EB-2014-0116

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Toronto Hydro-System Electric Limited for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2015.

CROSS-EXAMINATION COMPENDIUM OF THE SCHOOL ENERGY COALITION (Panel 5)

Jay Shepherd P.C.
2300 Yonge Street, Suite 806
Toronto, Ontario M4P 1E4

Jay Shepherd
Mark Rubenstein
Tel: 416-483-3300
Fax: 416-483-3305

Counsel to the School Energy Coalition

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.

5. CUSTOMER ENGAGEMENT ON PROPOSED CAPITAL INVESTMENTS

5.1. OEB Expectations

Section 5.4.2 in the Chapter 5 Filing Requirements expresses the OEB's expectations that the applicants' DSP submissions be supported by information related to the distributors' efforts to engage their customers on various facets of their capital planning processes. In particular, the OEB states that distributors should provide details regarding the approach they use "to engage customers for the purpose of identifying their needs, priorities and preferences", and "the aspects of the DSP that have been particularly affected by consideration of that information."[17]

5.2. Toronto Hydro's Approach

Exhibit 1B, Tab 2 Schedule 7 of Toronto Hydro's evidence for the 2015-2019 CIR application addresses each of the above-noted OEB expectations. To facilitate customer dialogue and input, the utility developed a series of comprehensive workbooks containing customer-friendly explanations of the components of Toronto Hydro's distribution system, key issues facing its asset base, and its draft plans as to how to address these issues. The workbooks were tailored specifically towards different subsets of the utility's customers (e.g., residential and commercial), and contain a range of customer class-specific specific questions seeking feedback on the information presented in the workbook. Toronto Hydro posted its workbooks on its website and advertised them through a number of channels.

In addition to generating and seeking online feedback on its workbook, Toronto Hydro (with the assistance of its external consultant) undertook a series of focus group sessions with representatives of different customer classes, supplementing these activities with an

[17] Filing Requirements, Chapter 5 at page 15, section 5.4.2.

on-line questionnaire and a tele-survey. The evidence at Exhibit 1B, Tab 2, Schedule 7 discusses the results of these and other related customer engagement activities, and explains how the insights gained through this work relate to the utility's planned work program.

6. CAPITAL AND DISTRIBUTION SYSTEM PLAN

6.1. OEB Expectations

The RRFE Report clearly states that the OEB's expectations with respect to the nature and content of a distributor's DSP and applicable supporting materials are set out in Chapter 5 of the Filing Requirements.[19] Among other things, the Chapter 5 Filing Requirements oblige a distributor to outline: its capital planning objectives; the criteria used for planning; processes used to identify and implement alternatives; and tools and processes used to identify, select, prioritize and pace the proposed expenditures.

6.2. Toronto Hydro's Approach

Toronto Hydro's DSP, filed at Exhibit 2B of this application, addresses the above-noted OEB expectations. Each proposed capital program identified in the DSP is supported by a detailed Business Case justification that provides the following information:

- A description of the proposed capital program and its purpose;
- Primary and secondary drivers for the investments (consistent with the guidance in the Chapter 5 Filing Requirements);
- Asset lifecycle information and failure impacts (where applicable);
- Approach to the timing and pacing of investments;
- Description of program benefits, including customer value;
- Program execution approach and mitigation of associated risks; and
- Other pertinent information.

[19] RRFE Report at page 52.

6. SPECIFIC Z-FACTOR

One of the incremental challenges inherent in a five-year rates plan is the need to contend with prudent, material unexpected costs. As part of this application, and as explained in further detail throughout this application,[15] Toronto Hydro has proposed restrained/constrained OM&A and capital funding requests. The funding that Toronto Hydro seeks in this application is expected to enable the utility to carry out the work that it has detailed in these programs. That funding, by definition, is not sufficient to address the prudent costs of material events that are outside the control of the utility and which have not been forecasted. Accordingly, Toronto Hydro proposes to incorporate within its rate framework the availability of Z-factor relief, which Toronto Hydro understands is available to CIR filers as part of the RRFE framework.

As detailed below, while Toronto Hydro expects that a request for relief would be exceptional, the utility has prepared a list of possible categories of specific events which it believes could occur, and where they occur, may necessitate additional funding during the term of the plan. The criteria that would apply to the consideration of any of these events would be the standard Z-factor criteria, most recently articulated by the OEB in its Decision on Enbridge Gas Distribution Inc.'s 2014 to 2018 Rate application.[16] To the extent the OEB has concerns with respect to the possible availability of Z-factor treatment in relation to any of the items set out below, Toronto Hydro asks the OEB to identify these concerns as part of this application.

6.1. Events with a one-time impact

One-time events that Toronto Hydro anticipates may give rise to a Z-factor application include:

- Extreme weather events such as storms;

[15] See for instance the Financial Planning Process (Exhibit 1C, Tab 3, Schedule 2), Overview of OM&A Expenditures (Exhibit 4A, Tab 1, Schedule 1) and Capital Expenditures Planning Process Overview (Exhibit 2B, Section E2).
[16] EB-2012-0459, Decision with Reasons (July 17, 2014) at pages 18-21.

- One-time investments made at the behest of government direction and outside of management's control, such as:
    - Smart Meter implementation;
    - Conservation and Demand Management;
    - Regional Planning; and,
- Any other one-time events that meet the Z-factor criteria.

6.2. Events with an ongoing impact

Material ongoing events that Toronto Hydro anticipates may give rise to a Z-factor application include:

- Changes to IESO market rules;
- Changes to OEB codes or policies, such as distributor rate design;
- Changes to income tax rates or laws;
- Changes to accounting frameworks or technical standards;
- Changes resulting from new or amended government legislation, regulation or policy, such as environmental laws;
- Ongoing investments made at the behest of government direction and outside of management's control; and,
- Any other ongoing events that meet the z-factor criteria.

In the interest of regulatory efficiency, Toronto Hydro proposes that any application for this treatment would compartmentalize the material impacts of the event, as opposed to undergoing a full regulatory review of the rate framework. For one-time events, Toronto Hydro would propose a targeted rate rider. For events with an ongoing impact, Toronto Hydro would propose an adjustment to the base revenue requirement if one was to occur in 2015, or else to the custom PCI.

While specific projects may change in scope, cost and timing during the CIR period, the utility has confidence that, over the course of the five-year planning horizon, the overall work program presented in the DSP can be executed as described. Prudence dictates that Toronto Hydro must retain the flexibility to execute an optimal mix of work in each given year. It is not possible to predict the specific work that will comprise Toronto Hydro's execution work program in 2019, but the utility can be certain that, over the five years of the application, this level of work, as set out in the DSP programs, is required.

IV. The proposed capital program ultimately delivers long-term value for customers

As discussed in part I of this section, the pace of investment during the 2015-2019 period is driven by system needs. The underlying need and establishment of pacing is described in detail in Toronto Hydro's asset management policy and processes[13] and in the capital expenditure plan.[14] At a high level, the long-term objective of Toronto Hydro's asset management policy is to achieve an optimal "steady-state", in which the number of assets that are past their economic end-of-life (explained below) is minimized. When the system is in that theoretical steady state, the total operating (or lifecycle) costs associated with the broader in-service asset population are minimized, meaning that customer value is maximized.

The concept of a steady state is based on Toronto Hydro's risk-based optimization approach to investment planning, which relies largely on use of the utility's Feeder Investment Model ("FIM") and other age and condition based information. Using these tools, Toronto Hydro determines the optimal asset renewal timing based on the economic end-of-life criteria for each asset. An asset reaches its economic end-of-life when the risk cost of continuing to operate the asset, which increases over time, becomes equal to or

[13] Exhibit 2B, Section D.
[14] Exhibit 2B, Section E.

greater than the cost of replacing the asset, which decreases over time. An asset management policy that strives to replace the broader population of assets at this "optimal intervention time" ensures that, on average, Toronto Hydro is minimizing the total costs of operating the system, thereby maximizing customer and utility value derived from the assets.

Theoretically, Toronto Hydro's risk based model defines the ideal "steady state" as the scenario where, on a system level, no assets are allowed to operate beyond their optimal intervention time, and all assets are replaced at exactly the optimal intervention time and no earlier (except those that inevitably fail prematurely). (Practically speaking, Toronto Hydro must group asset replacements into efficiently executable projects; therefore, the actual "steady state" will necessarily involve replacing a small percentage of assets before end-of-life and allowing a small percentage of assets to operate beyond end-of-life.)

As discussed in part I of this section, Toronto's distribution system currently features a high percentage of assets operating beyond end-of-life. Clearing this backlog and achieving "steady state" as quickly as possible is ideal for the utility and customers to the extent that it will minimize the duration that the distribution system is operating in an unbalanced state with higher than necessary aggregate lifecycle costs. However, in reality, clearing this backlog in one year (i.e., the economically ideal approach), or even over the duration of the five-year CIR period, would not be feasible as it would feature levels of investment that do not immediately align to Toronto Hydro's current resources and system constraints. For these reasons, Toronto Hydro's DSP is based on a paced execution strategy, which represents the minimum level of investment appropriate given system needs during the 2015-2019 period.

If Toronto Hydro were to continue at the proposed annual average pace of investment beyond 2019, the system is forecasted to reach steady state by approximately 2037. This paced approach has the advantage of more predictable and tolerable bill increases during the 2015-2019 period and alignment with Toronto Hydro's immediate execution capacity. The paced strategy also helps to ensure more predictable bill impacts and system performance beyond the achievement of steady-state, due to the more gradual or dispersed approach to clearing the backlog of end-of-life assets.

3. STRUCTURE AND COMPLIANCE OF TORONTO HYDRO'S DSP

Toronto Hydro has organized its 2015-2019 Distribution System Plan ("DSP")[15] in a manner consistent with Chapter 5 of the Filing Requirements. Toronto Hydro has worked to provide DSP content that aligns with the spirit of the RRFE Report, as expressed through the Chapter 5 Filing Requirements, and that allows the OEB to evaluate all aspects of the utility's detailed and integrated five-year capital plan within the context of this Customer IR application. Key features of the DSP include the following.

- The five major sections of Toronto Hydro's DSP adhere to the organizational structure outlined in sections 5.2 and 5.3 of Chapter 5. This includes:
  - **Section A**: DSP Overview
  - **Section B**: Coordinated Planning with Third Parties
  - **Section C**: Performance Measurement for Continuous Improvement
  - **Section D**: Asset Management (AM) Process
  - **Section E**: Capital Expenditure Plan

[15] Exhibit 2B.

Table 2 PSE Reply Report Cost Model Results

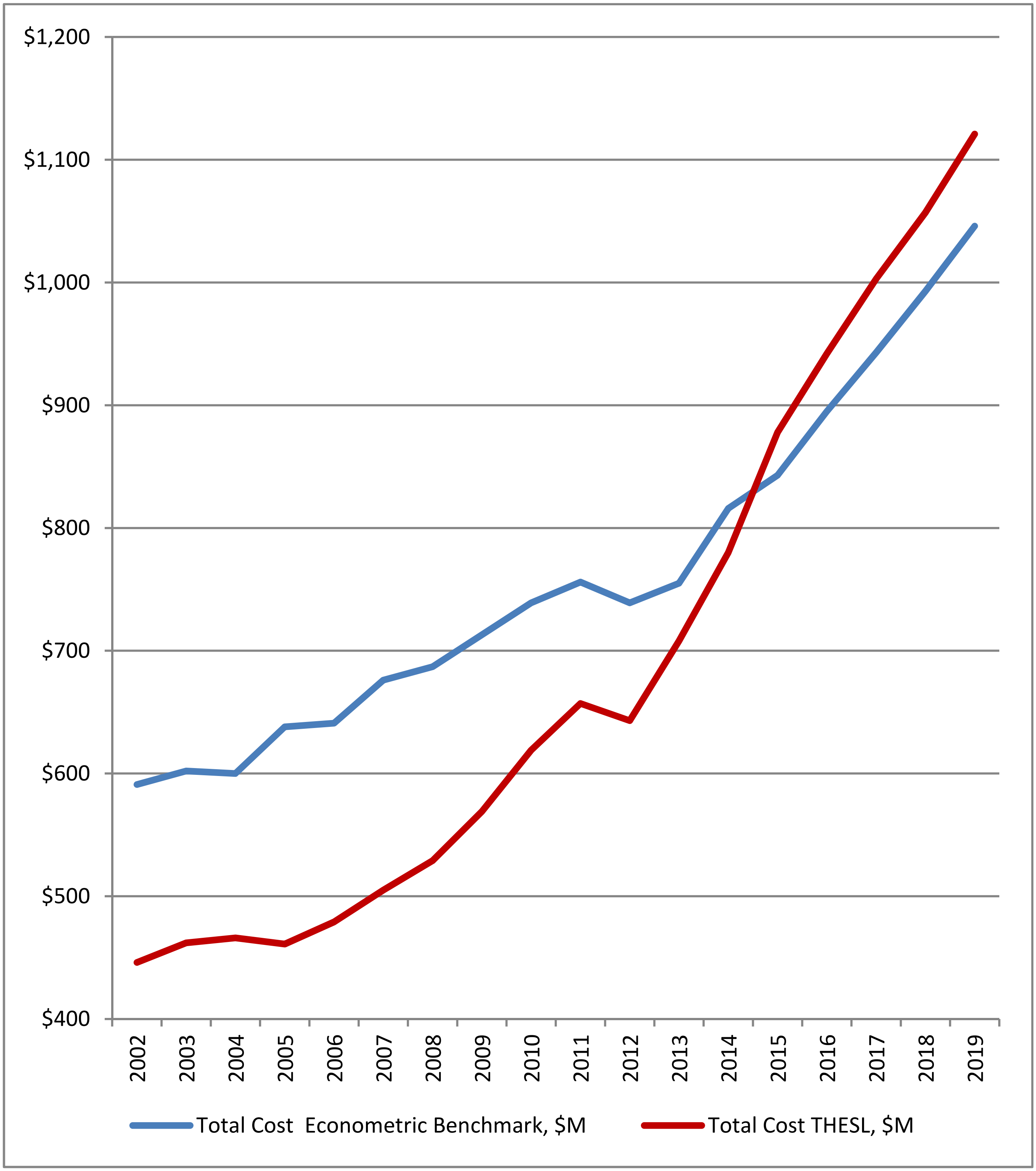
Year	Percent of U.S. Total Cost Econometric Benchmark	Total Cost Econometric Benchmark, $M	Total Cost THESL, $M
2002	-28.0%	$591	$446
2003	-26.5%	$602	$462
2004	-25.4%	$600	$466
2005	-32.4%	$638	$461
2006	-29.2%	$641	$479
2007	-29.2%	$676	$505
2008	-26.0%	$687	$529
2009	-22.6%	$713	$569
2010	-17.8%	$739	$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

