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Tab 5. Revenue Requirement and Rate Framework

1. As 2015 is a standard rebasing year, a cost-based revenue requirement should be approved under the RRFE.

2. Toronto Hydro's proposed return on rate base is a function of the 2015 rate base and the OEB-approved cost of capital.

3. The Cost of Capital and Capital Structure have been calculated as prescribed by the OEB and should be approved.

4. Depreciation expense has been appropriately calculated pursuant to MIFRS requirements and the asset service lives and policies approved by the OEB in EB-2010-0142.

5. Toronto Hydro estimated 2015 PILs cost are appropriate and should be approved.

6. Toronto Hydro's forecast Revenue Offsets have been appropriately calculated and should be approved.

7. The overall Service Revenue Requirement for 2015 of $ 707.3M has been fully justified.

8. 2016-2019 Rate Framework should be approved because it is consistent with the OEB's RRFE guidance and adapts it to Toronto Hydro's circumstances in innovative ways.

Tab 6. New Deferral and Variance Accounts

1. Toronto Hydro's proposals to establish new Deferral and Variance Accounts are appropriate and should be approved.

2. A Variance Account for Externally Driven Capital is required due to the unpredictable level of these externally driven expenditures.

3. A Variance Account should be approved for derecognition amounts.

4. Consistent with the OEB direction, Toronto Hydro seeks to establish a Variance Account for Renewable Enabling Investments subject to Provincial Rate Protection Recovery.

Tab 7. Rates, Load/Customer Forecast and Cost Allocation

1. Toronto Hydro requests a Deferral Account to recover the net new costs from the mandatory transition to monthly billing.

2. Toronto Hydro's load and customer forecast is robust and properly accounts for Conservation and Demand Management (CDM) savings and therefore should be used to set 2015 Base Distribution Rates.

3. Toronto Hydro employed the OEB's Cost Allocation Model in the development of the proposed rates; the revenue to cost ratios resulting from these rates are within OEB guidelines and should be approved.

4. The Rate Riders proposed by Toronto Hydro accurately reflect the balances from the DVA accounts proposed for clearance in this application and should be approved.

5. Toronto Hydro is proposing 2015 Retail Transmission Service Rates that were calculated using the forecasted billing determinants, the recently approved Uniform Transmission Rates (UTR), and the OEB's RTSR Workform and should be approved.

6. Toronto Hydro's proposed Specific Service Charges should be approved.

7. Toronto Hydro proposed rate year synchronization should be approved.

8. Standby Rates should be made permanent.

9. Toronto Hydro requests authority to cease tracking amounts in RCVA Accounts 1518 and 1548.

10. Toronto Hydro requests authority to close the Transit City Variance Account.

11. Toronto Hydro submits that the overall bill impacts from the proposed rates and rate riders are necessary to fund the investments and expenses required for the safe and efficient operation of the utility over the 2015-2019 period.

2. Capital Investment

1. **Toronto Hydro's Distribution System Plan (the "DSP" or "Plan") fully justifies the capital funding requested to operate, maintain and renew the distribution system in accordance with good utility practice.**

- Toronto Hydro has provided comprehensive and integrated evidence in support of its capital-related revenue requirement request for the years 2015-2019. In accordance with the OEB's direction, this has been presented in the form of the Distribution System Plan or DSP.

- The DSP is an integrated investment plan designed to address the RRFE objectives through:

    - renewing Toronto Hydro's aging distribution infrastructure so that customers continue to experience safe, reliable and cost-effective electricity service;

    - managing critical system-wide needs that go beyond end-of-life asset renewal, including load growth and contingency constraints, lack of operational flexibility to accommodate new load and undertake the switching needed to enable capital work, equipment accessibility issues, acute safety risks and security of supply issues; and

    - continuing to manage mandatory or otherwise necessary day-to-day requirements in terms of both efficient utility operations (e.g. on-going fleet and equipment, and IT systems renewal) and customer service obligations (e.g. customer connections and third-party service requests).

- The DSP investments are driven solely by the utility's obligation to maintain and operate the system to serve its customers in accordance with good utility practice.

- At the core of Toronto Hydro's DSP are the utility's significant multi-year capital needs, which, as validated in Toronto Hydro's customer engagement results, are aligned with its customers' identified needs and preferences.[1]

- These capital needs require Toronto Hydro to take proactive steps to renew the significant number of aging and deteriorating assets, and address legacy equipment and obsolete devices across its system.

- These needs also require the utility to make investments to resolve critical system-level issues and address capital requirements that support basic utility operations.

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[1] Exhibit 1B, Tab 2, Schedule 7, Appendix B at page 10.

- The DSP is comprised of detailed evidence regarding these capital needs, which includes rigorous justification of proposed investment plans for the 2015-2019 period. It does so on a system-wide, program-level and asset-specific basis.

- The DSP includes a comprehensive five-year capital expenditure plan comprised of 46 detailed capital programs, organized into the OEB's prescribed four investment categories, each with detailed justifications, including:

    1. a detailed need section describing the trigger and secondary drivers of investment and how those drivers relate to the forecasted investments for the five years of the program;

    2. a timing and pacing discussion, which describes and explains the pattern and level of spending over the five-year plan, including as it relates to the previous five-years;

    3. a ranking and prioritization section that describes the various factors considered when prioritizing projects within each specific program and the relative importance of those factors;

    4. a detailed program execution section that describes the types of operational considerations that may affect investment timing and cost, and how those considerations will be addressed over the five-year term;

    5. project-specific details for the 2015 test year;

    6. a long term plan that provides a high-level view of areas in the system that will be targeted over the 2016-2019 years in alignment with program drivers;

    7. a quantified business case evaluation demonstrating the positive net benefits that the proposed investments deliver for customers, accompanied by an options analysis; and

    8. a comprehensive program benefits table that describes the expected outcomes of each program in terms of the OEB's Chapter 5 evaluation criteria (i.e. Efficiency, Customer Value, Reliability, Safety, etc.).

- Other major components include:

    1. a detailed Asset Management Process section that describes Toronto Hydro's rigorous asset management processes, policies and decision-making tools;[2]

[2] Exhibit 2B, Section D.

2. a detailed Capital Expenditure Plan section that, in addition to the 46 capital programs, discusses forecasted system developments and provides information on Toronto Hydro's proposed paced investment strategy and the alternative strategies that were considered; [3]

3. a comprehensive suite of metrics and measures to track and drive continuous improvement and operational efficiency over the term; [4]

4. a coordinated planning section that provides all relevant details with respect to regional planning initiatives; [5]

5. a system capability assessment for renewable energy generation connections; [6] and

6. forecasted smart grid development within the five-year plan. [7]

- Toronto Hydro's comprehensive and fully integrated DSP provides the OEB with all of the information necessary to evaluate the plan in light of objectives outlined in the Chapter 5 of the Filing Requirements.

- The DSP was reviewed by Navigant Consulting Ltd., who determined that the planning processes and tools, as well as the drivers and types of proposed investments were well justified and aligned with the experience of other utilities in North America and industry best practices. [8]

- The DSP complies with both the letter and the spirit of the OEB's Filing Requirements. Most importantly, the DSP achieves the OEB's four performance outcomes:

  - It delivers customer value by putting forward a plan that:

    (i) seeks to minimize the total lifecycle cost of operating the distribution system by balancing capital costs with risk costs; [9]

    (ii) demonstrates alignment with customer needs and preferences; [10]

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[3] Exhibit 2B, Section E.
[4] Exhibit 2B, Section C.
[5] Exhibit 2B, Section B.
[6] Exhibit 2B, Section E3.
[7] Exhibit 2B, Section E1.3.2.
[8] Exhibit 1B, Tab 2, Schedule 4, Appendix B.
[9] Exhibit 2B, Section D3.
[10] Exhibit 2B, Section E2.4

(iii) seeks to minimize the number and duration of outages that customers experience due to failing assets; [11]

(iv) includes customer access investments necessitated by the growth occurring in the City of Toronto; [12] and

(v) includes targeted, high-value investments to improve customer outage and power quality experience.[13]

- It contains a number of investments that are responsive to public policy directives, such as putting conservation first, and contributing to the development of a smarter grid. [14]

- It focuses on operational effectiveness and continuous improvement through the use of market processes to procure 81% of the dollar value of the capital program and by improving internal process in areas such as design and engineering and materials handling.

- The DSP is consistent with Toronto Hydro's demonstrated ability to successfully plan and execute large and complex capital projects as is discussed in Section 4.1 "Execution."

    - Over 85% of the work contained within the DSP is of the same nature of the work that Toronto Hydro has carried out over the last three years.[15] The magnitude of annual proposed spend is comparable to the utility's recent capital programs, and is actually less than what was executed in 2014.[16]

    - With the requisite degree of flexibility to manage the execution complexities that come along with operating an aging system in a large dynamic urban environment, the utility is confident that it can execute this plan over the next five years.

        - Toronto Hydro regularly contends with realities on the ground that require it to adjust the timing and specifics of particular work (e.g. advance or defer a planned project because of weather, emerging needs, or municipal permitting).[17]

        - The utility has demonstrated its ability to execute work within forecasts over a multi-year period. For example, it executed its 2012-2014 capital program at a

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[11] Exhibit 2B, Section D1.

[12] Exhibit 2B, Sections E5.2, E5.3, E5.4, E5.5, E7.4, E7.7, E7.9, E7.10 and E7.11.

[13] Exhibit 2B, Sections E7.1, E7.2, E7.3, E7.4, E7.7, E7.8 and E7.11.

[14] Exhibit 2B, Sections E5.1, E5.5, E7.3, E7.10, E7.11.

[15] IR Response 2B-SIA-15(a), page 1, lines 19-23.

[16] Exhibit 1A, Tab 2, Schedule 1, pages 15-16.

[17] Exhibit 2B, Section C at pages 15-16.

cost that was within approximately 5% of forecasts, has started or completed 90% of the forecasted jobs (i.e. discrete work units), and substituted similar work for those jobs not undertaken.[18]

- Toronto Hydro will monitor its performance against the plan and drive continuous improvement in the implementation of the DSP using the suite of 12 sophisticated measures proposed below (see Sections 4.2 and 4.3, below). Through annual reporting, these metrics will allow the OEB to monitor:
    - a number of important customer-oriented performance outcomes of the DSP, namely SAIDI, SAIFI, CAIDI, FESI and MAIFI;
    - the implementation of the DSP through five distinct cost efficiency and effectiveness metrics; and
    - the effect of the DSP on critical system issues, such as outages caused by defective equipment and stations capacity availability.

2. The DSP demonstrates capital need and shows how Toronto Hydro will deliver value for money.

- Every investment that Toronto Hydro proposes over the 2015 to 2019 period is justified on the basis of customer value, system needs and/or operational needs.
- As assets age and deteriorate, their risk of failure grows, which in turn results in increased reliability-related risks and safety-related risks for customers, the general public and crew workers. These risks impose costs on the distribution system and the customers it serves.
    - To manage these risks, Toronto Hydro must undertake the proposed investments in the System Renewal category, along with certain complimentary and supportive investments in the System Service and General Plant categories respectively. Toronto Hydro's backlog of aging assets cannot reasonably be addressed in the course of the five-year capital plan. Therefore, Toronto Hydro has proposed a paced investment plan to address this backlog over a longer period.
- Toronto Hydro's plan is also designed to address grid capacity and operational constraints, security of supply, safety risks, system reliability and other inefficiencies within the grid, critical infrastructure needed to support distribution functions, as well as modification and enhancements required to enable customer access to electricity service.

[18] Exhibit OH, Tab 1, Schedule 3 at page 1.

- Finally, Toronto Hydro's plan recognizes its obligation to undertake investments necessary to connect customers to the distribution system.

- Investing less than the amounts included in this application will disadvantage customers by elevating the risk of failure, increasing the backlog of assets at or near their useful lives, and creating a snow plow effect that will make actions necessary to address aging infrastructure in future years more expensive and challenging.[19]

- In demonstrating need and value-for-money regarding its integrated investment plan, Toronto Hydro has presented:

    - extensive evidence on the design and development of its DSP,

    - detailed plans on a program basis, and

    - within each program, quantitative business case evaluations that incorporate sophisticated analytical models to show net benefits on a case-by-case basis.

- In compliance with the OEB's Filing Requirements, Toronto Hydro's investments are grouped in four categories:[20]

    1. **System Renewal Investments**: replacement of assets that are past or approaching their end-of-life in order to mitigate the risk of failure.

    2. **System Service Investments**: modifications and enhancements to Toronto Hydro's distribution system to ensure that the system continues to meet the utility's operational objectives while addressing system-wide critical issues and needs.

    3. **System Access Investments**: modifications and enhancements that Toronto Hydro is obligated to perform to provide customers with access to electricity service.

    4. **General Plant Investments**: maintenance and renewal of non-distribution assets (fleet, facilitates, information technology), which are the backbone of Toronto Hydro's operational activities.

- While the level of spending for each investment category is justified independently, the DSP was developed in an integrated fashion, with investments in a given category bearing a complementary or supportive relationship to investments in other categories. The plan as a whole

[19] OH Transcript Volume 5 (February 24, 2015) at page 134, lines 2-10.

[20] Filing Requirements for Electricity Distribution Rate Applications, Chapters 5 (July 17, 2013) [*Filing Requirements*] at pages 6-7; See also Exhibit 2B, Section A2 at page 6.

has been calibrated to deliver immediate and longer-term improvements to customer value while renewing system assets at a minimum pace.[21]

2.1 The age and condition of Toronto Hydro's assets drives the need for the requested System Renewal Investments.

- System Renewal investments are driven by the need to mitigate the risk of equipment failure through the replacement of assets that are past or approaching end-of-life with priority placed on replacing those assets that are in poor health condition.

- Key areas of investment within the System Renewal investment category include:

    - the ongoing renewal of end-of-life grid system assets, including overhead, underground, secondary network and stations assets;

    - replacement of aging and functionally obsolete legacy infrastructure such as rear lot, box construction and legacy underground and network equipment with infrastructure that meets current standards;

    - replacement of failed assets on a reactive basis; and

    - continued management of assets along Toronto Hydro's worst performing feeders.[22]

- The underlying driver of all asset renewal programs – including programs that address legacy systems and obsolete equipment – is the age and condition of the assets.

- Toronto Hydro also employs the use of additional asset management tools to assist it in pacing and prioritizing its investments.

<u>Asset Age Drives Need for Replacement</u>

- Currently, 26% of Toronto Hydro's assets are operating beyond the end of their useful lives. Notwithstanding Toronto Hydro's renewal investments over the last five years, the current percentage is an increase from 22% in 2011.[23] By the end of 2019, Toronto Hydro estimates that 33% of assets will be beyond their useful lives if the utility does not undertake a proactive strategy and instead operates on the basis of a run-to-failure approach.[24]

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[21] OH Transcript Volume 4 (February 23, 2015) at page 96, lines 10-20.

[22] Exhibit 2B, Section E6 at pages 1-6.

[23] TC Undertaking Response J1.3.

[24] Exhibit EC, Tab 1, Schedule 1 at page 8.

- Assets that are at or beyond their expected useful lives present a significant risk of failure, and asset failures increase potential safety risks to crews and the public, as well as increasing customer costs.

    - The useful life of an asset is the mid-point between Kinectrics' Minimum Useful Life and Maximum Useful Life for a specific asset type.[25] By definition, assets that are approaching or have surpassed this mid-point have reached an age when a majority of those assets typically fail and when the statistical probability of failure increases exponentially every year.[26]

    - Asset failures are costly to the utility and its customers. Direct costs include reactive repair and replacement work, which is typically more expensive than planned renewal work for the same assets.[27] The resulting outages impose costs on customers.

    - Many assets addressed in the System Renewal program are known to fail catastrophically, resulting in indirect costs from damage to adjacent or connected equipment as well as large and lengthy outages.[28] A recent example of catastrophic failure was the rash of pole fires caused by failing overhead porcelain insulators, described by Ms. Klein on Day 9 of the oral hearing.[29]

    - Asset failures cause customers to lose service and incur associated customer interruption costs. This can be especially costly to large businesses/institutions that experience direct revenue losses and other operational disruptions due to outages, but also imposes real costs on customers.[30]

    - Failing assets can also be a source of potential safety risks to both the public and crews, as described throughout the DSP business cases.[31]

<u>Overall Asset Condition is Declining</u>

- The increased risk of asset failure in Toronto Hydro's system is further demonstrated by the declining condition of Toronto Hydro's assets.

    - The Asset Condition Assessment Audit carried out by Kinectrics in 2014 ("ACA") shows a significant decline in the overall health of the Toronto Hydro's system. The ACA

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[25] IR Response 2B-OEBStaff-36(b) at page 2, lines 16-25.
[26] Kinectrics Report, Asset Depreciation Study for the Ontario Energy Board (July 8, 2010) at page 10.
[27] OH Undertaking Response J9.3, pages 1-2.
[28] Exhibit 2B, Section E6.1 at pages 21-23.
[29] OH Transcript, Volume 9 (March 3, 2015), page 80, lines 1-19.
[30] Exhibit 2B, Section E2, page 32, lines 3-13.
[31] Example: Exhibit 2B, Section E6.1, Table A (Safety).

monitors the condition of core asset classes within Toronto Hydro's distribution system and produces a Health Index ("HI") score that allows the utility to target its intervention efforts at those assets that are in the worst condition and more likely to fail.[32]

- o Kinectrics found "that there has been a downward trend in the overall health of a majority of THESL's asset groups. Of the 21 asset groups audited, only 4 groups showed improvements in overall health. For the remaining 17 asset categories, an overall decline in condition was observed."[33]

- The 2014 ACA Audit report classified performance for each of 21 asset classes on a scale of Very Good to Very Poor, and classified the degree of improvement or decline on a scale of Extremely Significant/Very Significant/Significant/Notable/Small. Some of the key findings of the 2014 ACA Audit are as follows:[34]

System	**Asset Type**	**Condition Trend / Health Index Distribution**
Stations	Power Transformers	• Very Significant Decline
	Switchgear	• Very Significant Decline
	Air Magnetic & KSO Oil Circuit Breakers	• Very Significant Decline • Kinectrics also noted a concern with the overall Health Index distribution of circuit breakers
	SF6 Circuit Breakers	• Significant Decline
Underground	Padmounted Transformers	• Extremely Significant Decline
	Submersible Transformers	• Very Significant Decline
	Vault Transformers	• Kinectrics noted a particular concern with respect to Vault Transformers, which are typically the only source of power in the buildings where they are located.
Overhead	Overhead Remote Switches	• Very Significant Decline
	Overhead Manual Switches	• Notable Decline
	Wood Poles	• Improvement • Kinectrics notes a concern with the Health Index distribution of this asset class due to there being 123,000 Wood Poles in the system, 11% of which are in Very Poor or Poor condition and 43% of which are in Fair condition.
Network	Network Transformers	• Very Significant Decline
	Network Protectors	• Significant Decline
	Network Vaults	• Extremely Significant Decline
	Cable Chambers	• Significant Decline

[32] OH Undertaking Response J1.5 at pages 1-3.
[33] Exhibit 2B, Section D, Appendix A at page 13.
[34] Exhibit 2B, Section D, Appendix A at pages 13-15.

Investment Prioritization Tools

- The Feeder Investment Model (FIM) is a sophisticated tool that allows Toronto Hydro to find the optimal balance between the economic benefits of deferring capital investments as long as possible and the additional failure costs (including customer interruption costs) associated with end-of-life and poor condition assets.[35] In the context of Toronto Hydro's large and growing end-of-life backlog, the FIM helps to target assets that carry the greatest amount of risk cost based on age, condition, configuration, loading, and other considerations, ensuring that projects are prioritized in a manner that maximizes value-for-money.[36]

- The ACA, discussed above, is also used to prioritize investments based toward assets or asset classes whose condition makes them more likely to fail.

- In short, if the performance of a particular asset is poor or the cost consequences to customers of asset failure are high, the replacement or refurbishment of that asset increases in priority.[37]

Pacing Proactive Asset Renewal

- Consistent with historical trends, a significant percentage of Toronto Hydro's investment plans over CIR period (2015-2019) are dedicated to system renewal efforts.

    - The utility is proposing to spend an average of approximately $252 million per year on System Renewal for the 2015-2019 period to mitigate the growing end-of-life backlog – approximately $30 million per year more than the annual average over the 2010-2014 period.[38] As explained, this increase is driven by the need to better address the impacts to customers from the growing end-of-life backlog and deteriorating asset health.

    - Toronto Hydro's planned asset renewal programs will target for replacement the "worst-of-the-worst" assets that will exceed the end of their useful lives or are in poor condition.

- The described proactive and paced approach to asset renewal delivers long-term value to customers in three ways:

    1. As previously mentioned, it is more costly to reactively address avoidable asset failures. As Mr. Walker described in testimony, reactive replacement can involve work outside of normal working hours, multiple site visits by multiple crews in order to locate the fault,

[35] Exhibit 2B, Section D3.1.2.1(i).
[36] OH Transcript, Volume 1 (February 17, 2015) at page 130, lines 1-14.
[37] OH Transcript, Volume 5 (February 24, 2015) at page 132, lines 5-9.
[38] Exhibit 2A, Tab 6, Schedule 3.

restore power, build a temporary service solution, and ultimately rebuild the larger area as part of a planned project. In the interim, additional assets in the area are likely to fail if they are of the same vintage or have similar health or performance issues. [39] A portion of these reactive costs will amount to wasted or avoidable expenditures, increasing the overall lifecycle cost of operating the distribution system.

2. Further, proactively renewing groups of assets as part of a planned project will typically lead to quantifiable cost efficiencies versus multiple one-off replacements.[40]

3. Finally, proactive investment mitigates the interruption costs incurred by customers as a result of asset failures.[41]

- Toronto Hydro quantifies all of these costs and benefits and weighs them against the benefits of deferring capital investment. The resulting Business Case Evaluations, which appear at the end of all System Renewal programs, provide empirical evidence of the consistently positive value-for-money that the proposed System Renewal investments will deliver for customers.[42]

- Toronto Hydro's System Renewal plan strikes a balance between the cost and pace of renewal relative to risk of asset failure and resulting cost consequences.

2.2 Toronto Hydro's proposed System Service investments are required to address critical deficiencies and inefficiencies within the distribution grid that impact reliability.

- System Service investment programs are driven by broader system design needs that include end-of-life asset renewal, but also go beyond that to address areas such as capacity and operational constraints, security of supply, safety risks, system reliability and other inefficiencies within the grid.[43]

- System Service investments include a number of cost-effective programs that account for a substantial portion of the projected reliability improvements (SAIDI in particular) over the 2015-2019 period.[44] These include:

    (i) the reconfiguration of feeders to improve restoration capabilities;

    (ii) the redesign of existing feeders such that fusing schemes are made more effective and resistance to tree contacts is improved;

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[39] OH Transcript Volume 6 (February 25, 2015), pages 67-68.
[40] Exhibit 2B, Section D3, page 27, lines 16-29.
[41] Exhibit 2B, Section D3.1.2.1(i).
[42] OH Undertaking Response J9.3, page 3.
[43] Exhibit 2B, Section E7, pages 2-3.
[44] IR Response 2B-AMPCO-1(b), pages 3-7.

(iii) targeted improvements to the downtown radial system to mitigate against low probability, high impact events; and

(iv) deployment of feeder automation and recloser technologies to significantly improve reliability performance by reducing the duration and number of customers impacted by an interruption.

- As demonstrated by the Business Case Evaluations, these high value-for-money investments will help Toronto Hydro improve service quality over the five-year period and the long-term while clearing the end-of-life backlog at a restrained pace.[45] Mr. Walker summarized the impact of system service investments and their relationship to system renewal as follows:

> MR. WALKER: I think it's important to distinguish renewal spend from some of our system service investments.
>
> We have system service investments that are specifically designed to impact reliability in SAIFI, as an example.
>
> Largely, those expenditures were undertaking to try and improve the customer's experience, while we try over a longer-term period to address the backlog in failing assets.
>
> So yes, capital expenditures, in general, are likely to improve reliability, but it really depends on the type of capital investment that you do.[46]

- Other System Service investments to address capacity and operational constraints (like certain System Access investments) are driven by the pace of population growth and urban development in the City of Toronto.[47]
  - Population and customer growth has been steady during the recent decade, with a notable acceleration since about 2010.[48]
  - Toronto has had more high-rise buildings under construction than any other North American city four years in a row.[49]

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45 Exhibit 2B, Section E7.3 at pages 35-36 (Feeder Automation).

46 OH Transcript, Volume 4 (February 23, 2015) at page 138, lines 14-24.

47 For example, Exhibit 2B, Section E7.9 at pages 7-12.

48 Exhibit 2B, Section D2 at page 2.

49 Exhibit 2B, Section D2 at pages 4-5.

- Load growth in the system continues to be highly localized, necessitating capital investment to deal with capacity shortfalls in the 2015-2019 period. In particular, the downtown core, the service area of Strachan TS, and the Southwest Toronto area will require additional capacity according to forecasts.[50]

- Toronto Hydro is addressing these constraints and other capacity needs (e.g. additional feeder positions at existing stations) through timely investments in the Stations Expansion program. [51]

- In recognition of the Government of Ontario's conservation first directive, Toronto Hydro is investing in targeted local demand response as an alternative to expansion where feasible and economical (e.g. Cecil TS).[52]

- Legacy assets that have introduced potential safety-related hazards to workers and/or the public will also be replaced as part of the System Service investment category. These include handwell replacements and polymer SMD-20 replacements – two types of assets with proven safety risks.[53]

- Overall, Toronto Hydro is planning to spend an average of $66 million per year on System Service programs, a budget that is consistent with the average annual spending in this category during the previous five-year period.[54]

2.3 System Access investments are required to meet Toronto Hydro's legal obligations to connect customers.

- System Access investment programs are driven by statutory, regulatory and other obligations that require Toronto Hydro to provide customers with timely access to its distribution system.[55]

    - Pursuant to the *Electricity Act, 1998* and the conditions of its distribution license, Toronto Hydro must connect a customer to its distribution system and to provide distribution service.[56] Where a connection request cannot be accommodated within the existing infrastructure, Toronto Hydro must enhance or expand its system to fulfill its obligation.[57]

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[50] Exhibit 2B, Section E7.9 at pages 22, 30 and 32.

[51] Exhibit 2B, Section E7.9.

[52] Exhibit 2B, Section E7.10.

[53] Exhibit OH, Tab1, Schedule 2 at pages 41- 42.

[54] Exhibit 2A, Tab 6, Schedule 3.

[55] Exhibit 2B, Section E5, at pages 1-3.

[56] S.O. 1998, c. 15, Sched. A.

[57] Section 26 of the Electricity Act requires an electricity distributor to provide generators, retailers, market participants and consumers with non-discriminatory access to their distribution system in accordance with its licence. This obligation to provide non-discriminatory access is reiterated in s. 6.1 of Toronto Hydro's distribution

  - In addition to a wide range of obligations under provincial jurisdiction,[58] Toronto Hydro must also comply with federal requirements regarding metering assets, as set out in the *Electricity and Gas Inspection Act*[59] which is administered by Measurement Canada.

  - A third driver of these investments is the need to modify aspects of the distribution system to accommodate property or infrastructure development by governmental authorities and other entities, such as road and public transit authorities.

- The investments in this category are necessary to meet system pressures related to economic growth and capacity constraints and to allow Toronto Hydro to satisfy its externally-mandated obligations as a distributor.[60]

  - Customer Connections investments connect new customers or upgrade existing customers to a larger service if requested. Customer connections investments are necessary to support growth in the City of Toronto, particularly the accelerated pace of high-rise construction.[61]

  - Load Demand investments allow Toronto Hydro to accommodate increased demand concentrated in areas of the City as exemplified by plans to rebuild and expand the civil infrastructure in the Windsor TS area to service the entertainment district customer base.[62] This is achieved by transferring loads to stations with available capacity, upgrading undersized equipment and cables, and ensuring civil infrastructure can support increased demand. These investments are necessary to allow Toronto Hydro to continue connecting customers in these areas without harming system reliability, customer value, and operational flexibility.[63]

  - Metering investments are necessary to comply with mandatory service obligations with respect to revenue metering and wholesale metering. This work includes testing meters, replacing damaged and obsolete meters and upgrading the collector stations. It also

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licence (ED-2002-0497). The licence also includes an obligation to connect (s. 7) and an obligation to sell electricity (s. 8).

[58] For example, section 4 of Toronto Hydro's distribution licence requires Toronto Hydro to comply with all applicable provisions of the *Ontario Energy Board Act* and the *Electricity Act*, and the regulations under these Acts, as well as to comply with the Market Rules.

[59] R.S.C. 1985, c. E-4.

[60] Exhibit 2B, Section 00 at page 9.

[61] Exhibit 2B, Section E5.2.

[62] Exhibit 2B, Section E5.4 at page 4, lines 7-8.

[63] Exhibit 2B, Section E5.4.

includes software investments that will help customers manage their energy use and costs by providing them with timely access to their data.[64]

- Externally Initiated Plant Relocations investments include the modification or relocation of distribution plant to accommodate property or infrastructure development. These investments are necessary to comply with external obligations, and to support growth and development in the City of Toronto.[65]

- Generation Protection Monitoring and Control investments alleviate existing connection capacity constraints that currently prevent the connection of distributed generation (including renewables) in a number of areas of the system. These investments will provide Toronto Hydro system controllers with necessary capabilities to safely and efficiently monitor and control these connections. As the amount of distributed generation capacity in the City of Toronto is expected to triple over the next five years, these investments are necessary for Toronto Hydro to accommodate distributed generation on its grid.[66]

- Relative to historical levels, expenditures in the System Access category will increase over the 2015-2019 period due to the following factors:[67]

  - Continued growth and development in the City of Toronto requiring new customer connections and short-term investments to support increased load demand concentrated in particular areas of the City;

  - Externally-mandated obligations with respect to metering assets;

  - The need to connect an additional 450 MW of distributed generation over the five year plan (more than three times the current capacity).[68]

2.4 Toronto Hydro's General Plant investments are necessary to support ongoing capital work and other utility operations in an efficient and cost-effective manner.

- The facilities, fleet, equipment and computer systems (hardware and software) essential to support Toronto Hydro's 24/7 operational activities are the investments that comprise the General Plant category.[69]

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[64] Exhibit 2B, Section E5.1.
[65] Exhibit 2B, Section E5.3.
[66] Exhibit 2B, Section E5.5.
[67] Exhibit 2B, E4.2.1.
[68] Exhibit 2B, Section E3.
[69] Exhibit 2B, Section E8 at pages 1-3.

- Relative to historical levels, expenditures in this investment category will increase over the plan period due to several relatively large, one-time investments in 2015 and 2016, including: [70]
    - Continued execution of the Operating Centers Consolidation Program (which will decrease Toronto Hydro's overall footprint and square footage per employee),[71]
    - Replacement of the obsolete and no longer vendor supported Enterprise Resource Planning (ERP) system,[72] and
    - Replacement of the obsolete voice radio system.[73]
- Investments in this category are needed to maintain and enhance the critical non-distribution assets that allow the utility to execute the proposed capital program, and perform maintenance activities and other business functions efficiently and effectively.[74]
    - Fleet and Equipment investments, such as routine vehicle and equipment retirement and replacement, are necessary to ensure that Toronto Hydro's fleet remains safe and reliable and operates at the lowest lifecycle cost.[75]
    - Facilities management and security investments relate to the ongoing maintenance of the operating centers that are the hub of the company's capital and maintenance programs, and that support functions which are critical to the effective and efficient operation of all facets of the utility's business. Investments in this category include undertaking critical building repairs and enhancing security.[76]
    - The Operating Centers Consolidation Program (OCCP) is a one-time investment that will enable Toronto Hydro to exit from four facilities it currently occupies (2 owned and 2 leased) and consolidate operations at three facilities that the company currently owns.[77]
        - This plan is expected to reduce Toronto Hydro's square footage by approximately 1.6 million square feet or 43%.[78]

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[70] Exhibit 2B, Section E4.2.4.
[71] Exhibit 2B, Section E8.3.
[72] Exhibit 2B, Section E8.6.
[73] Exhibit 2B, Section E8.7.
[74] Exhibit 2B, Section 00 at pages 11-12.
[75] Exhibit 2B, Section 8.1, page 1.
[76] Exhibit 2B, Section 8.2, page 3.
[77] Exhibit 2B, Section 8.3, page 1.
[78] Exhibit 2B, Section 8.3, page 9.

- The net after tax gains from the sale of the 2 owned facilities will be credited to ratepayers through a negative rate rider.[79]

- Computer Systems

  - Hardware – Toronto Hydro plans to replace and maintain both endpoint assets (e.g., computers and printers) and back-end hardware (e.g., servers, storage, and communications devices).[80]

    - These replacements are necessary to both maintain and enhance productivity by ensuring that employees have reliable computer equipment to perform their jobs and the company has the computer equipment necessary for its operations.

  - Software – These expenditures are necessary to refresh and update the software assets that enable Toronto Hydro to perform its work and to satisfy its obligations to customer and external parties.

    - The Software Upgrades sub-program includes the planned lifecycle upgrades of more than 100 applications that support core functions and processes relating to all aspects of Toronto Hydro's operations. [81]

    - The Software Enhancements and Regulatory Compliance sub-program includes projects that are designed to improve existing systems and processes, develop new reports and functionalities, provide business analytics, integrate IT systems and software applications, and enable the utility to adhere to the requirements of regulatory bodies such as Measurement Canada, the OEB and the IESO.[82]

  - The Enterprise Resource Planning (ERP) system is an IT program that performs critical "back-office" processes, such as work management, finance, human resource and supply chain activities to support Toronto Hydro's core utility operations. Over 2015-2016, Toronto Hydro plans to implement a new ERP with improved functionality, ongoing vendor support and enhanced cyber security.[83]

    - The current ERP, Ellipse, and associated legacy back-office applications have reached the end-of-life, will soon be ineligible for

[79] Exhibit 2B, Section 8.3, page 9.
[80] Exhibit 2B, Section 8.4 at pages 4-5.
[81] Exhibit 2B, Section 8.5 at page 6.
[82] Exhibit 2B, Section 8.5 at page 7.
[83] Exhibit 2B, Section 8.6 at pages 1-3.

vendor support, are difficult and expensive to maintain, lack critical functionality, and present cyber security risks.[84]

- The new ERP will incorporate new functional requirements that will deliver incremental benefits such as cost savings and process improvements and address the obsolescence and cyber security issues associated with Toronto Hydro's current ERP and associated legacy systems.[85]

3. Toronto Hydro's asset management and investment planning approaches have been externally verified as consistent with industry best practices.

- Toronto Hydro's capital expenditure plan was developed using an asset management approach that identifies the long-term needs of the system and seeks to balance those needs against the aggregate risk costs associated with asset failure.[86]

- Navigant Consulting, in their independent review of the DSP, described the asset management process and resulting plan as follows:

    - "THESL has conducted extensive technical evaluation of the condition of the assets it proposes to upgrade or replace. The underlying reasons as to why the equipment or facilities proposed for renewal are deficient are clearly evident from the analyses THESL engineers and support staff have performed and documented in the business cases."

    - "Proposed upgrades are based on rigorous and thorough condition assessment methods, using modern tools and methods."

    - "Project need and the evaluation of alternatives are based on similar asset management best practices and principles that leading utilities now employ, including optimizing the timing of renewal investments based on trade-off of cost and risk."[87]

- Through its asset management processes, Toronto Hydro has identified and evaluated a range of possible investment approaches:

    - Option 1: Address all critical issues and clear the backlog of end-of-life assets in 2015, maximizing value-for-money in the economically optimal way.

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[84] Exhibit 2B, Section 8.6 at pages 4-7.

[85] Exhibit 2B, Section 8.6 at pages 4-9.

[86] Exhibit 2B, Section D3

[87] Exhibit 1B, Tab 2, Schedule 4, Appendix B at page 3.

- Option 2: Address all critical issues and clear the backlog of end-of-life assets over the duration of the five-year CIR period, maximizing value-for-money by the end of the CIR term.

- Option 3: Execute a "paced" approach to mitigating the risks of the growing asset backlog, leveraging the utility's asset management tools to target the investments with the highest customer value during the period.[88]

- Toronto Hydro's objective was to devise a strategy that allows the utility to prudently manage system risks, but that recognizes rate impacts and the utility's execution capabilities within the five-year period.[89] The strategy that met this objective was Option 3, the paced approach.

- The paced approach involves average annual investment of $498 million per year over the plan period. This is the minimum level of investment that is appropriate given the magnitude of the asset backlog and other critical system issues and operational needs that the utility faces.[90]

- The paced approach will allow for more predictable and tolerable bill increases during the 2015-2019 period. Maintaining the paced approach over the longer-term will also improve predictability by spreading system renewal over a greater number of years, mitigating future "lumps" in capital need.

- The paced approach represents a balancing of system needs and customer impacts.[91]

- Adopting a plan with less investment than what is presented in this application would disadvantage customers in terms of both risk and cost by increasing outage risk, allowing the backlog of assets at or near their end of life to grow, and creating a snowplow effect by pushing needed asset renewal into future years.

3.1 Toronto Hydro developed the specific programs presented in its application through a rigorous integrated, system-wide investment prioritization process.

- In arriving at the paced investment strategy, Toronto Hydro developed a capital expenditure plan architecture consisting of 46 specific investment programs. The five-year forecasted expenditure levels in each of these programs are the result of an integrated, system-wide investment prioritization process that forms a key part of the long-term system review process.[92]

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[88] Exhibit 2B, Section E2 at pages 5, 19 and 21.
[89] Exhibit 2B, Section E2 at page 1, lines 9-16.
[90] OH Transcript, Volume 1 (February 17, 2015) at page 70, lines 12-19.
[91] OH Transcript, Volume 9 (March 3, 2015) at page 81, lines 1-5.
[92] Exhibit 2B, Section D1.2.1.

- The 2015 costs for each program are defined by the specific projects that have been scoped and estimated by the engineers for the 2015 execution work program.[93] The details of these projects are provided at the end of each individual program.

- 2016-2019 program-specific budgets were determined using:

    - the outputs of the long-term system review process, such as the location of end-of-life assets and identification of specific priority areas to be targeted for investment over the five-year period;[94] and

    - the application of engineering judgment to estimate, at a high-level, the costs of accomplishing work in the identified areas; this typically involves consideration of the characteristics of the areas or assets to be targeted and a detailed knowledge of the historical costs to do similar work in the same program.[95]

        - For example, the Rear Lot Conversion program contains a Proposed Work Plan section which identifies the general areas for conversion in the 2015-2019 period.[96] The engineer's examination of these areas relative to historical project-level accomplishments yielded the forecasted budget for the Rear Lot conversion program.

- As each budget year in the plan approaches, detailed projects for each program are developed, along with detailed cost estimates. Toronto Hydro expects the specific projects to ultimately vary in cost from the original high-level estimates; however, the utility believes that the forecasted program budgets are an accurate reflection of the amount of work required in each program over the five-year period.

3.2 Toronto Hydro's asset inspection and maintenance programs play an integral role in optimizing its capital assets.

- Maintenance activities allow Toronto Hydro to learn about asset condition and failure modes and sustain the intended operating condition of its assets to preserve operability.[97]

- The relationship between capital and system operations and maintenance (O&M) spending is complex and program-specific.[98]

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[93] Exhibit 2B, Section D1 at page 12, lines 29-31.
[94] Exhibit 2B, Section D3.1.1.
[95] OH Transcript, Volume 4 (February 23, 2015) at page 43, lines 20-28.
[96] Exhibit 2B, Section E6.6.6.1.
[97] Exhibit 2B, Schedule D1.2.3 at page 13.
[98] OH Transcript, Volume 4 (February 23, 2015) at pages 71-72.

- For example, while system renewal investments may eventually lead to a decrease in corrective maintenance as assets that are beyond their useful lives or in poor condition are replaced, the corrective backlog of assets requiring replacement is so substantial that many assets will fail before they can be addressed by the system renewal programs.[99]

4. Toronto Hydro has demonstrated its ability to execute the proposed capital program efficiently using the productivity inherent in market competition and has developed appropriate measures to track performance.

4.1 Toronto Hydro has executed a capital program of similar size and complexity over the past few years.

- Toronto Hydro has demonstrated that it can successfully execute a large and complex multi-year capital program:
  - Over the past five years (2010-2014), the utility has spent approximately $433 million per year, on average, on capital work.[100]
  - The successful delivery of the 2012-2014 ICM capital program approved by the OEB in EB-2012-0064 is particularly indicative of the utility's ability to deliver a capital program of the size and complexity contained in the application.[101]
    - 90% of the filed jobs were completed or in-progress at the end of the plan.
    - The remaining 10% of filed jobs were replaced by other work within OEB-approved ICM segments to address emerging needs.
    - In-service additions and capital expenditures were within approximately 5% of the utility's forecasts at the end of 2014.
- Consistent with its previous accomplishments, Toronto Hydro has put forward a capital plan that it can execute in the next five years, and has provided rigorous evidence to support this:
  - Each business case in the DSP contains a Program Execution section which (i) describes the nature of the work to be performed, (ii) provides details about the proposed work plan (where available), and (iii) explains the execution risks and mitigation measures.[102]
    - This evidence demonstrates that in putting together the DSP, Toronto Hydro has evaluated its ability to execute the proposed work within each program and has

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[99] OH Transcript, Volume 4 (February 23, 2015) at page 75, lines 17-23.
[100] Exhibit 2A, Tab 6, Schedule 3.
[101] Exhibit OH, Tab 1, Schedule 3 at page 1.
[102] Exhibit 2B, Section E6.9.5.

considered and mitigated the risks and challenges that it may encounter in doing so.

        - As Mr. Paradis noted: "… at planning stage we would account for technical realities that would create constraints in terms of execution. So, for example, if we want to do a voltage conversion and we need capacity at a given station to actually supply the load from 13-8 rather than 4 kV, and in order to make that capacity available requires load transfer to a different station, we would account for that reality in defining the plans, knowing that there's a sequence of projects that is required to make that possible. So those type of considerations would happen at the planning stage."[103]

    - Each year, capital investment projects go through a detailed scheduling and execution analysis that takes into account a number of important execution considerations, including external constraints, resource availability, system and seasonal requirements, permitting and moratoriums, and customer engagement and contributions. [104]

        - As noted in the evidence and indicated by Mr. Paradis, Toronto Hydro performed a scheduling and execution analysis against the proposed 2015 work plan.[105] The details of the test year work plan are provided in the 2015 Projects section of each program business case.[106]

        - Because the 2015 work plan is highly representative of types of work that the utility intends to execute in the 2016-2019 period,[107] the detailed scheduling and execution analysis that was performed against the 2015 work plan provides support for the utility's ability execute the proposed programs in its DSP.

    - Of course, given the age, size and intricacy of its system and the dynamic nature of the urban environment within which it operates, Toronto Hydro faces a number of execution constraints. However, with the requisite degree of flexibility over the next five years, the utility is confident that it can successfully manage these constraints and deliver the programs and plans in its DSP.[108]

- Toronto Hydro has appropriate standards, measures and processes to execute its capital work program safely, effectively and efficiently.

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[103] OH Transcript, Volume 4 (February 23) at page 35, line 5-16.
[104] Exhibit 2B, Section E2.3.
[105] OH Transcript, Volume 4 (February 23, 2015) at pages 38-39.
[106] For example, see Exhibit 2B, Section E6.3.7 at pages 42-56.
[107] OH Transcript, Volume 4 (February 23, 2015) at page 109, lines 17-24.
[108] Exhibit 1B, Tab 2, Schedule 4, Appendix A.

- The utility employs rigorous controls to manage material cost and scope changes to its work program.[109]

  - Any material variances in cost and scheduling trigger a formal change control process. As part of this process, a job's costs and benefits may be reevaluated in light of the proposed or necessary job changes and in relation to the overall capital program budget, system planning objectives and other considerations.

  - The change control process helps ensure that the capital program is executed cost-effectively and that it remains aligned to the short-term and long-term planning objectives detailed in the utility's rate filings.

- An independent review by Power System Engineering found that the standards which govern the design, construction, and maintenance of Toronto Hydro's distribution system are thorough, well-documented and consistent with industry best practices with respect to safety, reliability and efficiency.[110]

- Toronto Hydro's has an industry-leading environment, health and safety management program and an exceptional safety record:[111]

  - The utility operates an integrated Environment Health and Safety Management System that is certified by widely recognized standards (ISO 14001 and OHSAS 18001).[112]

  - Since 2008, Toronto Hydro has achieved notable improvements with respect to a number of key safety indicators.[113]

    - 56% decrease in total recordable injury frequency

    - 89% decrease in lost time injury severity

    - 83% decrease in lost time injury frequency

    - 79% decrease in restricted work days

  - These accomplishment are a testament to the effectiveness of Toronto Hydro's environment, health and safety policies, programs and procedures.

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[109] Exhibit OH, Tab 1, Schedule 3 at page 7.
[110] Exhibit 2B, Section D, Appendix B.
[111] OH Undertaking Response J1.1 and J7.2.
[112] Exhibit 4A, Tab 2, Schedule 14 at pages 7-13.
[113] Exhibit 4A, Tab 2, Schedule 14 at page 5.

    - Contractor safety performance is also excellent and is consistently monitored by Toronto Hydro.[114]

- To track execution of the capital plan, Toronto Hydro has proposed a Distribution System Plan Implementation Progress measure, which provides a rolling assessment of plan implementation progress by tracking cumulative capital spending relative to the five-year approved capital budget.[115]

- In short, the evidence clearly demonstrates that Toronto Hydro has put forward a DSP that it can successfully execute over the 2015-2019 period, and that it has appropriate controls, measures and processes in place to undertake this work safely, effectively and efficiently.

4.2 Toronto Hydro's procurement process drives continuous improvement and market efficiency for 81% of the utility's capital costs and it has successfully introduced measures to continuously improve the efficiency of its internal capital work.

- Approximately 81% of the costs associated with the capital work program are determined through a competitive procurement process.

  - As indicated by Mr. Walker in response to Member Quesnelle's question at Day 4 of the Oral Hearing, this figure represents three elements of the work execution: materials, civil design and construction and a significant portion of electrical design and construction work.[116]

  - As outlined by Mr. Nash at the Oral Hearing, Toronto Hydro has a rigorous procurement process for securing externally sourced services and materials.[117]

    - Procurement is based on qualified bidders offering individual fixed prices for various units of work. There are 6,400 different units in the most recent contract.

    - Once the contractors are selected on the basis of their qualifications and overall pricing, they are not guaranteed any particular amount of work. Instead, contractors are assigned to individual projects based on their cost to complete each project so that the lowest priced contractor for a particular type of project gets the work.[118]

  - Toronto Hydro's procurement process drives continuous improvement and efficiency for 81% of the utility's capital costs, and helps ensure that the services, equipment and

[114] OH Undertaking Responses J1.1 and J7.2.
[115] Exhibit 2B, Section C3.1.1.
[116] OH Transcript, Volume 4 (February 23, 2015) at page 88, line 4-16.
[117] OH Transcript, Volume 6 (February 26, 2015) at pages 98-100.
[118] OH Transcript, Volume 6 (February 26, 2015) at pages 104-108.

materials procured by Toronto Hydro represent the best value for its customers while also satisfying the operational needs of the utility.

- In short, through this approach, Toronto Hydro has captured the drive to continuously improve productivity inherent in competitive markets for 81% of its capital costs, and is directly passing this embedded productivity along to its customers.

- Internal costs account for approximately 19% of the capital expenditure plan. Toronto Hydro has made notable achievements in constraining these costs:

    - Toronto Hydro has negotiated one of the most competitive collective bargaining agreements in the industry with its union CUPE. This agreement secured a modest yearly wage increase that averaged 1.75% per year, through to the end of 2018.[119]

    - The utility has implemented various initiatives to maximize the output of its internal labour force, including:[120]

        - a performance and attendance management program which has resulted in a 45% reduction in absenteeism rates between 2008 and 2013, and which places the utility's absenteeism rate significantly below the municipal, provincial, and national averages.

- Over the 2015-2019 period, Toronto Hydro is committed to driving continuous improvement and efficiencies with respect to internal capital costs. The utility has proposed four measures to track and evaluate cost efficiency:

    - **Engineering, Design and Support Costs:** tracks the proportion of total distributional capital expenditures that relates to planning, engineering and support labour costs.[121] By tracking this measure, Toronto Hydro expects to drive productivity and efficiency in these underlying processes.

        - From 2012-2014, engineering, design and support costs declined from 7.5% to 4.4% of the capital costs. Over the 2015-2019 period, these costs are currently forecasted to account for approximately 6.2% to 6.8% of the utility's capital budget over the 2015-2019 period.[122]

    - **Materials Handling On-Cost:** tracks the eligible supply chain and warehousing costs, which are ultimately added to the utility's total capital costs as a percentage surcharge on

[119] Exhibit 4A, Tab 4, Schedule 5, at pages 9-10.
[120] Exhibit 1B, Tab 2, Schedule 5 at pages 21-23.
[121] Exhibit 2B, Section C3.2.
[122] IR Response 2B-SEC-19.

all materials issued through the utility's warehouse. By tracking this measure, Toronto Hydro expects to drive continuous improvement in the way it procures and distributes materials.[123]

- From 2012-2014, the supply chain and warehousing costs declined from approximately 2.4% to 1.8% of the capital cost. Over the 2015-2019 planning horizon, the utility expects these costs to continue to decline.[124]

- **Standard Asset Assembly Measure**: Once developed, tested and implemented, this measure will enable the utility to effectively track the internal labour inputs of completing specific types of assets in a manner that recognizes the complexity and diversity of the utility's service territory.[125]

  - This measure will enable Toronto Hydro to better analyze the costs of completing work on different asset assemblies in various configurations over time so as to drive efficiency.[126]

- **Contractor Cost Efficiency:** compares the costs of construction projects constructed "in-house" with the prices charged for equivalent work by external design and construction contractors retained by Toronto Hydro. [127]

  - This measure will provide Toronto Hydro useful insights for the continuous improvement of internal work execution.

- Together with the performance measures noted below, the cost efficiency measures noted above will allow the OEB to track progress of the DSP over the 2015-2019 period.[128]

4.3 The Customer-Oriented Performance measures will allow the OEB to track the performance outcomes of Toronto Hydro's system as the capital plan is implemented.

- Complementing the proposed Capital Planning Efficiency and Cost Effectiveness measures, and in response to specific OEB guidance, are seven measures of Customer Oriented Performance and Asset/System Operation Performance. They include:

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[123] Exhibit 2B, Section C3.3.
[124] IR Response 1B-BOMA-35.
[125] Exhibit 2B, Section C3.5.
[126] OH Transcript, Volume 1 (February 17, 2015) at pages 88-89.
[127] Exhibit 2B, Section C3.4.
[128] Exhibit 2B, Section C3.1.

- **SAIDI, SAIFI, CAIDI** – widely used and well understood measures of overall system reliability, specifically mandated by the OEB Filing Requirements.

    - Included in Toronto Hydro's DSP are the utility's SAIDI and SAIFI forecasts over the plan term, which represent two of the expected DSP implementation outcomes.[129] As noted by Mr. Paradis, these forecasts represent Toronto Hydro's best evaluation of the reliability consequences/outcomes of the proposed investments.[130]

- **Feeders Experiencing Sustained Interruptions (FESI)** – tracks the number of Toronto Hydro feeders that experience seven or more annual outages. [131]

    - Tracking the number of worst performing feeders will allow Toronto Hydro to gauge the effectiveness of the programs directed at the most vulnerable portions of its system.

- **Momentary Average Interruption Frequency Index (MAIFI)** – measures the frequency of momentary interruptions experienced on average by Toronto Hydro's customers. [132]

    - Momentary interruptions are a significant concern for certain subsets of the utility's customer base, including large commercial and industrial customers.[133]

    - By tracking MAIFI over the plan term, the utility expects to gauge the impact of certain capital and maintenance activities such as the Overhead Momentary Reduction Program, insulator washing, tree trimming and tree proofing.

- **Outages Caused by Defective Equipment** – tracks the number of outages occurring over a rolling 12-month period due to defective or otherwise malfunctioning equipment.[134]

    - The results of this measure will track the aggregate number of outages caused by plant deficiencies and will inform Toronto Hydro as to the effectiveness of its asset replacement strategies and preventive maintenance activities over the longer term.

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[129] Exhibit 2B, Section 00 at page 8.
[130] OH Transcript, Volume 4 (February 23, 2015) at page 135, lines 22-24.
[131] Exhibit 2B, Section C2.2.
[132] Exhibit 2B, Section C2.3.
[133] Exhibit 2B, Section C2.3.1 at page 12, lines 11-16.
[134] Exhibit 2B, Section C4.1.

- **Stations Capacity Availability** – tracks the number of stations where peak demand exceeds 90% of station capacity over the next five years. [135]
  - This measure will allow Toronto Hydro to gauge the effectiveness of its capacity planning processes and the timeliness of the associated constraint mitigation measures, including permanent load transfers, capacity increases, targeted CDM programs and other related activities.

5. The overall level of capital investment proposed is necessary to efficiently address the capital needs of Toronto Hydro's system for the benefit of customers.

- Toronto Hydro's DSP proposes an annual average of $498 million in capital, which represents a paced approach to addressing critical system-level issues, mandatory or necessary operational requirements and, most significantly, the growing backlog of end-of-life and obsolete assets.

- As described in the RRFE section of the outline, Toronto Hydro conducted telephone surveys of customers in its most populous rate classes (residential and small commercial) regarding the proposed plan to understand whether their values, needs and preferences aligned to the proposed paced approach
  - The results indicate that those customers surveyed were accepting of the associated bill increases in light of the proposed plan and the underlying system needs and projected benefits. [136]

- Navigant Consulting considered the overall level of proposed capital expenditures in Toronto Hydro's DSP and concluded the following:
  - "In summary, each of the proposed investment categories and business cases in THESL's DSP that Navigant reviewed is consistent with those currently or previously undertaken by many other urban utilities in Canada and the United States that Navigant has evaluated. Notably, we did not identify any projects or measures that are inconsistent in scope or need with programs implemented elsewhere. In Navigant's view, because of these reasons and the review and analysis presented in subsequent sections of our report, the proposed projects in THESL's DSP are reasonable and justified."[137]

- The reasonableness of Toronto Hydro's capital-related revenue requirement request is supported by an independent total cost benchmarking study prepared by PSE, which concludes that the

[135] Exhibit 2B, Section C4.2.
[136] Exhibit 1B, Tab 2, Schedule 7, Appendix B at pages 7-11.
[137] Exhibit 1B, Tab 2, Schedule 4, Appendix B at page 5.

utility's projected total costs are expected to remain within +/- 10% of the model predicted efficient cost levels.[138]

- As fully explained above, adoption of an investment plan with lower expenditures than are proposed in this application will tend to increase total costs to customers in the long term, in addition to posing unacceptable system risks.

[138] OH Transcript, Volume 9 (March 3, 2015) a page 29, lines 4-26.

E6.7 Box Construction Conversion

TYPICAL BOX CONSTRUCTION

E6.7.1 Summary

Program Description

The Box Construction Conversion program is a continuation of activities previously described in Phase 1 and 2 of Toronto Hydro's 2012-2014 ICM application. The projects that comprise this program are identical in nature to the jobs that constituted the OEB approved Box Construction segment in EB-2012-0064[1].

Box construction is a type of legacy 4.16 kV overhead construction that was used within the former (pre-amalgamation) City of Toronto. Due to a number of reliability, safety and load capacity issues, Toronto Hydro no longer uses box construction for new capital projects. To address these issues for legacy installations, this style of construction will be replaced with 13.8 kV or 27.6 kV overhead feeders.

[1] EB-2012-0064, Tab 4, Schedule B5.

TABLE A: SUMMARY OF PROGRAM BENEFITS

Customer Value	▪ Clearance issues with new or redeveloped buildings near box construction primary feeders can result in additional costs for connecting customers. These costs will typically be unnecessary following conversion to 13.8kV/27.6kV infrastructure. ▪ 13.8kV/27.6kV feeders can better accommodate larger customer connections in the downtown area
Reliability	▪ Average outage duration for 13.8 kV overhead feeders is lower than for 4 kV box construction feeders ▪ Impact of major storm events is less on 13.8 kV overhead feeders when compared to 4 kV box construction feeders
Safety	▪ Less congestion at top of 13.8kV/27.6kV poles reduces risk of electrical contact ▪ Greater accessibility with bucket trucks on 13.8kV/27.6kV overhead feeders allows for safer work practices ▪ 13.8kV/27.6kV overhead feeders adhere to clearances outlined in EUSR 129 ▪ Removal of legacy equipment such as shielded primary cable and Positect switches eliminates the safety issues associated with this equipment
Efficiency	▪ 13.8 kV overhead feeders have three times the capacity of box construction feeders ▪ Line losses are lower on 13.8 kV and 27.6 kV feeders ▪ Program projects are prioritized to avoid renewal of end-of-life legacy 4.16 kV stations equipment where possible
Other	▪ Avoid procurement issues associated with some box construction equipment

Program Drivers

The trigger driver for this program is Functional Obsolescence, due to the safety, capacity, procurement and reliability issues associated with this legacy construction. The trigger and secondary drivers for this program are summarized in Table ii.

TABLE B: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	▪ Legacy overhead construction standard no longer used for new capital projects ▪ High number of assets past useful life ▪ Skill set for maintaining/troubleshooting box construction is diminishing ▪ Procurement issues with legacy equipment
Secondary Drivers	**Reasoning**
Safety	▪ System complexity (multiple circuits through same area) ▪ Accessibility issues with bucket trucks ▪ Proper working clearances are often unattainable ▪ Equipment built to legacy construction standards creates additional safety risks
Efficiency	▪ Line losses are higher than 13.8 kV/27.6 kV overhead distribution, with a correspondingly higher carbon footprint.
Reliability	▪ Average outage duration of box construction feeders is greater than that of 13.8 kV feeders ▪ Impact of major storms shown to be greater on box construction feeders when compared to 13.8 kV overhead feeders in downtown core

Preferred Alternative

The Box Construction Conversion program analyzed and evaluated the following options:

(1) Replace the aged, legacy box construction with new box construction

(2) Convert the aged, legacy box construction to new 13.8 kV or 27.6 kV Infrastructure

Option II is the preferred option as it allows necessary working clearances, capacity to accommodate future load requests and higher overall system reliability. Option I would likely also has the disadvantage of forcing Toronto Hydro to continue investing in and maintaining stations assets at the 4 kV municipal stations that supply existing box construction feeders. Many of these stations are lightly loaded and avoided costs could be realized by decommissioning the stations following load conversion as part of the Box Construction program.

The difference in the cost of ownership between existing and renewed assets (ΔCOO) for the first year of the program is $22.44 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.7.7). Accounting for capital program costs, the first year's activities deliver a positive NPV of $5.64 million, confirming the economic prudence of the investments (see Section E6.7.7).

Timing and Pacing

The table below provides the estimated costs of the program for the 2015-2019 period. Given the current schedule, Toronto Hydro plans to address 65% of all box construction by the end of 2019. The conversion of all box construction feeders is expected to be complete by 2026.

TABLE C: HISTORICAL AND FUTURE SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	5.7	7.1	0.84	13.8	23.3	16.8	20.7	21.1	21.6	22.7

Ideally, due to the age and condition of existing box construction feeders, Toronto Hydro would convert all remaining box construction in the 2015-2019 period. However, converting all remaining box construction feeders over this time period is not feasible from an engineering perspective due a number of system constraints, including limited availability of certain feeders and the need to first upgrade certain Hydro One Networks Inc. (HONI) station equipment housed in Toronto Hydro transmission stations (TS).

E6.7.2 Program Description

The Box Construction Conversion program is a continuation of activities previously described in Phase 1 and 2 of Toronto Hydro's 2012-2014 ICM application. The projects that comprise this program are identical in nature to the jobs that constituted the OEB approved Box Construction segment in EB-2012-0064.

Box construction is a type of legacy 4.16 kV overhead construction that was used within the former (pre-amalgamation) City of Toronto and still exists in some areas of the city. Figure 1 shows a typical box construction installation. Due to a number of reliability, safety and load capacity issues, Toronto Hydro no longer uses box construction for new capital projects, rendering it a functionally obsolete standard. These issues are further described in Section E6.7.5.

FIGURE 1: TYPICAL BOX CONSTRUCTION

Toronto Hydro plans to address all of the issues related to box construction described in Section E6.7.5 through a proactive program that replaces these feeders with current standard 13.8 kV or 27.6 kV overhead construction. Figure 2 shows the conversion from highly concentrated cables in box construction to the less congested 13.8 kV or 27.6 kV overhead standards. The reduction in complexity and congestion at the top of the poles is apparent. Figure 3 illustrates another variation on the current 13.8 kV overhead construction standard.

FIGURE 2: ACTUAL CONVERSION PROJECT COMPLETED IN 2013 IN THE BYRON AVE. AND DANFORTH AVE. AREA. THE PHOTOGRAPH ON THE LEFT SHOWS THE 4.16 KV BOX CONSTRUCTION FEEDER PRIOR TO CONVERSION. THE COMPLETED PROJECT IS SHOWN IN THE PHOTOGRAPH ON THE RIGHT, WHERE ALL 4 KV BOX CONSTRUCTION HAS BEEN REMOVED AND REPLACED WITH A CURRENT CONSTRUCTION STANDARD 13.8 KV OH FEEDER.

FIGURE 3: TYPICAL CURRENT CONSTRUCTION STANDARD 13.8 KV OVERHEAD FEEDER

Toronto Hydro's Box Construction Conversion program targets all 4.16 kV box construction feeders. Toronto Hydro's objective is to replace the 4.16 kV box construction infrastructure with standard 13.8 kV or 27.6 kV overhead feeders and decommission associated 4.16 kV stations by 2026. Figure 4 shows a map of all box construction feeders in Toronto.

