USL customer, a meter. This is consistent with the initial Board report (EB-2005-0317) wherein customer is defined as follows:

For the purpose of the cost allocation filings, a "customer" is generally defined by a meter point that measures energy consumed over a period of time.

**Device**: A Device is the electrical equipment of the Unmetered Loads. Examples are individual Streetlights, Cable TV amplifiers, billboard lights, traffic lights and railway crossing signal lights. The identification of the number and types of devices is required in order to determine the electricity use associated with Unmetered Loads.

d) For purposes of its cost allocation model, Horizon Utilities used a connection count based on a survey of the actual number of daisy chained connections as determined by a study requested by the City of Hamilton. Given that this study has been completed, and Horizon Utilities has the actual connection count available them, the extent of daisy chaining in other distributors is not considered relevant for use in Horizon Utilities' model. As discussed in section 2.11.12.2 of the Chapter 2 Filing Requirements, the Board requires each distributor to base its weighting factors on the characteristics of its own distribution system and operations.

This page intentionally left blank

**C of H 4. Exhibit 1, Tab 2, Schedule 6, p. 3**

**Background:**

**i) In its prefiled evidence, Horizon states that it has not deviated from the Board's cost allocation methodologies as set out in the following documents:**

- ***Report of the Board, Review of Electricity Distribution Cost Allocation Policy*, March 31, 2011; and**

- ***Review of the Board's Cost Allocation Policy for Unmetered Loads*, December 19, 2013.**

**ii) In its Report of the Board in EB-2010-0219, "*Review of Electricity Distribution Cost Allocation Policy"*, dated March 31, 2011, the Board stated, at page 24:**

> **The Board also agrees that clarification of the issues raised by various stakeholders related to the terminology and methodology used to allocate costs to the Street Lighting class is necessary….. The Board believes that these issues are best addressed in the context of a separate consultation process focussed on the terminology and modeling methodology for the Street Lighting and USL classes.**

**iii) In the Report of the Board in EB-2012-0383, "*Review of the Board's Cost Allocation Policy for Unmetered Loads*", dated December 19, 2013, the Board stated:**

- **The Board remains concerned with the allocation of costs to daisy-chain configured systems. The disparity in the cost allocation result between a street lighting customer configuration with multiple devices per connection and a street lighting customer with a device to connection ratio close to 1:1 appears to be disproportionate when compared to actual costs to serve the street lighting rate class. The Board believes that further investigation is necessary before making a determination. The Board will issue a letter shortly to begin a consultation process for this single issue. (p. 6)**

- **The Board's policy remains that distributors should endeavour to move their revenue to cost ratios closer to one or 100% if this is supported by new data. That being said, the Board does not believe that there is sufficient evidence at this time to narrow the revenue to cost ratio range for the street lighting class. The Board has therefore concluded that the**

**revenue to cost ratio range for the street lighting rate class should not be narrowed at this time. (p. 6)**

**iv) In its Decision and Order in EB-2010-0131, dated July 7, 2014, the Board states: "The Board accepts Horizon's proposal to await the outcome of the consultation process on the terminology and modeling methodology for Street Lighting and Unmetered Scattered Load classes, as per the *Report of the Board on the Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219), dated March 31, 2011. The effective date for the implementation of any changes as a result of that consultation will be addressed at a later date." (p. 45)**

**(a) Given the Board statements cited in ii), iii) and iv) above, in what sense has Horizon "not deviated" from the Board's cost allocation methodologies"?**

**(b) Has the Board's consultation process on the terminology and modelling methodology for street lighting and unmetered scattered load classes been completed? If so, what is the outcome of that consultation process?**

**(c) If the Board's consultation process has not been completed, on what evidence does Horizon think it appropriate to change the methodology used for the allocation of costs (i.e. device:connection ratio) for the street lighting class and the revenue:cost ratio for that class?**

**Response:**

(a) In the Board's Decision and Order in Horizon Utilities' last Cost of Service Application (EB-2010-0131), dated July 7, 2011, the Board stated that: "The Board accepts Horizon's proposal to await the outcome of the consultation process on the terminology and modeling methodology for Street Lighting and Unmetered Scattered Load classes, as per the Report of the Board on the Review of Electricity Distribution Cost Allocation Policy (EB-2010-0219), dated March 31, 2011. The *Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) concluded on December 19th, 2013 with a Final Report of the Board: Review of the Board's Cost Allocation Policy for Unmetered Loads (EB-2012-0383). On pages 5-6 that report, the Board concluded that it would not change the cost allocation model or methodology at this time, but will add information to the instructions tab of the CA model relating to: weighting factors, definitions/terminology, and connection configurations. A consultation process on the allocation of costs to daisy-chain configured systems will likely begin later this year.

On this basis, Horizon Utilities has used the OEB-approved cost allocation model and has completed its cost allocation study using the currently approved OEB policies. Horizon Utilities does not believe that the Board's concerns, and intent to complete a policy process to review the current methodology for determining the number of street light connections to be used in the model, justifies changing the methodology at this time. Horizon Utilities believes that the appropriate time to make adjustments to the model would be when the review has been completed and either the existing methodology has been confirmed or an alternative methodology has been approved.

(b) No, as stated in part a) of this response, and as discussed in the Report of the Board Review of the Board's Cost Allocation Policy for Unmetered Loads (EB-2012-0383) it is expected that a new consultation process on the allocation of costs to daisy-chain configured systems will commence later this year.

(c) Horizon Utilities has not changed the methodology used for the allocation of costs. As required by OEB policy[1], Horizon Utilities uses the most current and accurate information available to it, including the device:connection ratio, in the cost allocation model.

Regarding Revenue to Cost Ratios, Horizon Utilities has followed the Board's policy and has proposed a Revenue to Cost ratio for the Street Lighting class that is within the Board's approved range and is closer to 100%. Historically, Horizon Utilities has increased the Revenue to Cost Ratio for the Street Lighting class in accordance with direction from the Board. In the Report of the Board: Review of the Board's Cost Allocation Policy for Unmetered Loads (EB-2012-0383), the Board explains:

*"The Board's CA Methodology was set out in a report issued by the Board on September 29, 2006 in EB-2005-0317. The CA Methodology has been in use since 2008 for setting electricity distribution rates. As distributors began using the CA Methodology, revenue to cost ratios in certain customer classes were found to be very low. The Board phased in more appropriate revenue to cost ratios over a number of years. Many street lighting customers saw significant increases to their bills during the phase in period."*

---

[1] EB-2012-0383 Report of the Board: Review of the Board's Cost Allocation Policy for Unmetered Loads states "*Distributors are encouraged to use information that is as accurate as possible based on their physical network design, and demand and consumption profile of devices and to stay apprised of progress in modeling of allocation of costs in this area including any further Board policy changes*".

This page intentionally left blank

**C of H 5. Exhibit 7, Tab 2, Schedule 6, p. 40**

**Background:**

**In the Report of the Board entitled *Review of Electricity Distribution Cost Allocation Policy* in EB-2010-0219, the Board stated: "To the extent that the application of the Board's cost allocation policies results in a significant shift in the rate burden amongst classes relative to the status quo, distributors should be prepared to address potential mitigation measures.**

(a) **Does Horizon consider a 24.5 percent rate increase from the current rates (2014) to those proposed for 2015 a "significant shift in the rate burden"?**

(b) **What mitigation measures, if any, has Horizon considered proposing for the street lighting class?**

(c) **Has Horizon considered smoothing the distribution bill impact, for the street lighting class, over the term of the proposal, to reduce the impact of the 24.5 percent increase from 2014 to 2015? If not, why not?**

**Response:**

a) The 24.5% increase referred to is on the distribution component of the bill only. The criterion for rate mitigation corresponds to a "significant shift in the rate burden" in relation to the total bill. Within this context, Horizon Utilities does not consider the 9.25% increase in total bill a significant shift in rate burden.

b) When evaluating the need for rate mitigation strategies, Horizon Utilities has considered the rate increases on a total bill basis, consistent with the Chapter 2 Filing Requirements section 2.11.12.2. On that basis, no mitigation was warranted as the bill impacts are below the Board's threshold level of 10%. Please also refer to Horizon Utilities' response to Interrogatory 8-Staff-33.

c) Please see Horizon Utilities' response a) and b) above.

This page intentionally left blank

**C of H 6. Exhibit 7, Tab 1, Schedule 1**

**Background:**

**The prefiled evidence states that "The 2015-2019 connections (unmetered) for the Street Lighting class are calculated using a ratio of 1.3141 Devices: 1 Connection." The result in the change of the ratio is an increase of approximately $1 million in costs allocated to the street lighting class.**

**(a) What is the relationship between the ratio of devices to connections, on the one hand, and the actual cost to serve the street lighting class, on the other?**

**(b) What evidence is Horizon relying on that the actual cost to serve the street lighting class has increased?**

**Response:**

(a) In the Board-approved cost allocation model, the number of connections is used as the allocator for allocating certain customer-related costs across the customer classes. For the Street Light class, the current practice (as provided in the instructions tab of the Cost Allocation Model) is to use the actual (preferable) or estimated (if no actual count exists) number of daisy chained street light connections in this allocator. The daisy chain approach serves as a weighting factor that recognizes that the causal costs of a street light are less than the causal costs of other (e.g., a residential customer) connection. The effect is to reduce the costs allocated to the Street Light class as compared to the original design of the cost allocation model for the 2006 Cost Allocation Information Filing which by default treated each device as a connection.

(b) Horizon Utilities is not asserting that updating the devices:connections ratio corresponds to an increase in the costs of serving the Street Light customers. The more accurate information on the daisy chain ratio demonstrates that, based on the currently approved cost allocation methodology, Horizon Utilities was under-allocating its customer-related costs to the Street Light class. In light of the more accurate information that is available, Horizon Utilities has updated its model to reflect this new information[1]. The prior estimate of a 2:1 ratio has now been shown to be incorrect.

[1] EB-2012-0383 Report of the Board: Review of the Board's Cost Allocation Policy for Unmetered Loads states "*Distributors are encouraged to use information that is as accurate as possible based on their physical network design, and demand and consumption profile of devices and to stay apprised of progress in modeling of allocation of costs in this area including any further Board policy changes*".

**C of H 7. Exhibit 7, Tab 1, Schedule 1**

**Background:**

**The prefiled evidence states that the ratio of devices to connections is based on the results of a 2013 audit of the number of daisy chained devices in the City of Hamilton. The scope of this audit included a physical count of the number of daisy chained devices in the City of Hamilton.**

**(a) Please provide a copy of the 2013 audit referred to in the prefiled evidence.**

**(b) Was the result of the 2013 audit used in the cost allocation methodology used to derive the proposed street lighting rates? If so, in what way and with what effect on rates?**

**(c) What is the impact on the costs of serving the street lighting class of the number of daisy chained devices in the City of Hamilton?**

**Response:**

(a) The City of Hamilton Streetlight Audit Report conducted by Utility Solutions Corporation, on behalf of both the City of Hamilton and Horizon Utilities (please refer to page 3 of the Report), dated November 6, 2013 is provided as C of H 7_Attch 1_City of Hamilton Streetlight Audit Report.

(b) Yes, the result of the 2013 audit was used in the current cost allocation models. The update reduced the device:connection ratio from 2:1 to 1.3141:1, which increased the costs allocated to the Street Light class. This increase in allocated costs is a contributing factor to the increase in Street Light rates. Table 1 provides a comparison of the 2015 rates as-filed in the Application compared to the rates assuming the daisy chain ratio for the Street Lighting class were to remain at 2:1.

**Table 1: Street Lighting Rates Comparison**

| | 2014 Existing Rates | 2015 Proposed Rates | 2015 Rates Assuming no Daisy Chain Update |
|---|---|---|---|
| **Per Device** | $2.39 | $2.97 | $2.62 |
| **Per kW** | $6.3601 | $7.9159 | $6.9824 |

(c) The current Board-approved cost allocation methodology is premised on the assumption that the relative causal cost (customer or connection-related costs) are more reflective of the number of daisy chained connections than they are of the number of devices. This methodology may be the subject of an upcoming OEB policy review process, as described in Horizon Utilities' response to Interrogatory COH-4.

# C of H 7_Attch 1_City of Hamilton Streetlight Audit Report

This page intentionally left blank


# Horizon Utilities

# City of Hamilton Street Light Audit Report

Prepared by: Utility Solutions Corporation

November 6, 2013

# Contents

# Executive Summary

## Project Background

The Street Lighting System in the City of Hamilton that is energized from Horizon Utilities' distribution system is either connected to Horizon's distribution house lighting bus or dedicated street lighting lines owned and operated by the City of Hamilton. The division of street lights connected to Horizon's bus vs. those connected to dedicated street lighting lines has been approximated over the years. Since the operational cost for each of these two connection types is different, both the City and Horizon agreed to have a street lighting audit performed to much more precisely determine the division between connection types. Utility Solutions Corporation, under its current resource contract with Horizon Utilities, was requested to perform the street lighting audit and report its findings.

## Project Approach

Utility Solutions was requested to perform a field audit of all street streetlights within Horizon Utilities' service territory. This number was estimated to be 40,000. The street lighting types can be broadly categorized as follows:

- Overhead residential
- Overhead arterial/commercial
- Overhead rural
- Underground subdivision
- Underground decorative
- Alleyway (small quantity)

The field audit involved deploying trained technicians to each accessible street light location. With the exception of underground subdivisions and high-speed roadways, technicians performed the audit on an individual basis by foot patrol. Underground supplied subdivisions and high-speed roadways were performed by two person crews using a vehicle.

Technician staff gathered and/or confirmed the following data at each street light location:

- Pole number verification
- Overhead or underground supply type
- Pole ownership
- Connection type for overhead lines (house lighting or dedicated street lighting bus)
- Lamp wattage (if shown)
- Presence of primary lines (Y/N)
- Presence of shared use (i.e., telecommunication/cable)

All field data was submitted to office technician staff for further processing. In the case of underground supplied street lights, office staff identified the connection type using Horizon's GIS based record system, Legend. Office staff also performed quality control and assembled the data for delivery to the client.

## Audit Findings

Using both Horizon Utilities and the City of Hamilton data sources, Utility Solutions identified a total of 39,340 street lights as being in scope for this project. These street light locations were inspected over a 2 ½ month period. The table below summarizes the audit results. More detailed findings can be found in the body of this report.

| Audit Item | Count | Comments |
|---|---|---|
| Total Light Locations | 39,340 | From client databases |
| Total Lights in Service | 37,934 | Identified in Field |
| Total D1s | 21,796 | D1 = Supplied from House Lighting Bus |
| Total D2s | 12,109 | D2 = Supplied from dedicated street light bus connection |
| Undefined Connections | 3,802 | Primarily UG supplied lights not shown in Legend |
| No Access | 227 | No Access to Pole/Light |

# Project Methodology

Utility Solutions implemented a three stage approach to complete this project as outlined below:

1. Data Organization and Route Mapping
2. Field Data Collection
3. Post Processing and Data Assembly

## Data Organization and Route Mapping

This stage of the project involved reviewing all of the street lighting data supplied by Horizon and the City of Hamilton to enable USC to assemble a full project scope map in terms of volume of street lights and geography. Utility Solutions assembled this data and created a personal geo-database in Shapefile format. The combined number of streetlights identified amongst the various sources was 39,340. All individual streetlights were subsequently mapped and provided to both Horizon and the City for scope verification.

The composite street lighting GIS file created by USC was used extensively throughout the project. From this file, USC created approximately 240 smaller route maps to facilitate the field collection work flow. Each route map contained street centreline information along with street light pole locations. In addition to the route map, a data collection form was created in Excel format. The collection form was used by USC field technicians to enter field data for all lights identified on the route map.

Where possible, maps were categorized to allow USC to adopt various field approaches for data collection. These categories included:

- Underground subdivision
- Overhead residential
- Arterial/Commercial
- High-speed roadways
- Rural
- Alleyways

# Field Data Collection

## Attribution Rules

Prior to performing data collection work, Utility Solutions worked closely with Horizon and the City to identify both attribution requirements and the treatment of different connection types (i.e., house lighting bus and dedicated street lighting line). The results of these discussions and reviews were documented by Utility Solutions in our *Attribution Rules Summary* document (included as Appendix A).

The *Attribution Rules Summary* document served as a field guide for recording the following classes of information:

- **Pole No. -** confirm that the client pole number in database is correct or provide actual field number if discrepancy exists
- **UG/OH Supply –** Identify if the supply feed to the street light is an underground or overhead supply
- **Pole Owner –** Identify the pole owner based on field conditions (e.g., where primary and/or house lighting exists, pole owner = HUC; where only dedicated S/L lines exist or light is fed UG and pole only has street light, then pole owner = COH). Rules were also provided for Bell and Hydro One poles.
- **Pole Attachments –** Six different attachment rules applied to COH poles, including shared use, electrical apparatus (e.g., conduits, electrical boxes), traffic signals, non-street light load, etc.
- **Wire Owner –** Identify if the street light was fed via a Horizon house light bus (D1) or a dedicated street lighting line (D2).
- **Lamp Wattage –** Confirm that the database wattage matched the field wattage label. If the street light did not have a wattage label, then record “No Wattage Shown.”
- **Primary Conductors –** If primary conductors exist on pole, record (Y); If primary conductors do not exist on pole, record (N).
- **Shared Use –** Identify if telecom and/or cable plant is attached to a Horizon pole, or in the rare circumstance, attached to a COH pole.

## OH Wire Ownership and Demarcation

As work progressed in the field from largely residential communities to more commercial and arterial roadways, the connection configurations in some cases became ambiguous. For example, one general rule was if the street light was connected to a house lighting bus (3 – wire larger gauge conductors), then the light would be considered a D1. However, it was identified in the field that in some cases there were branches of two or more street lights connected to a house lighting bus, but there were no Horizon customer connections on that same bus. It could be argued therefore that the City could be responsible for these supply lines as they could isolate the branch of lights without affecting Horizon customers. This particular scenario was brought to the attention of both Horizon and the City and a collection rule for USC to follow was agreed to. The collection rule was: **If there are 4 or more lights in a row (no breaks in the H/L bus) then we**

**place 4+ in the comment field and mark the location on a map.** This rule serves the purpose of flagging these locations for client review.

The above is just one example of a number of field conditions that were discussed where collection rules were agreed to. Approximately 20 different scenarios (many variations of each other) were reviewed with Horizon and the City.

The D1 (Horizon bus connection) and D2 (dedicated street light line) collection rules as shown in the Attribute *Summary Document* (Appendix A) are provided below.

## D1 Demarcation – Lights Supplied From House Lighting Bus

All S/L's that are supplied from a Horizon House Lighting bus/line that is operated by Horizon Utilities and is intended for supplying Horizon customers, and where applicable, street lighting loads. D1 designated lights = 1 connection point per light.

Field rules for determining D1 connections:

1) 3 wire tri-plexed or open secondary bus feeding both field side customers and S/Ls (only one 120/240V bus on pole line) = D1 – 1 connection point per light
    a. September 25, 2013 Update – for situations where 4 or more lights occur in a series on the same H/L bus without pole or mid-span service connections (i.e., no HZ customers), the field technician will denote this in the comment field by placing "**4+**". The client comment will read: "**4 or more D1s without HZ customer connections.**"
2) 4 wire quadra-plexed secondary bus feeding both field side customers and S/Ls – smaller gauge bundled conductor feeds S/Ls (only one 120/240V bus on pole line) = D1 – 1 connection point per light.

## D2 Demarcation – Lights Supplied From Designated Street Lighting Bus

D2 connections include all S/L's that are supplied from a designated S/L Lighting bus/line that is operated and maintained by the City of Hamilton and is intended for supplying only street lighting loads (September 25, 2013 Update: 2 wire or small gauge conductors). D2 designated lights will be grouped into branch circuits using Legend records. Each branch will be given a unique ID and the first light downstream from the supply source will be designated with an "S" to indicate the starting connection point to the supply. In cases where there is a street lighting pedestal, the S/L Ped (non-metered) will act as the connection and demarcation point and will be designated with an "S" as well (as opposed to the first street light).

These branches are considered as one connection point to multiple lights.