Table 2 - PSE Reply Report Cost Model Results

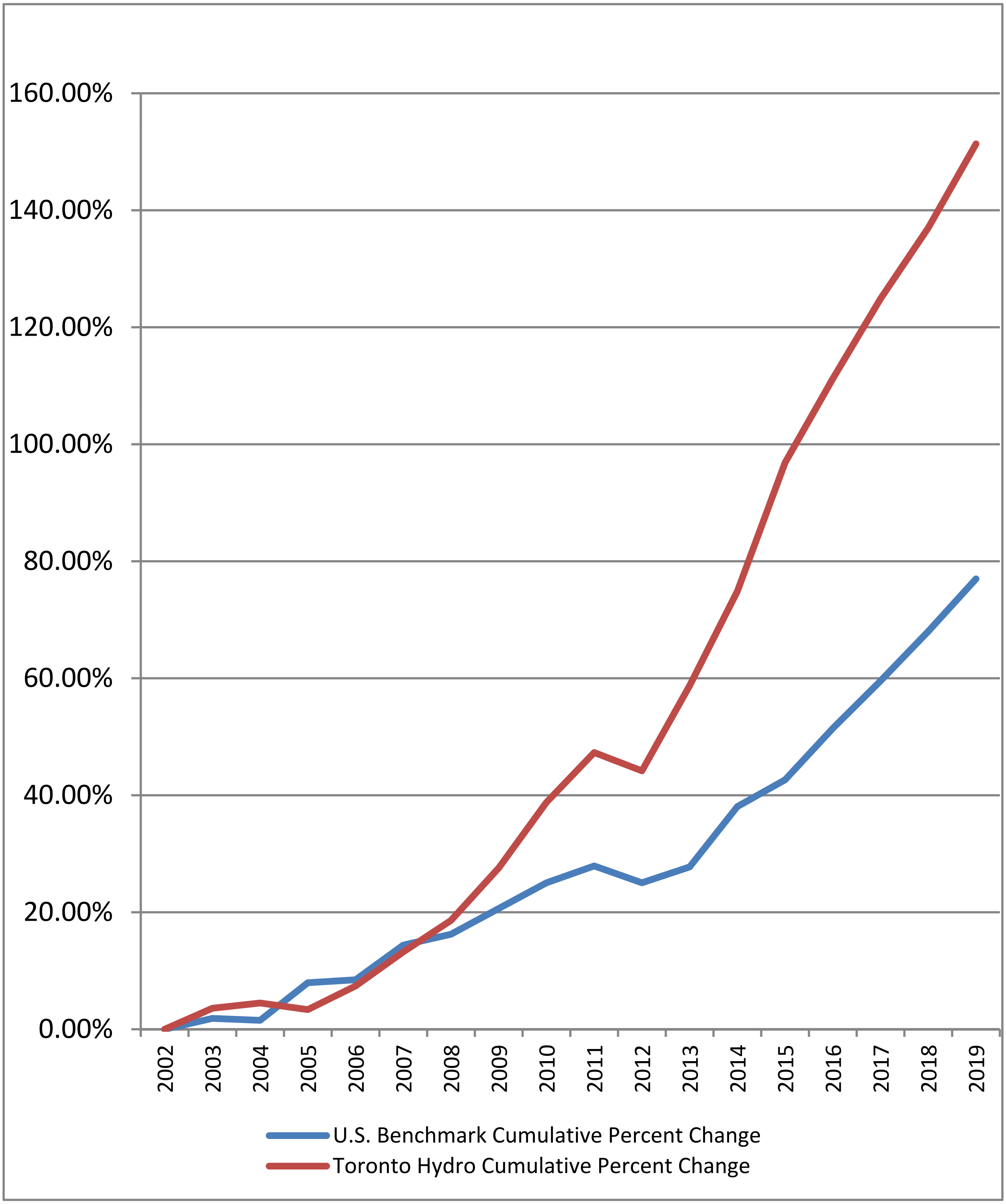
Year	Percent of US Total Cost Econometric Benchmark	Total Cost Econometric Benchmark, $M	Annual Percent Increase	Cumulative Percent Change	Five Year Moving Average increase	Total Cost THESL, $M	Annual Percent Increase	Cumulative Percent Change	Five Year Moving Average increase	THESL Cost at US Benchmark Levels	Excess THESL Cost	Percent Excess
2002	-24.53%	$591		0.00%		$446		0.00%				
2003	-23.26%	$602	1.86%	1.86%		$462	3.59%	3.59%		$454	$8	1.69%
2004	-22.33%	$600	-0.33%	1.52%		$466	0.87%	4.48%		$453	$13	2.92%
2005	-27.74%	$638	6.33%	7.95%		$461	-1.07%	3.36%		$481	-$20	-4.25%
2006	-25.27%	$641	0.47%	8.46%		$479	3.90%	7.40%		$484	-$5	-0.98%
2007	-25.30%	$676	5.46%	14.38%	2.82%	$505	5.43%	13.23%	2.59%	$510	-$5	-1.01%
2008	-23.00%	$687	1.63%	16.24%	2.77%	$529	4.75%	18.61%	2.84%	$518	$11	2.04%
2009	-20.20%	$713	3.78%	20.64%	3.69%	$569	7.56%	27.58%	4.33%	$538	$31	5.75%
2010	-16.24%	$739	3.65%	25.04%	3.10%	$619	8.79%	38.79%	6.72%	$558	$61	10.99%
2011	-13.10%	$756	2.30%	27.92%	3.52%	$657	6.14%	47.31%	7.28%	$571	$86	15.16%
2012	-12.99%	$739	-2.25%	25.04%	1.83%	$643	-2.13%	44.17%	5.36%	$558	$85	15.30%
2013	-6.23%	$755	2.17%	27.75%	1.94%	$708	10.11%	58.74%	6.63%	$570	$138	24.26%
2014	-4.41%	$816	8.08%	38.07%	2.83%	$780	10.17%	74.89%	7.27%	$616	$164	26.67%
2015	4.15%	$843	3.31%	42.64%	2.76%	$878	12.56%	96.86%	8.20%	$636	$242	38.01%
2016	5.25%	$895	6.17%	51.44%	3.60%	$942	7.29%	111.21%	8.50%	$675	$267	39.47%
2017	6.36%	$943	5.36%	59.56%	5.41%	$1,003	6.48%	124.89%	10.98%	$712	$291	40.94%
2018	6.45%	$993	5.30%	68.02%	6.18%	$1,057	5.38%	137.00%	9.66%	$749	$308	41.05%
2019	7.17%	$1,046	5.34%	76.99%	5.53%	$1,121	6.05%	151.35%	8.57%	$789	$332	42.01%

12 yrs.	Increase	38.07%	74.89%
	CAGR	3.00%	5.90%
17 yrs	Increase	76.99%	151.35%
	CAGR	4.18%	8.21%

PSE Cost Comparison



PSE Rate of Increase Comparison



ORAL HEARING UNDERTAKING RESPONSE
TO SCHOOL ENERGY COALITION

UNDERTAKING NO. J3.4:

Reference(s):

To produce a cost model result table using the PEG model, and to explain any significant difference.

RESPONSE:

The table below presents the same information as Table 2 of the PSE Reply Report for PEG's econometric cost model presented in the December 2014 benchmarking report. We have also presented the t statistic and the p-value on the hypothesis that the difference between THESL's cost (actual or projected) and THESL's predicted cost (*i.e.* total cost econometric benchmark) is zero.

PEG cannot reject the hypothesis that THESL's actual cost is equal to its predicted cost in any year from 2002 through 2014. However, we can conclude that there is a statistically significant difference between THESL's actual cost and its predicted cost in each year of the 2015-2019 Custom IR period. PEG therefore concludes that THESL is an average cost performer prior to its Custom IR period but is projected to be an inferior cost performer during its Custom IR period. We have no empirical basis for concluding that THESL's 2002 – 2014 cost evaluations result from the deferral of necessary capital expenditures during this period.

PEG has also not investigated whether THESL's cost evaluation in 2002 is impacted by differences in municipal accounting (which THESL used prior to 1999) and US GAAP accounting (used by the US electric utility sample), but it is theoretically possible. If such accounting differences exist, they would impact THESL's capital costs (and therefore its total costs) in 2002 since there would be a mismatch between THESL and the US sample in the capital accounting that is used to develop measured capital stocks, and capital costs, between 1989 and 1998. THESL's capital stocks and capital costs in 2002 (and beyond) will depend on THESL's initial, measured capital stock in 1989 and all capital additions it recorded from 1989 through 2001. This, in turn, implies that the different accounting rules THESL and the US utilities used to record capital values between 1989 and 1998 can lead to persistent cost differences for THESL and the US utilities even after both adopted US GAAP accounting in 1999.

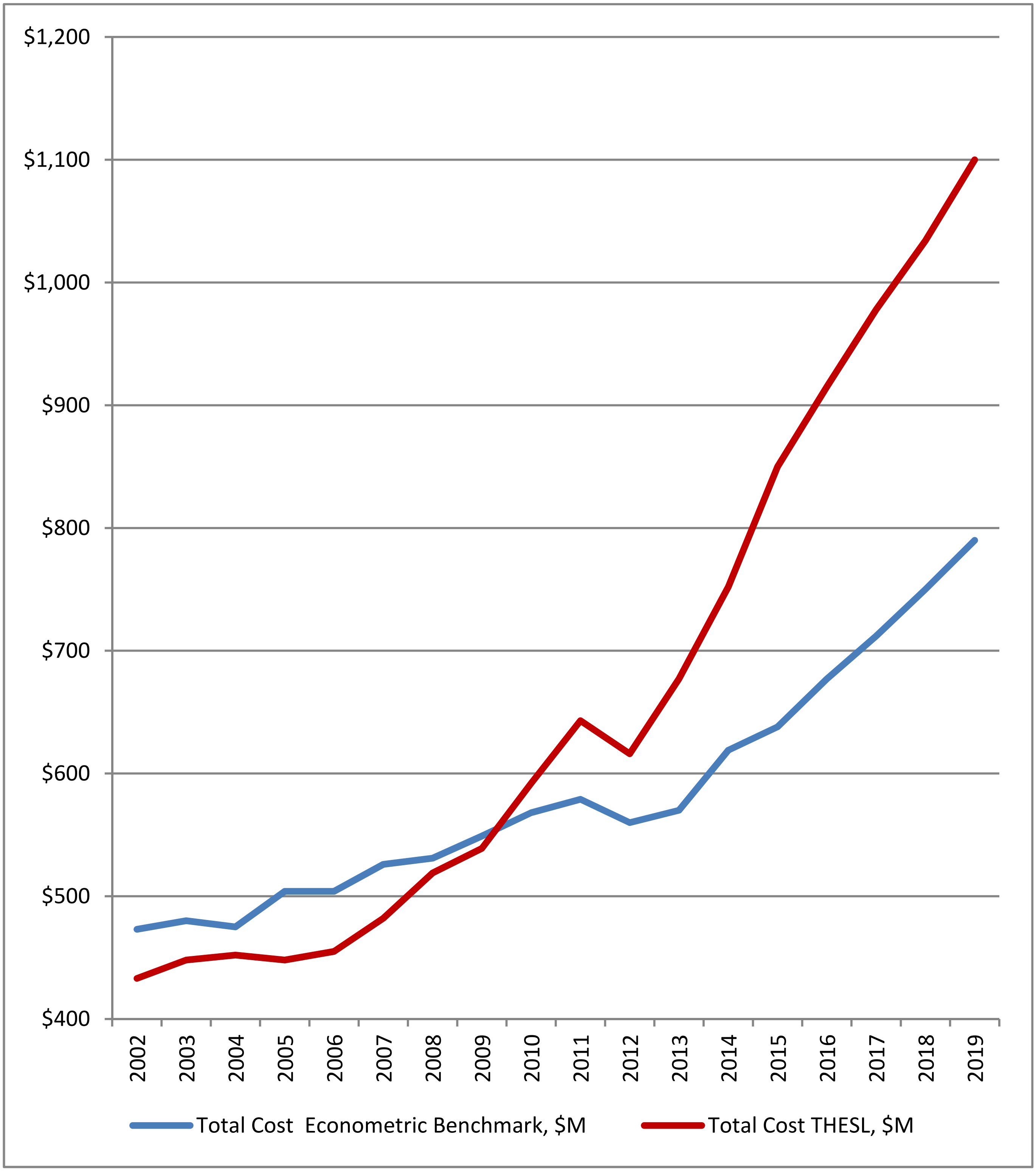
Panel: Dr. Lawrence Kaufmann

Table 2 - PEG Cost Model Results J3.4

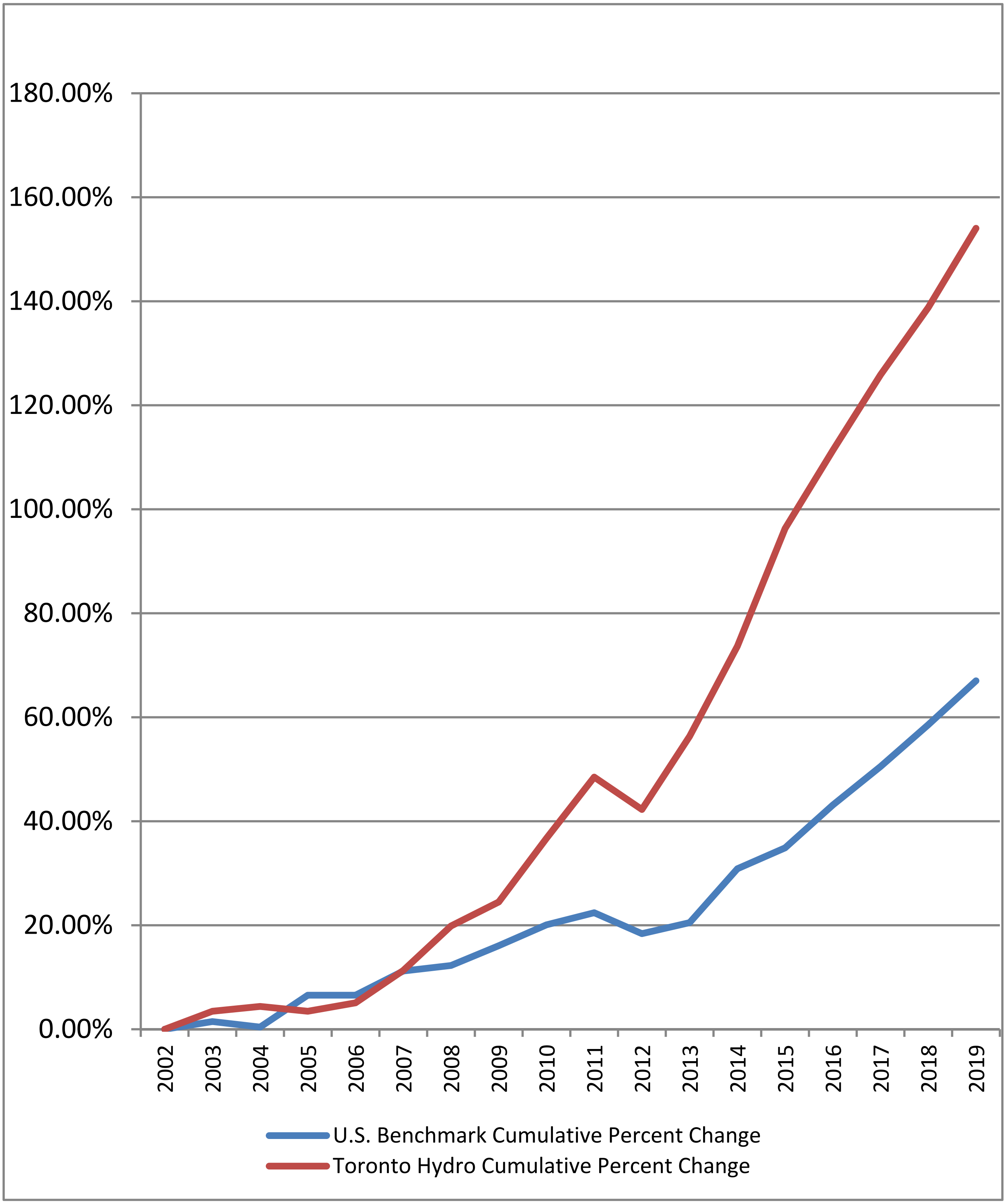
Year	*Percent of US Total Cost Econometric Benchmark*	*Total Cost Econometric Benchmark, $M*	*Annual Percent Increase*	*Cumulative Percent Change*	*Five Year Moving Average increase*	*Total Cost THESL, $M*	*Annual Percent Increase*	*Cumulative Percent Change*	*Five Year Moving Average increase*	*THESL Cost at US Benchmark Levels*	*Excess THESL Cost*	*Percent Excess*
2002	-8.46%	$473		0.00%		$433		0.00%				
2003	-6.67%	$480	1.48%	1.48%		$448	3.46%	3.46%		$439	$9	1.96%
2004	-4.84%	$475	-1.04%	0.42%		$452	0.89%	4.39%		$435	$17	3.95%
2005	-11.11%	$504	6.11%	6.55%		$448	-0.88%	3.46%		$461	-$13	-2.90%
2006	-9.72%	$504	0.00%	6.55%		$455	1.56%	5.08%		$461	-$6	-1.38%
2007	-8.37%	$526	4.37%	11.21%	2.20%	$482	5.93%	11.32%	2.22%	$482	$0	0.10%
2008	-2.26%	$531	0.95%	12.26%	2.08%	$519	7.68%	19.86%	3.11%	$486	$33	6.77%
2009	-1.82%	$549	3.39%	16.07%	3.05%	$539	3.85%	24.48%	3.77%	$503	$36	7.25%
2010	4.23%	$568	3.46%	20.08%	2.49%	$592	9.83%	36.72%	6.30%	$520	$72	13.85%
2011	11.05%	$579	1.94%	22.41%	2.92%	$643	8.61%	48.50%	8.10%	$530	$113	21.31%
2012	10.00%	$560	-3.28%	18.39%	1.27%	$616	-4.20%	42.26%	5.45%	$513	$103	20.16%
2013	18.77%	$570	1.79%	20.51%	1.44%	$677	9.90%	56.35%	5.97%	$522	$155	29.74%
2014	21.49%	$619	8.60%	30.87%	2.50%	$752	11.08%	73.67%	7.75%	$567	$185	32.71%
2015	33.23%	$638	3.07%	34.88%	2.42%	$850	13.03%	96.30%	8.54%	$584	$266	45.54%
2016	35.16%	$677	6.11%	43.13%	3.32%	$915	7.65%	111.32%	8.29%	$620	$295	47.64%
2017	37.36%	$712	5.17%	50.53%	5.32%	$978	6.89%	125.87%	11.52%	$652	$326	50.05%
2018	37.87%	$750	5.34%	58.56%	6.19%	$1,034	5.73%	138.80%	10.34%	$687	$347	50.60%
2019	39.24%	$790	5.33%	67.02%	5.42%	$1,100	6.38%	154.04%	9.07%	$723	$377	52.10%