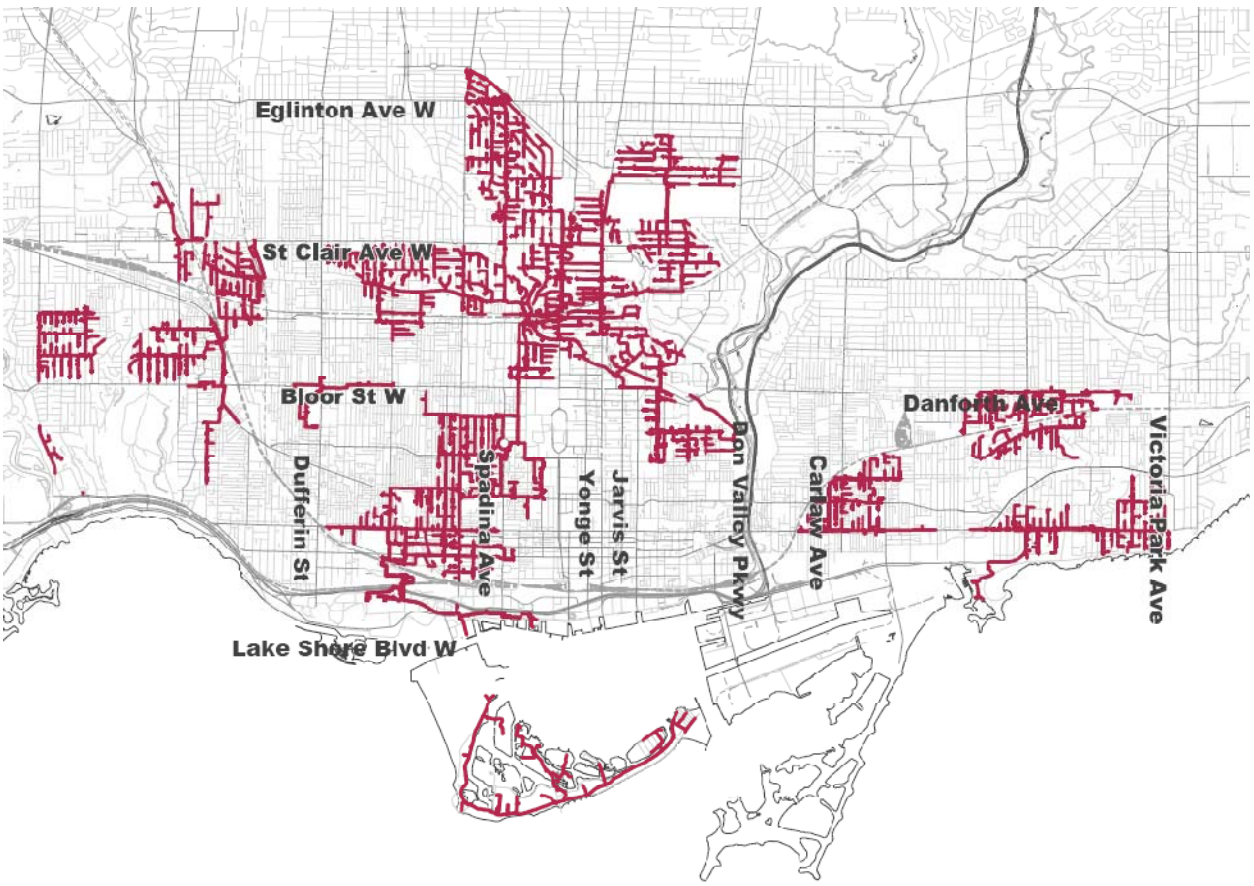
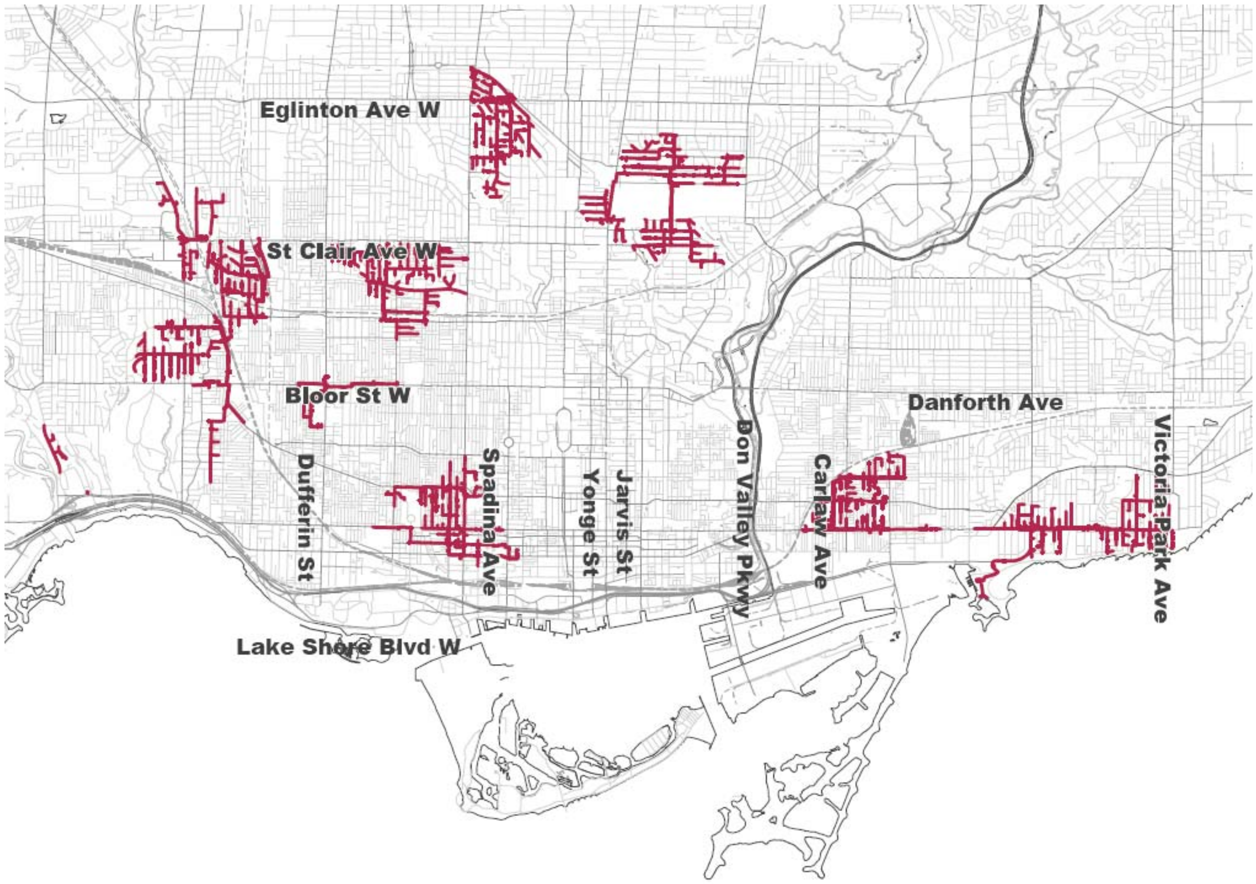


FIGURE 4: MAP OF ALL BOX CONSTRUCTION FEEDERS SLATED FOR CONVERSION THROUGH 2026

Total costs for the Box Construction Conversion program are estimated to be $103.1 million over the period of 2015 to 2019. Figure 5 shows a map of box construction feeders that Toronto Hydro will convert over this period.



1 **FIGURE 5: MAP OF PROPOSED FEEDER CONVERSIONS FOR 2015-2019**

The following table summarizes the number of assets that Toronto Hydro plans to replace over the 2015-2019 program by asset class.

TABLE 1: ASSETS TO BE REPLACED BY ASSET CLASS

Assets (Units)	2015	2016	2017	2018	2019	Total
OH Transformer	183	381	86	175	77	902
OH Switch	154	301	70	176	85	786
Poles	377	780	277	255	117	1,806
UG Switch	0	0	0	6	0	6
UG Transformer	20	27	9	52	17	125
OH Conductor (km)	23.5	46.2	11.4	24.4	11.5	117.1
UG Cable (km)	6.0	10.4	1.5	5.8	1.4	25.0

/C

Toronto Hydro evaluated the proposed program against the status-quo alternative of maintaining and replacing (on a like-for-life basis) the equipment used in box construction, and determined that proactive conversion is the best alternative. Table 2 summarizes the benefits associated with the Box Construction Conversion program.

1 **TABLE 2: SUMMARY OF PROGRAM BENEFITS**

Customer Value	▪ Clearance issues with new or redeveloped buildings near box construction primary feeders can result in additional costs for connecting customers. These costs will typically be unnecessary following conversion to 13.8kV/27.6kV infrastructure. ▪ 13.8kV/27.6kV feeders can better accommodate larger customer connections in the downtown area ▪ Aesthetic improvements ▪ The difference in the cost of ownership between existing and renewed assets (ΔCOO) for the first year of the program is $22.44 million, representing a reduction in negative impacts to customers (e.g., customer interruption costs, emergency repair costs) over the life of the assets (see Section E6.7.7). ▪ Accounting for capital program costs, the first year's activities deliver a positive NPV of $5.64 million, confirming the economic prudence of the investments (see Section E6.7.7).
Reliability	▪ Average outage duration for 13.8 kV overhead feeders is lower than for 4 kV box construction feeders ▪ Impact of major storm events is less on 13.8 kV overhead feeders when compared to 4 kV box construction feeders
Safety	▪ Less congestion at top of 13.8kV/27.6kV poles reduces risk of electrical contact ▪ Greater accessibility with bucket trucks on 13.8kV/27.6kV overhead feeders allows for safer work practices ▪ 13.8kV/27.6kV overhead feeders adhere to clearances outlined in EUSR 129 ▪ Removal of legacy equipment such as shielded primary cable and Positect switches eliminates the safety issues associated with this equipment
Efficiency	▪ 13.8 kV overhead feeders have three times the capacity of box construction feeders ▪ Line losses are lower on 13.8 kV and 27.6 kV feeders ▪ Program projects are prioritized to avoid renewal of end-of-life legacy 4.16 kV stations equipment where possible
Other	▪ Avoid procurement issues associated with some box construction equipment

E6.7.3 Why the Program is Needed

The Box Construction Conversion program is required to eliminate the reliability, efficiency and safety risks associated with the functionally obsolete box construction feeder design.

E6.7.3.1 Program Drivers

Table 3 presents the trigger and secondary drivers for replacing box construction. Box construction replacement is a System Renewal initiative with a trigger driver of functional obsolescence.

TABLE 3: PROGRAM DRIVERS

Trigger Driver	Reasoning
Functional Obsolescence	▪ Legacy overhead construction standard no longer used for new capital projects ▪ High number of assets past useful life ▪ Skill set for maintaining/troubleshooting box construction is diminishing ▪ Procurement issues with legacy equipment
Secondary Drivers	**Reasoning**
Safety	▪ System complexity (multiple circuits through same area) ▪ Accessibility issues with bucket trucks ▪ Proper working clearances are often unattainable ▪ Equipment built to legacy construction standards creates additional safety risks
Efficiency	▪ Line losses are higher than 13.8 kV/27.6 kV overhead distribution, with a correspondingly higher carbon footprint.
Reliability	▪ Average outage duration of box construction feeders is greater than that of 13.8 kV feeders ▪ Impact of major storms shown to be greater on box construction feeders when compared to 13.8 kV overhead feeders in downtown core

Functional Obsolescence

- Box construction is a 4 kV legacy overhead construction standard that Toronto Hydro no longer uses for new capital projects. This design is considered functionally obsolete due to a number of safety, load capacity, procurement and reliability issues that render it undesirable for new projects. In addition to these design deficiencies, a high number of box construction assets are past their useful lives (see Section E6.7.3.2 (i) for further details) and are likely to fail in the near future, leading to more frequent and extended outages on these feeders. Maintaining aging box construction could become more challenging in the future as experienced employees retire and the number of skilled resources with box construction knowledge and experience diminishes. Each of these issues is discussed in detail in the following subsections.

- Some legacy equipment associated with box construction is difficult to procure due to a limited number of suppliers or, in a few cases, no supplier. For example, only one North American supplier currently manufactures shielded primary cable. Since this cable is a 'non-stock, non-standard' item for the supplier, a lengthy 12-week lead time and a minimum quantity of 3000 metres is required for each order. Another example is Positect switches, which are no longer available from the manufacturer.
- Box construction's status as both a unique and functionally obsolete design creates additional pressures in terms of resource availability. In the past, when 4.16 kV box construction feeders were the standard design for overhead distribution, crews had continuous experience working on them. Now, because new employees work on 4.16 kV box construction feeders on an infrequent, "as-needed" basis and the older generation of employees is retiring, fewer employees have skills and experience related to this design.

Safety

- Unlike typical standard 13.8 kV/27.6 kV overhead circuits, box construction poles typically support multiple live circuits in a more congested and tightly packed configuration relative to current overhead construction standards, which increases the potential risk of electrical contact for crews.
- Some box construction circuits cannot be accessed with bucket trucks – the industry-wide practice for overhead pole maintenance – due to the physical arrangement of the feeders running through a single box pole. Power Line Workers must climb these poles, which increases the potential safety risk for Toronto Hydro employees. These additional safety risks include injury from the additional physical exertion from climbing, a more severe falling hazard when compared to the use of a bucket truck and increased risk of electrical contact due to the inability to use the insulated aerial boom and bucket liner found on bucket trucks.

- In certain box construction work scenarios, Toronto Hydro crews working in close proximity to the lines can have difficulty conforming to the working clearances defined in Electrical Utilities Safety Rules (EUSR) #129. The required 15 cm air gap between people/tools and energized conductors cannot always be achieved.

Some equipment associated with box construction was designed and installed before Toronto Hydro adopted current safe work practices. One example of this is the 'Positect' switch, an obsolete type of fused switch originally designed to be operated by hand that puts field crews in the arc flash zone of the switch. While a stick was developed to operate 'Positect' switches from a distance, operation of this switch with the stick is inefficient when compared to operating it by hand.

Efficiency

Delivering electricity at a primary voltage of 4.16 kV (as is the case with box construction) is less energy efficient when compared to 13.8 kV feeders. The line losses associated with a 4.16 kV system are approximately nine times higher than those of 13.8 kV lines. Efficiency savings can be realized from converting from 4 kV to 13.8 kV, as detailed in Section E6.7.7 Evaluation of Alternatives.

Reliability

The 4.16 kV box construction configuration has also contributed substantially to outages for Toronto Hydro's customers relative to the comparable 13.8 kV and 27.6 kV standards. Historically, outage duration on 4.16 kV box construction feeders has been significantly worse than that of other overhead configurations. Table 4 compares the historical reliability of box construction feeders to standard 13.8 kV overhead feeders in the former (pre-amalgamation) City of Toronto. Total customer hours interrupted (CHI) for box construction feeders is considerably higher (1.65 hours) than on the 13.8 kV system (1.26 hours), despite the fact that total customers interrupted (CI) is approximately equal between the two systems, (Both systems are also approximately 625 circuit kilometers in length.)

TABLE 4: AVERAGE OUTAGE DURATION (DATA 2000-2012)

	4.16 kV Overhead Box Construction	13.8 kV Overhead Construction
Total CI	142,023	149,613
Total CHI	234,491	188,813
Average Outage Duration	1.65 hours	1.26 hours

Major storm events have also been shown to have a larger impact on box construction feeders when compared to other overhead distribution configurations. On October 29th and 30th of 2012, the City of Toronto endured a powerful storm from Hurricane Sandy, causing several extended outages across the city. Figure 6 illustrates the total customer hours interrupted (CHI) and customers interrupted (CI) on overhead feeders in the downtown area during the storm:

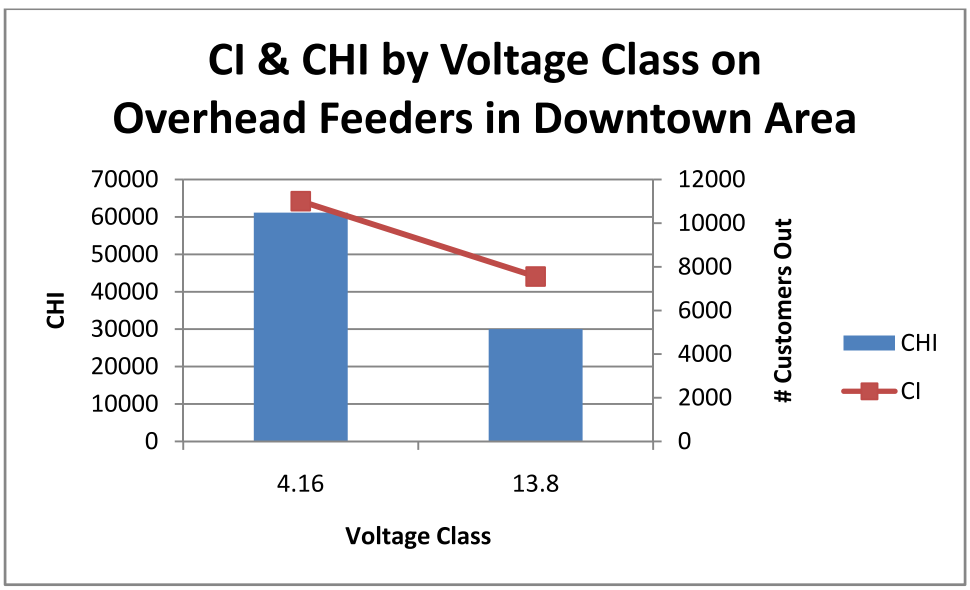


FIGURE 6: CI & CHI BY VOLTAGE CLASS ON OVERHEAD FEEDERS IN DOWNTOWN AREA DURING HURRICANE SANDY

The outage impact in terms of customer-hours interrupted was twice as high on 4.16 kV box construction circuits compared to standard 13.8 kV circuits. Factors contributing to outages and outage durations on box construction circuits include the following:

- Box construction assets are generally old and in poor condition; they are less able to withstand strong winds and contact from trees during storms compared to 13.8 kV overhead feeders in the downtown area.
- There are a limited number of field crews familiar with 4.16 kV box construction feeders, which contributes to delays in restoring power.

Figure 7 breaks down the areas impacted by the storm, sorted by station:

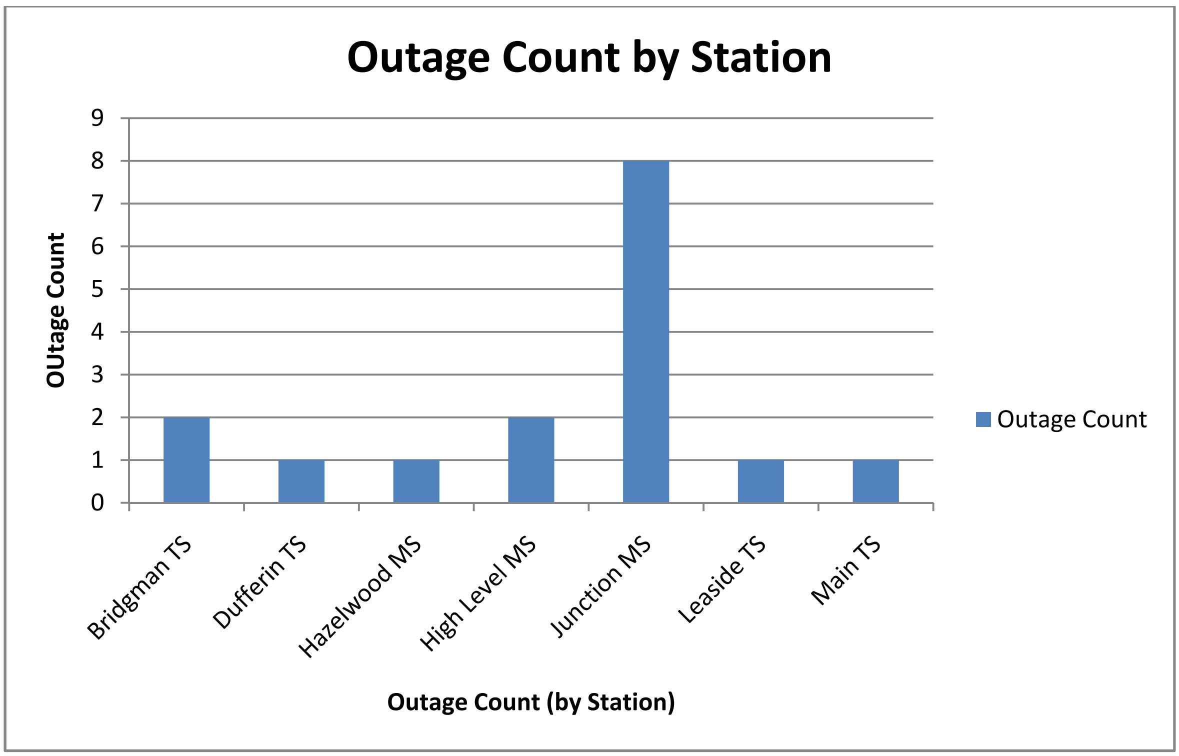


FIGURE 7: OUTAGE COUNT BY STATION IN DOWNTOWN AREA DURING HURRICANE SANDY

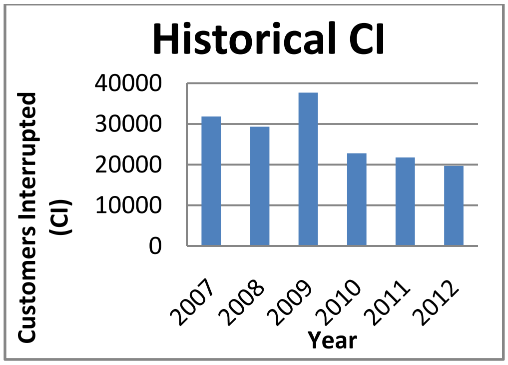
Junction MS, High Level MS and Hazelwood MS are stations that supply 4.16 kV box construction feeders (note: Hazelwood MS supplied only two distribution feeders at the time). The transformer stations (TS) shown serve the same areas but do not supply any box construction feeders. The figure shows that (i) Junction MS, which supplies a number of aging box construction feeders, experienced by far the most outages and (ii) 11 outages occurred on feeders from the three stations supplying box construction while only five outages occurred on feeders from the four transformer stations (TS) in the same area.

Reliability measures for box construction feeders in the 2015-2019 conversion program are summarized in Table 5.

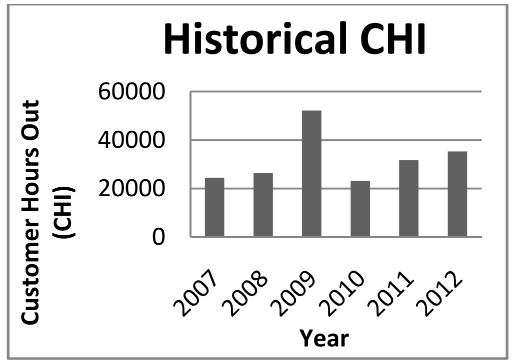
TABLE 5: HISTORICAL RELIABILITY FOR FEEDERS PROPOSED FOR CONVERSION

	2007	2008	2009	2010	2011	2012
Customer Hours Interrupted	24,469	26,465	52,139	23,218	31,665	35,298
Customers Interrupted	31,824	29,314	37,696	22,802	21,765	19,671
Average Outage Duration (hours)	0.77	0.90	1.38	1.02	1.45	1.79

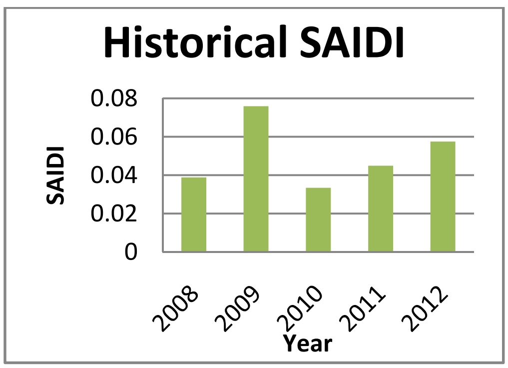
Figure 8 to Figure 11 illustrate customers interrupted (CI), customer hours interrupted (CHI), system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI) for feeders proposed for conversion.



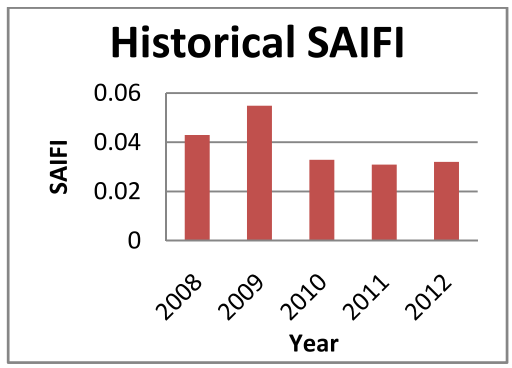
1 **FIGURE 8: HISTORICAL CI FOR FEEDERS**
2 **PROPOSED FOR CONVERSION**



5 **FIGURE 10: HISTORICAL CHI FOR FEEDERS**
6 **PROPOSED FOR CONVERSION**



3 **FIGURE 9: HISTORICAL SAIDI FOR FEEDERS**
4 **PROPOSED FOR CONVERSION**



7 **FIGURE 11: HISTORICAL SAIFI FOR FEEDERS**
8 **PROPOSED FOR CONVERSION**

Aging 4.16 kV Stations Assets

The 4.16 kV station assets that supply 4.16 kV box construction feeders are aging and in some cases require replacement in the near future. Rather than invest in legacy station equipment under the Station Switchgear Renewal (section E6.14), Station Power Transformer Renewal (section E6.15) or the Station Circuit Breaker Renewal (section E6.16) programs, Toronto Hydro's preferred alternative is to convert all 4.16 kV load from these stations to current standard 13.8 kV or 27.6 kV construction. This enables Toronto Hydro to eventually decommission the stations.

Load Capacity

Load capacity of 4.16 kV box construction feeders (3 MVA) is less than a third of the capacity of 13.8 kV overhead feeders (10 MVA). These feeders are not as flexible in accommodating new large customers or renewable generation suppliers. Toronto Hydro must connect these larger customers using alternative means, such as running a new feeder or extending an existing feeder to a given location, which requires additional time and Toronto Hydro resources. In these scenarios, the customer is also responsible for the additional connection costs, which are reflected in their Offer to Connect (OTC) agreement. Conversion to standard 13.8 kV or 27.6 kV feeders will help to mitigate such costs for future customers.

Clearance Issues

Clearance issues are also prevalent with 4.16 kV overhead box construction feeders. As per Canadian Standards Association (CSA) and Toronto Hydro standards, the clearance between overhead primary conductors and buildings must be greater than three meters. In many cases, as buildings are replaced, rebuilt or refurbished, they are being located closer to or even right against the lot lines, which compromises the line clearances previously achievable. Similar complications can arise from building restorations due to the temporary scaffolding required. In many instances, the three metre clearance cannot exist between the lot line and the closest primary conductor on the overhead box pole because of the large area that the box occupies at the top of the pole. In these situations, extensive planning must be done to isolate the conductors while maintaining safe and reliable supply to customers in the area. There is also a financial impact to customers, as the customer requesting the work is responsible for the cost of isolating the feeders that impede the required clearance. As standard 13.8 kV and 27.6 kV overhead feeders occupy a smaller area at the top of any given pole, the issues and costs related to the isolation of box construction feeders can ultimately be avoided in many cases with timely conversion. Figure 12 shows some examples of recent property development activities and their interference with the existing box construction plant.

FIGURE 12: **INSTANCES OF REQUIRED RECONFIGURATION**

Conclusion: Need for a Proactive Replacement Program

Toronto Hydro could elect to maintain and repair box construction wherever it currently exists during the 2015-2019 period. However, due to the high number of assets past their useful lives on these feeders (as seen in Figures 13 to 16 below), the utility anticipates that this status quo option would result in worsening reliability and avoidable maintenance costs from associated 4.16 kV MS's that could otherwise be decommissioned. Also, the safety and operational issues outlined in Section E6.7.5.4 would remain.

In contrast, Toronto Hydro's preferred alternative, i.e., the planned conversion program, will convert 44 outdated 4.16 kV box construction feeders to current standard 13.8 kV or 27.6 kV feeders between 2015 and 2019.

E6.7.3.2 Asset Details

(i) Asset Lifecycle

Figures 13 to 16 illustrate the asset age profiles for overhead transformers, underground transformers, overhead switches and poles on box construction feeders. The areas highlighted in red approximate the number of assets considered past useful life. Over one-quarter of overhead transformers (Figure 14) are 35 years or older, which exceeds the useful life of this asset class. In addition, roughly another one-quarter of overhead transformers are between 25-34 years of age and will soon be reaching the end of their 35 year lifecycle. Toronto Hydro plans to address overhead transformers reaching end-of-life within the 2015-2026 period to mitigate outage duration and frequency for customers and to improve safety and efficiency. A similar pattern is seen with underground transformers, where over half of the current assets are 35 years or older (Figure 15).

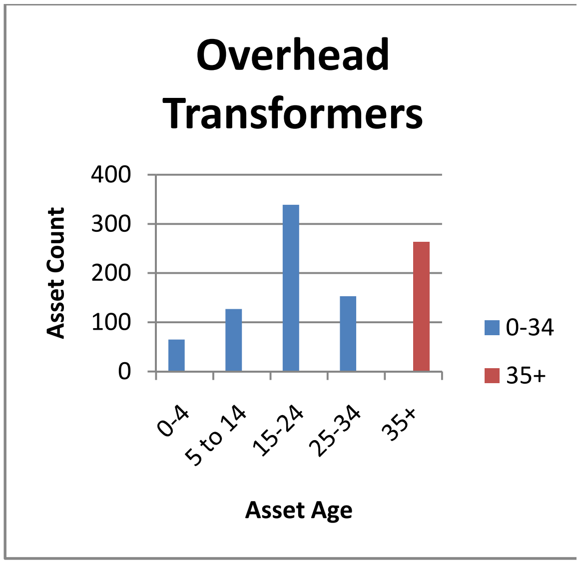


FIGURE 13: ASSET COUNT BY AGE GROUP FOR OVERHEAD TRANSFORMERS FOUND ON BOX CONSTRUCTION FEEDERS SCHEDULED FOR REPLACEMENT IN 2015-2019

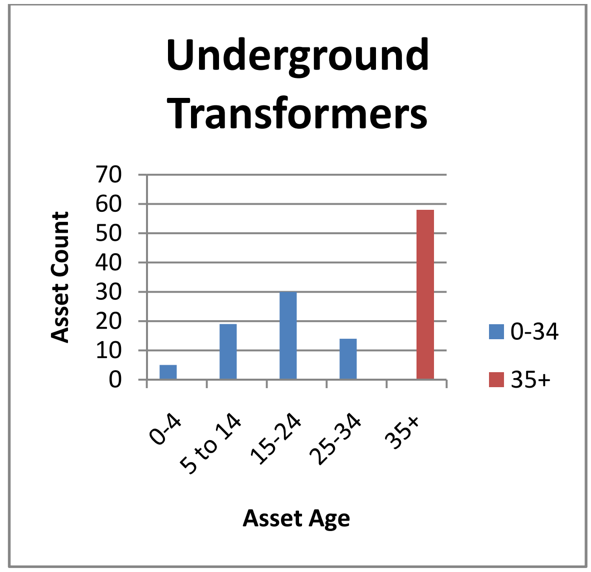


FIGURE 14: ASSET COUNT BY AGE GROUP FOR UNDERGROUND TRANSFORMERS FOUND ON BOX CONSTRUCTION FEEDERS SCHEDULED FOR REPLACEMENT IN 2015-2019

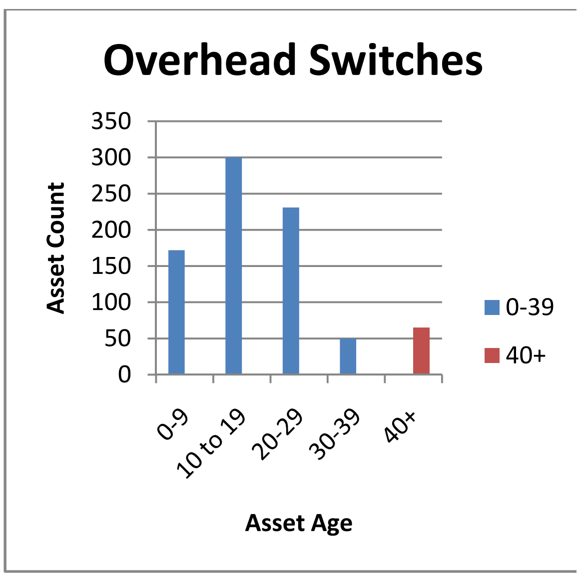


FIGURE 15: ASSET COUNT BY AGE GROUP FOR OVERHEAD SWITCHES FOUND ON BOX CONSTRUCTION FEEDERS SCHEDULED FOR REPLACEMENT IN 2015-2019

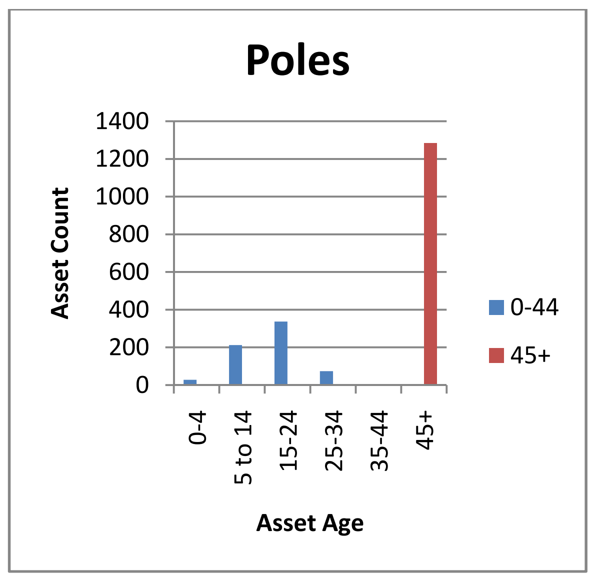


FIGURE 16: ASSET COUNT AGE GROUP FOR POLES FOUND ON BOX CONSTRUCTION FEEDERS SCHEDULED FOR REPLACEMENT IN 2015-2019

The majority of poles associated with the box construction are beyond useful life Figure 16), which raises failure risks and safety concerns for customers and crew workers. Overall, Figure 13 through Figure 16 show that approximately forty percent of box construction assets are past their useful lives and in need of replacement in order to mitigate failures, outages and safety risks.

(ii) Asset Failure Impacts

Depending on the failure mode and type of fault, there will be varying impacts on customers. However, Table 4 shows that on average, outage duration on 4.16 kV box construction feeders is considerably longer than on 13.8 kV overhead feeders. Figure 17 shows the cumulative number of customers per year who will be converted to standard 13.8 kV or 27.6 kV circuits as part of the ongoing Box Construction Conversion program. Figure 17 is a result of the criteria used to determine the order of conversion for these feeders; where possible, feeders from more lightly loaded stations are considered for conversion prior to the ones from heavily loaded stations. This approach allows those stations to be removed from service more quickly, thereby avoiding the associated future maintenance and asset replacement costs sooner.

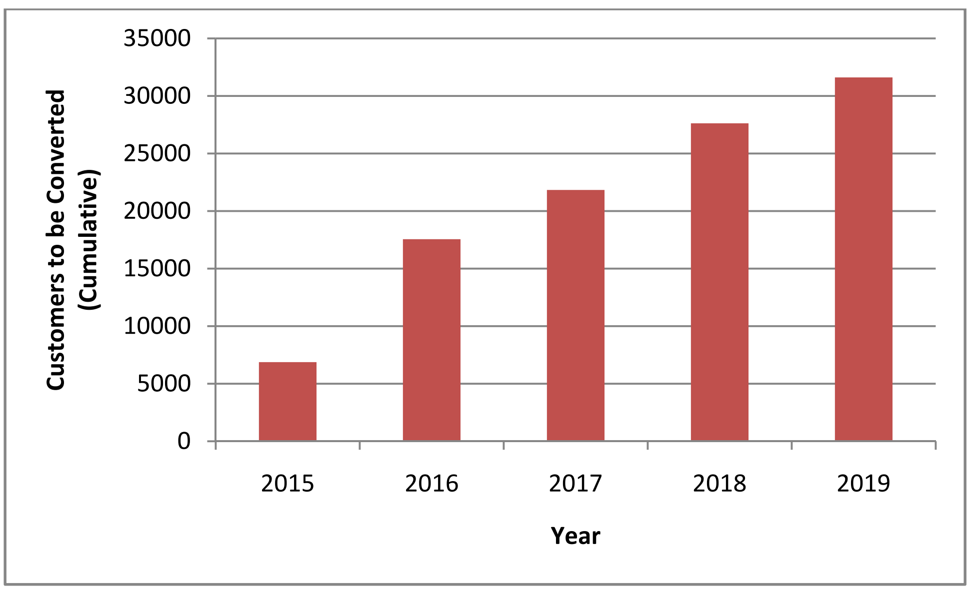


FIGURE 17: CUSTOMERS TO BE CONVERTED PER YEAR

E6.7.4 Timing & Pacing of the Program

Toronto Hydro plans to address all of the issues associated with 4.16 kV box construction feeders through a proactive program to convert these feeders to standard 13.8 kV or 27.6 kV overhead construction. The table below provides the estimated costs of the program for the 2015-2019 period. Given the current schedule, Toronto Hydro plans to address 65% of all box construction by the end of 2019. The conversion of all box construction feeders is expected to be complete by 2026.

TABLE 6: HISTORICAL AND FORECASTED SPENDING

	Historical Spending					Future Spending				
Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CAPEX ($M)	5.7	7.1	0.84	13.8	23.3	16.8	20.7	21.1	21.6	22.7

Ideally, Toronto Hydro would convert all remaining box construction in the 2015-2019 period. However, converting all remaining box construction feeders over this time period is not feasible from an engineering perspective due a number of system constraints, including limited availability of certain feeders and the need to first upgrade certain Hydro One Networks Inc. (HONI) station equipment housed in Toronto Hydro transmission stations (TS):

- <u>Availability of 13.8 kV or 4-wire (with neutral) feeders</u>: Three-phase overhead feeders require a fourth neutral cable to accommodate single-phase load (fed from a low-impedance 4-wire bus), but not all 13.8 kV feeders are ‘4-wire’ (e.g., underground 13.8 kV feeders can be either 3-wire or 4-wire). Only those 4.16 kV box construction feeders that have either 13.8 kV 4-wire feeders or a 4-wire bus at a station in their vicinity can be converted to 13.8 kV overhead feeders. In addition, the available 13.8 kV overhead feeders must have sufficient capacity to accommodate the existing 4.16 kV load, which is not always the case.

- <u>Some HONI-owned station equipment in Toronto Hydro transmission stations (TS) requires upgrades</u>: Station equipment, such as transformers, switchgear and busses, must be upgraded to accommodate a future 4-wire bus for 4.16 kV box construction conversion jobs. For example, Highlevel TS must have its high-impedance 3-wire 13.8 kV bus/transformer/switchgear upgraded to a low-impedance 4-wire bus to accommodate 4.16 kV conversion jobs at Highlevel MS. Therefore, stations like Highlevel MS have not been targeted for conversion in the 2015-2019 timeframe.

E6.7.4.1 Ranking & Prioritization

Toronto Hydro considers several factors when determining the sequencing of work within the Box Construction Conversion program. These include:

- **Asset condition and age** – Toronto Hydro's sequencing of planned work accounts for the risk of failure by considering which assets are in poor condition and past useful life. Assets prone to failure have a higher impact on customer service, satisfaction and reliability.
- **Proximity to 13.8 kV 4-wire bus with capacity** – Feeders that are especially far from the nearest available 4-wire bus with available capacity can encounter significant engineering challenges requiring additional planning and coordination to develop a feasible alternative supply. High Level MS is an example of a heavily loaded MS that has no 4-wire bus in its vicinity. An upgrade of the High Level TS 13.8 kV 3-wire bus to a 4-wire bus is required accommodate conversion projects in this area.
- **Avoiding replacing legacy 4.16 kV station assets** – Coordination with stations investment programs is a factor when prioritizing work, specifically the switchgear, power transformer and circuit breaker replacement programs. Stations that are targeted for decommissioning within the Box Construction Conversion program can potentially be part of station renewal efforts, and coordination is done to avoid the scenario of replacing station assets in one program that are targeted for decommissioning in another. Conversely, station assets that have been recently replaced have a lower replacement priority. An example of such a station is Sherbourne MS, where a station transformer was recently replaced in 2010. Accordingly, box construction conversion for this station's feeders is not scheduled until later in the conversion period (currently 2024).
- **Reliability** – An important prioritization criterion for many System Renewal and System Service investments is feeder reliability. All other prioritization factors being equal, Toronto Hydro intends to address the poorest performing feeders first.

Asset condition/age, reliability and avoiding replacement of legacy 4.16 kV stations assets are all important prioritization criteria that are considered when ranking box construction projects. Proximity to a 13.8/27.6 kV 4-wire bus with capacity is a limiting factor for the order of project execution, as explained in the above points. Projects are conditional on whether there is sufficient

13.8/27.6 kV overhead infrastructure in the vicinity for conversion. Projects lacking this infrastructure will necessarily occur later in the program sequence.

The following table shows the order of forecasted decommissioning of stations that will be made possible in part by the execution of the Box Construction Conversion program.

TABLE 7: PROPOSED STATION LEVEL DECOMMISSIONING 2015-2026

Year	Station
2015	MILLWOOD MS
2016	MERTON MS
2016	QUEENSWAY MS
2017	DUFFERIN MS
2017	DUPONT MS
2017	JUNCTION MS
2017	CARLAW MS
2017	WILTSHIRE MS
2018	CHAPLIN MS
2018	HAMMERSMITH MS
2019	DEFOE MS
2020	HIGH LEVEL MS
2020	RUNNYMEDE MS
2021	DANFORTH MS
2022	STRACHAN MS
2023	SPADINA MS
2024	SHERBOURNE MS
2025	UNIVERSITY MS

Year	Station
2026	ISLAND MS

E6.7.6 Program Execution

Toronto Hydro's proposed Box Construction Conversion program consists of multiple discrete projects over the 2015 through 2019 period. Detailed projects for the year 2015 are provided in Section E6.7.8. In a typical box construction conversion project, construction crews install new framed poles for 13.8 kV/27.6 kV overhead distribution in close proximity to the existing box construction poles. Next, crews install de-energized primary and secondary cable and pole-mounted transformers. Once the new circuit is energized, customers that were initially supplied from the box construction feeder(s) are transferred to the new service. After the entire load is transferred off of the box construction circuits in the area, the circuits are de-energized and the box construction infrastructure is physically removed. Figure 19 shows an example of an actual conversion project.

FIGURE 18: EXAMPLE OF BOX CONSTRUCTION CONVERSION JOB. (1) NEW POLES ARE INSTALLED IN CLOSE PROXIMITY TO EXISTING POLES. (2) NEW PRIMARY (TOP) AND SECONDARY CABLE (MIDDLE) INSTALLED (NOT ENERGIZED). (3) NOTE THAT CUSTOMERS STILL SUPPLIED FROM 4.16 KV BOX SERVICE, AND NOT NEW 13.8 KV/27.6 KV SERVICE. (4) CUSTOMERS ARE SWITCHED OVER TO NEW SERVICE. (5) ONCE ALL LOAD FROM CIRCUITS RUNNING THROUGH BOX POLES ARE DE-ENERGIZED, BOX CONSTRUCTION INFRASTRUCTURE (POLES, CIRCUITS, SWITCHES, TRANSFORMERS) CAN BE REMOVED.

The planned projects within the Box Construction Conversion program are occasionally broken into smaller "reactive" projects in order to make the most efficient use of Toronto Hydro resources. Toronto Hydro may proactively rebuild laterals of 4.16 kV box construction feeders in poor condition (identified by field crews) to 13.8 / 27.6 kV construction standards using reactive crew resources when they are not otherwise allocated to reactive work. Toronto Hydro would then continue to operate the lateral at 4.16 kV system voltage. When the eventual conversion of that feeder takes place, the poles and conductors on those laterals will already be prepared for the conversion, which allows the project to be completed in a more timely fashion. Another significant benefit of this approach is that the failure risks associated with poor condition 4.16 kV assets are eliminated in a more timely manner.

E6.7.6.1 Proposed Work Plan

The proposed work plan in the 2015-2019 period does not necessarily follow a station-by-station approach but rather indicates a milestone year when all load will be converted at a given station. Feeders proposed for conversion in the 2015-2019 period are summarized Table 8.

Issues may arise that are specific to certain conversions; however, current planning processes have not identified any major issues in years 2015-2019 other than the continued deterioration and aging of assets.

Ultimately, work proposed for 2016 to 2019 is of the same nature as work proposed from 2015. No major change in design standards or planning methodologies that could affect the work program are anticipated.

TABLE 8: 2015-2019 LONG TERM PLAN

/C

Year	Feeder	Station
2015	B4KS	KEELE & ST. CLAIR MS
2015	B3MD	MILLWOOD MS
2015	B1MR	MERTON MS
2015	B2MR	MERTON MS
2015	B4E	CARLAW MS
2015	B8E	CARLAW MS
2015	B1W	WILTSHIRE MS
2015	B2W	WILTSHIRE MS
2015	B3W	WILTSHIRE MS
2015	B2HS	HAMMERSMITH MS
2016	B71DU	DUPONT MS
2016	B10J	JUNCTION MS
2016	B6DU	DUPONT MS
2016	B4DU	DUPONT MS
2016	B3MR	MERTON MS
2016	B5MR	MERTON MS
2016	B4HS	HAMMERSMITH MS
2016	B13E	CARLAW MS

Year	Feeder	Station
2016	B5E	CARLAW MS
2016	B5OV	OVERDALE MS
2016	B2QU	QUEENSWAY MS
2017	B3DN	DUFFERIN MS
2017	B1DU	DUPONT MS
2017	B3J	JUNCTION MS
2017	B8J	JUNCTION MS
2017	B11J	JUNCTION MS
2017	B14J	JUNCTION MS
2017	B5W	WILTSHIRE MS
2018	B1CP	CHAPLIN MS
2018	B3CP	CHAPLIN MS
2018	B4CP	CHAPLIN MS
2018	B51CP	CHAPLIN MS
2018	B6CP	CHAPLIN MS
2018	B32HS	HAMMERSMITH MS
2018	B5HS	HAMMERSMITH MS
2018	B7HS	HAMMERSMITH MS
2019	B2DF	DEFOE MS
2019	B4DF	DEFOE MS
2019	B8DF	DEFOE MS
2019	B9DF	DEFOE MS
2019	B3DF	DEFOE MS
2019	B7DF	DEFOE MS

E6.7.6.2 Program Risks

The following are risks to program completion that Toronto Hydro considers when planning and executing box construction conversions.

- ***Timely third-party project completion:*** Some box construction conversion projects are contingent on the completion of HONI stations projects. For example, Toronto Hydro has scheduled a conversion project for Carlaw MS in 2015, but this project cannot start until a new bus at Carlaw TS is commissioned. A significant delay of HONI's portion of the Carlaw TS expansion will necessarily lead to a delay in Toronto Hydro's box construction conversion project. To mitigate this risk, Toronto Hydro will work closely HONI to ensure that there is a mutually agreed project schedule.

E6.7.7 Evaluation of Alternatives

E6.7.7.1 Quantification/Evaluation of Options

In addition to the benefits outlined in section E6.7.3.1 , the value derived from the Box Construction Conversion program can be further quantified by examining the difference in cost of ownership between the existing box construction design that will be replaced and the new standardized 13.8 kV overhead design that will be installed. This difference in costs includes quantified risks, taking into account the probability of failure of the asset, and multiplying this by the direct and indirect costs associated with in-service asset failures, including the costs of customer interruptions, emergency repairs and replacement. The underlying methodology and processes associated with the business case results provided below are further explained within Section D3.1.

(i) Status Quo ("Like-for-Like" Replacement)

In the status quo scenario, Toronto Hydro would continue to maintain and repair box construction assets wherever they are currently found, and replace failed assets as needed. Due to the high number of box construction assets past their useful lives, Toronto Hydro anticipates that maintaining the status quo would result in additional avoidable maintenance costs and deteriorating reliability, as described in section E6.7.3.1. Also, the safety and operational issues outlined in Section E6.7.5.4 would remain.

The status quo options requires Toronto Hydro to manage the issues described above in a reactive and less efficient manner, delaying the decommissioning of some municipal stations (MS) or possibly preventing decommissioning of the MS altogether. The continued cost of ownership associated with the status quo option (COO_E) is highlighted in Table 9.

TABLE 9: COST OF OWNERSHIP OF EXISTING ASSETS / STATUS QUO

Business Case Element	Cost (in Millions)
Status Quo/Existing State of Infrastructure	
Asset Risk **[AR_E]**	15.38
Non Asset Risk **[NAR_E]**	58.22
Maintenance Cost **[MC_E]**	1.55
Additional Quantifiable Benefits **[AQB_E]**	0
Cost of Ownership of Existing Assets **[COO_E]**	75.15

(ii) Conversion to Standardized 13.8 kV or 27.6 kV Infrastructure

The cost of ownership (COO) and program net benefit (NPV) associated with box construction conversion is further detailed in Table 12. The cost of ownership is established for both the existing state (COO_E) and the proposed new state (COO_N) based on the first year of planned activities in this program. The cost of reflects the risk of asset failure for a given state, including both direct and indirect costs. These costs include customer interruptions, emergency repairs, and asset replacements associated with the given design. In addition, the risk that non-asset failures contribute to a particular design is included in both the existing (NARE) and proposed (NARN) state. Non-asset risks are further explained in Section D3.3. Costs in maintenance activities are also included for both states and any additional benefit that is associated with the program that is external to the asset and non-asset related risk evaluation is quantified for both the existing state (AQBE) and new state (AQBN). Note that, for this program, AQB corresponds to savings from line losses as a result of conversion projects. All of these factors combine to form the COO for a particular design. For further details on the COO approach, please refer to Section D3.3.

When the difference in cost of ownership (ΔCOO) is compared to the associated program costs (PC) for the first year of activities, the box construction conversion produces a net present value (NPV) of $5.64 million, as shown in Table 10.

1 **TABLE 10: BOX CONSTRUCTION CONVERSION BUSINESS CASE EVALUATION (BCE)**

Business Case Element	**Cost (in Millions)**
Option 2: Conversion to Standardized 13.8 kV Feeders (N)	
Asset Risk **[AR_N]**	3.34
Non Asset Risk **[NAR_N]**	52.58
Maintenance Cost **[MC_N]**	0
Additional Quantifiable Benefits **[AQB_N]**	-3.21
Cost of Ownership of New Assets (Conversion to 13.8 kV) **[COO_N]**	52.72
Option 2: Project Net Benefit (NPV_1)	
Difference in Cost of Ownership [$\Delta COO_1 = (COO_E - COO_N)$]	22.44
Program Cost **[PC_1]**	16.80
Program Net Benefit [$NPV_1 = (\Delta COO_1 - PC_1)$]	**5.64**

E6.7.8 2015 Project Details

Table 13 shows the total program cost for 2015. The costs are broken into capital expenditure amounts associated with:

(a) previously filed projects that appeared as jobs in the OEB approved Box Construction segment as part of Toronto Hydro's 2012-2014 Incremental Capital Module (ICM) filing; and

(b) projects appearing for the first time as part of the 2015-2019 Customer Incentive Rate-setting (CIR) application.

TABLE 11: 2015 PROGRAM COSTS

2015 CAPEX ($M)	
ICM Jobs	**CIR Projects**
5.98	10.82

Table 14 lists all projects that Toronto Hydro plans to partially or completely execute as part of the 2015 work program. Note that the table shows total costs for each project. Depending on the precise start date of each project, portions of the total project cost may be incurred before or after 2015. For reference, projects that originally appeared as ICM segment jobs have been flagged as "ICM".

TABLE 12: 2015 PROJECTS

Project Number	Project Name	Total Project Cost	Start Date	Project Type
X12129	X12129 Merton-Millwood Conversion Phase 2 (B2MR, B3MD)	$1,972,609	2015	ICM
X12143	X12143 Merton-Millwood Conversion Phase 3 (B1MR, M2MR)	$1,897,845	2015	ICM
X13003	X13003 Convert 4 kV Dupont B6DU to 13.8 kV	$1,419,765	2015	ICM
X13004	X13004 Convert 4 kV Dupont B4DU/B71DU to 13.8 kV - Phase 3 UG Electrical	$890,496	2015	CIR
X13164	X13164 Voltage Conversion B2W/B1W PHASE 1	$1,234,184	2015	CIR
X13173	X13173 Convert 4 kV Wiltshire MS B3W to 13.8 kV system	$1,317,019	2015	CIR
X13174	B2W/B1W TO 13.8 kV VC PHASE II	$1,559,904	2015	CIR
X13693	X13693 (X11369) KS MS VC 4-13.8 kV BC ph2 (Construct only)	$690,125	2014	ICM
X14413	X14413 Convert Dupont 4 kV B4DU/B71DU- Ph 2 Decommission LOC2630	$183,815	2015	CIR
X14444	X14444 - P06 - Convert 4 kV B2HS to 13.8 kV overhead feeder	$2,331,130	2015	CIR
X15017	X15017 - P06 Box conversion to 13.8 kV Elec Carlaw B4E B8E Phase 1	$1,540,556	2015	CIR
X15281	X15281 P06 Box conversion to 13.8 kV B4E/B8E (phase 2)	$1,759,530	2015	CIR
TOTAL		**$16,796,984**		

The following subsections provide additional details for all of the projects listed in the table above.

E6.7.8.10 X12129 Project Description

Investment Category: System Renewal

Program: Box Construction Conversion

Project Title: Merton-Millwood Conversion Phase 2 (B2MR, B3MD)

Project Number: X12129 (ICM)

Project Year: 2015

Estimated Cost: $1,972,609

(i) Objective

The objective of this job is to prepare Millwood MS feeder B3MD and Merton MS feeder B2MR for conversion from 4.16 kV to 13.8 kV for eventual decommissioning of Millwood MS and Merton MS. The main objective is to mitigate the safety concerns associated with working around energized box construction, which is found on feeders from both Millwood MS and Merton MS.

(ii) Scope of Work

TABLE 13: X12129 SCOPE OF WORK DETAILS

District Neighborhood	MOORE PARK
Station(s)	MERTON MS, MILLWOOD MS
Feeder(s)	B2MR, B3MD

Table 14 outlines the historical reliability of this feeder (Note: the majority of this project is for the conversion of B3MD).

TABLE 14: HISTORICAL RELIABILITY – B3MD

HISTORICAL RELIABILITY PERFORMANCE – B3MD			
Reliability Metric	**2011**	**2012**	**2013**
Feeder CI	0	0	0
Feeder CHI	0	0	0

The project is bounded by Bayview Avenue to the east, Mount Pleasant Avenue to the west, Millwood Road to the north and Merton Street to the south. Table 15 details the quantities and kilometers of assets to be replaced.

TABLE 15: X12129 ASSETS REPLACED

Assets (Units)	2015
OH Transformer	30
OH Switch	23
Poles	34
UG Switch	0
UG Transformer	5
OH Conductor (km)	3.2
UG Cable (km)	0.6

(iii) Justification & Benefits

This work will mitigate potential safety risks, improve reliability and, when conversion is complete, reduce line losses. Associated benefits of this project align to the program benefits and drivers outlined in sections E6.7.2 and E6.7.3. Furthermore, deferral of this project will likely delay plans to decommission Merton MS and Millwood MS.

E6 SYSTEM RENEWAL INVESTMENTS

FIGURE 1: TORONTO HYDRO CREWS INSTALL A NEW UNDERGROUND TRANSFORMER

System Renewal investments are driven by the inability of existing distribution system assets to continue to perform at an acceptable standard. If the performance of a given asset is low or the consequences to customers of asset failure are high, replacing or refurbishing the asset(s) becomes a priority. As assets age and deteriorate, their risk of failure grows, which in turn results in increased reliability- and safety-related risks for customers, the general public and crew workers.

These asset renewal and reconfiguration investment programs will target and replace the "worst-of-the-worst" existing assets that are at, exceeding or near the end of their useful lives. Similarly, assets that no longer align to current operating practices are also targeted within this category, including those assets with accessibility (ravines, rear lots, highway crossings) or serviceability conflicts, which can result in increased reliability and/or safety-related risks. The execution of these asset renewal programs will result in the installation of asset infrastructure that meets current standards and is expected to carry a reduced cost of ownership for the utility and its customers versus the aging assets being replaced.

The System Renewal investment programs detailed within this section serve to target and replace these worst-of-the-worst overhead, underground, secondary network and stations assets. Table 1 describes the primary drivers for capital investments in this category.

TABLE 1: TRIGGER DRIVERS FOR SYSTEM RENEWAL CATEGORY

Driver	Description
Failure Risk	▪ There is the imminent risk of asset failure due to age or condition deterioration
Functional Obsolescence	▪ The asset/asset installation is no longer aligned to Toronto Hydro processes and practices such that it can no longer be maintained (e.g., lack of spare parts, lack of accessibility or operational constraints) or utilized as intended in the distribution system
Failure	▪ Failures have already taken place that Toronto Hydro must reactively respond to as part of capital investment activities.

Table 2 provides a brief description for each investment program within the System Renewal narrative along with total expenditures for each program from 2015 onwards to 2019. Individual section numbers for each investment program are also provided in this table.

TABLE 2: BRIEF DESCRIPTION OF SYSTEM ACCESS INVESTMENT PROGRAMS

Program Index and Name		Brief Description	Total (5 years)
E6.1	**Underground Circuit Renewal**	Replace end-of-life and obsolete underground assets with new ones on a "like-for-like" basis. The assets include switches, transformers, and cables. Replacing the assets will help improve system reliability and efficiency.	**$459 M**
E6.2	**Paper-Insulated Lead-Covered (PILC) Piece-outs and Leakers**	Program will address two issues related to underground PILC cable. PILC cables are aging and a number have developed cracks and pinholes and will either be replaced or repaired. The program will also increase cable length to address unsafe congested areas and allow the cables to be safely and properly routed.	**$7 M**
E6.3	**Underground Legacy Infrastructure**	Targets non-standardized equipment that is at or near end-of-life and poses a failure risk. Many of these assets are now obsolete and will be replaced with standardized equipment, helping to improve safety and system reliability.	**$27 M**

Program Index and Name		Brief Description	Total (5 years)
E6.4	**Overhead Circuit Renewal**	Focuses on replacing poles, switches, transformers, overhead accessories and street lighting assets that are either aged, in poor condition, or functionally obsolete on a "like-for-life" basis. Toronto Hydro expects the program to mitigate significant sources of outages that negatively impact service reliability to customers and may pose potential safety risks for employees and the general public.	**$147 M**
E6.5	**Overhead Infrastructure Relocation**	Provide a modern and efficient configuration to replace feeders that are past end-of-life and functionally obsolete from a design perspective to mitigate the number of system outages. Feeders will be relocated to eliminate difficult-to-access overhead plant, overhead egress plant and overhead plant crossing highways.	**$10 M**
E6.6	**Rear Lot Conversion**	This program replaces the existing, end-of-life rear lot distribution service configuration with an underground front lot access system to eliminate challenges in performing maintenance activities and to mitigate the increased risk of long duration outages inherent in the existing plant design. The conversion eliminates operational constraints and reduces the safety and reliability risks associated with this obsolete connection configuration.	**$59. M**
E6.7	**Box Construction Conversion**	This program transitions customers from functionally obsolete 4.16 kV box construction feeders to the current standard 13.8 kV or 27.6 kV overhead infrastructure. By eliminating box construction feeders, Toronto Hydro anticipates that the program will reduce safety concerns for crew members dealing with restricted working spaces, improve restoration times and mitigate costs related to load capacity constraint when connecting new customers in the downtown area.	**$103 M**
E6.8	**SCADA-MATE R1 Replacement**	This program replaces malfunctioning switches. Moisture has caused internal switch components to corrode. The corrosion poses significant potential safety hazards for the public and Toronto Hydro employees due to misrepresentation of the switch state, preventing core functions of the switch from being used. The new R2 design will improve remote functionality and reliability of the switch, thereby reducing prolonged outages and failure risk for customers.	**$13 M**

Program Index and Name		Brief Description	Total (5 years)
E6.9	**Network Vault Rebuild Program**	Rehabilitation of vaults that were identified to be high-risk to protect the assets that are housed within and to eliminate potential safety hazards for crews, pedestrians and emergency response crews in busy downtown areas. Rehabilitation options include decommissioning the vaults, rebuilding the vault roofs, or rebuilding the entire vault.	**$45 M**
E6.10	**Network Unit Renewal Program**	Replacement of obsolete and poor condition Network Units that are at risk of failure with new submersible Network Units. Toronto Hydro anticipates that this program is expected to increase service reliability, improve employee safety and reduce environmental concerns by mitigated oil leaks.	**$34 M**
E6.11	**Legacy Network Equipment Replacement (ATS & RPB)**	Replacement of automatic transfer switches (ATSs) and reverse power breakers (RPBs) with manual secondary switches, stand alone network protectors (SANPs), or network units. The ATSs and RPBs are no longer supported by their original manufacturer, making it difficult to comply with prudent maintenance practices and policies. These assets are also not submersible by design and are subject to a high risk of equipment failure.	**$5 M**
E6.12	**Network Circuit Reconfiguration**	Reconfiguration of the functionally obsolete network system by splitting a large secondary grid into enhanced mini grids. Increasing grid flexibility will enhance its ability to supply new classes of customers, to operate under different contingency events and decrease the necessity to drop the entire network during failure.	**$9 M**
E6.13	**Stations Switchgear Renewal**	Replacement of existing switchgears that have become functionally obsolete and that have passed the end of their useful lives. The existing non-arc resistant switchgear at municipal stations and transformer stations will be replaced with type C, arc resistant switchgear with vacuum circuit breakers.	**$106 M**
E6.14	**Stations Power Transformer Renewal**	Replacement of power transformers located at municipal stations across the city to mitigate the failure risk of prolonged outages due to assets at the end of their useful lives. This program will directly benefit customers connected to the transformers identified for replacement by reducing outage risk and increasing system reliability in their respective areas.	**$12 M**

Program Index and Name		Brief Description	Total (5 years)
E6.15	**Stations Circuit Breaker Renewal**	Replacement of obsolete oil circuit breakers, which are no longer supported by manufacturers, with stand-alone vacuum circuit breakers. Vacuum circuit breakers are cheaper to maintain and are less likely to fail catastrophically.	**$9 M**
E6.16	**Stations Control & Monitoring**	This program aims to replace aging and obsolete remote terminal units (RTUs) and install SCADA systems at substations with no SCADA capabilities. Existing RTUs and radio communications networks at Etobicoke MS and downtown Toronto TS will be replaced while modern SCADA systems at Scarborough MS will be installed.	**$5 M**
E6.17	**Stations Ancillary Systems**	Replacement of end-of-life and outdated ancillary systems (air compressors, station service power supply systems, fire alarm systems, and fire barriers) that are at risk of failure and functionally obsolete with more reliable modern technologies.	**$2 M**
E6.18	**Stations Buildings**	This program focuses primarily on the structural integrity of eleven TS and MS buildings in which electrical stations assets are housed. The program takes a proactive approach to improve existing station buildings to extend their serviceable lives. Toronto Hydro anticipates that this will help ensure uninterrupted service, protect the safety of crews and the public, and ensure the integrity of nearby customer property.	**$11 M**
E6.19	**Stations DC Battery Replacement**	Replacement of end-of-life DC batteries and chargers systems with new ones at various stations locations to mitigate battery failure risk and ensure faults are isolated to the local feeder. These batteries are used to provide the necessary power supply to operate the associated circuit breaker assets if the main power supply to the entire station is lost.	**$3 M**
E6.20	**Reactive Capital**	Accounts for unplanned, non-discretionary capital expenditures required to repair or replace assets. With proper budgeting and resource allocation, timely reactive work improves safety, reduces the backlog of assets to be maintained, avoids depriving other capital programs of planned resources and reduces strain on the distribution system.	**$166 M**

Program Index and Name		Brief Description	Total (5 years)
E6.21	**Worst Performing Feeder**	This program analyses the performance of feeders that are at risk of seven or more outages in a year and determines the root cause of the outage trend. Condition of the equipment will be assessed during feeder patrols and appropriate mitigation work will be performed to alleviate outages caused by design or environmental disturbances. The program improves the reliability of feeders, minimizes power outages for customers experiencing especially poor service, and mitigates the risk of additional asset failures.	**$8 M**
E6.22	**Distribution System Communication Infrastructure**	This program renews and improves the telecommunications system by identifying gaps in the communication service platform, updating the obsolete SONET technology and SCADA infrastructure. An updated telecommunication system reduces failure risk an provides safe, efficient and reliable supply of electricity to customers.	**$16 M**

The following Sections E6.1 though to E6.23 contain the details and justification for each capital investment program within the System Renewal investment category.