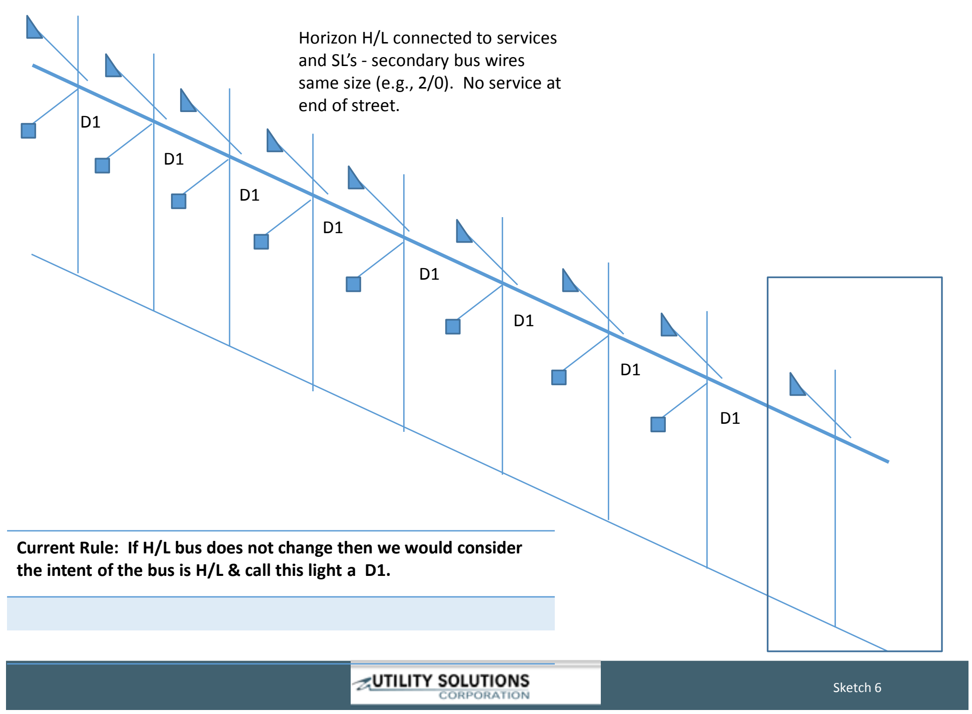
September 25, 2013 update: single light D2 lamps are to be recorded as D2s.

Field rules for determining D2 connections:

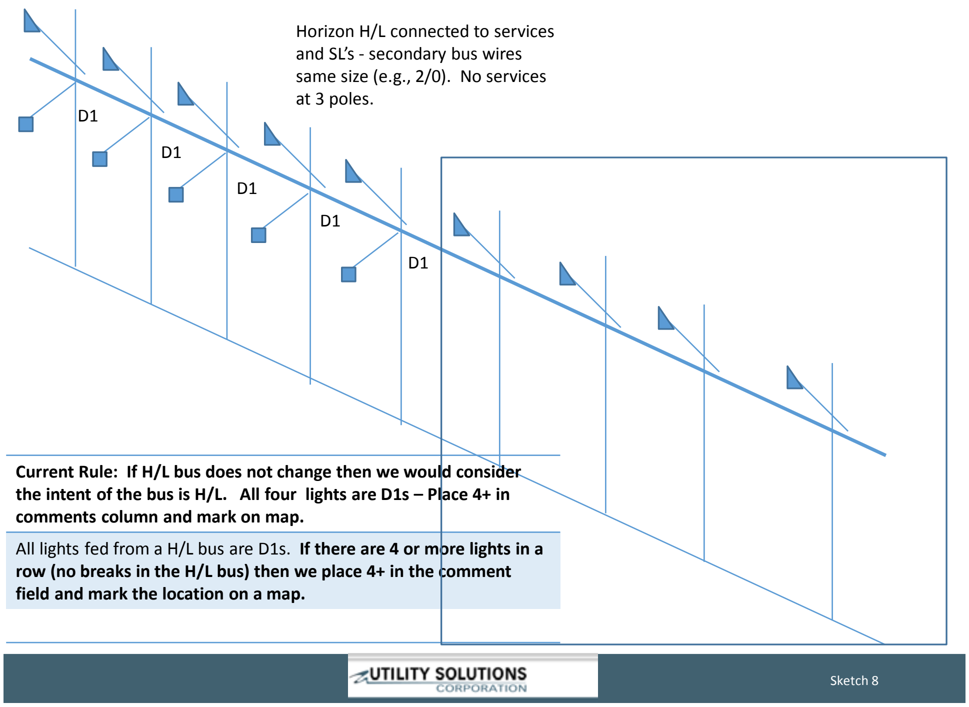
1) 2 or 3 wired open or bundled conductors only feeding S/Ls = D2 – branch circuit - one connection point to multiple lights
   a. Note: dedicated S/L buses can be the only secondary bus on the pole, or can be strung in parallel with other secondary H/L or 600 V busses
2) 4 wire open secondary bus feeding both field side customers and S/Ls – smaller gauge conductor feeds S/Ls (only one 120/240V bus on pole line) = D2 – branch circuit - one connection point to multiple lights
3) 5 wire open secondary bus – if designated S/L wires are connected to S/L's, then CoH ownership and branch style lamp (one connection point to multiple lights)
4) 5 wire open secondary bus – if designated S/L wires are not connected to S/L's (i.e., abandoned cables) then S/L's are connected to common H/L bus and lights = D1 – 1 connection point per light.

The following sketches depict several connection scenarios reviewed. For a description of all connection scenarios established, please refer to Appendix B - *OH Wire Ownership and Demarcation Sketches.*

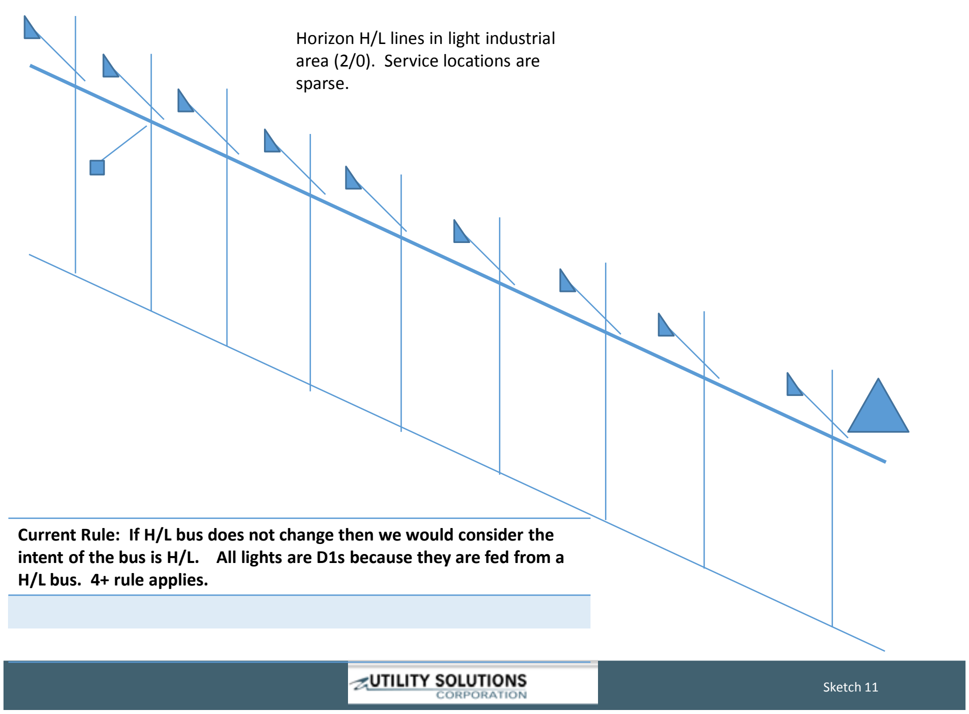
## D1 on House Lighting Bus (no customer connections from pole or mid-span)



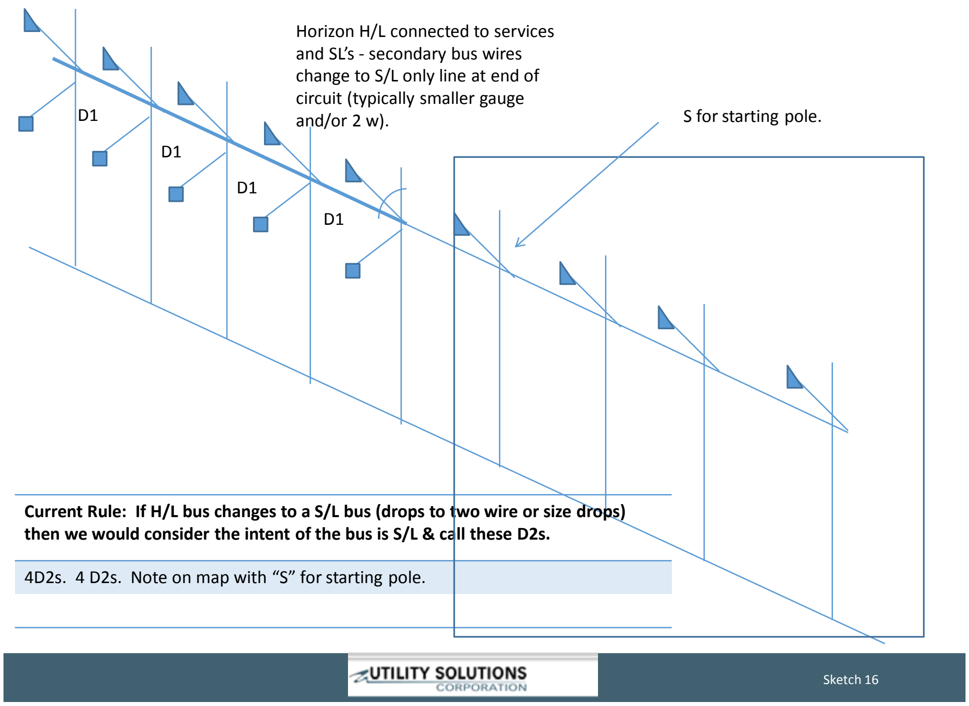
## D1s on House Lighting Bus (Flag as 4 or more rule)




## D1s on House Lighting Bus (Flag as 4 or more rule)



**D2s Extension from House Lighting Bus (D2 Branch with 4 lights)**




## Hazardous Field Conditions

During the course of the field inspection work a number of hazardous inspection scenarios were identified. These principally dealt with high-speed roadways and mountain access roads without adequate shoulder width for foot patrol. Approximately 500 street lights were deemed as hazardous due to road conditions.

Utility Solutions was unable to perform detailed foot patrol inspection on these lights, but did however manage to perform a vehicle patrol as an alternative. The vehicle patrol involved a two person crew driving at posted speed limits (slower where traffic volume permitted) during non-peak hours. The passenger of the vehicle performed a pole count to verify the database record count and randomly identified light wattages. Since the vast majority of lights within a given road segment appeared identical, there appears to be little risk associated with incorrect wattage values (e.g., mountain road lights all appeared to be 250W). These lights were subsequently identified in USC's records as "Collected via Vehicle Patrol, wattage not confirmed).

Vehicle Patrol was performed on the following roadways where foot patrol access was deemed unsafe:

- Claremont Access
- Sherman Access
- Kenilworth Access
- James Access
- Burlington Street overpass (east and west bound)

## Post Processing and Data Assembly

### Field Technician Submission QC

As noted above, all data was collected in the field based on both attribution and connection type rules. As map route areas were completed, the field technicians provided their data sets by map areas to office technical staff for post processing and data assembly.

The first component of the post processing activity involved a QC of the technicians' submission to ensure basic errors did not occur. While there were no major issues with this work component, the initial review included a check for missing data in predefined fields or incompatible entries such as a primary line on a City owned pole.

### Process for Determining Non-D1 Entries

At the completion of the initial QC, the data was made available to office technical staff for the identification and confirmation of non-D1 entries. Non-D1 entries included all underground supplied street-lights and all overhead street lights designated as D2s.

Office staff then followed the work flow agreed to for non-D1 entries. The work flow is described in the *Attribution Rules Summary* document (included as Appendix A). An excerpt pertaining to the treatment of non-D1 entries is provided below:

> **Process for determining UG D1 connections:**
>
> A post data processing effort will be undertaken using Legend's secondary (H/L and S/L) linear records to determine if the S/Ls are supplied from a common House Lighting bus or a designated S/L bus or feed. If the lights are shown as fed from a common House Lighting bus, then the lights will be recorded as D1 designated lights = 1 connection point per light.
>
> **Process for determining D2 connections:**
>
> **D2** connections include all S/L's that are supplied from a designated S/L Lighting bus/line that is operated and maintained by the City of Hamilton and is intended for supplying only street lighting loads (September 25, 2013 Update: 2 wire or small gauge conductors). D2 designated lights will be grouped into branch circuits using Legend records. Each branch will be given a unique ID and the first light downstream from the supply source will be designated with an "S" to indicate the starting connection point to the supply. In cases where there is a street lighting pedestal, the S/L Ped (non-metered) will act as the connection and demarcation point and will be designated with an "S" as well (as opposed to the first street light).
>
> These branches are considered as one connection point to multiple lights.
>
> September 25, 2013 update: single light D2 lamps are to be recorded as D2s.

## Pre-Submission QC and Deliveries

At the completion of the non-D1 identification phase, all processed records (including D1 entries) were assembled into delivery packages. USC provided a total of 5 deliveries, including a composite delivery at the end of the project.

Each delivery was QC'd prior to submission. The QC involved a number of steps which are summarized below. Any individual or grouping of records that did not meet QC criteria were set aside for subsequent analysis and action.

1. Filter the Pole_No values
    a. Check for blanks
    b. NEW values get removed and placed in 'Extracted_records_prior_to_submission.xlsx' on the U drive
2. Filter the USC_Pole_No values
    a. Check for blanks
    b. If blank and Bell pole, ensure that the comment reads 'No Pole Label'.
    c. N/A values must have a 'MISSING POLE NUMBER' or 'POLE NOT FOUND'
    d. Blank rows can be stored in the 'BLANKS.XLSX' file on the U drive
3. Perform match step on both POLE_No and USC_POLE_No, then delete the column
    a. =match (c3,b3,0), filter to see differences. Note that USC_POLE_No with a high value are most likely new poles
    b. Bell poles should have no USC_POLE_No which causes the N/A. Remove 'Bell' poles from filter
4. Filter USC_OH_UG
    a. Check for blanks, most likely 'MISSING POLE NUMBER' or 'POLE NOT FOUND'
5. Filter USC_POLE_OWNER
    a. Most common values HUC, COH, Bell, HONI and PR
    b. Check for blanks, most likely 'MISSING POLE NUMBER' or 'POLE NOT FOUND'. If blank, verify in Legend
    c. Ensure that if owner is COH, no values appear in HUC attachments
    d. Ensure that if owner is HUC, no values appear in COH attachments
    e. Highlight items that require further review
    f. Check for UG supply and HUC pole owner – only valid in rare cases
6. Filter LAMP_WATTA
    a. Check for blanks. Blank values are acceptable
7. Filter USC_LAMP_WATTA
    a. Ensure no blanks. NWS is acceptable. N/A if comments are 'MISSING POLE NUMBER' or 'POLE NOT FOUND'
    b. If N/A, ensure that comments are 'MISSING POLE NUMBER' or 'POLE NOT FOUND'
8. Filter COH / POLE ATTACH
    a. Blanks are acceptable

    b. Verify common values under filter
9. Filter COH / NON SL LOAD
    a. Blanks are acceptable
    b. Verify common values under filter
10. Filter HUC Primary
    a. Ensure no blanks
    b. Filter non blanks and note HUC Shared blank values
11. Filter HUC Shared
    a. Ensure no blanks
    b. Filter non blanks and note HUC Primary blank values
12. Filter USC_WIRE_OWNER
    a. Ensure no blanks
    b. Common values are D1, D2 and UNKNOWN
    c. UNKNOWN is most likely from comments which are 'MISSING POLE NUMBER', 'POLE NOT FOUND' or 'LEGEND DOES NOT SHOW CONNECTION TO SECONDARY'
    d. Filter by D1 and UNKNOWN to ensure no branching or start values
    e. Filter by D2 and ensure all records have a branch and start value
13. Filter Branch & Start
    a. Ensure that branch numbers are unique to start values
14. Comments
    a. Attempt to remove values not relevant for submission
    b. Communicate issues for review
15. Select all records and ensure that borders and left justify are applied
16. Review and note Highlighted records for later review

# Audit Findings

## Audit Findings – Connection Demarcation Designations

The following is a summary of the connection demarcation results based on the field audit and subsequent post processing effort for D1 and D2 designations. Where required, comments have been provided.

### Audit Count – D1s and D2s

| Item | Count/Value | Comment |
|---|---|---|
| D1 = House lighting connection | 21,796 | |
| D2 = Street light bus or line | 12,109 | |
| D2 Branches | 4,593 | |
| Undetermined Connections | 3,802 | Light or connection not identifiable (in Legend) |
| No Access | 227 | No Access to Pole/Light |

## Audit Findings – Attribution Data

The following is a summary of the field audit attribution values. Where required, comments have been provided.

### Attribute – Pole No.

| Item | Count/Value | Comment |
|---|---|---|
| Total poles missing labels | 4,696 | Includes all poles, i.e., Bell and COH poles without pole numbers. |
| Total labels missing digits | 267 | |
| Total "new" poles | 554 | Poles were entered as "New" if they appeared to be missed as a street light pole on the client's records. USC also included 'Undetermined 'poles from the City's database in this category. |
| Total poles with mismatch IDs | 1,101 | Indicates mismatches between client database pole numbers and what was found in the field. |
| Total poles not found | 1367 | Pole was not found in the field. This number also includes all duplicate client entries. |
| Total poles not accessible | 227 | Mostly private property and construction locations |

### Attribute – UG/OH Supply

| Item | Count/Value | Comment |
|---|---|---|
| Total street lights designated as OH supply | 22,196 | |
| Total street lights designated as UG supply | 15,377 | City poles normally fed UG but have temporary overhead connections were designated as UG supply (intended use). |
| Total Other | 134 | Primarily Alleyway or Underpass lights |
| Total not accessible | 227 | |
| Total in service | 37,934 | |

### Attribute – Pole Owner

| Item | Count/Value | Comment |
|---|---|---|
| Total poles designated as HUC | 18,924 | |
| Total poles designated as COH | 16,398 | |
| Total poles designated as Bell | 2,288 | |
| Total poles designated as HONI | 45 | |
| Total poles designated as PR (Private) | 52 | |
| Total non accessible | 227 | |
| Total | 37,934 | |

### Attribute – Pole Attachments

| Item | Count/Value | Comment |
|---|---|---|
| COH - Electrical Apparatus (e.g., boxes, relays, conduits) | 200 | |
| COH - Traffic signals/apparatus | 284 | |
| COH - Guy supports other pole | 43 | |
| COH - Shared use (e.g., cable/telecom) | 272 | |
| COH - Non-S/L Load (must be connected to city S/L wires) | 36 | |

### Attribute – Wattage

| Item | Count/Value | Comment |
|---|---|---|
| Total Street Lights – In Service | 37,934 | |
| Total Street lights with wattage labels | 31,301 | |
| Total street lights with wattage data match | 30,496 | |
| Total street lights with wattage data mis-match | 805 | |
| Total street lights with “no wattage shown” | 5,500 | |
| Total street lights “wattage not verified” | 499 | Primarily high-speed and mountain access roads |

### Attribute – Primary Conductors

| Item | Count/Value | Comment |
|---|---|---|
| Total HUC poles with primary conductors | 14,741 | Count to be confirmed |
| Total Bell poles with primary conductors | 1,311 | Count to be confirmed |

### Attribute – Shared Use (Telecom/Cable)

| Item | Count/Value | Comment |
|---|---|---|
| Total HUC poles with shared use | 15,371 | |
| Total COH poles with shared use | 271 | |

### "New "and Poles Not Found

| Item | Count/Value | Comment |
|---|---|---|
| "New" poles found | 553 | Lights not identified in client database but found in field |
| Poles/Lights not found | 1,367 | Includes poles not found, poles without streetlight and client duplicate records |