12 yrs.	Increase	30.87%	73.67%
	CAGR	2.43%	5.81%
17 yrs	Increase	67.02%	154.04%
	CAGR	3.64%	8.36%

PEG J3.4 Cost Comparison



PEG J3.4 Rate of Increase Comparison



ORAL HEARING UNDERTAKING RESPONSE TO SCHOOL ENERGY COALITION

UNDERTAKING NO. J3.1:

Reference(s):

To identify reasons for and quantify the difference in benchmark increases in the custom IR period versus the 12-year period prior to custom IR.

RESPONSE (Prepared by PSE):

As Mr. Fenrick indicated during the hearing, the primary drivers of the growth rate in the total cost benchmarks are inflation (capital input price and OM&A input price) and output growth (customers and peak demand). Other "outputs" that would increase costs such as reliability or safety improvement are not captured within the econometric total cost benchmarking framework.

Mr. Shepherd indicated two time periods for examination in this undertaking, 2002-2014 and 2015-2019. The primary differences in the cost benchmark growth rates during these two time periods are driven by the fact that the expected capital input price inflation is predicted to be higher in the custom IR period than during the historic years of 2002-2014 and measured outputs (customers and peak demand) are expected to increase more rapidly during the 2015-2019 period than the historic 2002-2014 time period. The capital input price was influenced by declining interest rates during the historic time period which is not forecasted to continue into the custom IR years.

Other variables will have a slight impact on the growth rates but the differences in those growth rates between time periods are negligible. The table below provides the estimates of the primary variables driving the cost benchmark growth rates. PSE notes that these are close approximations rather than exact impact estimates.

ORAL HEARING UNDERTAKING RESPONSE TO SCHOOL ENERGY COALITION

Time Period	PSE Reply Benchmark Average Annual Growth Rate	Contribution to the Average Annual Growth Rate*			
		Capital Price	OM&A Price	Customers	Peak Demand
2002-2014	**2.7%**	0.7%	0.9%	0.6%	0.1%
2015-2019	**5.4%**	2.7%	1.0%	1.1%	0.4%
Difference Between Periods	**2.7%**	**2.0%**	**0.0%**	**0.5%**	**0.3%**

*The table does not display the contribution to the growth rates from the trend variables and other variables with minor (< 0.1%) impact on the rate. As a result the numbers may not add.

ORAL HEARING UNDERTAKING RESPONSE
TO SCHOOL ENERGY COALITION

UNDERTAKING NO. J3.6:

Reference(s):

If the model generated for Undertaking J3.4 shows a difference, to identify why it is taking place, and to review data on the PSE model and attempt to determine and quantify reasons for the difference in the model.

RESPONSE:

This undertaking has several dimensions. PEG was asked to: 1) quantify the factors that caused the econometric benchmark in the PSE cost model to grow more rapidly on a prospective basis (over the projected 2015-2019 Custom IR period) than it did on a historical (2002-2014) basis; 2) quantify the factors that caused the econometric benchmark in the PEG cost model to grow more rapidly on a prospective basis (over the projected 2015-2019 Custom IR period) than it did on a historical (2002-2014) basis; and 3) identify any factors that are leading to differences in the growth rates between the PSE and PEG econometric benchmark costs on either a prospective or historical basis.

The data below present the annual growth rates in benchmark econometric costs in the PSE and PEG models for the 2002-2014 and 2015-2019 periods (the latter period corresponds to all five years in the Custom IR period; it is therefore calculated as the average growth in benchmark costs from 2014 to 2019). All growth rates in this response will be expressed in logarithmic rather than arithmetic terms; logarithmic growth rates are more convenient and natural in the current context because the cost models are also in logarithmic form. "Prospective" will also refer to the 2015-2019 period, since this undertaking specifically contrasted the 2002-2014 and 2015-2019 growth rates in econometric benchmarks (notwithstanding the fact that PSE forecast 2013 and 2014 benchmarks as well). The "PSE" growth rates below reflect the econometric benchmarks presented in their Reply Report; the "PEG" growth rates reflect the econometric benchmarks presented in our amended econometric work, after correcting minor errors in some utilities' high voltage transformer capacity data.

Average Annual Growth in Econometric Cost Benchmark (% per annum)

	PSE Cost Model	PEG Cost Model
2002-2014	2.69%	2.24%
2015-2019	4.97%	4.87%

Panel: Dr. Lawrence Kaufmann

PEG's approach for quantifying the factors in observed cost growth was designed to be as transparent and intuitive as possible. We considered and investigated an alternate approach that directly uses each independent variable's contribution to econometric benchmark cost. While this alternate approach would generate similar conclusions, it is also more complicated and less clear than the comparable analysis PEG presents in this response. However, to illustrate the contributions that each independent variable makes to econometric cost predictions, Exhibit K3.6 provides a table with these values on a prospective basis for the PSE model.

Our approach begins by recognizing that the change (expressed with a '^' over the variable) in an observed and measured cost (C) index can be decomposed into a change in an input price index (W) and an input quantity index (X).

$$\Delta\hat{C}^{Observed} = \Delta\hat{W}^{Observed} + \Delta\hat{X}^{Observed} \quad [1]$$

The change in a TFP index can be expressed as the growth in an elasticity-weighted output quantity index (Y) minus the growth in an input quantity index.

$$\Delta T\hat{F}P^{Observed} = \Delta\hat{Y}^{Observed} - \Delta\hat{X}^{Observed} \quad [2]$$

Equation [2] can be re-expressed as

$$\Delta\hat{X}^{Observed} = \Delta\hat{Y}^{Observed} - \Delta T\hat{F}P^{Observed} \quad [3]$$

Substituting [3] into [1] yields

$$\Delta\hat{C}^{Observed} = \Delta\hat{W}^{Observed} + \Delta\hat{Y}^{Observed} - \Delta T\hat{F}P^{Observed} \quad [4]$$

Appendix One of the Concept Paper that PEG wrote at the outset of 4^{th} Generation Incentive regulation showed that TFP growth can be decomposed into six different components: 1) a scale economy effect; 2) a Z variable effect; 3) a trend or technological change effect; 4) a cost share effect; 5) a non-marginal cost pricing effect; and 6) an inefficiency effect. The decomposition of TFP growth presented in that Concept Paper is replicated in equation [5] below, although for simplicity (and because they cannot be separately identified in the PSE study, given available data) the final three effects discussed above are aggregated together and termed a "residual" effect.

$$\Delta T\hat{F}P^{Observed} = \left(1 - \sum_i \varepsilon_i\right)\Delta\hat{Y}^{Observed} - \sum_n \varepsilon_Z \dot{Z}_n - trend + residual \quad [5]$$

Substituting [5] into [4] yields

$$\Delta\hat{C}^{Observed} = \Delta\hat{W}^{Observed} + \Delta\hat{Y}^{Observed} - \left[\left(1 - \sum_i \varepsilon_i\right)\Delta\hat{Y}^{Observed} - \sum_n \varepsilon_Z \dot{Z}_n - trend + residual\right] \quad [6]$$

Equation [6] can be simplified to the following:

$$\Delta\hat{C}^{Observed} = \Delta\hat{W}^{Observed} + \sum_i \varepsilon_i \Delta\hat{Y}^{Observed} + \sum_n \varepsilon_Z \dot{Z}_n + trend - residual \qquad [7]$$

It can be seen that historical cost growth can be decomposed into five components: 1) changes in input prices; 2) an elasticity-weighted change in output (*i.e.* multiply the growth in each output by its cost elasticity and sum across all outputs); 3) a Z variable effect (*i.e.* multiply changes in all Z variables by their cost function coefficients and sum across all Z variables); 4) the estimated trend coefficient; and 5) a residual term.

The same logic detailed in equations [1] – [7] also applies to prospective cost changes. In PSE's model, $\dot{Z}_n$ =0 for every Z variable since the only independent variables that PSE projects will change over the 2015-2019 period are input prices and outputs. Because the Z variables are not changing, the Z variable term drops out of the equation PEG used to decompose prospective cost growth. The four remaining components for decomposing prospective cost growth are presented in equation [8] below.

$$\Delta\hat{C}^{E} = \Delta\hat{W}^{E} + \sum_i \varepsilon_i \Delta\hat{Y}^{E} + trend - residual \qquad [8]$$

Accounting for the *differences* between projected and observed cost growth can be done straightforwardly by subtracting equation [7] from equation [8]; doing so and simplifying yields the following:

$$\Delta\hat{C}^{E} - \Delta\hat{C}^{Observed} = \Delta\hat{W}^{E} - \Delta\hat{W}^{Observed} + \sum_i \varepsilon_i \left(\Delta\hat{Y}^{E} - \Delta\hat{Y}^{Observed}\right) - \sum_n \varepsilon_Z \dot{Z}_n + residual^{E} - residual^{Observed} \qquad [9]$$

PEG applied equations [7], [8], and [9] to the PSE and PEG models. We then used these decompositions to examine and quantify which factors were most important for explaining the acceleration of benchmark econometric costs between the historical and projected periods, and for understanding differences between the PSE and PEG models.

The results of this analysis for the PSE model are presented in Table J.3.6.1. The most notable element in this table is that PSE projects a quite rapid acceleration in the capital service price in 2015-2019 compared with 2002-2014. Over the 2002-14 period, capital service prices grew by 1.14% per annum. Over the Custom IR period, capital service prices are projected to grow by 4.55% per annum.

The relatively slow growth in capital service prices over the 2002-14 period is partly due to the decline in interest rates. However, PSE projects interest rates and the cost of capital will remain constant over the Custom IR period. The cost of capital is therefore not contributing to PSE's projection of more rapidly growing capital service prices.

The projected acceleration in capital service prices is due to PSE forecasting that THESL's capital asset prices will grow at the average annual 40-year growth rate in the electric utility construction price index (the EUCPI; p. 29 of the July 2014 PSE Benchmarking Report). Between 1973 and 2013, the EUCPI grew at an average rate of 4.55%, which is identical to the projected, annual growth in capital service prices. However, recent inflation in the EUCPI has been much more modest. Below we present the 10-year average growth rates in the EUCPI over the entire 40-year period PSE used for its capital asset price forecasts.

1973-83	9.6% per annum
1983-93	3.2% per annum
1993-2003	2.4% per annum
2003-2013	2.0% per annum

PSE's forecast of capital asset prices is therefore greatly impacted by the inflation in capital asset prices during the high-inflation 1970s. This distant inflationary experience is built into PSE's forecast of capital asset prices. This forecast is, in turn, greatly impacting the growth rate of PSE's estimated econometric benchmarks for THESL relative to observed history.

In fact, Table J3.6.1 shows that PEG estimates 72.3% of the acceleration in PSE's econometric benchmark cost results from the assumed acceleration in capital asset prices (which accounts entirely for the acceleration in capital service prices since the cost of capital and depreciation rates are each assumed to remain constant). An additional 32.6% of the acceleration in PSE's econometric benchmark costs results from the more rapid assumed inflation in OM&A input prices. Output growth is also expected to accelerate over the Custom IR period, and the cost impact of more rapid output growth is projected to contribute 21.9% towards the acceleration of econometric benchmark costs.

Other factors are estimated to lead to a *deceleration* in econometric benchmark costs, which means they tend to offset the input price and output effects above. Between 2002 and 2014, PSE data show that there was a dramatic increase in the percent of load delivered to THESL's residential customers (from 19% of total deliveries in 2002 to 46.6% in 2014). Because PSE's model found that residential customers are more expensive to serve, this trend contributed to an increase in THESL's econometric cost benchmark of 0.28% per annum. Going forward, however, PSE assumes that the share of deliveries to residential customers will remain constant. The historically estimated 0.28% annual increase in econometric benchmark costs resulting from a more residential load profile is therefore projected to vanish under the Custom IR period, and this projected change contributes a 12.1% decline in econometric benchmark costs. The trend and residual effects contribute an additional 14.7% deceleration in the econometric benchmark cost.

