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March 8, 2016

via RESS e-filing – signed original to follow by courier

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
PO Box 2319
2300 Yonge Street, 27th floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Toronto Hydro-Electric System Limited ("Toronto Hydro")
Incremental Capital Module ("ICM") True-up Application
OEB File No. EB-2015-0173

Toronto Hydro writes to the Ontario Energy Board (the "**OEB**") in respect of the above-noted matter.

On May 10, 2012, Toronto Hydro filed an Application under section 78 of the *Ontario Energy Board Act, 1998*, S. O. 1998 c. 15, seeking approval for changes to the rates that it charges for electricity distribution to be effective June 1, 2012, May 1, 2013 and May 1, 2014. The OEB assigned File Number EB-2012-0064 to this matter.

The OEB issued its Partial Decision and Order on April 2, 2013 and Decision and Rate Order, including an Accounting Order, on May 9, 2013. As part of the Accounting Order, the OEB directed that a reconciliation process take place to reflect the difference between the revenue collected and the actual revenue requirement associated with actual in-service assets above the ICM materiality threshold. Accordingly, please find attached Toronto Hydro's ICM True-up Application.

Please do not hesitate to contact me if you have any questions.

Yours truly,

Andrew J. Sasso
Director, Regulatory Affairs
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:att.

:AJS\AD\acc

cc: Charles Keizer, Torys LLP
Amanda Klein, Toronto Hydro

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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-Electric System Limited for the true-up process directed by the Ontario Energy Board in EB-2012-0064;

AND IN THE MATTER OF an Application by Toronto Hydro-Electric System Limited for an Order or Orders approving or fixing just and reasonable distribution rates and other charges effective November 1, 2016 to December 31, 2017.

The Applicant, Toronto Hydro-Electric System Limited ("Toronto Hydro"), is a corporation incorporated under the *Business Corporations Act*, R.S.O. 1990, c. B. 17 and is licensed by the Ontario Energy Board (the "OEB") under licence number ED-2002-0497 to distribute electricity in the City of Toronto.

A. Form of Hearing Requested

Toronto Hydro requests that this application be disposed of by way of a written hearing.

B. Relief Sought & Proposed Effective Date

Toronto Hydro applies for:

1. Approval of the ICM true-up amount of $11.1 million and the resulting proposed rate rider (the "ICM True-up Rate Rider") as calculated at Exhibit 3, Tab 2, Schedules 1 through 4;
2. Approval of an associated Rate Order to be made effective November 1, 2016 to December 31, 2017, notwithstanding that the OEB's decision approving or fixing these rates and other charges may not be delivered until after that date; and

3. Other items or amounts that may be requested by Toronto Hydro during the course of the proceeding, and such other relief or entitlements as the OEB may permit.

C. Grounds for Application

The grounds for the Application are set out in detail in the Requests and Rationale summary at Exhibit 1, Tab 2, Schedule 2 to this Application and are summarized as follows:

1. In EB-2012-0064, Toronto Hydro applied for Incremental Capital Module (“ICM”) funding;
2. The OEB approved ICM funding through a rate rider (the “Initial ICM Rate Rider”);
3. The OEB directed that a true-up process take place at the end of the ICM period to reconcile differences between revenue collected from the Initial ICM Rate Rider and actual revenue requirement;
4. The OEB stated that variances would be refunded to or collected from customers through a new rate rider;
5. This Application is the means by which the OEB-prescribed true-up process will take place;
6. The difference between revenue collected from the Initial ICM Rate Rider and the actual revenue requirement is $11.1 million, which Toronto Hydro proposes to collect through the ICM True-up Rate Rider;
7. Actual costs that exceeded costs forecast in EB-2012-0064 were prudently incurred;
8. The OEB has the authority under section 78 of the *Ontario Energy Board Act, 1998* to make orders approving or fixing just and reasonable rates and other charges for the distribution of electricity;

9. The proposed ICM True-up Rate Rider and associated distribution rates and other charges are just and reasonable; and
10. Such further grounds as Toronto Hydro may advise and the OEB may permit.

D. List of Documentary Evidence

The following documentary evidence will be used at the hearing of this Application:

1. Pre-filed evidence including but not limited to the following:
    a) A Requests and Rationale summary which explains the results of Toronto Hydro's true-up process and the rate adjustments applied for (Exhibit 1, Tab 2, Schedule 2);
    b) Results of the true-up process for each project segment that qualified for ICM funding in EB-2012-0064 and supporting evidence (Exhibit 2, Tabs 1 to 13);
    c) A report by Power System Engineering that provides an opinion on the reasonableness of variances in OEB approved project segments (Exhibit 2, Tab 14);
    d) Calculation of the ICM true-up revenue requirement (Exhibit 3, Tabs 2 and 3);
    e) A summary of monthly customer bill impacts for representative customers on a distribution and total bill basis (Exhibit 3, Tab 1, Schedule 1);
    f) Additional documents and supporting evidence;
2. Updates to the evidence described above, as necessary; and
3. Such further evidence as Toronto Hydro may advise and the OEB may permit.

This Application has been prepared in accordance with the OEB's Filing Requirements for Electricity Distribution Rate Applications (updated July 16, 2015), as applicable, and the direction of the OEB in EB-2012-0064.

E. Affected Parties

The persons affected by this application are the ratepayers of Toronto Hydro's distribution business.

F. Contact for Application

Toronto Hydro's contact for this application is as follows:

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March 8, 2016

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
14 Carlton Street
Toronto, ON M5B 1K5

Signed by:

Andrew Sasso
Director, Regulatory Affairs

- Appendix to Legal Application -

Title of Proceeding:	Application by Toronto Hydro-Electric System Limited for the true-up process directed by the Ontario Energy Board in EB-2012-0064; and Application by Toronto Hydro-Electric System Limited for an Order or Orders approving or fixing just and reasonable distribution rates and other charges effective November 1, 2016 to December 31, 2017.
Applicant's Name:	Toronto Hydro-Electric System Limited ("Toronto Hydro")
Application Address:	14 Carlton Street Toronto, Ontario M5B 1K5
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REQUESTS & RATIONALE: TRUE-UP OF THE 2012-2014 INCREMENTAL CAPITAL MODULE APPLICATION

A. INTRODUCTION

In EB-2012-0064, Toronto Hydro applied to the Ontario Energy Board (the "OEB") for funding under the Incremental Capital Module ("ICM") (the "ICM Application") for a number of different capital project segments (the "ICM Segments") that Toronto Hydro intended to carry out in the 2012 to 2014 period the ("ICM Period").

The OEB approved initial funding for 13[1] of the ICM Segments through a single rate rider (the "Initial ICM Rate Rider"). The Initial ICM Rate Rider was determined by calculating the revenue requirement associated with Toronto Hydro's forecast of certain in-service additions ("ISAs") that were above the ICM materiality threshold.