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO

UNDERTAKING NO. J1.3:

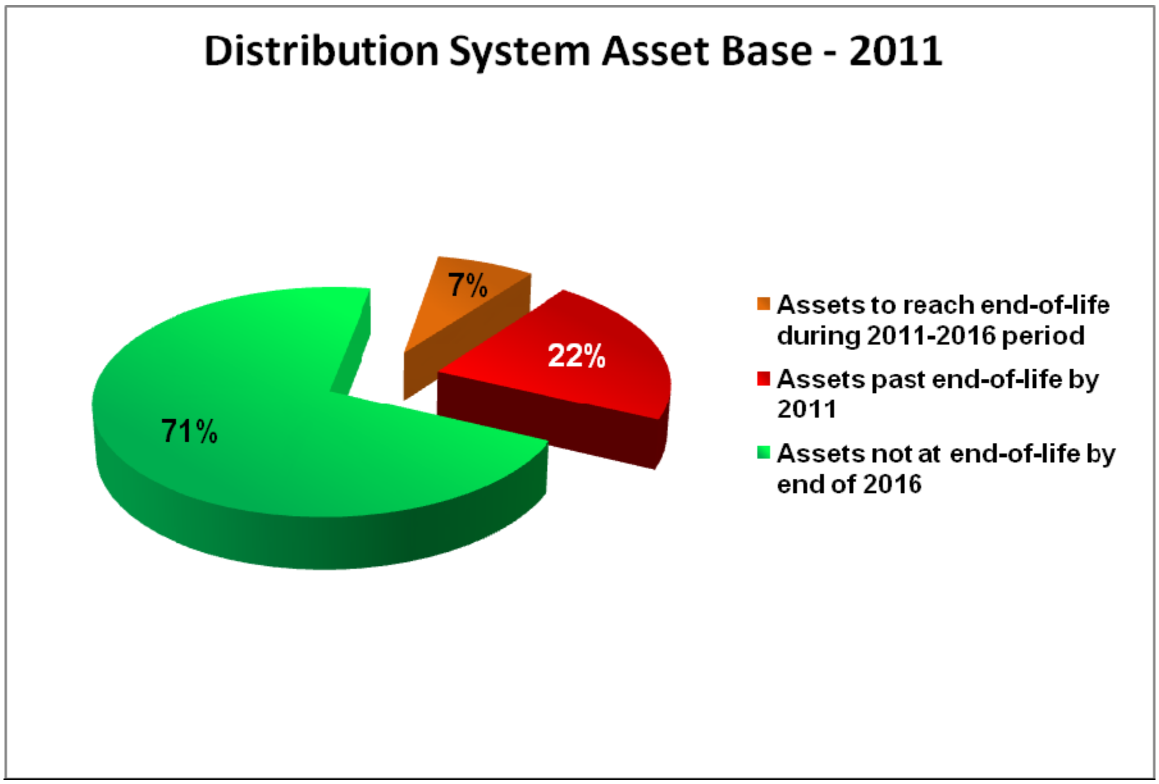
Reference(s):

To update slide 8 with 2011 data.

RESPONSE:

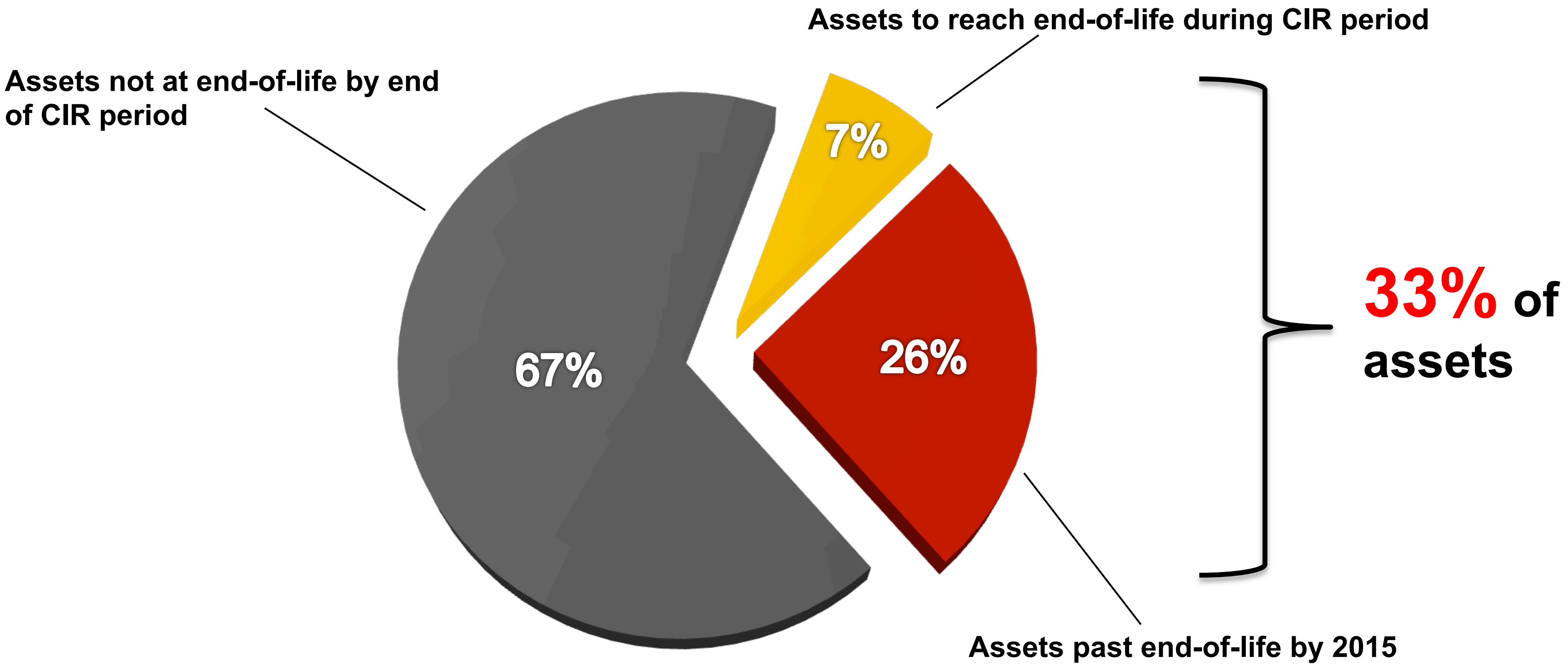
The figure noted below provides the useful life demographics of Toronto Hydro's electrical distribution assets in 2011. Comparing this figure to the figure provided in slide 8 of Exhibit EC1 illustrates that the proportion of assets operating at or beyond the end of useful life has increased from 22% in 2011 to a forecasted 26% in 2015. The two figures also demonstrate that the forecasted rate of aging – as represented by the proportion of existing assets to reach end-of-life over a given five year period – is the same for both baseline years (i.e., 7% for both the 2011-2016 and 2015-2019 periods).

TECHNICAL CONFERENCE UNDERTAKING RESPONSE TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO



Capital Needs: System Age

An **aging** system continues to be the main driver of Toronto Hydro's capital investment needs.



existing distribution system asset base

[ref: Ex 2B-Section E2.1]

on? Green light?

MR. WALKER: I'm sorry. Can you hear me now?

MS. LONG: Yes thank you. Maybe you could start again, just for everybody...

MR. WALKER: Certainly. In terms of our capital need, our aging system continues to be the main driver of our capital investment needs. And if you look at it from a demographics perspective, an asset demographics perspective -- and you can see that in this pie chart -- 26 percent of our assets are currently past their end-of-life. And over the next five years, the CIR period, a further 7 percent will be past end-of-life. So fully a third of our assets will ultimately be past end-of-life.

Moreover, as we continue beyond the CIR period, more and more assets every year will reach or exceed their end-of-life, making that red portion larger and larger.

So what does this mean? Well, if you consider the size and breadth of the Toronto Hydro system -- all the poles, the wires, the transformers, the switches, the cable duct structures, et cetera, et cetera -- this third of our assets represent billions of dollars in investment.

So what do we mean by end-of-life? Well, if you look at the lifecycle of an asset -- and this graph shows costs on the vertical axis and the number of years that the asset is in service on the horizontal axis -- the longer an asset is in service, the lower its capital cost is. And that's depicted by the green line here.

However, the longer it's in service, the greater the reassessment of the plan. But I guess what I wanted to clarify is, if you were to adopt those approaches, in your view, how would -- how would those approaches affect the customers of Toronto Hydro?

MR. WALKER: Well, given the level of assets that are past their end-of-life as it is today, we're seeing those effects very directly as, you know, as it affects our customers.

I've mentioned a couple of examples already where, you know, customers have suffered, and I've got many more that I could speak to.

The way I would characterize it is when I started at the Hydro, we used to have our crews organized in a group called construction and maintenance, and the reason we did that is their normal job would be to do capital construction, and they would be called away periodically if there was a reactive requirement, if something failed and it needed to be replaced, and then they would go back to their capital work.

Today, we have two departments and 13 full-time crews that do nothing but replacement of failing assets, and that's because of this age-related problem. Those assets are past end-of-life and are failing at a significant rate.

And that's what we're trying to address in this plan. It is something we need to address.

And if we were to take this plan and just spread it out over more years, that is going to become worse. That's going to be a worse situation for our customers. More of them are going to experience those failures.

And also, from a purely efficiency and cost perspective, the long-term cost of managing the system will go up, because rather than going out and replacing those assets today, let's say, we're going to incur another two or three years of reactive response, where we go out and replace bits and pieces of it and then have to go out and replace the whole thing at that point.

So it becomes very inefficient from a cost perspective. But from the customer's perspective, it is, you know, it's -- I had an example of a single customer whose service was down for ten days. He had an underground service wire into his house that was down for ten days because it failed. We came out, we repaired it. It failed again. We came out again and repaired it again.

And, you know, we had crews there day and night and on the weekend, and we could not re-energize that service. So we ultimately had to replace that individual's service. But you know that if his service is -- was reacting that way, the other services in that area are of the same vintage, the same type of cable, and the same ground conditions, the same loading conditions and so on. They're going to have the same sort of effect, and we'll be sending crews out there over and over and over again until we go out and address the underlying problem.

MR. KEIZER: Can I just have a moment?

Those are my questions.

MS. LONG: Thank you, Mr. Keizer.

THESL argued that the specific criticisms of the FIM largely fall into two major categories, which are: (1) the customer interruption costs used in the FIM and (2) the way the FIM calculates the amount of load that would be interrupted in an asset failure. THESL submitted that none of these criticisms, separately or together raise any doubt that the FIM is a valuable tool as THESL has used it. THESL concluded that the FIM clearly supports the cost-effectiveness of the projects and segments that it has proposed.

Board Findings

The Board finds that the FIM is a useful tool to compare the financial consequences of failure of aging assets to the benefits of delaying the work and to assess capital spending associated with replacement by extending service life as long as possible.

As conceded by THESL's witnesses, there are certain generalizations used in developing the inputs into the FIM. These include the type of customers in a particular area, and the impact that outages may have on them. The Board finds that these limitations do not outweigh the usefulness of this tool, and commends THESL for developing it. While the Board expects that it will continue to be refined, the Board notes that the level of detail sought by some of the intervenors may only be available at significant effort or cost.

Capital Program Segments

General Comments

While CCC did not take a position on the appropriateness of the projects, it urged the Board to carefully consider the submissions of Board staff, Energy Probe, AMPCO and VECC from a technical perspective, in assessing how it applies the criteria to determine an appropriate ICM for 2013. CCC submitted that those analyses clearly demonstrate that THESL's full request for 2013 should not be approved, as many of the segments and jobs proposed do not meet the ICM criteria.

Segment-by-Segment Assessment

The Board finds that THESL has provided sufficient evidence with respect to each segment for a determination to be made with respect to eligibility for an ICM. Each segment is discussed in the following sections.

TABLE 1: TRIGGER DRIVERS FOR SYSTEM SERVICE CATEGORY

Driver	Description
Safety	▪ Assets are exposing known safety-related hazards/risks to crew workers or the general public, or assets are an integral part of maintaining safe work practices, and the failure of those assets would likely result in safety-related hazards or risk exposure
Reliability	▪ Maintain or improve reliability at a local, feeder-wide or system-wide level
System Efficiency	▪ The need to improve restoration capability, ultimately resulting in substantial reliability and customer experience improvements ▪ The need to reduce losses in distribution lines
Capacity Constraints	▪ Expected changes in load that will constrain the ability of the system to provide consistent service delivery ▪ Current or potential incapability of the system to handle demand requirements

Table 2 provides a brief description for each investment program within the System Service narrative along with total expenditures for each program from 2015 onwards to 2019. Individual section numbers for each investment program are also provided in this table.

TABLE 2: DESCRIPTION OF SYSTEM SERVICE INVESTMENT PROGRAMS

Program Index and Name		Description	Total (5 years)
E7.1	**Contingency Enhancement**	Make improvements to feeders in the existing distribution systems that are currently unable to quickly restore power to affected customers under a contingency situation.	**$48.9 M**
E7.2	**Design Enhancement**	Implementing fusing enhancements to resolve the issues of undersized fuses, mis-coordinated fuses and redundant trunk sections that lack fusing. Replacement and strategic location of fuses and the implementation of tree proof conductors to mitigate sustained interruptions caused by tree contact outages.	**$7.27 M**
E7.3	**Feeder Automation**	Facilitating faster and less labour intensive system restoration procedures by replacing existing switches with autonomously operating Supervisory Control and Data Acquisition (SCADA) switches, reducing the impact of trunk outages to customers and isolating the faulted section of the feeder in less than a minute.	**$54.1 M**

Program Index and Name		Description	Total (5 years)
E7.4	**Overhead Momentary Reduction**	Installation of reclosers to provide flexibility to the system, fault protection and improve the distribution feeder reliability performance by limiting outage times and containing the outage to a minimum area.	**$1.91 M**
E7.5	**Handwell Upgrades**	Replacing the remaining legacy handwells with new standard handwells made from non-conducting composite materials to remove the risk of contact voltage to the public.	**$4.98 M**
E7.6	**Polymer SMD-20 Fuses**	Targets SMD-20 switches that were installed between 2006 and 2011, as breakages inhibit these switches from functioning safely as designed. New switches utilize a fiberglass core that has five times the strength of the previous design. Replacement of the switches eliminates the known safety risk to the public and Toronto Hydro employees.	**$4.84 M**
E7.7	**Downtown Contingency**	Providing distribution load transfer capability between stations in the downtown Toronto area by tying feeders from one station with feeders from an adjacent station. This program addresses a risk in the downtown area where no back-up is provided for certain low probability, high impact events.	**$3.36 M**
E7.8	**Customer Owned Station Protection**	Installation of utility-owned protection devices upstream of customer-owned substations to isolate any faults occurring at customer owned substations.	**$4.04 M**
E7.9	**Stations Expansion (including HONI contributions)**	Upgrades to either Toronto Hydro or Hydro One Networks Inc. owned transformer stations. These upgrades address recent trends in customer connection requirements and loading, by mitigating system limitations imposed by existing station equipment.	**$188 M** **/C**
E7.10	**Local Demand Response**	Providing medium-term capacity relief to Cecil TS by implementing a targeted and localized demand response strategy which primarily leverages new and existing demand response resources.	**$4.06 M**
E7.11	**Energy Storage Systems**	To provide a conventional support for local capacity constraints and service reliability issues throughout Toronto Hydro's distribution system. These systems are also categorized as a renewable enabling improvement to accommodate the increasing numbers of renewable energy generation (REG) connections.	**$10.8 M**

The following Sections E7.1 though to E7.10 contain the details and justification for each capital investment program within the System Service investment category.

E2.4.2 System Challenges & Priorities

(i) System Reliability

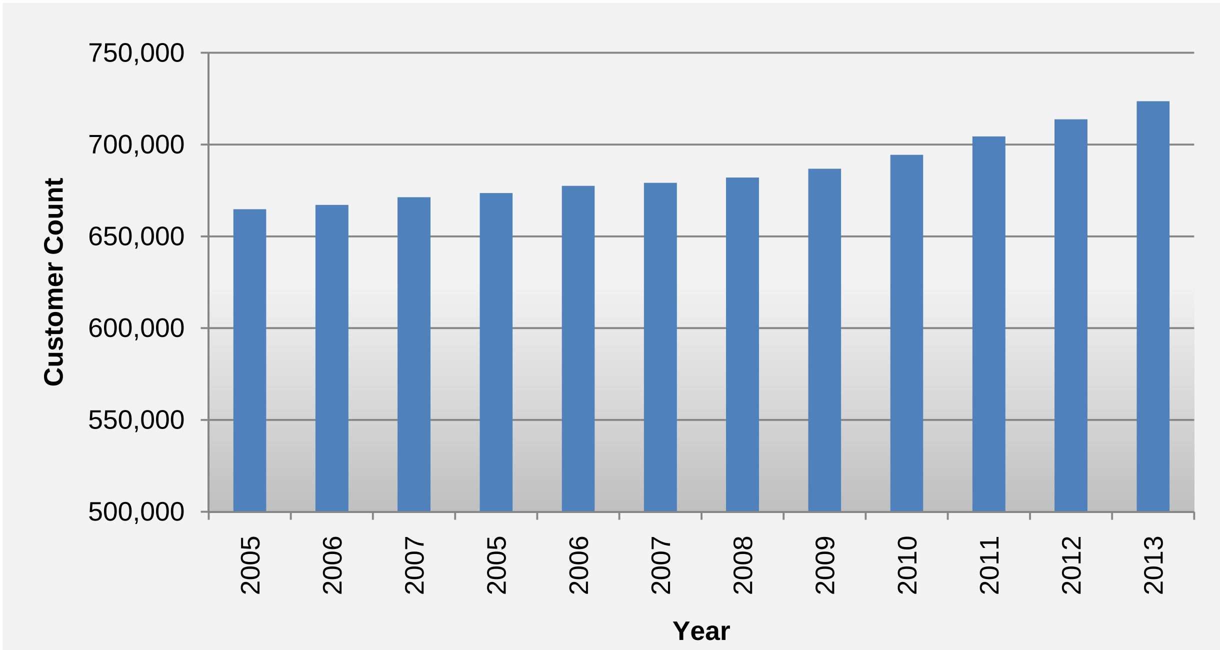
The following survey results describe the recent reliability performance of the system as experienced by the bulk of Toronto Hydro's customers.

- Over half of all customers in both the residential and GS < 50 kW classes have experienced outages during extreme weather events in the last twelve months.[10]
- Not including extreme weather, about half of all customers in these classes have experienced other power outages in the last twelve months.[11]
- 64% of GS < 50 kW customers report direct costs to their businesses as a result of outages.[12]
- Most participants in the mid-market GS workshops had experienced power service interruptions at their businesses in the previous twelve months. Both commercial and industrial customers experienced revenue and productivity losses due to these outages.[13]

As discussed in Sections D and E, Toronto Hydro's asset management policy with respect to system performance is focused primarily on risk-based decision making, where inferred customer interruption costs (CICs) are quantified as one of several risk costs associated with operating aging assets beyond their useful lives. The utility's chosen pace of system renewal is based largely on the objective of balancing these risks against the capital costs of asset replacement so that the total cost of operating the system is minimized over time. While Toronto Hydro does not set specific reliability targets as part of this process, it does project and track the reliability outcomes of its plan and considers adjustments to the prioritization of projects within and across programs if reliability outcomes are tracking below forecasts.

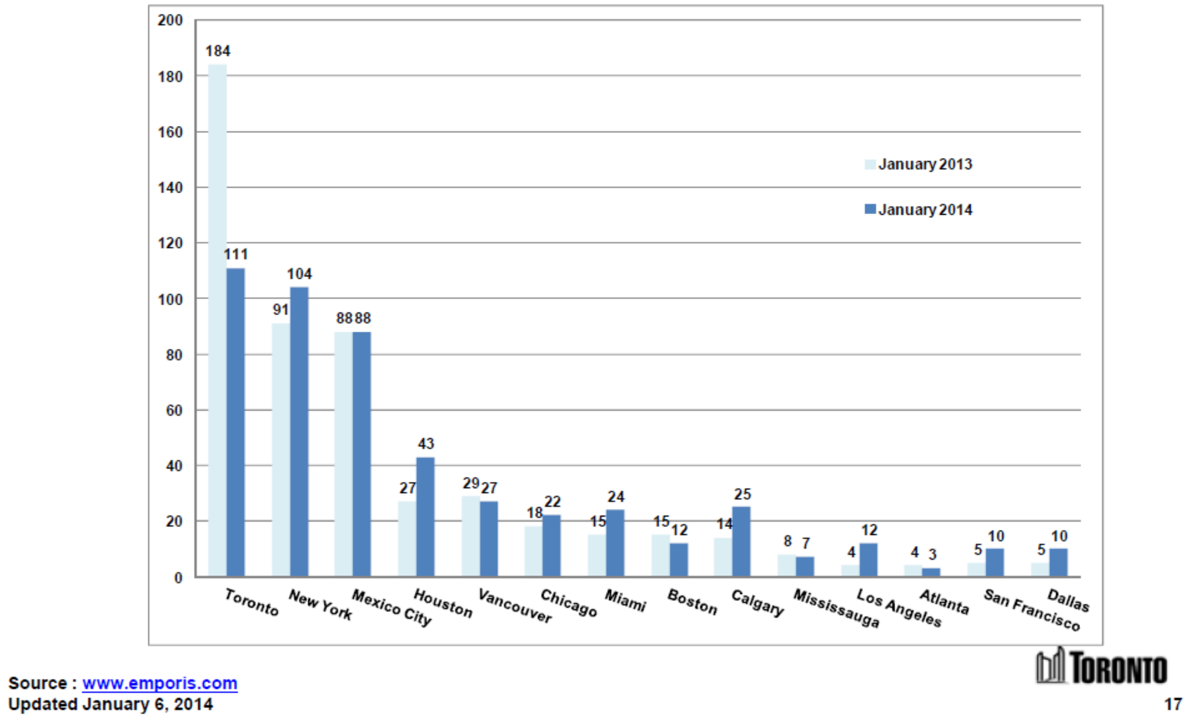
Customer expectations with respect to future reliability performance were captured through the telephone survey. Customers were informed of the current system average outage frequency (i.e. "the average Toronto Hydro customer experiences between one and two power outages per

[10] Ibid., p. 123
[11] Ibid.
[12] Ibid.
[13] Ibid., p. 84



1 **FIGURE 1: HISTORICAL TORONTO HYDRO CUSTOMER COUNTS**

2 Overall system load growth has also been slow and steady. However. growth is highly
3 concentrated due to the high number of large condominium developments. As such, some parts
4 of Toronto are experiencing large increases in demand.



1 **FIGURE 3: TORONTO ECONOMIC UPDATE JANUARY 2014 - NUMBER OF HIGH RISE BUILDINGS UNDER**
2 **CONSTRUCTION**

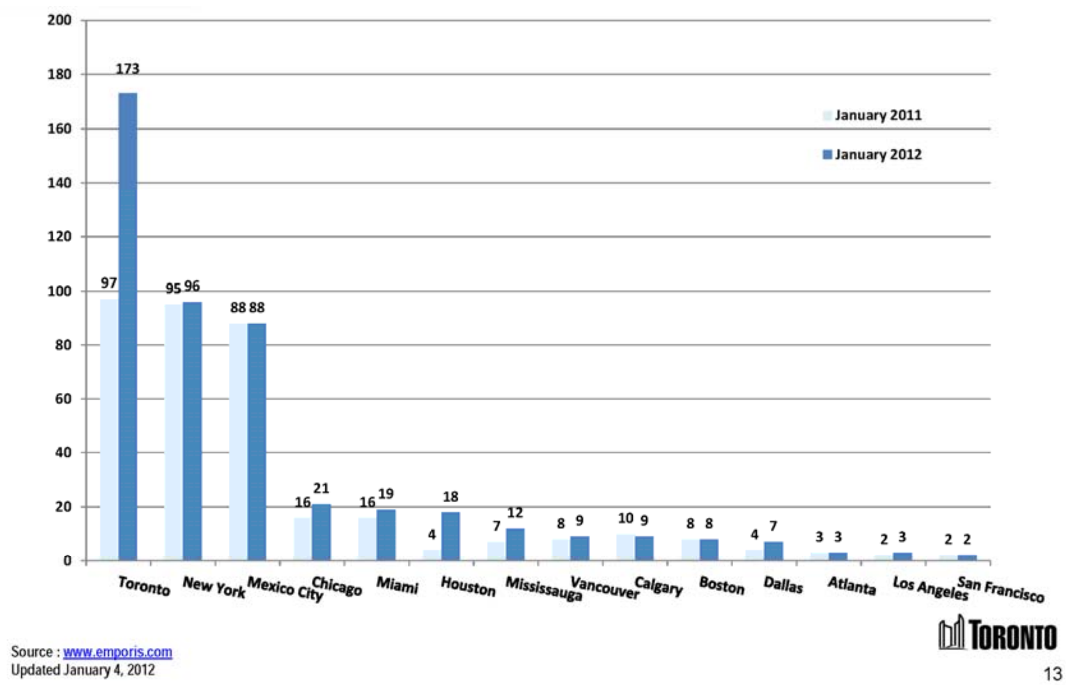


FIGURE 4: TORONTO ECONOMIC UPDATE JANUARY 2012 - NUMBER OF HIGH RISE BUILDINGS UNDER CONSTRUCTION

TABLE 6: 2014 LOAD FORECAST FOR COPELAND TS, ESPLANADE TS AND WINDSOR TS AREAS

STATION / BUS	FIRM CAPACITY(MVA)		YEAR										
	100%	95%	2013*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
COPELAND (115KV/13.8KV) TS													
A1-2CL	72	68			60	60	60	60	61	62	63	64	64
A3-4CL	72	68			9	61	63	63	64	65	66	67	68
Total of all Buses	144	136			69	121	123	123	125	127	129	131	132
Surplus MVA					75	23	21	21	19	17	15	13	12
% Loading (Load/Future Firm Cap)					48	84	85	85	87	88	90	91	92
ESPLANADE (115KV/13.8KV) TS													
A1-2GD	69	66	66	67	62	63	64	65	66	67	67	68	69
A3-4GD (Formerly A5-6GD)	69	66	57	57	61	63	65	66	67	68	68	69	70
A1-2X	69	66	56	61	63	49	50	50	51	52	52	53	54
Total of all Buses	207	198	179	185	186	175	179	181	184	187	187	190	193
Surplus MVA			28	22	21	32	28	26	23	20	20	17	14
% Loading (Load/2013 Firm Cap)			86	89	90	85	86	87	89	90	90	92	93
WINDSOR (115KV/13.8KV) TS													
A11-12	69	66	51	48	48	51	57	58	59	0	0	24	24
A13-14	41	39	34	38	33	34	34	35	35	36	36	37	37
A15-16	69	66	66	69	70	60	56	57	57	58	59	36	36
A17-18	49	47	43	44	0	44	45	46	46	47	47	48	49
A3-4	59	56	51	54	59	54	55	0	0	60	61	62	63
A5-6	59	56	56	67	46	0	0	55	56	57	57	58	59
Total of all Buses	337	321	301	320	256	243	247	251	253	258	260	265	268
Surplus MVA **			36	17	32	35	31	27	25	19	17	72	69
% Loading (Load/2013 Firm Cap) **			89	95	89	87	89	90	91	93	94	79	80
Total of all Stations													
Bus Total	688	655	480	505	511	539	549	555	562	572	576	586	593
Surplus MVA **			64	39	128	90	80	74	67	56	52	102	95
% Loading (Load/2013 Firm Cap) **			88	93	80	86	87	88	89	91	92	85	86

For planning purposes, Toronto Hydro considers a bus at a 13.8 kV station in the former City of Toronto area to be overloaded when it reaches 95% of the rated capacity. This is to account for the lead time required to offload a bus and implement a permanent solution, as well as the fact that the utility must keep sufficient spare capacity on each bus to accommodate any new customer connection requests. Typically, customers request connection anywhere from one to three years in advance, whereas a load relief solution can take anywhere from one to four years to implement, depending on the nature of the existing configuration. It is possible for a customer to request more load than is available on a bus in a shorter timeframe than Toronto Hydro can respond. As shown in the load forecast, within ten years, six of the busses supplied from Windsor TS, Copeland TS and Esplanade TS are forecasted to require capacity relief.

An important indicator of load growth is the number of new connection requests that are received from customers. These requests are submitted by existing and potential customers seeking to

(ii) Strachan TS

Strachan TS, located at Strachan Avenue and Fleet Street, supplies much of the south-west portion of central Toronto, including Exhibition Place, BMO Field and Ontario Place. The station is comprised of four load service busses, each supplied from two windings from two of four different HONI transformers located on site (designed as T12, T13, T14 and T16). HONI has indicated to Toronto Hydro that they plan to replace the 75 MVA T12 transformer because it has reached its end-of-life. This transformer supplies Toronto Hydro's A5-6T and A7-8T busses. Toronto Hydro is proposing to request that HONI upgrade the size of the replacement transformer from 75 MVA to 100 MVA. Under these circumstances, Toronto Hydro would be responsible for paying the incremental difference in cost relative to a like-for-like replacement. This will provide additional capacity and flexibility to the area at a fraction of the cost should such an upgrade be completed solely at Toronto Hydro's request. Currently, the A1-2T and the A9-10 busses are rated for 72 MVA; however their actual capacity is limited to 56 MVA by the transformer size. Once both transformers supplying a bus are upgrade to standard 100 MVA units, the full rating of the bus can be utilized.

The 2014 load forecast for the Strachan TS area is shown in Table 11.

TABLE 11: 2014 SUMMER LOAD FORECAST FOR STRACHAN TS

STATION / BUS	FIRM CAPACITY(MVA)		YEAR										
	100%	95%	2013*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
STRACHAN (115KV/13.8KV) TS													
A1-2	56	53	46	50	52	54	54	55	56	57	57	58	59
A9-10 (Formerly A3-4)	50	48	37	41	42	43	43	44	44	45	46	46	47
A5-6	40	38	23	25	29	31	32	33	33	34	34	34	35
A7-8	40	38	36	37	33	34	35	35	36	36	36	37	37
Total of all Buses	192	182	142	153	156	162	164	167	169	172	173	175	178
Surplus MVA			50	39	36	30	28	25	23	20	19	17	14
% Loading (Load/2013 Firm Cap)			74	80	81	84	85	87	88	90	90	91	93

By 2023, the station is forecasted to reach 93% loading overall. At that point in time, Toronto Hydro will have the option to request replacement of the other transformer(s) supplying the A1-2T or the A9-10T, which will result in a capacity increase to 72 MVA. This represents an opportunity to leverage HONI's planned asset renewal program to benefit Toronto Hydro ratepayers. Toronto Hydro estimates that its cost to complete this work will be $0.5M.

operational switching, although it is limited by technical considerations such as voltage drop and reliability, as longer feeders, such as those connecting these stations, generally have a negative impact on reliability. At these stations, the demarcation point between HONI and Toronto Hydro is the feeder breaker. HONI owns everything up to and including the secondary side of the feeder breaker, while Toronto Hydro owns everything electrically downstream from that point. The 2014 load forecast for these stations is provided in Table 12.

TABLE 11: 2014 SUMMER LOAD FORECAST (SOUTH-WEST TORONTO)

STATION / BUS	FIRM CAPACITY(MVA)		YEAR										
	100%	95%	2013*	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
FAIRBANK (115KV/27.6KV) TS													
B & Q	95	90	92	**99**	**102**	**105**	**106**	**107**	**101**	**102**	**103**	**104**	**106**
Y & Z	97	92	82	81	82	82	83	84	85	86	87	88	89
Total of all Buses	192	182	174	180	184	187	189	191	186	188	190	192	195
Surplus MVA			18	12	8	5	3	1	6	4	2	0	-3
% Loading (Load/2013 Firm Cap)			91	94	96	97	98	99	97	98	99	**100**	**102**
HORNER (230KV/27.6KV) TS													
B & Y	192	182	153	167	173	181	186	190	**195**	**199**	**204**	**208**	**213**
Total of all Buses	192	182	153	167	173	181	186	190	195	199	204	208	213
Surplus MVA			39	25	19	11	6	2	-3	-7	-12	-16	-21
% Loading (Load/2013 Firm Cap)			80	87	90	94	97	99	**102**	**104**	**106**	**108**	**111**
MANBY (230KV/27.6KV) TS													
B & Y	63	60	**72**	60	**68**	**70**	**72**	**73**	**75**	**77**	**78**	**80**	**82**
Q & Z (see note 2)	63	60	**67**	**68**	52	54	55	56	57	59	60	61	**63**
V & F	112	106	93	91	93	95	97	100	102	104	107	109	111
Total of all Buses	238	226	232	219	213	219	224	229	234	240	245	250	256
Surplus MVA			6	19	25	19	14	9	4	-2	-7	-12	-18
% Loading (Load/2013 Firm Cap)			97	92	89	92	94	96	98	**101**	**103**	**105**	**108**
RUNNYMEDE (115KV/27.6KV) TS													
B & Y	117	111	108	107	109	105	108	110	111	112	113	115	116
Total of all Buses	117	111	108	107	109	105	108	110	111	112	113	115	116
Surplus MVA			9	10	8	12	9	7	6	5	4	2	1
% Loading (Load/2013 Firm Cap)			92	91	93	90	92	94	95	96	97	98	99
Total of all Stations													
Bus Total	739	701	667	673	679	692	707	720	726	739	752	765	780
Surplus MVA			72	66	60	47	32	19	13	0	-13	-26	-41
% Loading (Load/2013 Firm Cap)			90	91	92	94	96	97	98	**100**	**102**	**104**	**106**

As can be seen in Table 13 above, Toronto Hydro is forecasting that the total capacity for the entire area will be exhausted by 2020. The load forecast utilizes a growth rate of 1.1% for Runnymede TS and Fairbank TS, and a growth rate of 2.3% for Manby TS and Horner TS. These growth rates were determined based on weather corrected historical peak loads. Actual peak load can vary significantly on a year-over-year basis if there is an abnormally large (or small) volume

E5 SYSTEM ACCESS INVESTMENTS

FIGURE 1: TORONTO HYDRO CREW MEMBER INSTALLING SMART METER AT A RESIDENTIAL LOCATION

The investment programs within the System Access investment category are driven by statutory, regulatory or other obligations on the part of Toronto Hydro to provide customers with access to Toronto Hydro's distribution system. One of the core investment programs relates to the connection of new customers to the grid as required under the terms of Toronto Hydro's distribution license, the Distribution System Code and the *Electricity Act, 1998*.[1] System Access investment programs also allow Toronto Hydro to manage and maintain its service to these connected customers through load transfer, switching and restoration capabilities.

The System Access category also includes the ongoing renewal of Metering assets to maintain compliance with Measurement Canada regulations and the IESO Market Settlement regulations. These regulations oblige Toronto Hydro to bill its customers accurately and to support IESO's critical market settlement infrastructure. Additionally, the Ontario Government's *Green Energy and Green Economy Act, 2009*,[2] encourages new generation sources, including photovoltaics, biogas and wind power generation to connect to the distribution system. The Generation Protection, Monitoring and Control (GPMC) program is required so that Toronto Hydro can continue to connect distributed generation (DG) projects to the distribution system. DG allows for the generation of electricity from many small decentralized sources and requires the bi-directional

[1] S.O. 1998, C. 15, Sched. A. ["*Electricity Act, 1998*"]
[2] S.O. 2009, C.12.

flow of electricity because DG sources are located in close proximity to the distribution loads that they serve.

Finally, System Access Investments include investments related to the relocation of existing Toronto Hydro plant in order to accommodate third party requests for facility relocation. Third parties requesting plant relocation are typically public agencies responsible for development of public infrastructure. Distribution expansion activities, where implemented in concert with such relocation work, are also included in this category. Table 1 provides the trigger drivers for capital investments in this category.

TABLE 1: TRIGGER DRIVERS FOR SYSTEM ACCESS CATEGORY

Driver	Description
Customer Service Requests	▪ The fulfilment of Toronto Hydro's obligation to connect a customer to its service. This includes both traditional demand customers and distributed generation (DG) customers. The obligation to connect holds as long as there are no safety concerns for the public or employees and there is no adverse affect on the reliability of the distribution system. ▪ Expansion or enhancements to the system when a connection cannot be made with existing infrastructure.
Mandated Service Obligations	▪ Compliance with all legal and regulatory requirements and government directives. ▪ Measurement Canada, the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO) impose regulations concerning metering that Toronto Hydro must comply with.
Third Party Requests	▪ Mandated system modifications for property or infrastructure development by government agencies and other entities.

Table 2 provides a brief description for each investment program within the System Access narrative along with total expenditures for each program from 2015 onwards to 2019. Individual section numbers for each investment program are also provided in this table.

TABLE 2: DESCRIPTIONS OF SYSTEM ACCESS INVESTMENT PROGRAMS

Program Index and Name		Descriptions	Total (5 yrs)	
E5.1	**Metering**	Enable Toronto Hydro to meet its mandatory service obligations with respect to revenue metering and wholesale metering. This will be accomplished by testing meters, replacing damaged and obsolete meters, and upgrading the under-capacity and obsolete collector stations. Upgrading Toronto Hydro's Interval Metering MDM software will help customers manage their energy use and costs by providing them with timely access to their data.	**$82 M**	/C
E5.2	**Customer Connections**	Toronto Hydro is obligated to connect new customers or upgrade existing customers to a larger service if requested, as required under the terms of Toronto Hydro's distribution license, the Distribution System Code and the *Electricity Act, 1998*. On average, 10,000 requests for new services, upgrades, and removals are made each year and the amount is expected to increase with current and proposed development.	**$261 M**	
E5.3	**Externally-Initiated Plant Relocation & Expansion**	Toronto Hydro is required to modify/relocate its system to accommodate property or infrastructure development (e.g., requests from a road authority to move a pole line). Toronto Hydro works with the external agency in question to accommodate the project, and investigates opportunities for cost-efficient expansion work.	**$20 M**	
E5.4	**Load Demand**	With increased load in concentrated areas due to the city's growth, equipment (such as undersized cables) in the system must be upgraded in the short-term to address contingency issues to accommodate this increased demand. The problem is expected to be addressed by transferring loads to stations with available capacity, upgrading undersized equipment and cables, and ensuring civil infrastructure can support increased demand. This will allow Toronto Hydro to continue connecting customers in these areas without harming system reliability, customer value, and operational flexibility.	**$75 M**	
E5.5	**Generation Projects Protection and Control**	Toronto Hydro is mandated to make every reasonable effort to connect distributed generation users. This program involves installation of bus-tie reactors at station buses, advanced protection systems, and monitoring and control systems to handle the increasing DG penetration in the City of Toronto, including renewable energy generation (REG) projects.	**$19 M**	/C

The following Sections E5.1 though to E5.5 contain the details and justification for each capital investment program contained within the System Access investment category.

E8 GENERAL PLANT INVESTMENTS

FIGURE 1: TORONTO HYDRO FLEET

Investment programs that fall under the General Plant investment category are essential to Toronto Hydro's 24/7 day-to-day operational activities. These investments include the upgrade and renewal of critical software and systems, vehicles and associated equipment, and facilities. This investment category also includes support programs for ongoing capital and maintenance activities.

Information Technology investment programs serve to upgrade and renew hardware and software that is critical to Toronto Hydro's planning and operations. Fleet and Equipment Services investments are required for the acquisition of new vehicles and on-vehicle equipment to replace existing units that are scheduled for replacement based on Toronto Hydro's fleet replacement criteria. This vehicle replacement is necessary to ensure that Toronto Hydro's fleet remains safe, reliable, and cost efficient. Vehicles are required to transport employees and materials to and from job sites, to perform work onsite, provide an onsite working area, and to provide shelter.

Similarly, the facilities-related investment programs address the necessary building improvements that are required to run Toronto Hydro's core business and the specific renovations needed at the different operating sites owned by Toronto Hydro. Therefore, these programs play a crucial role in sustaining Toronto Hydro's operations by providing its employees with a safer environment to operate in an efficient and reliable manner and to provide quality service for customers. Table 1 provides the trigger drivers for capital investments in this category.

TABLE 1: TRIGGER DRIVERS FOR GENERAL PLANT CATEGORY

Driver	Description
Functional Obsolescence	▪ The asset is no longer aligned to Toronto Hydro processes and practices such that it can no longer be maintained (e.g., lack of vendor support) or utilized as intended in support of the utility's business processes.
Safety	▪ Assets are an integral part of maintaining safe work practices, and the failure or lack of support of those assets would likely result in safety-related hazards or risk exposure.
System Maintenance and Capital Investment Support	▪ Required investments to support day to day business operations activities; sustaining operations by providing its employees with a safer environment to operate in an efficient and reliable manner.

Table 2 provides a brief description for each investment program within the General Plant narrative along with total expenditures for each program from 2015 onwards to 2019. Individual section numbers for each investment program can also be accessed from this table.

TABLE 2: DESCRIPTION OF INVESTMENT PROGRAM

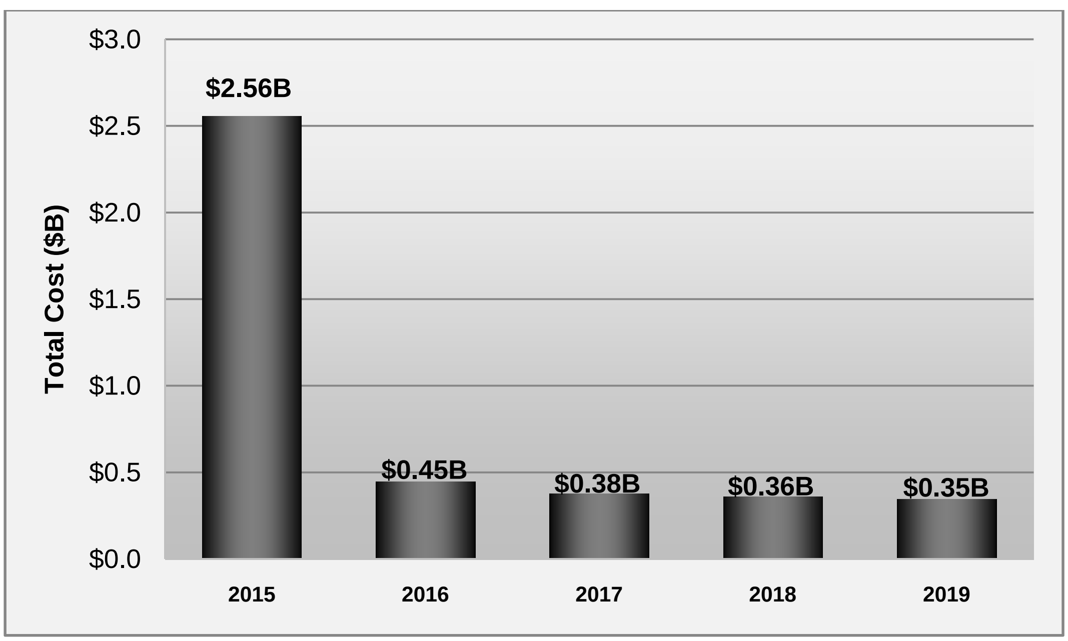
Program Index and Name		Brief Description	Total (5 years)	
E8.1	**Fleet and Equipment Services**	As Toronto Hydro's fleet ages, regular vehicle replacement and repair is necessary. This program replaces 24-95 vehicles a year as well as installing new equipment on existing vehicles requiring refresh or replacement, all to ensure the fleet is safe, reliable, and cost-efficient.	**$17.9 M**	
E8.2	**Facilities Management & Security**	Security enhancements are necessary to ensure assets, employees, and the general public are protected by up-to-date security equipment and technologies. Additionally, facilities program is needed to improve the safe, reliable and efficient operation of the work centers and stations as well as increase the overall asset value for all of Toronto Hydro.	**$31.8 M**	/C
E8.3	**Operating Centers Consolidation**	Consolidation of Toronto Hydro's operating centers is required to secure tenure for Toronto Hydro in the northwest and northeast areas of the City while delivering benefits to ratepayers. Toronto Hydro plans to vacate four facilities, two of which it currently owns, and relocate staff, equipment and operations to three facilities already owned by Toronto Hydro to achieve efficiencies and improve space utilization. The utility plans to sell the two surplus Toronto Hydro-owned facilities, crediting the net after-tax gains on sale and related	**$52.2 M**	/C

Program Index and Name		Brief Description	Total (5 years)
		tax savings to ratepayers through rate riders.	
E8.4	**IT Hardware Refresh**	The program addresses the renewal and maintenance of core backend infrastructure (e.g. servers, storage disks) and endpoint assets (i.e. laptops, desktops) that enable Toronto Hydro to plan and execute capital and operational programs and to fulfill its obligations to customers and applicable regulatory bodies.	**$36.7 M**
E8.5	**IT Software**	The Software program covers planned IT upgrades to more than 70 software applications that support Toronto Hydro's core functions and processes. Toronto Hydro must upgrade these applications to ensure their availability to meet operational needs, and to protect itself against cyber threats that could jeopardize the security of the distribution system and the privacy of sensitive operational, customer and employee information. The program also includes initiatives to enhance, modify or implement new software applications that are necessary to optimize business operations, or to comply with external requirements imposed by entities such as Measurement Canada, the OEB and the IESO.	**$81 M**
E8.6	**ERP Implementation**	The current end-of-life ERP, Ellipse, will soon no longer be supported by its vendor, introducing a number of technical risks. The program will replace Ellipse and 30 other legacy applications with a new ERP that meets functional requirements.	**$51 M**
E8.7	**Voice Radio System Upgrade**	The voice radio system is critical to Toronto Hydro's ability to safely and effectively deliver its planned capital and maintenance programs and to respond to trouble calls in a safe, timely and efficient manner. The current voice radio system cannot be supported by the vendor beyond 2016 and must be upgraded to mitigate safety and operational risks.	**$20 M**
E8.8	**Program Support**	This program will perform two studies to enhance the asset management process and improve the long-term and short-term strategy. The first will be a climate adaption study, focusing on at risk areas to extreme weather and climate change. The second will be a customer interruption study to estimate outage costs.	**$1.7 M**

The following Sections E8.1 though to E8.8 contain the details and justification for each capital investment program contained within the General Plant investment category.

Toronto Hydro's assessment is that the spending requirements reflected are ultimately representative of an economically optimal capital investment approach: execution of these investments would mitigate this backlog and allow for an immediate achievement of steady state. This approach would minimize the operating costs to which customers are exposed when considering capital and risk costs.

However, Toronto Hydro recognizes that executing a capital investment approach of this magnitude in a single year would constitute an unprecedented level of investment, and would result in large step-increases in rates. Moreover, the utility could not reasonably expect to execute this magnitude of investment in a single year considering current system constraints and available resources.



/C

FIGURE 4: ECONOMICALLY OPTIMAL CAPITAL INVESTMENT APPROACH (2015-2019)

Recognizing the infeasibility of completing this work in a single year, Toronto Hydro considered two alternative timelines in which to carry out this work: an "accelerated" strategy as well as the proposed "paced" strategy. The accelerated strategy would allow for the backlog of investments to be managed over the five-year DSP period, such that steady state is achieved by 2019 with a

(i) "Accelerated" Execution Strategy

The "accelerated" execution strategy is focused on mitigating the backlog of investments within the 5-year DSP period, such that steady state is achieved by 2020.

As illustrated in Figure 10, this strategy requires significant capital investments of approximately $830 million on average per year, with a total five-year investment of $4.17 billion. The advantage of this strategy is that steady state can be achieved in more rapidly, therefore mitigating the risks associated with the backlog within the five-year period. However, it is clear that the rate impacts from this strategy would be substantial for customers. Furthermore, the required investments do not align to Toronto Hydro's available resources and system constraints, and therefore there would likely be execution-related complexities.

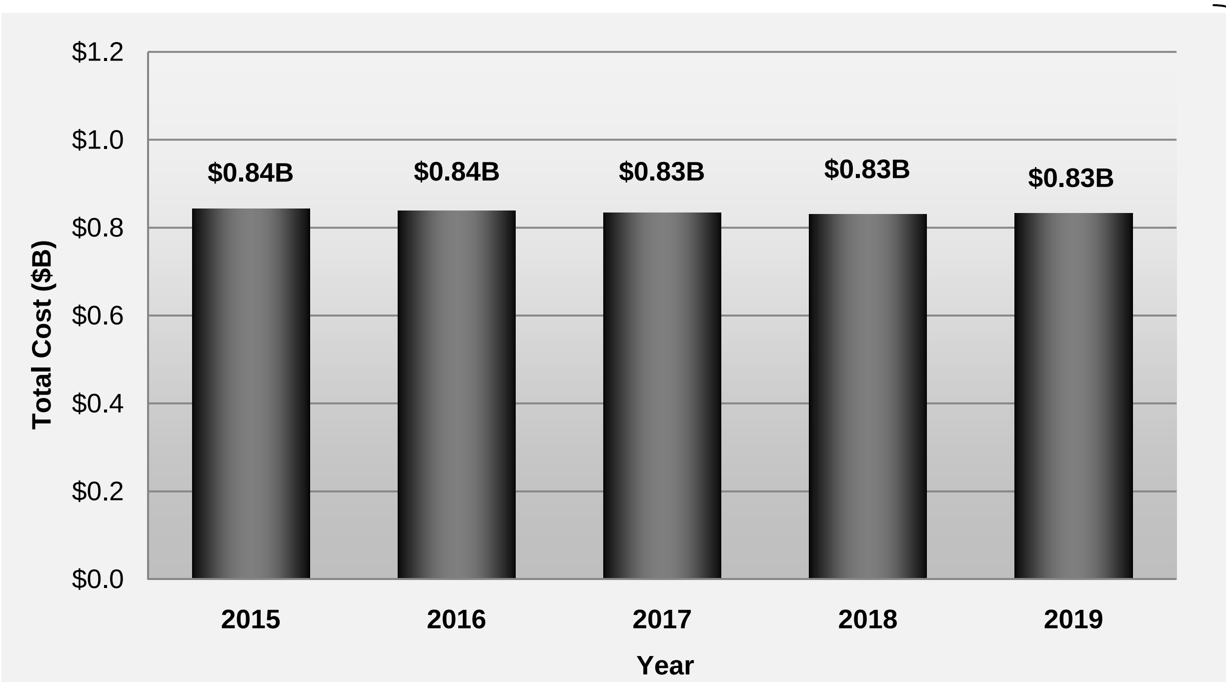


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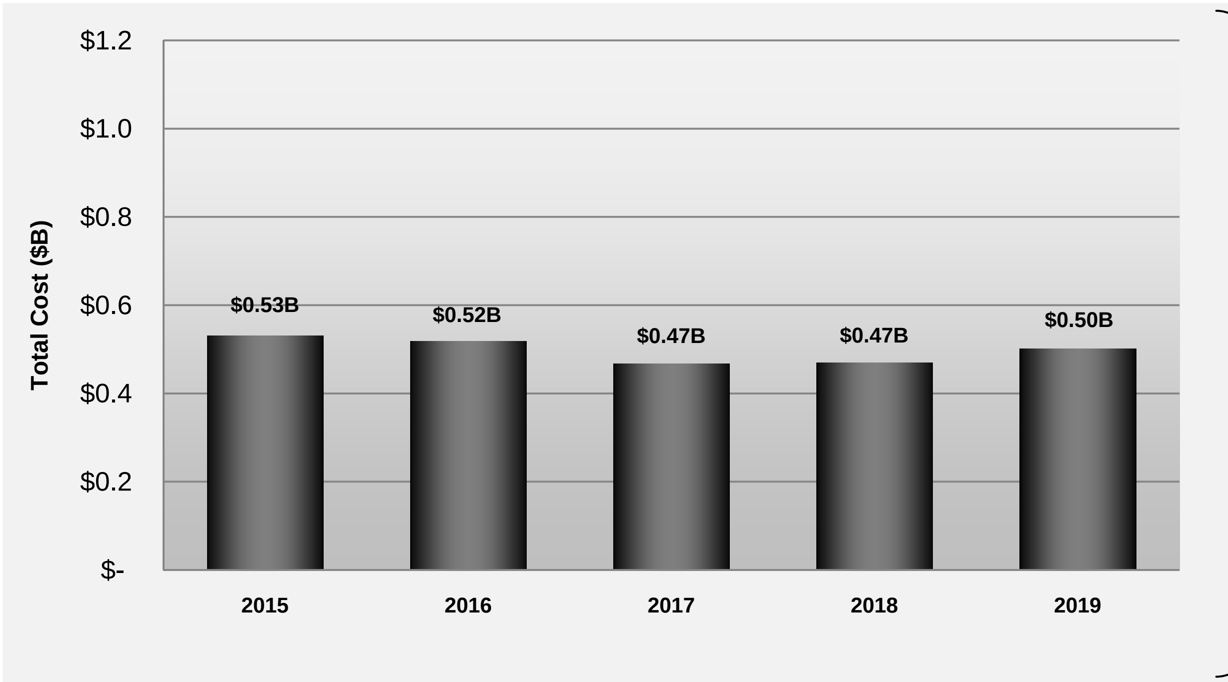
FIGURE 10: CAPITAL INVESTMENT APPROACH AS PER "ACCELERATED" EXECUTION STRATEGY



/C

FIGURE 11: CAPITAL INVESTMENT APPROACH AS PER "PACED" EXECUTION STRATEGY (2015-2019)

Toronto Hydro believes that the benefits of reduced rate impacts and execution complexities associated with the "Paced" execution strategy outweigh the benefits of the "Accelerated" execution strategy in terms of reaching the steady state within the five-year period. Based upon these results, Toronto Hydro has selected the "Paced" execution strategy as part of the 2015-2019 capital investment plan. Ultimately, the execution of the capital expenditure plan as per this strategy will result in predictable rates over the five-year DSP term due to the "paced" nature of the investments, and will ultimately allow for steady state achievement by 2037.

Figure 12 illustrates the useful life demographics following the achievement of steady state as per the "paced" execution strategy in 2037. The results illustrate how the replacement value associated with assets past their useful life decrease from 26% as of 2015 to 11% by 2037. Similarly, assets not exceeding their useful lives will increase from 67% as of 2015 to 80% by 2037.

Management Controls and Oversight

The absence of an automated link between the original filed job and the final suite of Projects has no significant bearing on Toronto Hydro's delivery and oversight of the actual work program. A formal change management process is triggered by any material variances in cost and scheduling between the High-Level Estimate and the Detailed Estimate, or between the Detailed Estimate and Project construction. (This oversight process is also triggered by the addition and cancellation of jobs from the work program, as well as changes to the scope of work.) As part of this process, a job's costs and benefits may be reevaluated in light of the proposed or necessary job changes and in relation to the overall capital program budget, system planning objectives and other considerations. This helps ensure that the capital program is executed cost-effectively and that it remains aligned to the short-term and long-term planning objectives detailed in the utility's rate filings.

two issues with you.

The first is a lot of things that were discussed in panel 1, which is about contracting and how that works.

Then I want to, secondly, talk about the enterprise resource planning system.

So first with respect to contractors, essentially as every intervenor in panel 1 asked about contracting, or how the contracting system works with respect to construction and maintenance and those, I want to understand from you better. And those questions were generally punted to you.

So I was wondering if you can talk about, at a broad level, how the framework works with those types of contractors.

How does the system work? How does the bidding work? What is the time frames? All of those sort of things.

MR. NASH: I can answer that for you.

The RFP process or RFQ process, depending whether we're looking for a proposal or a quote, is a fairly substantial process.

There's three major types of RFPs or RFQs that we do. It can be for supply of material that we would use in our distribution system, it would be for professional services, and then it would obviously be for contractors that we use in the field.

The process, regardless of what it is for, follows the exact same methodology.

So we will work with the business unit to develop a scope of what we're looking for out in the marketplace. We will work with that business unit to create basically what sort of pre-qualifications they are looking for, what type of work they're looking for, what types of companies we would being looking to go out in the market for. And we would send either the RFP or RFQ out to the market.

Depending on the type of service or goods or material that we're looking for, it could go out anywhere from a few weeks to a few months, depending on the size of the actual RFP or RFQ.

Once it has been out in the market for evaluation, the response will come back in to us. We will evaluate those with the business unit and my procurement groups together, and we will go through and answer any questions or ask any questions that we would have of the respondents.

There could be times when they may not have understood our scope clearly, so we want to make sure we get some clear definitions so that they understand what we're looking for and we understand what they quoted on.

Once that comes back in, we then do an evaluation of the RFP.

Prior to the RFP or the RFQ going out to the market, we will sit and actually do an evaluation matrix. So we want to make sure that evaluation matrix is done before the RFP goes out to the market, so when it comes back in we know what we're evaluating against.

When that comes back in, depending on how many respondents had responded to it, we will then go through what is called a short-listing process. That short-listing process will be taking our evaluation matrix, looking at how we broke out the evaluation matrix, whether it is cost, quality, schedule -- all of them can have different percentages -- and what is important to us, depending on whether we're looking for a service or a good or contractors.

Once that evaluation matrix is done and the short list has been created, most often we will invite those participants in for a presentation.

The presentation will be for them to give us an opportunity to walk through their proposal in more detail. It gives us the ability to ask questions back and forth, to make sure we're very clear and on the same page in terms of what we're looking for, and what we got a quote or proposal on.

Once that short-listing is created and the meetings have happened, the evaluation team will get back together again and then go through a final recommendation or final selection process.

Then once that is done, based on the amount of money that we're looking for, we have different approval levels within Toronto Hydro in terms of who has to sign off on that approval to give that good or service or distributor the supply material, and give them the contract.

MR. RUBENSTEIN: Let me first talk about materials. So say the application talks about replacement of a number of underground transformers; it is a common thing that Toronto Hydro has to do.

contractors?

Did you -- were there any other efficiency -- and I'm going to talk about metrics later, but any efficiency metrics that you applied to any of this pricing?

[Witness panel confers]

MR. WALKER: In looking at the 2015 work program, the breakdown of it as an example, 81 percent of the costs associated with the capital work program are market-driven. That's material costs which are market-driven, civil construction, which is all done by contractors, and a good portion of our electrical design and construction, which is also done by contractors.

So that, by definition, has the efficiency built into it, based on a market-driven bidding process.

The remaining costs are internal costs, and in our execution we're always looking for ways to find efficiencies. And I think where we're moving in the future with that is the asset assembly metric we're looking at, which is going to give us a better understanding of how we execute work and the difficulties that we have across our different types of assets that we're constructing, in order to learn from that and drive efficiencies.

We have also done a number of other things in terms of our material handling costs, having third-party logistics, taking some of the fleet costs and putting them out to the market, and so on.

So we have done a lot of things that are driving down those costs moving forward in the program, and those will translate into real cost savings in each individual program.

MR. CROCKER: Did you set targets?

MR. WALKER: We haven't set specific targets, no, but we are doing those things in order to achieve those costs by, you know, their normal execution.

MR. CROCKER: This leads me to some questions that come out of the motion that we brought, and which ultimately we didn't pursue as a result of discussions we had in an attempt to settle the motion.

And I think because of that, I'm probably directing my questions to Mr. Walker and Ms. Rouse. Okay?

On page 29 of the compendium, you provided historical spending and proposed future spending numbers. And then on page 30 of the compendium, what you provide is future units that you propose to replace; correct?

One doesn't necessarily follow the other, but that's what is reflected on those two pages?

MR. WALKER: Yes, that's correct.

MR. CROCKER: Okay. You haven't provided anywhere that I know of -- and I'm sure you'll correct me if I'm wrong -- the units that you proposed -- not proposed, that you actually replaced in 2010 to 2014; correct?

That's what we asked you for in the motion. That's what we couldn't find; correct?

[Witness panel confers]

MR. WALKER: I believe what we provided were units for projects that were in-service.

Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). (A detailed discussion of these reliability forecasts is provided in Section E2).

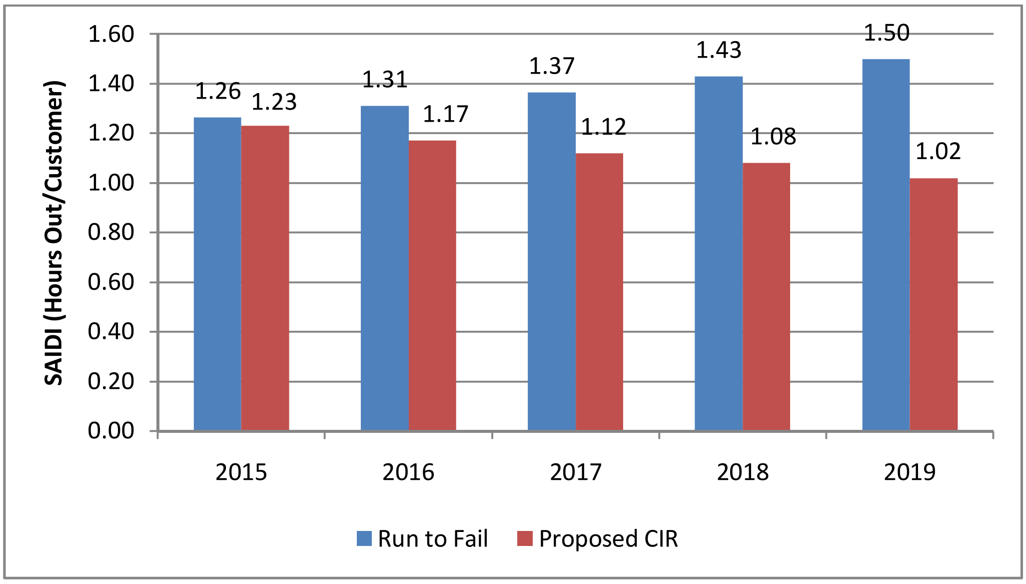


FIGURE 3: FIVE-YEAR SAIDI PROJECTION /C

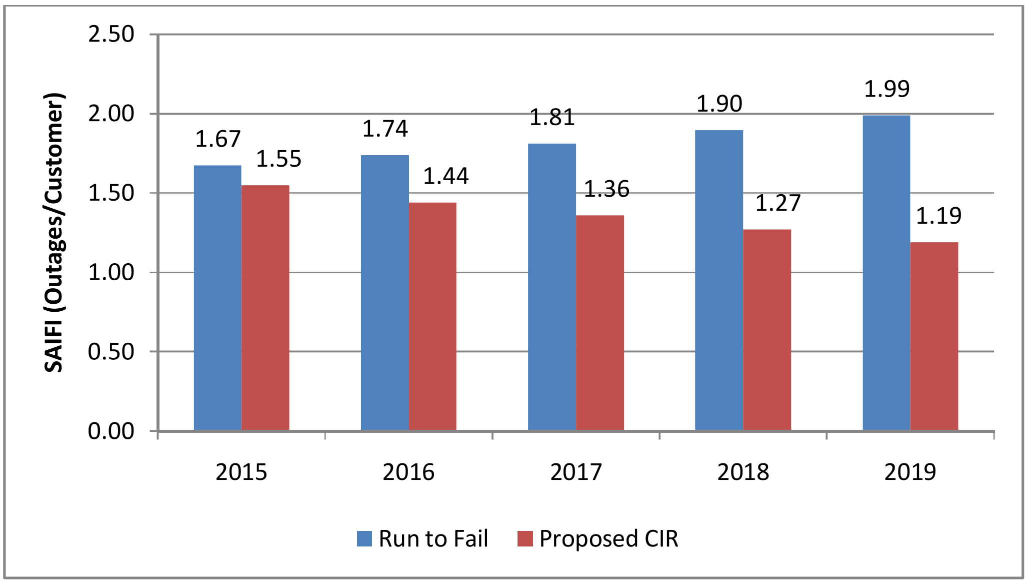


FIGURE 4: FIVE-YEAR SAIFI PROJECTION

3. Operations, Maintenance and Administration (OM&A)

1. Overview of OM&A evidence and programs

- The evidence filed by Toronto Hydro and presented during the hearing supports the OM&A-related revenue requirement request for the 2015 test year and the incentive rate framework proposed for 2016-2019.

- Toronto Hydro has followed the direction and guidance set out by the Board in the RRFE and Filing Guidelines.

- Toronto Hydro's OM&A programs are designed to achieve the RRFE objectives through:

    - (i) maintaining the distribution system and serving customers in accordance with good utility practice;

    - (ii) making modest enhancements to respond to customer needs and preferences, address critical system risks (i.e. cyber security) and drive continuous improvement;

    - (iii) complying with regulatory and legal obligations; and

    - (iv) supporting the safe, effective and efficient execution of the capital program.