## Appendix A - Attribution Rule Summary Document

Attribution Rules
Summary Updated 25

## Appendix B - *OH Wire Ownership and Demarcation Sketches*

OH Wire Ownership
and Demarcation Ske

## Horizon Utilities – City of Hamilton Street Lighting Audit

## Attribution Rules

Updated: August 29, 2013

Updated: September 25, 2013

| Attribute | Source | Rule(s) | CoH & HU Approval |
|---|---|---|---|
| **Pole No.** | Field observation | 1) If shown, confirm in H/H; If not on pole click N/A (Not Available)<br>2) If pole exists, but is different from Legend DB, then confirm pole existence & enter new number (some decoratives have a new number with a D prefix, these will need to be entered as new numbers)<br>3) If pole does not exist on record, then enter new pole location in the H/H and map | |
| **OH/UG Supply** | Field observation | 1) Click O/H where secondary bus is strung on poles<br>2) Click UG if lighting supply is fed from UG<br>3) Where UG fed lights are periodically fed from an OH supply (may be temporary), the supply designation would still be UG (i.e., "intended use" or normal condition) | |
| **Pole Owner** | Field observation | 1) O/H - Primary exists = **Horizon** – unless pole is identified in the field as Bell or HONI<br>2) O/H - House lighting exists (including taps from either side of pole) = **Horizon** – unless pole is identified in the field as Bell or HONI<br>3) O/H - Any Dx equipment (Txer, switch, etc.) = **Horizon -** unless pole is identified in the field as Bell or HONI<br>4) O/H - Only has secondary conductors for S/L – no other Dx equipment or wires = **CoH** - includes S/L pole with no luminaire | |

| | | | |
|---|---|---|---|
| | | a. Rules for attachments on S/L only poles (excluding direct non street lighting electrical connections to S/L wires)<br>i. If a S/L pole is used as a guy pole for a Horizon pole (such as one across the street), then the pole owner is COH. The guy is to be recorded as a "guy attachment". If pole has its own guy only, an attachment record is not required.<br>ii. Shared use attachments such as cable and/or telecom are to be recorded as "shared use attachments" – pole is still **CoH**<br>iii. Electrical boxes, equipment, conduits, etc. (not electrically connected to S/L lines) are to be recorded as "other electrical attachments" – pole is still **CoH**<br>iv. Any non-electrical attachments (excluding signage) are to be recorded as "non-electrical attachment"<br>v. Traffic signal equipment on a S/L pole is to be recorded as "traffic signal equipment attachment"<br>5) UG - No visible wires and no other linear cable plant (e.g., typical subdivision or arterial roadway S/L pole)= **CoH**<br>a. All attachment rules in 4a) above apply to UG S/L pole<br>6) UG – Decorative - No visible wires and no other linear cable plant = **CoH**<br>a. All attachment rules in 4a) above apply to UG S/L decorative poles<br>**b.** In all instances, regardless of attachments (wire & cable), decorative pole ownership is **CoH**<br>c. **September 25, 2013 Update:** A number of previously unlabelled City concrete poles have been labeled in the field using the suffix "C" (for Cobra-head). The labels used have black letters with white backgrounds. These poles are labelled in the DB, however the DB and field number will not match. The technician will verify the pole using the mapped location. The USC pole number entry will be the pole number shown on the pole. | |

| | | | |
|---|---|---|---|
| | | **7)** Designated S/L poles in BIA areas - pole ownership is **CoH**<br>8) ~~Traffic pole with S/L – ownership is **COH-Traffic**~~ **(September 25, 2103 Update –** delete this attachment category as this situation does not exist in the field)<br>9) S/L pole with traffic equipment – ownership is **COH,** however pole attachment record “traffic signal equipment” to be recorded (see 4a) – vi.<br>10) Bell poles – prefixed with “B” in Legend and has two Bell identifiers (small galvanized tacks nailed in) – pole ownership is **Bell**<br>a. **September 25, 2013 Update** – Bell poles will not have the corresponding pole number recorded in Horizon’s data base. Field crews will place a dash in the USC pole number field (i.e., acknowledging that the pole number is not the same as the DB, and they will place **“No Pole Label”** in the comment field. The client data set will have a blank in the USC pole number field and **“No Pole Label”** in the comment field.<br>11) Hydro One (HONI) poles – identified in Legend - pole ownership is **HONI**<br>a. September 25, 2013 Update – HONI poles will not have the corresponding pole number recorded in Horizon’s data base. Field crews will place a dash in the USC pole number field (i.e., acknowledging that the pole number is not the same as the DB, and they will place **“No Pole Label”** in the comment field. The client data set will have a blank in the USC pole number field and **“No Pole Label”** in the comment field. | |
| **Wire Owner** – Horizon<br>D1 Connection Designation | Field observation (O/H) – Legend UG | **D1** connections include all S/L’s that are supplied from a Horizon House Lighting bus/line that is operated by Horizon Utilities and is intended for supplying Horizon customers, and where applicable, street lighting loads. D1 designated lights = 1 connection point per light.<br>Field rules for determining D1 connections:<br>1) 3 wire tri-plexed or open secondary bus feeding both field side customers and S/Ls (only one 120/240V bus on pole line) = D1 – 1 | |

| | | | |
|---|---|---|---|
| | | connection point per light<br>**a.** September 25, 2013 Update – for situations where 4 or more lights occur in a series on the same H/L bus without pole or mid-span service connections (i.e., no HZ customers), the field technician will denote this in the comment field by placing "**4+"**. The client comment will read: "**4 or more D1s without HZ customer connections."**<br>2) 4 wire quadra-plexed secondary bus feeding both field side customers and S/Ls – smaller gauge bundled conductor feeds S/Ls (only one 120/240V bus on pole line) = D1 – 1 connection point per light<br>3) 5 wire open secondary bus – if designated S/L wires are not connected to S/L's (i.e., abandoned cables) then S/L's are connected to common H/L bus and lights = D1 – 1 connection point per light<br>Process for determining UG D1 connections:<br>1) A post data processing effort will be undertaken using Legend's secondary (H/L and S/L) linear records to determine if the S/Ls are supplied from a common House Lighting bus or a designated S/L bus or feed. If the lights are shown as fed from a common House Lighting bus, then the lights will be recorded as D1 designated lights = 1 connection point per light. | |
| **Wire Owner** – Horizon<br>D2 Connection Designation | Field observation (O/H) – Legend UG & branch extents | **D2** connections include all S/L's that are supplied from a designated S/L Lighting bus/line that is operated and maintained by the City of Hamilton and is intended for supplying only street lighting loads **(September 25, 2013 Update:** 2 wire or small gauge conductors). D2 designated lights will be grouped into branch circuits using Legend records. Each branch will be given a unique ID and the first light downstream from the supply source will be designated with an "S" to indicate the starting connection point to the supply. In cases where there is a street lighting pedestal, the S/L Ped (non-metered) will act as the connection and demarcation point and will be designated with an "S" as well (as opposed to the first street light).<br>These branches are considered as one connection point to multiple lights. | |

| | | | |
|---|---|---|---|
| | | **September 25, 2013 update:** single light D2 lamps are to be recorded as D2s.<br><br>Where applicable, other non-S/L load attachments observed in the field (e.g., bill boards) which are electrically connected to a S/L branch, will be recorded in the field for the pole/light record. These electrical attachments will be subsequently reviewed to determine potential changes to plant ownership as well as operation and maintenance responsibilities.<br><br>Field rules for determining D2 connections:<br><br>1) 2 or 3 wired open or bundled conductors only feeding S/Ls = D2 – branch circuit - one connection point to multiple lights<br><br>a. Note: dedicated S/L buses can be the only secondary bus on the pole, or can be strung in parallel with other secondary H/L or 600 V busses<br><br>2) 4 wire open secondary bus feeding both field side customers and S/Ls – smaller gauge conductor feeds S/Ls (only one 120/240V bus on pole line) = D2 – branch circuit - one connection point to multiple lights<br><br>3) 5 wire open secondary bus – if designated S/L wires are connected to S/L's, then CoH ownership and branch style lamp (one connection point to multiple lights)<br><br>Process for determining D2 branch extents:<br><br>1) A post data processing effort will be undertaken using Legend's secondary (H/L and S/L) linear records to determine if the S/Ls are supplied from a common House Lighting bus or a designated S/L bus or feed.<br><br>a. UG - if the lights are shown as fed from a designated S/L bus or feed, then the lights will be recorded as a D2 – branch circuit - one connection point to multiple lights<br><br>b. OH - for lights designated as D2's (from the field), corresponding Legend cable data will be used to determine the source and end | |

| | | | |
|---|---|---|---|
| | | branch points | |
| **Lamp Wattage** | Field observation | 1) If shown, record in H/H; If not on luminaire/pole, click N/A (Not Available)<br>2) Where 2 or more lamps exist on a pole, record separate wattages<br>3) Client data will include both the DB lamp wattage and the field collected lamp wattage. Discrepancies at a pole/lamp level can be identified. | |
| **Primary Conductors** | Field observation | 1) If primary conductors exist on pole, record (Y) in provided field<br>2) If primary conductors do not exist on pole, record (N) in provided field | |
| **Shared Use** – Horizon Poles | Field observation | 1) If shared use cable (i.e., telecom and/or cable) exists on pole, record (Y) in provided field<br>2) If shared use cable (i.e., telecom and or cable) does not exist on pole, record (N) in provided field<br>3) Note: Shared use attribution is also done for COH poles (see Pole Owner section, item 4a) iii | |

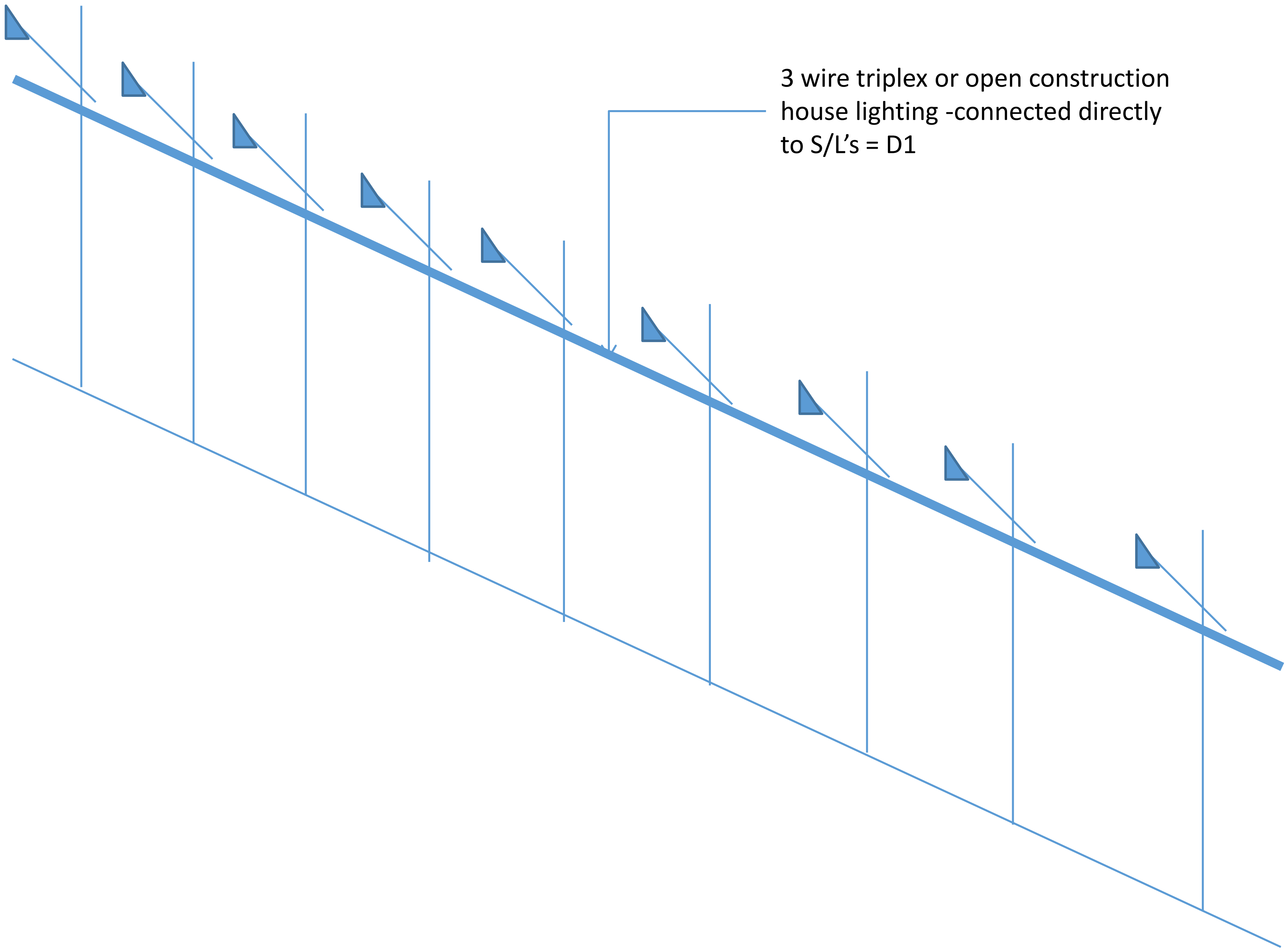
Other items discussed:

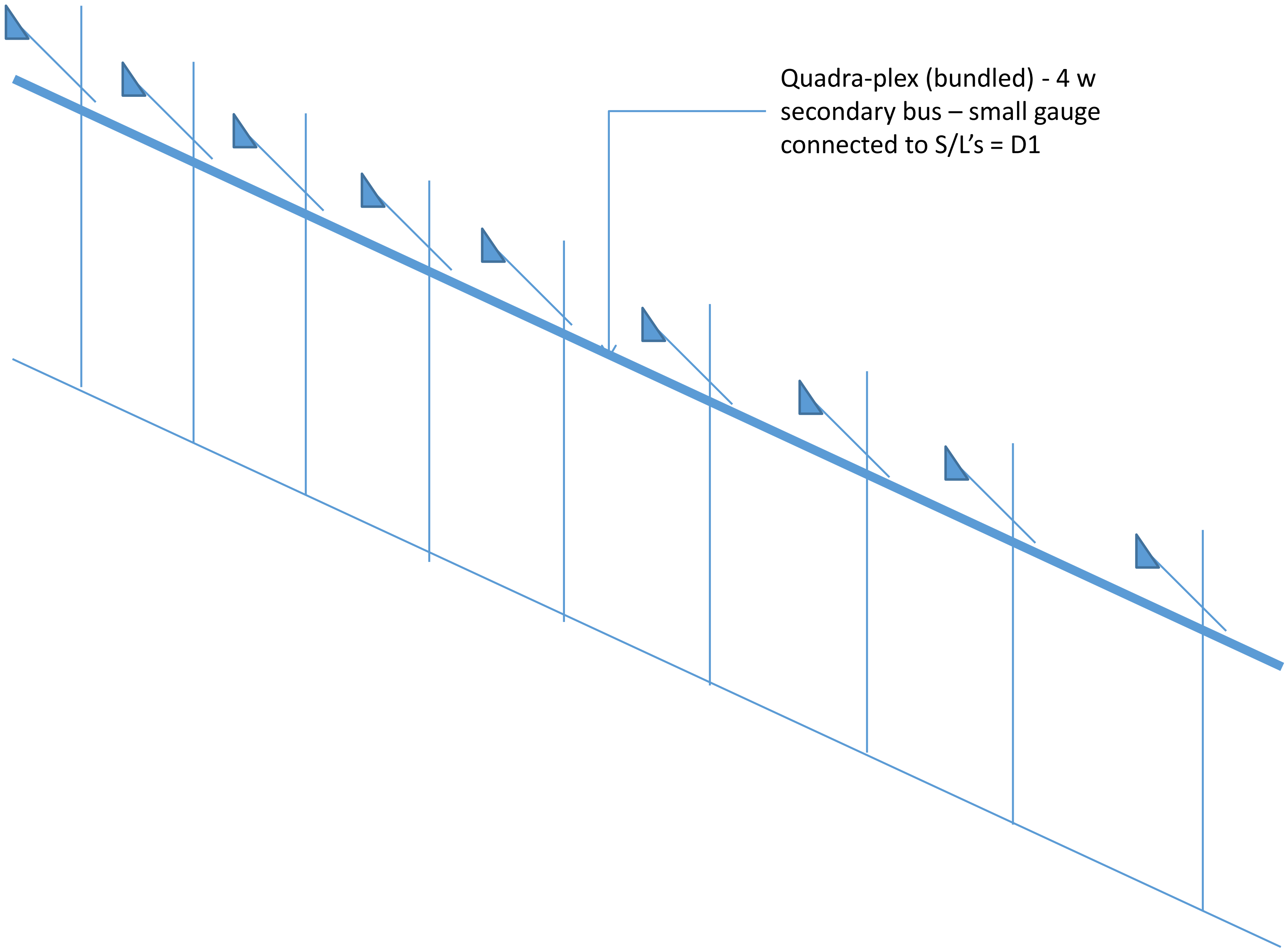
- Conflict/missing data/undetermined ownership resolution process? –
  - Response: USC to employ PAR process – City contacts: Mike Field and Peter Locs; Horizon contact TBD.
- Data schema and deliverables – what and how? –
  - Response: USC to provide schema and sample data set
- What process is in place to ensure that the audit does not overlap into metered street lighting systems?
  - Response: USC has requested Shapefile showing metered areas. CoH to look into.
  - Other info: all metered subdivisions are UG supplied.
  - Non-metered S/L loads are older areas.
  - Luminaire wattage is not in Legend for new metered sub-divisions.

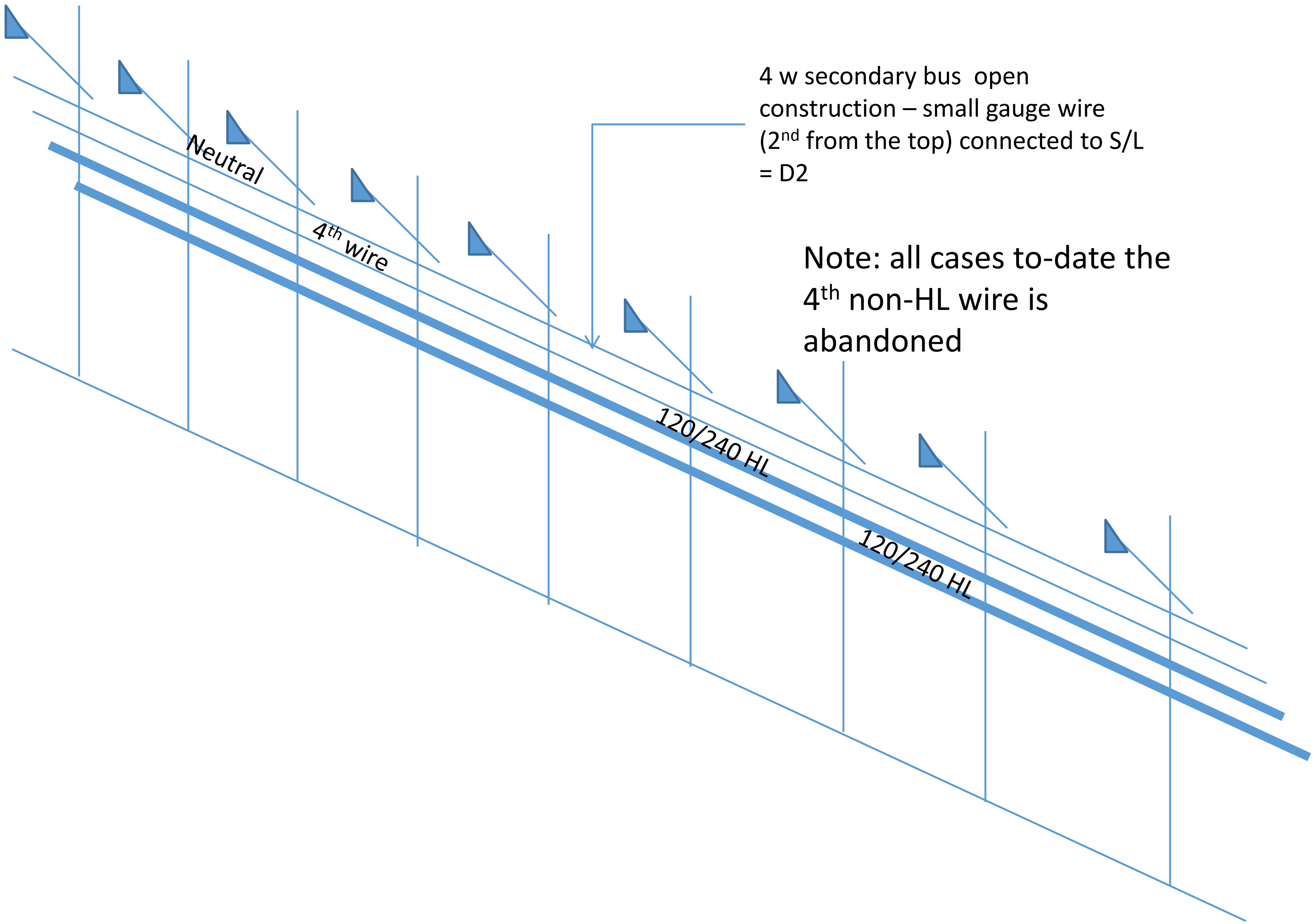
# Hamilton Street Lighting Audit - Field Scenarios