The OEB directed that a true-up process take place at the end of the ICM Period to reconcile any differences between revenue collected through the Initial ICM Rate Rider, which was based on forecast numbers, and the revenue requirement associated with the cost of actual ISAs above the ICM materiality threshold in each approved ICM Segment from 2012 to 2014.[2] The OEB held that any variances would be refunded to or collected from customers through a rate rider.[3] The OEB directed Toronto Hydro to track: (i) the revenue it collected through the Initial ICM Rate Rider; and (ii) the cost of actual ISAs in

[1] The 13 segments do not include Copeland Transformer Station (referred to as the Bremner Transformer Station at the time of the ICM Application) or ICM Understatement of Capitalized Labour, even though these were approved as part of the ICM Application. Further explanation of the treatment of the Copeland Transformer Station is included at footnote 14 below. Further explanation of the treatment of the ICM Understatement of Capitalized Labour is included at footnote 33 below.
[2] EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order at pp. 2-3.
[3] Ibid.

each approved ICM Segment.[4] This application is the means by which the OEB-prescribed true-up will take place.

The following is a summary of the OEB-prescribed true-up calculations:

a) **$41.2 Million in Forecast Revenue Requirement was collected through the Initial ICM Rate Rider –** Toronto Hydro collected $41.2 million through the Initial ICM Rate Rider. The Initial ICM Rate Rider was based on the forecast ISAs in approved ICM Segments that were above the materiality threshold.

b) **The Revenue Requirement Associated with Actual ISAs is $52.3 Million –** The revenue requirement associated with actual ISA expenditures is calculated in Exhibit 3 as $52.3 million.[5] The calculation may be summarized as follows:

   i. The actual ISAs in approved ICM Segments was calculated for each year in the ICM Period;

   ii. The portion of actual ISAs that exceeded the ICM materiality threshold in each year in the ICM Period were calculated. Actual ISAs exceeded the ICM materiality threshold in each of 2012, 2013 and 2014; and

   iii. The revenue requirement associated with actual ISAs in approved ICM Segments that exceeded the ICM materiality threshold in each of 2012, 2013 and 2014 totalled $52.3 million.[6]

c) **The Difference between Forecast and Actual Revenue Requirement is $11.1 Million –** The difference between the $41.2 million in forecast revenue requirement collected through the Initial ICM Rate Rider and the $52.3 million in revenue requirement associated with actual ISAs is $11.1 million, which Toronto

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[4] EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order at pp. 2-3.

[5] In calculating the revenue requirement associated with actual ISAs in each year in the ICM Period, Toronto Hydro followed the OEB's direction in the Partial Decision and Order (issued April 2, 2013) and Decision and Rate Order (issued May 9, 2013) and used the same inputs provided in the OEB's Incremental Capital Workforms used to calculate the Initial ICM Rate Rider, with changes only to the actual ISA amounts and associated depreciation and capital cost allowance amounts.

[6] The revenue requirement was calculated using the OEB's Incremental Capital Workform for 2015 Filers.

Hydro proposes to recover through a new rate rider (the "ICM True-up Rate Rider") to be established in this proceeding, further to the OEB's direction in the ICM Application.[7]

The balance of this document describes the main aspects of the Application, including the framework set out by the OEB for the true-up process, and provides a high-level overview and explanation of the variances between forecast and actual ISAs. In particular, Section 2 of this document provides the background of the OEB's approval of ICM funding for Toronto Hydro. Section 3 describes the OEB-approved true-up process that forms the basis for this Application. Section 4 addresses the variance analysis between forecast and actual ISAs.

Toronto Hydro's evidence also includes Exhibit 2, Tabs 1-13, which provides a comparison between each segment's forecast and actual ISAs, explains Toronto Hydro's accomplishments in relation to each segment's forecast number of jobs, and explains the reasons for the observed variance between forecast and actual ISAs in each segment. Exhibit 2, Tab 14 presents a report by Power System Engineering ("PSE") that examines ISAs and completed jobs for each segment. PSE concludes that the observed variances are reasonable and consistent with the expected magnitude of variance in light of industry experience in developing and undertaking complex, multi-year distribution capital programs. Exhibit 3 provides the calculation of the Initial ICM Rate Rider, a comparison of the forecast revenue requirement and the revenue requirement based on actual ISAs, and develops the ICM True-up Rate Rider.

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[7] EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order at pp. 2-3.

B. THE ICM APPLICATION – KEY FINDINGS FROM EB-2012-0064

1. PURPOSE OF THE INCREMENTAL CAPITAL MODULE ("ICM")

The purpose of the OEB's ICM is to enhance the formulaic nature of the Incentive Regulation Mechanism ("IRM") by providing an interim funding process for extraordinary spending requirements that arise during the IRM term. The parameters of the ICM are set out in reports issued by the OEB[8] but in brief, the ICM provides:

a) A process for the determination of capital work eligible for ICM funding and the approval of initial rate riders to fund forecast spending; and
b) A subsequent process for the review of actual spending relative to forecast spending and the approval of true-up rate riders to address any variances.[9]

This application relates specifically to the latter, the review of actual spending and the calculation of true-up rate riders.

2. PROCEDURAL HISTORY

On May 10, 2012, Toronto Hydro applied to the OEB under section 78 of the *Ontario Energy Board Act, 1998*, for approval of proposed distribution rates and charges under the OEB's IRM framework for the ICM Period.[10] As part of its application, Toronto Hydro requested ICM funding for critical capital projects that it expected to carry out during the ICM Period.[11]

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[8] See the Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (the "IR Report"), issued on July 14, 2008, Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors issued on September 17, 2008 (the "Supplemental Report"), and Addendum to the Supplemental Report issued on January 28, 2009.
[9] IR Report at pp. 33-34.
[10] EB-2012-0064, Toronto Hydro Electric-System Limited Application (May 10, 2012).
[11] Ibid.

The ICM Application was heard in two phases. Phase 1 addressed the 2012 and 2013 rate years. Following the Phase 1 hearing, the OEB rendered a Partial Decision and Order (issued on April 2, 2013)[12] and Decision and Rate Order including an Accounting Order (issued on May 9, 2013)[13] (collectively, the "Phase 1 Decisions").[14]

Phase 2 of the ICM Application addressed the 2014 rate year. The project segments for 2014 were consistent with the ICM Segments approved by the OEB in the Phase 1 Decisions.[15] Phase 2 was resolved by way of a settlement agreement which was accepted by the OEB on December 18, 2013 (the "Phase 2 Decision").[16]

Toronto Hydro's application for ICM funding was unique among other ICM applications. Unlike most other applications for ICM relief, Toronto Hydro's extraordinary capital needs did not arise from one or two large projects. Rather, Toronto Hydro had a widespread need to renew its aging infrastructure through multiple project segments, together comprising hundreds of discrete jobs spanning the ICM Period.[17]

3. APPLICATION OF ICM CRITERIA IN EB-2012-0064

In the Phase 1 Decisions, the OEB approved 13 project segments[18] for ICM funding based on the following eligibility criteria:

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[12] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013).
[13] EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013).
[14] Issues related to Copeland Transformer Station ("Copeland TS", referred to as "Bremner Station" during the ICM Application) were heard separately during Phase 1 of the ICM Application. The OEB approved funding for Copeland TS in the Partial Decision and Order (April 2, 2013). Ultimately, Copeland TS did not come into service during the ICM Period and does not form part of this true-up exercise. Toronto Hydro has not collected any revenues for Copeland TS through the Initial ICM Rate Rider. The revenue requirement associated with Copeland TS was addressed as part of Toronto Hydro's Custom Incentive Rate-setting Application for 2015–2019 (see EB-2014-0116).
[15] EB-2012-0064, Toronto Hydro Electric-System Limited Phase 2 Decision, Settlement Agreement (December 18, 2012) at p. 8.
[16] EB-2012-0064, Toronto Hydro Electric-System Limited Oral Hearing Transcript Vol. 11 (December 19, 2013) at p. 5.
[17] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p. 18.
[18] Not including Copeland TS or ICM Understatement of Capitalized Labour.

a) **Materiality:** ISAs in excess of the materiality threshold were eligible for ICM funding provided the criteria below (prudence and need) were met. The OEB calculated Toronto Hydro's materiality thresholds as follows: $173.0 million in 2012; $163.8 million in 2013; and $211.1 million in 2014. Pre-2012 construction work in progress ("CWIP") was included in the calculation of the materiality threshold.[19] Toronto Hydro has exceeded the applicable materiality threshold in each of the three years in the ICM Period.

b) **Prudence:** The approved work was prudent. The OEB held that prudent capital work is: work necessary to maintain the reliability and adequacy of the distribution system; work required to comply with applicable standards and public acceptability; and work performed in conjunction with other prudent capital work so as to achieve the lowest reasonable life cycle cost for customers.[20]

c) **Need:** The approved work was non-discretionary. The OEB held that non-discretionary capital work is work that must be performed in order to: comply with applicable laws or external requirements; keep the public and workers safe; address existing or imminent reliability degradations or capacity shortages; and avoid a material increase in costs that might arise if the project was delayed.[21]

d) **In-service Additions:** In-service additions, not capital expenditures in each year, were used to determine Toronto Hydro's eligibility for ICM funding.[22] An asset is considered "in-service" or "used or useful" if the necessary work has been completed for the asset to be placed into service.[23]

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[19] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at pp. 14-15.

[20] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at pp. 16-17.

[21] Ibid.

[22] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at pp. 12-13.

[23] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p. 14.

Based on the criteria, the OEB held that 13 of Toronto Hydro's proposed project segments were prudent, non-discretionary and were therefore eligible for ICM funding in 2012 and 2013. The OEB approved interim funding through the Initial ICM Rate Rider which was calculated using the OEB Workforms and inputting ISA expenditures as forecast for 2012 and 2013. While the calculation of forecast revenue requirement for 2012 determined that none of the ISAs in the approved ICM Segments would be above the materiality threshold, actual 2012 ISAs in the approved ICM Segments were above the materiality threshold. The revenue requirement associated with the 2012 actual ISAs above the materiality threshold forms part of the amounts to be recovered through the ICM True-up Rate Rider.

Pursuant to the OEB's Phase 2 Decision accepting the terms of the Settlement Agreement, the 2014 rate rider was set at zero with the expectation that any 2014 revenue requirement associated with the 2014 ISAs would be addressed through this application.[24]

4. ICM True-Up Framework

4.1. Introduction

As part of the Phase 1 Decisions, the OEB directed that a true-up process take place at the end of the ICM Period to address any variances between revenue collected through the Initial ICM Rate Rider and the revenue requirement associated with actual ISA expenditures. Variances were contemplated by the OEB in the Phase 1 Decisions and are to be expected when high-level forecasts are used to estimate expenditures for a large, complex capital program consisting of multiple jobs being executed in a dense urban environment.

[24] EB-2012-0064, Toronto Hydro Electric-System Limited Phase 2 Decision, Settlement Agreement (December 18, 2012) at pp. 8-9.

This section presents the framework used to compare Toronto Hydro's actual ISAs with the forecast ISAs used in developing the Initial ICM Rate Rider. In accordance with OEB direction, this comparison has been completed for each segment approved for ICM funding.[25]

For each of the 13 ICM Segments, the total amount of actual ISAs attributable to work in that segment during the ICM Period has been compared to the forecast ISAs. To the extent that the actual ISAs deviate from the forecast ISAs, the revenue requirement associated with the difference is included in the calculation of the amount to be collected from or returned to ratepayers in this proceeding.

4.2. THE PURPOSE OF TRUE-UP

As the OEB noted in the Phase 1 Decisions, the OEB's policy documents do not specifically discuss "true-up."[26] Rather, the policy contemplates a simple comparison between the estimated capital investment for ICM work (and the initial rate rider to fund it) and the actual investment required to complete that work (potentially resulting in a true-up rate rider). The purpose of this comparison is to hold both ratepayers and utilities harmless for differences between forecast and actual ISAs.

This forecast-versus-actual segment comparison is done year by year for ease of ratemaking and true-up purposes: in particular, to determine the difference between the revenue requirement collected in each year in the ICM Period and the revenue requirement associated with actual ISAs. However, in accordance with the direction of the OEB, true-up is a segment-level exercise performed over the entire ICM Period. The determination of whether overspending or underspending occurred in an ICM Segment can only be assessed over the entire ICM Period because the OEB permitted Toronto

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[25] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p. 75.
[26] Ibid.

Hydro to move funds between years within each ICM Segment.[27] In other words, even if Toronto Hydro invested more than the amount forecast for a particular ICM Segment in a given year, no overspending would have occurred until the total amount invested exceeded the total investment forecast in a segment over the entire ICM Period.

4.3. THE TRUE-UP PROCESS FOLLOWED IN THIS APPLICATION

The OEB established the true-up process for this proceeding in the Phase 1 Decisions, directing Toronto Hydro to:

a) track the total revenue collected from the Initial ICM Rate Rider;[28]
b) track actual ISA expenditures for each ICM Segment;[29]
c) calculate the revenue requirement associated with actual ISA expenditures above the materiality threshold;[30] and
d) compare the revenue collected from the Initial ICM Rate Rider with the revenue requirement associated with actual ISA expenditures above the materiality threshold so that any variances may be refunded to or collected from customers, as the case may be, through a rate rider.[31]

In particular, the OEB delineated the process by which the revenue requirement associated with actual ISA expenditures was to be calculated:

> At the time of the true-up, THESL will recalculate the revenue requirement impacts (using the ICM Workform) based on the actual in-service assets (used

[27] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at pp. 75-76.
[28] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p. 76; EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order at p. 2.
[29] EB-2012-0064, Accounting Order Partial Decision and Order (April 2, 2013) at p. 76; EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order at p. 2.
[30] EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order at pp. 2-3.
[31] EB-2012-0064, Toronto Hydro Electric-System Partial Decision and Order (April 2, 2013) at p. 75; EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order at pp. 2-3.

and useful) in Board-approved ICM segments in the sub-accounts of Account 1508, as described in Appendix E Schedule 2 of THESL's EB-2012-0064 *Draft Rate Order* filing of April 12, 2013, to determine the revenue requirement on an actual basis for each applicable period (e.g., 2013 and 2014). All other input information in the ICM Workform will remain unchanged other than changes to the incremental capital CAPEX and the depreciation/amortization expense.[32]

As is set out in the sections below and in Exhibit 3, Toronto Hydro has tracked this information and has used it to perform the revenue requirement true-up calculation.