- Toronto Hydro's OM&A related evidence includes a comprehensive plan comprised of 19 detailed OM&A programs, each with detailed justifications, including.[1]

    1. a detailed need section identifying the rationale for the underlying expenditures based on operational assessments of the utility's service obligations and compliance requirements,

    2. detailed explanations as to the drivers of historical, bridge and test year variances, and

    3. examples of completed and/or ongoing operational improvements to achieve efficiency, productivity and/or customer service enhancements.

    - Toronto Hydro's OM&A plans and resulting funding requests are structured around the principles of the OEB's 4th Generation Incentive Rate Making regime (4GIRM): that is, a single detailed Test Year budget (2015), followed by Custom Price Cap Index (PCI) formula-based increases for the remainder of the CIR period (2016-2019).[2] This IRM framework provides for up-front sharing of efficiency and productivity benefits that Toronto Hydro will work to achieve over the CIR period, despite the fact that OM&A

[1] Exhibit 4A, Tab 1, Schedule 1 at page 1, lines 21-27; IR Response 4A-CCC-30 at page 1, lines 10-18.
[2] Exhibit 1B, Tab 2, Schedule 3 at page 13, lines 8-18.

expenditures over this period are expected to increase by a greater amount than will be provided through the proposed Custom PCI formula.[3]

- As detailed throughout the evidence, Toronto Hydro expects that an expenditure plan less than proposed in this application will increase the risk to the utility's ability to execute its plans and meet its obligations and requirements over the CIR period.[4]

2. OM&A planning was both "top-down" and "bottom-up".

- Toronto Hydro adopted an iterative approach to OM&A planning, which involved an ongoing dialogue between departmental management, finance, regulatory and executive leadership.

- The purpose of Toronto Hydro's planning process was to develop and assess funding needs at the operational level, while also considering the overall budget amount in light of important factors such as rate impacts, mandatory obligations and other corporate strategic objectives.[5]

- Consistent with OEB guidance, Toronto Hydro's planning approach integrated both top-down and a bottom-up planning considerations.[6]

- In developing the OM&A funding request, Toronto Hydro's plans were informed by operational assessment such as supporting the execution of the capital investment plan,[7] asset maintenance requirements,[8] core staffing requirements,[9] reliability considerations,[10] and safety and legislative/regulatory obligations. [11]

- The plans are also informed by other important considerations such as customer needs (including service levels and consumption-management tools), rate impacts, value-for-money, productivity, and maintaining the financial health of the utility.[12]

- The resulting OM&A budget is the product of a balance between customer impact considerations, and the utility's ongoing operational requirements and statutory obligations.[13]

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[3] Exhibit 1B, Tab 2 Schedule 5 at pages 14-15, lines 26-5.
[4] For example, see Exhibit 4A, Tab 2, Schedule 1 at pages 41-42, lines 14-3; Exhibit 4A, Tab 2, Schedule 5 at pages. 12-13, lines 15-10; Exhibit 4A, Tab 2, Schedule 13 at pages 23-24, lines 27-3; Exhibit 4A, Tab 2, Schedule 16 at page 15, lines 14-17.
[5] IR Response 4A-OEBStaff-68(b) at page 2 lines 4-7; IR Response 4A-CCC-29.
[6] EB-2012-0033, Decision and Order (December 13, 2012) at pages 34-35.
[7] For example, refer to the Work Execution Management And Support Program at Exhibit 4A, Tab 2, Schedule 8.
[8] For example, refer to the Preventative & Predictive Maintenance Program at Exhibit 4A, Tab 2, Schedule 1.
[9] To learn more please refer to Exhibit 4A, Tab 4, Schedule 3.
[10] For example, refer to the Emergency Response Program at Exhibit 4A, Tab 2, Schedule 3.
[11] For example, refer to the Human Resources and Safety Program at Exhibit 4A, Tab 2, Schedule 14.
[12] Exhibit 4A, Tab 1, Schedule 1 at pages 5-6.
[13] Exhibit 1C, Tab 3, Schedule 2 at pages 1-3; IR Response 4A-CCC-29.

2.1. "Top Down" direction was provided by senior management to recognize overall budgetary constraints in light of customer impacts.

- Toronto Hydro's top-down OM&A budgeting objective was to synthesize system needs and functional requirements with customer impacts.[14]
    - Senior management directed the departmental subject matter experts to bring forward anticipated current and sustained needs.[15]
    - Departments were asked to identify needs, but also exercise restraint in bringing forward proposals. Where funding was requested for new initiatives or expanded activities, departments were required to justify those requests.[16]
- A crucial outcome of this top-down dimension of the planning process relevant to the utility's ratepayers is the application of budgetary constraints to proposed expenditures.
    - Among these constrained expenditures mandated by the top-down approach were reductions stemming from an amended workforce hiring and replacement strategy to provide less lead-time for the wave of retirements projected in the next five to 15 years (25% of the utility's workforce).[17]
    - Toronto Hydro also has chosen to employ contingent labour to perform certain administrative and support functions. While Toronto Hydro would prefer to have the continuity of knowledge and experience and the security of full-time employees, the approach chosen saves approximately $3 million a year in OM&A. [18]

2.2. "Bottom Up" plans, informed by "Top Down" direction, were developed to meet current and anticipated needs over the CIR period.

- Informed by the top-down direction, departments were asked to identify their anticipated current and sustained needs.[19]
- In response, the business units prepared detailed operational assessments of the utility's service obligations and compliance requirements, which entailed:[20]
    - Analyzing ongoing needs for 2015

[14] OH Transcript, Volume 9 (March 3, 2015) at page 21, lines 6-18.
[15] IR Response 4A-CCC-29.
[16] Exhibit 4A, Tab 1, Schedule 1 at pages 7-8.
[17] Exhibit 4A, Tab 1, Schedule 1 at page 4, line 15.
[18] Exhibit 4A, Tab 1, Schedule 1 at page 9, lines 13-18.
[19] IR Response 4A-CCC-29 at page 1.
[20] OH Transcript, Volume 7 (February 26, 2015) at page 92, lines 4-8.

- Justifying new initiatives and/or materially expanded activities
  - A number of new or expanded OM&A expenditures were identified through this process. An example is the proposed Disaster Preparedness Management program, which responds to the recommendations of Independent Review Panel that assessed the utility's response to the 2013 ice storm.[21]

- These operational assessments were provided to the executive leadership to make decisions and trade-offs about the utility's funding requests.[22]

2.3 The company's planning assumptions demonstrate cost control and recognize the impacts of the proposed Custom PCI formula.

- Toronto Hydro used both general and specific cost and economic assumptions in its 2015 OM&A planning process:[23]
  - specific labour wage increases pursuant to the utility's obligations under the collective agreements with CUPE and the Society;[24]
  - forecast labour cost increases for non-unionized employees consistent with market-assessments;[25] and
  - general inflation (1.7%) for other costs, consistent with the OEB's 2014 inflation factor.
- Toronto Hydro treated 2015 as a standard rebasing year.[26]
  - Budgets for each program were established based on their sustained costs/needs over the 2015-19 period subject to overall budgetary constraints.
  - One-time costs, such as the regulatory costs of the CIR application, were amortized over the 2015 -2019 period (i.e. only 20% of the costs were included in the 2015 budget).[27]
  - New initiatives and materially expanded activities were identified and justified.[28]

[21] Exhibit 4A, Tab 1, Schedule 4, at page 2, lines 19-22.
[22] OH Transcript, Volume 7 (February 26, 2015) at page 84, lines 21-28.
[23] Exhibit 4A, Tab 1, Schedule 1 at page 6, lines 22-28.
[24] Exhibit 4A, Tab 4, Schedule 5 at page 10.
[25] Exhibit 4A, Tab 4, Schedule 5 at pages 4-5.
[26] Exhibit 4A, Tab 1, Schedule 1 at page 8.
[27] Exhibit 4A, Tab 2, Schedule 17 at page 9.
[28] Exhibit 4A, Tab 2, Schedule 1 at page 8, lines 7-20.

- Additional costs required to support the capital program were included.[29]

- To control costs and drive continuous improvement and efficiency over the CIR period, Toronto Hydro determined that 2016-2019 OM&A expenditures will be managed within the funding provided by the Custom PCI formula (i.e. OEB-approved inflation and productivity factors and a custom stretch factor).[30]

3. Toronto Hydro overall OM&A costs over the 2015-2019 period are necessary and appropriate.

- Toronto Hydro's 2015 forecasted OM&A expenditures are $269.5 million – 13.2% or $31.5 million above 2011 actual expenditures ($238.6 million), which were virtually the same as the overall amount approved by the OEB in the utility's last rebasing application (EB-2010-0142).[31]

- To manage its expenditures within the PCI constraints over the 2012-2014 period, the utility took a number of crucial steps to enhance the efficiency of its operations, including:[32]

  - Conducting a restructuring program in 2012, which reduced the utility's headcount by approximately 200 full-time unionized and non-union employees;

  - Improving efficiency of its supply chain and warehousing operations by introducing a new Warehouse Management System, outsourcing a portion of warehousing operations and automating low-value activities;

  - Reducing administrative burden and improving service quality by outsourcing the management of 100+ facilities contractors to a single Facilities Management Organization;

  - Taking steps to rationalize the size of the utility's vehicle fleet and reducing the associated expenditures through a combination of outsourcing and process streamlining;

  - Improving the efficiency and scalability of its information technology operations by improving server technology and standardizing and streamlining the governance of all key IT processes;

  - Driving down injury frequency and avoiding the associated costs by implementing industry-leading health and safety standards and investing in safety awareness; and

[29] IR response 2B-OEBStaff-34(b) at page 3, lines 6-10; OH Transcript, Volume 7, (February 26, 2015) at pages 64-65, lines 28-6.
[30] Exhibit 1B, Tab 2, Schedule 3.
[31] Exhibit 4A, Tab 1, Schedule 1 at page 3, lines 16-20.
[32] Exhibit 1B, Tab 2, Schedule 5 at pages 11-12, lines 20-16.

  - Introducing a new Customer Care and Billing system and broadening the scope of available online self-service tools, including move processing, and electronic billing, which improved service levels and had a positive impact on the utility's working capital requirements.

- In addition to enabling Toronto Hydro to operate within the funding constraints of the IRM regime, these initiatives and improvements have enabled the utility to put forward a lower OM&A funding request for the 2015 test year than would be possible in their absence.

3.1. Growth in 2015 OM&A from 2011, the last rebasing year is reasonable in light of the growth in capital spending, new initiatives and other increased costs. These factors have been partially offset by an overall reduction in compensation costs.

- The increase since the last rebasing year averaged 3.3% per year, largely due to:

  - Increased spending needed to support the growing capital plan:

    - Hiring costs increase as additional staff are hired to execute and support the increased capital work.[33]

    - Additional costs for the apprenticeship program which is required to maintain a skilled internal workforce to execute capital work, particularly in light of the number of retirements within the skilled and certified trades category.[34]

    - Finance OM&A increases to process an increased volume of transactions related to the expanded capital program.[35]

    - Increases in the asset management and planning functions,[36] as well as work execution management and support.[37]

  - Necessary incremental expenditures including:

    - A new program designed to optimize the utility's preparedness for major disaster events, such as the 2013 ice storm;[38]

    - Funding requirements driven by external factors such as increases in vegetation management contract rates and postage increases;[39]

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[33] OH Transcript, Volume 7 (February 26, 2015) at page 22, lines 10-16
[34] Exhibit 4A, Tab 2, Schedule 14 at page 42, lines 4-5; Exhibit 4A, Tab 2, Schedule 3 at page 10, lines 12-25.
[35] OH Transcript, Volume 7 (February 26, 2015) at pages 64-65, lines 28-11.
[36] Exhibit 4A, Tab 2, Schedule 7.
[37] Exhibit 4A, Tab 2, Schedule 8.
[38] Exhibit 4A, Tab 2, Schedule 4 at pages 4-5, lines 25-14.
[39] Exhibit 4A, Tab 2, Schedule 1 at page 34, lines 7-24; Exhibit 4A, Tab 2, Schedule 13 at page 9, line 26.

- Maintenance expenditures related to street lighting assets being transferred to the utility's rate base, the costs of which are fully offset by City of Toronto contractual payments;[40]

- Customer care investments, including internal and external labour increases required to upgrade MDMR/MV90/gatekeeper billing and meter data management systems.[41]

- Planned incremental system O&M expenditures for core asset categories, including lines and stations maintenance.[42]

- Costs increases since 2011 have been partially offset by a reduction in compensation costs from $234.6 million in the last rebasing year to $225.3 million in the 2015 test year.[43] On average, approximately 60% of the compensation costs are expensed in a given year.

- In summary, Toronto Hydro planned OM&A expenditure levels are required in order to serve its customers, maintain its workforce and comply with legal and regulatory obligations.

3.2. OM&A Costs by Program[44]

OM&A Program	2015 Test Year ($M)	2011 Actual ($M)	Difference ($M) (2015-2011)
Preventative & Predictive Maintenance	20.1	13.7	6.4
Corrective Maintenance	22.2	25.8	-3.6
Emergency Response	15.3	13.3	2
Disaster Preparedness Management	2.4	0.9	1.5
Control Centre	8.4	8.4	0
Operations Support Customer-Driven Work	10.1	6.0	4.1
Operations Support Planning	12.9	9.0	3.9
Operations Support Work Program Execution Management and Support	6.1	5.0	1.1
Operations Support Work Program	15.2	14.9	0.3

[40] Exhibit 4A, Tab 2, Schedule 1 at page 14, lines 16-18; Exhibit 4A, Tab 2, Schedule 2 at page 8, lines 19-21; Exhibit 4A, Tab 2, Schedule 3 at page 15, lines 12-15; Exhibit 2A, Tab 5, Schedule 1 at pages 19-22.
[41] IR Response 4A-CCC-35 at page 2, Table 1.
[42] Exhibit 4A, Tab 2, Schedule 1 at pages 3-4, lines 14-3.
[43] IR Response 4A-Society-4, Appendix A.
[44] Exhibit 4A, Tab 1, Schedule 1 at page 4, Table 1.

OM&A Program	2015 Test Year ($M)	2011 Actual ($M)	Difference ($M) (2015-2011)
Execution			
Fleet and Equipment Services	8.9	8.7	0.2
Facilities Management	27.5	24.6	2.9
Supply Chain Services	9.9	7.1	2.8
Customer Care	46.1	41.9	4.2
Human Resources and Safety	16.1	13.7	2.4
Finance	17.9	16.1	1.8
Information Technology	34.9	30.3	4.6
Rates and Regulatory Affairs	8.4	7.2	1.2
Legal Services	5.5	5.5	0
Charitable Donations (LEAP)	0.8	0.7	0.1
Common Costs and Adjustments	1.0	5.7	-4.7
Allocations and Recoveries	-20.2	-19.9	-0.3
Total OM&A	**269.5**	**238.6**	30.9

- Explanations for major areas of increase:
  - **Preventative & Predictive Maintenance**[45]
    - Increased vegetation management to harden the system against storms.
    - Increased maintenance and testing based on Reliability Centred Maintenance and Condition-based Maintenance principles.
    - Increased inspection and maintenance to address the risks posed by customer owned equipment.
  - **Disaster Preparedness Management**[46]
    - Additional expenditures to develop a more comprehensive and robust framework for disaster preparedness planning, management and operation in

[45] Exhibit 4A, Tab 2, Schedule 1 at pages, 3-4, lines 14 – 3.
[46] Exhibit 4A, Tab 2, Schedule 4 at page 1.

light of the Independent Review Panel's recommendations following the December 2013 ice storm.

- **Operations Support Customer-Driven Work**[47]

  - Increased volumes of accommodated and anticipated connection requests, and the growing complexity of the underlying planning and design work.

  - Increased volume of requests for equipment locates as the contractor community and general public become more aware of the Ontario One Call process and due to increased development and construction.

- **Operations Support Planning**[48]

  - Increased record management and planning to accommodate system renewal and growth.

  - Higher grid monitoring requirements due to the continued increase in renewable distributed generation resources connecting to Toronto Hydro's system and the growth in electric vehicles.

- **Operations Support Work Program Execution Management and Support**[49]

  - Growth based on increases in the capital and maintenance initiatives which this program supports, but proportionally slower that the expansion of the capital and predictive maintenance programs.

- **Facilities Management**[50]

  - Increased maintenance costs related to an expansion of maintenance services at stations and maintenance associated with new facilities (i.e. Copeland) and increased lease costs due to the end of inducement payments and new leases being signed.

- **Supply Chain Services**[51]

  - Increased warehousing needs primarily due to material needs related to the expanded capital program.

[47] Exhibit 4A Tab 2, Schedule 6 at page 6, lines 16-24; at page 12, lines 9-25.
[48] Exhibit 4A, Tab 2, Schedule 7 at pages 7-10; Exhibit 2B, Section E3.
[49] Exhibit 4A, Tab 2, Schedule 8 at page 7, lines 1-21.
[50] Exhibit 4A, Tab 2, Schedule 11 at pages 7-8, lines 17-27 and at pages 10-11.
[51] Exhibit 4A, Tab 2, Schedule 12 at page 13, lines 1-28.

- **Customer Care**[52]

  - Increased billing costs due to increases in postage and printing, the cost of new technology and provisions for bad debt.

- **Human Resources and Safety**[53]

  - Increases primarily due to legal expenses associated with grievance arbitrations and other costs associated with the renewal of Toronto Hydro's aging workforce and growing capital program.

- **Information Technology**[54]

  - Maintenance contract cost increases to support new IT systems and the inclusion of SCADA and other communications servicing within IT.

4. Toronto Hydro has successfully managed compensation cost and staffing levels and will continue to do so over the CIR period.

- Toronto Hydro has reduced compensation costs from $234.6 million in its last rebasing year (2011) to a forecast of $225.3 million in the 2015 test year.[55]

  - Staffing levels were reduced by approximately 10 percent since 2011. Executives and Management employee numbers decreased between 2011 and 2015 – with the number of executives cut by more than one third.[56]

- These reductions demonstrate Toronto Hydro's prudent workforce management during the last IRM period and should increase the OEB's confidence in utility's ability to operate within the rates set, which is one of the prerequisites of the Custom IR rate-setting method.[57]

- Towers Watson conducted a comprehensive benchmarking review of Toronto Hydro's compensation and benefits against various peer groups in the industry, and found that overall, compensation and benefits at Toronto Hydro are closely aligned to mid-market (median) rates across all peer groups.[58]

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[52] Exhibit 4A, tab 2, Schedule 13 at pages 9-10, lines 20-13.
[53] Exhibit 4A, Tab 2, Schedule 14 at page 32, lines 9-27.
[54] Exhibit 4A, Tab 2, Schedule 16 at pages 12-15.
[55] Exhibit 4A, Tab 4, Schedule 1 at page 6, lines 2-6.
[56] IR Response 4A-VEC-48, Appendix A.
[57] Ontario Energy Board, Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (October 18, 2012) at page 19.
[58] Exhibit 4A, Tab 4, Schedule 6 at pages 1-2.5, 8-9, 15-16;

- Toronto Hydro also benchmarks executive compensation. The latest study prepared by Mercer for the Human Resource Committee of the Board of Directors indicates that compensation levels for Named Executive Officers at Toronto Hydro are generally at or below the market competitive levels.[59]

- Over the CIR period, CUPE wage increases which account for approximately half of the compensation costs, will be held to an average of 1.75% per year over the four years of the agreement (2014-2018).[60] Non-unionized employee wages are expected to remain within the market competitive range. This will be confirmed through annual market reviews.[61]

- As the labour market continues to tighten due retirements and labour shortages, there will likely be upward pressure on compensation.[62] Maintaining wages and benefits at market levels will be necessary to attract and retain qualified candidates.[63]

- The company structures compensation to align the behaviour and performance of the workforce with the core objectives and goals of the utility, such as commitment to safety and a customer service focus, and rewards employees that enable the utility to achieve its goals more effectively and efficiently. This philosophy has and will continue to drive performance improvement. [64]

[59] IR Response1B-SEC-8, Appendix N.
[60] Exhibit 4A, Tab 4, Schedule 5 at page 9, lines 2-6; IR Response 4A-Society-4, Appendix A.
[61] Exhibit 4A, Tab 4, Schedule 5 at pages 4-5, lines 20-6.
[62] Exhibit 4A, Tab 4, Schedule 4 at pages 27-28.
[63] Exhibit 4A, Tab 4, Schedule 5 at pages 3-5.
[64] Exhibit 4A, Tab 4, Schedule 5 at pages 7-9, lines 9-21.

FLEET AND EQUIPMENT SERVICES PROGRAM

1. SUMMARY

Table 1: Fleet and Equipment Services Program Costs ($ Millions)

Program	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Fleet & Equipment	8.7	8.6	8.7	8.4	8.9

The Fleet and Equipment Services ("FES") program encompasses the procurement, maintenance and disposal of Toronto Hydro vehicles, associated equipment, and employee personal protective gear/equipment. It is also responsible for ensuring that certain safety equipment and implements are tested and repaired in accordance with occupational health and safety requirements and other applicable standards. Comprehensive and timely delivery of these services facilitates Toronto Hydro's ability to carry out its electricity distribution activities in a safe, reliable, and expedient manner.

2. PROGRAM DESCRIPTION

The program and the associated budget are subdivided into two segments, namely:

- Equipment Services; and
- Lab Services.

The Equipment Services segment is comprised of services that oversee that Toronto Hydro's 660 vehicles and the associated equipment remain in good working order, are optimally utilized, and are safe for both the Toronto Hydro employees operating them and the general public they share roads with. This includes procurement, maintenance, and administration of vehicle use using a combination of internal and external resources to reduce safety risks and facilitate value-for-money. Over the 2011-2013 historical period, Toronto Hydro implemented a number of fleet-related productivity and efficiency-enhancing programs, which allowed the segment expenditures to remain generally flat over the more recent years.

Toronto Hydro plans to continue implementing further productivity and efficiency-enhancing initiatives to manage the maintenance costs, driven in large part by the planned volumes of fleet-related capital expenditures.[1]

The activities comprising the Lab Services segment are an important component of Toronto Hydro's strong health and safety performance. This includes regular testing of employee Personal Protective Equipment ("PPE"), and the repair of confined space gas monitors which assist in protecting Toronto Hydro crews working in underground vaults and cable chambers from being exposed to harmful gases. Lab Services segment expenditures also include the cost of repairs and tests for transformer network protection relays. The segment's expenditures have declined over the historical period due to the 2012 restructuring and outsourcing of some activities formerly performed in-house.

3. EQUIPMENT SERVICES SEGMENT

The Equipment Services segment covers all functions related to maintenance, repair and management of Toronto Hydro's vehicles and related equipment. The nature and frequency of vehicle maintenance activities are driven by the Ontario Ministry of Transportation requirements, vehicle manufacturer standards and specifications, safety testing requirements for vehicle-mounted equipment, Ministry of Labour standards, and vehicle warranty specifications.

[1] Exhibit 2B, E8.1

As of April 30, 2014, Toronto Hydro's fleet is composed of 660 units including cars, pickups, bucket trucks and other utility units such as sweepers, backhoes and forklifts.

All vehicles and equipment undergo periodic preventative maintenance, scheduled on the basis of time elapsed or distance travelled since the last inspection. Toronto Hydro performs the majority of this work in-house, typically inspecting each unit and the equipment mounted on it at least once a year, or as provided by manufacturer specifications or other relevant standards and regulations. In 2013, Toronto Hydro completed over 2,500 preventative maintenance jobs, totalling 7,200 hours of labour.

Toronto Hydro generally employs the services of external vendors for certain types of work, including:

- work that would expose Toronto Hydro employees to greater physical risk – such as vehicle suspension work;
- work that does not require the technical expertise of a licensed mechanic such as tire replacement;
- work requiring specific skills or credentials that Toronto Hydro Fleet employees do not posses, such as aerial lift dielectric testing; and
- work using equipment not owned by, or not readily accessible by the utility such as vehicle emissions testing.

Toronto Hydro also secures select services by way of competitive multi-year tenders, with respect to a number of fleet-related activities including:

- parts procurement and management;
- fuel procurement and delivery;
- commercial gas station fuel card services;
- GPS system licensing and technical support;
- tire replacement and repair service; and

- vehicle towing services.

The Requests for Proposal ("RFPs") to procure these services and the subsequent RFP evaluation frameworks are structured to minimize overall maintenance and administration costs, reduce vehicle downtime, and ensure predictable service levels over the length of the contract.

3.1. Segment Costs

Table 2 presents the Historical (2011-2013), Bridge (2014) and Test Year (2015) expenditures for the Equipment Services segment.

Table 2: Table 2: Equipment Services Costs ($ Millions)

Segment	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015Test
Equipment Services	8.0	8.0	8.1	7.8	8.3

3.2. 2011-2014

Toronto Hydro's 2012 and 2013 actual Equipment Services expenditures were essentially flat versus 2011 actuals, with minor cost increases resulting from normal inflationary pressures and the terms of the utility's collective agreements, offset by efficiencies from the initiatives described below.

Toronto Hydro forecasts its 2014 Bridge Year expenditures to be $0.3M lower than the 2013 actuals, due to lower payroll costs, and an anticipated reduction in parts purchases as vehicles are refreshed through 2013 and 2014.

Since 2011,Toronto Hydro has implemented several productivity and efficiency initiatives that helped the utility manage its fleet cost levels. These initiatives include:

- **Unit Reduction –** Toronto Hydro removed 79 vehicles from its fleet in 2011 to 2013, and expects to remove another seven by the end of 2014. This has been enabled by operational efficiencies elsewhere in the utility that subsequently reduced Toronto Hydro's transportation requirements.
- **GPS Implementation –** In 2010, Toronto Hydro equipped all of its vehicles with GPS telemetry units. Knowledge of each vehicle's exact location and electronic data query capabilities improved preventative maintenance attainment rates and reduced labour requirements for performance tracking (kilometres, engine hours etc).
- **Vehicle Sharing –** In 2011, Toronto Hydro undertook a small vehicle sharing pilot study for a single division, leading to increased vehicle utilization and reduction of dedicated vehicles by five units. The program is currently being expanded to large vehicles used throughout the organization.
- **Maintenance Optimization –** Starting in 2014, the utility extended the regular maintenance cycle for its light vehicles, thereby reducing requisite labour requirements, and aligning maintenance cycles with manufacturer recommendations.
- **External Service RFPs –** In 2013, Toronto Hydro held tenders for bulk fuel purchases, truck-to-truck diesel fuel delivery, and fuel card services. The resulting contracts are expected to generate additional savings in the above-noted areas.
- **Activity Outsourcing –** Toronto Hydro engaged a number of external vendors to support its fleet management functions, including consignment-based parts management and distribution, vehicle decommissioning and vehicle licence procurement and monitoring.

3.3. Test Year Segment Costs

Test Year expenditures are targeted to increase by $0.5 million from the projected 2014 Bridge Year expenditures. In addition to normal inflationary pressures, this increase is primarily due to a $0.2 million contractual labour cost increase and a $0.1 million increase in re-allocation of carrying costs for vehicles being used in the vehicle sharing program.

Over the 2015 Test Year and beyond, Toronto Hydro expects to manage equipment services segment increases through several further productivity and efficiency initiatives described below:

- **Vehicle Replacement Times –** in 2013, Toronto Hydro commissioned a comprehensive vehicle Life Cycle Analysis ("LCA") study, the findings of which are expected to allow the utility to realize operational efficiencies going forward.
- **Vehicle Sharing Expansion –** the utility expects that the planned expansion of the previously described program will result in further vehicle count reductions, leading to maintenance efficiencies and faster restoration of identified failures.
- **Incremental RFPs –** Toronto Hydro plans to issue competitive tenders for towing, tire supply and maintenance, and GPS services. The utility expects that these tenders will result in proposals offering service improvements and competitive pricing.

Fleet and Equipment Services activities are a foundational component of basic utility operations, as they facilitate Toronto Hydro vehicles being able to adequately support system maintenance and capital investment initiatives, and help to ensure that the utility's vehicles are safe, reliable, and deliver consistent performance. The proposed Equipment Services Test Year expenditures supports the provision of labour, replacement parts, fuel, services, and administration required to execute these activities. To enhance the value of these services, Toronto Hydro has taken a number of steps to improve the efficiency of its program delivery; these initiatives have had positive effect on constraining the utility's Test Year forecasts in light of increasing cost pressures associated with supporting Toronto Hydro's capital and maintenance programs.

Segment expenditures are generally driven by preventative maintenance and repair requirements identified by field staff. A reduction from the proposed level of spending may result in the following adverse consequences:

- **Safety Risks –** A reduction in segment expenditures could lead to reduction of frequency or scope of maintenance activities. Longer intervals between maintenance work could increase the possibility of defects going undetected, thus increasing the safety risk to Toronto Hydro employees and the general public.
- **Reliability Risks –** Reduction in maintenance levels could lead to increased vehicle downtime due to higher field failures, or an increase in the number of reported vehicle defects requiring vehicles to be taken out of service. Ultimately, fleet availability and vehicle or mounted equipment failure while on a reactive call could adversely affect Toronto Hydro's ability to deliver timely service to the public and result in prolonged outages.
- **Shop Productivity Impact –** Reduction in regular maintenance could result in longer and more complex repairs thereby prolonging the time it takes for vehicles to be returned to service when failures are identified.

4. LAB SERVICES SEGMENT

The Lab Services segment supports the acquisition, certification and testing of safety tools, implements, and PPE worn by Toronto Hydro's field crews. The expenditures comprising this segment include:

- cost of procurement, cleaning, inspection, and electrical testing of rubber gloves;

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 29:

Reference(s): Exhibit 4A, Tab 1, Schedule 1

Please provide all correspondence provided to internal staff regarding the development of the 2015 OM A budget and budgeting beyond 2015. Toronto Hydro has presented the OM&A evidence by Program. Are certain Directors/Managers responsible for each program or does the Company operate in according to another structure? If it does please provide that structure and indicate how the "programs" are managed within that structure. If possible please provide an organizational chart that describes who is responsible for each "program".

RESPONSE:

Toronto Hydro developed the OM&A plan on the basis of both a top-down and bottom-up approach as described in Exhibit 1C, Tab 3, Schedule 2. During the process, multiple planning activities were concurrently conducted, and inputs and outcome considerations were being formed. An iterative planning approach was used in order to facilitate robust decision-making and prudent planning.

Over a three-week period commencing in 2014Q1, a series of Finance-initiated meetings were held with departmental senior management regarding their respective OM&A. These meetings covered planning structure, approach and timing for the development of the 2015 OM&A budget. Departments were asked to identify their anticipated current and sustained needs for the five-year period in light of the multi-year constrained funding mechanism. Refer to Appendix A for the related material.

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

The organizational chart that describes Toronto Hydro’s senior management team and their respective responsibility for each program is attached as Appendix B.

FINANCIAL PLANNING PROCESS

1. OVERVIEW

Currently, financial planning at Toronto Hydro is conducted annually and results in a three-year Plan – a detailed plan for the first year and a directional plan for the next two years. Given the requirements of the five-year Custom Incentive Rate ("CIR") application, the term of the planning activities for the period beginning 2015 was extended to five years (the "planning activity").

2. APPROACH

Toronto Hydro's corporate plans are informed by a number of operational needs such as asset investment requirements, maintenance requirements, staffing requirements and legislative and regulatory obligations. The plans are also informed by other important considerations such as customer needs and preferences (including service levels and consumption-management tools), rate impacts, value-for-money, productivity, and maintaining the financial health and viability of the utility.

In other words, the utility considers a number of input considerations and objectives in order to generate its plans. No one of these considerations is determinative of the utility's ultimate plan, but they all inform it. For example, while Toronto Hydro views that a capital investment approach well above $500 million per year over the 2015-2019 period is optimal from an assets-needs perspective, in light of rate impacts and execution constraints, it has constrained its actual plan (and corresponding funding request to the OEB) to approximately $500 million per year over the 2015-2019 period.

Toronto Hydro synthesizes these input considerations into a strategic planning philosophy called its four pillars, which are:

Customer Service

- ✓ To provide long-term value for your money
- ✓ Make it easy to work with us
- ✓ Help you conserve energy
- ✓ Provide you with tools and technology

Operations

- ✓ Keep the lights on
- ✓ Keep our system safe
- ✓ Build a grid that supports a modern city
- ✓ Maintain above average productivity

People

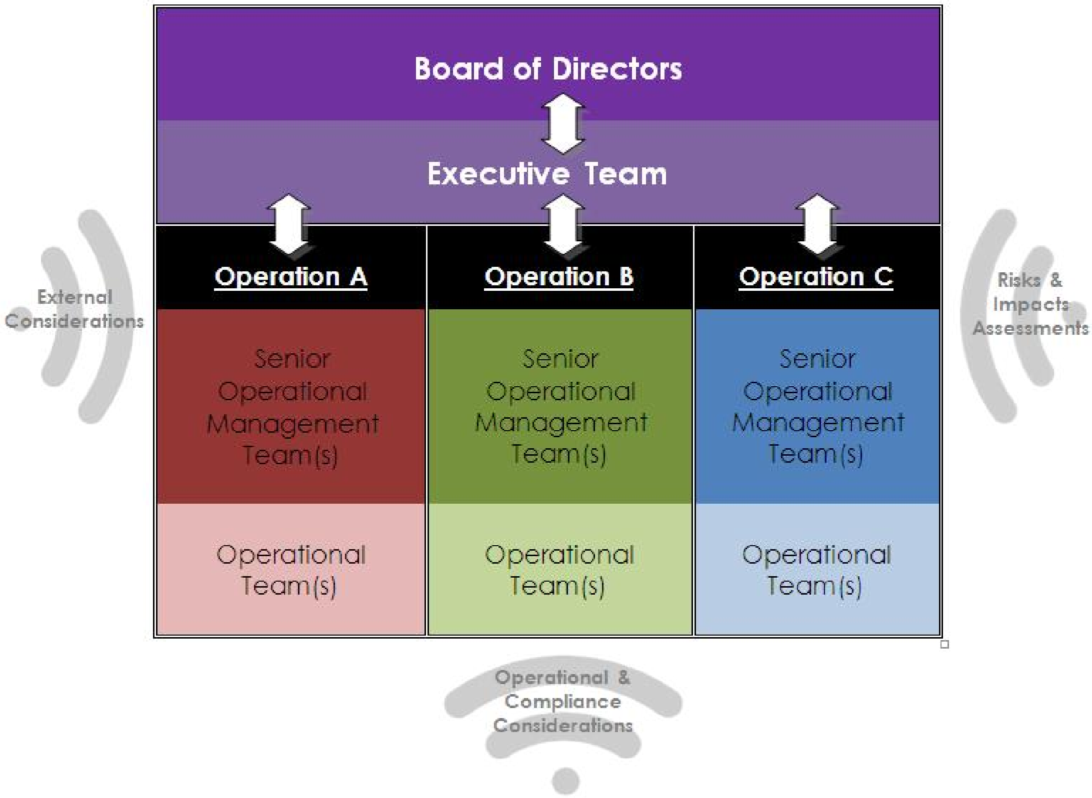
- ✓ Provide a healthy and safe workplace
- ✓ Develop a skilled and knowledgeable workforce
- ✓ Keep our workforce engaged and productive

Financial Strength

- ✓ Provide a Fair Return To Our Shareholder
- ✓ Continue to increase Shareholder Value

Toronto Hydro`s planning activity is guided by its Strategic Pillars and compliance requirements.

In executing its planning activities, the utility employs a combination of ‘top-down’ and ‘bottom-up’ planning models with an iterative planning process. That is, the overall business strategy outlining the general direction of the organization is communicated from the ‘top’ (senior management) ‘down’ to the operational teams. Subject matter experts then incorporate this direction into their different functional areas and operational realities, needs and strategies.



Finally, as operational plans incorporating the strategic direction are formed, they are proposed to the senior leadership at Toronto Hydro for review, impact assessments and approval.

In general, the planning process consists of four stages: 1. Corporate strategy establishment; 2. Operational plan proposals; 3. Proposal reviews and selection; and 4. Detailed development of projects and programs.

During the process, multiple planning activities are being concurrently conducted, and inputs and outcome considerations are being formed. An iterative planning approach is used in order to facilitate robust decision-making and prudent planning.

As noted above, description and variance analysis of each the above programs can be found in Exhibit 4A, Tab 2, Schedules 1 – 21. For additional context of the planning and budgeting activities underlying Toronto Hydro's 2015 Test Year OM&A ask, please refer to the following section of this schedule.

3. OM&A PLANNING AND BUDGETING

Toronto Hydro approached this rate application from the perspective of seeking to build an OM&A plan that facilitates the utility operating within an IRM framework for non-capital expenditures.[4] Accordingly, it structured a financial planning process for 2015- **/C**
2019 around the principles of the 4th Generation Incentive Rate Making regime (4GIRM). In particular, the utility approached its 2015 proposed OM&A expenditures from the perspective of savings it has achieved over the 3GIRM period together with resource requirements for 2015 and forward. Further, Toronto Hydro viewed 2016-2019 as years where its funding request would be consistent with the IRM framework – i.e., less than inflation and determined on the basis of a Price Cap Index-based formulaic adjustment.

An outcome of the Financial Planning process as described in Exhibit 1C, Tab 3, Schedule 2 is the operating, maintenance and administration ("OM&A") plan. In developing the funding request for OM&A, Toronto Hydro's plans were informed by a number of factors including operational needs such as asset investment requirements, maintenance requirements, staffing requirements, reliability, safety and legislative and

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[4] Subject to special considerations for capital, and reasonable off-ramps for potential expenditures that are unanticipated or unknown at the time of bringing this application. See Exhibit 1B, Tab 2, Schedule 3 for a discussion of Toronto Hydro's proposed off-ramp or Z-factor adjustments. Also see Exhibit 1B, Tab 2, Schedule 3 for discussion of Toronto Hydro's approach to building capital expenditures into a formulaic approach to ratemaking (which represents a modified IRM approach). **/C**

regulatory obligations. The plans are also informed by other important considerations such as customer needs (including service levels and consumption-management tools), rate impacts, value-for-money, productivity, and maintaining the financial health and viability of the utility, etc. These considerations roll up to the four pillars discussed at Exhibit 1C, Tab 3, Schedule 1 and Schedule 2.

No one of these considerations is determinative of the utility's ultimate financial plan, but they all inform ultimate funding requests. For example, Toronto Hydro believes that staffing levels beyond the operating costs proposed in this application are optimal based on the utility's assessment of its operating requirements, its retirement projections for the next five to 15 years, and the significant lead time for training certified and skilled trades (four to six years). However, the utility has moderated its funding request in light of other considerations, such as rate impacts.

Informed by the considerations described above, Toronto Hydro developed the OM&A plan on the basis of both a top-down and bottom-up approach as described in Exhibit 1C, Tab 3, Schedule 2. In general, Toronto Hydro's objective was to put forward a plan that largely maintained functional requirements such as safe and reliable grid operations and system performance, service levels and legal, regulatory and statutory compliance in an efficient manner.

Toronto Hydro used both general and specific cost and economic assumptions in its 2015 forecast of the operating costs. Labour costs have been adjusted to reflect the annual rate adjustments that Toronto hydro has committed to in its collective agreements. The labour cost forecast was also adjusted to reflect market-competitive pay increases for non-unionized employees. For more information, refer to Exhibit 4A, Tab 4, Schedule 5. Otherwise, a general inflation factor of 1.7% was applied, consistent with the OEB's current inflation factor.

Strategic Pillars, the utility made these decisions on the basis of the spectrum of input considerations, such as rate impacts.

An example of an area in which Toronto Hydro did not put forward the full possible sustained and reasonable OM&A request is Toronto Hydro's proposed staffing plan. To constrain compensation costs over the rate period, Toronto Hydro has limited its proposed workforce hiring and replacement strategy, despite the increasing wave of retirements that the utility projects to experience in the next five to ten years (25% of the workforce is eligible to retire by 2019) and notwithstanding apprenticeship and training period required for a Certified and Skilled Trades or Designated Technical Professionals (four to six years). Instead of ramping up its hiring plan, Toronto Hydro has implemented a multi-faceted staffing strategy to maintain quality service and value to rate payers, and to plan for upcoming retirements. For example, Toronto Hydro constrained its compensation costs by approximately $3 million by employing contingent resources rather than full-time employees to deliver a variety of administrative and support functions. Although the utility would prefer to have the continuity of knowledge and experience, and the security of full-time resources, it has opted for a different staffing model in this respect, in an effort to constrain costs.[5] **/C**

In building its five-year OM&A plan, while Toronto Hydro endeavoured to consider foundational expenditure requirements, including potential emerging requirements (e.g., extreme weather preparedness) that can be reasonably anticipated, it did not engage in a detailed five-year financial planning exercise. However, it did consider two important factors in assessing its ability to "live within" IRM for OM&A over the term of the CIR plan.

[5] Exhibit 4A, Tab 2, Schedule 3 **/C**

to track and manage the costs associated with the maintenance programs consistently across the utility and track year-over-year variances.

This transition from RC to activity-based presentation is particularly salient with respect to the OM&A evidence contained within Exhibit 4A, Tab 2, Schedules 6 through 9, describing the programs that in previous filings (e.g., EB-2011-0144) were presented as a single cost item described as Operations Support. Given a number of important and functionally distinct activities captured within the previous Operations Support definition, Toronto Hydro has made best efforts to provide dedicated descriptions and variance analysis for each of the four ensuing programs and the associated segments. However, for the reasons noted above, the utility employed estimates to determine the particular program/segment expenditures for the Historical and Bridge years.

2. OVERVIEW OF THE OM&A PROGRAMS AND EXPENDITURES

Toronto Hydro's total 2015 forecasted OM&A expenditures are $269.5 million – 13.2% or $31.5 million above the 2011 expenditures approved by the OEB ($238 million) in Toronto Hydro's latest rebasing application (EB-2010-0142), and $30.9 million or 13% above the 2011 actual expenditures ($238.6 million).[2] Overall, the cost increase from 2011 to 2015 represent an average of 3.3% a year. Toronto Hydro notes that Section 3 of this schedule details the process and considerations informing Toronto Hydro's budgeting of the 2015 Test Year OM&A budget, including the constraint and restraint exercised with deference to several inter-related factors including ratepayer impact, and the utility's operational needs and obligations. /C

[2] Because OM&A was settled on an envelope basis in the utility's last rebasing application (EB-2010-0142), and because 2011 OEB-Approved and 2011 actual expenditures were very similar ($238 OEB-Approved vs. $238.6 actuals expenditures), Toronto Hydro has only reported 2011 actual expenditures in the OEB appendices filed at Exhibit 4A, Tab 1, Schedules 2-5. /C

Toronto Hydro proposes to embed the OEB's productivity with its implicit incremental stretch factor unchanged within the proposed custom PCI. /C

3.2. Custom Stretch Factor

The second component of the X-factor is an explicit stretch factor. According to the OEB, "Stretch factors promote, recognize and reward distributors for efficiency improvements relative to the expected sector productivity trend."[8] Under the current methodology, which was updated most recently in 2013, utilities are assigned one of five stretch factors. This occurs on the basis of a comparison of the utility's total costs relative to their predicted total costs. The predicted total costs are determined using a total cost econometric model developed by PEG.[9]

As part of this application, Toronto Hydro is submitting alternative total cost benchmarking, the details of which can be found in the Power System Engineering's Econometric Benchmarking Report, at Exhibit 1B, Tab 2, Schedule 5 (the "PSE Report"). The alternative total cost benchmarking model prepared by PSE for Toronto Hydro is econometric in nature (similar to PEG's model) and includes an expanded data set. The results are statistically significant and relevant to the OEB's consideration of Toronto Hydro's performance.

Accordingly, Toronto Hydro submits that this is an appropriate basis for setting its stretch factor. As noted in the PSE Report, Toronto Hydro's forecasts of its total costs are within ten percent of its predicted total costs. Utilities within this demarcation point are assigned to Group III of the OEB's benchmarking cohorts, implying a stretch factor of 0.30%. Toronto Hydro therefore proposes that the stretch factor in the proposed custom PCI framework be set at 0.30%.

[8] OEB Rate Setting Parameters Report, *supra* note 3 at page 18.
[9] OEB Rate Setting Parameters Report, *supra* note 3 at page 19.

approaching the sample average in terms of customer size, total expenditures, load and energy throughput unlike the OEB Ontario-only model where the utility is a clear outlier.

The OEB acknowledged the outlier status of Toronto Hydro in the Ontario context, by excluding results of the utility's historical Total Factor Productivity ("TFP") assessment from the calculation of the Productivity Factor for rate-setting under the 4th Generation Incentive Rate-Setting ("4th Generation IR") regime.[13] The variability in the scale of operation and costs of observed utilities in PSE's combined dataset makes it possible to produce benchmark cost models that evaluate Toronto Hydro's performance in a rigorous manner, and allow PSE to account for the effect of business conditions not present elsewhere in Ontario (e.g., large urban core).

2.1.3. Ratemaking Incentives – the IRM Framework

Toronto Hydro's base rates have been escalating in accordance with the OEB's 3rd Generation Incentive Rate-Setting Price Cap Index ("PCI") mechanism since 2011, when the utility underwent its last rebasing proceeding (EB-2010-0142). In ensuring that its operating costs conformed to the funding levels provided by the PCI framework over the 2012-2014 period, the utility took a number of crucial steps to enhance the efficiency and promote sustainability of its operations, including:

- Conducting a Restructuring Program in 2012, which reduced the utility's headcount by approximately 200 full-time unionized and non-union employees;[14]
- Improving efficiency of its supply chain and warehousing operations by introducing a new Warehouse Management System, outsourcing a portion of warehousing operations and automating low-value activities;[15]

[13] EB-2010-0379, Report of the Board, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (December 4, 2013) at page 14.
[14] Exhibit 4A, Tab 4.
[15] Exhibit 4A, Tab 2, Schedule 12.

- Reducing administrative burden and improving service quality by outsourcing the management of 100+ facilities contractors to a single Facilities Management Organization;[16]
- Taking steps to rationalize the size of the utility's vehicle fleet and reducing the associated expenditures through a combination of outsourcing and process streamlining;[17]
- Improving the efficiency and scalability of its information technology operations by virtualizing the majority of the utility's servers and standardizing and streamlining the governance of all key IT processes;[18]
- Driving down injury frequency and avoiding the associated costs by implementing industry-leading health and safety standards and investing in safety awareness;[19]
- Introducing a new Customer Care and Billing ("CC&B") system and broadening the scope of available online self-service tools, including move processing, electronic billing etc, which improved service levels and had a positive impact on the utility's working capital requirements;[20]
- Other initiatives described throughout this application.

2.2. Future Productivity and Toronto Hydro's Productivity Culture

The utility's evidence in support of the productivity incentives built into the proposed Custom IR rate framework and the reasonableness of the utility's forecasted expenditures over the 2015-2019 horizon is based on:

1) Structural Elements of the CIR Framework;
2) Empirical Evaluation of the 2015-2019 Expenditure Forecasts;
3) Productivity Culture over the CIR Timeframe.

[16] Exhibit 4A, Tab 2, Schedule 11.
[17] Exhibit 4A, Tab 2, Schedule 10.
[18] Exhibit 4A, Tab 2, Schedule 16.
[19] Exhibit 4A, Tab 2, Schedule 14.
[20] Exhibit 4A, Tab 2, Schedule 13; Exhibit 2A, Tab 3.

OEB Appendix 2-K
EMPLOYEE COSTS /COMPENSATION TABLE

	2011 Actuals	2012 Actuals	2013 Actuals	2014 BRIDGE	2015 TEST
Number of Employees (FTEs including Part-Time)[1]					
Management (including executive)	61.8	53.0	55.2	55	55
Non-Management (union and non-union)	1,757.9	1,547.8	1,472.2	1,482	1,509
Total	1,819.7	1,600.8	1,527.4	1,537	1,564
Total Salary and Wages (including ovetime and incentive pay)					
Management (including executive)	$ 11,503,925	$ 10,484,857	$ 10,916,952	11,357,809	11,676,362
Non-Management (union and non-union)	$ 165,601,764	$ 149,723,035	$ 147,970,550	152,531,929	157,754,790
Total	$ 177,105,689	$ 160,207,891	$ 158,887,502	$ 163,889,738	$ 169,431,152
Total Benefits (Current + Accrued)					
Management (including executive)	$ 3,700,705	$ 3,207,397	$ 3,497,371	3,622,390	3,586,525
Non-Management (union and non-union)	$ 53,771,361	$ 52,158,435	$ 54,433,118	53,051,955	52,279,791
Total	$ 57,472,066	$ 55,365,832	$ 57,930,489	$ 56,674,344	$ 55,866,316
Total Compensation (Salary, Wages, & Benefits)					
Management (including executive)	$ 15,204,630	$ 13,692,253	$ 14,414,323	$ 14,980,199	$ 15,262,887
Non-Management (union and non-union)	$ 219,373,125	$ 201,881,469	$ 202,403,668	$ 205,583,884	$ 210,034,581
Total	$ 234,577,755	$ 215,573,723	$ 216,817,992	$ 220,564,082	$ 225,297,468

3. COMPENSATION COSTS AND STRATEGIES

Toronto Hydro expects to reduce compensation costs from $234.6 million in its last re-basing year (2011) to $225.3 million in the 2015 test year. In preparing this forecast, Toronto Hydro considered inflation rates contained in its collective agreements, relevant labour market-data and other factors such as the increasing size and complexity of the work-plan over the next five years.

3.1. Compensation Strategy

Toronto Hydro's strategy is to provide wages and benefits that are competitive in the markets where Toronto Hydro competes for talent. Refer to Compensation and Benefits Benchmarking Report prepared by Towers Watson (Schedule 6), which found that Toronto Hydro's compensation levels are generally aligned with the market.

Toronto Hydro's strategy also includes offering a compensation program that aligns the behaviour and performance of the workforce with the core objectives and goals of the utility. The compensation strategy is an important tool for communicating performance expectations, fostering productivity and rewarding employees for their contributions.

Between 2015 and 2019, Toronto Hydro intends to continue to rely on these principles to manage human resource requirements and costs appropriately and responsibly. The utility must do so with regard to the dynamic labour relations environment that it operates within, and the workforce challenges that it must contend with over the next five years.

3.2. Non-Bargaining Unit Employees

Less than one-third of Toronto Hydro's employees are not members of a bargaining unit. These employees receive a total cash compensation package comprised of base salary and variable performance pay. Salary grade/levels are set to correspond to a salary range. Salaries are set and adjusted with regard to external market benchmarking.

3.3. Bargaining Unit Employees

Approximately two-thirds of Toronto Hydro's employees are represented by the following bargaining units with collective agreements in-place:

- **CUPE** collective agreement effective February 13, 2014 to January 31, 2018.
- **The Society** collective agreement effective April 12, 2012 to December 31, 2015.

3.4. Benefits and Pensions

Full-time employees are entitled to medical and dental benefits, short and long-term disability income protection, life insurance, accidental death and dismemberment, and leaves of absence (maternity, adoption and parental leaves). Employees are also eligible to participate in the OMERS pension plan and receive post-retirement benefits. The cost of employee benefits is expected to decrease from $57.47 million in 2011 to $55.87 million in 2015.

Table 1 below provides a breakdown of Toronto Hydro’s Historical (2011-2013), Bridge and Test Year OM&A expenditures, broken down by program.

Table 1: Historical, Bridge and Test Year OM&A Expenditures by Program[3] /C

($M)	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test	
Preventative & Predictive Maintenance	13.7	16.0	12.8	16.1	20.1	
Corrective Maintenance	25.8	21.5	17.0	19.0	22.2	
Emergency Response	13.3	13.9	26.3	16.2	15.3	/C
Disaster Preparedness Management	0.9	-	-	-	2.4	
Control Centre	8.4	8.3	8.9	8.2	8.4	
Customer-Driven Work	6.0	5.9	7.0	8.2	10.1	
Planning	9.0	9.0	11.5	10.3	12.9	/C
Work Program Execution Management and Support	5.0	5.5	5.6	5.8	6.1	
Work Program Execution	14.9	13.8	13.0	14.3	15.2	
Fleet and Equipment Services	8.7	8.5	8.7	8.4	8.9	
Facilities Management	24.6	23.5	24.2	27.2	27.5	/C
Supply Chain Services	7.1	6.6	9.0	10.3	9.9	
Customer Care	41.9	37.5	39.7	42.2	46.1	
Human Resources and Safety	13.7	13.2	15.3	15.3	16.1	
Finance	16.1	14.7	15.7	17.0	17.9	
Information Technology	30.3	28.5	31.0	33.4	34.9	
Rates and Regulatory Affairs	7.2	7.8	8.4	6.4	8.4	/C
Legal Services	5.5	4.3	4.5	5.3	5.5	
Charitable Donations (LEAP)	0.7	0.7	0.7	0.7	0.8	
Common Costs and Adjustments	5.7	(6.0)	0.5	2.3	1.0	/C
Allocations and Recoveries	(19.9)	(17.4)	(13.3)	(19.9)	(20.2)	
Restructuring Costs	-	27.7	-	-	-	
Total OM&A	**238.6**	**243.5**	**246.4**	**246.6**	**269.5**	/C

[3] Numbers may not add up due to rounding. /C

customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor.

The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

The Board has determined that a minimum term of five years is appropriate. As is the case for 4th Generation IR, this term will better align rate-setting and distributor planning, strengthen efficiency incentives, and support innovation. It will help to manage the pace of rate increases for customers through adjustments calculated to smooth the impact of forecasted expenditures.

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

Annual Adjustment Mechanism

The allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including:

- the distributor's forecasts (revenues and costs, including inflation and productivity);

INTRODUCTION AND EXECUTIVE SUMMARY

Towers Watson was retained by Torys on behalf of its client Toronto Hydro to complete a review of market competitive compensation and benefits levels in January 2014.

Methodology

The review, findings and observations focused on compensation and benefits separately. Towers Watson encourages Toronto Hydro to consider compensation and benefits in aggregate when reviewing overall position to market for a given level or role.

The compensation review covered analysis of annualized base pay, target short-term incentive levels, and total target cash (base pay plus target short-term incentive) at Toronto Hydro and in the external market (see peer group notes below).

Following Towers Watson's advice, benchmark roles – selected to reflect the wide range of positions at Toronto Hydro – were identified to support the compensation analysis. Balanced selection criteria were applied to ensure functional or level based bias did not disproportionately skew the analyses. Benchmark roles covered 66% of Toronto Hydro's employee population (well within the range (50% - 75%) typically suggested for this type of analysis).

The benefits review covered aggregate analysis of both employer paid value and total (employer plus employee paid) value for all core benefits, including pension, savings, disability, health (active and retiree), dental (active and retiree), life insurance (active and retiree), vacation and holidays.

Peer group selection

On Towers Watson's recommendation and to ensure relevant conclusions could be drawn from the compensation analysis, the "external market" was viewed through a number of lenses with several peer groups identified:

- A named comparator group of companies from Towers Watson's 2013 Energy Compensation Survey to cover as many roles as possible (but focusing mostly on industry-specific jobs),
- A named comparator group of companies from Hay Group's 2013 Energy Industry Survey to cover as many roles as possible (focusing mostly on the utilities industry),
- A broader "whole sample" peer group covering all participants of Towers Watson's 2013 Energy Compensation Survey,
- A named comparator group of GTA companies from Tower Watson's 2013 General Industry Survey that meet headcount and revenue / budget scope criteria for non-industry-specific jobs, and
- A broader "whole sample" peer group covering all participants of the 2013 General Industry Survey as a supplementary reference point.

Benchmark jobs were matched to equivalent survey jobs and levels in the aforementioned Towers Watson and Hay Group compensation surveys to support the analysis. Survey matching was validated by Towers Watson and Hay Group consultants.

A single named peer group was identified to support the benefits analysis. Comparator organizations were selected on the basis of industry (vertically integrated electricity organizations and electricity and gas organizations – Canada-wide) and geography (energy companies operating solely in Ontario). Once established, Towers Watson's proprietary benefits valuation tool (BENVAL®) was used to provide a consistent valuation of the Toronto Hydro's benefits compared to those offered by other peer group organizations.

Details for each peer group are presented in the Appendix to this report.

Observations and findings

Compensation and benefits at Toronto Hydro are closely aligned to mid-market (median) rates across all peer groups.

Compensation

In most instances, and against all comparator groups, Toronto Hydro pay sits within what we would consider a market competitive range of +/-15% of the relevant mid-market data. Competitive positioning does not vary significantly between base pay and total target cash, with target short-term incentive award levels closely aligned to mid-market rates.

Benefits

The value of employer paid benefits is just below the median observed for the peer group. Including, employee contributions, Toronto Hydro sits just above the market median. This position is due to higher than typical employee pension contributions.

For this analysis, compa-ratios for multiple incumbent positions are based on median incumbent pay.

Our analysis summarized market competitiveness for the following compensation elements:

- Annualized base pay
- Target short-term incentive
- Total target cash ((annualized) base pay plus target short-term incentive award)

When interpreting the findings of the review, it is important to note that our analysis of market competitive pay is based on the data available to us. The findings presented in this report do not constitute a recommendation of pay for any particular individual. In our experience, pay levels of up to 15% either side of the mid-market data can be considered to be “market competitive”. This is, of course, dependent on a number of factors, including an individual’s experience, time in job and level of performance. We would normally expect companies to apply judgement in reaching individual pay decisions.

Benefits benchmarking and analysis

Benefits benchmarking was completed through Towers Watson’s proprietary benefits valuation tool (BENVAL®) which provides a consistent valuation of the Toronto Hydro’s benefits compared to those offered by other peer group organizations on a named basis. “Core” benefits covered in our review include pension, savings, disability, health (active and retiree), dental (active and retiree), life insurance (active and retiree), vacation and holidays.

BENVAL® analysis shows the competitiveness of the value of existing benefits programs by plan and in aggregate. The methodology has been tested and refined over the years to ensure a true “apples to apples” comparison.

The tool is underpinned by a controlled environment in which differences in the reported value of each organization’s benefits plans are exclusively a function of differences in plan provisions. Each organization’s benefits costs are affected by program design, but also by other factors which are not captured in this analysis such as funding decisions, plan experience and demographics.

To develop reported values, benefits are initially analyzed in terms of when they become payable:

- **Benefits payable in the future:** defined benefit pension plans (all ancillary benefits included) and post-retirement, health care and dental care benefits – are valued, in terms of anticipated prospective benefit payments being allocated over the employee’s entire working history (Projected Unit Credit with services prorate method).
- **Benefits potentially payable in the current year:** defined contribution pension plans, savings plans, pre-retirement death, health care and dental care benefits, disability benefits and vacations and holidays – are valued based on the probabilities of the various events occurring within the year, multiplied by the value of the benefit (Term Cost Method).

The employer-provided value of benefits is determined by deducting employee contributions from the total value of benefits provided. Each plan is valued under the same actuarial valuation method using a common set of actuarial assumptions and consistent employee population assumptions.

Compensation review findings

The tables below illustrate Toronto Hydro's position to market at an aggregate level for each grade in the organization. Data presented reflects mid-market (median) values.

Incumbent data has been aggregated to illustrate median for:

- Annualized base pay:
  - For hourly rate employees, annualized base pay is calculated taking hourly rate x 2080 hours
  - For weekly rate employees, annualized base pay is calculated taking weekly rate x 52 weeks
- Target short-term incentive (STI target %, expressed as a percentage of base pay), and
- Total target cash compensation (TTC ((annualized) base pay plus target short-term incentive)).

Competitive data for each compensation element are reported when median statistics are provided for positions with at least four participant matches. Average statistics are provided for positions with at least three participant matches.

As described in the methodology section of the report, compa-ratio analysis is presented for each of Toronto Hydro's current grades. All roles falling above or below 15% of the market median have been highlighted in red to highlight what Towers Watson considers to be a material variance from the market.

Aggregate Market Results by Grade: *Grades Y3 to V3*

				Towers Watson: 2013 Compensation Data (000s)												Hay Group: 2013 Compensation Data (000s)		
Toronto Hydro Compensation Data by Grade				Energy – Named Peer Group			Energy – Whole sample			General Industry – Named Peer Group			General Industry – Whole Sample			Utilities Peer Group		
Grade	Base Pay	Target STI	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC
Y3	$152.5	25%	$190.6	$166	24%	$192	$145	21%	$175	$166	24%	$182	$113	15%	$130	$130	---	$147
				-8%	---	-1%	6%	---	9%	-8%	---	5%	35%	---	47%	17%	---	30%
Y2	$128.2	15%	$147.4	---	---	---	$132	20%	$161	$133	16%	$150	$105	13%	$119	$121	---	$135
				---	---	---	-3%	---	-8%	-4%	---	-2%	22%	---	24%	6%	---	10%
X1	$136.0	12%	$152.3	---	---	---	$129	18%	$153	$142	16%	$163	$129	18%	$148	$118	---	$130
				---	---	---	5%	---	0%	-4%	---	-7%	5%	---	3%	15%	---	17%
W4	$108.1	10%	$118.9	---	---	---	$107	11%	$120	$104	14%	$117	$140	20%	$158	$108	---	$119
				---	---	---	1%	---	-1%	4%	---	2%	-23%	---	-24%	0%	---	0%
W3	$104.3	10%	$114.7	---	---	---	$106	13%	$123	$107	13%	$118	$121	18%	$137	$95	---	$100
				---	---	---	-2%	---	-6%	-3%	---	-3%	-13%	---	-16%	10%	---	15%
W2	$98.3	8%	$106.2	---	---	---	$71	10%	$75	$84	10%	$90	$85	12%	$94	$91	---	$94
				---	---	---	38%	---	42%	17%	---	18%	16%	---	13%	8%	---	13%
V4	$109.2	8%	$118.0	---	---	---	$103	10%	$113	---	---	---	$80	12%	$90	$100	---	$108
				---	---	---	6%	---	4%	---	---	---	37%	---	31%	9%	---	9%
V3	$100.0	8%	$108.0	$99	---	$109	$88	10%	$96	$94	10%	$100	$72	10%	$76	$85	---	$89
				1%	---	-1%	14%	---	12%	6%	---	9%	39%	---	42%	18%	---	22%

Aggregate Market Results by Grade: Grades V2 to CUPE

Toronto Hydro Compensation Data by Grade				Towers Watson: 2013 Compensation Data (000s)												Hay Group: 2013 Compensation Data (000s)		
				Energy – Named Peer Group			Energy – Whole sample			General Industry – Named Peer Group			General Industry – Whole Sample			Utilities Peer Group		
Grade	Base Pay	Target STI	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC	Base Pay	Target STI %	TTC
V2	$85.2	8%	$92.1	$96	---	$105	$84	10%	$94	$81	10%	$88	$63	9%	$68	$84	---	$88
				-11%	---	-12%	2%	---	-2%	6%	---	5%	35%	---	36%	1%	---	5%
V1	$85.7	8%	$92.6	---	---	---	---	---	---	---	---	---	$61	8%	$66	$75	---	$76
				---	---	---	---	---	---	---	---	---	41%	---	40%	15%	---	21%
U3	$64.8	6%	$68.7	$81	10%	$89	$74	10%	$80	$73	10%	$79	$60	10%	$63	$73	---	$72
				-20%	---	-23%	-12%	---	-14%	-11%	---	-13%	8%	---	9%	-11%	---	-4%
U2	$64.6	6%	$68.4	---	---	---	$64	8%	$69	$65	8%	$69	$53	7%	$55	$73	---	$72
				---	---	---	1%	---	-1%	-1%	---	-1%	22%	---	24%	-11%	---	-4%
U1	$64.7	6%	$68.6	---	---	---	$62	0%	$64	$66	8%	$73	$58	8%	$61	$69	---	$71
				---	---	---	4%	---	7%	-2%	---	-6%	13%	---	13%	-7%	---	-3%
T2	$58.7	6%	$62.2	---	---	---	---	---	---	---	---	---	$45	6%	$48	$64	---	$65
				---	---	---	---	---	---	---	---	---	30%	---	30%	-8%	---	-4%
T1	$48.3	6%	$51.2	---	---	---	$48	6%	$50	$50	7%	$53	$40	7%	$41	$66	---	$66
				---	---	---	2%	---	3%	-3%	---	-3%	22%	---	25%	-27%	---	-23%
SOCIETY	$101.4	8%	$109.5	$94	10%	$95	$94	12%	$111	$90	10%	$95	$79	10%	$84	$91	---	$94
				8%	---	15%	8%	---	-1%	13%	---	15%	28%	---	30%	12%	---	16%
CUPE	$86.3	0%	$86.3	$95	---	$94	$73	6%	$76	$56	4%	$59	$54	7%	$57	---	---	---
				-9%	---	-8%	18%	---	14%	54%	---	47%	61%	---	53%	---	---	---

Observations

With the exception of a minority of grades (see below for more detail), Toronto Hydro pay is closely aligned to mid-market rates across all peer groups. Following the peer group selection criteria, it is Towers Watson's view that the energy peer groups (Towers Watson and Hay Group) and the named general industry peer group were of most relevance since they represent the companies that Toronto Hydro is most likely to recruit individuals from and lose employees to. For this reason, we advise that the whole sample general industry peer group is only reviewed in instances where there is very limited or no peer group data.