SEPTEMBER 23RD

# Typical Cases

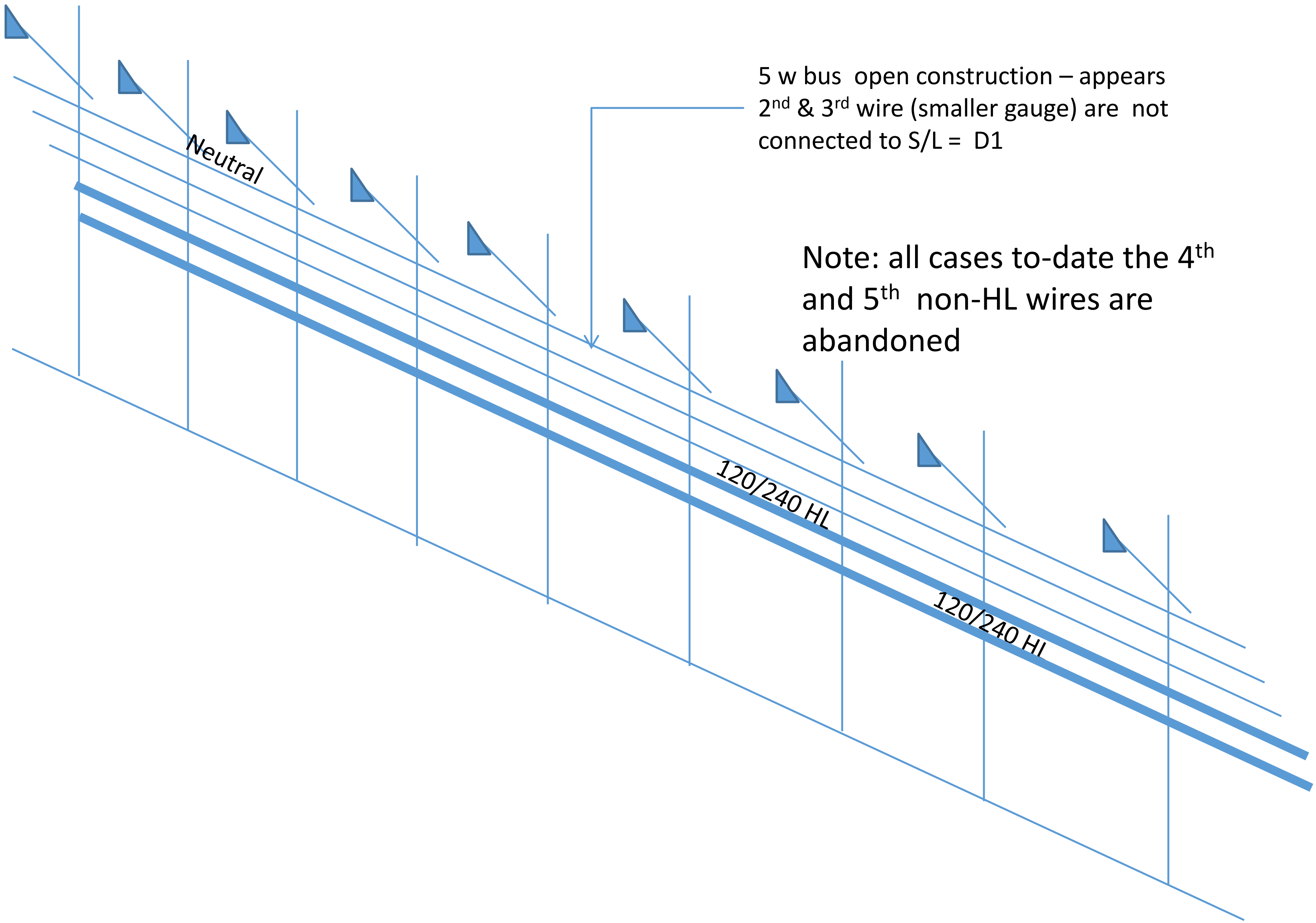

3 wire triplex or open construction house lighting -connected directly to S/L's = D1


Quadra-plex (bundled) - 4 w
secondary bus – small gauge
connected to S/L's = D1




4 w secondary bus open construction – small gauge wire (2nd from the top) connected to S/L = D2

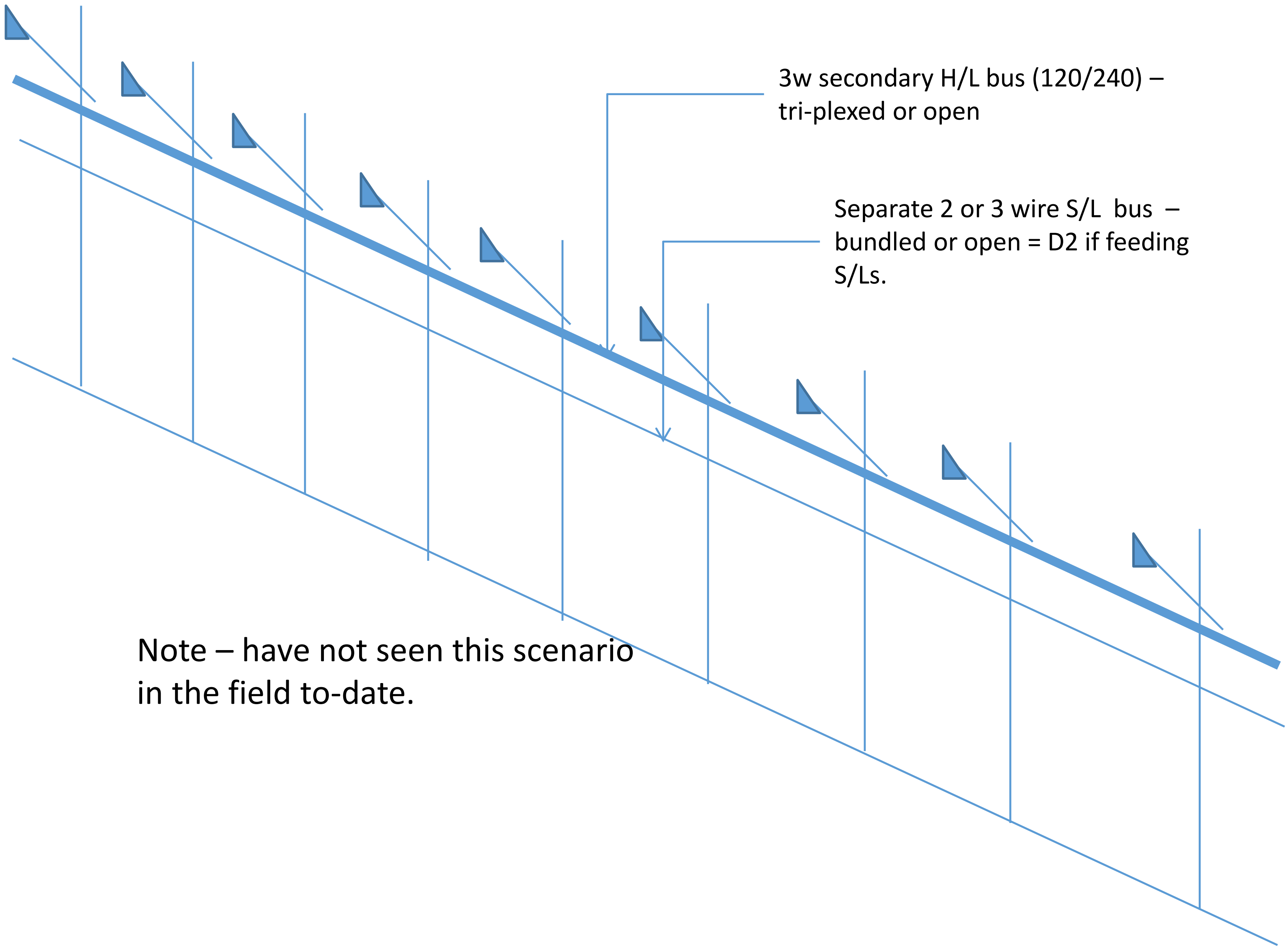
Note: all cases to-date the 4th non-HL wire is abandoned




5 w bus open construction – appears 2nd & 3rd wire (smaller gauge) are not connected to S/L = D1

Note: all cases to-date the 4th and 5th non-HL wires are abandoned

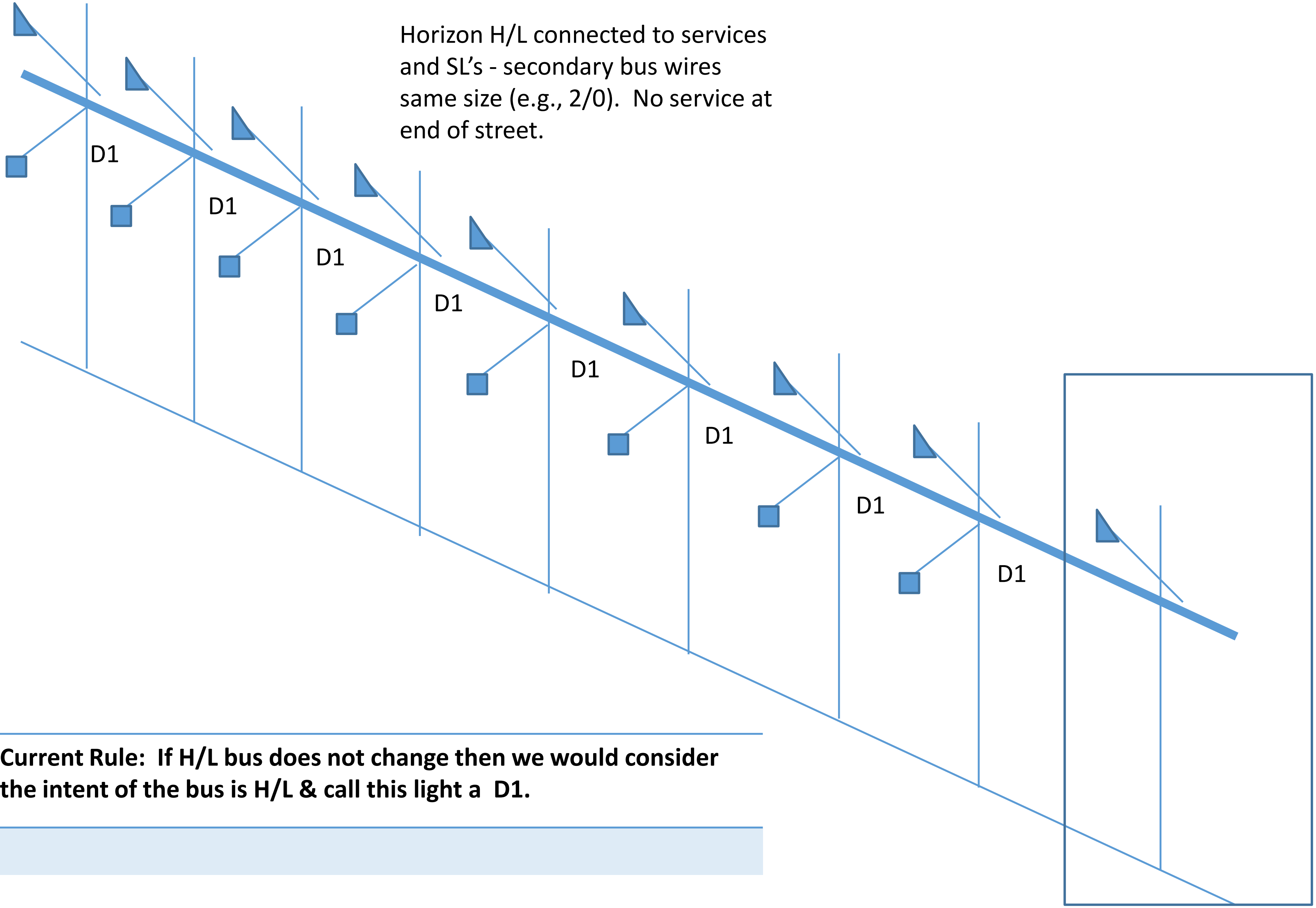
UTILITY SOLUTIONS CORPORATION




Note – have not seen this scenario in the field to-date.

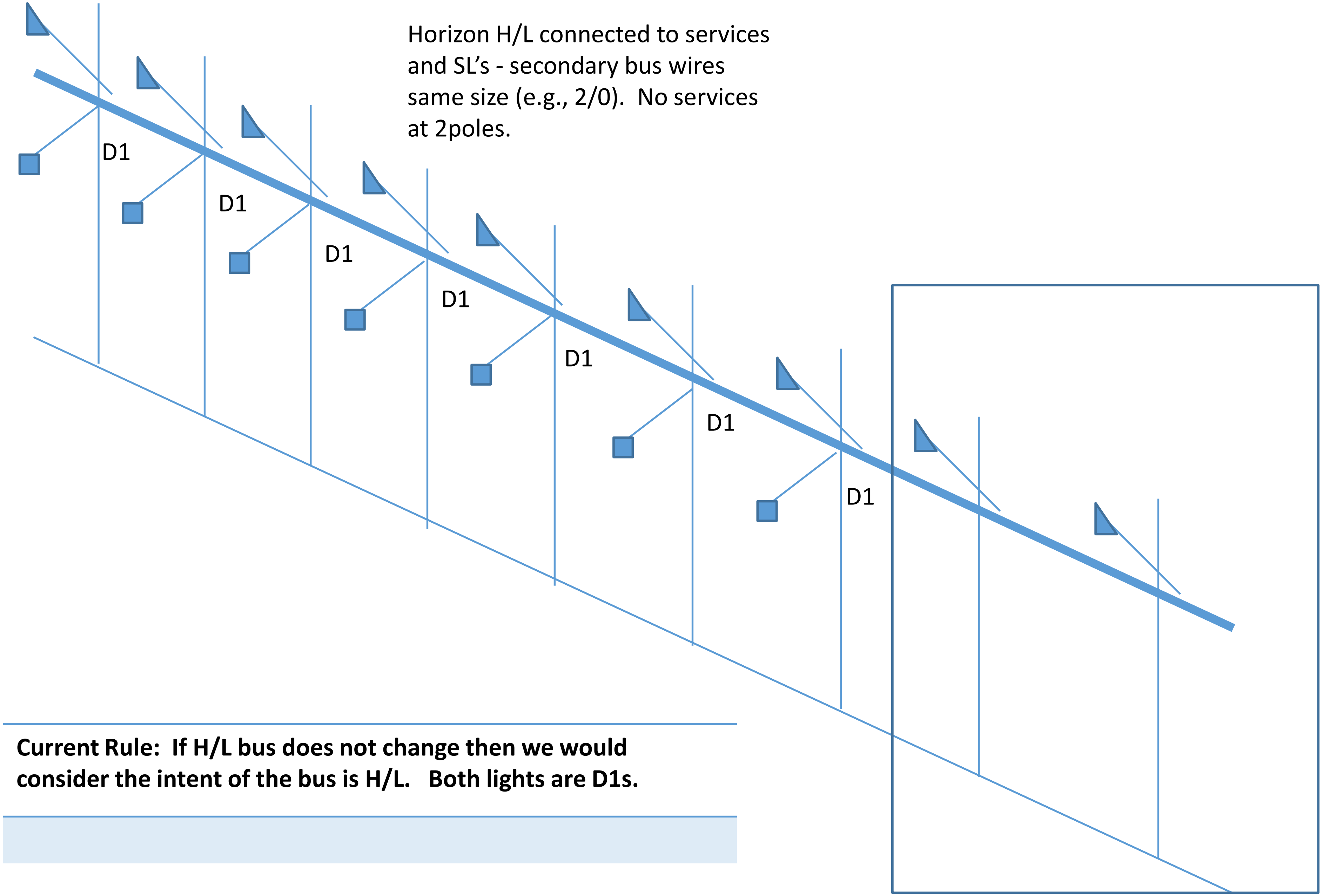
# Items for Discussion/Confirmation

Horizon H/L connected to services and SL's - secondary bus wires same size (e.g., 2/0). No service at end of street.

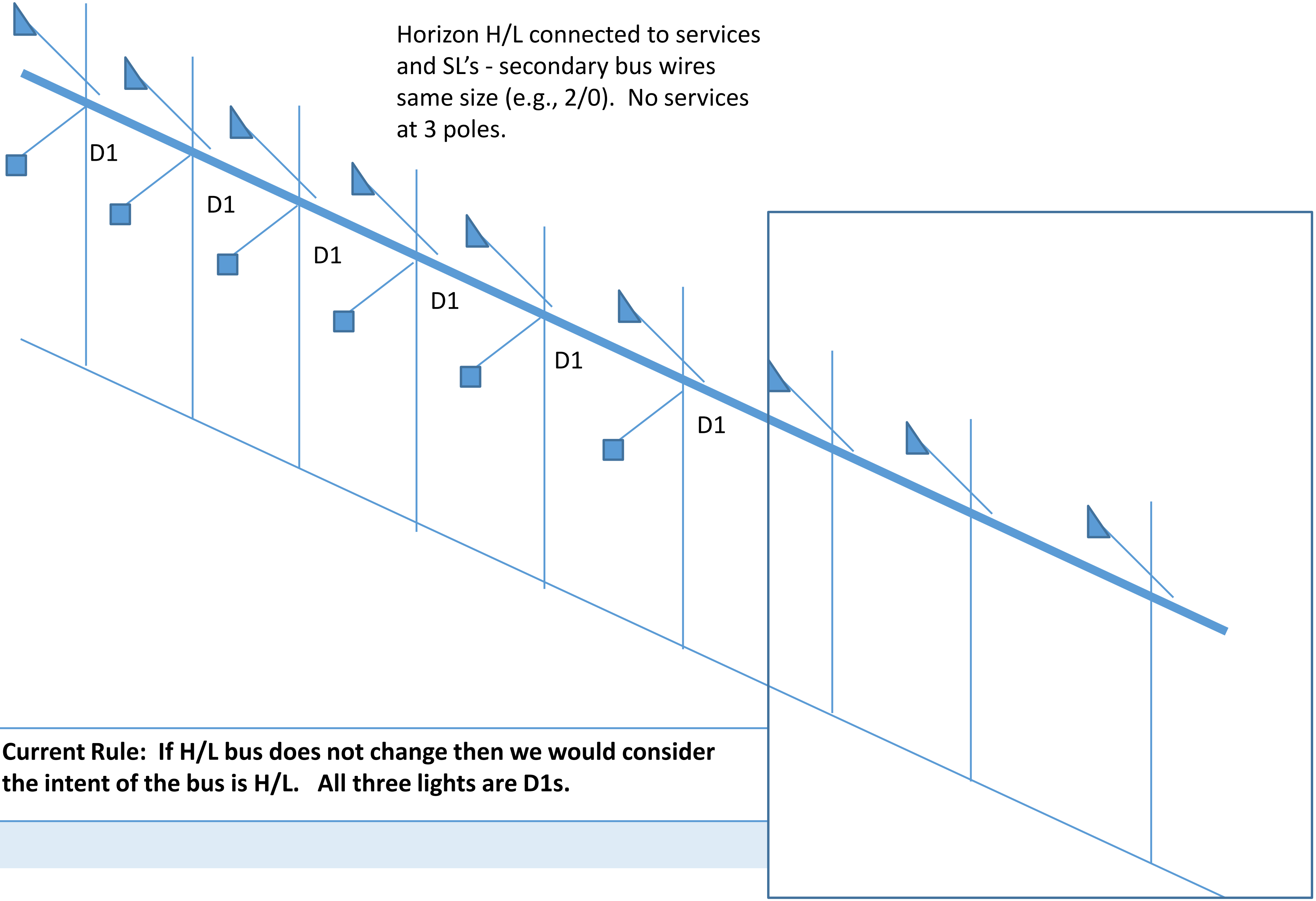



**Current Rule: If H/L bus does not change then we would consider the intent of the bus is H/L & call this light a D1.**

Horizon H/L connected to services and SL's - secondary bus wires same size (e.g., 2/0). No services at 2poles.