In sum, PEG finds that the main factor contributing to more rapid growth in PSE's econometric benchmark costs for THESL under its Custom IR plan is that PSE projects THESL's capital asset prices will grow by 4.55% per annum over the Custom IR period. This factor accounts for more than 72% of the acceleration in THESL's econometric cost benchmark under Custom IR. The second most important factor contributing to more rapid growth in econometric benchmark costs is PSE's assumed growth in OM&A prices. The third most important contributing factor is the assumed growth in output.

The results of this analysis for the PEG model are presented in Table J3.6.2. The results are broadly similar, because PEG did not adjust any of PSE's assumptions for the future when developing projected benchmark costs for THESL. Hence the same 4.55% annual increase in capital service prices are also built into the PEG econometric cost projections.

In fact, PEG's model shows somewhat more rapid acceleration relative to history than PSE's model, because PEG historically projected slower growth in THESL's benchmark costs than PSE (2.24% per annum for PEG vs. 2.69% per annum in the PSE model). PEG continues to project slower growth in THESL's benchmark costs under Custom IR, but the differences between the PEG (4.87% per annum) and PSE (4.97% per annum) projections are smaller on a prospective basis than on an observed, historical basis.

PEG estimates that 58.4% of the acceleration in our benchmark costs for THESL result from PSE's forecast of accelerating capital service prices. This is the most important factor contributing to more rapid growth in PEG's econometric benchmark costs for THESL under its Custom IR plan. The second most important contributing factor to this acceleration is the more rapid forecast in OM&A input prices (contributes 29.1%). The third most important contributing factor is the projected growth in output (contributes 17.2%). As with the PSE model, the growth in PEG's econometric benchmark costs declined due to the assumption that THESL would no longer continue to serve an increasingly residential load, as it did over the 2002-2014 period; this factor contributes -8.5% to the change in PEG's econometric benchmark costs. Trend and residual factors contribute 3.8% to the acceleration of PEG's benchmark costs.

1

Exhibit K3.6

		Toronto Hydro Data (Transformed)																	
Variable	Estimated Coefficient	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
CONST	20.101	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
WK	0.554	0.272	0.254	0.227	0.205	0.178	0.167	0.162	0.171	0.156	0.137	0.069	0.058	0.139	0.162	0.184	0.206	0.228	0.250
Y1	0.723	-0.329	-0.323	-0.317	-0.312	-0.309	-0.307	-0.301	-0.292	-0.277	-0.264	-0.251	-0.245	-0.227	-0.210	-0.193	-0.178	-0.164	-0.149
Y2	0.229	-0.100	-0.090	-0.154	-0.052	-0.050	-0.096	-0.144	-0.135	-0.097	-0.069	-0.088	-0.069	-0.069	-0.131	-0.099	-0.086	-0.074	-0.064
WKWK	0.063	0.037	0.032	0.026	0.021	0.016	0.014	0.013	0.015	0.012	0.009	0.002	0.002	0.010	0.013	0.017	0.021	0.026	0.031
Y1Y1	0.288	0.054	0.052	0.050	0.049	0.048	0.047	0.045	0.043	0.038	0.035	0.032	0.030	0.026	0.022	0.019	0.016	0.013	0.011
Y2Y2	0.171	0.005	0.004	0.012	0.001	0.001	0.005	0.010	0.009	0.005	0.002	0.004	0.002	0.002	0.009	0.005	0.004	0.003	0.002
WKY1	-0.004	-0.090	-0.082	-0.072	-0.064	-0.055	-0.051	-0.049	-0.050	-0.043	-0.036	-0.017	-0.014	-0.032	-0.034	-0.035	-0.037	-0.037	-0.037
WKY2	0.007	-0.027	-0.023	-0.035	-0.011	-0.009	-0.016	-0.023	-0.023	-0.015	-0.010	-0.006	-0.004	-0.010	-0.021	-0.018	-0.018	-0.017	-0.016
Y1Y2	-0.199	0.033	0.029	0.049	0.016	0.015	0.030	0.043	0.039	0.027	0.018	0.022	0.017	0.016	0.028	0.019	0.015	0.012	0.009
Z1	0.020	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306	14.306
Z2	0.037	-0.651	-0.714	-0.749	-0.647	-0.706	0.292	0.258	0.767	0.383	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244	0.244
Z3	0.141	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124	0.124
Z4	0.122	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710	0.710
Z5	-0.032	0.866	0.866	0.866	0.866	0.872	0.857	0.864	0.868	0.872	0.881	0.887	0.898	0.898	0.898	0.898	0.898	0.898	0.898
Z6	0.015	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995	-0.995
Z7	0.020	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176	-1.176
TREND	0.002	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18
WOM	N/A	1.000	1.024	1.054	1.086	1.108	1.148	1.181	1.186	1.228	1.253	1.269	1.288	1.310	1.340	1.371	1.404	1.438	1.472
Econometric Estimate:		20.299	20.294	20.267	20.292	20.278	20.300	20.289	20.323	20.322	20.324	20.291	20.296	20.355	20.366	20.401	20.428	20.456	20.483
EXP()		654,137,431	651,240,323	633,401,817	649,446,174	640,605,623	654,687,497	647,705,848	670,083,825	669,504,481	670,872,723	649,119,836	652,338,956	692,183,682	699,579,057	724,432,899	744,580,684	765,318,312	786,631,218
***WOM**		654,130,889	666,570,521	667,326,818	705,597,290	709,515,570	751,555,059	764,992,423	794,504,990	822,010,907	840,308,338	823,661,668	840,160,388	906,636,031	937,303,017	993,501,766	1,045,532,750	1,100,328,749	1,157,991,949
THESL Actual Cost:		435,010,368	450,339,136	454,122,880	449,667,584	457,014,912	484,482,944	518,147,392	535,624,544	586,112,768	637,697,472	598,313,344	657,159,296	729,767,040	824,746,240	887,888,000	949,368,896	1,003,643,904	1,067,738,240
Difference (ln):		-0.408	-0.392	-0.385	-0.451	-0.440	-0.439	-0.390	-0.394	-0.338	-0.276	-0.320	-0.246	-0.217	-0.128	-0.112	-0.096	-0.092	-0.081

Table J3.6.1

Decomposition of THESL Predicted Cost: PSE Model[1]

	THESL		Average	THESL		Average	Acceleration	
	2002	2014	Growth	2014	2019	Growth	Amount	Percent Explained
Predicted Cost	$ 591,000,000	$ 816,000,000	2.69%	$ 816,000,000	$ 1,046,000,000	4.97%	2.28%	
Input Price Effects								
Capital Price	11.65	13.36	1.14%	13.36	16.77	4.55%	3.42%	72.3%
OM&A Price	1.00	1.31	2.25%	1.31	1.47	2.34%	0.09%	32.6%
Capital Weight	69.9%	66.2%		66.2%	73.2%			
OM&A Weight	30.1%	33.8%		33.8%	26.8%			
Input Price Index			**1.49%**			**3.88%**	**2.39%**	**104.9%**
Output Quantity Effects								
Customers	665,043	736,076	0.85%	736,076	795,967	1.56%	0.72%	
Demand	4,771	4,921	0.26%	4,921	4,948	0.11%	-0.15%	
Customer Weight	78.0%	78.0%		78.0%	78.0%			
Demand Weight	22.0%	22.0%		22.0%	22.0%			
Output Quantity Index			0.72%			1.24%		
Customer Coefficient			0.738			0.738		
Demand Coefficient			0.208			0.208		
Cost Impact of Output Growth			94.6%			94.6%		
Output Effect			**0.68%**			**1.18%**	**0.50%**	**21.9%**
Other Effects								
Percent Residential	19.04%	46.60%	7.46%					
Percent Residential Coefficient			0.037					
Percent Residential Effect			**0.28%**				**-0.28%**	**-12.1%**
Trend + Residual			0.24%			-0.09%	-0.33%	-14.7%

[1] **The Customer, Demand and Percent Residential coefficients are based on the sample averages, because the THESL-specific coefficients were not provided with the PSE Reply Report.**

Table J3.6.2

Decomposition of THESL Predicted Cost: PEG Model

	THESL		Average	THESL		Average	Acceleration	
	2002	2014	Growth	2014	2019	Growth	Amount	Percent Explained
Predicted Cost	$ 473,149,648	$ 619,183,584	2.24%	$ 619,183,584	$ 789,746,473	4.87%	2.62%	
Input Price Effects								
Capital Price	11.65	13.36	1.14%	13.36	16.77	4.55%	3.42%	58.4%
OM&A Price	1.00	1.31	2.25%	1.31	1.47	2.34%	0.09%	29.1%
Capital Weight	69.8%	65.7%		65.7%	65.7%			
OM&A Weight	30.2%	34.3%		34.3%	34.3%			
Input Price Index			**1.50%**			**3.79%**	**2.30%**	**87.5%**
Output Quantity Effects								
Customers	665,043	736,076	0.85%	736,076	795,967	1.56%	0.72%	
Demand	4,771	4,921	0.26%	4,921	4,948	0.11%	-0.15%	
Customer Weight	76.3%	76.3%		76.3%	76.3%			
Demand Weight	23.7%	23.7%		23.7%	23.7%			
Output Quantity Index			0.71%			1.22%		
Customer Coefficient			0.674			0.674		
Demand Coefficient			0.210			0.210		
Cost Impact of Output Growth			88.4%			88.4%		
Output Effect			**0.62%**			**1.08%**	**0.45%**	**17.2%**
Other Effects								
Percent Residential	19.04%	46.60%	7.46%					
Percent Residential Coefficient			0.030					
Percent Residential Effect			**0.22%**				**-0.22%**	**-8.5%**
Trend + Residual			-0.10%			0.00%	0.10%	3.8%

ORAL HEARING UNDERTAKING RESPONSE
TO SCHOOL ENERGY COALITION

UNDERTAKING NO. J3.7:

Reference(s):

To identify factors behind any significant differences in the rate of change of costs in the benchmark and THESL numbers.

RESPONSE:

Our response to Undertaking J3.6 provided a detailed analysis of the factors giving rise to differences in the growth rates of econometric benchmark costs over the observed and prospective, Custom IR periods. PEG's original analysis did not focus on this issue, because we concentrated on ensuring comparability of PSE and PEG cost measures and technical, econometric issues. However, we do not believe that it is reasonable to project 4.55% annual growth in THESL's capital service prices under its custom IR period. The EUCPI data show that inflation rates of that magnitude have not been observed on a sustained, multi-year basis for more than 30 years.

PEG believes a more reasonable forecast in capital service prices is the 10-year historical growth in the EUPCI. As discussed in the response to Undertaking J3.6, the EUCPI has grown by 2.0% per annum over the 2003-2013 period. A more reasonable capital asset price forecast could potentially lead to a significant difference in the relationship between THESL's benchmark and projected costs over the Custom IR period.

To explore this issue, PEG amended our econometric benchmark model presented in response to J3.5 so that it projected 2% annual growth in capital service prices over the 2013-2019 period rather than the 4.55% assumed by PSE (with the possible exception of 2013, in which actual EUCPI data were available at the time of PSE's study). Recall that the response to J3.5 subtracted THESL's projected bad debt expenses from its total costs in 2013-2019 and therefore incorporated "Adjustment #1" recommended in the PSE Reply Report.

PEG presents the results of this amended econometric model in Table J3.7.1 below. The amendments do not impact the 2002-2012 data used to estimate the model or PEG's 2002-2012 benchmarking results for THESL. Compared with the Table presented in response to Undertaking J3.4, this table reflects only the impact of changing the asset price forecast for THESL over the 2013-2019 period. PEG's results below therefore differ from the results presented in PSE's Reply Report in three ways: 1) PEG has not accepted PSE's proposed adjustment for CDM expenses (because it adds historical and projected expenses to THESL's cost measure that are not part of this application); 2) PEG does not include an urban core dummy variable because our statistical work rejects the hypothesis that this is a significant driver of electricity distribution costs, after other independent variables are controlled for; and 3) PEG projects 2% annual asset price growth rather than the 4.55% PSE projection for the Custom IR period.

One result of this change is the growth in THESL's econometric benchmark costs slows markedly over the Custom IR period. Recall from the response to Undertaking J3.6 that PEG's previous work projected annual growth in benchmark costs for THESL of 4.87% per annum during the Custom IR years. After the projected growth in capital asset prices over these years is reduced to 2% per annum from 4.55% per annum, PEG's econometric benchmark grows by only 3.0% per annum. This growth rate is more compatible with historical changes in econometric benchmark costs.

It can also be seen that THESL is now a worse cost performer. THESL's costs are projected to 33.1% above their benchmark levels in 2015. This projected difference rises to 45.2% by 2019. All these differences are statistically significant.

The increasingly worse THESL performance is expected, because slower projected input price inflation will have a cumulative effect on the cost benchmarks. By continually leading to less escalation in cost benchmarks compared with PEG's earlier econometric model, the gap between THESL's actual and projected costs will continue to widen over time.

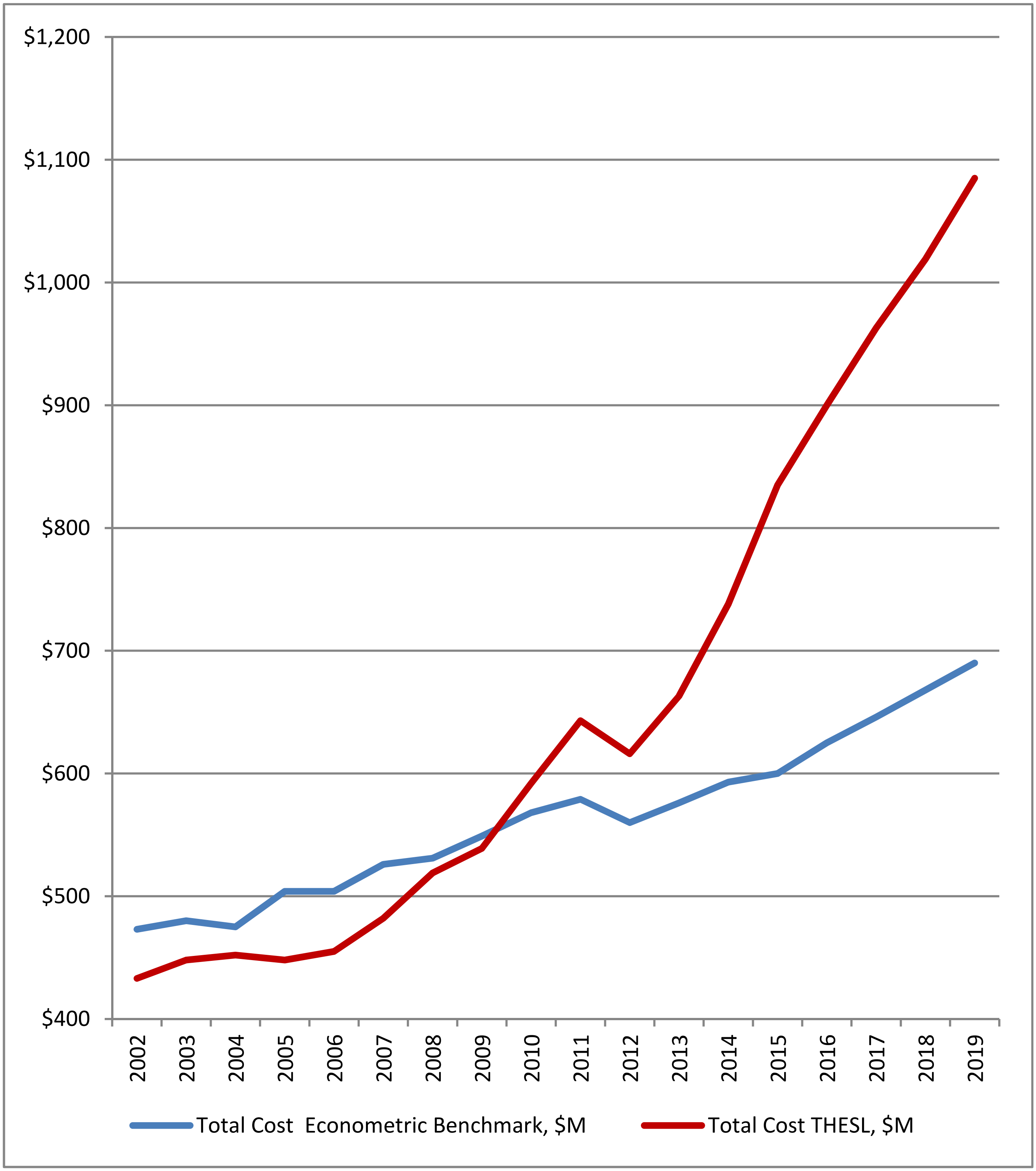
PEG believes the refinements of our cost projections in this undertaking lead to more accurate inferences on THESL's projected cost performance. They also strengthen our conclusion that THESL is projected to be an inferior cost performer under its Custom IR plan.