Target total cash (TTC)

Data was very limited for Towers Watson's named company energy peer group. However, where data was available, Toronto Hydro TTC levels were broadly aligned to market. The one exception is grade "U3" which, at an aggregate level, was behind market by 23%.

Toronto Hydro TTC levels were equally well aligned to Towers Watson's whole sample energy peer group. With the exception of grade "W2" which was 42% ahead of the market, all grades were positioned within the market competitive range of +/-15% of mid-market rates. Although at face value "W2" pay levels appear anomalous we understand that this is a result of compression within the bargaining unit.

Appendix 2: In-Scope Jobs

"In-scope" jobs (those included within the scope of the review) were carefully selected in order to provide representative coverage of Toronto Hydro's employee population. Although no single job or group of jobs have been deliberately excluded from the scope of the review, Toronto Hydro acted on the advice of Towers Watson in ensuring that in-scope jobs did not disproportionally focus on single incumbent positions (this would weaken the extent to which the review of findings are representative of the whole organization) or include positions that are unique to Toronto Hydro and that do not have external data availability.

To guide the selection of in-scope jobs, Toronto Hydro followed Towers Watson's advice to include:

- Both corporate and operational positions
- Management, unionized, and individual contributor jobs
- Multiple incumbent jobs (i.e., single jobs that cover a population of 5 or more employees)
- Positions at each level in the organization
- Jobs across multiple functions to ensure no functional bias

It is Towers Watson's view that the in-scope jobs listed below provide an accurate reflection of the broader compensation and benefits picture at Toronto Hydro. They represent a group of driver positions and cover 66% of Toronto Hydro's employee population which is well within the range (50%-75%) that we typically encourage our clients to strive for.

In scope positions are listed below:

#	Title	Current Grade	#	Title	Current Grade
1	Director, Employee/Labour Relations	Y3	21	Supervisor, Project Planning	W4
2	Director, Strategy & Enterprise Risk Management	Y3	22	Supervisor, Facilities	W3
3	Director, Power System Services	Y3	23	Supervisor, Supply Chain Services	W3
4	Controller	Y3	24	Supervisor, Construction & Maintenance	W3
5	Director, Program Support Office	Y3	25	Supervisor Program Management Office	W3
6	Director, IT Security, Architecture & Infrastructure Operations	Y3	26	Supervisor, Design	W3
7	Director, Environmental Health & Safety	Y3	27	Supervisor, Call Centre	W2
8	Director, Legal Services & Corporate Secretary	Y3	28	Architect, Database & Integration	V4
9	Director, Rates & Regulatory Affairs	Y3	29	Enterprise Project Management Consultant	V3
10	Director, Internal Audit	Y3	30	IT Technical Consultant	V3
11	Manager, Call Centre	Y2	31	Senior Financial Analyst	V3
12	Manager, Talent Acquisition	Y2	32	Employee Labour Relations Consultant	V3
13	Manager, Rates	Y2	33	Safety & Environmental Consultant	V3
14	Manager, Finance Operations	Y2	34	Senior Internal Auditor	V3
15	Manager, Project Management	Y2	35	Strategic Planning Consultant	V3
16	Senior Litigation Counsel	X1	36	Solicitor, Commercial	V3
17	Lead, Regulatory Counsel	X1	37	Regulatory Counsel	V3
18	Lead, Corporate Applications	W4	38	Program Management Consultant	V2
19	Lead, Legal Services, Commercial	W4	39	Communications Consultant	V2
20	Lead, Project Management	W4	40	Financial Analyst	V2

In scope roles continued…

#	Title	Current Grade
41	Talent Acquisition Consultant	V2
42	Claims Investigation Specialist	V1
43	Quality Assurance Associate	U3
44	Research Analyst	U3
45	Environmental Health & Safety Associate	U3
46	Payroll Analyst	U2
47	Staffing Associate	U2
48	Enterprise Risk Management & Policy Administration Analyst	U2
49	Executive Assistant	U1
50	Marketing Coordinator	U1
51	Service Requisition & ID Security Coordinator	U1
52	Desk Side Support	U1
53	Claims Administrator	T2
54	Organizational Development Administrator	T1
55	Administrative Assistant	T1
56	Engineer	SOCIETY
57	Senior Office Clerk 1	CUPE
58	Certified Meter Mechanic / Tester	CUPE
59	Certified Power Cable Person	CUPE
60	Crew Leader, Certified Power Cable	CUPE

#	Title	Current Grade
61	Customer Service Representative	CUPE
62	Distribution System Technologist	CUPE
63	Engineering Technologist Level 1	CUPE
64	Engineering Technologist Level 2	CUPE
65	Power System Controller	CUPE

and cost effective manner while preserving management's rights to manage and direct the workforce. For example, the most recent round of bargaining that the utility engaged in with CUPE resulted in a variety of changes aimed at improving efficiency and productivity and reducing costs in both the short and long term, including agreeing to a modest 1.75% average wage increase over four years and significant cost containment with respect to post-retirement benefits.

Toronto Hydro bargains with the focus of achieving the best outcomes with its customers in mind. For example, in the most recent round of bargaining with CUPE, Toronto Hydro introduced provisions that allow for work to be performed outside of the traditional scheduled hours of work. This change improves Toronto Hydro's ability to serve its customers, to respond to trouble calls more efficiently, and to accommodate the realities of operating in large and dynamic urban environment.

The utility continually reviews external compensation data to understand the compensation landscape both at the time of negotiation, as well as in the years preceding and following bargaining. In doing so, the utility monitors bargaining trends and reviews past settlements. In preparation for the most recent round bargaining with CUPE, the utility also undertook a compensation study by an independent third party, Towers Watson. To review the results of this study, refer to report filed at Exhibit 4A, Tab 4, Schedule 6.

4.1. CUPE Collective Agreement

The current collective agreement with CUPE was signed on February 13, 2014 and is valid until January 31, 2018. The table below (Table 3) summarizes the year over year percentage increases in base salary under the previous and current collective agreement.

Table 3: CUPE Base Salary Increases (2011 – 2017)

2011	2012	2013	2014*	2015	2016	2017
3.0%	3.0%	3.0%	1.5%	1.75%	1.75%	2.0%

*New collective agreement effective February 1, 2014 until January 31, 2018.

In negotiating the modest wage rate increases illustrated above, Toronto Hydro considered: 1) the OEB's 4th Generation IRM inflation parameters[5], which were released in November 2013; and 2) the Towers Watson compensation benchmarking study (Exhibit 4A, Tab 4, Schedule 6), which found that CUPE positions were somewhat ahead of the market. Based on these key considerations, Toronto Hydro's bargaining position was that the year over year increases had to stay relatively close to inflation in order to maintain alignment with the competitive market.

4.2. Society Collective Agreement

The current Collective Agreement with the Society was ratified on April 12, 2012 and is valid until December 31, 2015. The table below (Table 4) summarizes the year over year base salary percentage increases for Society employees.

Table 4: Society Base Salary Increases (2011-2015)

2011	2012	2013	2014	2015
2.75%	1.5%	1.75%	2.0%	2.0%

Toronto Hydro's objectives during the 2012 negotiations with the Society – all of which were achieved, were to:

(1) obtain stability through a long term agreement,
(2) control current and future costs through modest wage rate increases, and
(3) resist any changes that would limit or restrict management's right to manage and direct the workforce.

[5] EB-2010-0379 Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors (Issued November 21, 2013 and corrected on December 4, 2013).

	2011 Actuals	2012 Actuals	2013 Actuals	2014 BRIDGE	2015 TEST
Number of Employees (FTEs including Part-Time)[1]					
Executive	9.2	7.4	8.0	6.3	6.0
Management (excluding Executive)	52.7	45.6	47.2	48.2	49.0
Non-Management (Non-Union)	462.4	442.9	458.5	509.3	533.5
Non-Management (Union)	1,212.8	1,104.9	1,013.7	972.8	975.0
Total	1,737.0	1,600.8	1,527.4	1,536.6	1,563.5
Total Salary and Wages (including overtime and incentive pay					
Executive	$ 2,840,668	$ 2,554,144	$ 2,661,984	$ 2,469,509	$ 2,424,089
Management (excluding Executive)	$ 8,663,257	$ 7,930,713	$ 8,254,968	$ 8,888,300	$ 9,252,273
Non-Management (Non-Union)	$ 48,004,982	$ 47,222,946	$ 48,661,644	$ 54,545,454	$ 58,152,615
Non-Management (Union)	$ 117,596,782	$ 102,500,089	$ 99,308,906	$ 97,986,475	$ 99,602,175
Total	$ 177,105,689	$ 160,207,891	$ 158,887,502	$ 163,889,738	$ 169,431,152
Total Benefits (Current + Accrued)					
Executive	$ 972,941	$ 719,048	$ 752,393	$ 700,663	$ 651,611
Management (excluding Executive)	$ 2,727,764	$ 2,488,349	$ 2,744,978	$ 2,921,727	$ 2,934,914
Non-Management (Non-Union)	$ 15,372,984	$ 15,506,703	$ 17,144,667	$ 18,400,258	$ 18,485,032
Non-Management (Union)	$ 38,398,376	$ 36,651,732	$ 37,288,451	$ 34,651,697	$ 33,794,760
Total	$ 57,472,066	$ 55,365,832	$ 57,930,489	$ 56,674,344	$ 55,866,316
Total Compensation (Salary, Wages, & Benefits)					
Executive	$ 3,813,609	$ 3,273,192	$ 3,414,377	$ 3,170,172	$ 3,075,700
Management (excluding Executive)	$ 11,391,021	$ 10,419,062	$ 10,999,947	$ 11,810,027	$ 12,187,187
Non-Management (Non-Union)	$ 63,377,966	$ 62,729,649	$ 65,806,311	$ 72,945,712	$ 76,637,647
Non-Management (Union)	$ 155,995,158	$ 139,151,820	$ 136,597,357	$ 132,638,172	$ 133,396,935
Total	$ 234,577,755	$ 215,573,723	$ 216,817,992	$ 220,564,082	$ 225,297,468

4. RRFE Compliance

1. Given the utility's significant multi-year capital need, Custom IR is the only appropriate rate-setting option for Toronto Hydro.

- As previously described in the Capital portion of the Argument in Chief (Tab 2), Toronto Hydro's Distribution System Plan establishes the need for a significant five-year capital commitment to renew aging assets to address growing asset failure, connect customers, and meet ongoing operational needs.
  - While the utility expects to see shifts in spending between categories and programs from year-to-year to accommodate operational realities and emerging issues, there is a high degree of certainty of timing and associated expenditures across the five-year plan because of Toronto Hydro's demonstrated overall system investment needs. [1]
- Ultimately, due to the nature, magnitude and consistent level of Toronto Hydro's capital needs, only the Custom IR approach offers a suitable rate-setting mechanism under the Renewed Regulatory Framework for Electricity (RRFE).[2]
  - The OEB has indicated that one of the key considerations in developing the regulatory options within the RRFE is the need to better accommodate "differing circumstances of distributors," including, for example, differing "asset profile and investment needs."[3]
- The OEB also indicated that Custom IR would be appropriate for distributors with "significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures."[4]

2. Toronto Hydro's Custom IR application complies with the OEB's policy guidance and direction under the RRFE.

- Toronto Hydro's approach to this application was to adopt the OEB's policy and standard approaches wherever possible, and to only depart – i.e. customize – where required in order to meet the RRFE objectives.
  - The custom approach is driven by the level of capital investment that the utility needs to maintain its system and serve its customers in accordance with good utility practice.

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[1] Exhibit 1B, Tab 2, Schedule 4 at page 1.
[2] Exhibit 1B, Tab 2, Schedule 4 at pages 14 -15; OH Transcript, Volume 9 (March 3, 2015) at page 29, lines 7-19.
[3] Ontario Energy Board, Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (October 18, 2012) [*RRFE Report*] at page 8.
[4] RRFE Report at page 14.

- Toronto Hydro closely followed the OEB's guidance under the RRFE in preparing the form and content of this application. [5]
    - Toronto Hydro applied the tenets of the RRFE throughout its application: this includes the form of the application and rate-setting approach, productivity and benchmarking evidence, and customer engagement activities.
    - Toronto Hydro followed Chapters 2 and 5 of the OEB's Filing Requirements throughout this application: this includes the form and content of the Distribution System Plan, and the form and content of its OM&A evidence.[6]
- The proposed rate-setting framework is closely aligned with the OEB's 4th Generation IRM framework, and includes customized elements that accord with the OEB's guidance to CIR applicants.[7]
    - Standard elements:
        - Standard rebasing in Year 1
        - Price Cap Index for years 2 to 5 of the plan, using the OEB's inflation and productivity factors
        - Rate treatment for OM&A and Revenue Offsets
        - Z-factor treatment, approach to Deferral and Variance Accounts.[8]
    - Custom elements:
        - Proposed Custom Capital ("C") factor in years 2 to 5 of the plan, which
            - reconciles Toronto Hydro's capital need within a price cap index on the basis of forecast capital-related revenue requirement, and
            - reflects productivity and efficiency gains achieved through (i) the competitive procurement process that determines 81% of Toronto Hydro's capital costs, (ii) various modes of constraining internal costs which account for approximately 19 percent of capital costs.[9]

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[5] Exhibit 1B, Tab 2, Schedule 2 at pages 1-5.
[6] Filing Requirements for Electricity Distribution Rate Applications, Chapters 2 and 5 (July 17, 2013) [*Filing Requirements*].
[7] Exhibit 1B, Tab 2, Schedule 3 at pages 1-4.
[8] Exhibit 1B, Tab 1, Schedule 3 at page 3, lines 24-27; at page 17, lines 16-18
[9] Refer to Tab 2, Section 4.2 of the Argument in Chief Compendium.

    - A stretch factor in years 2 to 5 consistent with the OEB's methodology and established on the basis of Power System Engineering's (PSE) total cost benchmarking results.

- Toronto Hydro responded to the OEB's expectation that Custom IR applicants provide evidence to enable a rigorous assessment of adequacy of the utility's past and future productivity levels. Consistent with the RRFE guidance, the evidence filed by Toronto Hydro includes:

  - a review of the utility's past productivity achievements,[10]

  - a Total Cost and Reliability Econometric Benchmarking study,[11]

  - examples of current and anticipated productivity/efficiency plans and initiatives for all major functional areas, as well as the utility's corporate culture of productivity;[12] and

  - a benchmarking study undertaken by UMS to assess Toronto Hydro's productivity across all of its major functions against utilities in Canada and the US.[13]

- In recognition of the OEB's focus on performance measure and continuous improvement, Toronto Hydro's application includes a framework of 12 capital performance measures that the utility proposes to track and report on over the 2015-2019 timeframe.[14]

  - The proposed performance measurement framework addresses all three OEB-mandated categories (i.e. customer oriented performance, cost efficiency and effectiveness with respect to planning and implementation, and asset/system operations performance) and includes a number of innovative measures.[15]

    - Particularly, a subset of the measures will track Toronto Hydro's efficiency with respect to capital costs that are not determined by the competitive market.

- Toronto Hydro engaged with its customers regarding the utility's capital plans.

  - The application details the customer engagement work that the utility undertakes in the ordinary course,[16] and the customer engagement work undertaken by its consultant, Innovative Research Group, on the Distribution System Plan.[17]

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[10] Exhibit 1B, Tab 2, Schedule 5, Appendix A at page 5.
[11] Exhibit 1B, Tab 2, Schedule 5, Appendix B at pages 1-7.
[12] Exhibit 1B, Tab 2, Schedule 5 at pages 12, 17-18.
[13] IR Response 1B-SEC-8, Appendix A.
[14] Exhibit 2B, Section C1.1 at page 3.
[15] Filing Requirements, Chapter 5 at section 5.2.3.
[16] Exhibit 1B, Tab 2, Schedule 7 at pages 1-12.
[17] Exhibit 1B, Tab 2, Schedule 7, Appendix B at pages 7-8.

- The evidence filed by Toronto Hydro conforms with the OEB's Filing Requirements.
  - Toronto Hydro filed a stand-alone integrated Distribution System Plan, in accordance with the OEB's Chapter 5 Filing Requirements.
    - The Distribution System Plan evidence begins with a comprehensive discussion of the utility's asset management philosophy, the planning process, and the quantitative tools that underpin Toronto Hydro's capital program.
    - The specific capital investments proposed are first organized into the four investment categories prescribed in the Filing Requirements: System Renewal, System Access, System Service and General Plant. [18]
    - Within each of the four categories the proposed work is presented in discrete capital program-based business cases.
  - Toronto Hydro presented its OM&A evidence on a program basis in accordance with the OEB's Chapter 2 Filing Requirements.
    - The OM&A costs are shown for 19 discrete programs, each comprised of several activity-based segments.
    - The evidence discusses the nature of expenditures, the underlying cost drivers and the current and planned activities aimed at efficiency, productivity or improvements in service quality.[19]

3. Toronto Hydro's econometric benchmarking supports the reasonableness of the proposed investments.

- Consistent with the OEB's increasing focus on productivity and performance evaluation,[20] Toronto Hydro's application features a comprehensive total cost and reliability benchmarking study prepared by PSE, a recognized expert in the field of utility performance measurement.[21]
- PSE's total cost benchmarking study is grounded in the OEB's own benchmarking approach and methods. It uses an econometric approach based on sophisticated translogarithmic (translog) modelling that is equivalent to the OEB's approach in the way it determines expected efficient cost levels for a utility with Toronto Hydro's business conditions.[22]

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[18] Exhibit 2B Section 00 at page 26, Table 3.
[19] Exhibit 4A, Tab 1, Schedule 1 at page 4, Table 1.
[20] RRFE Report at page 13.
[21] Exhibit 1B, Tab 2, Schedule 5, Appendix B.
[22] OH Transcript, Volume 2 (February 19, 2015) at pages 10-29; Exhibit 1B, Tab 2, Schedule 5, Appendix B at pages 11, 36, 40; Exhibit 1B, Tab 2, Schedule 5, Appendix C at pages 4-6, 11, 15.

- The study's combined sample includes 73 Ontario and 85 U.S. utilities. In doing so, the model captures the effects of operating in Ontario's economic and regulatory environment as well as other important business conditions Toronto Hydro shares with dense, large, and mature urban utilities.[23]

- The results of the PSE total cost benchmarking study demonstrate the reasonableness of the utility's past and projected cost levels by demonstrating that they are within +/- 10% of the benchmark. This evidence empirically supports the assignment of the middle (0.3%) stretch factor.[24]

- The PSE study provides empirical confirmation, at a 99% confidence level, that serving a dense urban core is a major cost driver that distinguishes Toronto Hydro from other Ontario distributors, appropriately placing it into the same cohort as major North American urban centres like New York and Chicago.[25]

- The study's derivation of future benchmark costs is based on comprehensive methodology and assumptions that reflect econometric research best practices.[26]

- Even following conservative cost definition adjustments, like adding over $50 million in annual CDM expenditures to Toronto Hydro's costs, the utility's benchmarking results over the 2015-2019 timeframe remain within the range of the OEB's middle efficiency cohort.[27]

- While Toronto Hydro's application is based on the comprehensive discussion of the capital and OM&A spending plans over the 2015-2019 period, the results of the PSE study provide a strong empirical data point regarding the utility's relative efficiency.

- Supplementing PSE's total cost benchmarking study is its econometric reliability study. Toronto Hydro recognizes that this is the first such study filed by an electric utility in Ontario, and commissioned it because the utility believed it could be useful to the Board.[28]

    - The study confirms Toronto Hydro's strong record on average interruption duration, indicative of robust operating procedures and highly skilled system response crews.

    - At the same time, and consistent with Toronto Hydro's aging distribution plant, the frequency of outages experienced its customers is significantly higher than would be expected based on the modelling. The capital program is expected to help the utility improve its performance relative to the benchmark in the latter years of the CIR period.

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[23] Exhibit 1B, Tab 2, Schedule 5, Appendix B at pages 3-4.
[24] Exhibit 1B, Tab 2, Schedule 5, Appendix C at pages 11, 15.
[25] Exhibit 1B, Tab 2, Schedule 5, Appendix C at page 6.
[26] OH Undertaking Response J2.9 at pages 1-9.
[27] Exhibit 1B, Tab 2, Schedule 5, Appendix C at page 11, Table 2.
[28] Exhibit 1B, Tab 2, Schedule 5, Appendix B at pages 11-12.

4. Toronto Hydro considers customer needs and preferences as matter of course, and specifically engaged its customers regarding the proposed Distribution System Plan. Through the latter exercise, the utility found that a majority of its customers accept the need for the proposed capital plan.

- Toronto Hydro's application details the customer engagement work that the company undertakes in the ordinary course of its business.[29]
  - These efforts include regular contact with residential and small business customers around issues such as billing, service requests, conservation and demand management, and local capital projects.
  - For commercial customers, Toronto Hydro is active in presenting to trade and industry associations.
  - Finally, for the large volume commercial and institutional customers that are covered by the "key accounts" program, engagement includes periodic visits aimed at understanding these customer's need and issues. For key accounts, Toronto Hydro prioritizes its contacts to meet with customers who face significant reliability or service quality issues.[30]
- Toronto Hydro's customer engagement evidence also includes a report and supporting materials from Innovative Research Group discussing customer engagement on the proposed Distribution System Plan.[31]
  - This engagement took multiple forms including a comprehensive workbook, focus groups, a voluntary on-line survey and a statistically valid telephone survey of residential and small volume commercial customer.
  - The bottom line, as determined through the statistical telephone survey, is that customers surveyed in Toronto Hydro's most populous rate classes – the residential and small business classes – gave qualified acceptance to the proposed plan at the proposed bill increases.[32] While few welcome an electricity price increase, Toronto Hydro's customers ultimately felt that the proposed increases were necessary.[33] The results of the customer engagement exercise confirm that Toronto Hydro has struck a reasonable balance that is aligned to customer needs and preferences.

[29] Exhibit 1B, Tab 2, Schedule 7 at pages 1-12.
[30] OH Transcript, Volume 9 (March 3, 2015) at pages 113-116
[31] Exhibit 1B, Tab 2, Schedule 7, Appendix B.
[32] Exhibit 1B, Tab 2, Schedule 7, Appendix B, at page 108.
[33] OH Transcript, Volume 9, (March 3, 2015) at pages 88, 100-102, 130; Exhibit 1B, Tab 2, Schedule 7, Appendix B at pages 10-11.

ALIGNMENT WITH OEB GUIDANCE

1. OVERVIEW

The purpose of this schedule is to describe how Toronto Hydro's 2015-2019 Custom Incentive Rate-Setting ("Custom IR" or "CIR") application aligns with the Ontario Energy Board's ("OEB") guidance contained within the Renewed Regulatory Framework for Electricity Distributors, and the Filing Requirements (together, "OEB Guidance").

Specifically, in preparing this application, Toronto Hydro has considered the tenets of the Report of the Board "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" issued October 18, 2012 (the "RRFE Report"), as well as Chapters 2 and 5 of the OEB's Filing Requirements for Electricity Distribution Rate applications issued July 17, 2013 (the "Filing Requirements").

Toronto Hydro has applied this approach understanding that aside from Chapter 5 of the Filing Requirements, there are no specific filing requirements for the CIR applicants. However, and as discussed in more detail below, Toronto Hydro's view is that the RRFE Report clearly conveys a number of key policy and mechanistic/administrative components of the OEB's expectations for CIR applications. These include the form of the rate-setting mechanism, areas of focus for the enquiry, and the scope and nature of evidence filed in support of the applications.

Toronto Hydro's view is that, in addition to substantive reasons to follow OEB Guidance, doing so also aids in the utility's application being accessible and digestible to the OEB, intervenors and the public. In particular, Toronto Hydro's Custom IR application aligns with OEB Guidance as follows:

1) The mechanism of the CIR Rate-Setting Framework;
2) The scope and nature of productivity evidence, including benchmarking;

3) Capital planning and implementation performance measures;
4) Evidence of customer engagement on the proposed capital investments;
5) A Distribution System Plan ("DSP") that conforms to Chapter 5 of Filing Requirements;
6) A program-based presentation of the Operations, Maintenance & Administration ("OM&A") expenditures; and
7) General adherence to Chapter 2 of the Filing Requirements.

Table 1 below provides a brief overview of these seven aspects.

Table 1: OEB Guidance Addressed in Toronto Hydro's 2015-2019 CIR Application

	OEB Guidance	Toronto Hydro's 2015-2019 CIR Application	Evidence Reference
1	A Custom Index rate-setting model, incorporating benefit-sharing through a Productivity Factor and a Stretch Factor, using the OEB's Inflation and Productivity analysis.[3]	OEB Guidance Addressed. The Application is based on a Custom Index rate-setting approach, incorporating the elements of the OEB's PCI framework, and the results of the OEB's inflation and productivity analysis.	Exhibit 1B, Tab 2, Schedule 3. Exhibit 1B, Tab 2, Schedule 5.
2	CIR productivity evidence should enable a sufficiently rigorous assessment of adequacy of the past and future productivity levels.[4] CIR applicants are expected to provide benchmarking evidence in support of reasonableness of their cost forecasts.[5]	OEB Guidance Addressed. The application includes a review of the utility's past productivity achievements, a Custom Total Cost and Reliability Econometric Benchmarking study, along with specific examples of current and anticipated productivity/efficiency initiatives and the utility's	Exhibit 1B, Tab 2, Schedule 5, and Appendices.

[3] RRFE Report at page 13.
[4] RRFE Report at page 70.
[5] RRFE Report at page 13, Table 1.

	OEB Guidance	Toronto Hydro's 2015-2019 CIR Application	Evidence Reference
		corporate culture of productivity.	
3	DSP filings must be supported by Performance Measures covering Customer-Oriented Performance, Cost Efficiency / Effectiveness of Planning and Implementation, and Asset / System Performance.[6]	OEB Guidance Addressed. Toronto Hydro's DSP includes 12 capital performance measures that the utility proposes to track and report on over the CIR timeframe. The measures address all three specific OEB-mandated categories.	Exhibit 2B, Section C.
4	Applications must showcase the applicants' efforts to engage their customers on their capital plans and planning processes.[7]	OEB Guidance Addressed. Toronto Hydro's application details the steps taken by the utility to engage its customers on the proposed DSP, along with the results of these engagements.	Exhibit 1B, Tab 2 Schedule 7
5	CIR applicants are required to file a DSP as specified in Chapter 5 of the OEB's Filing Requirements.[8]	OEB Guidance Addressed. Toronto Hydro's DSP has been prepared according to the Chapter 5 requirements.	Exhibit 2B and Appendices.
6	Applicants should showcase their year over year variance analyses based on their OM&A programs.[9]	OEB Guidance Addressed. Toronto Hydro Historical, Bridge and Test Year OM&A expenditures are presented on a	Exhibit 4A.

[6] Filing Requirements, Chapter 5 at page 11, section 5.2.3.
[7] Filing Requirements, Chapter 5 at page 15, section 5.4.2.
[8] Filing Requirements, Chapter 5 at page 7, section 5.1.3.
[9] Filing Requirements, Chapter 2 at page 27, section 2.7.

	OEB Guidance	Toronto Hydro's 2015-2019 CIR Application	Evidence Reference
		program basis.	
7	The Cost of Service Filing Requirements are relevant for Custom IR filers.[10]	OEB Guidance Addressed. Toronto Hydro's application for the 2015 Test Year is sufficiently compliant with the Chapter 2 Filing Requirements.	Exhibit 1A, Tab 3, Schedule 2 All Exhibits.

The remainder of this schedule discusses each of the above-noted elements of the RRFE guidance and the manner in which Toronto Hydro's 2015-2019 CIR application reflects this guidance in more detail. Toronto Hydro's evidence for the 2015-2019 CIR application addresses each of the above-noted OEB expectations.

2. CIR RATE-SETTING FRAMEWORK

2.1. OEB Expectations

In the RRFE Report, the OEB notes its expectation that the form of the CIR applications is to be that of a "Custom Index", covering Capital and OM&A expenditures, supplemented with a Productivity Factor, and a benefit-sharing mechanism in the form of a Stretch Factor or another construct determined on a case-by-case basis.[12]

The RRFE Report also notes that a distributor's rate trend will be set on the basis of a combination of:

- A distributor's cost, inflation and productivity forecasts;
- The OEB's productivity analysis; and
- Benchmarking to assess the reasonableness of a distributor's forecasts.

[10] RRFE Report at page 70.
[12] RRFE Report at page 13.

RATE FRAMEWORK

This schedule describes the rate framework that Toronto Hydro proposes to apply for the 2015 to 2019 period.

Toronto Hydro submits that the proposed rate framework is:

- Concordant with OEB policy, and in particular with the objectives and guidance set out in the Report of the Board "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" issued on October 8, 2012 (the "RRFE Report");
- Based on sound ratemaking principles; and,
- Expected to provide funding that:
    - Reconciles Toronto Hydro's significant, multi-year investment needs; and,
    - Constrains operational funding increases going forward at less than the rate of inflation.

1. SUMMARY

To better conform to the OEB's Guidance for CIR applicants, Toronto Hydro is proposing a rate framework that is a modification of the standard 4th Generation IR approach.

Year 1 is a traditional rebasing year, with costs allocated and rates set on the basis of a forecast Test Year.

Distribution rates in Years 2 through 5 are adjusted annually by a custom Price Cap Index ("PCI"):

$$\mathbf{PCI = I - X + C}$$

Where,

- "**I**" is the OEB's inflation factor, determined annually
- "**X**" is the sum of:
    - The Board's productivity factor.
    - Toronto Hydro's custom stretch factor.
- "**C**" provides funds incremental to "I – X" that are necessary to reconcile Toronto Hydro's capital need within a PCI framework.

Toronto Hydro submits that the proposed framework is concordant with OEB policy in the following respects:

- The proposed rate framework is comprehensive.
- The proposed rate framework is informed by Toronto Hydro's forecasts.
- The proposed rate framework is informed by the OEB's inflation and productivity analyses.
- The proposed rate framework is informed by benchmarking to assess the reasonableness of the Toronto Hydro's forecasts.
- The proposed rate framework includes a productivity and stretch factor.
- The proposed rate framework covers the entirety of the application's five year term.

In this way, Toronto Hydro is proposing a rate framework that differs from previous CIR filers.

2. YEAR 1: STANDARD REBASING

The first year of the proposed rate application is a standard rebasing year, consistent with the OEB's 4th Generation Incentive Rate-Setting ("4th Generation IR") approach.

Toronto Hydro developed and submitted in this application a forecast of its base revenue requirement for 2015. The utility developed forecasts of its costs based on its capital and operational plans for 2015. The Distribution System Plan ("DSP") and Operations, Maintenance & Administration ("OM&A") evidence contained in Exhibits 2B and 4A, respectively, provides the details supporting these projected costs. The calculated revenue requirement resulting from these projections is detailed in the Revenue Requirement evidence filed at Exhibit 6.

Similarly, Toronto Hydro employed the OEB's Cost Allocation model to allocate the revenue requirement to its eight rate classes and developed base distribution rates for each class. The standard rebasing approach maintains revenue-to-cost ratios for each class within the boundaries set out in the OEB's 2011 Review of Electricity Cost Allocation Policy.[1] For more information about Cost Allocation and Rate Design, please refer to Exhibits 7 and 8, respectively.

In addition to the base distribution rates, Toronto Hydro is applying to clear a number of Deferral and Variance accounts. Based on the values Toronto Hydro proposed for clearance, a number of new rate riders are proposed. These rate riders are proposed to be implemented beginning in 2015, and have various clearance time-frames. For more information about these rate riders, please refer to Exhibit 9, Tab 3.

3. YEARS 2 TO 5: CUSTOM PCI

Under 4th Generation IR, the years following a rebasing year constitute a period where distribution rates are subject to an incentive rate mechanism ("IRM"). The IRM is a formulaic approach to rate making under which distribution rates are adjusted annually using a two-component PCI:

[1] EB-2010-0219

PCI = I – X

The I-factor is intended to reflect changes to the input prices faced by the industry (i.e., inflation), while the X-factor is intended to capture changes in the productivity of the Ontario electricity distribution industry as a whole, and differences between utilities within it.

In the RRFE Report, the OEB offers alternative forms of rate making "to accommodate differences in the operations of distributors, some of which have capital programs that are expected to be significant."[2] The OEB notes that the CIR option in particular "will be most appropriate for distributors with significant large multi-year… investment commitments that exceed historical levels," whereas 4th Generation IR is more suitable for utilities with "some" incremental needs.[3] The evidence at Exhibit 1B, Tab 2, Schedule 4 and the Distribution System Plan at Exhibit 2B discuss Toronto Hydro's capital investment needs and, by extension, the appropriateness of the CIR option in greater detail.

A challenge for CIR applicants like Toronto Hydro is to reconcile their significantly large, multi-year investment commitments within a framework that concords with RRFE guidance. To this end, Toronto Hydro proposes that these needs be reconciled within a custom PCI framework that entrenches the OEB's inflation and productivity factors within a formulaic approach to adjusting distribution rates.

The following subsections discuss the retention of the inflation and productivity factors and the inclusion of the customized elements of the proposed PCI formula.

[2] RRFE Report at page 9.
[3] RRFE Report at page 14.

This report is an update to the original PSE report dated July 31, 2014. This report contains results which incorporate updated cost and customer forecasts provided to PSE from Toronto Hydro.

1 Executive Summary

On October 18, 2012 the Ontario Energy Board ("the Board") released a report entitled "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" ("RRF"). In the RRF, three rate-setting methods were discussed. One of those methods was labeled "custom incentive regulation," or "Custom IR."

On page 18 of the RRF, the Board states that "In the Custom IR method, rates are set based on a five year forecast of a distributor's revenue requirement and sales volumes." The RRF also lays out the use of benchmarking as a key element used to inform the Board of the reasonableness of the revenue forecasts.[1]

In a November 21, 2013 Report of the Board, titled "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors,"[2] ("November 2013 Board Report") the Board clearly indicates its preference for econometric benchmarking over peer group benchmarking. Furthermore, the Board indicates its preference for total cost benchmarking over partial cost benchmarking.[3]

Power System Engineering, Inc. was asked by Toronto Hydro to conduct a benchmarking study of Toronto Hydro's past and projected total cost and reliability performance in reference to the utility's 2015-2019 Custom IR application. Toronto Hydro asked PSE to investigate the possibility of expanding the scope of utility observations in the study beyond Ontario, in order to assess the potential effect of certain business conditions experienced by Toronto Hydro.

1.1 Overview of PSE's Benchmarking Process

In accordance with the RRF and the November 2013 Board Report, Power System Engineering, Inc. ("PSE") conducted econometric total cost benchmarking of Toronto Hydro-Electric System Limited ("Toronto Hydro"). This benchmarking was done as part of Toronto Hydro's Custom IR proposal. In its 2015 Custom IR proposal, Toronto Hydro estimates its projected costs from 2015 to 2019, and its projected reliability metrics from 2015 to 2019. The purpose of PSE's benchmarking analysis is to evaluate the reasonableness of Toronto Hydro's historical and projected total cost amounts and system reliability metrics. This is done by comparing Toronto Hydro's actual or projected values with the benchmarking model's predicted values.[4]

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[1] Found in "Table 1: Rate-Setting Overview – Elements of Three Methods," on page 13 of the RRF.

[2] Case EB-2010-0379.

[3] See page 19 of the November 2013 Board Report.

[4] In this paper we will use "forecasted" or "projected" costs and reliability to refer to Toronto Hydro's estimates of those values in the future, and "predicted" or "expected" or "benchmark" costs and reliability to refer to the

The benchmarking analysis uses historical cost and reliability data from a dataset comprised of multiple utilities to create a model; this model relates cost and reliability to certain variables. The model is then used to predict Toronto Hydro's "expected" (benchmarked) cost and reliability. In past stretch factor research, the Board has used an Ontario-only dataset to create the econometric model. In the present report, PSE augmented the Board's Ontario benchmarking dataset with data from U.S. investor-owned utilities. Thus the general approach of our benchmarking analysis is as follows:

1. PSE assembled the historical costs of all utilities in the dataset, along with the variables that affect cost, such as customer levels, weather, wage levels, density, etc.
2. Using the historical data, PSE estimated an econometric model that expresses the relationship between the variables and cost.
3. For each utility in the sample, we can then produce "benchmark" values. In Toronto Hydro's case, the benchmarks represent the costs we would expect for an average-performing utility with the number of customers, weather, wage levels, density, percent undergrounding, etc. faced by Toronto Hydro.
4. We then compare the costs that are expected (predicted) for Toronto Hydro by the model to Toronto Hydro's historical and projected costs, which allows us to: (1) evaluate the historical performance, and (2) determine whether forecasted costs are reasonable.

We used a similar process to analyze Toronto Hydro's past and future reliability metrics. The general strategy is the same whether using a U.S.-only dataset, or a combined Ontario/U.S. dataset.

1.2 The Need for a Combined U.S./Ontario Dataset

In the November 2013 Board Report, the Board recognized that certain distributors may have "extenuating circumstances" that dictate different treatments.[5] The summary of why different treatment is needed in the present case is that the unique size and urban characteristics of Toronto Hydro's service territory make it an outlier among Ontario distributors. For a suitable benchmarking analysis, using a dataset that includes U.S. utilities is necessary. A brief summary of Toronto Hydro's outlier status appears in this section; further discussion on why PSE believes Toronto Hydro is a candidate for a different treatment in regards to its benchmarking evaluation and stretch factor assignment is found in Section 6.

To see why Toronto Hydro is an outlier, consider that the number of customers served is generally recognized as the leading driver of cost for electric distribution utilities. In terms of customers served, Toronto Hydro is practically without peers in the Ontario industry. Perhaps Hydro One Networks could be considered a peer in terms of sheer number of customers served, yet it has operating circumstances vastly different than those found in the Toronto area. The next

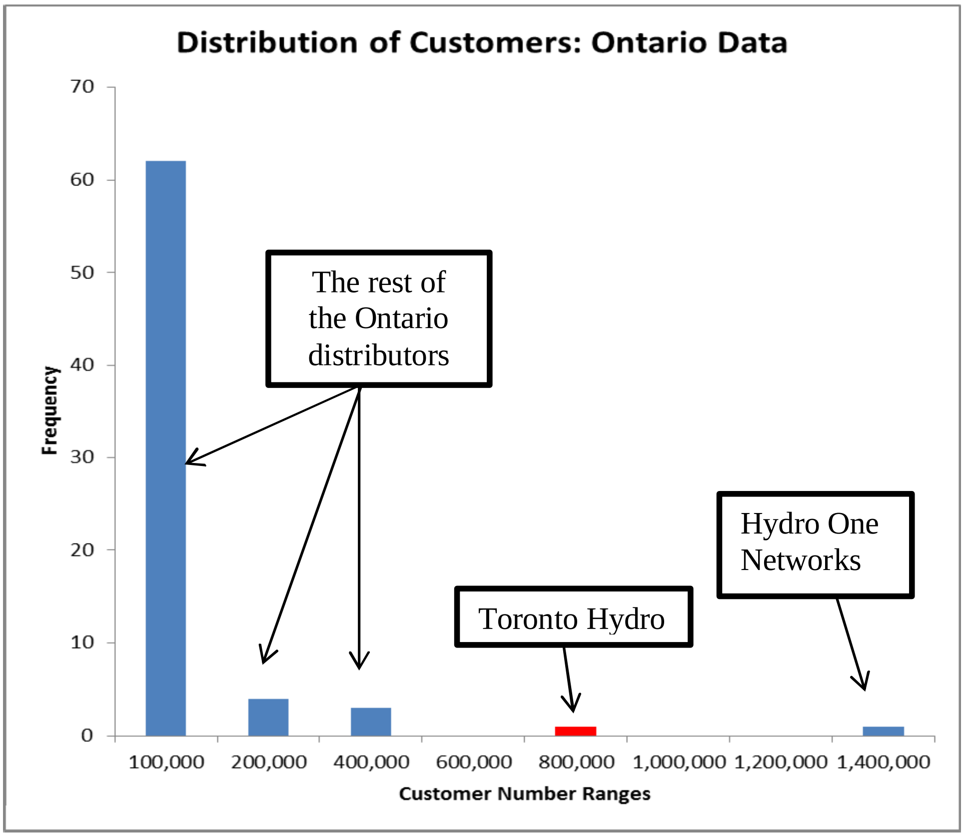
econometric model's outputs for those metrics.

[5] See page 22 of the November 2013 Board Report.

largest distributor in terms of customers served, Powerstream Inc., has fewer than half the number of electric customers of Toronto Hydro.

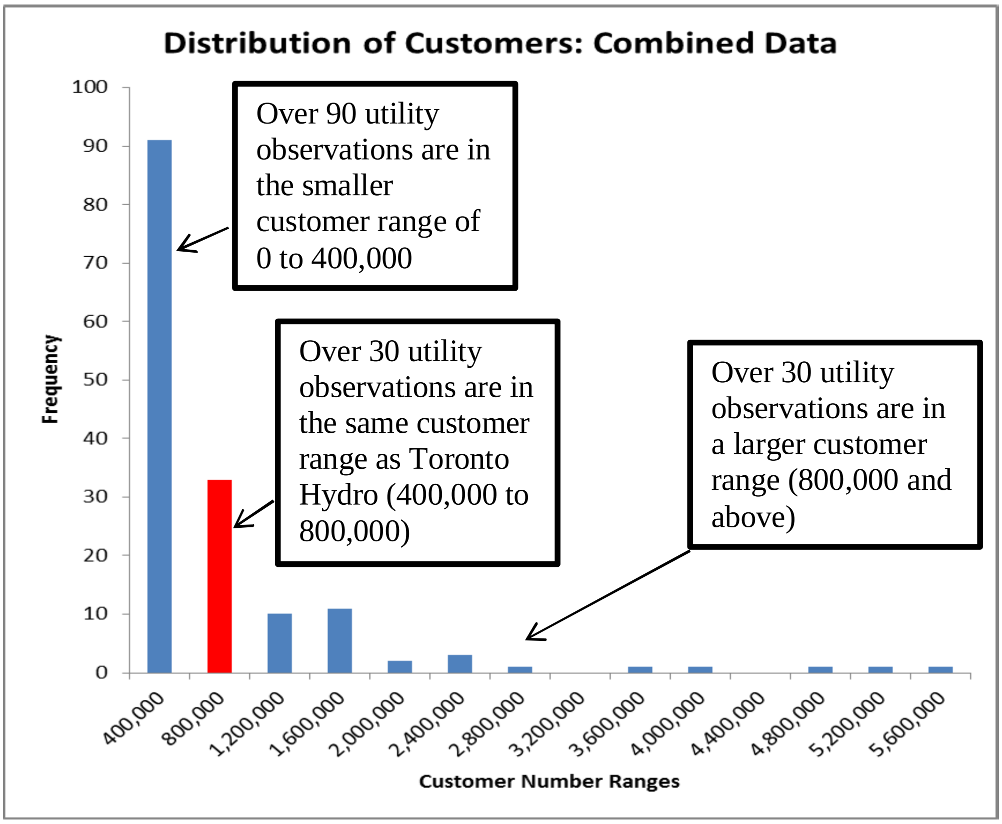
Figure 1 illustrates the vast differences between Toronto Hydro and the rest of the Ontario distributors, in terms of number of customers served. Related to this difference is the fact that Toronto Hydro also serves a large urban core (the Toronto area). Serving a large urban core presents unique cost challenges that are discussed further in another PSE report attached as an Appendix to this report entitled, "Capital Requirements for Serving Developed Environments."

Figure 1 Distribution of Customers: Ontario Dataset



After adding U.S. utilities to the Ontario dataset, Toronto Hydro ceases to be an outlier in terms of the number of customers. Figure 2 illustrates how in the combined Ontario/U.S. dataset, there are many utilities with more customers than Toronto Hydro, and many with fewer. When conducting econometric benchmarking, having a data sample with variable values that encompass those of the studied utility is essential to the accuracy of the exercise.

Figure 2 Distribution of Customers: Combined Dataset



1.3 Total Cost Benchmark Findings

As stated earlier, the RRF requests distributors include benchmarking of revenue forecasts in their Custom IR applications. In the November 2013 Board Report, the Board cites total cost econometric benchmarking as its preferred method for setting stretch factors.

PSE believes the Board's preference for total cost econometric benchmarking is the correct approach when benchmarking cost levels. Total costs are defined as the sum of (1) OM&A expenses, and (2) the depreciation and opportunity costs of capital. This is quite similar to how revenue requirements are calculated, and so total costs are somewhat analogous to the distribution portion of revenue requirements.[6] Partial cost benchmarking approaches, such as OM&A benchmarking, exclude large swaths of cost, which can skew performance evaluations.

PSE also endorses econometric benchmarking because of its increased accuracy relative to peer group approaches. The econometric benchmarking method contains the ability to statistically test included variables and results, includes a relatively large number of variables that enter the analysis, and does not require the researcher to choose a peer group or exclude large portions of

[6] Total costs are not exactly analogous to revenue requirements, however, because of the generalizations needed to offer a fair analysis between utilities with varying depreciation rates, rate of returns, historical capital addition patterns, and cost definitions.

the available data.

PSE used a total cost econometric benchmarking model to benchmark Toronto Hydro's historical costs, and its projected total costs during the Custom IR period (2015 to 2019). PSE first derived an econometric model from the historical dataset. Using that model and its parameter values, we then calculated total cost benchmarks. For past years, we used historical variables to calculate the benchmarks. For 2014 to 2019 benchmarks, we used Toronto Hydro projections for the variables that enter the model. This process serves as a benchmark evaluation of the company's projected total costs.

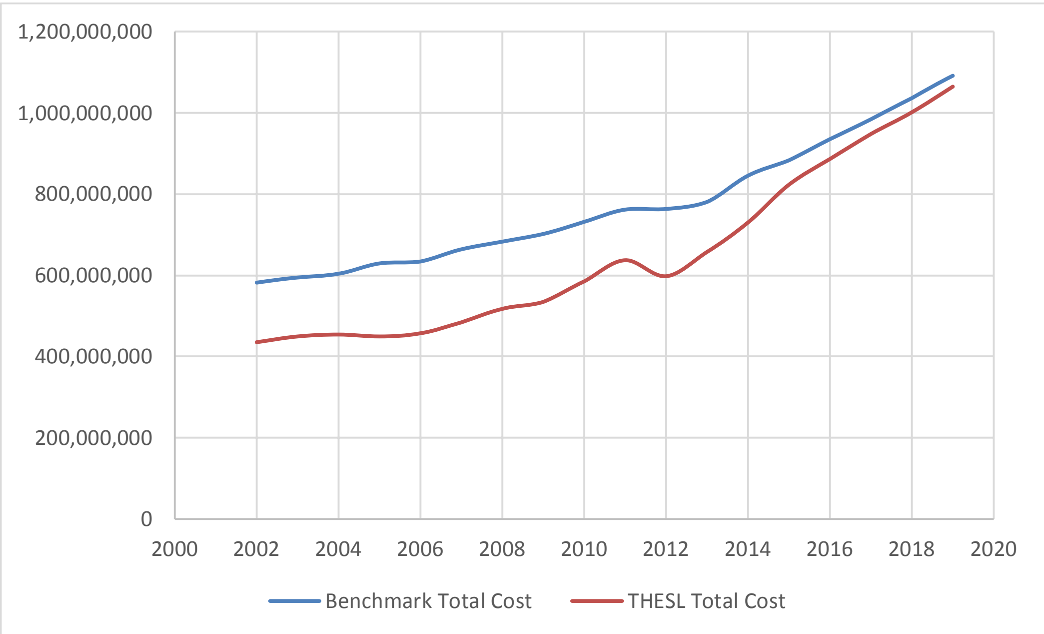
Our total cost econometric benchmarking results indicate the following findings.

1. The historical total cost levels of Toronto Hydro are below benchmark expectations at a 90% confidence level when using a dataset that includes both Ontario and U.S. utilities.

2. The projected total cost levels during the Custom IR period remain below the benchmark predictions, although they do converge towards benchmark expectations, and the "statistically below expectations" conclusion is no longer applicable at a 90% confidence level.

The following graph illustrates the historical and projected benchmarked costs and company costs for Toronto Hydro using a dataset comprised of 156 distributors from Ontario and the U.S.

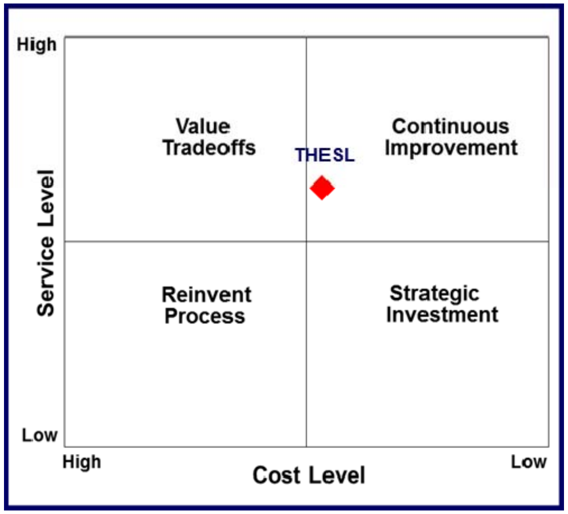
Figure 3 Historical and Projected Total Costs vs. Benchmarked Costs



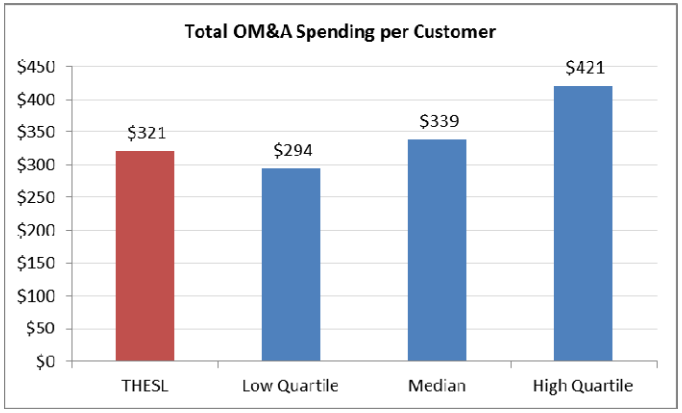
PSE also conducted benchmarking research using a U.S.-only dataset, which indicates similar findings to the combined dataset. Both samples show Toronto Hydro has been below its total cost benchmark values, and this persists through the projected years, albeit with a convergence towards benchmark costs. Further details and results for the U.S.-only dataset, along with the

Applying our 2-dimensional assessment framework, THESL hovers around the peer group median with respect to cost and compares favorably with respect to overall service level.

Overall Performance



Key Drivers for the **cost evaluation** includes overall OM&A spending per customer and the appropriateness of THESL's capital reinvestment levels given the need to address aging infrastructure, maintain recent improvement trends in reliability and increase system flexibility through automation and added capacity:



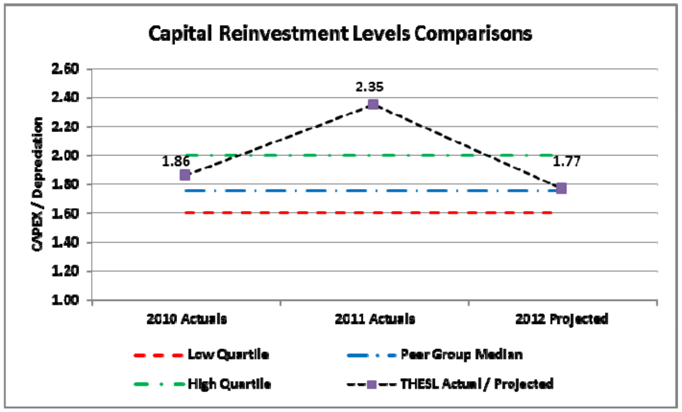


TABLE 1: PROPOSED PERFORMANCE MEASURES FRAMEWORK

Customer-Oriented Performance	Cost Efficiency/ Effectiveness of Planning and Implementation	Asset/System Operation Performance
1. System Average Interruption Duration Index (SAIDI). 2. System Average Interruption Frequency Index (SAIFI). 3. Customer Average Interruption Duration Index (CAIDI). 4. Feeders Experiencing Sustained Interruptions (FESI). 5. Momentary Average Interruption Frequency Index (MAIFI).	1. Distribution System Plan Implementation Progress. 2. Planning Efficiency: Engineering, Design and Support Costs. 3. Supply Chain Efficiency: Materials Handling On-Cost. 4. Construction Efficiency: Internal vs. Contractor Cost Benchmarking. 5. Construction Efficiency: Standard Asset Assembly Labour Input.	1. Outages caused by defective equipment. 2. Stations capacity availability.

In developing the proposed measures, Toronto Hydro referred to the Section 5.2.3, Chapter 5 of the Ontario Energy Board's (OEB) *Filing Requirements for Electricity Transmission and Distribution Applications*[1], which sets out the key parameters for measures or metrics supporting the applicants' Distribution System Plan filings. Toronto Hydro's proposed framework of measures is consistent with the OEB's expectations set out in the Chapter 5 Filing Requirements, and should provide the OEB with useful insights into the quality and sophistication of the utility's distribution planning and implementation activities, as well as Toronto Hydro's improvement in recent years.

For each proposed measure, (with the exception of new measures) Toronto Hydro provides performance results along with the associated trend over the recent years, describes the methodology used to calculate the measure and its implementation, and outlines the ways in which the measure informs and/or otherwise interacts with the utility's Distribution System Plan and the related processes. Where relevant, Toronto Hydro also describes the unique planning

[1] Ontario Energy Board, *Filing Requirements for Electricity Transmission and Distribution Applications*, (Toronto: Ontario Energy Board, 2013). ["*OEB Filing Requirements*"]

- where applicable the expected date(s) on which final deliverables are expected to be issued.

c) the comment letter provided by the OPA in relation to REG investments included in the distributor's DS Plan (see 5.2.4.2), along with any written response to the letter from the distributor, if applicable.

5.2.3 Performance measurement for continuous improvement

As mentioned in section 5.0, good distributor planning is an essential element of the Board's performance-based rate-setting approaches. The Board understands that distributors often use certain qualitative assessments and/or quantitative metrics to monitor the quality of their planning process, the efficiency with which their plans are implemented, and/or the extent to which their planning objectives are met. The Board expects that this information is used to improve continuously a distributor's asset management and capital expenditure planning processes.

a) identify and define the methods and measures (metrics) used to monitor distribution system planning process performance, providing for each a brief description of its purpose, form (e.g. formula if quantitative metric) and motivation (e.g. consumer, legislative, regulatory, corporate). These measures and metrics are expected to address, but need not be limited to:
   - customer oriented performance (e.g. consumer bill impacts; reliability; power quality);
   - cost efficiency and effectiveness with respect to planning quality and DS Plan implementation (e.g. physical and financial progress vs. plan; actual vs. planned cost of work completed); and
   - asset and/or system operations performance.

b) provide a summary of performance and performance trends over the historical period using the methods and measures (metrics/targets) identified and described above. This summary must include historical period data on: 1) all interruptions; and 2) all interruptions excluding loss of supply' for a) the distribution system average interruption frequency index; b) system average interruption duration index; and c) customer average interruption duration index.[15]

   Where performance assessments indicate marked adverse deviations from trend or targets (including any established in a previously filed DS Plan), provide a brief explanation and refer to these instances individually when responding to provision 'c)' below.

c) explain how this information has affected the DS Plan (e.g. objectives; investment priorities; expected outcomes) and has been used to continuously improve the asset management and capital expenditure planning process.

[15] The data should be calculated as stipulated in section 2.1.4.2 of the Board's Reporting and Record Keeping Requirements.

Executive Summary

More than 300 customer participated in the qualitative stages of the consultation where we explored the range of responses, while another 1,200 customers responded to the quantitative stage where we documented the incidence of needs and preferences across the customer population.

The following section provides the detailed findings on the needs and the preferences of Toronto Hydro's General Service and residential customer base. In this section, we provide a high level overview of Toronto Hydro customers' needs and preferences.

Customer Needs

Most Toronto Hydro customers are generally satisfied with the job Toronto Hydro does running the electricity distribution system. This pattern was consistent across all forms of customer input.

Overall Satisfaction across Consultation Activities

	Directional				Generalizable	
	Residential Groups	GS under 50 kw Groups	Mid-Market GS Workshop	Online Workbook	Residential Survey	GS Survey
Very Satisfied	6	5	9	26%	23%	19%
Somewhat satisfied	15	21	25	49%	50%	54%
Somewhat dissatisfied	9	4	7	12%	14%	13%
Very dissatisfied	3	1	0	9%	10%	8%
Don't know	0	0	0	4%	3%	7%

When we asked what Toronto Hydro can do better to improve services, comments focused on four major areas:

- Lower prices.
- A general desire for improved reliability or increased investment in infrastructure to improve reliability.
- Faster restoration times, particular during major outages such as the summer flooding or ice storm.
- Improved communications, again particularly during major outages.

This paradox of *lower prices* while seeking *service improvements* is the key dilemma the consultation sought to explore and better understand.

The consultation focused deeper on the question of outages. In the qualitative stage, the workbook shared information about the systems current average level of reliability and sought customer feedback on satisfaction with current levels of reliability and response to major events. With the flooding in the summer and the ice storm in December of 2013, major events were at the forefront of customer thoughts.

As the tables below illustrate, while a majority of customers are satisfied with the average frequency and duration of outages and with Toronto Hydro's management of recent major events, a significant minority are not satisfied.

Customer Satisfaction with Current Average Outage Frequency

	Directional			
	Residential Groups	GS under 50 kw Groups	Mid-Market GS Workshop	Online Workbook
Very Satisfied	5	3	4	16%
Somewhat satisfied	12	14	13	37%
Somewhat dissatisfied	7	6	9	25%
Very dissatisfied	9	7	7	20%
Don't know	0	1	0	2%

Customer Satisfaction with Current Average Outage Duration

	Directional			
	Residential Groups	GS under 50 kw Groups	Mid-Market GS Workshop	Online Workbook
Very Satisfied	4	4	9	17%
Somewhat satisfied	13	10	15	38%
Somewhat dissatisfied	9	7	12	24%
Very dissatisfied	7	10	4	19%
Don't know	0	0	1	2%

Customer Satisfaction with Management of Major Events

	Directional			
	Residential Groups	GS under 50 kw Groups	Mid-Market GS Workshop	Online Workbook
Very Satisfied	3	4	10	27%
Somewhat satisfied	12	13	13	39%
Somewhat dissatisfied	7	4	10	15%
Very dissatisfied	9	6	4	14%
Don't know	0	3	3	5%
Refused / No response	2	1	1	N/A

The qualitative consultation activities spent additional time on exploring the impacts of outages on customers, acceptable frequencies and durations of outages as well as trade-offs between frequency and duration. Those findings are detailed in the following section.

The telephone survey built on the qualitative feedback and asked questions about customer preferences on the trade-off between cost and reliability.

Table 1: Rate-Setting Overview - Elements of Three Methods

	4th Generation IR	Custom IR	Annual IR Index
Setting of Rates			
"Going in" Rates	Determined in single forward test-year cost of service review	Determined in multi-year application review	No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism
Form	Price Cap Index	Custom Index	Price Cap Index
Coverage	Comprehensive (i.e., Capital and OM&A)		
Annual Adjustment Mechanism – Inflation	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts	Composite Index
Annual Adjustment Mechanism – Productivity	Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor		Based on 4th Generation IR X-factors
Role of Benchmarking	To assess reasonableness of distributor cost forecasts and to assign stretch factor		n/a
Sharing of Benefits	Productivity factor		
	Stretch factor	Case-by-case	Highest 4th Generation IR stretch factor
Term	5 years (rebasing plus 4 years).	Minimum term of 5 years.	No fixed term.
Incremental Capital Module	On application	N/A	N/A
Treatment of Unforeseen Events	The Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options.		
Deferral and Variance	Status quo	Status quo, plus as needed to track capital spending against plan	Disposition limited to Group 1 Separate application for Group 2
Performance Reporting and Monitoring	A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.		

appendix B; correct?

MR. SONJU: Yes, that is correct.

MR. SMITH: Now, Mr. Fenrick, can I return to you?

And with the Board's leave, I'd like to conduct a brief examination in-chief. My objective is to highlight for you the areas of agreement and disagreement between PSE and PEG, which I think will be of assistance to you.

MS. LONG: The Panel would find that helpful. Thank you, Mr. Smith.

MR. SMITH: Mr. Fenrick, do you have your first report there?

MR. FENRICK: Yes, I do.

MR. SMITH: Okay. Can I ask you to turn to page 2?

We know you did an econometric benchmarking study of cost and reliability performance. Turning to page 2 of that, at the top of the report, can you describe briefly for the Board the methodology you followed in conducting that work?

MR. FENRICK: Absolutely. We, PSE and my staff, put together a series of historical data that used and followed the fourth-generation IR methodology, as far as the Ontario data set that was put together in that proceeding.

We took -- took that historical data, combined it with FERC Form 1 and other US data sources to create a data set.

From that data set, we supplemented it with Toronto Hydro projections of costs and number of customers and reliability and those types of projections, and we created an econometric model, very similar to the same methodology used in the fourth-generation IR.

Out of that model was calculated benchmarks that predicted the expected cost levels, reliability levels of Toronto Hydro, both from a historical perspective and a projected perspective. And then we compared those benchmarks to the actual observed cost or the projected costs to infer performance of Toronto Hydro in both the historical period and the projected period.

MR. SMITH: You mentioned earlier that you combined the Ontario-only data with US data. And why did you do that, sir?

MR. FENRICK: The reason we combined the Ontario data with the US data set is, given the specific and somewhat unusual circumstances of Toronto Hydro as far as size and serving an urban core city, we felt the Ontario data set alone was insufficient for a proper and accurate benchmarking study, which is the reason why we combined the data set, which does have a number of larger utilities in size of customers and also utilities with more urban characteristics than are found in Ontario alone.

MR. SMITH: Can I ask you to turn to page 11 of your report, sir? What I would like to do is -- if you could just briefly identify the conclusions you reached, dealing first with cost and then reliability.

So on the cost side, looking at the historical information, what were your conclusions?

MR. FENRICK: Yes. So when we put together the US data set and the Ontario data set, we looked at the two data sets, the combined data set which was the Ontario data with the US data, and then our second data set was a US-only data set.

In doing those two data sets, we performed two separate econometric models, essentially two separate studies of those two data sets. Our findings were, on a historical basis from 2010 to 2012, Toronto Hydro was a statistically superior cost performer.