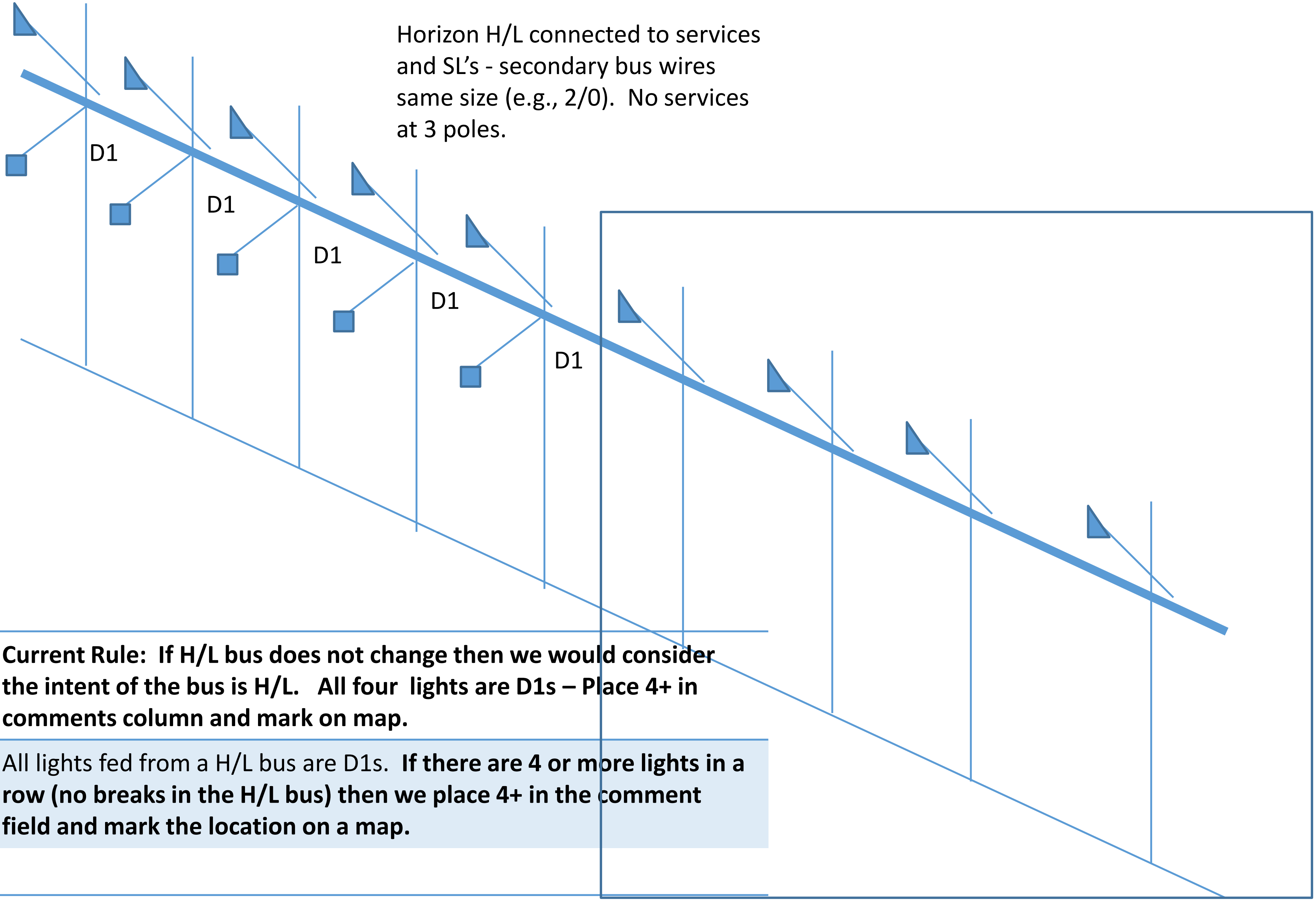



**Current Rule: If H/L bus does not change then we would consider the intent of the bus is H/L. Both lights are D1s.**




**Current Rule: If H/L bus does not change then we would consider the intent of the bus is H/L. All three lights are D1s.**

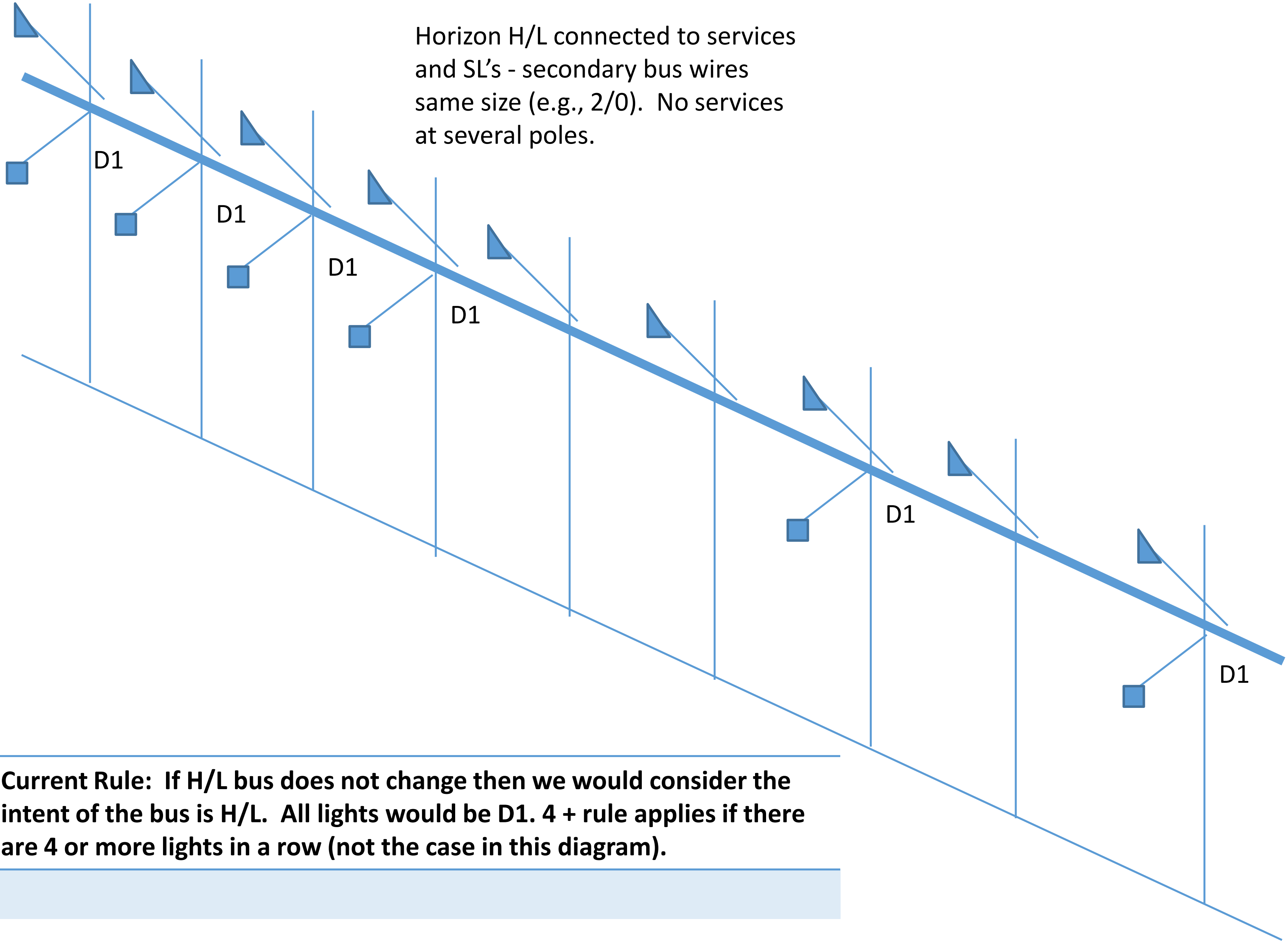
Horizon H/L connected to services and SL's - secondary bus wires same size (e.g., 2/0). No services at 3 poles.




**Current Rule: If H/L bus does not change then we would consider the intent of the bus is H/L. All four lights are D1s – Place 4+ in comments column and mark on map.**

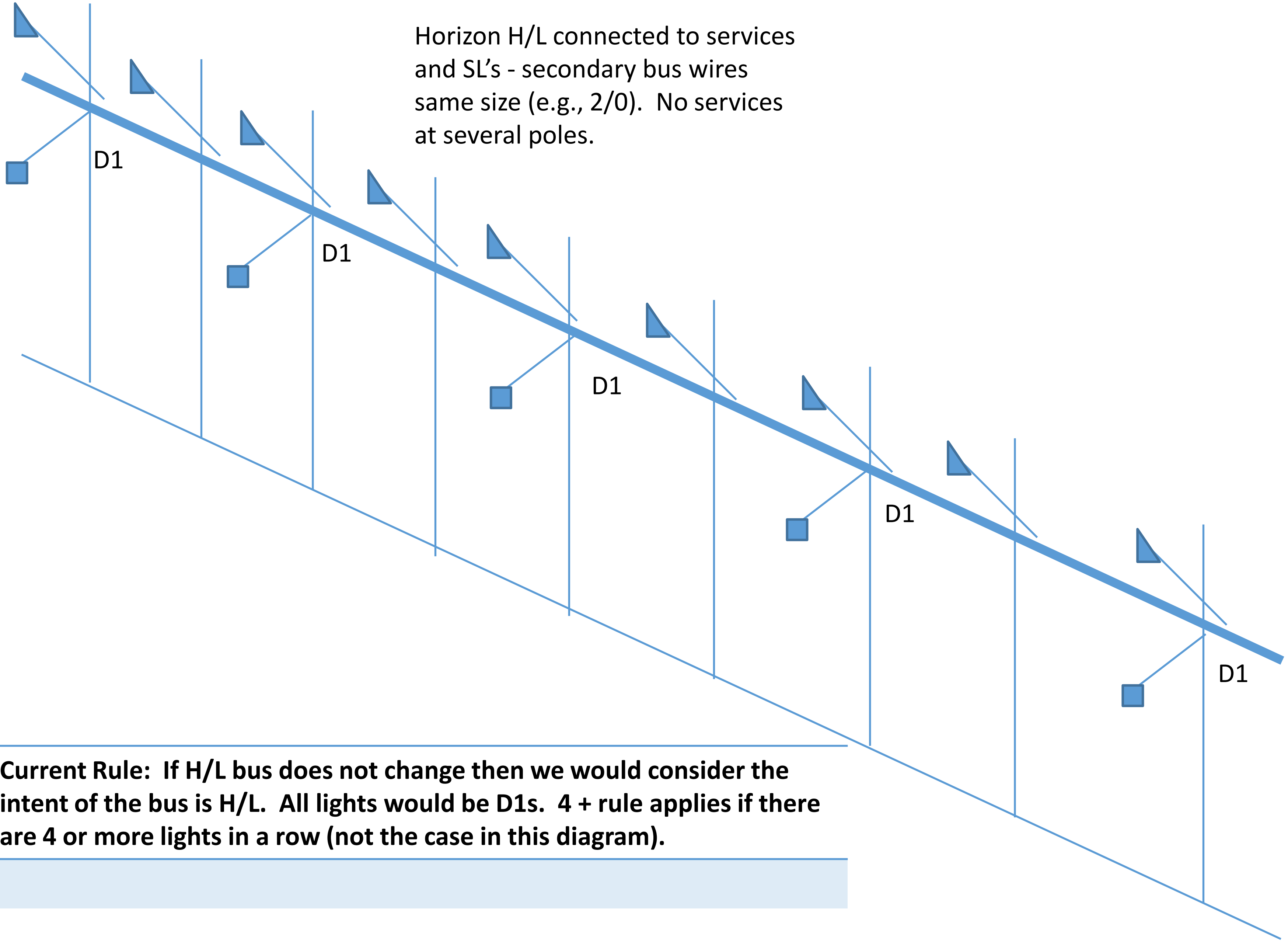
All lights fed from a H/L bus are D1s. **If there are 4 or more lights in a row (no breaks in the H/L bus) then we place 4+ in the comment field and mark the location on a map.**

Horizon H/L connected to services and SL's - secondary bus wires same size (e.g., 2/0). No services at several poles.

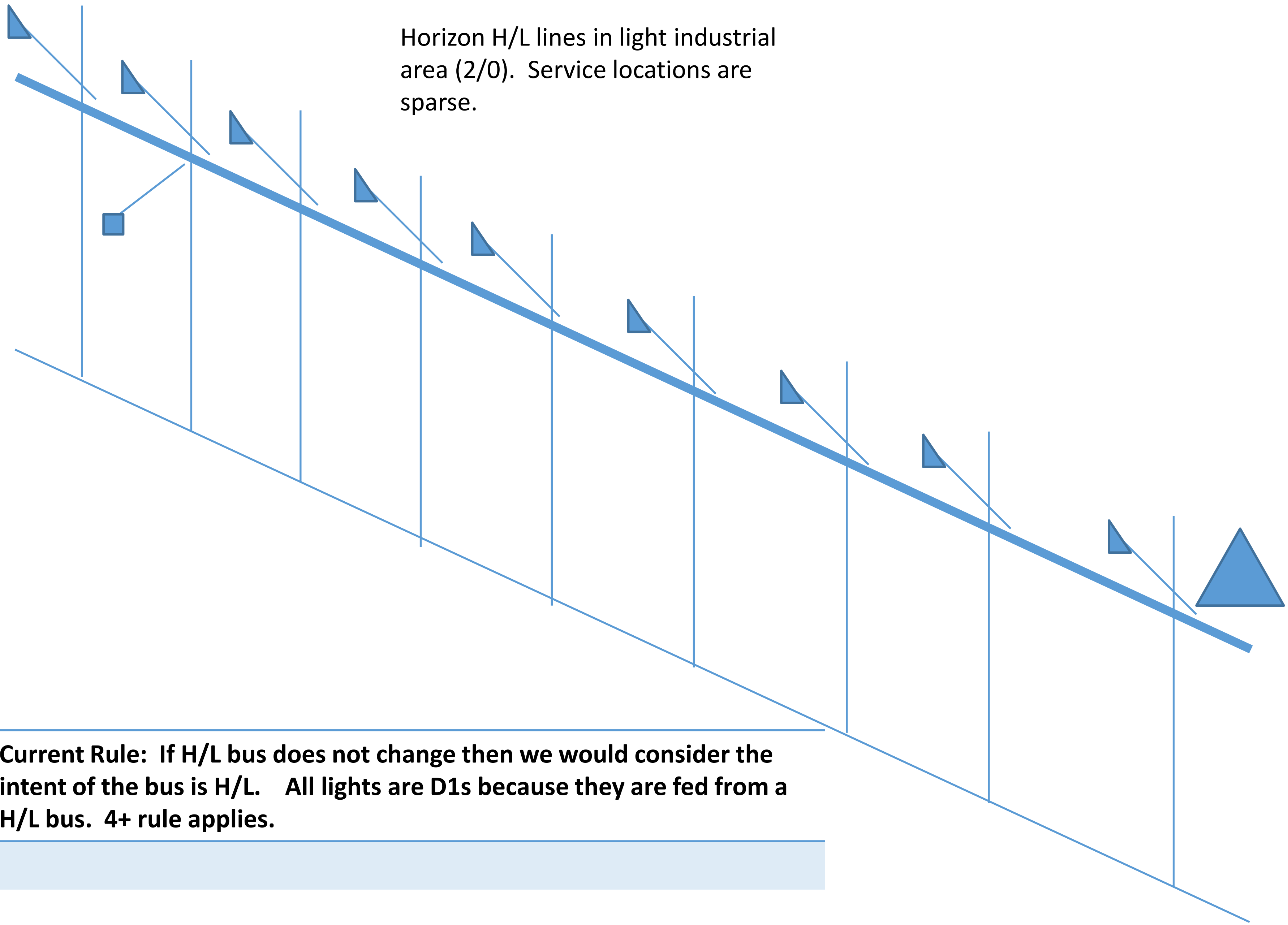



**Current Rule: If H/L bus does not change then we would consider the intent of the bus is H/L. All lights would be D1. 4 + rule applies if there are 4 or more lights in a row (not the case in this diagram).**

Horizon H/L connected to services and SL's - secondary bus wires same size (e.g., 2/0). No services at several poles.



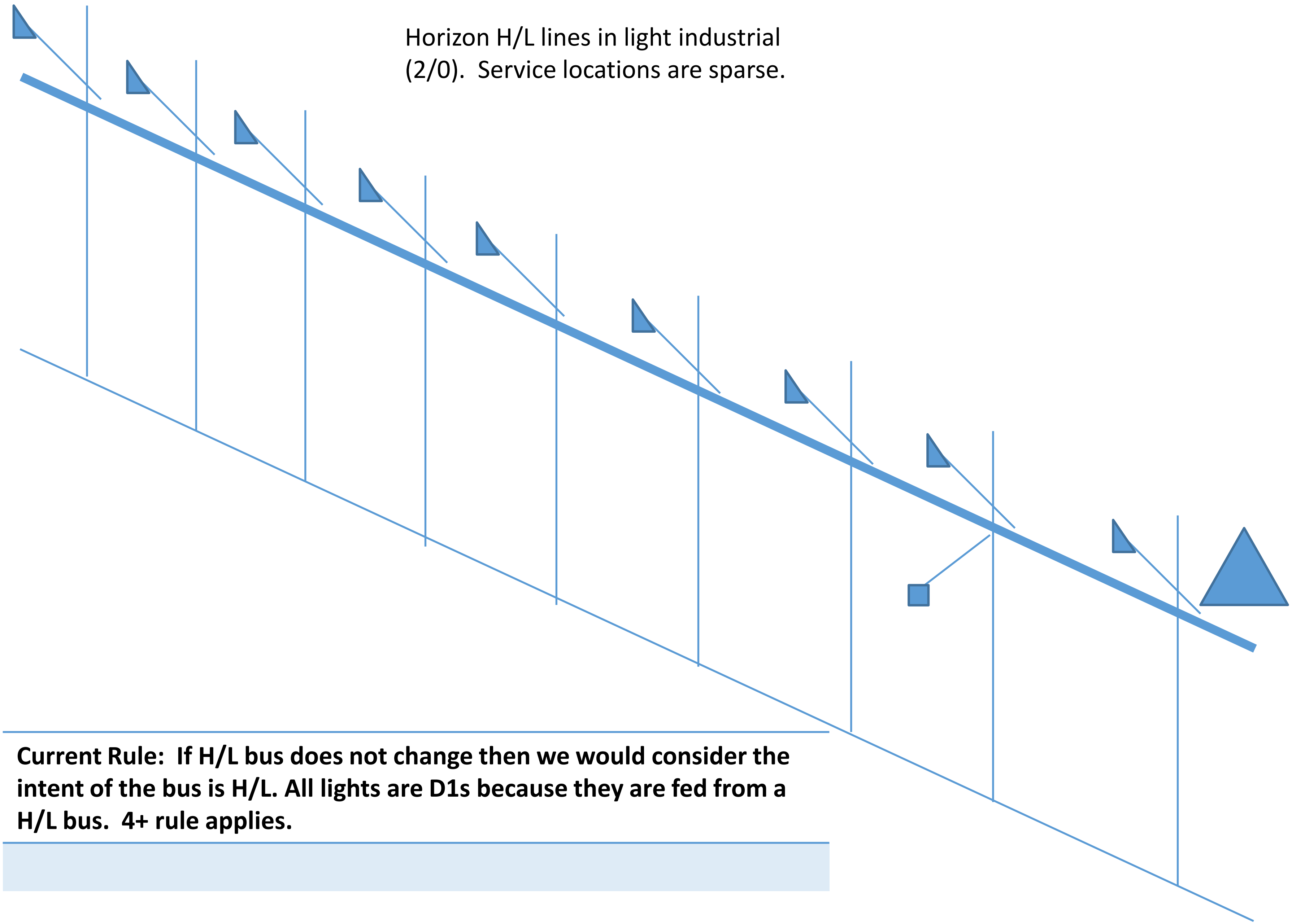

**Current Rule: If H/L bus does not change then we would consider the intent of the bus is H/L. All lights would be D1s. 4 + rule applies if there are 4 or more lights in a row (not the case in this diagram).**



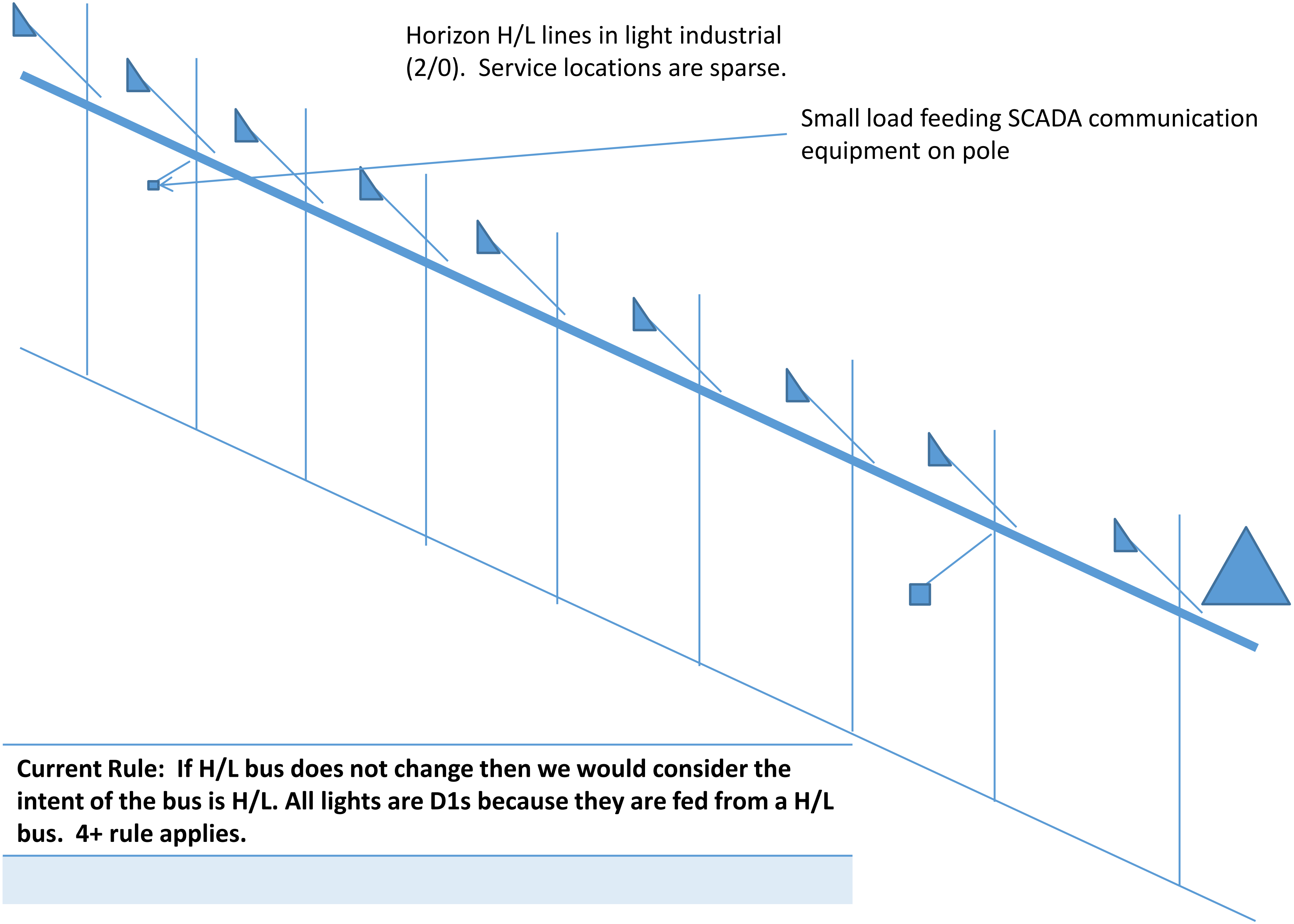
Horizon H/L lines in light industrial area (2/0). Service locations are sparse.