[32] EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order.

C. REVENUE REQUIREMENT TRUE-UP CALCULATION

1. REVENUE COLLECTED THROUGH THE INITIAL ICM RATE RIDER

Toronto Hydro collected $41.2 million in revenue from the Initial ICM Rate Rider through to the end of April 2015, when the Initial ICM Rate Rider ended.

2. ACTUAL ISAS VERSUS FORECAST ISAS

During the ICM Period, differences arose between the ISAs that were forecast at the ICM Application and the actual ISAs, as follows:

i. actual ISAs exceeded forecast ISAs in 6 of the 13 ICM Segments in the amount of $70.8 million; and
ii. actual ISAs were less than forecast ISAs in 7 of the 13 ICM segments in the amount of $32.5 million.

Overall, Toronto Hydro's prudently incurred actual ISAs exceeded the forecast ISAs on which the Initial ICM Rate Rider was based.

As indicated in Table 1, below, variances between the forecast ISAs and actual ISAs occurred in all ICM Segments. As detailed in Section 4 below, variances occurred for two primary reasons: (1) differences between forecast and actual ISA costs; and (2) differences between the number of jobs forecast and the number completed. Given the nature and complexity of the capital program, variances are to be expected and were contemplated by the OEB in the ICM Decisions.

Table 1 below describes the variances between forecast and actual ISAs and includes the following information:

a) the 13 approved ICM Segments (excluding Copeland TS);
b) the forecast ISAs for each ICM segment over the ICM Period;
c) the actual ISAs for each ICM segment over the ICM Period; and

d) a calculation of the variance between the forecast and actual ISAs for each ICM Segment over the ICM Period in dollars and percentage.

Table 1 does not include ISAs approved for Copeland TS or forecast amounts for the ICM Understatement of Capitalized Labour.[33]

As indicated in Table 2, in six ICM Segments actual ISAs exceeded forecast ISAs by $70.8 million in the aggregate. ISAs in excess of the forecast amounts were prudent and non-discretionary. Evidence in respect of the prudence of these investments is included at Exhibit 2.

As indicated in Table 2, in seven ICM Segments actual ISAs were $32.5 million less than forecast ISAs. The revenue requirement related to this amount should be credited to ratepayers in accordance with the direction set out in the Phase 1 Decisions.[34]

Taking the net result of the ISAs in all 13 ICM Segments, Toronto Hydro's actual ISAs exceeded the forecast ISAs that formed the basis of the Initial ICM Rate Rider. Toronto Hydro proposes to recover the associated revenue requirement through the ICM True-up Rate Rider, pursuant to the Phase 1 Decisions.[35]

[33] As part of Toronto Hydro's Phase 1 evidentiary update in October 2012, a number of jobs were deferred from the 2012-2013 period to 2014, resulting in a lower overall amount of forecast work for the 2012-2013 period. Toronto Hydro did not update the allocation of Capitalized Labour (i.e., Engineering Capital) across the re-forecasted list of jobs at that time, but instead showed the surplus Engineering Capital costs as a separate line item called "ICM Understatement of Capitalized Labour." The OEB authorized $8.3 million in ISA funding for the ICM Understatement of Capitalized Labour and this amount has been fully-allocated across the final list of completed jobs in each year on an actuals basis.

[34] EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order at p. 3.

[35] Ibid.

Table 1: Forecast ISAs vs. Actual ISAs

ICM Segment	Forecast ISAs ($ millions)	Actual ISAs ($ millions)	Variance ($ millions)	Variance (%)
Underground Infrastructure	124.4	180.0	55.6	44.7
PILC Piece Outs and Leakers	6.9	2.8	(4.1)	(59.9)
Handwell Replacement	37.5	36.4	(1.1)	(3.0)
Overhead Infrastructure	79.7	83.7	4.0	5.0
Box Construction	29.3	23.0	(6.4)	(21.7)
Rear Lot Construction	50.8	58.0	7.3	14.3
Network Vaults & Roofs	22.5	17.3	(5.2)	(23.2)
Fibertop Network Units	12.0	13.6	1.6	13.3
Automatic Transfer Switches & Remote Power Breakers	3.4	1.9	(1.5)	(43.1)
Stations Power Transformers	3.9	5.0	1.1	29.5
Stations Switchgear	16.7	5.0	(11.7)	(70.2)
Metering	17.0	18.2	1.2	7.0
Externally Initiated Plant Relocations & Expansions	36.9	34.4	(2.5)	(6.7)

3. REVENUE REQUIREMENT ASSOCIATED WITH ACTUAL ISAs

The revenue requirement associated with actual ISA expenditures in each year is calculated in Exhibit 3 as $52.3 million. In performing this calculation, Toronto Hydro followed the OEB’s direction in the Phase 1 Decisions and used the same inputs provided in the ICM Workforms used to calculate the Initial ICM Rate Rider, with changes only to the actual ISA amounts and associated depreciation and capital cost allowance ("CCA") amounts. The calculation of the revenue requirement associated with actual ISA expenditures is summarized as follows:

i. Actual ISAs in approved ICM Segments were calculated for each ICM year;
ii. The portion of actual ISAs that exceed the ICM materiality threshold in each ICM year was calculated. Actual ISAs exceeded the ICM materiality threshold in each of 2012, 2013 and 2014; and
iii. The revenue requirement associated with actual ISAs in approved ICM Segments that exceeded the ICM materiality threshold in each of 2012, 2013 and 2014 totalled $52.3 million.[36]

Figure 1, below, provides a visual summary of ISAs in each year that are eligible for ICM funding and which were used to calculate the revenue requirement associated with actual ISAs in approved ICM Segments, where:

- the *blue bars* are actual ISAs for non-ICM work;
- the *orange bars* are actual ISAs in approved ICM Segments;
- the *red dashed lines* are the annual ICM materiality thresholds; and

[36] The revenue requirement to be recovered is calculated using the OEB's Incremental Capital Workform for 2015 Filers.

- the *green brackets* indicate actual ISAs in approved ICM Segments that are above the ICM materiality threshold and qualify for ICM funding.