I believe in the combined data set, our result was 21.5 percent below the expected or benchmarked values for the 2010-2012 time period.

On a cost basis, we also ranked Toronto Hydro to the utilities within that study. For instance, in the -- compared to just the Ontario utilities within the combined data set, Toronto Hydro was found to be 15th out of the 71 distributors in the cost benchmarking.

For the projections -- that was the historical period. For the projections, we found that Toronto Hydro's performance moves from statistically superior to the normal, the normal range within the plus-minus 10 percent set in fourth-generation IR for the stretch factor of 0.3 percent. So they move from statistically superior to normal, based on the capital planning put forth.

MR. SMITH: Does that capture the conclusions that you have set out on page 11, in items 1 through 3? Have I got that correct?

MR. FENRICK: Yes.

MR. SMITH: What about item 4? What was your conclusion there?

MR. FENRICK: So yes, moving to the reliability, we did the same two data sets --

MR. SMITH: Sorry, just before we move to the reliability item, I would like you to just focus in on item 4, which deals with the stretch factor. What was your conclusion there?

MR. FENRICK: Yes. Essentially the conclusion there is Toronto Hydro moves from statistically superior in the historical time period to the normal -- normal range, statistically, from a statistical basis basically zero, kind of in at normal range within the plus-minus 10 percent, which I believe is cohort number 3 in the fourth-generation incentive regulation proceeding, implying a 0.3 percent -- puts them in a 0.3 percent stretch factor range.

MR. SMITH: All right. Let's look at reliability. And turning to conclusion 5, what was your conclusion with respect to reliability?

MR. FENRICK: Similar to the total cost benchmarking, we created two data sets: the combined data set, which is the Ontario-US, and the US-only. So we performed two separate models for two separate measures, being SAIFI, which is the number of frequency of outages that customers experience per year, and SAIDI, the duration of outages that a typical customer experiences per year.

So we had the two data sets and did the two separate evaluations on both of those. Our findings for SAIFI, the frequency of outages, is, on a historical basis, Toronto

Hydro is quite a bit above the benchmarked values, statistically significantly above the benchmarked values, implying that their customers are experiencing a higher number of outages than our benchmarks would suggest.

Into the projected period of the reliability, this moderates to a normal level, not statistically significant, still slightly above the benchmarks but not statistically significant in a count of that normal range.

On the SAIDI -- and I should mention both the combined data set and the US data show very similar results for SAIFI and for SAIDI. Regarding SAIDI, we found that Toronto Hydro's customers are experiencing a lower number of outage duration minutes than our benchmarks would expect after factoring in all of the external conditions. This is from a historical basis. And then projected -- the company projects with their SAIDI that gets even lower, where it gets into the statistically significant territory through the custom IR period.

MR. SMITH: What do you mean by "even lower"?

MR. FENRICK: Well, sorry. By "even lower," the Toronto Hydro's customers will experience less duration minutes on a percentage basis that would be even -- it would be greater than what our historical findings are.

So for instance in the 2010 to 2012 period, which -- this is bullet 6 on the conclusions -- we find that Toronto Hydro SAIDI is 48 percent below benchmark expectations.

So 48 percent -- customers are experiencing 48 percent below the benchmark expected SAIDI. In --

MR. SMITH: And this is what you mean by:

"This implies that Toronto Hydro customers experience 48 percent fewer outage minutes than the models predict."

MR. FENRICK: Yes, correct.

And the bullet point 6 continues -- by 2015 our models show 84 percent below on the SAIDI. So the customers will experience 84 percent fewer outage minutes, based on the company's projections of SAIDI, based on the plan.

MR. SMITH: All right. And that's SAIDI on the SAIFI side?

MR. FENRICK: The SAIFI, I believe -- I believe I already addressed that.

MR. SMITH: My apologies. I had SAIDI on the mind.

Let me turn from that report. You're aware that a report was filed by Pacific Economics Group in December of 2014?

MR. FENRICK: Yes.

MR. SMITH: And you reviewed that report and prepared a reply report?

MR. FENRICK: Yes, I did.

MR. SMITH: Okay. What I would like you to do is turn up that reply report, if you could. What I would like to focus in with you, sir, is on the areas of, broadly speaking, the areas of agreement and disagreement between your report and the report filed by Pacific Economics Group.

So let's perhaps take them in the order in which they appear in the report. Let's talk about reliability. Where are we on the issue of reliability in terms of agreement and disagreement?

MR. FENRICK: Yes. Perhaps looking at page 2 of our reply report, figure 1, it's my understanding that PEG put together a new -- looked at our data set, our reliability data set, put together, made some adjustments, some modifications to that data set, and then recalculated the model using the US -- the US-only data set.

As you can see, there's substantial agreement on the reliability benchmarks. If we look at figure 1, the blue line is the PSE calculated benchmarks, where we calculated the benchmarks, and those are basically the expectations, given the external conditions of Toronto Hydro, of where we felt the SAIDI number would be.

The green line is PEG's calculations and their benchmarks found in the PEG report. You can tell, despite varying data sets, varying models, and two experts looking at this issue, the benchmarks are, we kind of say in the report, nearly indistinguishable. The green line and the blue line are tracking each other quite closely.

This contrasts with PEG's finding that there is some disagreement on SAIDI. You know, looking at the graph and looking at the results, we feel that is wholly due to PEG looking at the more dated time period of 2009 through 2011. If you look at the same time periods, the benchmarks are wholly similar.

I should add too, similar story on figure 2 of SAIFI as well, where the benchmarks are tracked quite closely on the findings, our findings and PEG's findings.

MR. SMITH: All right. Would it be fair to summarize then, sir, that even if you looked at the 2009 to 2011 model developed by PEG and applied Toronto Hydro's data to it, that you would end up with similar results?

MR. FENRICK: Between PSE and PEG?

MR. SMITH: Yes.

MR. FENRICK: Yes. I mean, regardless of the time period, whatever time period one chooses to examine, the PSE and PEG results are going to be quite, quite similar, show quite similar results.

MR. SMITH: So you referred to figure 1, which deals with SAIDI, and just for the purpose of the record, looking at figure 2, is it your evidence you can make the same observations with respect to the blue and green lines on figure 2 on page 3?

MR. FENRICK: Yes. And I would add that PEG themselves in the report stated that the SAIFI findings are quite similar as well. It was just on the SAIDI where they felt there was some differences. It's our contention that both of these results are wholly similar.

MR. SMITH: Let's turn to the issue of cost, and that's discussed beginning at page 4 of the reply report, and perhaps you can turn there.

So let's look at the areas again of agreement and disagreement, broadly speaking. Starting with the issue of agreement, where are we?

MR. FENRICK: I think in terms of agreement, there's substantial agreement between PEG and PSE. As far as the whole methodology of econometric benchmarking, and just the methodology, a lot of that is due to the fact that we -- we followed PEG's methodology put forth in fourth-generation IR, used the data -- the data set put together for the Ontario, including Toronto Hydro, the same definitions, put together the same cost data. So we took that right from fourth-generation IR.

We also followed what was used as far as the trans-log cost function and those types of specifications. I would say, moving from our original report to the PEG report, there continued to be some substantial agreement as far as PEG used the US data set and benchmarked using the US data set, which we believe is truly a move in the right direction, as far as an accurate portrayal of Toronto Hydro's performance.

PEG also put forth they believe that uncollectible accounts for the US data should be excluded, due to the fact that the Ontario data set excluded bad debt expenses.

To that, we agree. We think that is an improvement. That does make costs more comparable, which is really what we're trying to get after, is: Can we make costs comparable between the US data set and the Ontario and Toronto Hydro data set? And we believe that is also a move in the right direction.

MR. SMITH: So there is nevertheless, despite the broad agreement, some areas of disagreement that you have identified in the report. As I understand it, there are three, and what I would like to do is go through each of those.

As you say at page 4, these are three adjustments that you feel are necessary. So let's go through each of them and you can tell me what the adjustments are, and why you feel they were appropriate.

So item 1 relates to bad debt expenses, and is captured under heading 3.1. Can you tell us there the adjustment that you have proposed?

MR. FENRICK: Yes. So adjustment 1 has to do with the desire to have cost comparability. We needed the same cost definitions for the sample that we're benchmarking, the US sample, with Toronto Hydro.

And as I mentioned in my prior answer, we agree with PEG's suggestion that the uncollectible accounts should be excluded in the US data set; that increases the cost comparability.

With the one caveat, is PSE, when we put together the original data set, was under the impression that bad debt expenses were included into the Ontario data.

For that reason, the bad debt expenses were also included into Toronto Hydro's projections.

Based on what we've come to find out after our original report, that bad debt expenses are actually not included in the Ontario data and thus we should take out uncollectible accounts in the data, what also needs to happen is the projections for Toronto Hydro also need to subtract out the bad debt expenses that were previously put in there.

So that's not currently being done in the PEG report. We corrected that, and that is now in the PSE reply report to get those costs comparable on that issue.

MR. SMITH: Just taking your last point, at page 5 of the reply report, sir, you identify that PEG asserts that its estimates of Toronto Hydro's 2013-2019 projected costs -- and these are PEG's words -- "implicitly" subtracts out bad debt expenses.

Do you agree with that?

MR. FENRICK: No, I don't.

MR. SMITH: Why not?

MR. FENRICK: The reason I disagree with that is PEG laid out their methodology for how they calculated the projections for Toronto Hydro. And that is really all we're dealing with on this issue.

PEG and PSE agree on the historical data does not include bad debt expenses. The US data now does not, for the PSE reply report and the PEG report.

The one issue is on the projections. PEG says that they -- the bad debt expenses are implicitly added because of the methodology for which they calculated the projections.

What they -- what PEG did is they took PEG's 2012 cost measure and then to escalate it to 2013, 2014, 2015, et cetera, they took the growth rate in PSE's cost levels that are found in the original report, and took that growth rate and then escalated their 2012 measure to 2013, 2014, 2015, et cetera.

So the issue there is that in the 2012 PSE measure, bad debt expenses were not included in that cost definition.

In 2013, bad debt expenses were included in the cost definition.

And that was because in the 2012, we were unaware that bad debt expenses were excluded. So we thought we would -- we should include those expenses moving forward for Toronto Hydro.

So we have an issue where our PSE's 2012 costs do not have bad debt expenses in there. The 2013 costs do have bad debt expenses. If you take that growth rate and apply it -- PEG's 2012 measure, that's implicitly adding bad debt expenses. Just based on the math of -- the base year does not have bad debt expenses, the 2012. The 2013 does have bad debt expenses.

That's -- to my mind, that is certainly adding bad debt expenses into PEG's projections of Toronto Hydro's costs.

And in the reply report, we simply subtract out those bad debt expenses to come up with a more cost-comparable measure.

MR. SMITH: Let's turn to the second adjustment, and as I understand it, that relates to conservation demand management expenses, and it is captured under heading 3.2.

Why don't you tell us what the issue is there, and the adjustment that you made?

MR. FENRICK: Yes. So in the PEG report, they subtract out the customer service and information expenses from the US data.

This was in an effort to make costs comparable, because in the Ontario data set CDM expenses are not included, and PEG believes that the CDM expenses for the US utilities are included and they're included in the customer service and information expense category.

So what PEG did was to subtract out the whole customer service and information category from the US data set in an effort to make costs comparable.

The problem with that is Toronto Hydro certainly has customer service expenses embedded in the cost definition, and so we have a cost comparability issue. By subtracting out all of the customer service and information expenses, the US data does not have customer service and information expenses in their cost definition.

Conversely, Toronto Hydro does have those customer service and information expenses in its cost definition. And we know that because in the fourth-generation IR, the cost definitions certainly did include customer service functions within Toronto Hydro and the rest of Ontario.

So PSE looked at the situation and said: Okay, how can we get costs to be comparable between the US sample and the Toronto Hydro -- in the Toronto Hydro and the rest of Ontario, for that matter?

The way to do it is quite simply just add the CDM expenses back into Toronto Hydro's definition, and then leave the CSI -- the customer service information -- expenses in the US sample.

So what we did was we went to Toronto Hydro and requested: Hey, can you provide us with all of your CDM expense levels so we can add that into your cost definition?

And so we did that in the reply report, and that creates a situation where the US data set now has customer service information and CDM expenses into the cost definition, and Toronto Hydro has all of their customer service information and all of their CDM expenses into their cost definition.

So now we have more cost comparability, with the caveat we're not exactly sure -- it's very likely that's unfavourable to Toronto Hydro.

We contacted the FERC Form 1 team, as far as how CDM expenses are actually accounted for in the US, and it's unclear if all of those expenses are actually in the US cost definition.

But in an effort to avoid kind of gray area issues that we could quibble over, but it is hard to come with a true and fast realization or conclusion to them, we said: Okay, we'll just agree with PEG all of the CDM expenses are in the US data set, and add Toronto Hydro's CDM expenses to those to create a cost comparability issue.

That also makes the cost definitions far more comprehensive as well.

I don't think excluding customer service expenses is a very comprehensive cost definition. When we're doing total cost benchmarking, the more comprehensive we can make the cost definition, the better.

In one of the interrogatories, PEG was asked, you know: Why didn't you just add the CDM expenses? The reply was: Well, CDM is not in distribution rates.
Very true, but there's been a precedent. In the fourth-generation IR proceeding, when PEG did their benchmarking work they included contributions in aid of construction in the benchmarking cost definition to make costs more comparable. I think that is the overriding guiding principle when doing benchmarking, is: Can we get those costs comparable? Can we get the same across the sample?

And to me, this is the way to do that, to make sure the US data has the customer service and information and CDM, Toronto Hydro has customer service and CDM, and then we can move forward. That is the change number two that we suggest.

MR. SMITH: All right. Let's turn to the final adjustment you made, and it relates to the urban core and high-voltage variables.

And why don't you tell us the adjustment that you made and why, first at a high level? And then I will have some more specific questions.

MR. FENRICK: As far as the high level of the urban core variable, you know, we kind of -- we took a step back, and I talked to the engineering folks at Power System

Engineering and asked them, you know: Are there cost challenges to serving an urban utility, an urban core, dense -- highly dense urban core, such as Toronto? Are there more challenges there than a more suburban or less urbanized utility might face?

And Mr. Sonju and others agreed that they thought that would be the case. We actually put forth the engineering study that was in appendix 2 to my report that quantified and studied the added cost challenges to serving an urban core relative to other environments, such as suburban or rural, those types of things, and looked at the cost challenges and the cost implications of serving an urban core.

This essentially served the basis for our urban variable, that provided the justification to include that variable in there, because now we have an engineering basis and studies showing, yes, we do believe that costs will go up substantially, serving an urban core relative to other environments, with the exception of rural is also -- also a high-cost area. It is kind of you have got two ends of the spectrum there.

MR. SMITH: And just so the record is complete, is that your report, Mr. Sonju, entitled "Capital requirements for serving developed environments"?

MR. SONJU: Yes, that's what Mr. Fenrick was referring to.

MR. SMITH: And you agree with his summary of the conclusion of your report --

MR. SONJU: Yes. He did it quite well.

MR. SMITH: -- with respect to the cost of serving an urban environment? Thank you.

Okay. So what did you do, then, with this hypothesis and engineering study as it relates to the urban core variable?

MR. FENRICK: Yes. So given the engineering study and the hypothesis that serving a highly dense urban core will drive up costs, we then inserted -- we created the variable that's found in the original report, as well as the reply report, and tested the hypothesis: Does this meaningfully drive electric utility total costs? And what we found is yes, the sign was positive, which is what our a priori expectation was. And it was also highly statistically significant at the 99.9 percent level, which led us to conclude yes, this is a highly significant cost driver. It aligns with the engineering study. All the statistics say this is a highly relevant variable. This needs to be included into the model.

MR. SMITH: And what does it mean -- you indicated earlier that it was positively signed. What does that mean?

MR. FENRICK: That essentially means that the coefficient, when you put -- you put these variables into the econometric model, and the coefficient was positive. At a high level, what that means is costs are expected to increase if the utility is serving an urban core.

You know, all else being equal, if you have two equal utilities, as far as number of customers, you know, all the other variables, you have two of the utilities exactly the same but one is serving an urban core and the other one is not, the model would say that utility that's serving that urban core is going to have higher costs, cost benchmarks and cost level expectations, than that utility that is not serving that urban core.

MR. SMITH: How did you arrive at a determination of whether the utility was serving an urban core?

MR. FENRICK: There, we looked at Toronto, and it's a large city. What we wanted to do is to have an objective threshold. We didn't want to make arbitrary distinctions between what is and what is not.

To us, we used the 1 million -- if the population was 1 million or above, according to the US Census Bureau, it was given a value of 1. To us, you know, a city serving -- or having the population of 1 million is a large city. That seems like a really large urban centre along the lines of a Toronto.

So given that desire, we based it on having a 1 million population or above within the city limits.

MR. SMITH: So let's turn to the adjustment you made. What was the adjustment that you made in the reply report?

MR. FENRICK: Relative to the model that PEG put together, a fairly simple adjustment, as far as, we simply substituted, you know, the urban core variable in -- because we feel that that variable is needed. It's statistically significant. All the engineering theory says it should be included.

So we inserted that into the model, replacing PEG's high-voltage variable, which is incorrectly signed based on their corrected econometric model. It has the wrong sign. It is a negative sign, which means the more high voltage a utility serves, costs actually go down. That violates the benchmarking principle of needing to have a correctly signed, sensibly signed variable.

That variable is also statistically insignificant, meaning it has no -- you know, you cannot reject the hypothesis that that variable is actually a meaningless variable.

In my experience and number of years doing this, estimating a lot of total cost models, I have never actually come across a business condition that is incorrectly signed and statistically insignificant. Those aren't included in benchmarking models, based on established industry principles, some of which were established by PEG themselves. And you can see in the reply report some quotes there.

And so we felt that variable cannot stay. It violates benchmarking principles best practice. That needs to be taken out. We need to insert the urban core variable to capture those extra urban costs.

MR. SMITH: And when you say "insert the urban core variable," was the urban core variable included in your initial report?

MR. FENRICK: Yes, it was. And then PEG took that

urban core variable out, and then we reinserted it.
MR. SMITH: I see. Okay.
Let's -- it's in writing, and we needn't go over it, but there is further explanation for your conclusion with respect to the urban core variable, sir, if I understand it, throughout section 3.3 at pages 7 through 9; is that correct?
MR. FENRICK: Yes, that's correct. Responding to some of the criticisms from PEG.
MR. SMITH: And after we take the adjustments that you've -- the three adjustments that you made, what is your conclusion?
MR. FENRICK: So the conclusion is consistent with PSE's original report. We found after making those three adjustments that we discussed, the utility -- the historical total costs of the utility are minus 15.2 percent below benchmarks for the 2010 through 2012 period. That's, again, statistically significant.
Similar to the original report, that total cost finding increases over the custom IR period but still remains in the normal -- the normal range of the plus or minus 10 percent range, which is the 0.3 percent stretch factor that was set in fourth-generation IR.
MR. SMITH: Thank you very much. Those are my questions in examination-in-chief. And thank you very much, members of the Board.
MS. LONG: Thank you, Mr. Smith.
Ms. Helt, do I understand that you are going to start

they occur. Thus, SAIDI performance tends to be more related to OM&A spending, whereas SAIFI performance is related more to capital spending.

1.6 Custom IR Conclusions

PSE's benchmark research leads us to the following statements relating to the company's Custom IR proposal:

1. Toronto Hydro is entering the Custom IR period with strong recent cost performance (i.e., costs are below the expected values), with its average 2010 to 2012 total costs being estimated at 21.5% below benchmark values using the combined dataset results.[10]

2. This strong cost performance persists to 2015, although with some moderation. Toronto Hydro's 2015 total cost level forecast is estimated to be 7.1% below benchmark values, and is, in our opinion, reasonable from a benchmarking perspective.

3. Toronto Hydro's Custom IR period (2015 through 2019) total cost level projections remain below benchmark expectations. By 2019, the company is estimated to still be below benchmark values by 2.6%. Based on this, the company's Custom IR projections are, in our opinion, reasonable from a benchmarking perspective.

4. Total costs are projected to be well within the 0.3% stretch factor range of plus/minus 10% set in the November 2013 Board Report. In terms of ranking, in the combined total cost rankings based on historical performance, Toronto Hydro is 30th out of the 156 Ontario/U.S. utilities. If Ontario distributors are isolated in the rankings, for the combined model, Toronto Hydro is ranked 15th out of the 71 distributors. Based on these findings, reducing the stretch factor from 0.6% to 0.3% seems in line with the Board's intention of assigning a 0.3% stretch factor to utilities with "normal" total cost benchmark evaluations.

5. Toronto Hydro's capital infrastructure seems to be producing a higher than expected number of outages. The company's average 2010-2012 SAIFI is 73% above benchmark expectations. This implies Toronto Hydro customers experience 73% more outages then our models predict. The SAIFI projections, assuming full funding, move the company towards the benchmark SAIFI value, reducing the number of outages experienced by customers. Thus, the company's plan to increase capital spending to address SAIFI is, in our opinion, reasonable from a benchmarking perspective.

6. Toronto Hydro's response to outages, measured by SAIDI, is quite strong and is projected to continue to be strong. The company's 2010-2012 average is 48% below benchmark expectations. This implies that Toronto Hydro customers experience 48%

[10] In this section, we discuss only the results for the combined dataset. The U.S.-only results are similar, although they indicate Toronto Hydro is even further below its benchmark values than when using the combined dataset (i.e. when using the U.S.-only dataset, Toronto Hydro's benchmarked costs are higher, thus its performance more impressive).

fewer outage minutes than our models predict. By 2015, the company's SAIDI is projected to be nearly 84% below benchmark expectations.

From a benchmark perspective, the benchmark analysis shows that THESL's spending forecasts should converge the company's SAIFI and total costs towards PSE's benchmark expectations (while SAIDI remains at a strong level). Based on the projections, the projected spending should result in a utility more aligned with its externally-derived benchmark values from both a total cost and SAIFI perspective.

The infrastructure cost effectiveness is the cost of infrastructure required to serve a unit of coincident demand. In the case of this analysis, dollars per kW was used. As shown in Table 6-3, the range varies from $1,700 per kW for the studied rural area, to $600 per kW for the urban residential area to $1,600 per kW for the metro/urban core area.

Table 6-3 Infrastructure Cost by Area Type Table

	Rural	Suburban Residential	Suburban Commercial	Urban Residential	Urban Commercial	Metro / Urban Core
Plant Cost/Demand ($/kW)	$ 1,700	$ 700	$ 400	$ 600	$ 1,200	$ 1,600

The results are also illustrated in Figure 6-3. The infrastructure cost effectiveness from one area to the next increases or decreases by a factor of 1.3 to 2.3.

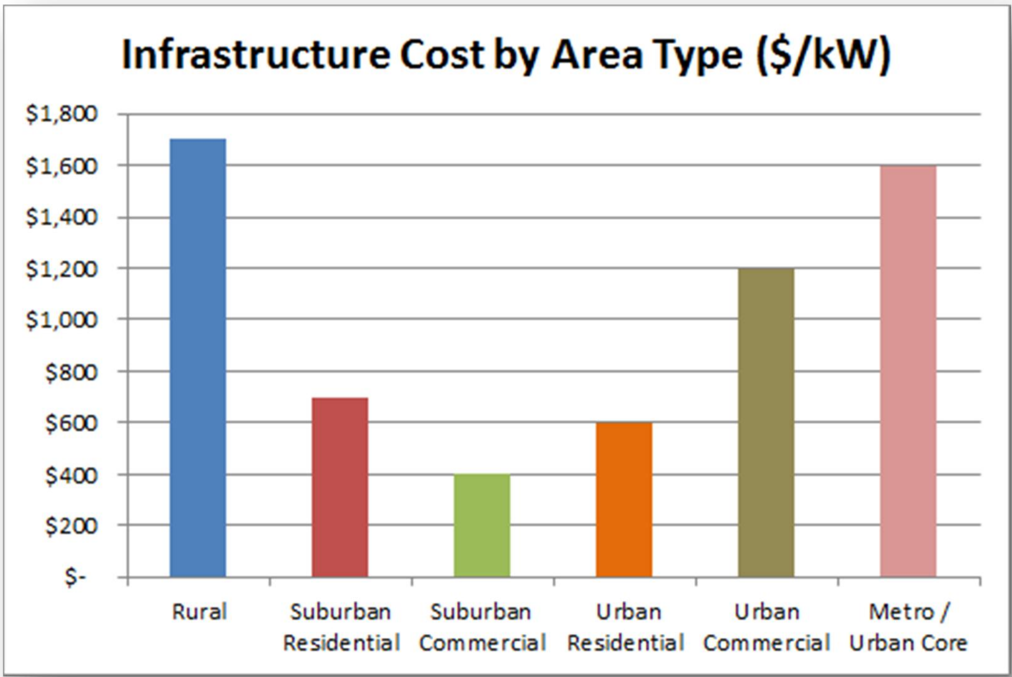
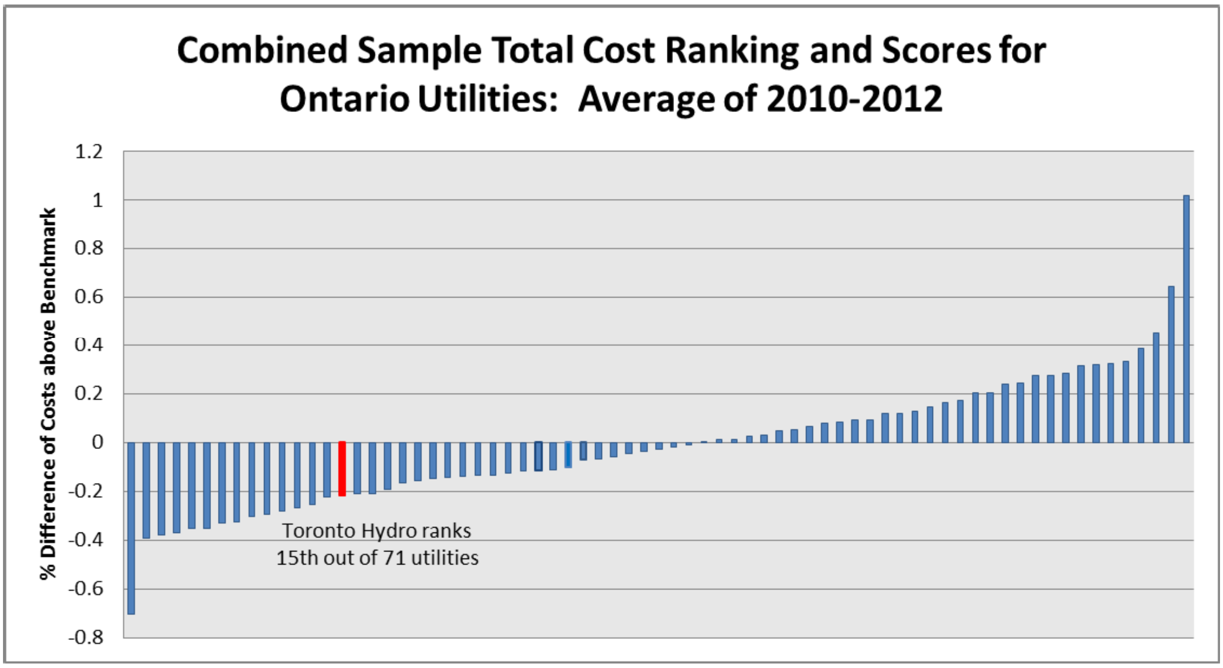


Figure 6-3 Infrastructure Cost by Area Type

It can be easily seen that the cost effectiveness of required infrastructure for the six areas studied does not result in an upward or downward trend as demand density increases. Rather, the cost effectiveness represents a U-shape where rural and metro/urban core areas are the least cost effective in terms of required infrastructure to serve the loads within the given environments. Conversely, suburban residential, suburban commercial, and urban residential areas are the most cost effective environments to serve.

Figure 11 Combined Sample, Ontario Utilities Only: Econometric Total Cost Ranking

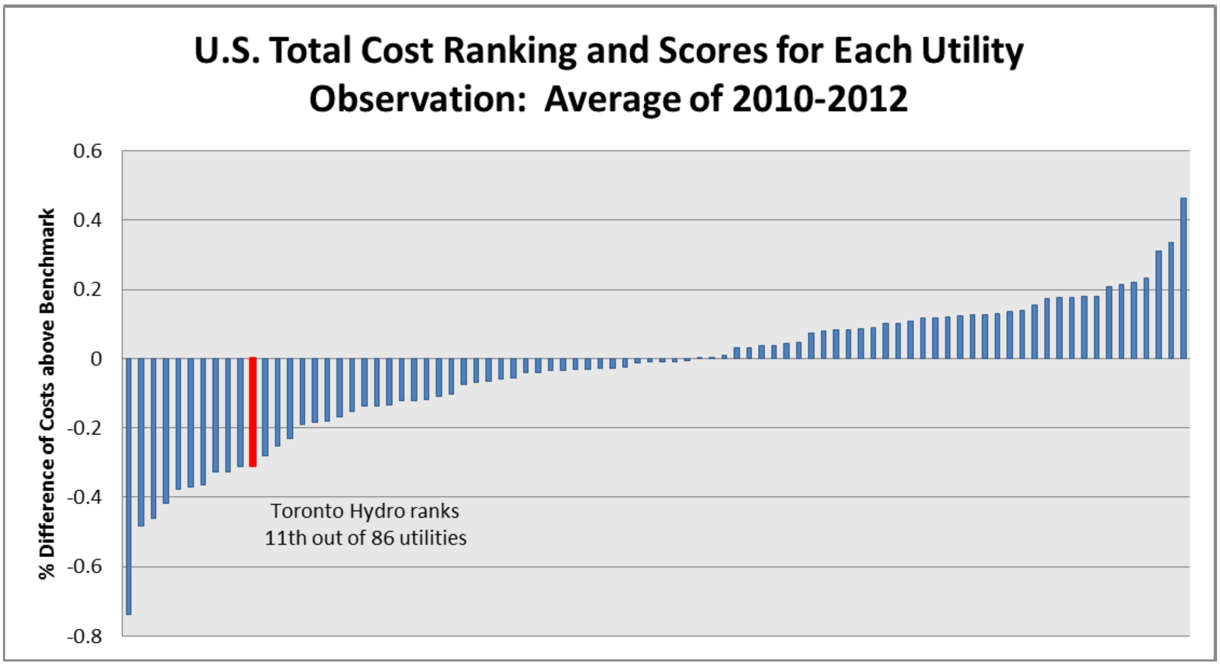


3.2 Econometric Results for the U.S.-Only Dataset

The estimates from the total cost model based on the U.S. data are presented in Table 7. The results in the table show that the cost function parameter estimates have plausible signs and magnitudes. The first order terms of all variables that are fully interacted have the theoretically expected signs and are statistically significant.

The U.S. total cost observations for each utility can be ranked based on the percent difference in the actual total costs to the benchmark total costs. Toronto Hydro finds itself 11th out of 86 utilities included in the U.S. sample when an average of the 2010-2012 differences are ranked. The distribution of utilities and the company's placement is illustrated in the following graph.

Figure 13 U.S.-Only Sample: Total Cost Econometric Ranking



3 Total Cost Results and Model

As the experience of incentive regulation in Ontario has shown, benchmarking tends to be an iterative process. Putting together data sets, explanatory variables, and models takes time and requires input from multiple stakeholders. Throughout this process, benchmarking evaluations tend to become more accurate, comprehensive, and trustworthy, resulting in improved evidence to better inform decisions.

Relative to PEG's 4th Generation Incentive Regulation benchmarking model, the PEG Report made strides in conducting a fair total cost benchmarking evaluation in relation to THESL. This was primarily done by using the U.S. data set.[3] PSE agrees with PEG that excluding uncollectible account expenses from the U.S. data is appropriate, given that bad debt expenses were excluded for all of the Ontario utilities.[4] PEG also included THESL's smart meter expenses in its cost definition. While this is unfair to THESL, since only a handful of U.S. utilities in the dataset have fully deployed smart meters, in an effort to only focus on major issues, PSE will not modify PEG's treatment of smart meters in the Reply Report results.

However, three adjustments to PEG's Research are necessary to make cost definitions comparable and to make the model align with benchmarking best practices. These are:

1. Make THESL's forecasted costs comparable to past costs by excluding bad debt expenses,
2. Make cost definitions comparable and more comprehensive between THESL and the U.S. sample by adding in THESL's CDM costs and re-inserting customer service and information expenses for the U.S. sample, and
3. Re-introduce in the model the logical, properly signed, and statistically significant urban core variable, and exclude the incorrectly signed and statistically insignificant high voltage variable.

These three adjustments are discussed in the following sections.

3.1 Adjustment #1: Bad Debt Expenses

PEG correctly states that uncollectible account expenses should be subtracted for the U.S. sample. PSE agrees that this improves the comparability of costs, but we note that PEG should also subtract out bad debt expenses for THESL's forecasted time period of 2013 to 2019 (PEG did not do this). PSE requested this data from THESL and has subtracted bad debt expenses, along with other non-comparable costs such as property taxes that were previously in the forecasted cost data. This was done in an effort to define forecasted costs in the same way in THESL's and U.S. utilities' historical costs.

[3] Recall that PSE did estimate two models, a U.S. only and a combined U.S. and Ontario model. Both models showed similar results for THESL. In the interests of brevity and time, we only discuss the U.S. model in this report. PSE does dispute, however, PEG's statement in its Responses to Interrogatories (1-THESL-60) that "PEG believes there is no value in PSE's Ontario benchmarking, because PSE selected the TFP-based cost measure for THESL while the Ontario distributors were intentionally benchmarked using a different, benchmarking-based cost measure." This is incorrect; PSE used the same cost definition for both THESL and the rest of the Ontario distributors. The only exception to this is THESL's cost 2013-2019 projections included the added costs of bad debt expenses.

[4] PSE used PEG's data set found in the 4th Generation IR to attempt to replicate PEG's cost definitions as closely as possible. In doing that, PSE was unaware that bad debt expenses were excluded (which is why THESL's projected costs include bad debt expenses). PEG made it clear that these were excluded; thus, excluding those same type of expenses from the U.S. data set and from THESL's 2013-2019 cost projections is appropriate.

In PEG's response to THESL's Interrogatories, 1-THESL-23, PEG asserts that its estimates of THESL's 2013-2019 projected costs "implicitly" subtract bad debt expenses. This is incorrect. PEG takes its 2012 costs, which excluded bad debt, and for projected costs for 2013-2019 adjusts it by PSE's annual percentage change (from Table 6 of the PSE September Report). This method does not explicitly or implicitly exclude bad debt expenses for the 2013-2019 period, because PSE's 2013-2019 costs include THESL's bad debt expenses, whereas the historical 2002-2012 costs do not.

As an illustration, PEG's 2013 total cost value is calculated using PEG's 2012 cost value and then escalated by the growth rate in PSE's total costs from 2012 to 2013. PEG believes this in some way "implicitly" subtracts out bad debt expenses. However, in the PSE total cost measure the 2012 value excludes bad debt expenses, whereas the 2013 value includes bad debt expenses. By escalating PEG's 2012 total costs by this growth rate, PEG is implicitly adding bad debt expenses into their total cost projections for THESL, creating a mismatch in costs between THESL's projected costs and those of the rest of the sample. The PSE approach is to simply subtract out bad debt expenses in the projected data so the cost definition matches the rest of the sampled data.

3.2 Adjustment #2: Conservation Demand Management Expenses

PEG excluded the entirety of the "customer service and information expenses" for all of the U.S. utilities, in an effort to exclude CDM expenses for U.S. utilities, similar to the Ontario cost definition. However, three problems arise with this: 1) THESL and other Ontario utilities also incur non-CDM customer service expenses that are not being excluded by PEG, creating a cost comparability problem and making the treatment advantageous to the U.S. and disadvantageous to THESL; 2) Eliminating a large expense category makes the total cost definition far less comprehensive, despite the Board's preference for comprehensive total cost benchmarking; and 3) There is no assurance that U.S. utilities record all of their CDM expenses within the customer service and information cost category. [5]

To solve the first two problems, PSE added in THESL's CDM expenses and re-added customer service and information expenses back into the total cost definition for U.S. utilities. This made the cost definitions comparable between THESL and the U.S. sample, addressed PEG's concern, and made the cost definitions far more comprehensive than the definition used by PEG (which excludes all customer service and information expenses).

It is not known if all U.S. utilities report CDM costs in the customer service category. PEG claims on page 25 of its Report that CDM often constitutes the largest expense for the customer service and information expenses, thus somehow justifying the exclusion of the <u>entire</u> cost category for the U.S. sample only (THESL non-CDM customer service and information expenses are still included in the PEG definition). However, PEG does not provide any evidence that CDM constitutes the largest expense component of the customer service and information category, when asked in 1-THESL-24 (d).

To assist with this issue, PSE contacted FERC directly; the "FERC Form 1 team" explained to PSE that each state records these expenses differently, and there is no clear guidance on the issue. More specifically, the FERC Form 1 team stated:

[5] PEG claims in its response to 1-THESL-24 (a) to have subtracted out all of the customer service and information expenses not related to CDM for both the historical and projected THESL costs. This statement is incorrect, based on PSE's review of PEG's working materials, where no such adjustment is apparent nor mentioned in the PEG Report.

> Demand-side management (DSM) is a distribution activity regulated at the local jurisdictional level, not at the Federal level. Each jurisdiction sets its own methods for the accounting for and recovery of DSM activities, including direct expensing or recovery through of some or all of the costs in a regulatory asset. They may also have specific reporting requirements for DSM activities. Look to each company's tariff, and the local jurisdictional authority, for specific information on the treatment of DSM activities, and in which regulatory accounts such activity is charged.[6]

In an effort to provide conservative evidence in this proceeding and only address clear-cut necessary changes, PSE will assume that U.S. utilities report all CDM activities in the customer service and information expense category (even though this is likely not the case for all U.S. utilities). Thus, PSE included all of THESL's CDM expenses, which are projected at $51 million in 2015. Along with the smart meter expense inclusions for THESL, this assumption also makes the PSE Reply Report less favorable to THESL (e.g., if we were able to ascertain all CDM expenses for each utility and how they were recorded, THESL's results would most likely be better).

3.3 Adjustment #3: Model Specification with Urban Core and High Voltage Variables

PEG modified PSE's U.S. model by removing the urban core variable and including a high voltage capacity variable.[7] In this PSE Reply Report, following established industry practice, PSE removed PEG's high voltage variable, which is statistically insignificant and incorrectly signed, and re-included PSE's urban core variable, which is logical, signed correctly and statistically significant at a 99% confidence level.

The fact that the high voltage variable is signed incorrectly (it should be positive, but is negative in the PEG Report Corrections) and statistically insignificant at even the 90% confidence level disqualifies the variable from being included. Business condition variables that are incorrectly signed or statistically insignificant are not included in econometric benchmarking models. PEG's use of this variable, and its exclusion of the urban core variable, are not in-line with benchmarking best practices. PEG has stated the need for business condition variables to be correctly signed and statistically significant in a report to the Board. In a report dated March 20, 2008 "Benchmarking the Costs of Ontario Power Distributors" on page 52, PEG writes:

> All included business conditions were required to have elasticity estimates that were plausible (e.g. sensibly signed) and significantly different from zero. All variables found to be statistically significant were included in the final model. Since, additionally, we consider for inclusion only variables that are predicted by theory or that seem relevant on the basis of our industry experience, the model is not a 'black box' that confounds attempts at earnest appraisal.

In this proceeding, PEG has provided conflicting models with different signs for the high voltage variable, but in both models the variable is statistically insignificant. PEG's original December 2014 Report provided a model in Table Three that showed a statistically insignificant high voltage variable, but one that was positively signed. Then in PEG Report Corrections, PEG submitted a revised Table Three; this time the high voltage variable was <u>negatively</u> signed, but still statistically

[6] Correspondence from FERC.

[7] PEG also removed the percent undergrounding variable, although failed to mention this change or explain why the change occurred in the PEG Report.

Table 2 PSE Reply Report Cost Model Results

Year	Percent of U.S. Total Cost Econometric Benchmark	Total Cost Econometric Benchmark, $M	Total Cost THESL, $M
2002	-28.0%	$591	$446
2003	-26.5%	$602	$462
2004	-25.4%	$600	$466
2005	-32.4%	$638	$461
2006	-29.2%	$641	$479
2007	-29.2%	$676	$505
2008	-26.0%	$687	$529
2009	-22.6%	$713	$569
2010	-17.8%	$739	$619
2011	-14.0%	$756	$657
2012	-13.9%	$739	$643
2013	-6.3%	$755	$708
2014	-4.6%	$816	$780
2015	4.1%	$843	$878
2016	5.2%	$895	$942
2017	6.2%	$943	$1,003
2018	6.3%	$993	$1,057
2019	7.0%	$1,046	$1,121

5 PSE Conclusions

After making the three straightforward adjustments previously discussed, PSE finds that THESL's total costs are 15.2% below benchmarks in 2010-2012. During the Custom IR period, THESL's costs remain within the 4th Generation IR 0.3% stretch factor range. THESL's SAIFI is historically above benchmarks, but converges towards benchmarks during the Custom IR period. THESL's SAIDI is below benchmarks, and is projected to continue to be lower during the Custom IR period.

Based on these results and the discussions throughout this Reply Report, PSE's conclusions are:

- A stretch factor during THESL's Custom IR plan of 0.3% is consistent with 4th Generation IR. THESL's total cost results remain in the "normal" range of +/- 10% and implies the 0.3% value. Reliability is mixed, with SAIFI being worse and SAIDI being better than expected. Throughout the Custom IR period, however, SAIDI is projected to be over 100% below benchmarks and statistically superior, whereas THESL's SAIFI is projected to converge towards the benchmark and be statistically average during the Custom IR period.
- PEG's suggestion of lengthening the Custom IR plan to eight years from five should be rejected. THESL's 5-year Custom IR proposal provides an improved alignment between reliability and costs while maintaining total cost levels within the "normal" range. Lengthening the time period will stunt this improved alignment.
- THESL's 2015 test year total cost levels are reasonable from a benchmark perspective. Even with the conservative nature of PSE's Reply Report results, THESL's 2015 total costs are in the "normal" range.
- Given the enhancement in reliability resulting from THESL's proposal (in particular for SAIFI), the Custom IR plan will better align THESL with its total cost and SAIFI benchmarks. This is an improvement and is likely to provide value to THESL customers.

cost relative to benchmark, and I believe you said the numbers were 33 percent versus 7 percent. Do you recall that?

DR. KAUFMANN: Roughly, yes.

MR. SMITH: Roughly. And that's a 26 percent difference?

DR. KAUFMANN: Yes.

MR. SMITH: And you identified that your estimation is that the urban core variable accounts for 15 percent?

DR. KAUFMANN: Correct.

MR. SMITH: So that would leave 11 percent, being the difference that arises from the other cost comparability issues that have been identified?

DR. KAUFMANN: Assuming that the PSE costs had been computed correctly, yes.

MR. SMITH: Okay. Now, you're an economist, sir?

DR. KAUFMANN: Yes.

MR. SMITH: And you're not an engineer?

DR. KAUFMANN: No.

MR. SMITH: And you are not tendered and qualified as an engineer?

DR. KAUFMANN: No.

MR. SMITH: And in fact, you were asked an interrogatory -- it's THESL 36 -- and that interrogatory was asked in relation to the appendix attached to the PSE benchmarking study. Do you see that?

DR. KAUFMANN: Correct.

MR. SMITH: And that is the report -- now I've misplaced it -- but that's the report that Mr. Sonju authored; correct?

DR. KAUFMANN: Yes.

MR. SMITH: And what you say there, after being asked whether you agree or disagree with PSE findings laid out in the engineering study, what you say is that:

> "Dr. Kaufmann has reviewed and considered PSE's engineering report. However, because Dr. Kaufmann is not an engineering expert, he does not have an opinion on the technical merits of PSE's engineering analysis."

DR. KAUFMANN: Correct.

MR. SMITH: And that's a fair statement?

DR. KAUFMANN: It is.

MR. SMITH: And that fair statement would apply, I take it, with equal force to Toronto Hydro's Distribution System Plan?

DR. KAUFMANN: I'm not so sure about that. That's not a completely engineering-based analysis where -- what I'm talking about here are the technical merits, in terms of the actual quantitative evidence that was developed by them in terms of the impact of metro core conditions relative to, you know, urban residential conditions, and the impact -- the quantitative change of operating in one set of conditions versus another, the impact of that.

That is mostly what I meant, in terms of the technical merits.

MR. SMITH: Right. So let me ask the question a bit

DR. KAUFMANN: Yes.

MR. SMITH: I took it from THESL 34 that your standard practice was not to include business condition variables in reported econometric results when they're not statistically Significant. And that is correct?

DR. KAUFMANN: That is correct. Standard practice.

MR. SMITH: Okay. And in the 2008 report to the Board there was a similar observation made. Do you have the compendium handy?

DR. KAUFMANN: I do.

MR. SMITH: And you will see, if you look at page 2 of this compendium -- now, this is from the 2008 report that was authored by PEG; correct?

DR. KAUFMANN: Yes.

MR. SMITH: And am I correct that this report was not authored by you?

DR. KAUFMANN: You are correct.

MR. SMITH: It was authored by Dr. Lowry?

DR. KAUFMANN: Yes.

MR. SMITH: And he was then the president of PEG; is that correct?

DR. KAUFMANN: He still is. I'm a senior advisor at PEG.

MR. SMITH: Okay. And what he says in looking at the model --

DR. KAUFMANN: Actually, I should correct. We were both partners in PEG at the time.

MR. SMITH: So what we have excerpted there on the first page or the second page of the compendium, here you're talking about the -- or what's being talked about is the featured model. And what is reflected there is, as it says in the third paragraph:

"All included business conditions were required to have elasticity estimates that were plausible, for example, sensibly signed and significantly different from zero."

And that was a correct statement?

DR. KAUFMANN: Yes.

MR. SMITH: And that applied to all business condition variables which PEG determined should be included?

DR. KAUFMANN: In this particular model, yes.

MR. SMITH: Now, can I ask you to turn to page 32 of your report? Actually, it may be better -- this is in your original report. A letter was filed on behalf of Board Staff on December 17th, 2004, which updated this table 3, and you provided a revised table 3; correct?

DR. KAUFMANN: Yes, yes.

MR. SMITH: Maybe we could have that pulled up.

MS. HELT: Mr. Smith, just for clarity on the record, I believe that was 2014, not 2004; is that correct? Friday afternoon?

MR. SMITH: Yes, it is. 2014.

There we go. So if we turn to page 2 of that letter -- sorry, page 3. Page 3 attaches your revised data and model. Do you see that?

DR. KAUFMANN: I do.

MR. SMITH: And this is essentially revising the table that could be found at page 32 of your initial report?

DR. KAUFMANN: Yes.

MR. SMITH: And what you're revising there is that there were certain errors in the MVA data; correct?

DR. KAUFMANN: The MVA of transformation. That's correct.

MR. SMITH: Right. That's the high-voltage -- that relates to the high-voltage variable?

DR. KAUFMANN: It does, yes.

MR. SMITH: Right. Now, if we could just spend a minute on this so I understand, the business condition variables that are set out on this table, am I correct that those are variable K, which is capital price?

DR. KAUFMANN: Yes.

MR. SMITH: And that has an asterisk beside it, and that means that it is statistically significant at the 95 percent level?

DR. KAUFMANN: Yes.

MR. SMITH: And then we have N, which is the number of retail customers; correct?

DR. KAUFMANN: Correct.

MR. SMITH: And D, which is peak demand?

DR. KAUFMANN: Mm-hmm. Correct.

MR. SMITH: I ought to have covered that off. But both of those are statistically significant at the 95 percent level?

DR. KAUFMANN: Yes.

MR. SMITH: And then the third -- sorry, the fourth business condition variable is cap, C-A-P; correct?

DR. KAUFMANN: Yes.

MR. SMITH: And that is your high-voltage business condition variable?

DR. KAUFMANN: Yes, it is.

MR. SMITH: And that variable is not statistically significant at the 95 percent level, is it?

DR. KAUFMANN: No, it's not.

MR. SMITH: And if we wanted to know its statistical significance, what we do is we look at the P value and take 1 minus the P value; correct?

DR. KAUFMANN: Yes.

MR. SMITH: So that tells us that its statistical significance is roughly 59 percent?

DR. KAUFMANN: Actually, the statistical significance is 41 percent. That is the...

MR. SMITH: But --

DR. KAUFMANN: And as I explained in my examination-in-chief, there was a good -- we did this. I explicitly included this to show that we had done the work to do what we could to control for the high-voltage issue, and I wanted to display the results of that work. This does not have -- so it's not standard practice, but this was a very important issue in fourth-generation IR. I wanted to show we addressed this issue.

This was the best we could do because we could not actually adjust the cost, as we would have liked to have

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UNDERTAKING NO. J9.2:

Reference(s):

To review the Figures in SEC's cross-examination compendium.

RESPONSE (Prepared by PSE):

PSE was asked to comment on conclusions made by Dr. Kaufmann in undertaking responses J3.6 and J3.7, with respect to the discrepancies in capital cost inflation rates underlying the PSE and PEG models. The request for PSE commentary originated in the course of Mr. Shepherd's cross-examination of Ms. Klein, where Mr. Shepherd referred to PSE's capital inflation price assumptions as "errors" discovered and corrected by Dr. Kaufmann. PSE disagrees with Dr. Kaufmann's conclusions and Mr. Shepherd's comments in relation to PSE's earlier evidence. PSE provides the following response.

Having reviewed PEG's responses to J3.6 and J3.7, PSE understands that the discrepancy between the PEG and PSE models on capital price inflation is a product of a late model adjustment performed by PEG in the course of completing the Oral Hearing undertaking responses. Prior to the submission of Dr. Kaufmann's undertakings, both the PSE and PEG models utilized identical capital input price assumptions originally developed by PSE. At no point prior to submission of undertaking responses J3.6 and J3.7 did PEG voice any concerns regarding PSE's capital inflation assumptions or ask any questions to investigate the matter further.[1]

[1] At the request of PEG and Board Staff, PSE provided its models, data, and computer code to PEG shortly after the PSE report was filed in July 2014. This was done in order to move the proceeding further by allowing PEG the maximum amount of time to thoroughly review all of PSE's materials which included the underlying assumptions. PEG filed its report in December.

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PEG bases its new capital asset inflation assumption on the 2003-2013 average annual growth rate of the Canadian Electric Utility Construction Price Index (EUCPI), which amounts to a rate of 2.0% over the 10-year period. PSE, on the other hand, based its capital asset inflation assumption on the long-term (40-year) average annual growth rate of the EUCPI and the Constant Interest Rate Assumption, which produced a result of about 4.5%.

PSE has a number of methodological concerns with PEG's new capital price assumption. In PSE's opinion, there are three main reasons why PEG's 2003-2013 growth rate assumption is inappropriate and should be rejected in favor of PSE's original assumption, which was used by PEG throughout the proceeding until it filed undertakings J3.6 and J3.7 at Mr. Shepherd's request. These reasons are:

1. The Electric Utilities Construction Price Index (EUCPI) utilized by PEG includes financing costs, which can distort construction prices if they are not properly controlled for. The 2003-2013 timeframe used by PEG as the basis for its 2015-2019 capital price inflation rate featured rapidly declining interest rates, which materially understate PEG's inflation assumptions.
2. If PEG chose to use the most recent 10-year period as the basis for its forward-looking inflation assumption, the appropriate means of doing so would be by using the Handy-Whitman Index of Public Utility Construction Costs – an authoritative U.S. source on utility construction prices, which isolates the effect of financing costs on utility construction prices. Using the Handy-Whitman Index for electric distribution construction prices, PEG's future capital construction assumption would be set at 6.1%/year – significantly higher than PSE's current assumptions.

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3. PSE's engineering experience in producing cost estimates and construction work plans suggests that over the next five years the capital asset inflation can be expected to fluctuate around 4-5%. This assessment is based on recent project construction close-out costs, shortages of specialized labor, and levels of demand for transmission and distribution materials driven by emerging economics and aging North American infrastructure.

The remainder of this response discusses each of the three above-noted considerations in more detail.

1. Issues with using 2003-2013 Growth rate in the EUCPI index.

The EUCPI includes financing costs which will drive down the growth rate during periods of declining interest rates embedded within the index. Statistics Canada states that one of the data sources for the index is financing costs which are gathered from the Bank of Canada.[2]

The relationship between the EUCPI and interest rates can be shown by including the interest rate changes into a table with the EUCPI changes. In PEG's response to J3.6, Dr. Kaufmann showed the historical growth rates of the EUCPI from 1973-1983, 1983-1993, 1993-2003, and 2003-2013. The implication appears to be that PSE included the 1970s time period because of the rapid increase in the EUCPI so as to artificially drive up the EUCPI growth rate. That implication would be incorrect. Instead, PSE included the 1970s time period because 40 years is sufficiently long to include periods of rapid interest rate increases and periods of rapidly declining

[2] http://www23.statcan.gc.ca/imdb/p2SV.pl?Function=getSurvey&SDDS=2316#a

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interest rates. Additionally, we used the 40-year period because this was the assumption used by PEG in 4th Generation IR regarding the useful life of assets.

Below is a table of EUCPI growth rates produced by PEG in J3.6 but now augmented with the interest rate growth rates inserted for those same time periods and the 40-year growth rates also calculated.[3]

	EUCPI Annual Average Growth Rate (includes financing costs)	Interest Rate Annual Average Growth Rate (10-year U.S. Treasury)	
1973-1983	9.6%	4.8%	Increasing interest rate period
1983-1993	3.2%	-6.4%	Declining Interest rate period
1993-2003	2.4%	-3.8%	Declining Interest rate period
2003-2013	2.0%	-5.3%	Declining Interest rate period
1973-2013	4.3%	-2.7%	Declining Interest rate period

Using PEG's suggestion of considering only the 2003-2013 EUCPI growth rate of 2.0% would artificially reduce growth due to the substantial decline in the interest rates during that period. Embedding this decline into the projected data is tantamount to assuming interest rates will continue to decline by 5.3% per year over the next five years, which is unrealistic.

2. The Handy-Whitman Index

Both PSE's and PEG's research use the U.S. Handy-Whitman construction cost indexes for electric distribution assets. These indexes are not influenced by financing costs. Electric utility capital asset inflation, measured by the Handy-Whitman

[3] PSE's 4.55% assumption does not match the 1973-2013 number exactly because we actually used the 1972-2012 time period as that was the most recent information available at the time of the original research. We use these time periods to align with what PEG showed in response J3.6.

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indexes, has far outpaced general economy-wide inflation trends for the last ten years.[4] Assets used for electric distribution are quite different from goods generally used throughout the economy. This divergence in the electric distribution asset inflation rate corresponds to the growth in emerging global economies, efforts to address aging infrastructure resulting from the build out of capital infrastructure in the post-World War II era that now requires replacement, and the lack of an adequate supply of specialized labor within the industry.

In the table below we examine how capital asset inflation has increased over the 2003-2013 time period cited by PEG as the most appropriate time period to use. The table shows the six different regions of the U.S. produced by the Handy-Whitman publication.

	2003-2013 Handy Whitman Indexes for Total Distribution Electric Plant Average Annual Growth Rate (does not include financing costs)
North Atlantic	6.3%
South Atlantic	6.3%
North Central	5.8%
South Central	6.2%
Plateau	6.2%
Pacific	5.9%
U.S. Average	6.1%

[4] Please see a newsletter article, entitled "Uncharted Waters," authored by Mr. Sonju regarding the divergence of general economy-wide inflation and recent capital asset inflation, which can be located at http://www.powersystem.org/media/articles/pse-spring13-web.pdf

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If the 2003-2013 time period is seen by PEG as the most appropriate and a constant interest rate assumption is used, PEG should have inserted one of the numbers in the table above into its model, rather than the 2.0% EUCPI growth rate influenced by the pronounced decline in interest rates during the 2003-2013 time period. If PEG had instead inserted the North Atlantic Handy-Whitman growth rate of 6.3%, for example, PSE estimates that PEG's findings would show THESL in the 0.3% stretch factor range during the historical time period (recall its finding is +8.0% during that time period) and only move THESL to Group 4 during the Custom IR period with a stretch factor of 0.45%, rather than 0.6%.

3. PSE Experience with Electrical Construction Projects

PSE conducts a large number of engineering studies for electric utilities. Our engineers and clients have noticed the increase in capital asset prices throughout the past decade. We are also aware of industry discussions about the shortage of specialized labour, expected to persist at least for the next five years. The aging infrastructure within the North American industry and the demand from the emerging global economies have also contributed to the capital asset inflation levels.

In recent years, PSE's engineering professionals have typically used a capital asset price inflation assumption between 4% and 5% in their engineering and design work. This rate assumes some slow-down in inflation from the last ten years (which was approximately 6%), as measured by the Handy-Whitman indexes, and we judge it to be the most realistic expectation for capital asset inflation within the U.S. electric distribution industry.

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The long-term EUCPI growth rate of 4.5% seems reasonable to PSE's engineering expert, Mr. Sonju, but PEG's assumed growth rate of 2.0% does not. This opinion is based on:

- The review of recent trends in project close out costs,
- Review of the recent history if the Handy-Whitman indexes for electric distribution,
- The demand for electric transmission and distribution materials driven by the emergence of global economies,
- Aging infrastructure, which will likely cause increased capital spending across North America (thus driving up demand for capital assets), and
- The lack of supply of specialized labour within the industry.

In summary, PEG's newly introduced capital asset inflation assumption of 2.0% should be rejected along with its new model results found in J3.7. The original assumption, used by both PSE and PEG throughout this proceeding, should continue to be used.

Given the recent discussions regarding appropriateness of certain variables, their definitions and other model assumptions, it may be helpful to summarize where the benchmarking results are in light of PEG's acceptance of bad debt expenses and the continued use of the original assumption on capital asset inflation, as substantiated by PSE above. In the table below we summarize the results, now noting there are only two main disagreements between PEG and PSE, assuming the original capital asset inflation assumption remains. The remaining disagreements are:

1. PEG's removal of all of the customer service and information expenses from the U.S. data in its model. PEG defends this treatment by stating that CDM expenses

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for THESL are not included in distribution rates. There is precedent in the 4th Generation IR benchmarking work to include expenses not included in distribution rates (e.g., CIAC) to accomplish cost comparability. PSE corrected the cost comparability issue by re-including the U.S. customer service and information expenses and adding in THESL's CDM expenses.

- From Dr. Kaufmann's testimony, the two cost comparability issues amounted to about an 11% difference in results between PEG and PSE. With the bad debt issue (which had an impact of about 2%) now resolved the remaining difference due to the CSI/CDM disagreement is roughly 9%.

2. In PEG's model the urban core variable is excluded, and the high voltage variable is included. Whereas in PSE's model the urban core variable is logically-signed and statistically significant at the 99% level, PEG's high voltage variable is incorrectly-signed and statistically insignificant.
    - Based on Dr. Kaufmann's testimony, the model differences amount to roughly 15% of the 24% difference in results between PEG and PSE.

Putting aside PEG's new capital asset inflation assumption for the reasons articulated above, the table below summarizes the results and the two remaining main disagreements.

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Summary of Benchmarking Results				
	2010-2012	2015	2019	Stretch Factor Implication
PEG Result (after the bad debt correction, found in response J3.5)	8.0%	27.0%	31.7%	Historical period = 0.3%, Custom IR period = 0.6%
Approximate PEG Result (After making the CSI/CDM Adjustment suggested by PSE)	-1%	18%	23%	Historical period = 0.3%, Custom IR period = 0.45%
PSE Reply Result (After CSI/CDM adjustment and substituting urban core for high voltage variable)	-15.2%	4.1%	7.0%	Historical period = 0.15%, Custom IR period = 0.3%

at three times the rate of the benchmark -- and I understand that you may not agree that that is true, but if it's in fact true, then how does that reconcile with your request for more money?

You're asking for $1.2 billion over the next five years; this evidence appears to suggest that that is unreasonable. I am inviting you to explain why it is still reasonable, even if this is true.

[Witness panel confers]

MS. KLEIN: So again, Mr. Shepherd, with respect to PEG's numbers, that's something that we would have to take subject to check.

But with respect to the reasonability of our requests, that is, in fact, this application and what we have endeavoured to demonstrate to the Board through the thousands of pages of evidence to justify the nature of the funding request, the revenue requirement that we seek through this application. And then we have sought to provide additional data points through PSE's benchmarking study, as well as a number of other third-party reports to the Board and through the evidence that you have heard from the witnesses over the last nine days.

MR. SHEPHERD: You will agree with me that the reasonableness of your request -- from a top-down point of view -- recall bottom-up, top-down, the Board requires both, right?

MS. KLEIN: Sorry, I didn't hear the last part of your sentence there.

MR. SHEPHERD: The RRFE requires both. It requires a bottom-up analysis and it requires a top-down analysis; isn't that right? I think we agreed on that.

MS. KLEIN: I think we have maybe different terminology for top-down and bottom-up. Maybe you could just help me understand what you mean when you say the RRFE requires a bottom-up and a top-down.

MR. SHEPHERD: Why don't you rephrase it the way you think is correct?

MS. KLEIN: Well, I'm not actually sure what you mean, so maybe you could tell me what you mean and then I can try to answer that question for you.

MR. SHEPHERD: We spent some time going through this. I understood you to be saying that the RRFE requires you to provide evidence that a top-down analysis shows your costs to be reasonable. Is that not what your evidence is?

MS. KLEIN: I see. By "top-down" you're referring to what we would call the external third-party benchmarking evidence with respect to the reasonableness of our cost forecasts?

MR. SHEPHERD: Yes.

MS. KLEIN: We have provided that in response to the Board's guidance in the RRFE and elsewhere.

MR. SHEPHERD: That is a requirement of the RRFE, that you show reasonableness through that kind of benchmarking, right?

MS. KLEIN: It is the guidance contained within the RRFE, yes.

MR. SHEPHERD: So if the Board concludes that the correct top-down or benchmarking analysis is in fact Dr. Kaufmann's, which shows you 39 percent higher than the benchmark, is it reasonable to conclude, therefore, that the amount of money that you should get from the ratepayers should go down?

MS. KLEIN: Again, Mr. Shepherd, I think you're asking me to take as an assumption that the PEG analysis is the appropriate analysis here. Our view is that the PSE analysis is the appropriate analysis.

But quite apart from that, the justification for the funding that we have requested is contained within the details of the application that the company has put forward. I think we have about 46 or so capital business cases, and I can't remember how many OM&A, but I think it is 22 or so, with those detailed justifications for the revenue requirement that we're seeking over the five years on what we would say is a needs-based assessment for what we need to serve our customers over that period.

MR. SHEPHERD: So then even if the benchmarking evidence shows that your costs are too high, the Board should rely solely on your bottom-up analysis? Is that right?

MS. KLEIN: Mr. Shepherd, I don't agree that the benchmarking analysis shows the costs are too high. What I'm saying is that in addition to the benchmarking analysis there is the company's own evidence with respect to the reasonableness of the request, as well as a number of other third-party reports on specific items throughout the application intended to provide the Board further data points with respect to the funding that we're seeking over the next five years.

MR. SHEPHERD: I am going to ask you to agree that -- if you go back to page 32, I am going to ask you to agree that under the PEG cost models the increase in your -- in the benchmark is 16.36 percent from 2014 to 2019. Will you accept that, subject to check? It is just 690 minus 593, divided by 593. 16.36 percent.

MR. SMITH: I'm sorry. Just the time frame, Mr. Shepherd?

MR. SHEPHERD: 2014 to 2019. So the custom IR period, the benchmark goes up in the custom IR period by 16.36 percent, according to Dr. Kaufmann. Do you agree with that?

MR. RUCH: Subject to check.