Table 2 - PEG Cost Model Results J3.7.1

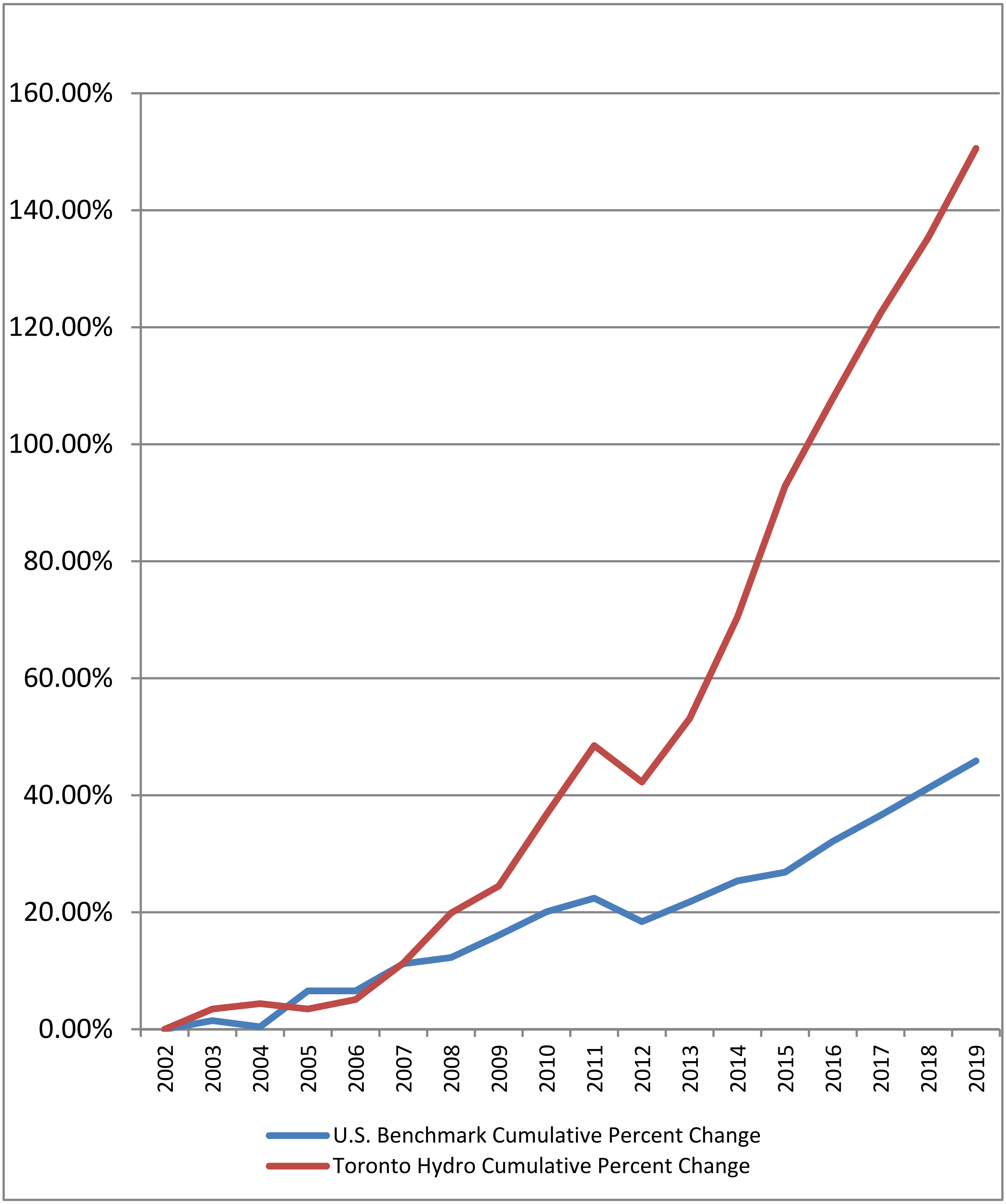
Year	*Percent of US Total Cost Econometric Benchmark*	*Total Cost Econometric Benchmark, $M*	*Annual Percent Increase*	*Cumulative Percent Change*	*Five Year Moving Average increase*	*Total Cost THESL, $M*	*Annual Percent Increase*	*Cumulative Percent Change*	*Five Year Moving Average increase*	*THESL Cost at US Benchmark Levels*	*Excess THESL Cost*	*Percent Excess*
2002	-8.46%	$473		0.00%		$433		0.00%				
2003	-6.67%	$480	1.48%	1.48%		$448	3.46%	3.46%		$439	$9	1.96%
2004	-4.84%	$475	-1.04%	0.42%		$452	0.89%	4.39%		$435	$17	3.95%
2005	-11.11%	$504	6.11%	6.55%		$448	-0.88%	3.46%		$461	-$13	-2.90%
2006	-9.72%	$504	0.00%	6.55%		$455	1.56%	5.08%		$461	-$6	-1.38%
2007	-8.37%	$526	4.37%	11.21%	2.20%	$482	5.93%	11.32%	2.22%	$482	$0	0.10%
2008	-2.26%	$531	0.95%	12.26%	2.08%	$519	7.68%	19.86%	3.11%	$486	$33	6.77%
2009	-1.82%	$549	3.39%	16.07%	3.05%	$539	3.85%	24.48%	3.77%	$503	$36	7.25%
2010	4.23%	$568	3.46%	20.08%	2.49%	$592	9.83%	36.72%	6.30%	$520	$72	13.85%
2011	11.05%	$579	1.94%	22.41%	2.92%	$643	8.61%	48.50%	8.10%	$530	$113	21.31%
2012	10.00%	$560	-3.28%	18.39%	1.27%	$616	-4.20%	42.26%	5.45%	$513	$103	20.16%
2013	15.10%	$576	2.86%	21.78%	1.66%	$663	7.63%	53.12%	5.44%	$527	$136	25.74%
2014	24.45%	$593	2.95%	25.37%	1.57%	$738	11.31%	70.44%	7.24%	$543	$195	35.95%
2015	39.17%	$600	1.18%	26.85%	1.10%	$835	13.14%	92.84%	8.05%	$549	$286	52.02%
2016	44.00%	$625	4.17%	32.14%	1.56%	$900	7.78%	107.85%	7.84%	$572	$328	57.30%
2017	49.07%	$646	3.36%	36.58%	3.01%	$963	7.00%	122.40%	11.04%	$591	$372	62.84%
2018	52.54%	$668	3.41%	41.23%	3.13%	$1,019	5.82%	135.33%	10.53%	$612	$407	66.64%
2019	57.25%	$690	3.29%	45.88%	3.21%	$1,085	6.48%	150.58%	9.22%	$632	$453	71.77%

12 yrs.	Increase	25.37%	70.44%
	CAGR	2.00%	5.55%
17 yrs	Increase	45.88%	150.58%
	CAGR	2.49%	8.17%

PEG J3.7.1 Cost Comparison



PEG J3.7.1 Rate of Increase Comparison



ARTICLE 2
OBJECTIVES AND PRINCIPLES

2.1 Purposes

The purposes of this *Shareholder Direction* are as follows:

a) subject to the *Board's* authority to manage or supervise the management of the business and affairs of the *Corporation*, to provide the *Board* with the *Shareholder's* fundamental principles regarding the *Business*;

b) to inform the residents of the *City of Toronto* of the *Shareholder*'s fundamental principles regarding the *Business*; and

c) to set out the accountability, responsibility and relationship between the *Board* and the *Shareholder*.

2.2 Shareholder Objectives and Principles

2.2.1 Subject to *Law*, the *Corporation* shall and shall direct its *Subsidiaries* to conduct their affairs and govern their operations in accordance with such rules, policies, directives or objectives as *Directed by Council* from time to time.

2.2.2 The following objectives and principles shall govern the operations of *Toronto Hydro*:

a) to operate *Toronto Hydro* on an efficient and commercially prudent basis;

b) to optimize the *Shareholder*'s return on equity and operate *Toronto Hydro* with a view to meeting the financial performance objectives of the *Shareholder* as set out in this *Shareholder Direction*;

c) to provide a reliable, effective and efficient electricity distribution system that supports the electricity demands of residents and businesses in the *City of Toronto*;

d) to operate *Toronto Hydro* in an environmentally responsible manner consistent with the *City of Toronto's* energy, climate change and urban forestry objectives and, as appropriate, utilizing emerging green technologies;

e) to ensure that the *Business* is managed in material compliance with all *Law*; and

f) to engage in recruitment and procurement practices designed to attract employees and suppliers from the *City of Toronto*'s diverse community.

#		Consolidated Financial Summary 2013 (*Sic*) - 2019										Comments		References
1	**Energy Probe TCQ 49**													
2	Toronto Hydro Submission	Approved	Actual	Actual	Estimate	Proposed		Proposed	Proposed	Proposed	Proposed	**Comments**		**References**
3		2011	2012	2013	2014	2015		2016	2017	2018	2019			2015-2019: E1B_T02_S03
4	Operating Revenues	522	524.2	546.05	546.5	661.2		691.5	747.0	800.1	843.5	*See Cover Letter Para 11*		2012-2014: Toronto Hydro RRR
5	Other Revenues	26	19.4	25.4	25.7	46.1		46.8	47.4	48	48.7			Filings and Supporting Materials
6	Total Revenue	548	543.6	571.45	572.2	707.3		738.3	794.4	848.1	892.2			
7														
8	Total OM&A Expense	238.6	215.8*	246.4	246.6	269.5		273.3	277.1	281	284.9	*See Cover Letter Para 8*		Past/Test Year data: E4A_T01_S01; *2012 amount is ne
9	Rate Base	2298.2	2534.3	2658.4	2774.9	3313.5		3683.9	3977.9	4199.8	4415.2			Information underlying E1B_T02_S03
10	**Capital Factor**													
11	Interest Expense					*81.80*		*90.90*	*98.20*	*103.70*	*109.00*			
12	Depreciation & Amortization					*208.20*		*222.00*	*248.20*	*266.70*	*287.20*			
13	Return on Capital (ROE)					*123.30*		*137.10*	*148.00*	*156.30*	*164.30*			
14	PILs/Income Taxes					*24.4*		*14.90*	*22.80*	*40.50*	*46.70*			
15	Subtotal Capital-Related RR					*437.80*		*465.0*	*517.30*	*567.20*	*607.30*			
16	*Cn*					-		*4.11*	*7.57*	*6.68*	*5.01*			E1B_T02_S03
17	*Scap*					-		*0.67*	*0.69*	*0.71*	*0.72*			
18	*PCI*					-		*4.57*	*8.00*	*7.09*	*5.41*	**PCI=I-X+Cn-Scap*(I-X)**		
19	**Total Gross Revenue Requirement**	548	543.6	571.45	572.2	707.3		738.3	794.4	848.1	892.1			
20	**Other Revenues**	-26	-19.4	-25.4	-25.7	-46.1		-46.8	-47.4	-48	-48.7			
21	**RATES REVENUE REQUIREMENT**	**522**	**524.2**	**546.05**	**546.5**	**661.2**		**691.5**	**747**	**800.1**	**843.5**	*See Cover Letter Para 9, 10*		
22														
23														
24	Total Debt	1378.9	1520.58	1595.04	1664.94	1988.1		2210.34	2386.74	2519.88	2649.12	60.00%	4.11%	
25	Common Equity	919.3	1013.72	1063.36	1109.96	1325.4		1473.56	1591.16	1679.92	1766.08	40.00%	9.30%	
26	Total Rate Base	2298.2	2534.3	2658.4	2774.9	3313.5		3683.9	3977.9	4199.8	4415.2	100.00%	6.19%	Information underlying E1B_T02_S03
27														
28														
29		**CAPEX and In Service Asset Additions**												
30	**Capital Expenditures**													
31	Total System Access Capital	58.3	53.2	86.6	76	86.1		93.5	100.9	90.4	85.5			
32	Total System Renewal Capital	219.3	157.2	231.1	286.4	251.7		235	246.3	260.1	265.5			
33	Total System Service Capital	75.6	38.4	83.7	104.1	86.8		56.5	62.5	49.5	73.9			E3A-T06_S02, App 2-AA
34	Total General Plant Capital	67.7	29.3	33.8	109.5	104.6		99.4	28.9	32.1	27.9			
35	Other	24.6	9.9	10.5	13.3	10.3		19.8	28.6	37.9	49.4			
36	**Total Distribution Capital**	**445.5**	**288.0**	**445.7**	**589.2**	**539.6**		**504.2**	**467.4**	**470.0**	**502.2**			
37														
38	**In-Service Asset Additions**													
39	Total System Access Capital													
40	Total System Renewal Capital													
41	Total System Service Capital													
42	Total General Plant Capital													
43	Other													
44	**TOTAL ISAs**	439.1*	**209.4**	**381.3**	**480.3**	**653.6**		543.1	505.7	441	529.9			Interrogatory 2B-SEC-25. *2011 ISA reflects the actual a
45	**Variation**											*See Cover Letter Para 12*		
46														
47		**OM&A**												
48	**Description**	**Bd Approv**	**Actual**	**Actual**	**Estimate**	**Test Base**		**Proposed**	**Proposed**	**Proposed**	**Proposed**	**Categories/Taxonomy**		
49		**2011**	**2012**	**2013**	**2014**	**2015**		**2016**	**2017**	**2018**	**2019**			
50	Operations	59.7	55.9	59.5	58.5	70.3								
51	Maintenance	56.1	54.8	66.8	59.3	61.2								
52	Billing and Collecting	40.6	36.0	35.2	37.9	41.5								
53	Community Relations	2.9	2.9	2.9	2.7	2.7								
54	Administrative and General	72.6	67.8	75.0	81.2	86.5								
55	Taxes Other Than Income Taxes	5.9	-2.3	6.4	6.5	6.5								
56	Donations	0.7	0.7	0.7	0.7	0.8								
57	**TOTAL**	**238.6**	**215.8**	**246.4**	**246.6**	**269.5**		**273.3**	**277.1**	**281**	**284.9**	*See Cover Letter Para 8*		Past/Test Year data: E4A_T01_S01;
58	**Variation: Restructuring Costs**		27.7											

t of 27.7 restructuring costs

ɑmount.