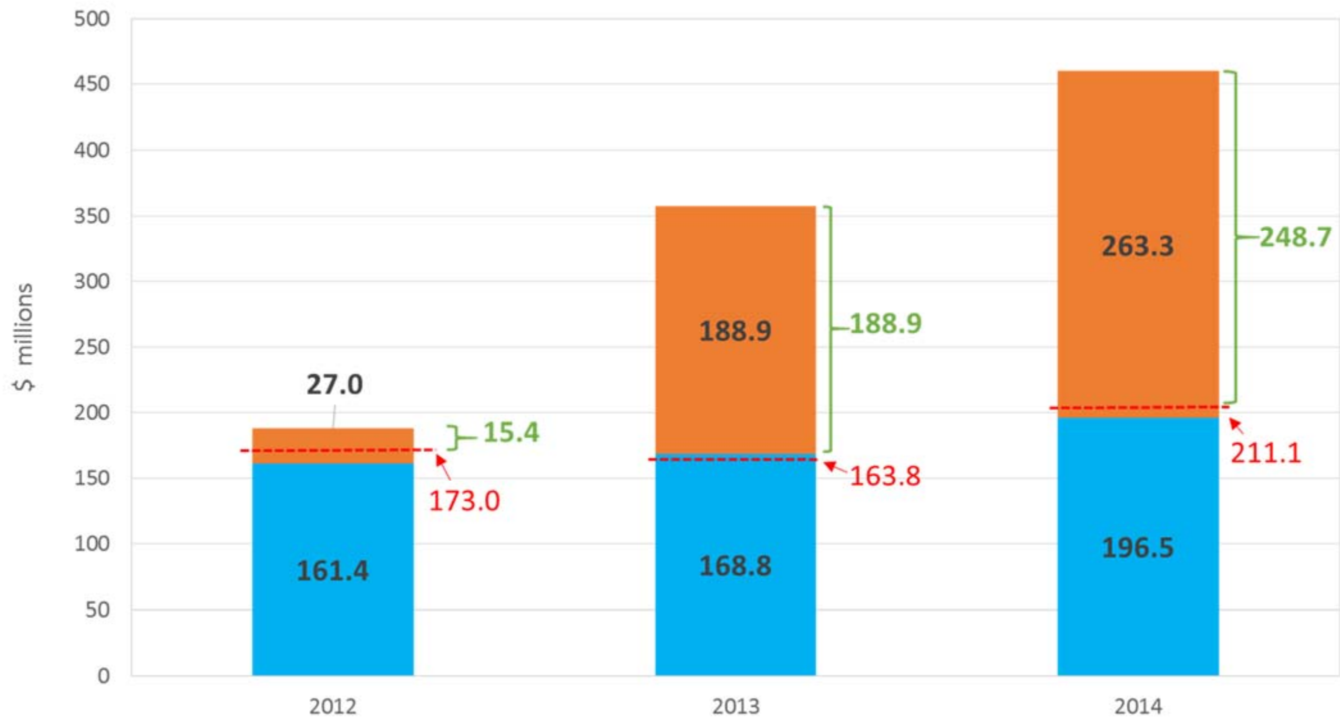

Figure 1: Actual ICM Eligible ISAs by ICM Year

In 2012, Toronto Hydro completed $27.0 million in actual ISAs in approved ICM Segments (orange bar). Of these ISAs only $15.4 million (green bracket) were above the ICM materiality threshold (red dashed line) and qualified for ICM funding. Toronto Hydro used $15.4 million to calculate the actual revenue requirement and ICM True-up Rate Rider.

In 2013, Toronto Hydro completed $188.9 million in actual ISAs in approved ICM Segments (orange bar). All of these ISAs were above the ICM materiality threshold (red dashed line) and qualified for ICM funding. Toronto Hydro used $188.9 million to calculate the actual revenue requirement and ICM True-up Rate Rider. An additional

$5.0 million in ISAs were also above the materiality threshold but these ISAs were part of segments or projects that the OEB expected would be funded through base rates or borrowing. Toronto Hydro has not included this additional $5.0 million in its calculation of the actual revenue requirement and ICM True-up Rate Rider even though this amount is above the ICM materiality threshold.

In 2014, Toronto Hydro completed $263.3 million in actual ISAs in approved ICM Segments (orange bar). Of these ISAs only $248.7 million (green bracket) were above the ICM materiality threshold (red dashed line) and qualified for ICM funding. Toronto Hydro used $248.7 million to calculate the actual revenue requirement and ICM True-up Rate Rider.

In total, $453.0 million in actual ISAs qualify for ICM funding. Using this number in the OEB's ICM Workforms results in an actual revenue requirement over the ICM Period of $52.3 million, as calculated in Exhibit 3.

4. INCREMENTAL REVENUE REQUIREMENT

In the Phase 1 Decisions, the OEB held that the revenue requirement associated with variances between forecast and actual ISAs would be refunded to or collected from customers through a rate rider.[37]

The difference between the $41.2 million of revenue collected from the Initial ICM Rate Rider and the $52.3 million revenue requirement associated with actual ISAs in approved ICM Segments is $11.1 million, which Toronto Hydro proposes to recover through the ICM True-up Rate Rider as calculated in Exhibit 3.

[37] EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order at pp. 2-3.

5. TORONTO HYDRO'S 2015-2019 CUSTOM INCENTIVE RATE-SETTING APPLICATION

Toronto Hydro filed a Custom Incentive Rate-setting ("CIR") application for 2015-2019 on July 31, 2014.[38] In its CIR application, Toronto Hydro proposed a deferral of the ICM true-up, noting that as of the CIR application filing date the 2012-2014 ICM work program was still in progress.[39]

Later in the proceeding, Toronto Hydro proposed that a variance account be established to capture differences between (a) amounts approved in the CIR Decision for inclusion in 2015 opening rate base related to ICM work during the ICM Period, and (b) any disallowance based on prudence that may result from the ICM true-up process in this proceeding.[40]

The OEB accepted Toronto Hydro's proposals.[41]

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[38] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected September 23, 2014).
[39] EB-2014-0116, Toronto Hydro-Electric System Limited Application (filed July 31, 2014, corrected September 23, 2014), Exhibit 2A, Tab 9, Schedule 1.
[40] EB-2014-0116, Toronto Hydro-Electric System Limited Reply Argument (April 20, 2015) at p. 225.
[41] EB-2014-0116, Toronto Hydro-Electric System Limited Decision and Order (December 29, 2015) at p. 52.

D. VARIANCE EXPLANATIONS

1. INTRODUCTION

In the Phase 1 Decisions, the OEB directed that reconciliation for any variances be performed on a segment level basis over the ICM Period.[42] Accordingly, Exhibit 2, Tabs 1-13 to this application contains a schedule for each ICM Segment which includes a detailed variance analysis for each segment over the course of the ICM Period.

In addition, PSE was engaged to provide an opinion on the reasonableness of variances between the OEB-approved ISAs and actual ISAs at a segment level. PSE's report is found at Exhibit 2, Tab 14 to this application. PSE concludes that based on the differences between forecast and actual ISAs, and given the stage at which Toronto Hydro estimated the costs included in the ICM Application, the variance ranges for the segments are reasonable. They also find that the justifications Toronto Hydro provided for the observed differences in those segments having larger variation are reasonable based on industry experience in implementing large, complex, multi-year capital programs.

This section provides an overview of the reasons for variances within the ICM Segments. Variances arose in each of the 13 ICM Segments for two main reasons. First, variances occurred where the actual cost of individual jobs was more or less than the forecast cost; that is, where actual ISAs were more or less than forecast ISAs. Second, variances occurred where jobs were added, deferred or cancelled in an ICM Segment.

Actual ISA amounts varied from forecast ISA amounts for five primary reasons as described in the sections below. Exhibit 2 to this application includes a comparison of

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[42] EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order at pp. 2-3.

forecast ISAs against actual ISAs for each ICM Segment and explains the primary reasons for variances within the segment, consistent with the OEB's direction that true-up be performed at a segment level. For ICM Segments where actual ISAs exceed the forecast ISAs over the ICM Period, Toronto Hydro has explained the prudence of the additional work and why the associated revenue requirement should be recovered.