MR. SHEPHERD: And do you agree that the Toronto Hydro costs in the same period go up 47.02 percent, from 738 to 1,085 in that period?

MR. RUCH: Subject to check, but I will note that this uses a different cost definition than the costs that we have put forward in our application.

MR. SHEPHERD: Of course, because it is supposed to be apples-to-apples, right?

MR. RUCH: I think the benchmark to the costs for the purposes of benchmarking, what we have put forward is a different -- there's a difference in the cost definition

- On investment in new technologies, two-thirds (67%) of residential customers and six-in-ten (61%) General Service customers agree that investments in new technology will increase system reliability, make local distribution system more efficient and save money in the long run. About two-in-ten (RS: 19%; GS: 20%) preferred the argument against investment in new technologies. Again, residents in Central Toronto region (73%) are most likely to agree to investment in new technologies.
- Two-thirds (66%) of residential customers and over half (56%) of General Service customers believe that Toronto Hydro should be wise with its spending on equipment and tools, but they also think it is important that staff have the equipment and tools needed to manage the system efficiently and reliably.

Overall Assessment of Plan

Residential Acceptance: Nearly six-in-ten residential (58%) customers accept the rate increase. Most of that support appears reluctant (39%): they “don't like the increase, but feel it's necessary to maintain the grid”. However, only a third (34%) thinks the rate increase is unreasonable and would not support it.

Q: Looking at the cost of the Toronto Hydro plan and outcomes it is expected to achieve, which point of view is closest to your own? Would you say…?	
Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more	4%
I am satisfied with the balance between outcomes and the proposed rate increase	15%
I don’t like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard	39%
I think the bill impact is too high and Toronto Hydro needs to scale back its plans	34%
No response	8%

General Service Acceptance: General Service customers are less supportive of rate increases than residential customers: just under half (48%) of organizational customers support the proposed Toronto Hydro plan and about four-in-ten (41%) think the bill impact would be too high.

Q: Looking at the cost of the Toronto Hydro plan and outcomes it is expected to achieve, which point of view is closest to your own? Would you say…?	
Toronto Hydro should plan to achieve higher outcomes, even if the rates need to go up even more	3%
I am satisfied with the balance between outcomes and the proposed rate increase	15%
I don’t like the rate increase, but I think it is necessary to maintain the grid to a reasonable standard	30%
I think the bill impact is too high and Toronto Hydro needs to scale back its plans	41%
No response	11%

So the particular environment that we're dealing with at this point in time is one that is fairly sensitive to increasing rates?

MR. LYLE: Yes. You can actually, I think, see it even more clearly if you turn to page 140 of the report, in terms of the residential.

So you can see there the cross pressure, the conflicting pressures that consumers feel.

So if you look at the table on the bottom of that page, we asked people:

> "Do you agree or disagree: the cost of my electricity bill is a major impact on my finances that require I do without some other important priorities."

56 percent agree with that, with 34 percent strongly.

But if you look at above the page and you look at:

> "No one likes to pay more for electricity, but I think we have an obligation to maintain the reliability of our local grid for future generations."

You get 80 percent agreeing.

So people have this tension between wanting reliability, wanting to leave behind a good grid. But in the meantime, they have bills to pay and they don't like paying more for anything.

MR. JANIGAN: Reliability, increasing system reliability would be an important element in getting customers to buy into rate increases, for example?

in terms of what is more important.

Now, given that we went that far into the discussion, it made a lot of sense to close the discussion by asking: What do you think overall?

And that's interesting, but really the core of the insights we're looking for here for the work of assessing a plan was on the needs, does this plan address the needs that people identified, which are things like reliability and better communications and outages, and their choices about whether they would do more renewal or less renewal, more modernization or less modernization, without speaking specifically to the plan, which is primarily a technical issue which should be dealt with in a technical process.

So what we're trying to do here is discover the values of the customers, their preferences, and not so much rely on them to make a judgment on whether this is the best plan to meet that.

MR. JANIGAN: But I take it the outcomes they were presented with were largely the outcomes that Toronto Hydro has provided in its plan.

I mean, don't take this as a criticism. That is where you have to get your instructions --

MR. LYLE: But again, in the survey we didn't really dwell on the actual specifics of what would be in the plan.

In the workbooks we actually laid out quite a bit of detail, but the survey itself was focussed on these value choices.

We didn't ask them to take the role of the Board and to make technical decisions about efficiency and about the age of the equipment and the relative health of the equipment and what can you leave longer and what can you not.

We just asked them to say: If it comes down to, at the end of the day, having a system that is -- that maintains its current level of reliability and pay more, or take in a little bit less reliability and pay less, which would you prefer?

And they said: I'll pay more for more reliability overall.

MR. JANIGAN: The majority?

MR. LYLE: Yes.

MR. JANIGAN: Yes.

MR. LYLE: Not everyone.

MR. JANIGAN: No, not everyone.

And I think you termed the instructions, or the materials that were given to the workbook and the focus groups -- something like "Electricity 101"?

MR. LYLE: Right.

MR. JANIGAN: Now, were the students of "Electricity 101" told that Toronto Hydro runs a return on investment that is market-based and is earned on everything they bill to replace every asset?

MR. LYLE: I don't think so. But what we were looking for in the grid was -- or in the workbook was to get their views on what their needs were, and on what value choices they would make.

We weren't looking for policy direction on how to structure the regulation of distributors.

MR. JANIGAN: Okay. Thank you. Those are all of my questions for this panel, Madam Chair.

MS. LONG: Thank you, Mr. Janigan.

Ms. Girvan, are you ready to proceed?

MS. GIRVAN: Yes. Just a second, please.

CROSS-EXAMINATION BY MS. GIRVAN:

MS. GIRVAN: I have a few questions from AMPCO and I just thought I would start with those, as Mr. Grice couldn't be here today. So I will just start with those.

The first question relates to the technical conference Undertaking J1.2, Energy Probe 52. And this relates to performance metrics and the issue about what's been included and not included in the SAIFI and SAIDI calculations.

So the question is: Could we get 2015-2019 projections without MEDs and loss of supply?

I think what we heard on day 2 of the hearing was that the projections for SAIDI and SAIFI for 2015-2019 exclude MEDs, but include loss of supply.

MR. SMITH: Well, unless someone on the panel can correct me, I don't know the answer to whether we can get it or not. I don't think these witnesses know, and I don't know.

But we can certainly make an inquiry, and if we can do it, we will do it.

MR. LYLE: Well, I am happy to. I mean, if you take a look at how people responded, what you see when you look at all the reports that are there is that essentially consumers are conflicted. No one wants to pay more for anything, right?

But also electricity plays a key role in their life, one that they don't normally think very much about.

And so when they have a chance to see the situation in terms of where the grid is and then they're given choices -- and the workbook was interesting in this, in that they were able to see two scenarios with a firm entity in terms of what the different worlds looked like that weren't starkly different, right? There was clearly more reliability if you look at the plan that Toronto Hydro was putting forward than in the run-to-failure plan, but it wasn't the lights were going to go out if you didn't do what they said. It was just you were going to have more problems with reliability if you paid less. If you paid more, you would have less problems with reliability, and then you would also have some other benefits, increased modernization.

MR. SHEPHERD: You presented the customers with two options: We're going to let everything break and then fix it after it breaks, or we're going to fix things before they break. Those were the two options you gave them, right?

MR. LYLE: We gave them the range, yes.

MR. SHEPHERD: Okay. And so you didn't say to them:

MR. LYLE: "Not sure" is important, because that gives people an opt-out if they don't feel they have enough information.

MR. SHEPHERD: Indeed. But I guess you split it up as -- there's three answers that say the plan is okay, and one that says it's not.

MR. LYLE: Well, the first answer actually says it is not okay. The first answer says they should do more. So it is a criticism from the other end.

One criticism says you're not doing enough in terms of outcome. The other criticism says you're not doing enough in terms of keeping prices down. And then there are two in the middle, one of which is someone who thinks it is the right balance and they're happy with it, and one is someone who is frustrated with the price increase but thinks they have to do it.

MR. SHEPHERD: But it's true, isn't it, that the first three answers are: Go ahead and spend the money?

And it is only the fourth answer that's: Don't spend the money. Right?

MR. LYLE: Well, the first answer is actually: Spend more.

MR. SHEPHERD: It is still at least approval of spending as much, right?

MR. LYLE: Yes.

MR. SHEPHERD: So isn't it unusual to have a set of answers in which three of the answers approve at least as much as the person wants, and only one is opposed?

MR. LYLE: No, because if you just ask people: Do you support or oppose an increase, people get frustrated, because they say: I don't want to say yes to a price increase. I don't want a price increase.

If I look at it and I say: Well, I think it's necessary, then I might go along with it. But don't ask me to say I think it's a good idea.

So "support/oppose" leaves people frustrated and not feeling they can totally express their view.

One way to look at that: I don't like the rate increase, but I think it is necessary, that is like an orange light. It says: Okay, I will go along with this. You have made the case. But you need to pay attention to how much you're asking me to pay because I can't keep paying forever at these sort of rates.

So they're saying: Pay attention to my need to keep spending under control.

MR. SHEPHERD: Can you turn to --

MR. LYLE: You're saying something different than the people that say: I'm satisfied with the balance of the outcomes and the proposed rate increase.

They're saying, you know: I'm okay with this. This works for me. That is a green light; it's not an orange light.

MR. SHEPHERD: So go to page 10 of your materials, please.

MR. LYLE: Of the report, or the workbook?

MR. SHEPHERD: Yes. This is your summary of the

5. Revenue Requirement and Rate Framework

1. **As 2015 is a standard rebasing year, a cost-based revenue requirement should be approved under the RRFE.[1]**

   - The components of revenue requirement are return on rate base, depreciation, OM&A costs, Payment in Lieu of Taxes (PILs), and revenue offsets.

     - While depreciation is function of the capital plan, depreciation expense is discussed below.

     - OM&A has been discussed previously.[2]

     - The remaining components of revenue requirement are discussed in this section.

2. **Toronto Hydro's proposed return on rate base is a function of the 2015 rate base and the OEB-approved cost of capital.**

   - The 2015 rate base has been correctly calculated and should be approved.

   - Toronto Hydro has determined 2015 rate base as the average of the opening and closing balances for the net book value of property, plant and equipment plus a working capital allowance.[3]

     - 2015 opening rate base includes the addition of in-service amounts, including those associated with the in-service ICM capital expenditures, as discussed further below.[4]

     - 2015 opening rate base includes the addition of the street lighting assets.[5]

     - 2015 opening rate base also reflects a reduction due to the removal of stranded assets related to the Smart Meter program.[6]

     - 2015 opening rate base also reflects a reduction due to the transition from USGAAP to MIFRS accounting.[7]

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[1] Exhibit 1B, Tab 2, Schedule 3, at page 1, lines 21-23.
[2] Toronto Hydro, Argument in Chief Compendium at Tabs 2 and 3.
[3] Exhibit 2A, Tab 1, Schedule 1 at page 2, lines 1-3.
[4] Exhibit 2A, Tab 1, Schedule 1 at page 11, lines 1-3.
[5] Exhibit 2A, Tab 5, Schedule 1.
[6] Exhibit 2A, Tab 1, Schedule 1 at page 5, line 15.
[7] Exhibit 2A, Tab 1, Schedule 1 at page 11, line 7.

- The following Table shows proposed in-service additions from 2015 through 2019:[8]

	2015	2016	2017	2018	2019
In-service Additions	$539.7M	$671.6M	$505.7M	$441.0M	$529.9M

- While much discussion occurred in the proceeding about the implications of ICM work and ICM True-Up on 2015 rate base, the results of Toronto Hydro's preliminary analysis of ICM jobs and Toronto Hydro's support for a variance account to capture any differences between ICM-related amounts included in 2015 rate base and the amount of ICM in-service additions (ISAs) ultimately found prudent in the ICM true-up should lay this issue to rest.[9]

- As contemplated by the OEB's decision in EB-2012-0064, a review of the ICM spending will take place at the "Segment" level (defined as "project" level in the decision), and will involve reconciliation of jobs within the Segments and between ICM years.[10]

    - This process will necessarily be complex and involve detailed information.[11]

    - While the ICM period concluded at the end of 2014, Toronto Hydro is still in the process of finalizing its financial accounting records for the full 3-year period.[12]

    - Toronto Hydro anticipates filing this information for the ICM true-up in Q2 of 2015.[13]

- Toronto Hydro believes that the true-up process, when complete, will show actual ISAs for the ICM work that are close to current forecast.[14]

- As a result, the impact of the ICM projects on opening rate base, should be generally aligned with the values shown in the filing.[15]

    - Nevertheless, Toronto Hydro recognized the concerns of parties with respect to the implications of the true-up process for the determination of 2015 rate base.

[8] Exhibit K3.3 at Row 44 (as revised March 2, 2015).
[9] OH Transcript, Volume 7 (February 25, 2015) at pages 156-157, lines 10-14.
[10] EB-2012-0064, Decision and Order (April 2, 2013) at pages 75-76.
[11] IR 2B-OEBStaff-39 at pages 4-6.
[12] OH Transcript, Volume 1 (February 17, 2015) at page 106-107, lines 23-9; for a description of the true-up process please refer to Exhibit OH, Tab 1, Schedule 3, Appendix A.
[13] IR 2B-OEBStaff-39 at page 6, lines 4-5.
[14] Exhibit OH, Tab 1, Schedule 3 at page 1.
[15] Exhibit OH, Tab 1, Schedule 3 at page 1, lines 19-23.

- Therefore, as indicated by Ms. Klein at Day 7 of the Oral Hearing, [16]
  - Toronto Hydro supports a variance account to capture the difference between the amount included in 2015 opening rate base associated with ICM projects and the amount ultimately found prudent as a result of the ICM true-up.
  - If any revenue requirement consequence results from this difference, Toronto Hydro proposes that it be cleared as part of the ICM true-up clearance.

- The Cost of Capital and Capital Structure have been calculated as prescribed by the OEB and should be approved.

- In its application, Toronto Hydro indicated that it would apply the 2015 approved Return on Equity outlined in the OEB's Cost of Capital Parameter Updates for 2015 Applications.[17] As it happens, the approved Return on Equity issued by the OEB on November 20, 2017 is the same as the ROE forecast included in the application.[18]

- Toronto Hydro's 2015 debt costs, which reflect market-based actual and forecast debt, are appropriate, and should be approved as requested.[19]

- Toronto Hydro continues to comply with the OEB-deemed Capital Structureto determine its overall Weighted Average Cost of Capital. [20]

3. Depreciation expense has been appropriately calculated pursuant to MIFRS requirements and the asset service lives and policies approved by the OEB in EB-2010-0142.

- Toronto has provided details regarding the Depreciation, Amortization and Depletion by Asset Group for the 2011 to 2013 historical years, 2014 bridge year and 2015 test year.[21]

- Toronto Hydro reviews the useful lives of its assets annually to ensure that they remain appropriate. With the exception of the change noted below, there have been no material changes to the estimated useful lives approved in the last rebasing application (EB-2010-0142).[22]

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[16] OH Transcript, Volume 7 (February 25, 2015) at page 156-157, line 10-14.
[17] Exhibit 5, Tab 1, Schedule 1 at pages 1-2.
[18] Board Letter, Cost of Capital parameter Updates for 2015 Application (November 20, 2014).
[19] Exhibit 5, Tab 1, Schedule 1 at pages 3-5; Exhibit 5, Tab 1, Schedule 2 at page 2.
[20] EB-2009-0084, Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (December 11, 2009).
[21] Exhibit 4B, Tab 1, Schedule 1, Appendix A.
[22] Exhibit 4B, Tab 1, Schedule 1 at page 4, lines 4-6.

- Toronto Hydro has elected to depreciate its Customer Care and Billing software over ten years, rather than the 4 to 5 years usually used for software, because this software is designed to be upgraded to meet new requirements, rather than having to be fully replaced, thereby extending its estimated useful life.[23]

- For the purpose of this application (as well as historically), Toronto Hydro has calculated depreciation based on the month that an asset is in service, rather than on the basis of the half year rule. This approach more accurately reflects the asset's future economic benefits over its useful life and better aligns with accounting requirements.[24]

4. Toronto Hydro estimated 2015 PILs cost are appropriate and should be approved.

- Toronto Hydro manages its tax costs diligently in an effort to keep the effective rate of tax as low as possible.[25]

- Toronto Hydro has calculated PILs appropriately using the OEB approved model.[26]

5. Toronto Hydro's forecast Revenue Offsets have been appropriately calculated and should be approved.[27]

- Other than the proposed revenue offsets related to wireline attachments, which are the subject of a separate phase of this proceeding, parties have not raised any issues with the forecasted amounts for 2015.

- With the transfer of former street-lighting assets into Toronto Hydro's ratebase, Toronto Hydro has included the contract revenue from the City of Toronto used to offset the maintenance costs of these assets in its calculation of revenue offsets.[28]

6. The overall Service Revenue Requirement for 2015 of $ 707.3M has been fully justified.

- After subtracting Revenue Offsets of S46.1M, the requested Base Revenue Requirement is $655.0M, which Toronto Hydro requests the OEB approve as the basis for setting 2015 distribution rates.[29]

[23] Exhibit 4B, Tab 1, Schedule 1 at page 5, lines 1-10.
[24] Exhibit 4B, Tab 1, Schedule 1 at pages 5-6.
[25] Exhibit 4B, Tab 2, Schedule 1 at page 1, lines 1-12.
[26] Exhibit 4B, Tab 2, Schedules 1 and 2.
[27] Exhibit 3, Tab 2, Schedule 1.
[28] Exhibit 3, Tab 2, Schedule 1 at page 1, lines 8-10.
[29] Exhibit 6, Tab 1, Schedule 1 at page 1, Table 1

7. 2016-2019 Rate Framework should be approved because it is consistent with the OEB's RRFE guidance and adapts it to Toronto Hydro's circumstances in innovative ways.

- Toronto Hydro is seeking approval of its custom Price Cap Index ("PCI") framework to set distributions rates for 2016 to 2019.[30]

- As previously noted, Toronto Hydro is proposing a custom rate framework that is responsive to and consistent with the OEB's policy guidance under the RRFE that the Custom IR method is most appropriate for utilities with significant, long-term capital needs and that the OEB expects robust evidence filed in support.[31]

- **Rates for Years 2 through 5 will be adjusted by a custom price cap index.[32]**

- In 4th Generation IR, the standard price cap index is "I – X": inflation less productivity and the approved stretch factor.[33]

- Toronto Hydro's rate framework proposal adapts the OEB's standard price cap index in two ways, both of which are consistent with OEB's guidance for Custom IR applicants:

    - Toronto Hydro proposes a custom stretch factor value on the basis of external total cost benchmarking results.

        - The stretch factor is derived using the OEB's methodology and Power System Engineering's Total Cost Benchmarking study results (PSE Benchmarking Results) which found that,[34]

            - Toronto Hydro's total costs are forecast to remain within +/- 10% of its benchmark through the duration of the 2015-2019 period according to the PSE Benchmarking Results.[35]

        - Using the OEB's Stretch Factor demarcation points, the PSE Benchmarking Results place Toronto Hydro in Group III, corresponding to a 0.3% stretch factor.[36]

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[30] Exhibit 1B, Tab 1, Schedule 1 at page 1, lines 21-23
[31] Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach (October 18, 2012) at page 19 [*RRFE Report*].
[32] Exhibit EC, Evidence Conference Presentation at page 15.
[33] Exhibit 1B, Tab 2, Schedule 3 at page 10, lines 4-5.
[34] Exhibit 1B, Tab 2, Schedule 3 at page 7; Exhibit 1, Tab 2, Schedule 5, Appendices B and C.
[35] Exhibit 1B, Tab 2, Schedule 5, Appendix C at page 11.
[36] Exhibit 1B, Tab 2, Schedule 5, Appendix C at page 9.

        - Retaining a stretch factor set on the basis of total cost benchmarking results is consistent with the OEB's guidance that the annual adjustment mechanism for Custom IR applicants should be informed by external benchmarking.[37]

    - Toronto Hydro proposes a Custom Capital ("C") Factor that reconciles Toronto Hydro's significant, long-term capital investment needs within a price cap framework.[38]

        - The C Factor reconciles Toronto Hydro's capital need in excess of what is provided through the OEB's "I – X" framework under 4th Generation IR.[39]

            - Cn is the forecast change in capital-related revenue requirement divided by total revenue requirement.[40]

            - The component of "I – X" that funds fund incremental capital investment is automatically returned to ratepayers.

            - This is accomplished by reducing Cn, and by extension the value of the custom PCI, by Scap*(I – X).[41]

        - Through the C-factor, Toronto Hydro's annual rate adjustment mechanism is informed by the utility's forecasts of the revenue requirement associated with in-service additions resulting from the capital investment plan, consistent with the OEB's guidance to Custom IR applicants.[42]

- Toronto Hydro's proposed ratemaking framework is otherwise unchanged from the standard 4th Generation IR approach.

- The description of each term of the Custom PCI formula and the values of the Custom PCI for which Toronto Hydro is seeking approval are detailed in the evidence.[43]

- Toronto Hydro's approach follows the OEB's policy guidance set out in the RRFE.[44]

    - The proposed rate framework is comprehensive, and cover the entire five year term.

    - The proposed rate framework is informed by Toronto Hydro's forecasts.

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[37] RRFE Report at page 20.
[38] Exhibit EC, Evidence Conference Presentation at page 17.
[39] Exhibit EC, Evidence Conference Presentation at page 19.
[40] Exhibit 1B, Tab 2, Schedule 3, at page 8-10, lines 24-2.
[41] Exhibit 1B, Tab 2, Schedule 3 at page 11.
[42] RRFE Report at page 190.
[43] Exhibit 1B, Tab 2, Schedule 3 at pages 12-13.
[44] Exhibit 1B, Tab 2, Schedule 3 at pages 14-15.

- The proposed rate framework embeds the OEB's inflation and productivity factor directly into the custom PCI.

- The proposed rate framework is informed by external benchmarking evidence.

- The proposed rate framework shares benefits with ratepayers upfront,

    - explicitly through the embedded productivity and stretch factors, and

    - implicitly through the efficiencies gained by the utility's rigorous procurement process which determines 81% of the capital costs through market-driven analyses mechanisms.[45]

[45] Toronto Hydro, Argument in Chief Compendium at Tab 2, Section 4.2.

The program turned out mainly as we expected it to. We completed, or have in progress, nine out of ten of the filed jobs. We substituted the work as required based on the emerging needs, and we're coming in at a 5 percent variance above the overall forecasted costs.

MR. SMITH: Let me ask this follow-up question, then. How does that true-up process that you identified relate, then, to the opening rate base that Toronto Hydro has asked for in this proceeding?

MS. KLEIN: Sure. So true-up is about revenue reconciliation between approved and actual in-service assets during the IRM, which, in our view, is distinct from the 2015 opening rate base.

However, a portion of the 2015 opening rate base will be based on in-service additions that relate to ICM spending.

And we understand that there is some connection between the true-up process and the opening rate base for this proceeding.

We are confident in the prudence of the spending that is associated with the forecasts of the ICM segments, and that would include some of the spending that would be above forecast in those segments. And in order to provide the Board and the parties with some comfort regarding those details, we would -- we would propose actually a variance account to capture any difference between the amount of the ICM-based in-service additions that are currently forecast, and then the amount that would be approved by the Board at true-up.

This would effectively mean that 2015 opening rate base would be set on the basis of the utility's forecasts, as in any other rebasing application. But the existence of the variance account would provide the Board with the ability to change the revenue requirement impacts of opening rate base, in the event that any portion of the ICM work is found to be imprudently incurred.

In other words, this would allow this opening rate base to be retroactively adjusted, through the operation of a negative rate rider.

Again, we have high confidence in the prudence of the work, but we understand the parties might want to have an opportunity to satisfy themselves on that point.

MR. SMITH: Okay. I have a question for you, Mr. Seal, or maybe two.

Can you just help us with what's been marked -- I have lost the exhibit cite, but the "Bill impacts" exhibit that we just marked, that you prepared?

What is it that is being shown here, and where did it come from?

MR. SEAL: Certainly. This exhibit is really a summary, as noted at the bottom of that exhibit, from Exhibit 8, tab 7, schedule 1.

So these are our bill impact tables, which are quite detailed bill impacts by year, by various rate components.

And I think during the course of this hearing there have been some indications and some discussion of bill

REVENUE REQUIREMENT AND SUFFICIENCY / DEFICIENCY

Toronto Hydro earns the majority of its revenue through the distribution tariff and earns other revenues through the provision of non-distribution related activities. These other revenues offset the required revenue to be collected from Toronto Hydro's distribution service customers.

The recovery of Deferral and Variance Accounts is not included in the revenue requirement. Deferral and Variance Accounts are recovered through separate rate riders as described in Exhibit 9.

Table 1 below summarizes THESL's 2015 revenue requirement.

Table 1: 2015 Revenue Requirement ($ millions)

	2015 Test Year
OM&A Expenses	265.1
Amortization/Depreciation	206.5
Property Taxes	6.5
Income Taxes (Grossed up)	22.0
Deemed Interest Expense	80.2
Return on Deemed Equity	120.8
Service Revenue Requirement	**701.1**
Revenue Offsets	46.1
Base Revenue Requirement	**655.0**

/C

Full details on the calculation of Revenue Requirement, including the Determination of Net Utility Income, Statement of Ratebase, Actual Utility Return on Rate Base, Indicated Rate of Return, Requested Rate of Return and the Deficiency in Revenue can be found in the Revenue Requirement WorkForm, filed as Exhibit 6, Tab 1, Schedule 2.

customized to fit the specific applicant's circumstances. Consequently, the exact nature of the rate order that will result may vary from distributor to distributor.

The Custom IR method will be most appropriate for distributors with significantly large multi-year or highly variable investment commitments that exceed historical levels. The Board expects that a distributor that applies under this method will file robust evidence of its cost and revenue forecasts over a five year horizon, as well as detailed infrastructure investment plans over that same time frame. In addition, the Board expects a distributor's application under Custom IR to demonstrate its ability to manage within the rates set, given that actual costs and revenues will vary from forecast.

The Board has determined that a minimum term of five years is appropriate. As is the case for 4th Generation IR, this term will better align rate-setting and distributor planning, strengthen efficiency incentives, and support innovation. It will help to manage the pace of rate increases for customers through adjustments calculated to smooth the impact of forecasted expenditures.

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

Annual Adjustment Mechanism

The allowed rate of change in the rate over the term will be determined by the Board on a case-by-case basis informed by empirical evidence including:

- the distributor's forecasts (revenues and costs, including inflation and productivity);

Rate Framework

Overview

- Rate framework rooted in OEB's 4th Generation IRM approach.
  - Year 1: Rebasing
  - Years 2 to 5: Price Cap Index equal to "I – X"

- Toronto Hydro's rate framework customizes the 4th Generation IRM price cap in two ways:
  1. Adds Custom Capital ("C") Factor to reflect capital needs; and,
  2. Adopts the OEB's Stretch Factor that reflects custom benchmarking results.

	Year 1	Years 2 to 5
4th Gen IRM	Rebasing Year	**Standard** Price Cap Index
CIR	Rebasing Year	**Custom** Price Cap Index

Rate Framework

Custom Stretch Factor

- Toronto Hydro applies the OEB's Stretch Factor on the basis of PSE's total cost benchmarking.
- This results in Toronto Hydro's Custom Stretch Factor

Table 3: Demarcation Points and Stretch Factor Values

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

Source: Table 3. Emphasis Added | OEB (2013) *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379)

Rate Framework

Custom Capital Factor

- RRFE provides that CIR is for distributors with significantly large, multi-year capital needs.

Toronto Hydro approach to Custom Capital Factor:

- Reconcile Toronto Hydro's capital need in excess of "I – X" within a price cap framework:
  - Step 1: Reconcile Toronto Hydro's capital need **[C_n]**
  - Step 2: Give back the capital component of "I – X" **[S_{cap} * (I – X)]**

Rate Framework

C-Factor

“C_n”

- C_n = forecast changes in capital-related revenue requirement divided by total revenue requirement.
- C_n is applied to base rates.

$$C_n = \frac{\Delta RR_{cap}}{RR_{total}}$$

Table 1: Calculation of C_n ($ Millions)

Revenue Requirement Component	2015	2016
Interest	80.2	89.5
ROE	120.9	135.0
Depreciation	206.5	221.6
PILs/Taxes	24.0	14.7
Capital-related RR	**431.6**	**460.9**
OM&A	269.5	
Revenue Offsets	(46.1)	
Total RR	**655.0**	

/C

The change in forecast capital related revenue requirement from 2015 to 2016 is $29.3 million ($460.9 million minus $431.6 million). The total revenue requirement in 2015 is $655.0. C_n for 2016 is therefore: **/C**

$$C_n = (460.9 - 431.6) / 655.0 = \mathbf{4.47\%}.$$

Calculating C_n for years beyond 2016 requires a forecast of total revenue requirement. Capital-related revenue requirement, as noted, is determined on a forecast basis. By contrast, OM&A and Revenue Offsets are assumed to increase by "I – X". A more detailed discussion of why this is the case can be found towards the end of this schedule.

Applying this method results in values for C_n that are summarized in Table 2 based on inputs summarized in Table 3. These values represent the amount by which base rates would need to be increased to fund Toronto Hydro's capital needs over the course of the rate term.

Table 2: Values of C_n for 2016 to 2019 (in percent)

	2016	2017	2018	2019
C_n	4.47	8.25	6.68	5.01

/C

Table 3: Inputs for the determination of C_n for 2016 to 2019

Revenue Requirement Component	2015	2016	2017	2018	2019
Interest	80.2	89.5	98.4	103.9	109.2
ROE	120.9	135.0	148.3	156.6	164.6
Depreciation	206.5	221.6	248.3	266.8	287.4
PILs/Taxes	24.0	14.7	22.6	40.3	46.5
Capital-related RR	**431.6**	**460.9**	**517.6**	**567.5**	**607.6**
OM&A	269.5	273.3	277.1	281.0	284.9
Revenue Offsets	(46.1)	(46.8)	(47.4)	(48.0)	(48.7)
Total RR	**665.0**	**687.5**	**747.4**	**800.5**	843.8

/C

With the inclusion of C_n in the custom PCI, Toronto Hydro would receive sufficient funding for its capital needs as presented in the DSP. However, the "I – X" increase retained in the custom PCI from the standard 4th Generation IR framework does provide some degree of incremental funding. Absent additional constraints, the custom PCI formula would risk over-funding relative to Toronto Hydro's capital need because a portion of the "I – X" increase could be committed to capital expenditures. Toronto Hydro proposes to remove this risk through an automatic distribution rate reduction captured in the C-factor to constrain the impact of C_n.

An efficient and principled approach is to reduce the C-factor by a capital-related proportion of "I – X". Toronto Hydro proposes that this "scaling" factor be determined

The above discussion sets out the variables that constitute Toronto Hydro's proposed custom PCI. The resulting PCI value for a given year would, in keeping with IRM principles, be applied to all distribution rates from the previous year to determine the following year's distribution rates.

To summarize, the custom PCI is determined in the following fashion:

$$\mathbf{PCI = I - X + C, \text{ or}}$$
$$\mathbf{PCI = I - X + C_n - S_{cap} * (I - X)}$$

Where,

- "**I**" is the OEB's inflation factor, determined annually
- "**X**" is the sum of:
  - The OEB's productivity factor of 0.0%
  - Toronto Hydro's custom stretch factor, applying the OEB's methodology to Toronto Hydro's alternative benchmarking model
- "**C**" is difference of:
  - $\mathbf{C_n}$, a reflection of Toronto Hydro's capital investment need
  - $\mathbf{S_{cap} * (I - X)}$, an offsetting adjustment required to ensure that the C-factor provides funding only in excess of what is already provided for capital through "I – X"

While the custom PCI cannot be calculated until the OEB determines its inflation factor for a given year, it is possible to develop scenarios using the methodology detailed in this schedule and an assumed value for the I-factor.

Table 5 shows the components of the custom PCI based on an assumed I-factor of 1.7%, its value at the time of writing, and the corresponding value of the custom PCI. This is the same I-factor that is used to calculate bill impacts, which can be found in Exhibit 8, Tab 7, Schedule 1. Again, this is for illustrative purposes only.

Table 5: Custom PCI Values Assuming An Inflation Factor Of 1.7% For Each Year

CUSTOM PCI COMPONENT (%)	2016	2017	2018	2019
I	1.7	1.7	1.7	1.7
X - productivity	0.0	0.0	0.0	0.0
X - custom stretch	-0.3	-0.3	-0.3	-0.3
C_n	4.47	8.25	6.68	5.01
S_{cap}	67.1	69.3	70.9	72.0
Custom PCI	**4.94**	**8.68**	**7.09**	**5.41**

/C

4. CONCLUSION

4.1. Policy Concordance

The manner in which the rate framework submitted as part of this CIR application concords with the OEB's guidance in the RRFE Report is fundamental to Toronto Hydro's development of this application. Toronto Hydro has deliberately chosen a framework that includes a standard rebasing year followed by four years of a custom PCI framework as the mechanism by which to have its distribution rates set over the course of the term. It has done so because, in Toronto Hydro's view, this represents an approach that is appropriately concordant with RRFE guidance. Where this proposed rate framework does not explicitly conform to that guidance, it is Toronto Hydro's view that its approach is reasonable and appropriate. One such example is the explicit inclusion of the OEB's inflation and productivity factors into the custom PCI formula, which goes further than the OEB's guidance to be "informed" by those analyses.

Table 1: Rate-Setting Overview - Elements of Three Methods

<table>
<tr><th colspan="2"></th><th>4th Generation IR</th><th>Custom IR</th><th>Annual IR Index</th></tr>
<tr><td colspan="5">Setting of Rates</td></tr>
<tr><td colspan="2">“Going in” Rates</td><td>Determined in single forward test-year cost of service review</td><td>Determined in multi-year application review</td><td>No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism</td></tr>
<tr><td colspan="2">Form</td><td>Price Cap Index</td><td>Custom Index</td><td>Price Cap Index</td></tr>
<tr><td colspan="2">Coverage</td><td colspan="3">Comprehensive (i.e., Capital and OM&A)</td></tr>
<tr><td rowspan="2">Annual Adjustment Mechanism</td><td>Inflation</td><td>Composite Index</td><td rowspan="3">Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor’s forecasts (revenue and costs, inflation, productivity); (2) the Board’s inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor’s forecasts</td><td>Composite Index</td></tr>
<tr><td>Productivity</td><td>Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor</td><td>Based on 4th Generation IR X-factors</td></tr>
<tr><td colspan="2">Role of Benchmarking</td><td>To assess reasonableness of distributor cost forecasts and to assign stretch factor</td><td>n/a</td></tr>
<tr><td colspan="2" rowspan="2">Sharing of Benefits</td><td colspan="3">Productivity factor</td></tr>
<tr><td>Stretch factor</td><td>Case-by-case</td><td>Highest 4th Generation IR stretch factor</td></tr>
<tr><td colspan="2">Term</td><td>5 years (rebasing plus 4 years).</td><td>Minimum term of 5 years.</td><td>No fixed term.</td></tr>
<tr><td colspan="2">Incremental Capital Module</td><td>On application</td><td>N/A</td><td>N/A</td></tr>
<tr><td colspan="2">Treatment of Unforeseen Events</td><td colspan="3">The Board’s policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario’s Electricity Distributors, will continue under all three menu options.</td></tr>
<tr><td colspan="2">Deferral and Variance</td><td>Status quo</td><td>Status quo, plus as needed to track capital spending against plan</td><td>Disposition limited to Group 1
Separate application for Group 2</td></tr>
<tr><td colspan="2">Performance Reporting and Monitoring</td><td colspan="3">A regulatory review may be initiated if a distributor’s annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.</td></tr>
</table>

In considering its custom approach, Toronto Hydro was particularly concerned with the contents of Table 1 in the RRFE Report.[11] This table provides some of the clearest indications of the OEB's expectations for prospective applicants.

The remainder of this sub-section outlines how Toronto Hydro's proposed rate framework concords with the guidance provided in that table.

The proposed rate framework is comprehensive. Toronto Hydro proposes that the rate framework commence with a standard rebasing year to determine base distribution rates, followed by four years where a custom PCI governs incremental changes to those base rates. Base rates are determined by a base revenue requirement that relates to both capital and operating costs.

The proposed rate framework is informed by Toronto Hydro's forecasts. The rebasing year offers the opportunity to test capital and operating expenditures. The C-factor in the custom PCI is calculated based on a forecast of Toronto Hydro's capital-related revenue requirement during the remainder of the term, which can also be tested. This incorporates expectations of inflation for its capital costs, as set out in Exhibit 2A, Tab 6, Schedule 1.

The proposed rate framework is informed by the OEB's inflation and productivity analyses. The proposed rate framework is not only informed by, but firmly entrenches the OEB's productivity analyses through the inclusion of its inflation and productivity factors within the custom PCI formula. While not a requirement, Toronto Hydro believes this is to be a distinctive element of its proposed rate framework.

[11] RRFE Report at page 13.

The proposed rate framework is informed by benchmarking to assess the reasonableness of the distributor's forecasts. The custom PCI incorporates a custom stretch factor that applies the OEB's methodology of assigning stretch factors but that uses Toronto Hydro's alternative total cost benchmarking model, as set out in Exhibit 1B, Tab 2, Schedule 5.

The proposed rate framework includes a productivity and stretch factor. In Toronto Hydro's view, the inclusion of the OEB's productivity factor and a custom stretch factor into the custom PCI meets the OEB's expectations for the sharing of (financial) benefits.

The proposed rate framework covers the entirety of the application's five year term.

4.2. Implications for OM&A and Revenue Offsets

An intended implication of this custom PCI framework is the amount of funding that is as a matter of consequence provided for OM&A and Revenue Offsets. Tested in the standard rebasing fashion in 2015, the custom PCI provides incremental funding for OM&A and Revenue Offsets in the amount of only "I – X". Consider the entire custom PCI formula, with the C-factor in its constituent parts:

$$CPI = I - X + C_n - S_{cap}*(I - X)$$

By design, C_n reconciles Toronto Hydro's capital investment need, leaving the remaining terms to fund increases in OM&A and Revenue Offset. In simplified terms, that amount is:

$$(1 - S_{cap}) * (I - X)$$

6. New Deferral and Variance Accounts

1. Toronto Hydro's proposals to establish new Deferral and Variance Accounts are appropriate and should be approved.

- Toronto Hydro's Application requested approval of four new Deferral and Variance Accounts:
    - **Variance Account for Externally Driven Capital.**[1]
        - This request is driven by the volatile and unpredictable spending patterns commonly associated with capital work initiated by third parties.
    - **Variance Account for Derecognition amounts.**[2]
        - This request is driven by Toronto Hydro seeking to protect its ratepayers and the company from volatility associated with the derecognition of assets under IFRS.
    - **Variance Account for Renewable Enabling Investments Provincial Rate Protection Recovery.**[3]
        - This request is driven by the need to ensure consistency between the amounts collected by the IESO and the actual portions of the revenue requirement of Toronto Hydro's investments eligible for provincial rate recovery.
    - **Deferral Account for the Mandatory Transition to Monthly Billing.**[4]
        - This request is driven by the Board's recent requirement for LDCs to implement monthly billing for their residential and GS<50 customers and the utility's expectation that the costs of doing so will be material and exceed any savings.
- Toronto Hydro is also proposing to track material differences between the amounts cleared to customers through the proposed rate rider for gains on sale of properties related to the Company's Operating Centers Consolidation Program, and the actual sale amounts (which are yet to be determined).[5] A variance account should be established to track these differences and enable their disposition in a future proceeding.

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[1] Exhibit 9, Tab 1, Schedule 1 at pages 26-28.
[2] Exhibit 9, Tab 1, Schedule 1 at page 28.
[3] Exhibit 9, Tab 1, Schedule 1 at pages 28-30.
[4] Exhibit 9, Tab 1, Schedule 1 at page 30.
[5] Exhibit 8, Tab 1, Schedule 1 at page 13.

- Finally, Toronto Hydro indicated during the oral hearing that it would support a variance account to capture any differences between ICM-related amounts included in 2015 rate base and the amount of ICM in-service additions ultimately found prudent in the ICM true-up.[6]

2. A Variance Account for Externally Driven Capital is required due to the unpredictable level of these externally driven expenditures.[7]

- As detailed in Exhibit 2B, Section E5.3, spending related to work initiated by third parties can be volatile from year to year, required on short notice and is therefore relatively unpredictable.[8]
    - Toronto Hydro has included a base amount ($4M) in its capital projections. This amount reflects a highly conservative baseline spend level for this type of capital work and is substantially below currently forecast 2015-2019 expenditures.
    - As the utility explained in an interrogatory response and under cross examination, the proposed treatment is appropriate as the scope and timing of this work is controlled by external agencies, making the forecasting inherently uncertain.[9]
    - Accordingly, Toronto Hydro believes that it is in the best interest of customers to include only a base amount of funding for this volatile and unpredictable spend category up front in rates, and subsequently recover or refund any differences from the base amount through a variance account that will be cleared in future proceeding.

3. A Variance Account should be approved for derecognition amounts.[10]

- Under modified IFRS, gains or losses arising from derecognition of assets are required to be recorded as depreciation expense during the period in which the asset is derecognized.[11]
- While Toronto Hydro has included its forecast of derecognition amounts in its forecast depreciation expense over the 2015-2019 period, the nature, quantity and variety of assets replaced over the 2015-2019 period may differ from forecast, potentially resulting in high degree of variability in the amount of derecognition expense incurred.
- To control for this potential variability, Toronto Hydro proposes to establish a variance account to capture differences between the derecognition amounts approved in rates, and the actual amounts experienced. Doing so will protect both the ratepayers and the utility, by allowing any differences to be addressed in a future proceeding.

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[6] OH Transcript, Volume 7 (February 25, 2015) at page 156-157, lines 10-14.
[7] Exhibit 9, Tab 1, Schedule 1 at pages 26-28, lines 5-5.
[8] Exhibit 2B, Section 5.3 at pages 3-4.
[9] IR Response 2B-SIA-22; OH Transcript, Volume 4 (February 23, 2015) at pages 23-24, lines 10-22.
[10] Exhibit 4B, Tab 1, Schedule 2 at pages 3-7; Exhibit 9, Tab 1, Schedule 1 at page 28, lines 7-24.
[11] Exhibit 4B, Tab 1, Schedule 2 at pages 1, lines 15-17.

4. **Consistent with the OEB direction, Toronto Hydro seeks to establish a Variance Account for Renewable Enabling Investments subject to Provincial Rate Protection Recovery.** [12]

   - As detailed in the application, Toronto Hydro is seeking approval for Provincial Rate Protection Recovery of eligible amounts related to renewable enabling investments.

   - As directed by the OEB, Toronto Hydro is seeking a variance account to capture the differences between the revenue requirement costs incurred by the utility for approved eligible investments, and amounts that are collected from the IESO as a result of any OEB order directing such payments from the IESO to Toronto Hydro.

   - As with other proposed Variance Accounts, the disposition of the actual amounts at a later date, as ordered by the OEB, would ensure that both the utility and the ratepayers are protected against any variability between the forecasted and actually incurred amounts.

5. **Toronto Hydro requests a Deferral Account to recover the net new costs from the mandatory transition to monthly billing.**

   - On February 5, 2015, the OEB issued a Notice of Proposal with respect to a variety of billing-related issues. Among the proposed amendments is a requirement for all distributors to move to monthly billing for residential and GS<50kW customers by the end of 2016.[13]

   - Given that the application was submitted significantly in advance of the OEB's determination on the issue of monthly billing, Toronto Hydro's proposed expenditures do not include any amounts related to the mandated transition.

   - However, by way of an interrogatory response, Toronto Hydro has provided evidence indicating that it expects the costs of this requirement to be material, and significantly exceed of any cost savings anticipated by the OEB in the consultation documentation.[14]

   - Accordingly, Toronto Hydro submits that a Deferral Account is the appropriate treatment for the net new costs of moving to monthly billing, as they are non-discretionary, their timing and amount are uncertain; and they are forecast to be material.

[12] Exhibit 2A, Tab 8, Schedule 1; Exhibit 9, Tab 1, Schedule 1 at pages 28-30, lines 26-4.
[13] EB-2014-0198, Notice of Proposed Amendments to the Distributions System Code (February 6, 2015).
[14] IR Response 4A-CCC-34.

The program turned out mainly as we expected it to. We completed, or have in progress, nine out of ten of the filed jobs. We substituted the work as required based on the emerging needs, and we're coming in at a 5 percent variance above the overall forecasted costs.

MR. SMITH: Let me ask this follow-up question, then. How does that true-up process that you identified relate, then, to the opening rate base that Toronto Hydro has asked for in this proceeding?

MS. KLEIN: Sure. So true-up is about revenue reconciliation between approved and actual in-service assets during the IRM, which, in our view, is distinct from the 2015 opening rate base.

However, a portion of the 2015 opening rate base will be based on in-service additions that relate to ICM spending.

And we understand that there is some connection between the true-up process and the opening rate base for this proceeding.

We are confident in the prudence of the spending that is associated with the forecasts of the ICM segments, and that would include some of the spending that would be above forecast in those segments. And in order to provide the Board and the parties with some comfort regarding those details, we would -- we would propose actually a variance account to capture any difference between the amount of the ICM-based in-service additions that are currently forecast, and then the amount that would be approved by the Board at true-up.

This would effectively mean that 2015 opening rate base would be set on the basis of the utility's forecasts, as in any other rebasing application. But the existence of the variance account would provide the Board with the ability to change the revenue requirement impacts of opening rate base, in the event that any portion of the ICM work is found to be imprudently incurred.

In other words, this would allow this opening rate base to be retroactively adjusted, through the operation of a negative rate rider.

Again, we have high confidence in the prudence of the work, but we understand the parties might want to have an opportunity to satisfy themselves on that point.

MR. SMITH: Okay. I have a question for you, Mr. Seal, or maybe two.

Can you just help us with what's been marked -- I have lost the exhibit cite, but the "Bill impacts" exhibit that we just marked, that you prepared?

What is it that is being shown here, and where did it come from?

MR. SEAL: Certainly. This exhibit is really a summary, as noted at the bottom of that exhibit, from Exhibit 8, tab 7, schedule 1.

So these are our bill impact tables, which are quite detailed bill impacts by year, by various rate components.

And I think during the course of this hearing there have been some indications and some discussion of bill

RESPONSES TO SUSTAINABLE INFRASTRUCTURE ALLIANCE OF ONTARIO INTERROGATORIES

INTERROGATORY 22:

Reference(s): Exhibit 2B Section E5.3, Page 3; Exhibit 9, Tab 1, Schedule 1

Concerning the Externally Initiated Plant project in Section E5.3, THESL states that:

> "Although the utility forecasts that this program will cost approximately $119 million between 2015 and 2019, it has included only one-sixth of this amount (approximately $20 million) in its revenue requirement, or approximately $4.0 million of net Toronto Hydro costs per year. This sub-forecast amount represents a base level of spending that will be required over this term. Toronto Hydro proposes to seek rates funding only for this sub-forecast base amount, with a variance account to record differences from this amount."

In Exhibit 9, Tab 1, Schedule 1 THESL goes on to say that:

> "To reconcile the variable, non-discretionary nature of the work with its resulting bill impact, Toronto Hydro has intentionally included a below-forecast level of Relocation Spending in the utility's Distribution System Plan ("DSP") for the 2015-2019 period"

a) Given that the $4.0 million annually is less than any annual actual amount of historic spending in this area since 2010, and given that THESL is actually forecasting a notable increase in spending in this area over 2015-2019, please explain why THESL nonetheless proposes including a "below forecast level" of spending in rates. Does THESL anticipate the possibility that its forecast variances could be overstated by as much as 5/6ths in each year?

RESPONSES TO SUSTAINABLE INFRASTRUCTURE ALLIANCE OF ONTARIO INTERROGATORIES

b) Is THESL concerned that the proposed approach could result in a likely material underrecovery, requiring an additional collection from customers in 2019 and beyond? Why should ratepayers in 2019 and onwards be responsible for costs deliberately under-recovered from 2015- 2019 ratepayer groups?

c) Would THESL consider including the full forecast amount (or some materially higher percentage of it – e.g., 90%) in its revenue requirement, subject to variance account treatment at the end of 2019? Why or why not?

RESPONSE:

a) The work contained in the Externally Initiated Plant Relocation Program (Exhibit 2B Section E5.3) is entirely driven by capital projects initiated by other agencies. As their capital programs change over time, the impact on Toronto Hydro is often uncertain. For example, $73M out of $119M predicted for 2015-2019 comprises large projects such as GO Transit Electrification between Union and Pearson, Eglinton Light Rail Transit ("LRT") project and other Metrolinx Transit projects such as Finch West and Sheppard LRT, for which the scopes and timing are not entirely confirmed and are subject to change.

Historically, annual spending in respect of externally-initiated plant relocation work has ranged between $1M and $19M. Toronto Hydro has estimated that expenditures of $4M annually would capture the majority of the more consistently incurred small and medium size relocation projects that the utility reasonably expects over the forecast period. The proposed variance account will be used to record the cost of the additional projects and protect ratepayers from the potential that any portion of the

RESPONSES TO SUSTAINABLE INFRASTRUCTURE ALLIANCE OF ONTARIO INTERROGATORIES

full forecast of third party work does not materialize due to the unpredictable nature, cost and timing of externally-initiated plant relocations.

b) Toronto Hydro believes its proposed approach best balances the need for funding for these uncertain projects with the recognition of the potential rate impacts for the 2015-19 period. Toronto Hydro's is not deliberately under-recovering any amounts. Please see response to part (a).

c) Please see response to part (b).

MR. RUBENSTEIN: So when we're talking about the -- we talked about roughly 2 and a half billion dollars in capital expenditures. You are actually forecasting to spend roughly $2.6 billion, then; correct?

MS. ROUSE: Yes, that is correct, based on the latest information that we have available about the externally-initiated plant segment.

But there are reasons, as I stated before, that we have set it up in this fashion, so I would like Mr. Paradis to comment on that.

MR. RUBENSTEIN: Sure.

MR. PARADIS: Can you just clarify what you would like me to comment on?

MR. RUBENSTEIN: Your colleague said you had something to explain. I didn't ask.

MR. PARADIS: I can provide some explanation as to why that amount was chosen and why the approach was chosen for the specific investment program.

MR. RUBENSTEIN: Please.

MR. PARADIS: And as we've detailed it to some extent in our response to SIA 22, we mentioned that this program in particular is greatly impacted by external agencies and their timelines and their commitment to certain investment programs of their own. And that introduces for us a certain level of variability in terms of timing.

And since the driver for this work is very much connected to those external agencies' timing in terms of their own work, we felt it was fair for our customers to take a conservative approach in defining an amount and reconcile our spend at the end of the period once the work has all actually taken place.

MR. RUBENSTEIN: Do you agree with me that 20 million out of a forecast of 119 million is a sliver of the total amount? It is a small part?

MR. PARADIS: 4 million is in the range of what we have consistently incurred for this program in the past. So we are -- in prior years we ranged anywhere between 1 million to $9 million for this program. So we felt 4 million was a fair level of certainty, in terms of spending based on historical experience.

MR. RUBENSTEIN: But if your forecast is correct, you will collect, when we come back in 2020 for the next rate-setting period, the 99 million? If your forecasts are correct. Or maybe more?

MR. PARADIS: As mentioned, those type of projects are very much subject to variability in terms of the external parties that initiate the work. Therefore we would reconcile at the end of the period, depending on what actually took place, and we would accurately reflect the level of expenditures associated with the program.

MR. RUBENSTEIN: All right. Thank you very much.

I want to understand how we got to the -- how you built the capital expenditure budget. If I could take you to page -- this is at page 8 of the compendium.

So my understanding is the sort of first thing that you did is you determined, if we were going to achieve what

RESPONSES TO CONSUMERS COUNCIL OF CANADA INTERROGATORIES

INTERROGATORY 34:

Reference(s): Exhibit 4A, Tab 2, Schedule 13, page 3

Has Toronto Hydro done a business case analysis regarding monthly billing? If so, please provide that business case analysis. If the Board mandates monthly billing by January 1, 2016, what will be the costs and benefits for Toronto Hydro? How would Toronto Hydro propose that mandated monthly billing be implemented in the context of its five-year plan?

RESPONSE:

Toronto Hydro has conducted a business case analysis regarding the conversion to monthly billing. This analysis is outlined in Toronto Hydro's recent submission in response to the EB-2014-0198, Draft Report of the Board: Electricity and Natural Gas Distributor's Residential Customer Billing Practices and Performance, attached as Appendix A to this response.

In terms of the implementation strategy, Toronto Hydro would propose, if mandated, that the lowest cost transition strategy would be to combine this effort with the next planned software version upgrade of Toronto Hydro's Customer Information System, which is tentatively projected to be undertaken in the latter years of the this CIR filing period. Toronto Hydro would nevertheless anticipate that, were the OEB to proceed with mandatory monthly billing, utilities would be allowed to recover any incremental costs in a timely manner.

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October 9, 2014

via RESS e-filing – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("THESL")
Draft Report of the Board: Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance
OEB File No. EB-2014-0198

THESL writes to the Ontario Energy Board ("OEB") in respect of the above-noted matter.

On September 18, 2014 the Ontario Energy Board ("OEB") released a Draft Report of the Board entitled *Electricity and Natural Gas Distributors' Residential Customer Billing Practices and Performance (*"The Draft Report"). In the Draft Report, among other issues, the OEB conveys its intent to mandate the issuance of monthly electricity bills for all residential customers in Ontario starting January 1, 2016. The key considerations cited as driving the contemplated transition are enabling customers to better manage their consumption, control costs and budget for the expenditures associated with their electricity bills. While the Draft Report acknowledges that a mandatory transition to monthly billing would likely result in incremental costs, it expresses its expectation that such costs should be largely offset by the benefits of monthly billing and related activities, including improved cash flow / working capital reductions, reduced arrears and bad debt expenditures and enhanced customer communications. Further cost efficiencies are also expected from the assumed increases in the uptake of e-billing services that provide opportunities for cost reductions in the areas of printing and delivery.

In the Report, the OEB poses two specific questions to the utilities, namely to:
(1) List the potential barriers and anticipated benefits of the mandatory monthly billing transition as contemplated and;
(2) Discuss the merits of a similar transition for seasonal customers.

THESL is pleased to provide its response to question (1) only, along with some general comments. The utility does not currently serve any seasonal customers, and as such takes no position on the issue of billing frequency for these consumers. THESL also notes that it is a signatory to the submission of the Coalition of Large Distributors ("CLD"), and provides this submission to supplement the CLD submission with considerations and analysis based on THESL's specific circumstances.

General Comments

As a matter of general comment, THESL supports the OEB's intention to enable consumer control of their energy usage and the resulting expenses, which is consistent with the OEB's increased Focus on Consumers, as articulated in the *Renewed Regulatory Framework for Electricity* (RRFE) Board Report and the subsequent policy statements. However, in addition to answering the OEB's specific request for commentary, THESL has several comments on general nature in response to the discussion provided in the Draft Report.

On the issue of customer consumption management as enabled by billing frequency, THESL customers (and presumably most, if not all, residential customers in Ontario) currently have online tools at their disposal that provide them with consumption information at intervals far shorter than any billing frequency could reasonably accomplish. These tools are an important by-product of Smart Meter and Advanced Metering Infrastructure investments that the distributors already have in place. While THESL acknowledges that not all customers have access to and/or awareness of these online tools, the utility respectfully submits that the value proposition of monthly billing from the conservation perspective should consider the existence of consumption management tools that are already in place.

In a similar manner, the OEB already mandates equal payment plans that enable customers to better predict and budget for their electricity costs. In THESL's view, this offering substantially addresses the OEB's objective of allowing consumers to manage regular expenses by budgeting for payments on a monthly basis. This is the case for all distributors, including those with bi-monthly billing cycles, since equal payment plan customers are charged every month. As with the consumption management objectives, THESL submits that the value of a mandatory monthly billing transition as a tool to reduce the cost management/budgeting burden be assessed in the context of existing service offerings that may already accomplish the underlying objectives and require no incremental costs.

THESL also notes its concern regarding the contemplated implementation timeline of January 1, 2016, should the mandatory transition be ultimately required. Based on experience of implementing the projects of similar complexity and magnitude, and as further elaborated below, THESL believes that the contemplated timeline may introduce significant implementation risks, mandate higher implementation costs than under longer-term transition scenarios (see the alternatives discussion below), and result in utilities being required to postpone the implementation of other important planned customer care activities in the area of customer care. It is THESL's respectful submission that these risks could be substantially mitigated if the OEB were to adopt a more gradual transition timeline, such as the 5-10 year transition window proposed by the CLD.

Finally, and consistent with the CLD response, THESL respectfully submits that should the OEB mandate a transition to monthly billing, consideration should be given to the cost consequences for distributors and the resultant impact on their financial performance. The OEB's Draft Report lists 12 distributors that are not currently planning a transition to monthly billing, with another seven in various stages of planning for such an event. It is therefore reasonable to assume that at least the utilities that are not currently planning a move to monthly billing do not have access to the incremental rates funding that would enable them to undertake such a transition, short of postponing other planned (and OEB-approved) activities, which is often impractical or contrary to good utility practice. While some of these costs could be offset by the benefits noted by the OEB, in some cases (such as with arrears and bad debt provisions) these benefits would take several years to materialize, if at all. Given these considerations, it is THESL's submission that in the event of a mandatory monthly billing transition as contemplated in the Draft Report, distributors should be permitted to seek recovery of such incremental costs in a timely manner. The OEB could consider reviewing the cost recovery claims through some form of a hybrid generic proceeding that would permit concurrent consideration of individual distributors' expenditures.

In responding to the OEB's specific question posed in the Draft Report, THESL endeavoured to quantify the anticipated costs and benefits of a transition to monthly billing based on its understanding of the areas of anticipated benefits, its current cost structures, experience in implementing customer-oriented projects of similar scale and scope, and the utility's near- and longer-term plans, as most recently articulated in its 2015-2019 Custom Incentive Regulation (CIR) application currently before the OEB (EB-2014-0116). Estimates for some of the cost categories (particularly those related to later stages in what is a complex multi-step undertaking) may be subject to material changes on the basis of the results of prior steps and/or unanticipated findings that commonly emerge in large-scale undertakings. Accordingly, THESL notes that variances between estimates and actual costs, and the utility's projections may occur.

The remainder of this submission details the major steps comprising the project of this scope, quantifies the impact of anticipated benefits, and discusses potential alternative approaches along with their cost implications. The utility acknowledges that experiences and considerations may vary materially across the sector, but nevertheless hopes that this information will be helpful to the OEB in making further determinations on the matter in question.

THESL's Response to the OEB's Question

For the electricity distributors that do not offer monthly billing, what are the barriers faced in meeting the Board's goal of having all residential customers moved to monthly billing by January 1, 2016? What are the offsetting benefits such as reduced costs?

Based on THESL's analysis and as substantiated in further detail in the remainder of this document, THESL respectfully submits that a mandated transition to mandatory monthly billing for residential customers as contemplated in the Draft Report, would result in material cost increases, only partially offset by the anticipated quantifiable benefits. The degree of benefit quantification is based on he information currently available to THESL, and could, in the utility's assessment, benefit fro, further consultation with other sector participants and the ratepayers. Along with potential benefits, further efforts would be required to fully assess the impact of indirect costs to the utility and direct costs to customers that are not readily quantifiable based on the insights currently available to THESL.

Furthermore, THESL submits that potential implementation efficiencies could be gained by undertaking the transition work in parallel with other planned customer care-related activities, consistent with existing utility plans. The viability of this option, however, is limited by the January 1, 2016 implementation timeline provided in the Draft Report. THESL would therefore encourage the OEB to consider a phased transition approach with a 5-10 year implementation window as advanced in the CLD submission on this matter.

Finally, given the RRFE commitment to balancing the considerations of Customer Focus, Operational Effectiveness, Public Policy Responsiveness, and LDC Financial Performance, THESL would like to re-emphasize its position that utilities should be granted the opportunity to seek timely recovery of their prudently incurred costs outside of the normal re-basing proceedings, through such potential avenues as the Z-Factor hearings, Incremental/Advanced Capital Modules and/or some form of a generic proceeding, as may be deemed appropriate by the OEB.

The following information details THESL's commentary and quantification of estimated benefits and costs associated with a transition to mandatory monthly billing on a timeline contemplated in the Draft Report.

1.0 Anticipated Benefits

1.1 Working Capital Allowance Reductions

As a part of its 2015-2019 CIR application pre-filed evidence (EB-2014-0116), THESL filed a Lead-Lag study performed by Navigant. The study uses a methodology of deriving a utility's working capital requirements that should be familiar to the OEB from multiple previous proceedings. Using its methodology, Navigant calculates THESL's total Average Revenue Lag (that is, revenue-weighted number of days between the time the utility has to make payments/transfers to its payees and the time it receives the funds from its customers) to be 55.04 days. Applying this number to the calculation of expense leads and the aggregate amounts of eligible 2015 expenditures, results in the Working Capital Requirement of $241.7 million (including HST), which represents 8% of THESL's OM&A and Cost of Power Expenditures – a significant improvement from prior years, owing in large part to the successful introduction of a new Customer Care and Billing (CC&B) system in 2011.

To estimate the impact of a transition to monthly billing THESL made the appropriate adjustments to its Revenue Lag and HST Lead components consistent with the expected impact of monthly billing frequency. The impact of these changes to the Lead-Lag components results in an estimated reduction of THESL's Working Capital Allowance by approximately $1.9 million, or 0.28% of the applied-for 2015 Revenue Requirement.

1.2 Bad Debt/Arrears

THESL echoes the CLD's submission that absent any empirical data as to the customer propensity to pay their bills, or to pay their bills on time under the monthly vs. bi-monthly regime, there is no reliable means of estimating the value of potential benefits of increased billing frequency on the distributors' arrears and default write-offs. THESL understands the OEB's assumption that it is likely the case that some customers struggle to pay their electricity bills on time due to the aggregate amounts of their bi-monthly charges, and would likely prefer to receive a smaller bill each month. However, THESL submits that an equally plausible assumption is that at least a certain portion of customers do not pay their bills within the prescribed timelines for reasons that have little to do with power affordability and budgeting issues. For these customers, a transition to monthly billing could conceivably result in doubling of the amount of late bills per year, thereby creating incremental expenditures for the distributors beyond those driven by the increased frequency of bill issuance. Given a variety of potential scenarios, THESL respectfully requests that prior to concluding this change in policy, the OEB work with utilities that have transitioned to monthly billing in recent years to evaluate the effect of changes to billing frequency on bad debt or arrears.

1.3 Customer Communication and Customer Convenience

THESL has grouped these potential benefits together due to the fact that in both cases the benefits are difficult to reliably quantify in financial terms, as they involve inherently individual preferences (i.e., what is seen convenient or informative to one person is not necessarily so to another). On the other hand, the associated costs of such activities are relatively straightforward to quantify, by estimating the total costs based on an increased volume of bill inserts, newsletters etc (assuming a utility would choose to include communications materials into bills every month following a transition). As with Bad

Debt/Arrears, THESL respectfully submits that the optimal means of estimating the net value of these benefits would be through a customer engagement exercise.

1.4 E-Billing Savings

With regard to E-billing, while THESL fully supports the increased adoption of this service for a number of reasons, it notes that E-billing is an activity that involves its own cost-benefit considerations that exist outside of the billing frequency realm. Encouraging higher uptake involves marketing and IT expenditures in the near term, with significant uncertainty surrounding the ultimate uptake levels and the resulting benefits.