Revenue Requirement Comparison - Application vs. U.S. Benchmark

Application (Source Energy Probe TCQ 49)

Year	*2014*	*2015*	*2016*	*2017*	*2018*	*2019*	*Total*
Gross Costs ($ millions)	572.2	707.3	738.3	794.4	848.1	892.1	3980.2
Increase		135.1	31	56.1	53.7	44	319.9
Percentage		23.61%	4.38%	7.60%	6.76%	5.19%	55.91%

PEG Final Results - U.S. Benchmark Increases 2015-2019 (Source J3.7.1)

Gross Costs ($ millions)	572.2	579.0	603.1	623.4	644.6	665.8	3115.8
Benchmark Increase		6.8	24.1	20.3	21.3	21.2	93.6
Percentage		1.18%	4.17%	3.36%	3.41%	3.29%	16.36%
Application Excess		128.3	135.2	171.0	203.5	226.3	864.4
Percentage Excess							27.74%

PSE Final Results - U.S. Benchmark Increases 2015-2019 (Source PSE Reply Table 2)

Gross Costs ($ millions)	572.2	591.1	627.6	661.3	696.3	733.5	3309.8
Benchmark Increase		18.9	36.5	33.6	35.0	37.2	161.3
Percentage		3.31%	6.17%	5.36%	5.30%	5.34%	28.19%
Application Excess		116.2	110.7	133.1	151.8	158.6	670.4
Percentage Excess							20.26%

to its contact with residential customers, in that it generally relates to account inquiries, billing information changes, follow-up on outage restoration, energy conservation incentives or specific customer requests such as new connections.

Toronto Hydro also engages in other forms of indirect communication with customers through its interactions with industry associations on conservation, reliability and infrastructure investment issues. Organizations such as the Building Owners and Managers Association ("BOMA") and the Toronto Board of Trade can help the utility effectively disseminate critical information to their large memberships.

In addition, Toronto Hydro collaborates with the City of Toronto Better Buildings Partnership within the Energy Efficiency Office to pursue conservation opportunities within the municipal sector as well as leveraging demand response programs to support the emergency generation and preparedness plans for city affiliates such as Toronto Community Housing. Toronto Hydro is also a member of Weatherwise, a partnership convened by the City and Civic Action comprised of public, private and Not-For-Profit organizations identifying the risks of extreme weather.

1.3. Very Large Customers

Finally, Toronto Hydro has an engagement program – the Key Account Management Services program – dedicated to its very large or "key account" customers. The utility created this program to better understand and respond to the unique experiences, preferences and service needs of this type of customer. Key account customers are typically sophisticated commercial and institutional entities who have a strong grasp of their service requirements and a good working knowledge of the electricity sector. **/C**

In 2012, the initial scope of the key account management service program was to offer formal engagement meetings annually to customers with an electricity demand greater than 5 MW or with a large aggregate of multiple commercial accounts throughout the city. In 2013 , Toronto Hydro expanded the scope to include customers whose demand exceeds 1 MW and who are served by feeders that have been experiencing a high frequency of outages. Generally, Toronto Hydro prioritizes meeting with key account customers who are experiencing the worst reliability and/or that are most significantly affected by service quality issues (e.g., food processors and pharmaceutical companies who must dump product and re-sterilize equipment; health care facilities concerned with patient procedures; plastic moulding companies with equipment concerns; etc.).

Formal key account management meetings typically address the following topics:

- Review of the customer's annual reliability performance and customer experience;
- Toronto Hydro reliability investigations and root cause analysis reports;
- Improving Reliability and Services – Infrastructure Renewal Program;
- Regulatory environment, current filing, system reliability, capital plan and investments, rate impact;
- Available account management services, including single point of contact, 24/7 outage management service, energy data management, billing services; and
- Conservation and Demand Management ("CDM"), including incentive program opportunities, energy efficiency training and support, electricity savings verification.

/C

Toronto Hydro endeavours to customize its key account management services to best suit individual customers' specific needs and preferences. This customization can occur regarding the form and frequency of how the customer prefers to be engaged. Accordingly, while Toronto Hydro aims to meet with this group of customers on a consistent basis, some may choose to forego a meeting, while others prefer multiple meetings over the course of a year in order to address specific needs and opportunities.

As explained in more detail below, the information presented by Toronto Hydro is customized for each customer for their reliability experience, current and planned investments in their local area, conservation and demand programs and the rate impact of investments on their current bill.

1.3.1 Key account meeting structure and engagement materials

Toronto Hydro's key account management services meetings are currently structured around a standardized presentation. The presentation has evolved over time, but typically addresses four main topic sections:

1. **Overview:** Includes an overview of the utility, historical system spending, historical system reliability measures (i.e. SAIDI/SAIFI), drivers of outages, future investment needs, investments to improve reliability, and from time-to-time, current information on the regulatory process, including a brief, high-level discussion of recently concluded rate applications and/or pending applications.
2. **Customer Specific Details:** Includes customer specific reliability performance, reliability investigations and cause of outages, and generally serves as an opportunity to discuss the customer's experience. This typically includes a discussion of planned capital projects that will address the customer's service.
3. **Bill Information:** Using a bill sample or the customer's bill, Toronto Hydro explains the various components of the electricity bill and explains how costs could potentially be reduced.
4. **Conservation and Demand Management (CDM) programs:** Includes a status review of past and current conservation projects. Toronto Hydro introduces possible CDM program opportunities that could help reduce electricity costs for the customer.

/C

The objective of these meetings is to give large, sophisticated and knowledgeable customers (typically senior management) an opportunity to discuss their specific needs in a timely and efficient format. Therefore, the level of focus given to each section of the presentation is ultimately dictated by customer-specific needs and preferences. Generally, Toronto Hydro finds that large customers are interested in discussing the details of their specific reliability experience, potential remedies to reliability issues, and how to manage their electricity costs.

To illustrate the range of content provided to key account customers, Appendix C includes a sample of a presentation deck provided to a customer during the development of the Application. These decks were subject to updates from time-to-time and included customer-specific information. The sample deck provided does not include any customer-specific information, but rather an explanation of the type of customer-specific information that may appear on a given deck. **/C**

1.3.2 Outcomes of the Key Account Process

Toronto Hydro uses the input received from the Key Account Management Services program to plan CDM programs and to inform capital and maintenance program planning in areas such as the Worst Performing Feeder program (Exhibit 2B, Section E6.21) and the Vegetation Management maintenance segment (Exhibit 4A, Tab 2, Schedule 1, Section 5). Toronto Hydro also uses these meetings to better understand the impact of momentary interruptions and to inform the prioritization of longer-term capital investments as the work plan is executed. The following are examples of projects that were created and/or prioritized in response to feedback received through key account engagement:

- A backup feed for a large financial institution was found to be susceptible to moisture related outages. On those occasions when it was active, the customer's sensitivity to power quality made the risk unacceptable to them. Based on this customer input, operations was able to connect to an alternate feeder.

- The causes of some outages are difficult to source. For the most sensitive key account customers, Toronto Hydro has installed sophisticated power quality meters to assist in diagnosing reliability issues, which could be utility or customer equipment related.
- The supply to a particular hospital is through a heavily treed area, making it more susceptible to outages. Following discussions with the customer, Toronto Hydro responded by intensifying its tree trimming program in that location.
- A large retail mall was susceptible to frequent outages due to the deterioration of its direct buried feeder cable. After ongoing engagement, Toronto Hydro replaced the feeder as a reprioritized renewal project.

The utility plans to continue to offer the Key Account Management Services program throughout the 2015-2019 planning period.

/C

For further information on the utility's day-to-day customer contacts and forms of engagement see Toronto Hydro's Customer Relationship Management program.[3]

1.3.3 Letters Of Comment From Key Account Customers

During its regular meetings in 2013 and 2014, Toronto Hydro informed key account customers about the OEB's increasing focus on customer engagement as part of the renewed regulatory framework, and invited customers to submit letters of comment outlining their concerns and opinions on matters such as service quality, reliability, and cost of electricity, as well as the utility's ongoing, renewal-focused capital investment plans. Overall, Toronto Hydro received 15 letters of comment, copies of which are attached as Appendix A. Toronto Hydro notes that it previously submitted similar letters

[3] Exhibit 4A, Tab 2, Schedule 13.

of comment with the 2012-2014 ICM application (EB-2012-0064). These were filed as Appendix B in the response to undertaking JT2.2 (Phase 1 of the proceeding). /C

2. DSP-SPECIFIC CUSTOMER ENGAGEMENT

In addition to the utility's ordinary course customer engagement activities described above, Toronto Hydro has engaged with its customers specifically around this application and the utility's DSP for 2015-2019.

Toronto Hydro's DSP-specific customer engagement activities were guided by the Ontario Energy Board's ("OEB") expectations in the RRFE Report,[5] which states that distributors should provide services in a manner that responds to identified customer preferences,[6] and Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications ("Chapter 5").[7] Chapter 5 requires that a distributor describe its customer engagement activities to obtain information on their preferences and show how it considered those preferences in its plan.[8]

/C

[5] Report of the Board "Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach" (October 18, 2012) [the "RRFE Report"].
[6] RRFE Report at page 2.
[7] Ontario Energy Board, Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, "Consolidated Distribution System Plan Filing Requirements," (March 28, 2013) ["Chapter 5"].
[8] Chapter 5 at section 5.0.4.

Toronto Hydro-Electric System Limited
EB-2014-0116
Exhibit 1B
Tab 2
Schedule 7
Appendix C
Filed: 2015 Jan 15
(38 pages)

Key Account Customer Name

Attendees

Date

TORONTO HYDRO

Action Log

Note: If applicable, this slide contains information about customer-specific issues and outlines the action items undertaken by the parties to address those issues.

TORONTO HYDRO

Agenda

1. Introduction
2. Improving Reliability and Services –
   Infrastructure Renewal Program
3. Key Account Management Services
4. Conservation and Demand Management (CDM)

Regulatory
Infrastructure Renewal Up-date

- The Ontario Energy Board (OEB) has approved the Toronto Hydro 2013 Rate Application
  - Decision issued on April 2, 2013

- Toronto Hydro requested a rate increase to cover Incremental Capital for a variety of asset renewal projects
  - The capital program is intended to enhance safety and reliability of the distribution system for the benefit of customers and employees.
  - The decision provides for an increase in capital spending to address aging electricity distribution infrastructure, and allows for the construction of the new Copeland Transformer station in downtown Toronto to relieve existing stations and provide for future load growth in the area. Copeland Station will be the first transformer station built in downtown Toronto since the 1960s.

Toronto Hydro-Electric System Limited

Regulatory Environment

Cost of Service

- To 2010
- Annual review of Operating and Capital Expenses to set rates
- LDC evidence tested through a public hearing process with Intervenors

Incentive Regulation + Incremental Capital

- 2012-2014
- Rates set by formula
- Operating expenses are fixed less a productivity factor
- Incremental capital is required to maintain asset renewal program; specific projects must be justified through the hearing process

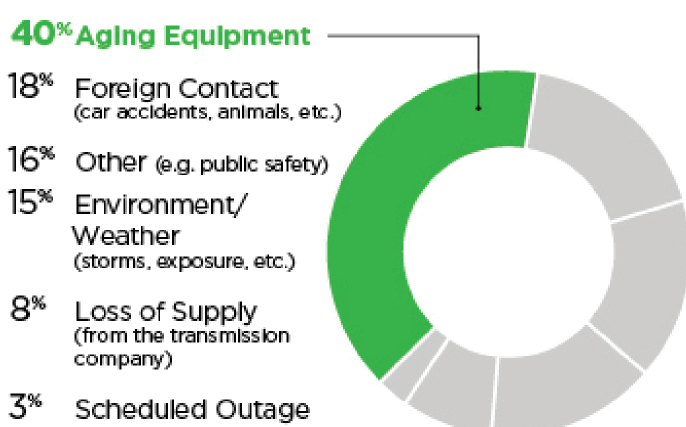
Custom Incentive Regulation

- 2015-2019
- Rebase of OpEx and CapEx in 2015
- Regulatory goal of giving customers rate certainty for a 5 year period
- Risk to LDC of fixed budgets
- Opportunity for LDC to present evidence for unique needs for funding beyond the base formula

TORONTO HYDRO

40% of Outages in Toronto are Due to Aging Equipment

- Some areas of the city are experiencing an unacceptable number of power outages. Thanks to our capital investment in infrastructure, equipment-related outages are down 10% since 2009. In 2013, we expect to invest approximately $327 million in infrastructure upgrades to help improve service reliability.



TORONTO HYDRO

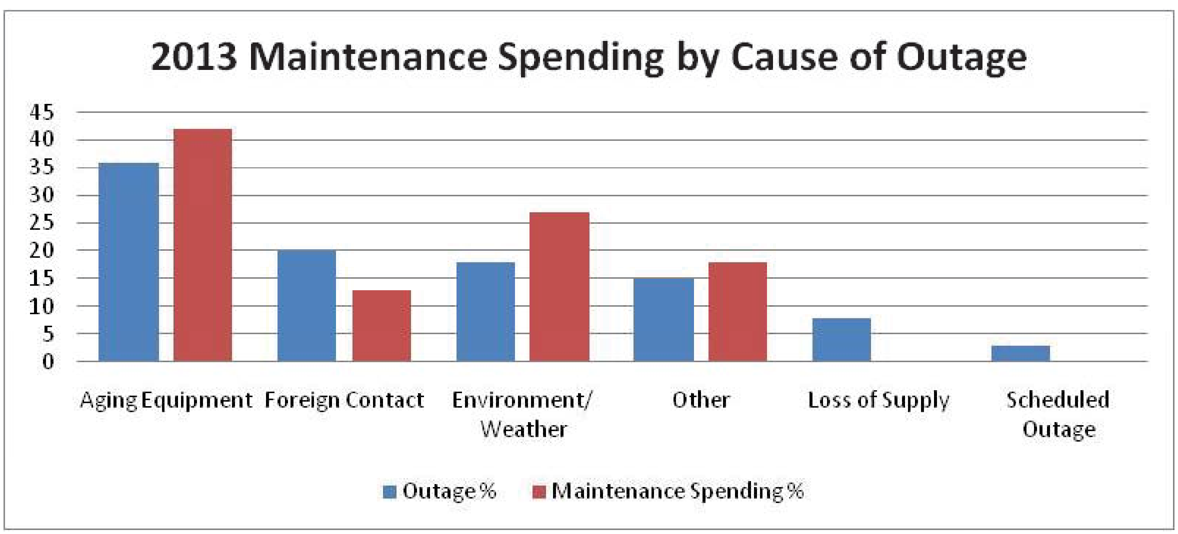
Investments to Improve Reliability

2013 Capital Investment by Ward (approximate)

Ward	Capital Projects Category Overhead	Stations	Underground	Total Ward
1	5,740,767	507,036	3,449,452	$9,697,255
2	6,808,892			$6,808,892
3	2,545,439		268,122	$2,813,561
5	4,549,263	855,846	227,422	$5,632,531
6	2,469,781			$2,469,781
7	5,554,819		753,738	$6,308,557
8	876,595	1,558,702	3,912,393	$6,347,690
9	1,821,589		2,289,126	$4,110,714
10	660,842	826,110	317,566	$1,804,517
11	5,859,475	326,000	7,784	$6,193,259
12	2,920,027			$2,920,027
13	1,025,728		478,720	$1,504,448
14	63,788		206,859	$270,647
15	930,827			$930,827
16	37,947	83,300	1,727,030	$1,848,277
17	1,609,892		439,587	$2,049,479
18	120,902	87,935	2,312,805	$2,521,642
19	2,532,504	311,571	156,994	$3,001,070
20	12,000	761,971	6,799,544	$7,573,515
21	926,585		2,841,381	$3,767,966
22	79,534	422,007	3,175,399	$3,676,939
23	4,573,675	623,154	1,842,894	$7,039,723
24	559,957	332,500	2,199,797	$3,092,254
25	889,820		3,274,502	$4,164,322
26	497,859		2,031,802	$2,529,661
27	16,166	472,648	3,865,500	$4,354,314
28	700,000		7,532,868	$8,232,868
29			253,009	$253,009
30	1,991,317	151,503	436,254	$2,579,074
31			151,444	$151,444
32	10,323		1,031,598	$1,041,920
33	208,844		4,409,712	$4,618,556
34	1,661,766		717,608	$2,379,374
35	611,172			$611,172
36	816,927		309,593	$1,126,520
37	69,495	228,302	124,219	$422,016
38	205,755	126,888	261,134	$593,777
39		7,900	3,312,212	$3,320,112
40			3,798,678	$3,798,678
41	43,405	516,456	5,404,131	$5,963,992
42			7,726,828	$7,726,828
43	243,327	417,387	787,988	$1,448,702
44			2,705,952	$2,705,952
N/A	456,139	78,007	183,099	$717,246
N/A (Across City)	2,419,113	82,500	3,536,880	$6,038,493
Grand Total	**$63,122,256**	**$8,777,723**	**$85,261,624**	**$157,161,604**