2. VARIANCES BETWEEN FORECAST AND ACTUAL ISAS

Actual ISAs varied from forecast ISAs for five primary reasons. First, variances occurred as the result of the ordinary refinement of cost estimates as a job moved from a high-level to a detailed design. For example, variances occurred where one job was expanded or merged into another single job in order to address emerging system needs and/or gain operational efficiencies associated with the particular work.

Second, variances occurred during the construction phase of a job due to site-specific conditions, for example, where field inspections revealed that the equipment or environmental conditions presented different challenges (or opportunities) than anticipated, or that practical constraints required different asset configurations.

Third, variances occurred where Toronto Hydro had to accommodate third party constraints or requirements. For example, variances occurred when the City of Toronto introduced an unplanned road cut moratorium in the area of a job, causing Toronto Hydro to modify the job's scope or timing.

Fourth, variances occurred for costs that were charged at the project close-out phase of the job, such as design costs and road cut repairs. These costs were typically estimated using historical averages, with the expectation that actual costs would vary from job to job. For example, variances occurred where actual road cut costs for a job were more or less than the road cut costs that were estimated based on historical averages during the estimating phase.

Finally, in a small number of cases, variances were attributable to errors in the original estimates that were filed in the ICM Application.

These five primary drivers of cost variance are referred to in Exhibit 2 to explain instances where actual ISAs varied from forecast ISAs over the ICM Period. They are summarized in Table 3 and are described in further detail in the sections below.

2.1. HIGH-LEVEL TO DETAILED DESIGN VARIANCES

The vast majority of variances occurred as a result of relying on job estimates for forecast costs. As was detailed in Toronto Hydro's evidence in the ICM Application, in developing estimated job costs, Toronto Hydro relied primarily on high-level planning estimates with the expectation that these estimates would be necessarily refined as the job progressed from high-level planning to execution and, sometimes, during execution based on the conditions encountered on the ground. These changes are necessary for the prudent planning and execution of a large-scale capital plan, comprised of hundreds of jobs with multiple assets types, and spanning multiple years. As Toronto Hydro explained in its evidence in the ICM Application, cost estimates are refined throughout the process that takes a job from high-level design to completion.[43] This approach is standard practice for project cost estimation for construction projects.

The following sections contain a description of the steps typically taken by Toronto Hydro to progress a job from high-level to detailed design.

[43] EB-2012-0064, Toronto Hydro Electric-System Limited Application (filed May 10, 2012, updated October 31, 2012), Tab 2, Addendum at pp. 10-11.

Table 2: Common Drivers of Variance – Table of Variance Codes

Variance Type	Explanation
High-level to Detailed Design Variance	Variances attributable to the progression from the high-level planning estimates that formed the basis of the ICM Application to the detailed designs contained in the final execution work plan. They are due to changes in: job scope, design elements, applicable standards, and system operations requirements.
Field Conditions & Execution Requirements	Variances that arise due to site conditions encountered during the construction phase. These include site conditions, operational constraints (e.g., loading, switching and outage restrictions), and labour and equipment costs that arise during construction.
Third-party Requirements & Constraints	Variances due to third party requirements or constraints, including the City of Toronto, Hydro One, customers, or other third parties, arising for example from collaborative agreements or coordination issues.
Variance in Allocated Costs	Variances due to differences between the average allocated costs (e.g., design costs, road cuts, and engineering capital) for individual jobs in the high-level planning estimates and the actual overhead costs incurred for each individual job as calculated at project close-out.
Errors	Variances due to errors made in the high-level planning estimates or in the ICM Application.

2.1.1. Creation of Project Segments

Toronto Hydro's ICM capital program is comprised of segments. Each segment contains discrete jobs undertaken for a similar purpose. Each segment uses a common approach to demonstrate the need for the work and explains the process used to prioritize the jobs within it.

For example, all jobs in the Overhead Infrastructure segment involved work associated with replacing aging, deteriorated and non-standard overhead assets such as wood poles, Completely Self-Protected transformers, bare and undersized conductor, and porcelain switches and hardware.

2.1.2. The Initial Job Scoping Process

Each job is identified through a scoping process. Jobs are evaluated based on the age and known condition of the assets targeted for replacement, whether they meet updated safety standards and how they affect the overall operation of Toronto Hydro's distribution system. Large assets such as station switchgear are evaluated individually. Smaller assets are evaluated by area or region, or by electrical circuit configuration, as appropriate.

The scoping process is intended to establish system investment needs at a high-level and the relative priority of jobs using high-level estimates. Information produced in the scoping process is used to facilitate the development of preliminary Execution Work Programs ("EWPs") and establish budgets at aggregate levels for those EWPs.[44] Not all jobs identified in the scoping process can be included in a given year because of budgetary and other constraints (e.g., switching capacity, resources constraints or scarcity of necessary field skills).

2.1.3. Development of Execution Work Programs

The preliminary EWPs are developed early in the year prior to the year in which the work will take place and do not involve any detailed scheduling of the jobs or the resources necessary to accomplish them. During the period between development of the preliminary and final EWPs, the list of jobs typically changes due to the emergence of

[44] EWPs consist of the various distribution system-related jobs and activities that are scheduled and resourced for execution within a given budget year.

higher priority work or constraints that impact Toronto Hydro's ability to execute jobs included in the preliminary EWPs. Consequentially, jobs and resources are not scheduled until the work programs for the coming year are finalized late in the year prior to execution.

2.1.4. Cost of High-level vs. Detailed Design Estimates

The level of expected accuracy for a given cost estimate depends on the amount of time and resources allocated to estimating the job. The majority of job scopes included in the preliminary EWP are created using high-level estimates. High-level estimates are based on standardized costs for installing various types of assets. They do not incorporate area-specific considerations (e.g., the location of other utilities' equipment, trees or other obstacles; soil conditions; landscaping and building set-backs), which frequently increase the final cost of a job. High-level estimates also do not incorporate input from field staff, which can change the final scope of the job by providing more detailed information on asset condition and configuration.

High-level estimates typically cost significantly less than 1% of a job's total cost to create. Enhancing estimate accuracy at a greater cost is not typically justified at the preliminary budgeting stage because many jobs are subsequently refined and in some instances, jobs are deferred or cancelled. It is therefore not cost-effective to create detailed estimates for the preliminary EWP.

In contrast, detailed estimates created closer to execution require full designs and typically cost up to 10% of a job's overall cost. For this reason, Toronto Hydro does not begin detailed design work until a job is scheduled in the preliminary EWP and strives to have most detailed design work completed by the time the EWP is finalized (late in the year prior to construction). To do otherwise would not be cost-effective given the modifications and deferrals discussed above.