Moreover, in THESL's experience, E-billing adoption by customers is a gradual process, which may significantly delay the realization of the any potential benefits that could offset the costs. THESL has been offering the E-billing service since 2002, and its current subscription rate is around 10% of the customer base, which results in efficiencies that fall significantly short of offsetting the costs of mandatory transition to monthly billing as currently contemplated by the OEB. At this point, THESL possesses no information to suggest that near-term E-billing uptake can increase at the pace significantly higher than historical trends. Accordingly, THESL would encourage the caution in anticipating incremental cost offsets in the magnitude of the forecasted monthly billing costs in the near term.

2.0 Estimated Costs

For the purposes of this analysis, THESL divided the estimated implementation costs into two separate categories, namely One-Time Costs (which include the operating and capital project planning, execution and completion costs), and Ongoing Costs (the incremental costs expected to be incurred for the duration of the project). To provide additional context for its estimates, THESL also outlines the specific circumstances and drivers that in its assessment necessitate these expenditures. The cost estimates themselves were derived on the basis of the utility's experience in implementing large customer care-related projects (e.g. the recently completed Customer Care and Billing system (CC&B) transition), the state of its existing hardware and software, and other ongoing or planned projects in the area of customer are.

2.1 One-Time Costs

To assess the cost impact of one-time transition to monthly billing in the timeline approaching that contemplated by the OEB, THESL developed a preliminary project scope that for the purposes of this analysis is referred to as Base Case. The Base Case is premised on balancing objectives of respecting the OEB's timelines, and observing good utility practice and sound project management. The Base Case project scenario consists of five main steps, ranging in completion timelines between four and 16 months. The steps are:

1. Rectifying known billing system challenges
2. Update configuration, schedules and move customers to monthly cycles
3. Volume test to identify bottlenecks in system performance and operational processes
4. Rectify issues found through volume testing
5. Validate that bill accuracy and timeliness remained unaffected past the transition.

Each step plays a distinct role in facilitating the transition by undertaking the necessary modifications and/or testing of software, hardware and business processes that support monthly billing. Of critical importance are the volume testing activities (Steps 4-5), the associated rectification and subsequent re-testing to ensure that the amended processes and infrastructure do not result in errors that can have a major impact on the utility's service quality, customer satisfaction performance and costs of rectifying any unanticipated issues post-transition.

The one-time costs incurred during the project consist of capital (Capitalized IT Labour, IT Hardware) and OM&A expenditures (general labour). The table below provides a summary of the range of potential costs, based on a "Favourable" and a "Conservative" scenario:

Estimated One-Time Costs

Scenario	Business Labour	IT Labour	Hardware	Total ($M)*
Favourable	$2.2	$1.6	$1.4	**$5.2**
Conservative	$4.0	$3.0	$1.4	**$8.3**

** numbers may not add up due to rounding*

THESL has also evaluated three alternative implementation approaches to the Base Case that vary according to their respective scopes, underlying drivers and associated risks:

Alternative 1:
Merge implementation with suitable major customer care projects planned for in the medium-term.

Pro: Lower costs (40%-50% of the Base Case) and work effort due to shared analysis and testing effort.

Con: Project timing/scheduling significantly outside of the OEB timeline (CC&B upgrade planned for 2018).

Alternative 2:
Full redesign of THESL's customer care business processes related to billing accuracy to optimize the system performance, enhance accuracy and efficiency, and manage the recurring costs.

Pro: Greatest customer and operational productivity and accuracy benefits, potential reductions to the ongoing costs.

Con: Greatest upfront cost (200%-225% of the Base Case) and time to deliver.

Alternative 3:
Make the transition as quickly as possible and address the system/process issues as they arise. Only critical known challenges would be addressed prior to the transition, with other enhancements being made based on production results, as issues occur.

Pro: Potential ability to meet proposed Jan 1, 2016 date in the shortest timeline and potentially lowest up-front cost.

Con: Unacceptably high risk, inability to understand impact to bill accuracy or timeliness, unknown operational impact and effort to resolve once problems occur. Significant potential for occurrence of high-impact events that affect billing accuracy, customer satisfaction, regulatory compliance and costs.

While THESL believes that there are alternatives to the Base Case that could result in lower one-time costs, higher quality of the resultant system configuration and processes and potential efficiencies for the ongoing costs. However, in THESL assessment these options have significant deficiencies in light of the OEB-contemplated implementation timing, compatibility with the utility's plans regarding the timing of other customer care projects, or unacceptably high implementation risks under a streamlined scenario.

For additional information on the scope, costing and discussion of the Base Case and alternative scenarios of one-time implementation, please see Appendix A to this submission.

2.2 Recurring Costs

Beyond the one-time implementation costs, the introduction of mandatory monthly billing for all residential customers would bring about a number of incremental costs, associated with doubling of the volume of expenditures normally associated with bill issuance, delivery, payment processing, collection and related activities.

The following table details these incremental expenditures, using the data based on current costs, THESL's experience in implementing similar initiatives and estimates based on THESL's understanding of the nature and magnitude of the incremental process changes.

Estimated Recurring Cost of Monthly Billing ($M)

Cost Category	Incremental Cost
Postage	$2.6
Paper	$0.1
Envelope	$0.2
Printing	$0.2
Incremental Billing Enquiries (Call Centre)	$0.7
Meter Data Management, manual reads and Verification/Edits	$0.9
Clerical Billing tasks	$0.5
Payment Processing	$0.5
Collections Activities	$0.2
Corporate Communications	$0.2
TOTAL	**$6.1**

** numbers may not add up due to rounding*

The estimates presented above reflect reasonable assumptions, including incremental staffing using partially outsourced labour, and lower incremental call volumes per bill issued than what is currently the case, among others. As noted above, THESL prepared these estimates on the basis of its experience with implementing customer care initiatives of large magnitude, the state of its current processes associated with data collection, bill issuance and payment processing, customer contact behaviour, current cost structures and contractual arrangements, and other similar information. Given the information available to support certain assumptions, the forecasted costs, once realized, could vary by up to 20%.

In calculating the incremental costs, THESL took a conservative approach and assumed certain tasks would not simply double in volume. Should the OEB elect to conduct further stakeholdering on this issue, as suggested by THESL in this submission, the utility would welcome the opportunities to work with other distributors that have completed transitions to monthly billing in recent years to confirm these assumptions based on these distributors' experience.

THESL further notes that the above calculations include only the direct costs, specifically attributable to the transition project as proposed in the Draft Report. To obtain the full estimate of costs, further assumptions need to be made for other costs, including lost staff productivity throughout and for at least 6 months following the transition project, the impact (financial, operational and reputational), associated with postponement of other planned projects to divert resources to billing transition, incremental management oversight time, marketing resources to communicate the changes, and other potential cost drivers.

3.0 Impact to THESL Customers

Based on the benefit and cost projections discussed above, THESL's analysis results in the following conclusions:

Total Estimated Costs and Benefits of Transition to Monthly Billing ($M)

Category	OM&A*	Capital*
Benefits (Quantifiable)	$1.9	
Costs (One-Time)**	$2.2	$3.0
Costs (Sustained)	$6.1	
Net Cost *(Costs – Benefits)*	**$6.4**	**$3.0**

** Table showcases "Favourable" scenario estimates as described above.*

The resultant figures allow THESL to derive a high-level revenue requirement impact estimate of the contemplated undertaking. Assuming full eligibility of the forecasted costs, normal treatment of capital costs, THESL's applied-for 2015 WACC of 6.19%, recovery of one-time OM&A costs in a single year, and THESL's proposed 2015 CIR Service Revenue Requirement, the *net* rate impact (costs less quantifiable benefits) on THESL's 2015 proposed revenue requirement in year 1 would be 1.15%, reducing to 0.82% in the subsequent years once the one-time OM&A costs have been recovered. Given that the contemplated transition would only affect residential customers, THESL infers that the vast majority (if not the entirety) of the incremental costs would be allocated to the residential rate class only, resulting in a customer rate increases that are higher than the provided revenue requirement impact. In THESL's assessment, the business case of undertaking the transition to monthly billing as contemplated in the Draft Report timelines is negative.

Beyond the costs incurred as a result of distributor activities to enable and oversee the administration of monthly billing, THESL submits that the total cost estimate should include the direct costs to customers associated with more frequent payment of bills. These costs would include additional postage costs (which have recently increased) for customers paying their bills by mail, or transaction charges applied by banks for those using other payment options.

THESL acknowledges that its cost analysis could be further enhanced by additional information provided by other parties that may be in a better position to quantify the impact of some of the benefits listed by the OEB.

Subject to other distributors submitting such, or other potential information sources at the OEB's disposal, THESL would encourage the OEB to undertake further stakeholdering, working groups, and/or other similar activities with the aim of further quantifying the costs and benefits of the proposed transition.

All of which is respectfully submitted.

Please do not hesitate to contact me if you have any questions.

Yours truly,

[original signed by]

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:AK\DB\acc

APPENDIX A

Additional Information on One-Time Cost Analysis.

Base Case

In order to efficiently transition to monthly billing within the timelines approaching those currently contemplated by the OEB's Draft Report, THESL would approach the monthly billing transition project in five main steps:

	Key Step Objectives	**Estimated Duration**
1)	Rectify known billing system challenges	6 months
2)	Update configuration, schedules and move customers to monthly cycles	6 months
3)	Volume test to identify bottlenecks in system performance and operational processes	16 months
4)	Rectify issues found through volume testing	
5)	Validate bill accuracy and timeliness remained unaffected past the transition	4 months

For the purposes of this analysis, this approach is referred to as the Base Case. The Base case approach is optimal for the purposes of the contemplated transition, since its scope only includes the enhancements that are directly related to and required by the transition to monthly billing. While other potential approaches could result in lower implementation costs (see the "Alternatives" subsection below) they are not included in the Base Case as they would not be feasible under the timeline currently contemplated by the OEB.

Step 1: Rectify known challenges with monthly billing

In the normal course of business THESL has identified a number of system/process issues that are expected to require intervention should the utility transition to monthly billing for all of its residential customers. These challenges fall into two categories:

a) Time-Related: system/process issues efficiently resolved in time to maintain timely bi-monthly billing, but require permanent solutions to comply with a shorter 30-day billing cycle

b) Volume-Related: issues involving manual processes and workarounds, which are feasible and cost effective at current volumes (20,000 bills issued per day), but could not be sustained under a monthly billing cycle, requiring process automation.

Step 2: Update configuration, schedules and move customers to monthly billing cycles

Once the known issues arising from shorter billing cycles have been addressed, the project would focus on the customer information system changes required to implement monthly billing. Given that THESL's core CC&B system is relatively new and has functionality to bill customers every month, the switch would be relatively simple from a system configuration perspective. However, a number of supporting processes would have to be re-designed to enable the doubling of daily workflow for the utility's staff, supporting systems and external vendors.

Step 3: Volume test to identify bottlenecks in system performance and operational processes

In this step, THESL would prepare the necessary data and setup to execute a sustained full-scale volume test. The outputs of this test will be two lists of issues that require resolution. The first list would identify system performance limitations; either hardware related or where poor quality code results in inefficient use of hardware resources. The second list would highlight the operational processes that cannot be sustained with the increased volumes and shorter timelines associated with monthly billing.

Step 4: Rectify issues found during volume testing

The list of hardware and code issues identify in Step 3 are generally not expected to require long lead times to resolve. However rectifying these issues typically involves implementing expensive hardware resources, which comprise a significant portion of the capital hardware costs provided below.

While data flows are fundamentally unchanged under the monthly billing cycle, the operational processes that cannot be sustained present a more complex challenge. Each process, and the associated management controls, would require in-depth assessments and alternative solution evaluations. Solutions may include system modifications, process changes and/or the acquisition of additional resources to perform the process; each with different timelines, capital investment requirements, ongoing operational cost, training and change management trade-offs.

To ensure process efficiency and integrity, THESL would repeat Steps 3 and 4 multiple times to assess the "flow on" effects of higher volumes and test the resolution of earlier performance bottlenecks.

Step 5: Validate bill accuracy and timeliness remained unaffected by the transition

The execution of steps 1 through 4 would bring about a number of new isolated activities/process steps, each with potential to affect the accuracy of the issued bills. Given the significance of potential impact on billing accuracy, customer satisfaction and utility costs to rectify any unanticipated issues post-transition, this step is crucial from the regulatory compliance, customer relationship and operational effectiveness perspectives.

The following information quantifies the costs associated with the five-step Base Case approach presented above.

One-Time Cost Estimates

Base Case: Favourable Scenario ($M)

Step	Business Labour Estimate	IT Labour Estimate	Hardware Estimate	Total Step Estimate
1) Rectify known challenges with monthly billing	$0.1	$0.1		$0.2
2) Update configuration, billing schedules and move customers to monthly billing cycles	$0.1	$0.1		$0.2
3-4) Identify/rectify performance issues (2 iterations)	$1.0	$0.9	$1.3*	$3.2
Resourcing	$0.1	$0.01		$0.1
5) Validate bill accuracy and timeliness	$0.1	$0.3		$0.9
Deployment	$0.1	$0.1		$0.2
Contingency (10%)	$0.2	$0.1	$0.1	$0.5
Totals	**$2.2**	**$1.6**	**$1.4**	**$5.2**

* includes hardware, operating system and Oracle database licenses, system memory and additional storage.
** numbers may not add due to rounding

Base Case: Conservative Scenario($M)

Step	Business Labour Estimate	IT Labour Estimate	Hardware Estimate	Total Step Estimate
1) Rectify known challenges with monthly billing	$0.1	$0.1		$0.2
2) Update configuration, billing schedules and move customers to monthly billing cycles	$0.1	$0.1		$0.2
3-4) Identify/rectify performance issues (2 iterations)	$2.5	$2.2	$1.3*	$6.0
Resourcing	$0.1	$0.01		$0.1
5) Validate bill accuracy and timeliness	$0.6	$0.3		$0.9
Deployment	$0.1	$0.1		$0.2
Contingency (10%)	$0.4	$0.3	$0.1	$0.8
Totals	**$4.0**	**$3.0**	**$1.4**	**$8.3**

* includes hardware, operating system and Oracle database licenses, system memory and additional storage.
** numbers may not add due to rounding

As showcased in the above tables, THESL estimates that the one-time costs associated with a transition to monthly billing under the timelines that attempt to approach those currently contemplated by the OEB would result in the incremental costs in the range of $5.2-$8.3 million, of which between $3.0-$4.4 million would be capital costs,[1] with the remainder ($2.2-$3.9 million) representing one-time OM&A expenditures. Prior to quantifying the anticipated ongoing project costs, the following section addresses other potential implementation alternatives that may have impact on the one-time costs.

Other Evaluated Alternatives

(a) Merge with Other Planned Projects

THESL's 2015-2109 CIR filing includes four major projects with significant impacts to the billing process, namely:

- The Meter Data Management/Repository (MDM/R) integration with the provincial MDMR for residential customers;
- Upgrade of the meter data collection and validation system for large and medium Commercial and Industrial customers (MV90);
- Upgrade of meter data collection/validation/editing system e for residential and small Commercial and Industrial customers (ODS) and;
- Scheduled upgrade to the Customer Care and Billing (CC&B) system (affects all customers).

Of the above-noted initiatives, the contemplated transition to monthly billing aligns with the CC&B upgrade. Based on its current plans and system needs, THESL does not anticipate commencing this upgrade until 2018 – significantly past the OEB's contemplated timeline .

Pro: Lower overall one-time costs and work effort due to shared analysis and testing effort.
Con: Scheduling of project does not align with the proposed Jan 1, 2016 date.
***Cost (vs. Base Case)*:** 40-50% of the Base Case.

[1] Assuming full capitalization of IT Labour and Hardware.

(b) Full Redesign

This potential approach would involve the ground-up redesign of THESL's customer care business processes affected by billing frequency. Unlike the Base Case Scenario which merely *modifies* the existing processes built for bi-monthly billing to fit the requirements of monthly billing, the Full Redesign option would *gradually rebuild* the business processes for optimal performance. This option would also likely have a positive impact on the ongoing costs discussed below.

Pro: Greatest customer and operational productivity and accuracy benefits, potential reductions to the ongoing costs.
Con: Greatest upfront cost and time to deliver.
Cost (vs. Base Case)**:** 200%-225% of the Base Case due to larger scope.

(c) Go-live and Address on Demand

This approach is premised on making the transition as quickly as possible and addressing the system/process issues as they arise. Only critical known challenges would be addressed prior to the transition and other enhancements would be made based on production results.

Pro: Potential ability to meet proposed Jan 1, 2016 date in the shortest timeline and lowest up-front cost
Con: Unacceptably high risk, inability to understand impact to bill accuracy or timeliness, unknown operational impact and effort to resolve once problems occur. Significant potential for occurrence of high-impact events that affect billing accuracy, customer satisfaction, regulatory compliance and utility costs.
Cost (vs. Base Case): Not estimated due to unknown scope and nature of subsequent issues.

7. Rates, Load/Customer Forecast and Cost Allocation

1. Toronto Hydro has proposed rates, rate riders and specific service charges that are necessary for the safe and efficient operation of the utility over the 2015-2019 period and have been developed based on OEB policy.

- Toronto Hydro seeks approval for: Base Distribution Rates, Rate Riders, Retail Transmission Service Rates and new and updated Specific Service Charges.[1]
    - The proposed rates are necessary to fund the investments and operating expenses that are required for safe and efficient operation.
    - The proposed base distribution rates have been developed in accordance with OEB-approved methodologies and models.
        - The 2015 distribution rates are derived from:
            - the proposed 2015 Revenue Requirement as detailed in the Revenue Requirement Work Form.[2]
            - the OEB's Cost Allocation Model.[3]
            - the forecast of loads and customers (billing units) prepared according to the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013).[4]
        - The 2016-19 rates are based on the proposed Custom Price Cap Index. [5]
        - Toronto Hydro has provided proposed tariff sheets.[6]
    - The Rate Riders are based on the amounts proposed for clearance for various deferral and variance (DVA) accounts and other accounts, and the forecast of loads and customers. [7]

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[1] Rates – Exhibit 8, Tab 3, Schedule 3; Rate Rider – Exhibit 9, Tab 1, Schedule 1 at pages 24-25 and Tab 3, Schedule 1; Retail Transmission Rates – Exhibit 8, Tab 6, Schedule 1; Specific Service Charges – Exhibit 8, Tab 2, Schedule 1
[2] Exhibit 6, Tab 1, Schedule 2.
[3] Exhibit 7, Tab 1, Schedule 2.
[4] Exhibit 3, Tab 1, Schedule 1 at page 2, lines 1-3.
[5] Exhibit 8, Tab 1, Schedule 1 at page 1, lines 5-9.
[6] Exhibit 8, Tab 3, Schedule 3.
[7] Exhibit 9, Tab 3, Schedule 1.

    - The Retail Transmission Service Rates are based on the approved Uniform Transmission Rates and the forecast of loads by rate class and are calculated using the 2015 RTSR Workform.[8]

    - The proposed Specific Service Charges reflect the utility's costs of providing the various services.[9]

- Toronto Hydro also seeks approval for several other rate-related changes:

    - Approval to synchronize its rate year with its fiscal year, beginning January 1, 2016.[10]

    - Approval to declare its past Standby Rates final, as they have been interim since 2006.[11]

    - Relief from recording amounts related to retailer costs and revenues in RCVA accounts 1518 and 1548.[12]

    - Approval to close Account 1508 Transit City Variance account.[13]

2. Toronto Hydro's load and customer forecast is robust and properly accounts for Conservation and Demand Management (CDM) savings and therefore should be used to set 2015 Base Distribution Rates.

- Toronto Hydro forecast has been prepared according to the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013).[14]

- Toronto Hydro has provided the data used and has detailed the methodologies employed in developing these forecasts.[15]

- The forecast also includes an explicit forecast of CDM savings, as required by the RRFE.[16]

- A summary of load and customer forecast is contained in Table 1 of Exhibit 3, Tab 1, Schedule 1.

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[8] Exhibit 8, Tab 6, Schedule 1.
[9] Exhibit 8, Tab 2, Schedule 1.
[10] Exhibit 8, Tab 1, Schedule 1 at pages 8-10.
[11] Exhibit 8, Tab 1, Schedule 1 at pages 7-8.
[12] Exhibit 9, Tab 1, Schedule 1 at page 20, lines 1-5.
[13] Exhibit 9, Tab 1, Schedule 1 at page 22.
[14] Exhibit 3, Tab 1, Schedule 1 at page 2, lines 1-3.
[15] Exhibit 3, Tab 1, Schedule 1.
[16] Exhibit 3, Tab 1, Schedule 1 at page 3, lines 6-11.

3. Toronto Hydro employed the OEB's Cost Allocation Model in the development of the proposed rates; the revenue to cost ratios resulting from these rates are within OEB guidelines and should be approved.

- In completing the Cost Allocation Model, Toronto Hydro reviewed and updated all of the inputs to the model.[17]

- The rates for all classes, as proposed by Toronto Hydro, conform to the revenue to cost ratio guidelines in the OEB's report in EB-2010-0219, Review of Electricity Distribution Cost Allocation Policy (March 31, 2011).[18]

- The revenue to cost ratios resulting from the proposed rates are summarized and compared with the OEB guideline ranges for each class in Table 2 of Exhibit 7, Tab 1, Schedule 1.

4. The Rate Riders proposed by Toronto Hydro accurately reflect the balances from the DVA accounts proposed for clearance in this application and should be approved.

- **Residuals from Past Approved DVA clearances** – This rider should be approved to clear the residual variances between DVA amounts previously approved for clearance by the OEB, and amounts actually collected from customers through approved rate riders.[19]

- **Rate Rider for Smart Meter Entity** – This rider should be approved to clear the variance account capturing differences between amounts paid by Toronto Hydro to the IESO to fund the Smart Meter Entity and amounts recovered from customers through the OEB approved charge.[20]

- **Low Voltage Variance** – This rider should be approved to clear the variance account capturing the difference between amounts paid to Hydro One for low voltage services, and amounts collected from customers.[21]

    - Toronto Hydro does not have a retail charge to customers for this service, as annual amounts are too small to be reflected in a rate. This account has therefore captured amounts paid to Hydro One since last clearance (2010).

- **PILS/Tax Variance (Account 1592)** – This rider should be approved to clear amounts that have been recorded in Account 1592 to reflect differences in statutory tax rates.[22]

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[17] Exhibit 7, Tab 1, Schedule 1 at page 2.
[18] Exhibit 7, Tab 1, Schedule 1 at page 6, lines 14-19.
[19] Exhibit 9, Tab 1, Schedule 1 at page 6, lines 25-28.
[20] Exhibit 9, Tab 1, Schedule 1 at page 18A.
[21] Exhibit 9, Tab 1, Schedule 1 at page 6, lines 17-19.
[22] Exhibit 9, Tab 1, Schedule 1 at page 7, lines 2-6.

- **PILS/Tax HST/OVAT Tax Credit Variance** – This rider should be approved to clear variances arising due to the difference between Provincial Sales Tax (PST) amounts included in 2010 distribution rates, and Harmonized Sales Tax (HST) amounts, which were eligible for an HST Input Tax Credit. This amount had not been previously cleared, as the finalization of amounts to be included in this account was completed after the utility's last rebasing in 2011.

- **Gains on Sale of Named Properties Variance** – This rider should be approved to clear the variance between amounts included as revenue offsets in Toronto Hydro's 2010 distribution rates related to the sales of certain named properties, and the actual value of the sales amounts.[23] This account was approved by the OEB in EB-2009-0139, and has not been cleared since because the values of the sales were established after the utility's last rebasing.

- **Hydro One Capital Contributions Variance** – This rider should be approved to clear the variance between the revenue requirement implications of Hydro One capital contribution amounts approved for inclusion in distribution rates for each of 2010 and 2011, and actual Hydro One capital contribution amounts.[24] The OEB approved this account in EB-2009-0139.

- **LRAM Variance Account** – This rider should be approved to clear the calculated Lost Revenue Adjustment Mechanism (LRAM) amounts related to the difference between CDM volumes included in the load forecast at the time of the last rebasing, and the actual CDM amounts verified by the OPA.[25]

    - Toronto Hydro provided details on the CDM volumes included in the OEB approved load forecast, the OPA verified volumes, and the methodology used to determine the LRAM amounts.[26]

    - Toronto Hydro generally followed the OEB's LRAM guidelines[27] in calculating the amounts, but varied by providing a more accurate measure of the savings incorporated during the rate year.[28]

    - Toronto Hydro ensured that it used CDM values net of free-riders in the calculation of the LRAMVA, as required.[29]

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[23] Exhibit 9, Tab 1, Schedule 1 at pages 12-13.
[24] Exhibit 9, Tab 1, Schedule 1 at pages 16-18.
[25] Exhibit 9, Tab 1, Schedule 1 at page 14, lines 3-9.
[26] Exhibit 9, Tab 2, Schedule 5.
[27] EB-2012-0003, Guidelines for Electricity Distributor Conservation and Demand Management (April 26, 2012); OEB Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013), Chapter 2, Appendix 2-I.
[28] Exhibit 9, Tab 2, Schedule 5 at page 1.
[29] Exhibit 9, Tab 2, Schedule 5 at pages 5-6.

- **Rate Rider for Stranded Meter Disposition** – This rider should be approved to clear balances that have been recorded as stranded meter assets due to the Smart Meter program implementation.
    - As provided for in section 2.5.1.4 of the OEB's Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013), and in section 3.7 and Appendix A-1 of the Guideline G-2011-0001: Smart Meter Funding and Cost Recovery – Final Disposition (Dec 15, 2011), Toronto Hydro is requesting clearance of the December 2014 Net Book Value of stranded conventional meters. [30]
    - The amounts are recorded in Account 1555 since being transferred there in December 2013. Supporting details of the amounts are provided in OEB Appendix 2-S.[31]
    - These amounts have been removed from the 2015 opening rate base, as required.[32]
- **Rate Rider for IFRS Transitional PP&E amounts** – This rider should be approved to clear amounts contained in Account 1575 relating to transitional differences as a result of adopting IFRS effective January 1, 2015 [33]
    - The amounts are consistent with Article 510 of the OEB's Accounting Procedures Handbook (APH). The details are shown in Appendix 2-EC at Exhibit 9, Tab 2, Schedule 4.[34]
- **Rate Rider for Post-Employment Benefits Tax Savings** – This rider should be approved to clear amounts received by Toronto Hydro as a result of tax reassessments covering the years 2011-2013.[35]
    - Toronto Hydro amended its tax filings related to the treatment of postemployment benefit plan costs, and received a favourable decision from the Ministry of Finance.
    - Toronto Hydro has proposed to return the refunds received as a rate rider to customers over the CIR plan, as one of the means to mitigate the rate impacts of TH's capital program.

[30] Exhibit 9, Tab 1, Schedule 1 at page 14, lines 12-18.
[31] Exhibit 2A, Tab 4, Schedule 2.
[32] Exhibit 2A, Tab 4, Schedule 1 at page 2, lines 5-6.
[33] Exhibit 9, Tab 1, Schedule 1 at pages 14-16.
[34] Exhibit 9, Tab 2, Schedule 4.
[35] Exhibit 8, Tab 1, Schedule 1 at page 13.

- **Rate Rider for 2012-2014 Lost Revenue** – This rider should be approved to recover lost revenue associated with the operation of the IRM framework over the 2012-14 period, as it applies to 2011 year-end rate base not included in distribution rates.[36]
    - Toronto Hydro had sought relief on this issue during the IRM/ICM proceeding (EB-2012-0064). The utility interpreted the OEB's decision in that case to say that while it is not appropriate to seek amounts during IRM period, request for relief may be applicable at rebasing.
    - Toronto Hydro also submits that OEB's announcement of a process to review the impact of the half-year rule on subsequent IRM period provides evidence that the OEB recognizes the issue.[37]
    - Toronto Hydro has relied on evidence previously provided and updated to reflect In-Service Addition amounts rather than capital expenditures.[38]
- **Rate Rider for OCCP Savings** – This rider should be approved to give immediate effect to Toronto Hydro's proposal to return to customers the forecasted proceeds from the sale of properties related to its Operating Centers Consolidation Program.[39] This rider will help mitigate the impacts of Toronto Hydro's capital program on customers.
- Toronto Hydro has allocated the clearance of the various rate riders based on the methodologies outlined in the OEB's EDDVAR Report (EB -2008-0046).[40]
- The riders have been developed based on forecast billing units, and are applied over different periods of time, in order to smooth overall bill impacts.[41]
- The evidence includes a summary of the proposed amounts for clearance, allocation to classes and resulting rate riders.[42]

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[36] Exhibit 8, Tab 1, Schedule 1 at pages 13-15.
[37] EB-2014-0219, Letter re Board Staff Proposal for New Policy Options for the Funding of Capital Investments (June 20, 2014).
[38] Exhibit 8, Tab 1, Schedule 1 at pages 13-15 and Appendix A; OH Transcript, Volume 8 (February 27, 2015) at pages 2-3, lines 22-11.
[39] Exhibit 8, Tab 1, Schedule 1 at page 13, lines 1-9.
[40] Exhibit 9, Tab 1, Schedule 1 at page 24.
[41] Exhibit 9, Tab 1, Schedule 1 at pages 24-25.
[42] Exhibit 9, Tab 3, Schedule 1.

5. Toronto Hydro is proposing 2015 Retail Transmission Service Rates that were calculated using the forecasted billing determinants, the recently approved Uniform Transmission Rates (UTR), and the OEB's RTSR Workform and should be approved.[43]

- Toronto Hydro will update these rates at the time of the Draft Rate Order because the rates in evidence do not reflect the most recent UTRs, which were issued after this application was filed.[44]

- For the 2016-2019 period, Toronto Hydro proposes to update these rates for the updated UTR's at the same time it updates its distribution rates according to the Custom PCI.[45]

6. Toronto Hydro's proposed Specific Service Charges should be approved.

- Toronto Hydro's is proposing continuation of previously approved OEB standard charges as outlined in Chapter 11 of the Distribution Rate Handbook (DRH) for services for which a fee is applicable and is also requesting approval for several new Specific Service Charges from those described in the DRH but not included on Toronto Hydro's current Tariff Sheet.[46]

- Toronto Hydro requests approval to update the amount charged for Specific Service Charges to reflect current costs as shown in its evidence.[47]

    - For the Specific Service Charge increases, Toronto Hydro has based the updates on estimates of the current costs of providing these services.[48]

        - Toronto Hydro has not changed these rates since they were first approved by the OEB in 2006.

        - The updated rates generally conform to the methodology originally used to set the rates for all distributors in 2006 except for three of the charges: Account Setup charge, Temporary Service Install and Remove, and the Wireline rate.[49] For these three services, the updated charges were determined based on Toronto Hydro's estimates of its specific costs to provide the services as shown in the evidence. [50]

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[43] Exhibit 8, Tab 6, Schedule 1.
[44] Exhibit 8, Tab 1, Schedule 1 at page 10, lines 9-13.
[45] Exhibit 8, Tab 1, Schedule 1 at page 10, lines 15-16.
[46] Exhibit 8, Tab 2, Schedule 1 at page 1, lines 8-13.
[47] Exhibit 8, Tab 2, Schedule 1 at pages 1-2.
[48] Exhibit 8, Tab 2, Schedule 1, Appendix A.
[49] Exhibit 8, Tab 2, Schedule 1 at page 6, lines 2-10.
[50] Exhibit 8, Tab 2, Schedule 1 at pages 7-8.

- Toronto Hydro previously charged on a time and materials basis for the services that comprise the four new Specific Service Charges proposed – Request for Billing or System Information, Account History Charge, Service Call for Customer Owned Equipment or Missed Appointments, and Temporary Service Install and Remove.[51]
    - Toronto Hydro seeks approval for Specific Service Charges for these items due to increases in the frequency of requests for these types of services.
- The updated rate for Wireline attachments is subject to an ongoing review.
    - A decision on this rate will also impact the Revenue Offsets used to determine Base Revenue Requirement, and hence base Distribution Rates.
- Revenue arising from Specific Service charges goes directly to the Revenue Offsets, which reduces the Revenue Requirement needed to be collected through Distribution Rates.[52] As a consequence, if the OEB approved Specific Service Charges differ from those requested, any difference will need to be reflected in Revenue Offsets.

7. Toronto Hydro proposed rate year synchronization should be approved.

- Toronto Hydro has requested synchronizing its rate year with its fiscal year beginning January 1, 2016.[53]
- January 2016 was proposed instead of January 2015 because the application was filed according to the timeline for a May 2015 rate implementation date.[54]
- Toronto Hydro is not proposing to calculate 2015 rates based on recovering the full year of revenue requirement over an eight-month May to December period.[55]
- A January rate year start will better align Toronto Hydro's rate and fiscal years improving the transparency of financial information and bringing greater certainty to investment and operational planning.[56]
- Toronto Hydro believes no customers will be adversely affected by this change, and notes that a number of other distributors have already moved to a January rate year.

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[51] Exhibit 8, Tab 2, Schedule 1 at pages 3-4.
[52] Exhibit 3, Tab 2, Schedule 1 at pages 1-2.
[53] Exhibit 8, Tab 1, Schedule 1 at pages 8-10.
[54] Exhibit 8, Tab 1, Schedule 1 at page 8, lines 24-28.
[55] Exhibit 8, Tab 1, Schedule 1 at page 8, line 27 to page 9, line 2.
[56] Exhibit 8, Tab 1, Schedule 1 at page 9, lines 5-16.

8. Standby Rates should be made permanent.

- Toronto Hydro's current Standby rates have been set on an interim basis since the 2006 rate year (RP-2005-0020).[57]
    - In 2013, the OEB initiated a consultation on the Development of Standby Rates Policy for Load Displacement Generation (EB-2013-0004), but the results of this consultation, in which Toronto Hydro participated as a working group member, have not yet been released.
- Given the amount of time that the Standby rates have been interim, Toronto Hydro is seeking an OEB order making past rates final.
    - As noted in a number of interrogatory responses, while Toronto Hydro has not billed any of its customers on these standby rates because their load characteristics have rendered the rates inapplicable, Toronto Hydro nevertheless would like the past rates to be declared final for administrative certainty.[58]
    - For the currently proposed Standby rates (as provided in the proposed Tariff Schedules), Toronto Hydro proposes that they remain interim, until the previously noted consultation is concluded.[59]

9. Toronto Hydro requests authority to cease tracking amounts in RCVA Accounts 1518 and 1548.

- The APH identifies two Variance Accounts – Acct 1518 and 1548 – where distributors are required to record costs and revenues related to the operation of the Retail market. [60]
- As noted in the evidence, Toronto Hydro has not been recording amounts in these accounts since the OEB's Regulatory Assets Phase Two hearings, based on its interpretation that the Decision in that hearing indicated that Toronto Hydro no longer needed to track amounts in these accounts.[61]
- As a result of the recent audit conducted by the OEB's Audit group, Toronto Hydro has decided to seek formal relief on a going-forward basis from having to track these costs and revenue in the APH variance accounts.[62]

[57] Exhibit 8, Tab 1, Schedule 1 at pages 7-8.
[58] IR Responses 8-VECC 59 and 60.
[59] Exhibit 8, Tab 1, Schedule 1 at page 8, lines 3-5.
[60] Exhibit 9, Tab 1, Schedule 1 at page 19.
[61] Exhibit 9, Tab 1, Schedule 1 at page 19, lines 13-15.
[62] Exhibit 9, Tab 1, Schedule 1 at page 20, lines 2-5.

- Instead, and consistent with Toronto Hydro's practice since the Regulatory Assets Phase Two Decision, Toronto Hydro proposes to include the costs and revenues related to this activity as part of its normal Revenue Requirement. Toronto Hydro believes this is the most administratively efficient approach since the variances are not material.[63]

10. Toronto Hydro requests authority to close the Transit City Variance Account

- This account, approved by the OEB in EB-2009-0139, was intended to capture any revenue requirement consequences of the City's Transit City program, but since it did not attract any spending, Toronto Hydro requests approval from the OEB to close this account.[64]

11. Toronto Hydro submits that the overall bill impacts from the proposed rates and rate riders are necessary to fund the investments and expenses required for the safe and efficient operation of the utility over the 2015-2019 period.

- As required, Toronto Hydro has provided the bill impacts resulting from its proposed rates and rate riders, for different levels of consumption for each rate class.[65]

- The monthly bill impacts for a typical customer in each class were summarized in the Oral Hearing Exhibit K7.5, which shows that over the 2015 to 2019 period the average annual impact on the total bill is 2.4% for residential; 1.8% for small commercial and 0.8% for large users. The impact for all rates classes is well below the 10% impact at which mitigation must be considered.

[63] Exhibit 9, Tab 1, Schedule 1 at pages 19-20.
[64] Exhibit 9, Tab 1, Schedule 1 at page 22, lines 8-14.
[65] Exhibit 8, Tab 7, Schedule 1.

LOADS, CUSTOMERS AND REVENUE

Toronto Hydro's total load, customer and distribution revenue forecast is summarized in Table 1. The revenue forecast is calculated based on proposed distribution rates, excluding commodity, rate riders, and all other non-distribution rates.

Table 1: Total Load, Revenues and Customers

YEAR		Total Normalized GWh	Total Normalized MVA	Total Distribution Revenue ($M)	Total Customers
2009	Actual	25,572.8	42,754.7	$475.2	689,399
2010	Actual	25,607.2	43,273.3	$519.3	696,729
2011	Actual	25,419.0	43,020.2	$522.2	705,756
2012	Actual	25,639.2	43,544.5	$527.9	713,093
2013	Actual	25,213.2	42,658.7	$529.5	724,144
2014	Bridge	25,018.5	42,712.7	$539.4	736,974
2015	Test	24,993.3	42,697.2	$655.1	749,679
2016	Test	25,027.4	42,806.2	$692.8	763,091
2017	Test	24,841.6	42,631.3	$754.4	773,850
2018	Test	24,696.9	42,584.4	$810.5	785,107
2019	Test	24,611.4	42,529.2	$857.8	796,865

/C

Notes:

1. Total Normalized GWh are purchased GWh (before losses), and are weather normalized to the Test Year heating and cooling degree day assumptions.
2. Total Normalized MVA are weather normalized MVA.
3. Total Distribution Revenue is weather normalized and includes an adjustment for the Transformer allowance.
4. Total Customers are as of mid-year and exclude street lighting devices and unmetered load connections.

The detailed load forecasts by rate class are shown at Exhibit 3, Tab 1, Schedule 1, Appendix B. Forecasts of customers by rate class are shown at Exhibit 3, Tab 1, Schedule 1, Appendix C. Forecast of distribution revenues by rate class are shown at Exhibit 3, Tab 1, Schedule 1, Appendix E.

Table 2: Revenue / Cost Ratios (%)

Rate Class	2011 OEB Approved	2015		OEB's Guideline Ranges
		Model	Proposed	
Residential	89	94	94	85-115
Competitive Sector Multi-Unit Residential		110	100	
General Service <50kW	97	90	92	80-120
General Service 50-999kW	118	119	119	80-120
Intermediate 1000-4999kW	124	102	102	80-120
Large Use	116	95	96	85-115
Streetlighting	71	92	82	70-120
Unmetered Scattered Load	82	87	89	80-120

/C

The proposed Revenue to Cost ratios for all THESL rate classes are within the OEB's "target ranges".

With respect to the CSMUR class, as directed in the EB-2010-1042 decision, Toronto Hydro has adjusted rates to this class to make the revenue-to-cost ratio equal to unity. This ensures that this class is recovering its fully allocated costs.

With respect to the Streetlighting class, rates for this class were maintained at the same level as 2014. As is explained in more detail in Exhibit 8, Tab 1, Schedule 1, the cost allocation model with respect to the Streetlighting class is subject to further OEB review. Until such time as that review is complete, and given that rates to this class since 2006 have risen substantially due to the implementation of the existing cost allocation model, Toronto Hydro believes it is not appropriate to set rates for 2015 based on the current cost allocation model.

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VIA E-MAIL AND WEB POSTING

June 20, 2014

To: All licensed Electricity Distributors
All Registered Intervenors in Electricity Distribution Rate Applications

Re: Board Staff Proposal for New Policy Options for the Funding of Capital Investments
Board File Number EB-2014-0219

The *Report of the Board - Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (the "RRFE Report") represented a further and significant evolution of the approaches for rate regulation of the sector. The RRFE Report envisages that distributors will engage in longer term planning, including engaging customers on their needs and expectations, and to take into account ratepayers' ability and willingness to pay. Longer term planning, based on sound asset management practices, should enable distributors to plan, prioritize and pace capital programs accordingly. In turn, this should also provide for more predictability and stability of rates while allowing the distributors to make necessary investments.

In light of the Board's expectations, the Board plans to consider revised approaches to the funding of capital. Of consideration is whether the current rate regulatory cycle under the Price Cap Incentive Rate-setting option (Price Cap IR) results in distributors planning for more capital expenditures in the year of rebasing (or the prior year) to maximize the rate base at that point in time rather than planning based on good asset management practices. A goal would be to facilitate the optimization and pacing of expenditures throughout the term of Price Cap IR thus avoiding large increases in capital expenditures at the time of rebasing.

Board staff has developed two new mechanisms on which it will be seeking comments before bringing new policy options to the Board for consideration:

1. Eliminate the effect of the half year rule on test year capital additions for the intervening years between rebasing applications (i.e. during the subsequent IR plan) by adjusting for the incremental revenue requirement (depreciation expense plus return on capital and associated taxes/PILs) of the test year capital additions. This is proposed to be accomplished through an adjustment (to be referred to as the D_1-factor) to the price cap formula in the first IR application subsequent to the cost of service application that resulted in rebased rates. The half year rule would still apply for the test year.

2. Introduce a new funding mechanism that would enable reviews during a cost of service application for the need and prudence of any proposed incremental capital module funding requests for discrete projects that are part of a distributor's DSP, and that are planned to come into service during the IRM period. The rate adjustment would still occur in the IRM year in which the asset would come into service. The revised mechanism will be named an Advanced Capital Module ("ACM").

These proposals are also fairly technical in nature, while being designed to be practical and to leverage information already required as part of distribution rate applications. To receive input, Board staff has formed a working group. This working group includes several representatives from electricity distributors who had adopted the Price Cap IR option for 2015 rates, as well as other stakeholders well positioned to provide input on Board staff's proposals in an expeditious manner. The participants on the working group are included as Appendix B.

Appendix A to this letter contains information regarding cost awards for the consumer representatives on the working group.

If you have any questions regarding this consultation, please contact Keith Ritchie at 416-440-8124, or by e-mail at Keith.Ritchie@ontarioenergyboard.ca. The Board's toll-free number is 1-888-632-6273.

Sincerely,

Original Signed By

Kirsten Walli
Board Secretary

Atts.

cc: Working Group Members (Appendix B)

Appendix A
To Cover Letter Dated June 20, 2014
EB-2014-0219
COST AWARDS

Consultation Process for New Policy Options for the Funding of Capital Investments

Cost Award Eligibility

The Board has invited a number of stakeholders to participate in the stakeholder meeting on Capital Funding Options on June 25, 2014, including the School Energy Coalition and the Vulnerable Energy Consumers Coalition. These stakeholder representatives would generally be considered *prima facie* eligible for an award of costs under the Board's *Practice Direction on Cost Awards.* Therefore, the Board considers it appropriate in the circumstances to waive the following in relation to all of these participants: (a) the requirement to submit a request for cost award eligibility; and (b) the process for objections which would otherwise have applied in accordance with the Board's *Practice Direction on Cost Awards*.

Eligible Activities

Cost awards will be available in relation to participation on the stakeholder session on June 25, 2014, to a maximum equal to actual meeting time multiplied by 1.5 to account for preparation and reporting. Participants will also be eligible to claim costs for other eligible activities that may arise as part of this consultation process.

Cost Awards

When determining the amount of the cost awards, the Board will apply the principles set out in section 5 of its *Practice Direction on Cost Awards*. The maximum hourly rates set out in the Board's Cost Awards Tariff will also be applied.

The Board will use the process set out in section 12 of its *Practice Direction on Cost Awards* to implement the payment of the cost awards. Therefore, the Board will act as a clearing house for all payments of cost awards in this process.

Appendix B
To Cover Letter Dated June 20, 2014
EB-2014-0219
WORKING GROUP MEMBERS

Chris Amos
Consultant
Waterloo North Hydro Inc.

George Armstrong
Vice-President, Corporate Services
Veridian Connectionc Inc.

Cristina Birceanu
Director of Regulatory Affairs
Guelph Hydro-Electric System Inc.

John Bonadie
Director of Revenue
Enersource Hydro Mississauga Inc.

Bill Harper
Consultant
Vulnerable Energy Consumers Coalition

Colin Macdonald
Senior Vice-President, Regulatory Affairs and Customer Service
PowerStream Inc.

Margaret Maw
Chief Financial Officer
Lakeland Power Distribution Limited

Margaret Nanninga
Vice-President Finance
Kitchener-Wilmot Hydro Inc.

Keith Ritchie
Project Advisor, Electricity Rates and Accounting
Ontario Energy Board

Jay Shepherd
Counsel
School Energy Coalition

Maurice Tucci
Director, Regulatory & Technical Policy
Electricity Distributors Association

Rate Riders Development

	RESIDENTIAL	CSMUR	GS < 50 kW	GS - 50 to 999 kW	GS > 1000 to 4999 kW	LARGE USER	STREETLIGHTING	UNMETERED SCATTERED LOAD		
	A	B	C	D	E	F	G	H	I	
2015 Forecast Billing Determinants										
kVA	N/A	N/A	N/A	26,395,826	10,671,871	5,305,030	324,479	N/A	42,697,206	
kWh	4,909,898,145	213,116,822	2,118,402,162	9,848,614,894	4,654,535,571	2,228,386,374	114,092,929	41,132,354	24,128,179,251	
Non-RPP kWh	308,667,131	1,831,511	360,993,267	7,203,076,041	4,431,593,661	2,228,386,374	114,074,934	4,404,055	14,803,939,178	
Number of Customers	612,985	54,122	69,131	12,054	440	49	1	898	749,680	
Allocators										
2013 kWh	20.2%	0.4%	8.8%	40.5%	20.0%	9.4%	0.5%	0.2%	100.0%	
2013 Distribution Revenue	43.4%	1.8%	12.8%	26.4%	8.6%	4.4%	2.1%	0.5%	100.0%	
2011 Revenue Offsets	50.6%	1.9%	18.9%	20.5%	4.1%	1.6%	1.6%	0.8%	100.0%	
2009/10 Reg Assets Allocation	18.2%	0.7%	8.2%	42.4%	19.6%	10.2%	0.5%	0.2%	100.0%	
2013 Non-RPP kWh	2.1%	0.0%	2.4%	48.3%	31.0%	15.4%	0.8%	0.0%	100.0%	
2011-13 LRAMVA	-4.6%	0.1%	27.2%	81.1%	-1.1%	-2.8%	0.0%	0.0%	100.0%	
2013 Smart Metering Entity Rider Recovery	85.2%	5.2%	9.6%							/C
Stranded Meters	51.4%	0.0%	31.8%	16.8%	0.0%	0.0%	0.0%	0.0%	100.0%	

	Total Amount For Clearance	ALLOCATOR	RESIDENTIAL	CSMUR	GS < 50 kW	GS - 50 to 999 kW	GS > 1000 to 4999 kW	LARGE USER	STREETLIGHTING	UNMETERED SCATTERED LOAD	TOTAL	
Rate Rider for RSVA - WMS		2013 kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Rate Rider for RSVA - Network		2013 kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Rate Rider for RSVA - Connection		2013 kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Rate Rider for RSVA - Power - GA		2013 Non-RPP kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
Rate Rider for Smart Metering Entity	$ 440,222	2013 Smart Metering Entity Recov	$ 375,165	$ 22,792	$ 42,265	$ -	$ -	$ -	$ -	$ -	$ 440,222	/C
Rate Rider for Low Voltage Variance	$ 1,243,869	2013 kWh	$ 251,869	$ 5,035	$ 109,302	$ 503,506	$ 248,861	$ 117,527	$ 5,739	$ 2,031	$ 1,243,869	
Rate Rider for PILs and Tax Variance	$ (2,477,855)	2013 Distribution Revenue	$ (1,074,291)	$ (45,550)	$ (318,298)	$ (653,631)	$ (212,638)	$ (108,868)	$ (52,768)	$ (11,810)	$ (2,477,855)	
Rate Rider for PILs and Tax Variance HST	$ (1,171,876)	2013 Distribution Revenue	$ (508,075)	$ (21,543)	$ (150,536)	$ (309,128)	$ (100,565)	$ (51,488)	$ (24,956)	$ (5,586)	$ (1,171,876)	
Rate Rider for Gain on Sale Named Properties	$ 5,751,104	2011 Revenue Offsets	$ 2,911,291	$ 111,412	$ 1,085,597	$ 1,176,695	$ 234,628	$ 91,363	$ 93,756	$ 46,363	$ 5,751,104	
Rate Rider for Hydro One Capital Contributions Variance	$ 1,853,428	2013 Distribution Revenue	$ 803,567	$ 34,071	$ 238,086	$ 488,914	$ 159,053	$ 81,433	$ 39,470	$ 8,834	$ 1,853,428	
Rate Rider for Residual RARA	$ (1,810,389)	2009/10 Reg Assets Allocation	$ (329,829)	$ (12,622)	$ (148,909)	$ (767,101)	$ (354,001)	$ (184,593)	$ (9,645)	$ (3,688)	$ (1,810,389)	
Rate Rider for LRAMVA	$ 3,552,374	2011-13 LRAMVA	$ (161,870)	$ 2,976	$ 967,980	$ 2,881,653	$ (37,559)	$ (100,807)	$ -	$ -	$ 3,552,374	
Rate Rider for Stranded Meters Disposition	$ 15,791,311	Stranded Meters	$ 8,118,464	$ -	$ 5,020,984	$ 2,651,863	$ -	$ -	$ -	$ -	$ 15,791,311	
Rate Rider for IFRS - 2014 Derecognition	$ 30,506,428	2013 Distribution Revenue	$ 13,226,272	$ 560,798	$ 3,918,767	$ 8,047,259	$ 2,617,921	$ 1,340,345	$ 649,661	$ 145,405	$ 30,506,428	
Rate Rider for POEB - Tax Savings	$ (23,300,560)	2013 Distribution Revenue	$ (10,102,118)	$ (428,333)	$ (2,993,122)	$ (6,146,430)	$ (1,999,547)	$ (1,023,745)	$ (496,206)	$ (111,059)	$ (23,300,560)	
Rate Rider for 2012-14 Lost Revenue	$ 33,304,363	2013 Distribution Revenue	$ 14,439,336	$ 612,232	$ 4,278,182	$ 8,785,323	$ 2,858,027	$ 1,463,276	$ 709,245	$ 158,741	$ 33,304,363	
Rate Rider for Operations Center Consolidation Plan Sharing	[redacted]	2013 Distribution Revenue	[redacted]									
TOTAL	[redacted]		[redacted]									

Rate Riders	Proposed Recovery Period (years)	Billing Unit	RESIDENTIAL	CSMUR	GS < 50 kW	GS - 50 to 999 kW	GS > 1000 to 4999 kW	LARGE USER	STREETLIGHTING	UNMETERED SCATTERED LOAD	
Volumetric Rate Riders											
Rate Rider for RSVA - WMS	1	$/kWh or $/kVA	-	-	-	-	-	-	-	-	
Rate Rider for RSVA - Network	1	$/kWh or $/kVA	-	-	-	-	-	-	-	-	
Rate Rider for RSVA - Connection	1	$/kWh or $/kVA	-	-	-	-	-	-	-	-	
Rate Rider for RSVA - Power - GA	2	$/kWh	-	-	-	-	-	-	-	-	
Rate Rider for Low Voltage Variance	1	$/kWh or $/kVA	0.00005	0.00002	0.00005	0.0188	0.0230	0.0219	0.0174	0.00005	
Rate Rider for PILs and Tax Variance	1	$/kWh or $/kVA	- 0.00022	- 0.00021	- 0.00015	- 0.0244	- 0.0197	- 0.0202	- 0.1604	- 0.00029	
Rate Rider for PILs and Tax Variance HST	1	$/kWh or $/kVA	- 0.00010	- 0.00010	- 0.00007	- 0.0116	- 0.0093	- 0.0096	- 0.0759	- 0.00014	
Rate Rider for Gain on Sale Named Properties	1	$/kWh or $/kVA	0.00059	0.00052	0.00051	0.0440	0.0217	0.0170	0.2850	0.00113	
Rate Rider for Hydro One Capital Contributions Variance	1	$/kWh or $/kVA	0.00016	0.00016	0.00011	0.0183	0.0147	0.0151	0.1200	0.00021	
Rate Rider for Residual RARA	1	$/kWh or $/kVA	- 0.00007	- 0.00006	- 0.00007	- 0.0287	- 0.0327	- 0.0343	- 0.0293	- 0.00009	
Rate Rider for LRAMVA	1	$/kWh or $/kVA	- 0.00003	0.00001	0.00046	0.1077	- 0.0035	- 0.0187	-	-	
Rate Rider for IFRS - 2014 Derecognition	4	$/kWh or $/kVA	0.00067	0.00066	0.00046	0.0752	0.0605	0.0623	0.4937	0.00088	
Rate Rider for POEB - Tax Savings	3	$/kWh or $/kVA	- 0.00069	- 0.00067	- 0.00047	- 0.0766	- 0.0616	- 0.0634	- 0.5028	- 0.00090	
Rate Rider for 2012-14 Lost Revenue	4	$/kWh or $/kVA	0.00074	0.00072	0.00050	0.0821	0.0660	0.0680	0.5390	0.00096	
Rate Rider for Operations Center Consolidation Plan Sharing	3	$/kWh or $/kVA	[redacted]								
Per Customer Rate Riders											
Rate Rider for Stranded Meters Disposition	5	$/cust/30 days	0.22		1.19	3.62					
Rate Rider for Smart Metering Entity	1	$/cust/30 days	0.05	0.03	0.05						/C

Given the length of time since these rates were first determined by the OEB to be interim, Toronto Hydro is concerned about potential retro-activity. For that reason, Toronto Hydro requests that previous Standby Rates be declared final, but that the Standby rates proposed in the current application be made interim until such time as the OEB concludes its process on Standby Generation.

3. 2016-19 PRICE CAP INDEX

As part of a custom IRM framework, Toronto Hydro is proposing a rate framework for the 2016-19 period which adjusts rates based on a Price Cap Index. The Price Cap Index incorporates components to reflect inflation, productivity and the significant capital needs of the utility. A detailed explanation of the mechanism is contained in Exhibit 1B, Tab 2, Schedule 3.

In this evidence, Toronto Hydro has developed proposed base distribution rates for 2016-2019 based on projections for the various components of the Price Cap Index. As noted in Exhibit 1B, Tab 2, Schedule 3, Toronto Hydro plans to update the inflation and C-factor components of the mechanism annually, prior to the beginning of the rate year. The utility will submit an application to the OEB that incorporates these components, for final determination of base distribution rates.

4. RATE YEAR SYNCHRONIZATION

Toronto Hydro is seeking approval in this application to align its Rate Year with its Fiscal Year effective January 1, 2016. Rates for 2015, the utility's rebasing year, are proposed to be effective May 1, 2015. Rates for the first year under the proposed Price Cap would be effective January 1, 2016. Toronto Hydro confirms that it is not requesting any special treatment for the calculation of 2015 rates (i.e., it is not calculating rates based on recovering the full year of revenue requirement over an eight-month May to December period). Toronto Hydro believes that neither customers nor the utility are harmed by this proposed change in rate year.

Toronto Hydro's fiscal year is January to December. As a public debt issuer, Toronto Hydro is required to produce public financial statements on a fiscal year basis, and to regularly explain these statements to financial markets (i.e., bond holders, credit rating agencies, short-term creditors) and to the utility's shareholder. When revenues received by the utility are not aligned with the costs, presentation of this material can become more complex and less transparent.

More importantly, having a rate year which begins four months later than the fiscal year often means that rate decisions are not available before the beginning of the year in which Toronto Hydro is making investments and operational decisions and incurring costs. The uncertainty over this period makes planning much more difficult, especially in light of the significant capital work the utility is currently undertaking.

Toronto Hydro acknowledges that implementing distribution rates January 1st will introduce an additional annual rate change for customers. However, the utility believes that customers will not be unduly affected, and note that quarterly rate adjustments for natural gas customers has been an industry norm for some time. Additionally, a number of LDC's have previously been granted approval for moving to a January 1st rate year and Toronto Hydro is unaware of any particular instances of negative feedback. Toronto Hydro believes the benefits of rate year synchronization have been well established in the regulatory forum, and is seeking the same treatment.

Since Toronto Hydro's currently application is being submitted on a schedule which would not likely permit a January 2015 rate implementation date, the utility believes it is appropriate to seek the change in rate year for the following year, and avoid the regulatory complexity of interim rates and foregone revenue rate riders for the 2015 rebasing year. Toronto Hydro believes this is in the interests of all stakeholders.

5. OTHER RATES AND CHARGES

5.1. Retail Transmission Service Rates ("RTSRs")

Toronto Hydro's proposed RTSRs for 2015 are calculated using the OEB's RTSR model, and filed as Exhibit 8, Tab 6, Schedule 1 (and as a live MS Excel model). The proposed 2015 rates in the model reflect the projected 2015 billing units, applied to the current Uniform Transmission Rates ("UTRs"). Toronto Hydro will update the calculated rates when the 2015 UTRs are available.

Over the 2016-19 period, Toronto Hydro proposes to file updated RTSR models and calculated rates as the UTRs are updated annually.

5.2. Retail Service Charges

Toronto Hydro is not proposing any changes to the current Retail Service Charges. As noted in Exhibit 9, Tab 1, Schedule 1, the utility is requesting approval to be relieved from recording variances in the Retail Service Cost Variance Accounts since the historical estimated variances have been minimal, and the cost of tracking these costs separately outweighs the benefits.

5.3. Wholesale Market Service Rate ("WMS") and Rural and Remote Rate Protection ("RRRP")

Toronto Hydro has reflected a WMS rate of $0.0044/kWh and a RRRP rate of $0.0013/kWh in this application. If these rates are changed by the OEB during the 2015-

Bill Impacts

		Monthly Bill						Percent					
		2015	2016	2017	2018	2019	*Average*	2015	2016	2017	2018	2019	*Average*
Residential	Distribution (Subtotal A)	3.11	2.68	3.36	5.30	2.49	*3.39*	9.4	7.4	8.7	12.6	5.3	*8.7*
	Dist + PassThrough (Subtotal B)	3.15	2.64	3.36	5.30	1.71	*3.23*	8.6	6.7	7.9	11.6	3.4	*7.6*
	Delivery (Subtotal C)	3.28	2.64	3.36	5.30	1.71	*3.26*	6.9	5.2	6.2	9.3	2.7	*6.1*
	Total Bill (excl tax & OCEB)	3.28	2.64	3.36	5.30	1.71	*3.26*	2.5	1.9	2.4	3.7	1.2	*2.4*
CSMUR	Distribution (Subtotal A)	0.46	1.72	2.60	3.21	1.88	*1.97*	1.7	6.2	8.9	10.0	5.3	*6.4*
	Dist + PassThrough (Subtotal B)	0.47	1.72	2.60	3.21	1.10	*1.82*	1.6	5.8	8.3	9.5	3.0	*5.6*
	Delivery (Subtotal C)	0.52	1.72	2.60	3.21	1.10	*1.83*	1.5	5.0	7.2	8.3	2.6	*4.9*
	Total Bill (excl tax & OCEB)	0.52	1.72	2.60	3.21	1.10	*1.83*	0.8	2.5	3.6	4.3	1.4	*2.5*
GS<50	Distribution (Subtotal A)	8.35	4.57	2.30	10.90	5.73	*6.37*	10.1	5.0	2.4	11.1	5.3	*6.8*
	Dist + PassThrough (Subtotal B)	8.45	4.47	2.30	10.90	4.95	*6.21*	9.3	4.5	2.2	10.3	4.2	*6.1*
	Delivery (Subtotal C)	8.76	4.47	2.30	10.90	4.95	*6.28*	7.5	3.6	1.8	8.2	3.4	*4.9*
	Total Bill (excl tax & OCEB)	8.76	4.47	2.30	10.90	4.95	*6.28*	2.7	1.3	0.7	3.2	1.4	*1.8*
GS 50-999	Distribution (Subtotal A)	273.50	153.98	227.87	341.13	178.95	*235.09*	11.5	5.8	8.1	11.3	5.3	*8.4*
	Dist + PassThrough (Subtotal B)	280.79	146.69	227.87	341.13	178.95	*235.09*	9.5	4.6	6.8	9.5	4.5	*7.0*
	Delivery (Subtotal C)	299.67	146.69	227.87	341.13	178.95	*238.86*	6.5	3.0	4.5	6.5	3.2	*4.7*
	Total Bill (excl tax & OCEB)	299.67	146.69	227.87	341.13	178.95	*238.86*	1.4	0.7	1.0	1.5	0.8	*1.1*
GS 1-5	Distribution (Subtotal A)	774.11	790.68	948.94	1292.46	688.28	*898.89*	8.5	8.0	8.9	11.1	5.3	*8.3*
	Dist + PassThrough (Subtotal B)	815.01	749.79	948.94	1292.46	688.28	*898.90*	6.7	5.8	6.9	8.8	4.3	*6.5*
	Delivery (Subtotal C)	899.33	749.79	948.94	1292.46	688.28	*915.76*	4.6	3.7	4.5	5.8	2.9	*4.3*
	Total Bill (excl tax & OCEB)	899.33	749.79	948.94	1292.46	688.28	*915.76*	0.8	0.7	0.8	1.1	0.6	*0.8*
LU	Distribution (Subtotal A)	4512.09	4582.21	5301.20	7166.52	3845.26	*5081.46*	8.9	8.3	8.9	11.0	5.3	*8.5*
	Dist + PassThrough (Subtotal B)	4718.69	4375.61	5301.20	7166.52	3845.26	*5081.46*	8.0	6.8	7.8	9.7	4.8	*7.4*
	Delivery (Subtotal C)	5225.61	4375.61	5301.20	7166.52	3845.26	*5182.84*	5.1	4.0	4.7	6.1	3.1	*4.6*
	Total Bill (excl tax & OCEB)	5225.61	4375.61	5301.20	7166.52	3845.26	*5182.84*	0.9	0.7	0.9	1.1	0.6	*0.8*
SL	Distribution (Subtotal A)	-0.57	0.46	0.56	0.83	0.41	*0.34*	-8.9	7.8	8.9	12.1	5.3	*5.1*
	Dist + PassThrough (Subtotal B)	-0.57	0.45	0.56	0.83	0.41	*0.34*	-8.6	7.5	8.6	11.8	5.2	*4.9*
	Delivery (Subtotal C)	-0.56	0.45	0.56	0.83	0.41	*0.34*	-7.5	6.6	7.7	10.6	4.7	*4.4*
	Total Bill (excl tax & OCEB)	-0.56	0.45	0.56	0.83	0.41	*0.34*	-4.1	3.5	4.2	5.9	2.8	*2.4*
USL	Distribution (Subtotal A)	4.45	2.09	3.17	4.16	2.30	*3.23*	15.2	6.2	8.9	10.7	5.3	*9.3*
	Dist + PassThrough (Subtotal B)	4.46	2.07	3.17	4.16	2.30	*3.23*	14.7	5.9	8.6	10.4	5.2	*8.9*
	Delivery (Subtotal C)	4.50	2.07	3.17	4.16	2.30	*3.24*	13.4	5.4	7.9	9.6	4.8	*8.2*
	Total Bill (excl tax & OCEB)	4.50	2.07	3.17	4.16	2.30	*3.24*	6.4	2.8	4.1	5.2	2.7	*4.3*

Source: Exhibit 8, Tab 7, Schedule 1, Corrected Feb 6, 2015