**Current Rule: If H/L bus does not change then we would consider the intent of the bus is H/L. All lights are D1s because they are fed from a H/L bus. 4+ rule applies.**

Horizon H/L lines in light industrial (2/0). Service locations are sparse.



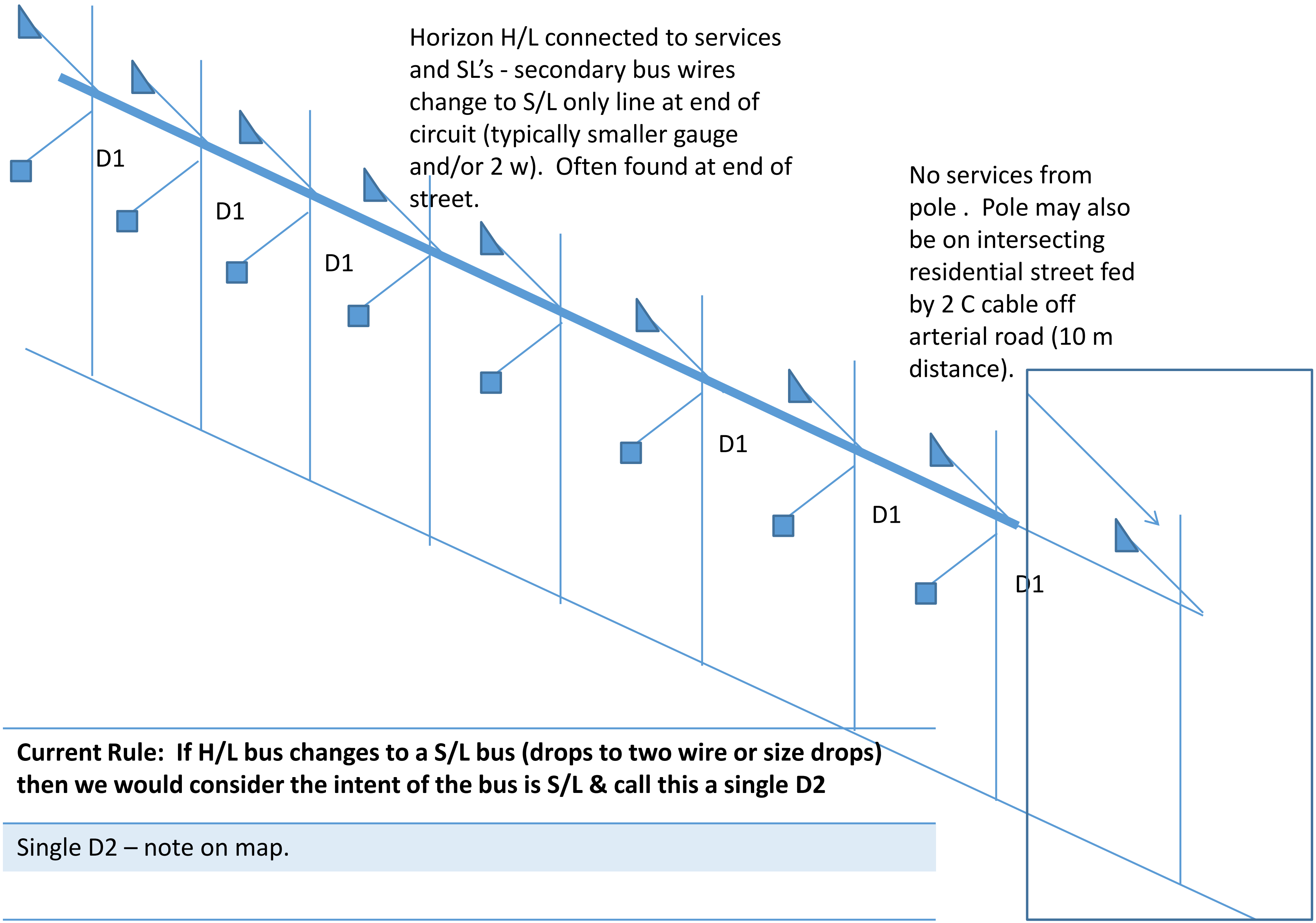
**Current Rule: If H/L bus does not change then we would consider the intent of the bus is H/L. All lights are D1s because they are fed from a H/L bus. 4+ rule applies.**




**Current Rule: If H/L bus does not change then we would consider the intent of the bus is H/L. All lights are D1s because they are fed from a H/L bus. 4+ rule applies.**

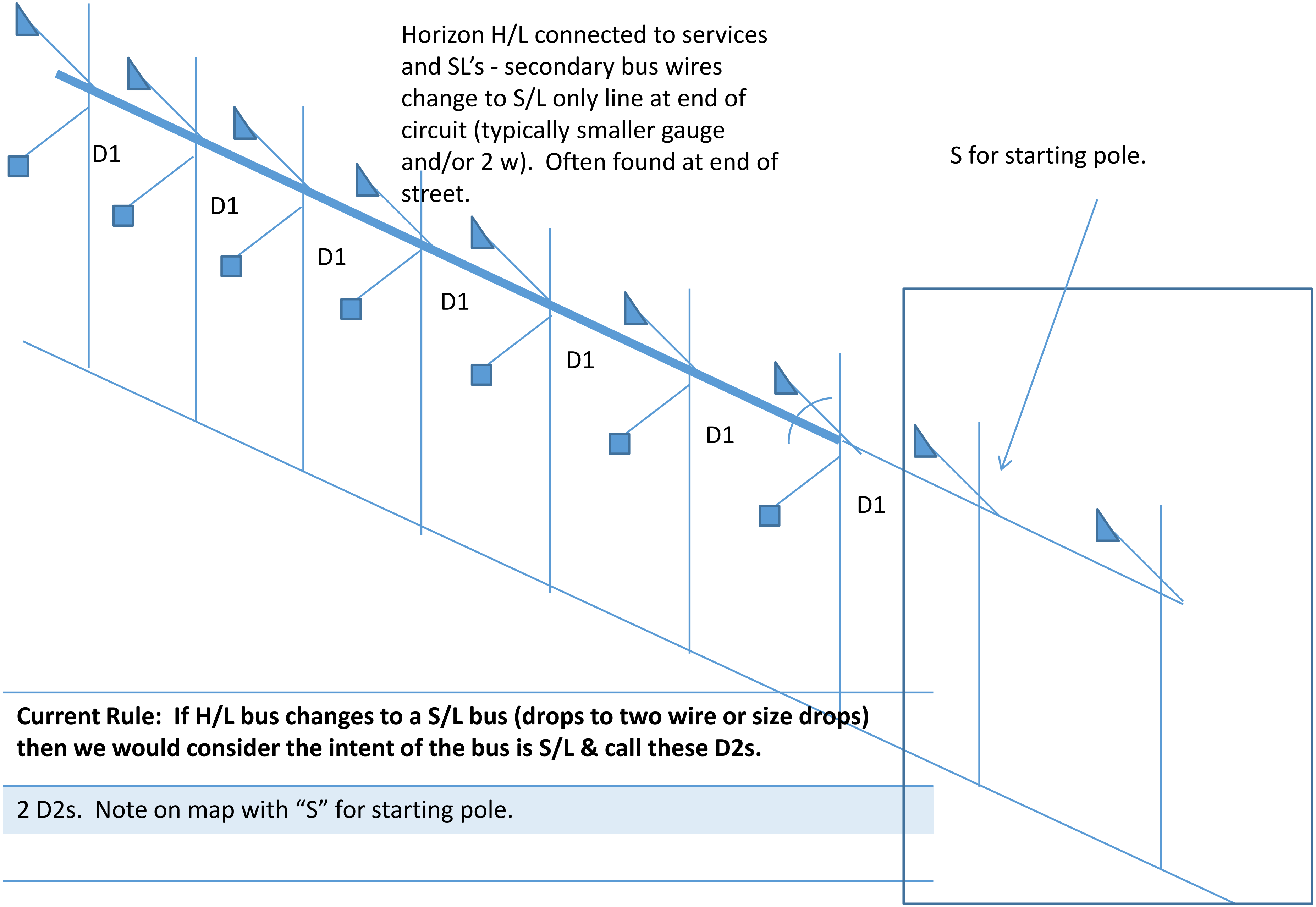
Horizon H/L connected to services and SL's - secondary bus wires change to S/L only line at end of circuit (typically smaller gauge and/or 2 w). Often found at end of street.

No services from pole . Pole may also be on intersecting residential street fed by 2 C cable off arterial road (10 m distance).



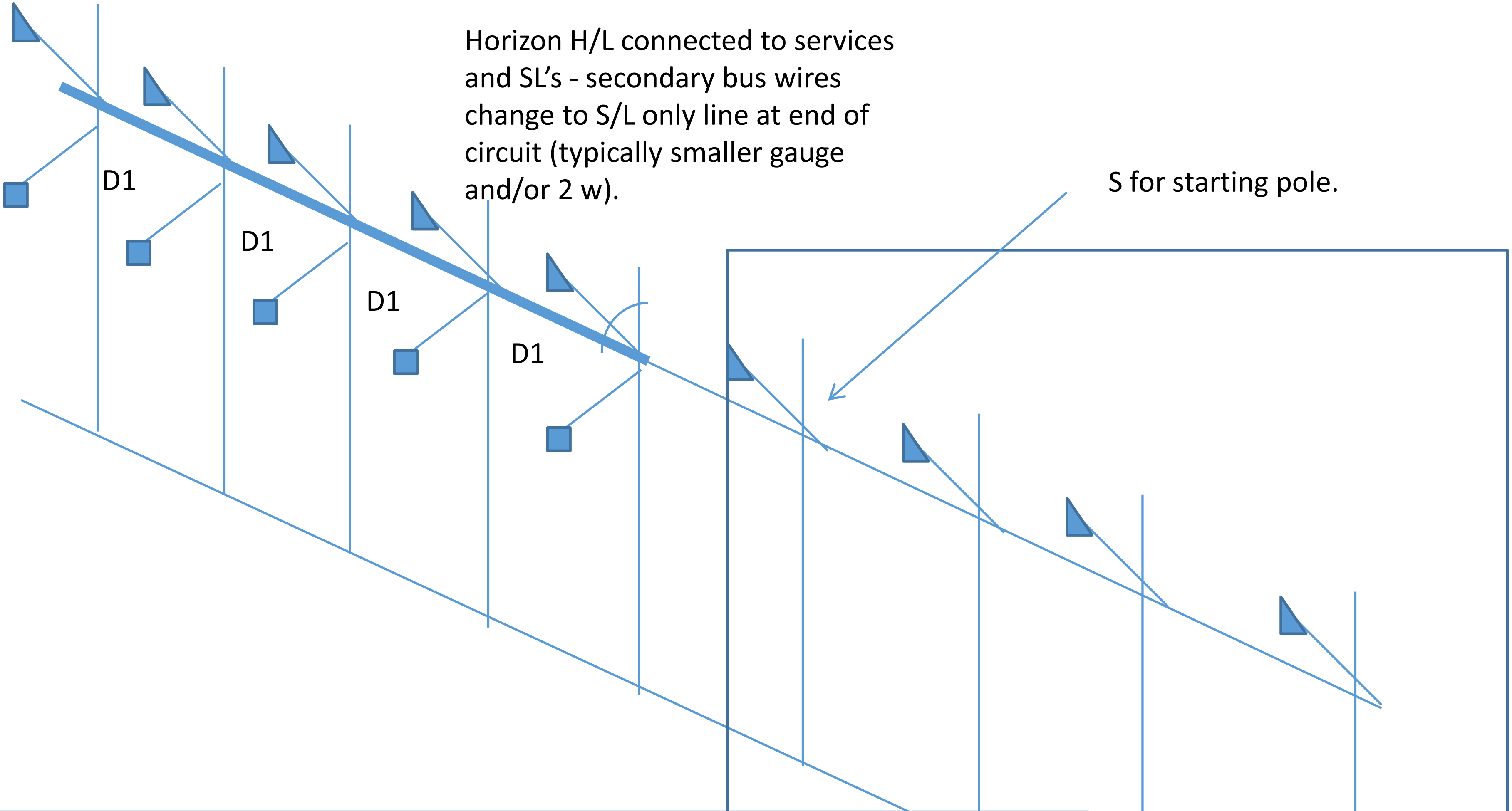

**Current Rule: If H/L bus changes to a S/L bus (drops to two wire or size drops) then we would consider the intent of the bus is S/L & call this a single D2**

Single D2 – note on map.



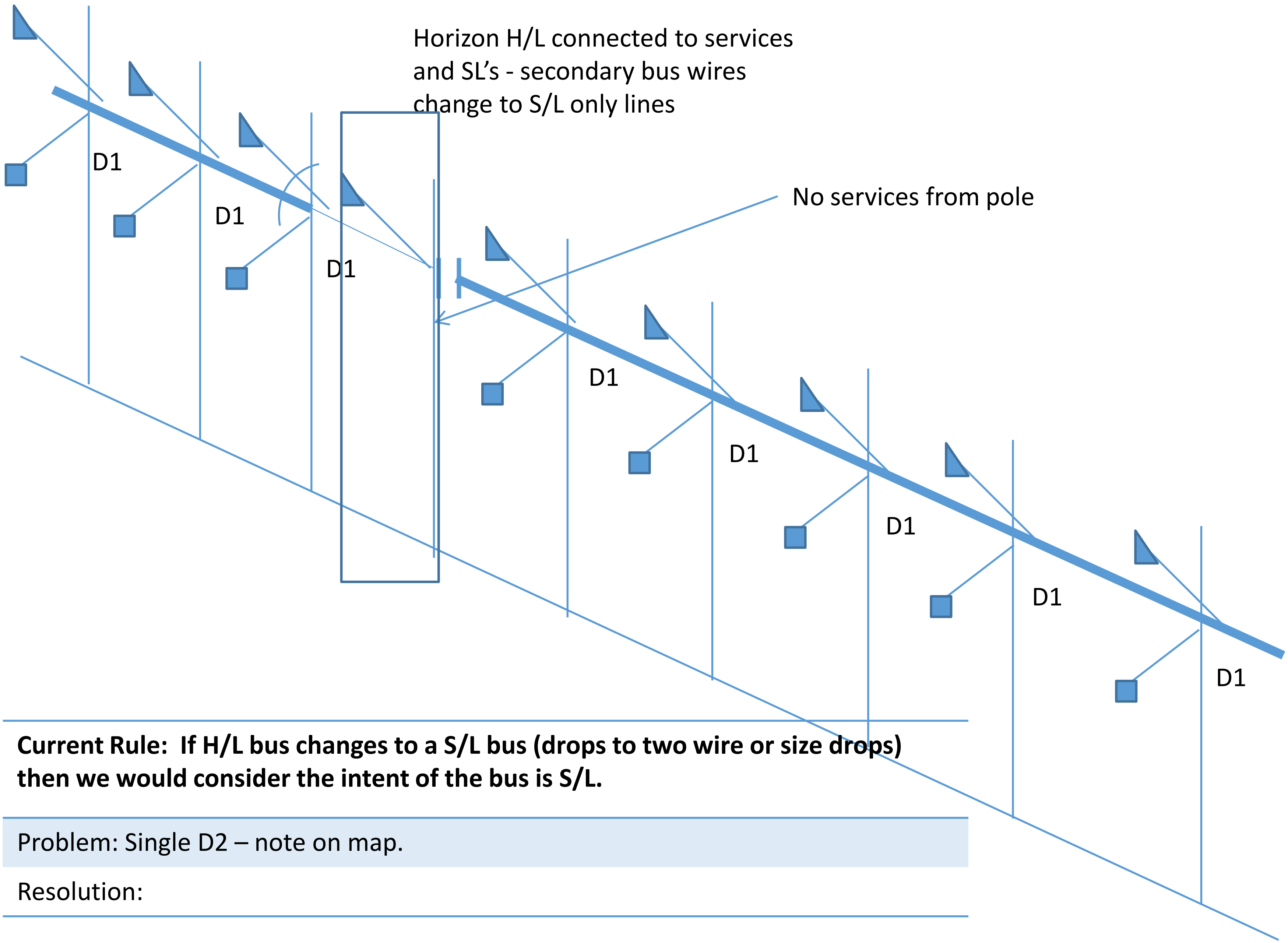

**Current Rule: If H/L bus changes to a S/L bus (drops to two wire or size drops) then we would consider the intent of the bus is S/L & call these D2s.**

2 D2s. Note on map with "S" for starting pole.




**Current Rule: If H/L bus changes to a S/L bus (drops to two wire or size drops) then we would consider the intent of the bus is S/L & call these D2s.**

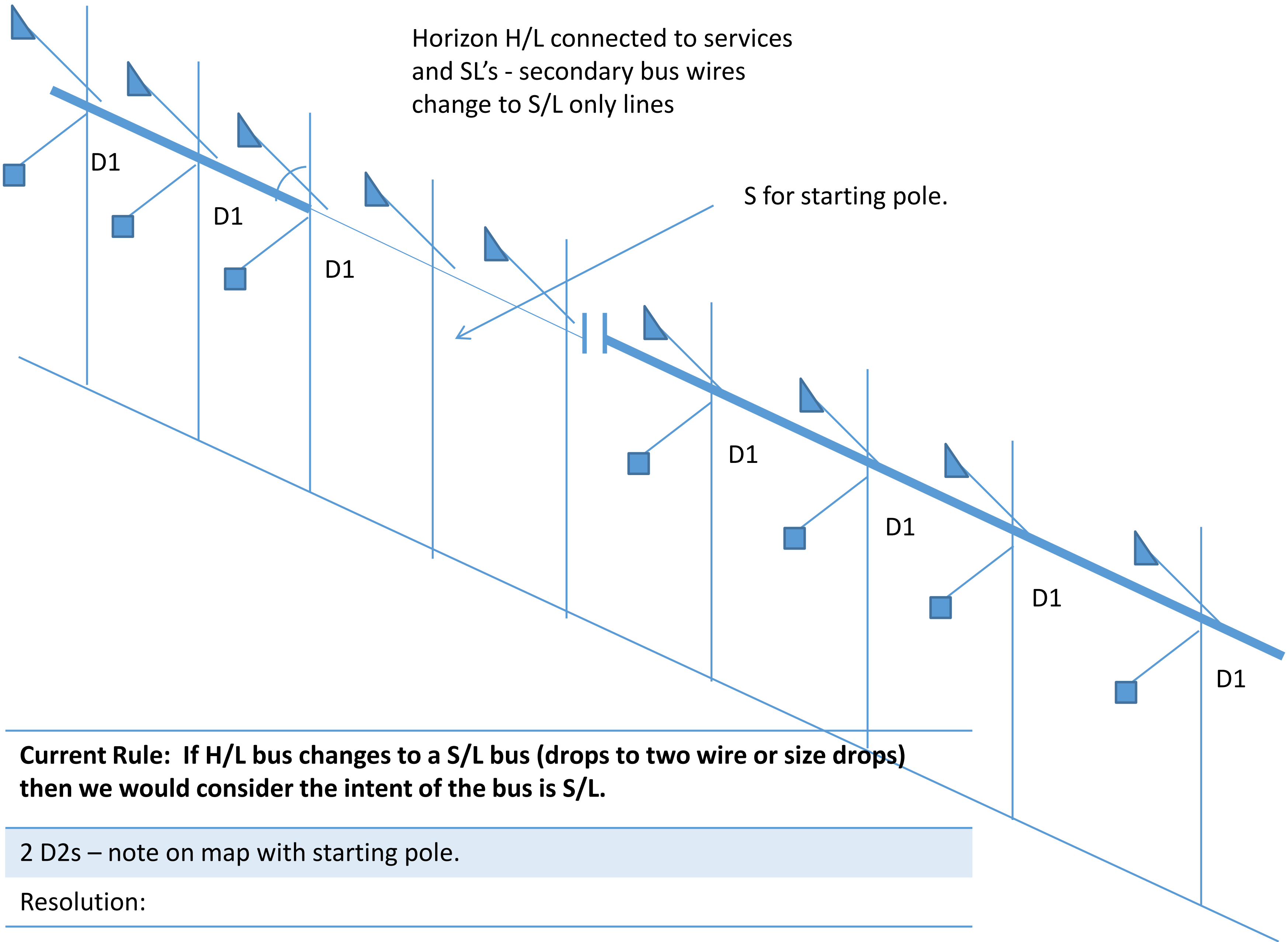
4D2s. 4 D2s. Note on map with "S" for starting pole.