2.1.5. Accepted Industry Standards

Toronto Hydro's high-level estimates can and do vary from the actual cost of the completed jobs even where the scope of the jobs remains unchanged between the initial planning and execution. This type of variance is an accepted part of project cost estimation generally and has specifically been recognized for cost estimation in the utility industry.[45]

2.2. FIELD CONDITIONS & EXECUTION REQUIREMENTS

Variances occur at the execution stage of a job where field conditions, operational constraints or other factors cause costs to change during construction. For example, in some jobs, material modifications to equipment numbers and configuration must be made to account for the particular conditions at the project site. In some instances, it may be difficult for Toronto Hydro's designers to anticipate potential challenges to the asset positioning and configurations used in the design, particularly when the jobs involve underground assets or construction, or work on customers' properties. As such, a number of job variances were driven by design or construction requirements that only became apparent following the actual commencement of the jobs and after the targeted equipment and its positioning were physically visible to the crews.

2.3. THIRD-PARTY REQUIREMENTS & CONSTRAINTS

Variances occurred where Toronto Hydro had to accommodate the requirements or constraints of third parties such as the City of Toronto, Hydro One or Toronto Hydro customers.

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[45] For an example of the variances contained in a cost estimation approach approved for transmission projects, see, Alberta Electricity System Operator, Cost Estimating Framework (ISO Rule 9.1.2) AESO Recommendations, October 17, 2014. This document can be accessed at: http://www.aeso.ca/downloads/AESO_CostEstimatingFrameworkRecommendationPaper.pdf.

Third party requirements often arise after high-level estimates have been completed. For instance, the City's permitting process requires a detailed design estimate. As a result, modifications required by the permitting process were not included as part of the high-level estimates. City requirements for work in the road allowance also led to a number of jobs being re-scoped or executed at different times, for example, where the City required Toronto Hydro to install switches below-grade instead of above-ground or imposed road-cut moratoriums.

The timing of when work could be performed also impacted costs. Coordinating work schedules with third parties like Hydro One can lead to delays and impact work schedules. Where third parties required work to be performed in off-peak hours, Toronto Hydro incurred higher labour costs that were not accounted for in the estimates filed in the ICM Application.

Work in the Externally-Initiated Plant Relocations segment is driven by the schedules and requirements of third-parties. A number of cost variances experienced at the job level in this segment were the result of third-party decisions that were outside of Toronto Hydro's control.

2.4. VARIANCE IN ALLOCATED COSTS

A number of costs are compiled centrally by Toronto Hydro and then attributed to individual jobs at project closeout. Examples include costs for road cut repairs billed by the City of Toronto and centralized costs for design and engineering services. These costs are then attributed to specific jobs based on the cost and nature of the completed work. Toronto Hydro's approach to accounting for allocated costs in the ICM Application was to apply a consistent percentage-based adder to a job's forecast costs. Variances sometimes occurred when the amount of these allocated costs at close-out were greater or less than the average amounts assumed in the high-level estimates.

2.5. ERRORS

In a small number of cases, variances are attributable to errors in the original estimates that were filed in the ICM Application, for example where a job was filed with an estimated cost of $1. Generally, these are clerical or computational errors that failed to accurately capture the costs of the high-level design or that were made in preparing the list of estimates for the ICM Application.

3. VARIANCES DUE TO ADDED, CANCELLED OR DEFERRED JOBS

Variances also occurred in ICM Segments as a result of jobs being added, deferred or cancelled. In some ICM Segments, circumstances required that additional work be undertaken. In other ICM Segments, circumstances occurred that hindered the ability to undertake them during the ICM Period. These types of changes to the forecast work in each segment were anticipated in the evidence in the ICM Application. For example:

> By way of a real-world example, while THESL has provided a list of specific Fibertop network unit replacements that it has proposed to complete in 2014, operational realities may require it to reprioritize this list of replacements, such that Fibertop units not currently scheduled to be replaced in 2014 may be advanced to be replaced during the ICM cycle, displacing previously scheduled jobs – in other words, circumstances may require that certain fibertop replacement jobs be moved-up in the queue. Accordingly, it may be the case that THESL is driven to substitute some of the approved Fibertop replacement jobs with other Fibertop jobs that were not contemplated for replacement in 2014 at the time of the application. These jobs would not be materially distinguishable in scope from those already approved. THESL understands that the principles underlying the ICM framework, and in particular the Phase 1 Decisions, contemplate such additions and substitutions (as long as the new jobs fit the ICM criteria and are

essentially the same as approved jobs).[46]

In the ICM Phase 1 Decisions, the OEB acknowledged Toronto Hydro's operational need to add, delete or adjust the timing of particular work within the ICM Segments, recognizing that ICM-eligible spending on the specific jobs within a segment may vary.[47]

Exhibit 2 provides a breakdown of the status of jobs in the segment including whether they were completed, in progress, added, deferred, or cancelled during the ICM Period and an explanation at a segment level on why these changes occurred. Job level detail is included for added jobs (referred to as "analogous jobs") to demonstrate that these jobs were prudent, non-discretionary and analogous to other jobs in the ICM Segment.

In short, the evidence in Exhibit 2 shows that analogous jobs were prudent and non-discretionary and the work was required during the ICM Period to address urgent issues, because it was most efficient to complete it in conjunction with other ICM jobs, or because external factors prevented the completion of a filed job so another urgent job was substituted in order to use available resources efficiently.

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[46] EB-2012-0064, Toronto Hydro Electric-System Limited Application Evidence Update for 2014 (August 19, 2013), Tab 9, Schedule 1 at p. 10.

[47] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p. 75; EB-2012-0064, Toronto Hydro Electric-System Limited Decision and Rate Order (May 9, 2013), Accounting Order at p. 3.

CERTIFICATION OF EVIDENCE

I, Amanda Klein, Vice President, Regulatory Affairs and General Counsel to Toronto Hydro-Electric System Limited ("Toronto Hydro") hereby certify that the evidence submitted to the Ontario Energy Board in support of Toronto Hydro's Incremental Capital Module True-up Application (EB-2015-0173) is accurate, consistent and complete to the best of my knowledge.

This certificate is given pursuant to the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* (revised July 16, 2015).

DATED this 8th day of March, 2016.

Amanda Klein
Vice President, Regulatory Affairs
and General Counsel

LEGAL DISCLAIMER

The information in these materials is provided to the Ontario Energy Board (the “OEB”) for the purpose of presenting the OEB with the results of the directed true-up process arising from its decision in EB-2012-0064 (the “Application”) and not for any other purpose. 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 and future requirements 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 “aims”, “anticipates”, “believes”, “budgets”, “committed”, “could”, “estimates”, “expects”, “forecasts”, “intends”, “may”, “might”, “plans”, “projects”, “schedule”, “should”, “strives”, “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 that may be present in these materials includes, but is not limited to, statements regarding Toronto Hydro’s future results and performance, as well as expected nature, timing and cost of capital and operational programs. The statements that make up the Forward-Looking Information are based on assumptions that include, but are not limited to receipt of applicable regulatory approvals and requested rate orders. 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.

All Forward-Looking Information in these materials is qualified in its entirety by the above cautionary statements, except as required by law, or by the OEB for the purposes of the Application. 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, except as required under securities laws, or by the OEB for the purposes of the Application.