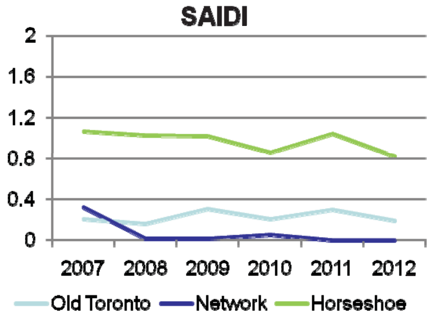
TORONTO HYDRO

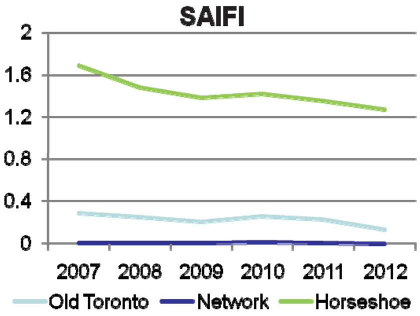
Investments to Improve Reliability

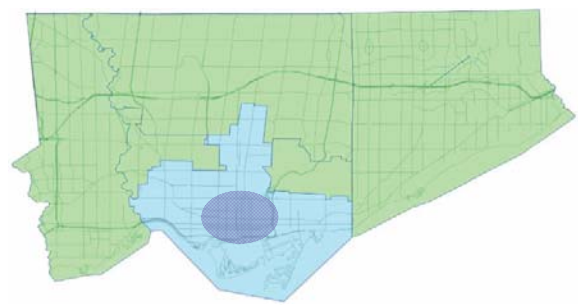


TORONTO HYDRO

Provincial Measures for Reliability







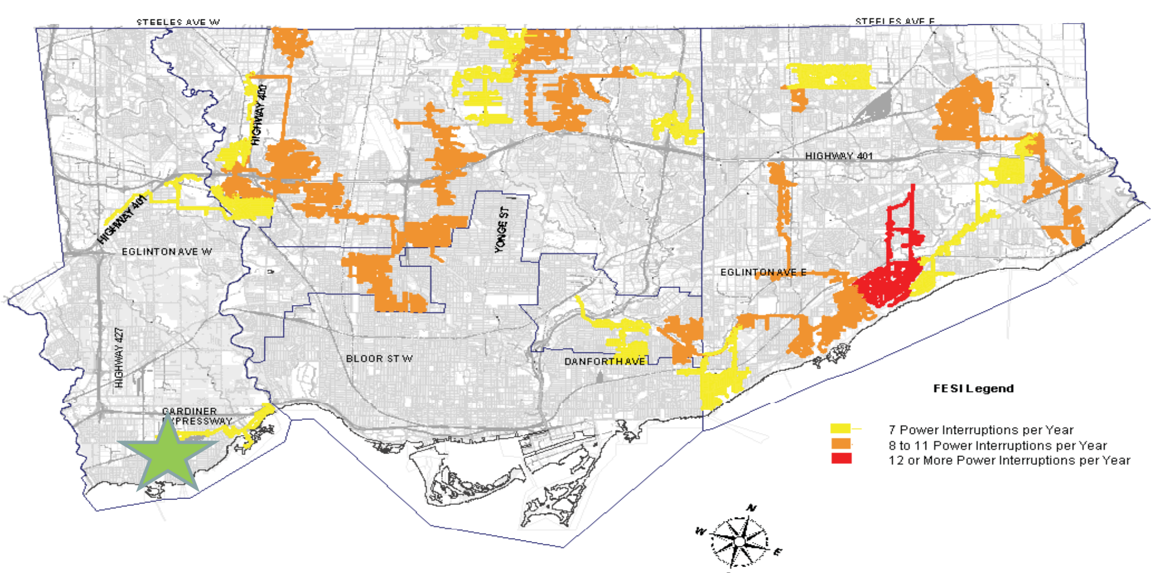
- *System Average Interruption Frequency Index (SAIFI)*
- *System Average Interruption Duration Index (SAIDI)*

Note: Momentary interruptions, those less than 1 minute, are not included

TORONTO HYDRO

DO YOU LIVE/WORK/TRAVEL HERE?

Toronto Hydro's Grid: Areas of In Need of Attention



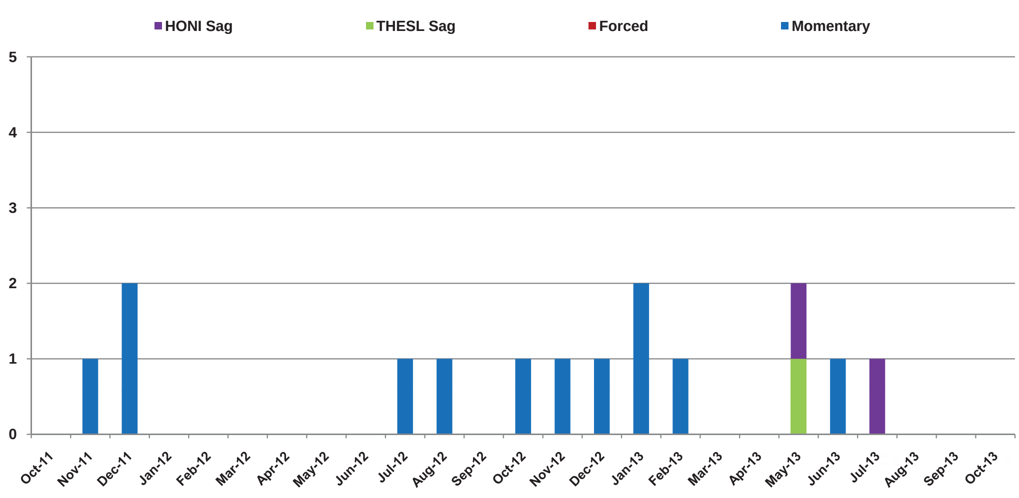
Your Outage Experience

Note: If applicable, this slide includes customer-specific outage information for each of the customer's facilities.

TORONTO HYDRO

Your Power Reliability/Quality Summary

Note: If applicable, this slide includes customer-specific power reliability information, which may be presented as follows:



TORONTO HYDRO

Root Cause Analysis

Note: If applicable, this slide includes a root cause analysis of a particular power reliability/quality issue (i.e. momentary outages) that the customer is experiencing, and provides an explanation of the mitigation measures that Toronto Hydro has taken or proposes to undertake to address the issue.

Inspection Programs and Status

Note: If applicable, this slide includes a description of the inspection programs that apply to the specific customer, and an update with respect to the status of those program for the given year. For example:

1. **Infrared Audit Program**

   Infrared inspection of both primary and secondary overhead line components is performed. This identifies potential "hot spots" and allows corrective measures to be taken before they have an impact on system reliability.

2. **Cable Chamber Inspection Program**

   Cable chambers for underground feeders are inspected for electrical and civil deficiencies.

3. **Other Feeder Asset Inspections**
   Inspections performed on assets which are attached to the same feeder that supplies the Molson plant. Insulators are pressure washed to reduce the possibility of flashovers.

2013 Rate Impact

UNDER DEVELOPMENT FOR 2014

General Service, 50 kW to 1MW

(150,000 kWh/month 349 kW, 90% PF)

Year	Distribution	Transmission	Regulatory	Commodity	Total
Change	~~3.4%~~ 3.7%	12.5%	-5.4%	10.2%	7.7%

General Service, 1 MW – 5 MW

(800,000 kWh/month, 1,600 kW, 90% PF)

Year	Distribution	Transmission	Regulatory	Commodity	Total
Change	~~3.0%~~ 2.4%	12.4%	-5.4%	10.2%	7.7%

Large User, > 5MW

(4,500,000 kWh/month, 8,491 kW, 90% PF)

Year	Distribution	Transmission	Regulatory	Commodity	Total
Change	~~3.2%~~ 2.4%	12.5%	-5.3%	10.2%	7.7%

- *Rates reflect current best estimates and are subject to change*
- *Rate Order approved by the OEB on May 9, 2013, file EB-2012-0064; rate increases effective June 1.*
- *Commodity cost based on HOEP+GA rates*

TORONTO HYDRO

Toronto Hydro's Key Account Management Service

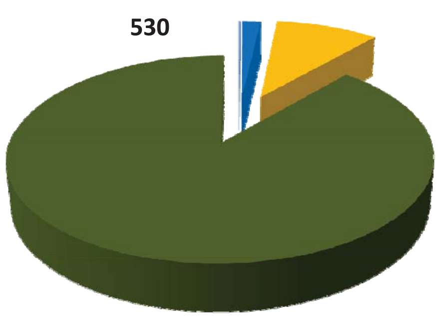
TORONTO HYDRO

The Importance of Toronto Hydro's Business Customers

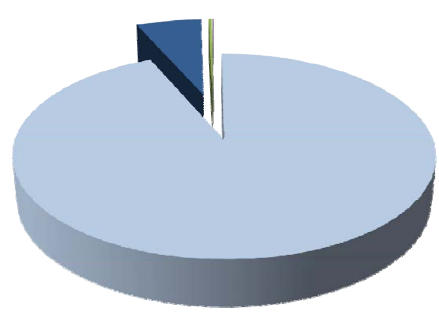
- Toronto Hydro has over 80,000 business customers
  - Representing all sectors – Municipal, Academic, Healthcare, Commercial, Industrial
  - 530 of these customers have a demand of over 1,000 kW – the Key Accounts
  - Customers with multiple sites, such as larger property management or institutional customers are also aggregated as a Key Account
- We recognize these customers as distinct from our residential customers:
  - Businesses support the economic development of the City and provide employment
  - You are important to THESL and the City - Substantial electricity revenue comes from THESL business sector – 12% of our customer base provides 80% of our revenue
  - We recognize that Business customers can be significantly affected by outages in lost productivity of goods and services produced and delivered, and human resource management to name a few
  - Business customers have sensitive technology. Power quality is essential to uninterrupted operations.
  - Communications is vital to outage management.

Key Account Customer Profile

Total Customers



Revenue per Customer

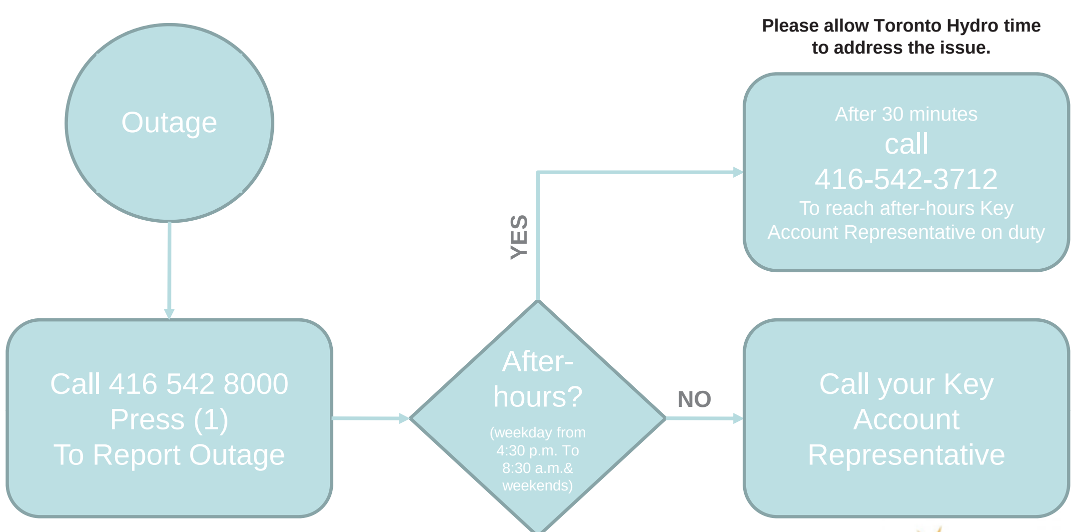


Customer Segment	Total Revenue	Total Customers	Revenue Per Customer
Large Business >1,000 kW	$728 million	530	$1,373,280
Medium Business 50-1,000 kW	$1,089 million	12,129	$89,762
Small Business <50 kW	$273 million	68,431	$3,989
Residential <50 kW	$709 million	637,910	$1,111
	$2,799 million	719,000	

Key Account Management Services

- Account Management
  - Single point of contact for all aspects of the relationship with Toronto Hydro
  - To manage issues and ensure customer needs are met
  - Work with internal Departments to improve levels of customer service
    - Distribution System, Customer Information System, Conditions of Service, Metering Systems, Billing, Collections, Rates, Power Quality & Reliability, CDM programs, Ministry of Energy, Ontario Energy Board and Independent Electricity System Operator, Regulatory Information
- Outage Management
  - 24/7 After hours outage response service
- Data Management
  - MV90 online energy consumption data
  - Special energy consumption data requests
- Billing Services
  - eBills
  - Pre-authorized payment

Power Outage - Key Account Call-in Process



New Proactive Outage Management

- Severe weather during the month of July impacted Toronto Hydro service and caused several prolonged outages throughout the city.
- The outages generated significant amounts of feedback from customers, including more frequent outage status updates are needed for businesses.
  - Key contacts have a need for ongoing updates related to outages at their facilities in order to shift business operations accordingly.
- We are developing a commercial customer outage communication program whereby commercial customers will receive customized outage alerts during severe weather emergencies via the communication channel of their choice (email, phone, text).