**Current Rule: If H/L bus changes to a S/L bus (drops to two wire or size drops) then we would consider the intent of the bus is S/L.**

Problem: Single D2 – note on map.

Resolution:

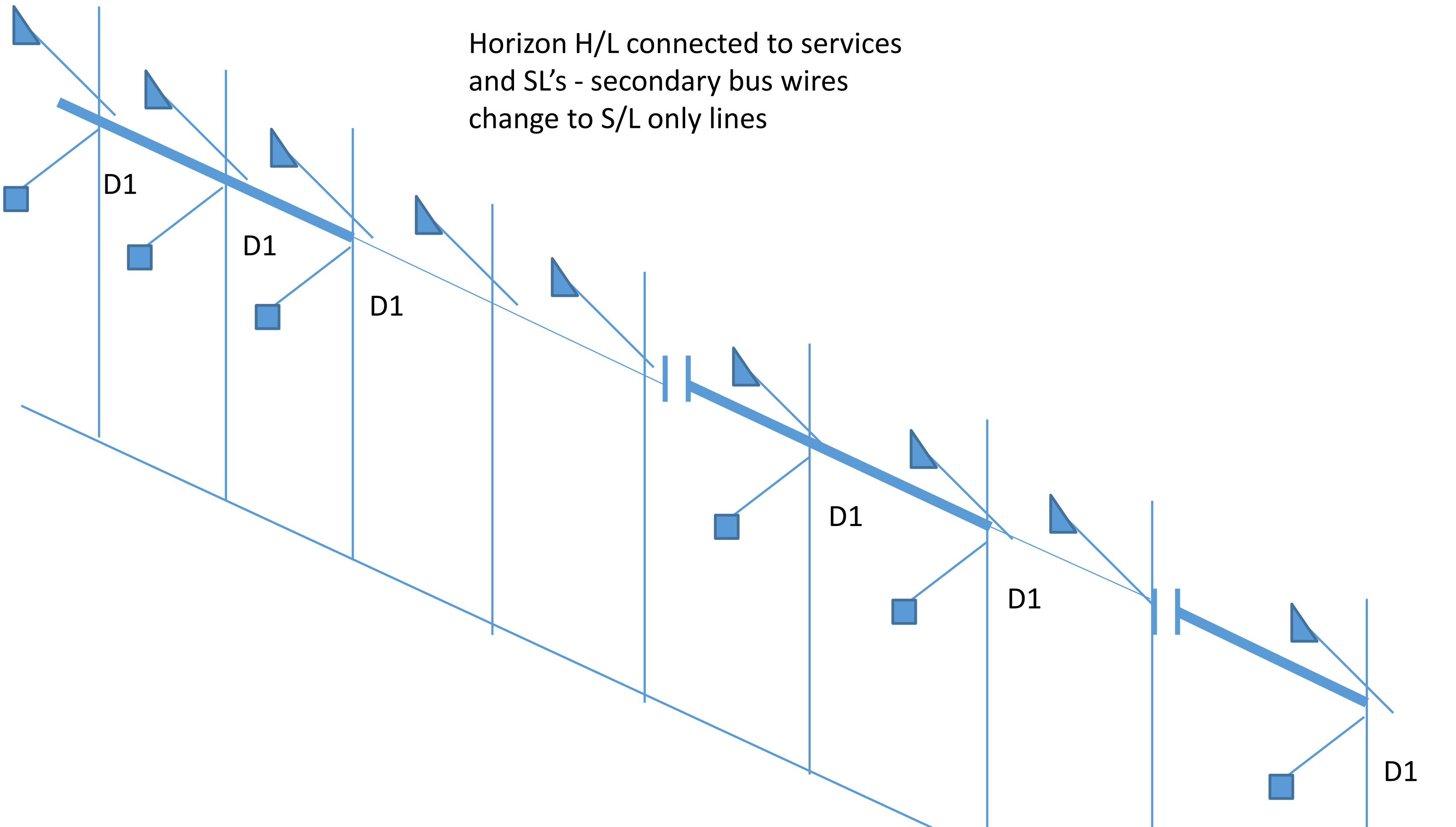



**Current Rule: If H/L bus changes to a S/L bus (drops to two wire or size drops) then we would consider the intent of the bus is S/L.**

2 D2s – note on map with starting pole.

Resolution:

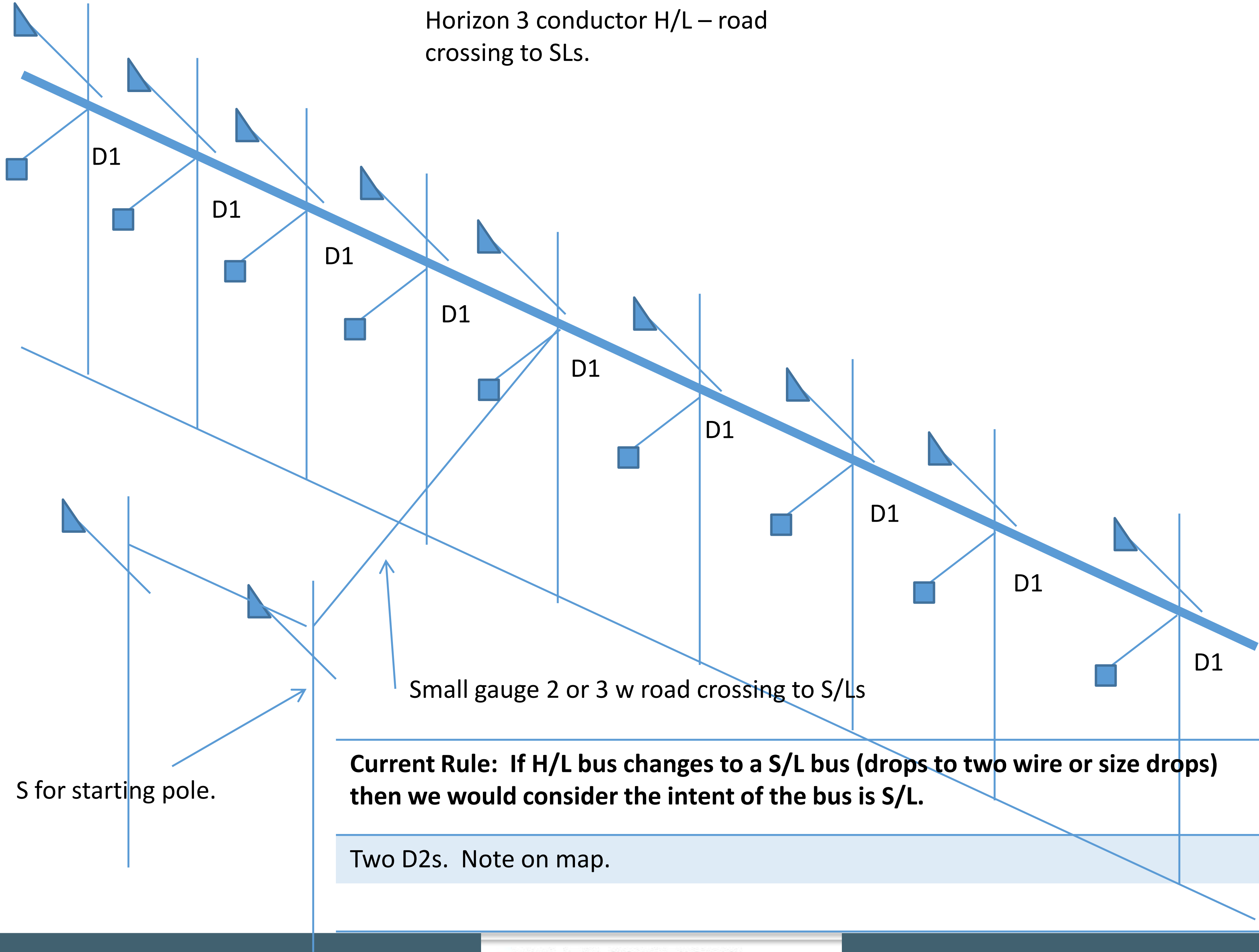
Horizon H/L connected to services and SL's - secondary bus wires change to S/L only lines




**Current Rule: If H/L bus changes to a S/L bus (drops to two wire or size drops) then we would consider the intent of the bus is S/L.**

Two D2s + 1 D2 – Note as two separate locations on map.

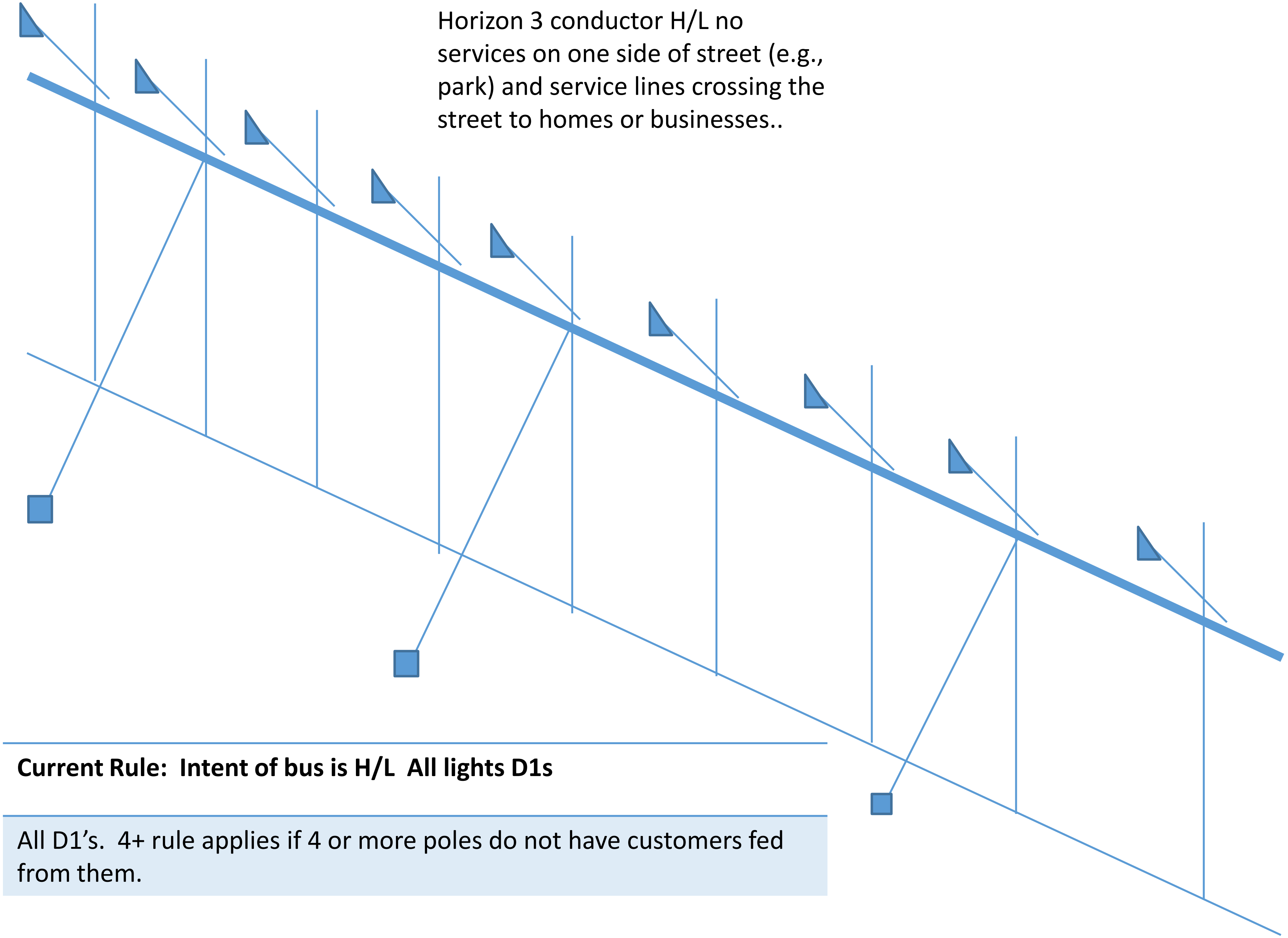
Horizon 3 conductor H/L – road crossing to SLs.




**Current Rule: If H/L bus changes to a S/L bus (drops to two wire or size drops) then we would consider the intent of the bus is S/L.**

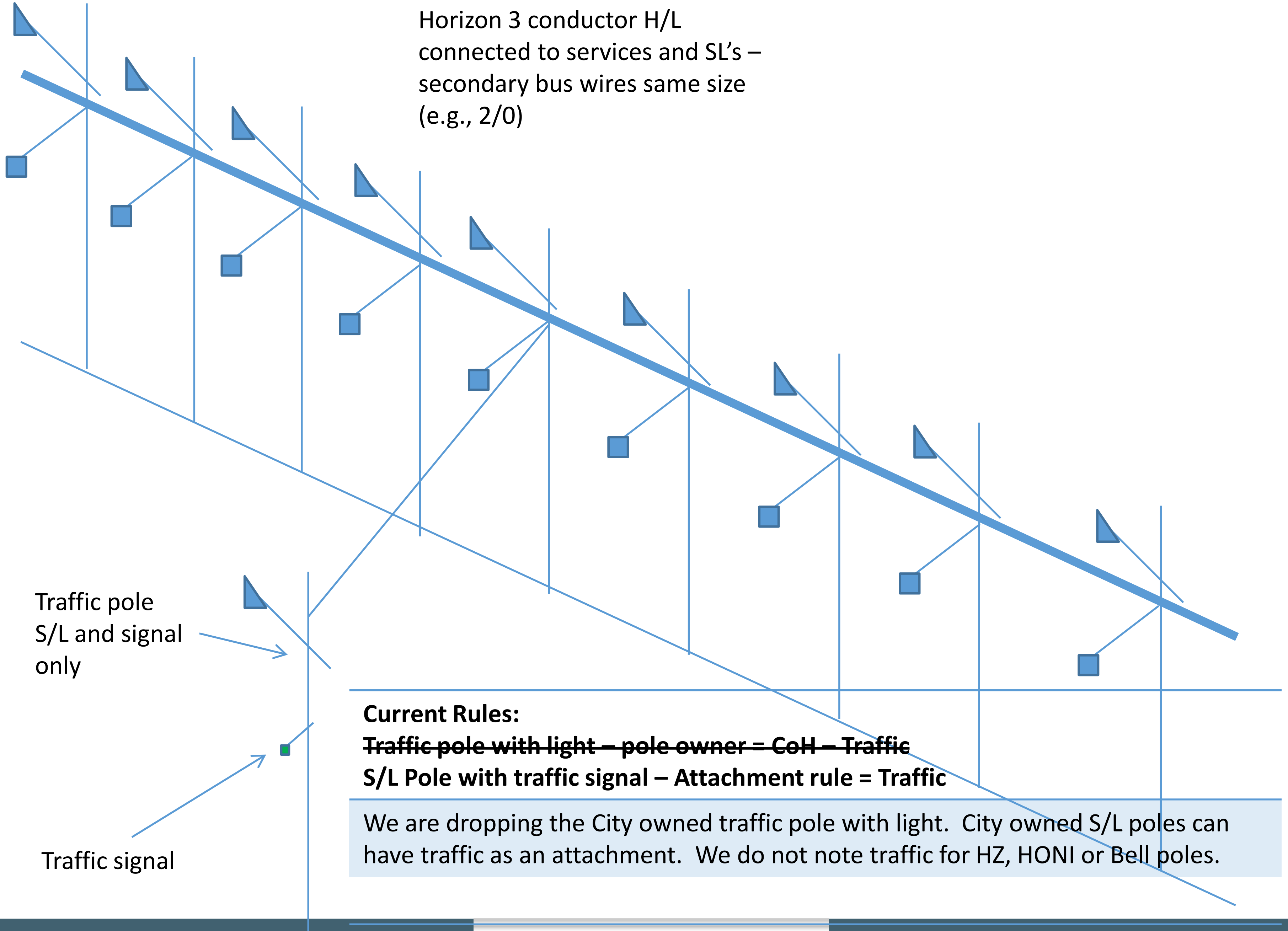
Two D2s. Note on map.

Horizon 3 conductor H/L no services on one side of street (e.g., park) and service lines crossing the street to homes or businesses..



**Current Rule: Intent of bus is H/L All lights D1s**

All D1's. 4+ rule applies if 4 or more poles do not have customers fed from them.