TORONTO HYDRO

Continuously Improving Our Service…

Communications

- ❑ Power outage email notification – 2014 launch
- ❑ Quarterly Newsletters – "eConnect for Biz"

Metering

- ❑ Power quality, data access, analytics

Self Service

- ❑ Enhanced energy data management (MV Web Replacement)
- ❑ On line transactions

CDM

- ❑ Incentives, training and support
- ❑ Post 2015 program development

Other…

TORONTO HYDRO

CDM Programs

- Government
- Industrial
- Small Business
- Agricultural
- Commercial
- Institutional

TORONTO HYDRO

Conservation and Demand Management Business Incentive Programs

- Commercial & Institutional
  - Commercial
  - Institutional
  - Multi-Residential
  - Agricultural
    - Audit Funding
    - Retrofit Program
    - Small Business Lighting
    - High Performance New Construction
    - Existing Building Commissioning
- Industrial
- Residential
- Home Assistance Program

TORONTO HYDRO

Commercial & Institutional Programs

SMALL BUSINESS LIGHTING

- Up to $1,500 of free lighting upgrades (increase from $1,000) New!

AUDIT FUNDING

- Funding of up to 50% of the cost to conduct an energy audit
- Building Systems audit to promote systems balancing (hydronic, air) New!

RETROFIT PROGRAM

- Funding to install high-efficiency equipment and new control systems
- Cover up to 50% of the cost; $400/kW (or $0.05/kWh) for **lighting** and $800/kW (or $0.10/kWh) for **non-lighting**
- Monitoring and Targeting measure now eligible New!
- Property Managers and Facility Managers now eligible participants

EXISTING BUILDING COMMISSIONING (EBCx)

- Paid for evaluating and implementing retro-commissioning strategies of systems with chilled water plants New!
- Up to $30,000 of incentives available for investigation

TORONTO HYDRO

New Program Opportunities

APPLICANT REPRESENTATIVE INITIATIVE

- Applicant representative receive incentive payments for successful projects - we pay you or your contractor
  - $20/KW for the first 300kW
  - $40/kW beyond 300kW

PILOT PROGRAMS UNDERWAY

- Multi-unit Residential Building Demand Response (“Suitesaver")
- Commercial Energy Management and Load Control (“Gridsaver")

TORONTO HYDRO

Training and Support

- Energy into Action conference held spring and fall
- Dollars to $ense Workshops with NRCan
- Industry specific events: Compressed Air Workshop, Refrigeration
- Staff support on projects and process - to help identify CDM opportunities, develop business cases and file CDM applications
- eConnect for Biz Newsletter for program updates

CDM Projects Summary

Note: If applicable, this slide contains information about customer-specific CDM projects.

CDM Beyond 2014

- OPA working with LDCs to extend current programs in to 2015 based on Minister's Directive in December 2012
- Provincial Long Term Energy Plan
  - ➢ Released December 3
  - ➢ Commits to 6 years of stable funding
  - ➢ Framework is under development between distributors, Ministry and OPA
  - ➢ Recognizes Conservation First as a way to mitigate new investments in supply, transmission and distribution
    - ➢ A necessary component of regional and distributor planning processes
  - ➢ IESO will evolve existing Demand Response programs
    - ➢ Development of a capacity market

Summary

- Investments to improve reliability
- Key Account Management Services
  - Outage communications
  - Issue resolution
- Support available from Toronto Hydro to help identify CDM opportunities, develop business cases and file CDM applications
- Information and Training opportunities
  - Energy into Action conference held spring and fall
  - Dollars to $ense Workshops with NRCan

Disclaimer

The information in these materials is based on information currently available to Toronto Hydro Corporation and its affiliates (together hereinafter referred to as "Toronto Hydro"), and is provided for information purposes only. Toronto Hydro does not warrant the accuracy, reliability, completeness or timeliness of the information and undertakes no obligation to revise or update these materials. Toronto Hydro (including its directors, officers, employees, agents and subcontractors) hereby waives any and all liability for damages of whatever kind and nature which may occur or be suffered as a result of the use of these materials or reliance on the information therein. These materials may also contain forward-looking information within the meaning of applicable securities laws in Canada ("Forward-Looking Information"). The purpose of the Forward-Looking Information is to provide Toronto Hydro's expectations about future results of operations, performance, business prospects and opportunities and may not be appropriate for other purposes. All Forward-Looking Information is given pursuant to the "safe harbour" provisions of applicable Canadian securities legislation. The words "anticipates", "believes", "budgets", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify Forward-Looking Information, although not all Forward-Looking Information contains these identifying words. The Forward-Looking Information reflects the current beliefs of, and is based on information currently available to, Toronto Hydro's management. The Forward-Looking Information in these materials includes, but is not limited to, statements regarding Toronto Hydro's future results of operations, performance, business prospects and opportunities. The statements that make up the Forward-Looking Information are based on assumptions that include, but are not limited to, the future course of the economy and financial markets, the receipt of applicable regulatory approvals and requested rate orders, the receipt of favourable judgments, the level of interest rates, Toronto Hydro's ability to borrow, and the fair market value of Toronto Hydro's investments. The Forward-Looking Information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the Forward-Looking Information. The factors which could cause results or events to differ from current expectations include, but are not limited to, the timing and amount of future cash flows generated by Toronto Hydro's investments, market liquidity and the quality of the underlying assets and financial instruments, the timing and extent of changes in prevailing interest rates, inflation levels, legislative, judicial and regulatory developments that could affect revenues, and the results of borrowing efforts. Toronto Hydro cautions that this list of factors is not exclusive. All Forward-Looking Information in these materials is qualified in its entirety by the above cautionary statements and, except as required by law, Toronto Hydro undertakes no obligation to revise or update any Forward-Looking Information as a result of new information, future events or otherwise after the date hereof.

TORONTO HYDRO

Appendix

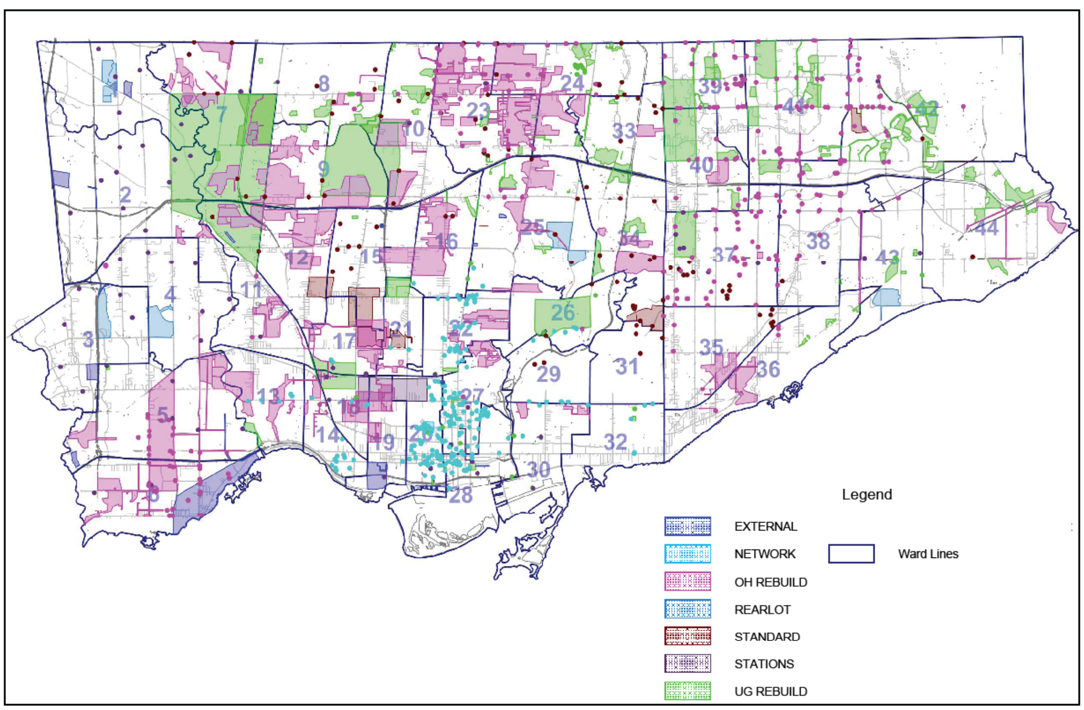
TORONTO HYDRO

Customer Account Profile

Note: This slide contains customer-specific account information such as consumption profiles for the customer's facilities and a breakdown and explanation of the customer's invoice.

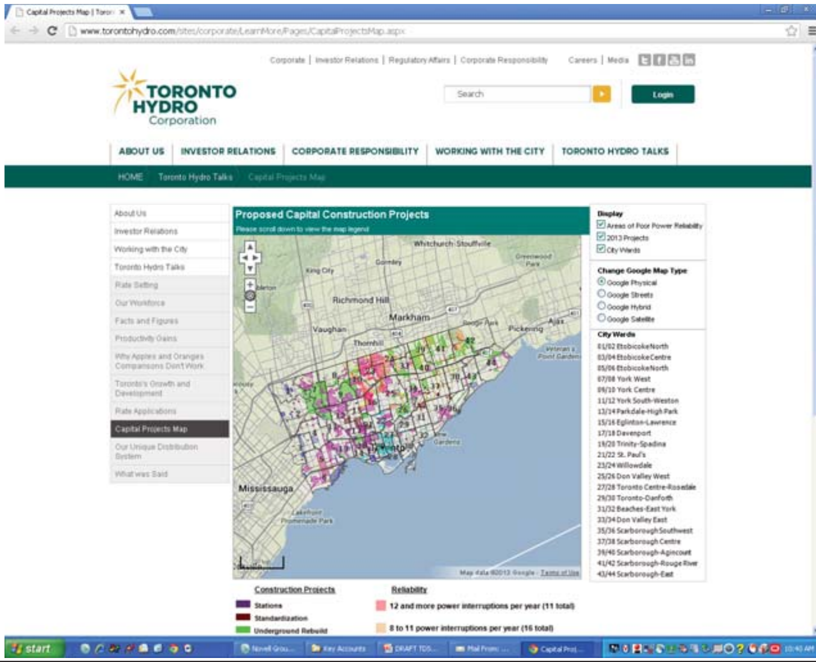
TORONTO HYDRO

Investments to Improve Reliability



Investments to Improve Reliability

http://www.torontohydro.com/sites/corporate/LearnMore/Pages/CapitalProjectsMap.aspx



New Proactive Outage Management

- Letter sent to business customers
- Website registration

Toronto Hydro-Electric System Limited
14800 Yonge Street
Toronto, Ontario M2M 3T3

August 6, 2013

<<NAME>>
<<MAILING_ADDRESS1>>
<<MAILING_ADDRESS2>>
<<MAILING_CITY>>, <<MAILING_STATE>>
<<MAILING_POSTAL>>

PERTAINING TO:
Account: <<ACCOUNT>>
<<PREMISE_ADDRESS1>>
<<PREMISE_ADDRESS2>>
<<PREMISE_CITY>>, <<PREMISE_STATE>>
<<PREMISE_POSTAL>>

Dear <<NAME>>,

In an effort to continuously improve our power outage communications and help you better manage your business operations, we are in the early stages of developing a new outage communication program for our commercial customers. This program would be activated during power outages caused by severe weather and storm situations and provide you with timely updates related to the progress of restoring outages affecting your business.

To gauge your interest in joining this new program and how you would prefer to receive future communications, we invite you, or the appropriate contact at your company, to complete the short registration form.

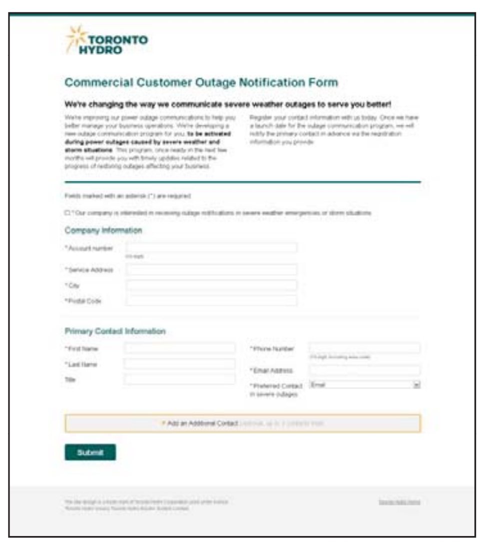
Simply visit www.bizoutageinfo.com today to provide us with your feedback. As we continue to develop this program over the next few months, we will provide you with updates related to our progress.

The registration form will be available until Thursday, October 31.

Once we have a launch date for the outage communication program, we will notify you in advance via the registration information you provide.

Sincerely,

Lauren Kirk
Manager, Customer Care



TORONTO HYDRO

Commercial Customer Outage Notification Form

We're changing the way we communicate severe weather outages to serve you better!

Fields marked with an asterisk (*) are required

Company Information

*Account number
*Service Address
*City
*Postal Code

Primary Contact Information

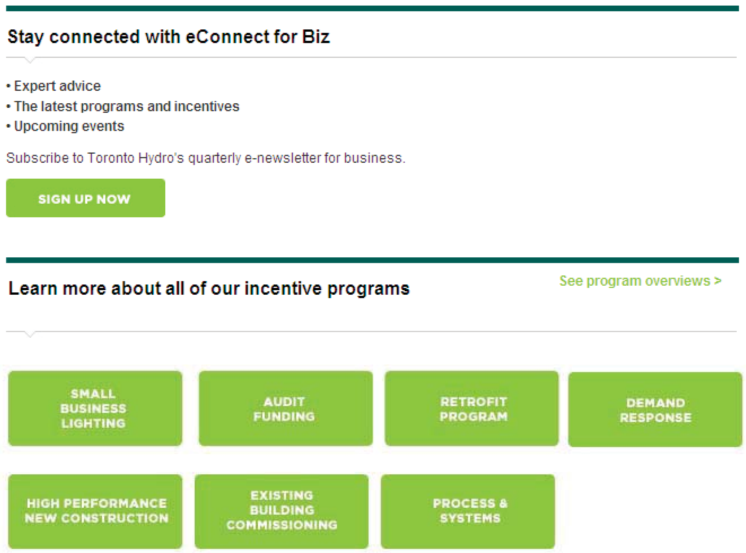
*First Name
*Last Name
Title
*Phone Number
*Email Address
*Preferred Contact in severe outages: Email

+ Add an Additional Contact

Submit

eConnect for Biz Newsletter

http://www.torontohydro.com/sites/electricsystem/electricityconservation/businessconservation/Pages/default.aspx



TORONTO HYDRO

Web Links for Electricity Market Information

- Electricity system operation and regulation, IESO:
  http://www.ieso.ca/imoweb/siteShared/power_system.asp
- Electricity Planning:
  - Ministry of Energy: Long Term Energy Plan
    http://www.energy.gov.on.ca/en/ltep/
- Electricity Pricing:
  - Aegent Energy Advisors Inc.:
    www.aegent.ca/
  - AMPCO:
    www.ampco.org
  - E2Energy Inc.
    www.e2energyinc.com/index.php
  - IESO – Global Adjustment:
    www.ieso.ca/imoweb/siteShared/electricity_bill.asp?sid=bi
  - OPA – Global Adjustment:
    http://www.powerauthority.on.ca/about-us/electricity-pricing-ontario/understanding-electricity-system-costs/understanding-global-adjustment

TORONTO HYDRO