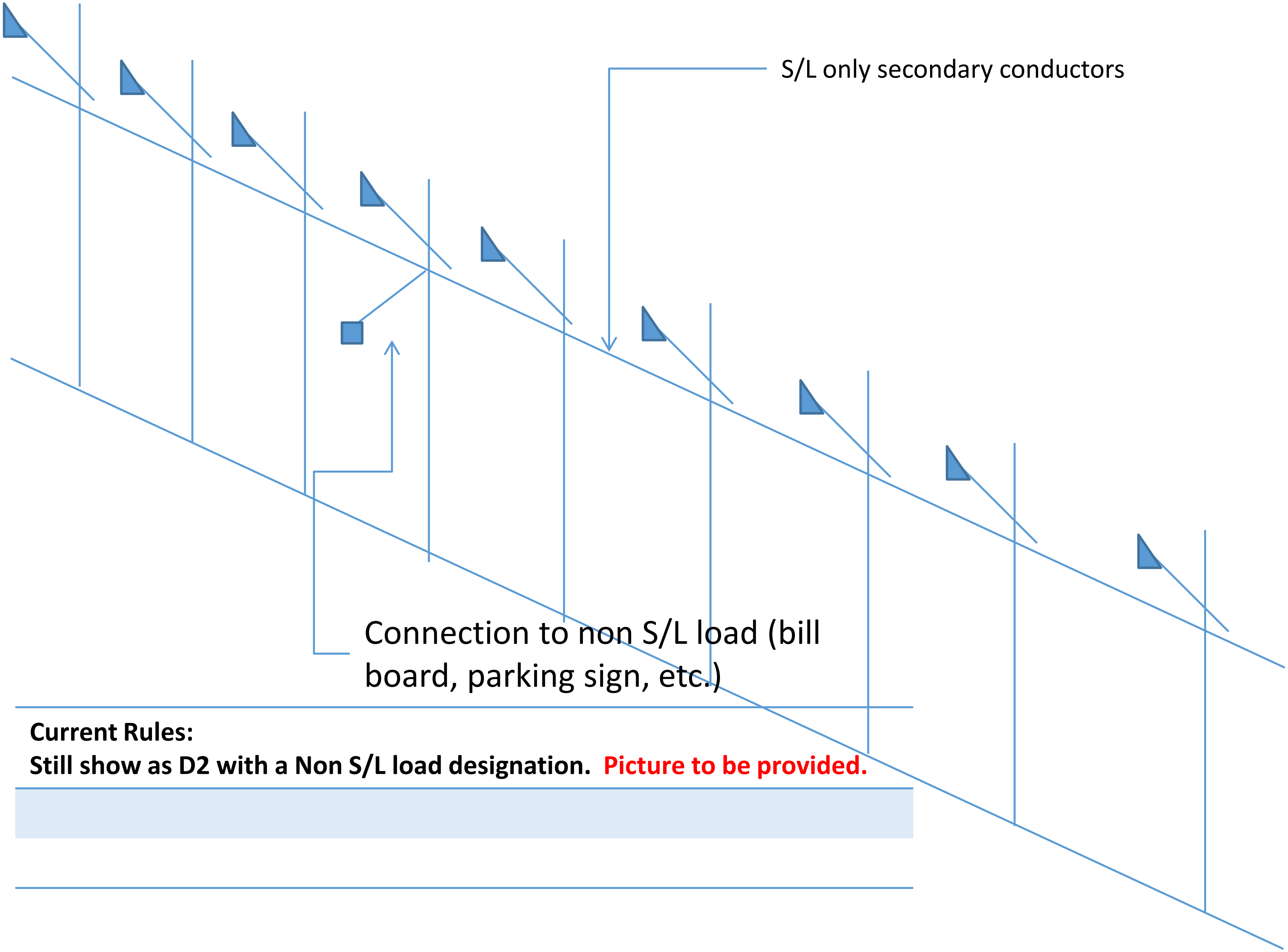



**Current Rules:**

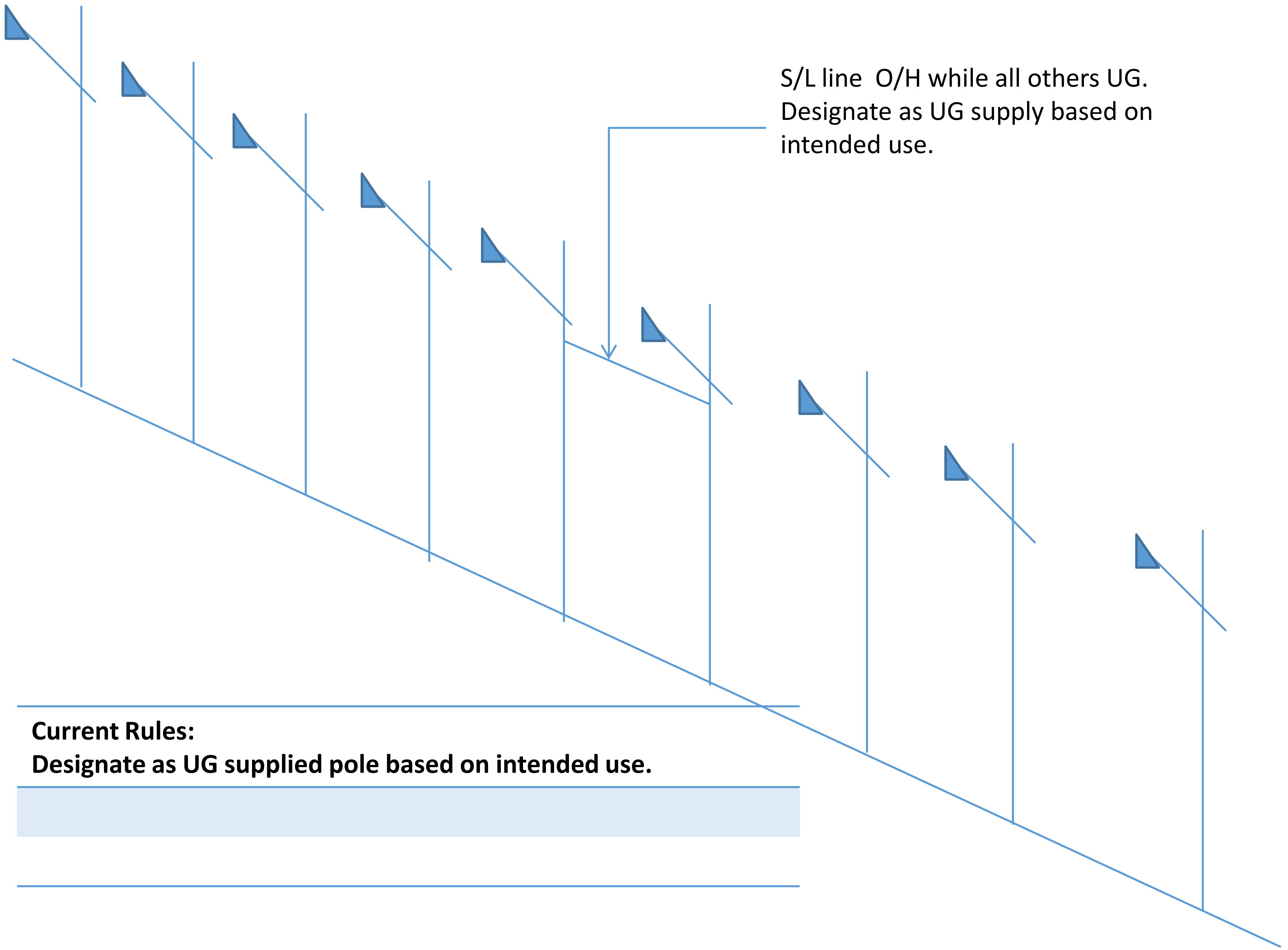
~~**Traffic pole with light – pole owner = CoH – Traffic**~~

**S/L Pole with traffic signal – Attachment rule = Traffic**

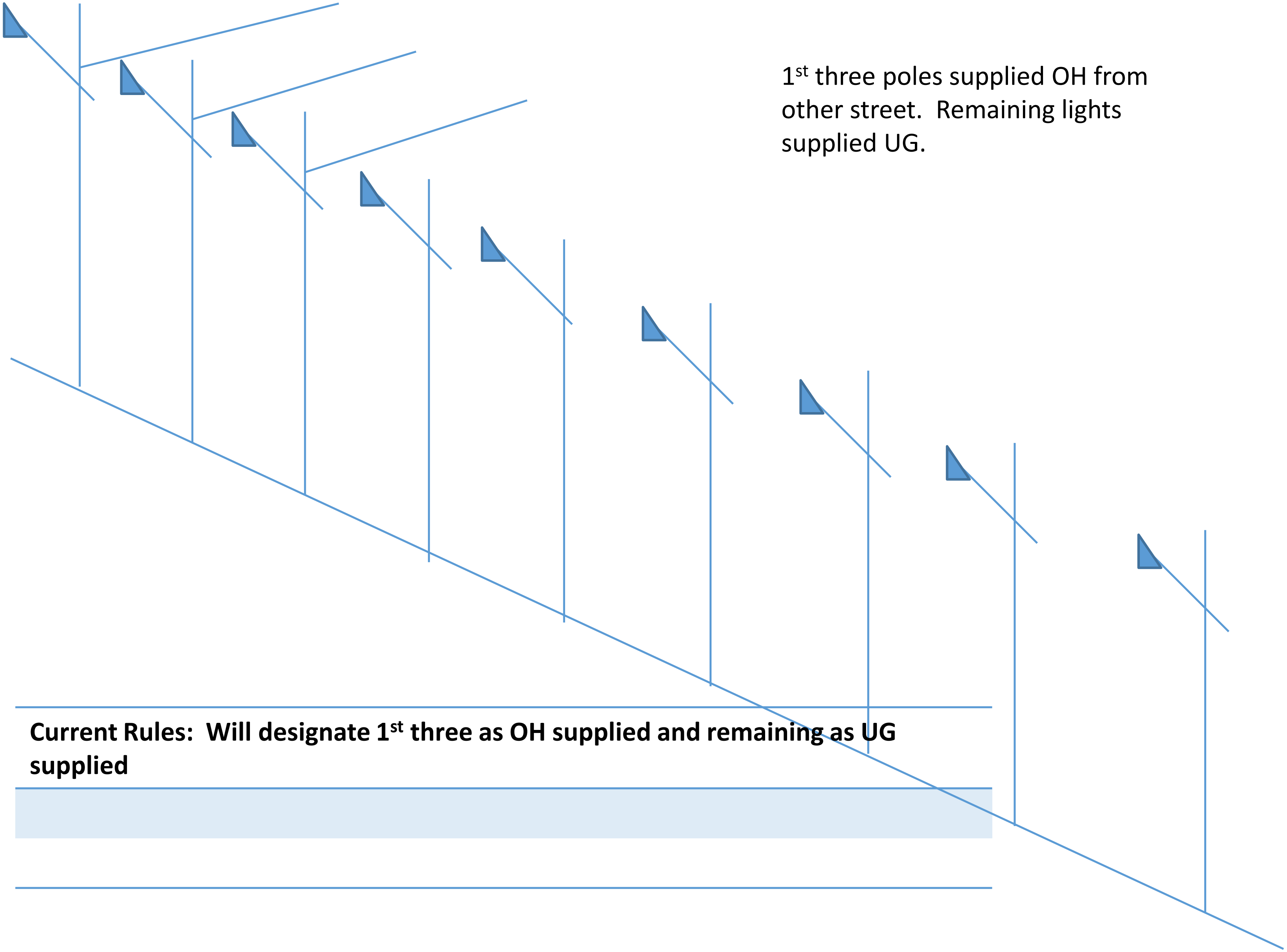
We are dropping the City owned traffic pole with light. City owned S/L poles can have traffic as an attachment. We do not note traffic for HZ, HONI or Bell poles.




**Current Rules:**
**Still show as D2 with a Non S/L load designation. Picture to be provided.**

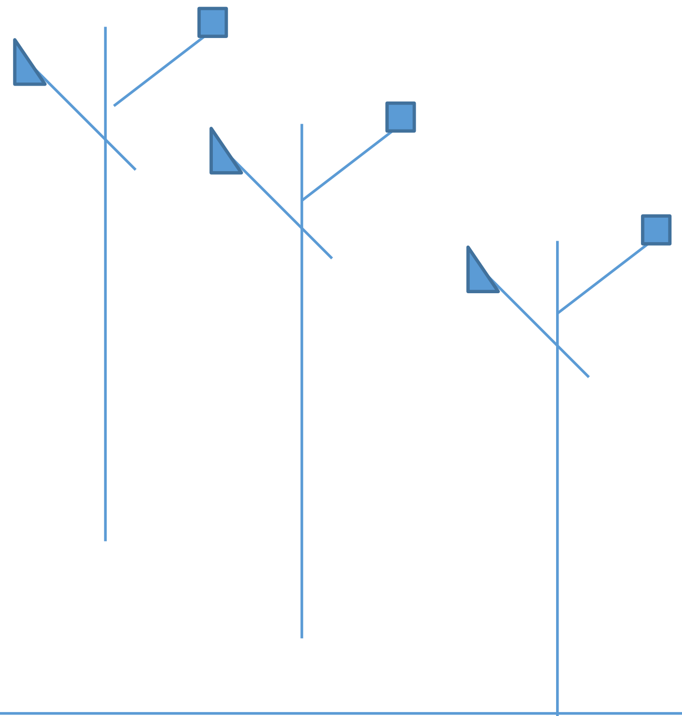



**Current Rules:**
**Designate as UG supplied pole based on intended use.**



1st three poles supplied OH from other street.  Remaining lights supplied UG.

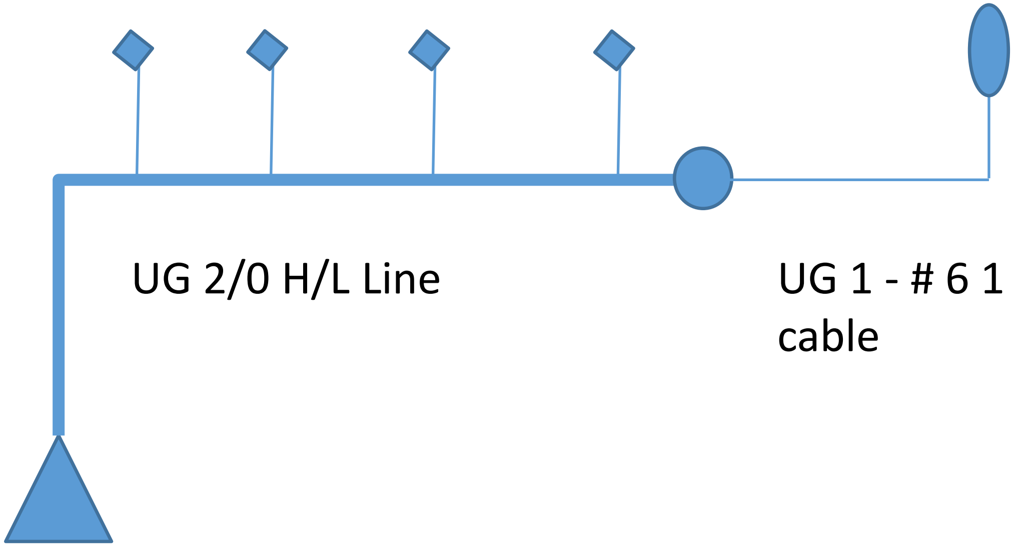
**Current Rules:  Will designate 1st three as OH supplied and remaining as UG supplied**



**Current Rules: Appear as typical UG fed S/L poles, however residential service lines exit top of pole. Designate pole ownership as HZ rather than CoH.**

Put unknown for D1 or D2 – these will be sorted out in the office.

Make a note if it appears that the S/L conductors are connected to the service wires feeding the house.




**Current Rules:**
**S/Ls fed off same bus as homes are D1s**
**<u>S/Ls fed from separate cables from Xer or pedestal are D2s</u>**

Because this is a designated S/L wire, the light will be D2.

**C of H 8.** **Exhibit 1, Tab 2, Schedule 6, p. 6**

**Background:**

**i) In its prefiled evidence, Horizon states that "The Street Lighting usage per customer has remained stable through the 2011-2013 historical periods and based on the historical trend is forecasted to be similar over the forecasted Test Years".**

**ii) Between 2005 and what is projected for 2019, Horizon's distribution-based charges for street lighting will have increased from approximately $500,000 annually to approximately $2.8 million annually.**

(a) **What is the relationship between usage per customer and cost?**

(b) **If the usage per customer has remained stable, and is forecasted to remain stable, what is the basis for the claimed material increase in the cost to serve the street lighting class and in the corresponding material increase in the proposed rates?**

**Response:**

**(a)** Usage refers to electricity consumption (i.e., kW and kWh consumption) and the number of connections. For the street lighting class, the energy consumed per connection is very low relative to other classes and as a result, the kWh consumption has very little impact on the total allocated costs of the distribution system. The energy related costs allocated to the Street Light class are very small. Since street lights are normally not on in monthly peak demand hours, the Street Light class attracts very little in the way of demand-related costs. Almost all of the costs allocated to the Street Light class are customer-related (i.e., connection-related) costs. Compared to other customer classes, the costs allocated to the Street Light class are sensitive primarily to the number of connections. Table 1 provides a breakdown of the costs allocated to the Street Light class for 2015.

**Table 1: Street Lighting Allocated Costs:**

| 2015 Cost Allocation | | | | |
|---|---|---|---|---|
| **Allocator** | **Horizon Revenue Requirement** | **Allocated to Street Light** | **% of Total Horizon Costs** | **% of Total Street Light Costs** |
| Demand Related | 60,683,584 | 9,669 | 0.02% | 0.28% |
| Energy Related | 230,598 | 2,088 | 0.91% | 0.06% |
| Customer & Connection Related | 42,724,427 | 3,421,690 | 8.01% | 99.66% |
| Other | 14,795,333 | - | 0.00% | 0.00% |
| Total | 118,433,942 | 3,433,447 | 2.90% | 100.00% |

(b) The primary driver behind the increase in costs allocated to the Street Light class is the change in the daisy chain ratio. For the 2006 Information Filing to the Board (EB-2005-0317), Horizon Utilities had used an estimated 2:1 daisy chain ratio for this class. In its 2008 and 2011 Cost of Service Applications, in the absence of better information, Horizon Utilities continued to use the same 2:1 ratio.

More recently, a street light audit was completed by Utility Solutions Corporation for Horizon Utilities and the City of Hamilton. The audit was referenced and included in Horizon Utilities' response to Interrogatory City of Hamilton 7. The inclusion of the audit results in a weighted average ratio for the Street Lighting class as a whole produced a daisy chain ratio of 1.3141:1. As compared to the previously used ratio of 2:1, the revised ratio resulted in increased costs being allocated to the Street Light class.

**C of H 9. Exhibit 1, Tab 2, Schedule 6, p. 31**

**Background:**

**In its prefiled evidence, Horizon compares itself to the utilities in a cohort.**

**(a) What are the utilities to which Horizon compares itself and what is the basis for the comparison?**

**(b) For the utilities to which Horizon compares itself, has Horizon done the following:**

**(i) Compared the street lighting class cost on a per kWh consumed basis?**

**(ii) Compared its street lighting cost allocation as a percentage of total cost allocation?**

**(iii) Compared its percentage of revenue per device?**

**(iv) Compared its device to connection ratio?**

**Response:**

a) In its pre-filed evidence, Horizon Utilities compares itself to all utilities on the two metrics of revenue and controllable cost per customer and references its assignment to a performance based regulation cohort grouping under the OEB's Renewed Regulatory Framework for Electricity. In the latter, all distributors are benchmarked and compared against each other rather than the cohort. Based on performance, each utility is assigned to a cohort for the purposes of being assigned a stretch factor for improving performance. Horizon Utilities is in Cohort II, which is the group with the second best stretch factor. The cohort is not used to compare utilities with like characteristics. In other areas of its Application, Horizon Utilities does compare itself to other utilities on reliability metrics (See Page 20 of the Distribution System Plan included in the Application at Exhibit 2, Tab 6, Appendix 2-4). In its annual report, Horizon Utilities compares itself to all utilities and to Golden Horseshoe utilities on revenue per customer, controllable cost per customer and return on equity. It also compares itself to the average of all utilities on total revenues, operating expenditures, capital expenditures and payments in lieu of taxes for the purposes of determining the Global Reporting Initiative™ metric of Direct Economic Value.

b) For the utilities to which Horizon Utilities compares itself, Horizon Utilities has:

i. Not compared the street lighting class cost on a per kWh consumed basis. The industry uses comparisons across utilities on a total cost per kWh consumed basis as one of its cost benchmarks. The relative performance by this measure reflects the characteristics of each distributor's service area (e.g., its density and average customer size) as well as its operating efficiency.

ii. Not compared its street lighting cost allocation as a percentage of total cost allocation. The industry does not use comparisons of the percentage of costs allocated to rete classes since this measure would primarily reflect the different mix of customer classes in each distributor's service area.

iii. Not compared its percentage of revenue per device. The industry does not use comparisons of the percentage of revenue per device since this measure would primarily reflect the different mix of customer classes in each distributor's service area.

iv. Compared its device to connection ratio. Table 1 below provides the comparison of Horizon Utilities' Device:Connection Ratio to four Ontario LDCs.

**Table 1: Comparison of Device:Connection Ratio**

| Horizon Utilities (EB-2010-0131) | Horizon Utilities (EB-2014-0002) | Enersource | Veridian | Powerstream | Burlington |
|---|---|---|---|---|---|
| **2.0** | **1.31** | **4.6** | **6.9** | **2.9** | **10.0** |

As discussed in Horizon Utilities' response to Interrogatory C of H 7, Horizon Utilities updated the Daisy Chain ratio in the application to incorporate the results of the City of Hamilton Streetlight Audit Report conducted by Utility Solutions Corporation (C of H 7_Attch 1_City of Hamilton Streetlight Audit Report). This measure is not a standard measure produced by distributors since it is determined by the historical configuration used when street lights in the service area were installed.

**C of H 10.**

**Background:**

**In the Report of the Board in EB-2012-0383, "*Review of the Board's Cost Allocation Policy for Unmetered Loads*", dated December 19, 2013, the Board made the following observations, at page 9:**

- **It appeared that municipal customers were unaware of the phasing-in of higher revenue to cost ratios that had taken place over the past three to five years.**
- **In general, communication between unmetered load customers and their distributors was not optimum and it may be possible to improve those communications.**

**(a) Please describe the communications between Horizon and the City of Hamilton with respect to the proposed rates for the street lighting class.**

**Response:**

Horizon Utilities engaged stakeholders, customer representatives, and key accounts of Horizon Utilities' Distribution System Plan and its impact to rates as part of the Customer Consultation process. A summary of Horizon Utilities' Customer Consultation begins on page 212 of the Distribution System Plan and the results of the engagement are summarized in the Innovative Customer Consultation Report, Appendix D ("Innovative Report").

The City of Hamilton was identified as a Key Account in the Customer Consultation process. The City of Hamilton Key Account meeting was held on January 8, 2014 at City Hall with senior City of Hamilton staff. The structure of the Key Account Validation Interviews process is provided in the Innovative Report, and includes: discussion of the rate application process; the Workbook consultation; and the timelines for communicating the specific rate impacts for all customer classes.

Following the receipt of its Letter of Direction and Notice of Application on May 9, 2014 from the Board, Horizon Utilities began communicating the rate impacts to customers and stakeholders.

Email communications to stakeholders and key account customers began on May 15, 2014. The communication included: the reasons for the proposed rate increase; the year-over-year indicative Distribution impacts; and the Total Bill impacts for the applicable rate classes or where appropriate, the specific customer. The letter also included the contact information of Horizon Utilities' staff who were available to respond to any resulting questions from customers.

The City of Hamilton was advised of the impacts of Horizon Utilities' Application to its accounts by rate class including the street lighting class on May 15, 2014.

Horizon Utilities also made arrangements with senior City of Hamilton staff to discuss the proposed rates and impacts for the Street Lighting class in detail. These meetings were held on June 11, 2014 and June 16, 2014.

Over and above communications specific to the Horizon Utilities Distribution rates as proposed in this Application (EB-2014-002), Horizon Utilities has held at least six meetings with City of Hamilton staff between April in 2013 and June 2014, in an effort to provide clarity to the Street Light class rate setting process and the drivers in the Board's cost allocation model that impacts the rates. Horizon Utilities also engaged Elenchus Research Associates, its independent consultant and an expert in the area of economic regulation including cost allocation and rate design, to support the utility and the City of Hamilton's efforts towards increased transparency and understanding of cost allocation.