B1 – UNDERGROUND INFRASTRUCTURE SEGMENT

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro proposed the Underground Infrastructure segment to replace direct-buried Cross-Linked Polyethylene ("XLPE") cable and air-insulated pad-mounted switchgear units with Tree-Retardant ("TR") XLPE cable in concrete-encased ducts and SF_6-insulated pad-mounted switchgear. The specific assets identified for replacement were beyond end-of-life and had shown increasing failure trends in recent years, contributing significantly to the aggregate outage statistics on the utility's underground system. Moreover, the switchgear identified for replacement presented a potential safety risk for Toronto Hydro field crews. Where economic, Toronto Hydro also proposed to replace non-standard submersible transformers with switchable submersible transformers.

2. OEB DECISION

The OEB found that the nature of the work in the Underground Infrastructure segment, as filed, qualified for ICM treatment.[1] Having found that the work was both necessary and prudent, the OEB made no reduction to Toronto Hydro's funding request.[2] Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto Hydro's forecast of approximately $64.6 million of ISAs in 2012 and 2013. Toronto Hydro forecasted an additional $23.1 million in 2014 ISAs related to work proposed in Phase 1 of EB-2012-0064 (i.e., jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the Initial ICM Rate Rider.

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[1] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p.24.
[2] Ibid.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $180 million. In addition to the forecasted ISAs of $87.7 million from Phase 1, this includes:

- approximately $36.7 million in ISAs that Toronto Hydro forecasted in Phase 2 for jobs commencing in 2014, which were approved in the Phase 2 Decision but not funded through the Initial ICM Rate Rider or any rate adder; and
- about $55.6 million in additional prudent and non-discretionary ISAs associated with both filed and analogous jobs as described in the sections below.

The revenue recovered through the Initial ICM Rate Rider for this segment did not sufficiently cover the revenue requirement of all necessary and prudent work performed as part of this project segment. The revenue requirement associated with the ISAs that were not sufficiently funded through the Initial ICM Rate Rider remain to be recovered through the ICM True-Up Rate Rider.[3]

B. SEGMENT OVERVIEW

The primary driver for the proposed work in the Underground Infrastructure Segment was reliability, as the direct-buried cables represented about half of all underground system outages and showed an increasing trend in sustained interruptions per kilometer of the installed asset. In a similar manner, the air-insulated pad-mounted switches had exhibited a rising trend in failures over the previous decade. The switches were usually connected to several feeder trunk circuits, further amplifying the impact of failures: a typical outage affected as many as 1,400 customers for an average duration of 50 minutes.

[3] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.

Toronto Hydro proposed to replace the existing assets with new standard assets that would mitigate the specific failure characteristics of the legacy direct-buried circuits. In the case of direct-buried XLPE, the moisture from the surrounding soil had contributed to accelerated hydrothermal aging, leading to a deterioration of the insulation and eventual failure as contaminants interacted with the energized cable. Toronto Hydro proposed to replace these legacy cables with concrete-encased TR-XLPE cables, which offer superior protection from environmental degradation over the asset lifecycle compared to the alternatives of cable rejuvenation/splicing or direct-buried TR-XLPE cables, both of which would leave the cable exposed to moisture contained in the soil. Concrete-encased cable conduits are also preferable for outage restoration, as the cost and time to rectify a failed cable housed in a protective duct are considerably lower than those of the other alternatives.

A secondary driver for this segment was safety. Legacy air-insulated pad-mounted switches had an open-air design that allowed for accumulation of external contaminants and moisture in the switching compartment, leading to corrosion and instances of premature failure. Their live-front design created a risk of flashovers as assets failed, which presented a significant safety risk for Toronto Hydro staff during outage restoration efforts and regular maintenance. To replace these switches, Toronto Hydro proposed to install SF_6-insulated switches where all electrical components are completely sealed within a dielectric medium, offering optimal protection against the ingress of foreign substances and enhanced safety.

This segment was geographically based, with jobs targeting replacement of all assets addressed by this segment in a particular area. The majority of jobs filed within the Underground Infrastructure segment targeted the assets of a single feeder, identified on the basis of reliability statistics analysis, failure modes, safety incidents and asset performance. In all cases, Toronto Hydro proposed replacing direct buried cable and air-insulated pad-mounted switches concurrently to maximize efficiency and solve all equipment performance issues comprehensively. A number of jobs also proposed replacing non-standard, non-switchable submersible transformers with the current standard models used by the utility. Toronto Hydro identified these transformers for replacement based on asset condition and their significant contribution to outage frequency due to the multi-taps installed on the units.

Toronto Hydro filed 172 discrete jobs to address anticipated reliability, safety and operational efficiency concerns in this segment during the ICM Period. The utility anticipated that these jobs would be completed, partially completed or in progress by the end of the ICM Period.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the variance between the forecast ISAs and the actual ISAs over the ICM Period. Toronto Hydro put into service $55.6 million more than forecasted. While ISAs in 2012 were lower than forecast, higher than forecast additions in both 2013 and 2014 produced the additional in-service amount. Higher than forecast ISAs in this segment are the result of both job-level variances and the addition of a number of analogous jobs that Toronto Hydro determined to be necessary in light of the equipment's performance, condition, and other considerations described below.

Table 1: Forecast vs. Actual In-service Additions

	Forecast ISAs				Actual ISAs				Variance
	2012	**2013**	**2014**	**Total**	**2012**	**2013**	**2014**	**Total**	**Total**
ISAs ($M)	12.7	51.9	59.8	**124.4**	9.7	66.8	103.5	**180.0**	**55.6**

Table 2 summarizes the job-level accomplishments for this segment during the ICM Period. Over ninety percent (92%) of the originally forecasted jobs (159) were completed or in progress by the end of 2014. The utility cancelled one job due to a conflict with the Eglington LRT project. Twelve other jobs were deferred to the 2015-2019 period either in light of scheduling conflicts with third-parties (e.g., unforeseen road moratoriums or coordination with major transit projects) or to enable the attainment of other analogous jobs that were identified as more critical during the course of the ICM Period. As shown in Table 2, Toronto Hydro added 18 of these priority jobs, all of which were completed in the ICM Period.

Table 2: 2012-2014 Job-level Accomplishments

Segment Jobs Breakdown	Number of Jobs
Total Forecasted Jobs	**172**
Less: Deferred or Canceled Jobs	(13)
Add: Analogous Jobs	18
Total Segment Jobs	**177**
Less: In Progress Jobs	(37)
Total Jobs with ISAs	**140**
Breakdown of Total Jobs with ISAs	**Number of Jobs**
Completed Jobs	129
Partially Completed Jobs	11
Total Jobs with ISAs	**140**

The primary considerations driving Toronto Hydro's decision to complete the analogous jobs were:

- reliability performance of aging equipment (with most affected feeders experiencing multiple equipment-related interruptions for a number of consecutive years); and

- irreversible damage or deterioration of assets identified through field inspection.

Complete information regarding the investment drivers, scope of work and final costs for all analogous jobs can be found in the Appendix to this Schedule.

D. REVIEW OF VARIANCES

Within the Underground Infrastructure segment, four types of variance causes explain the cost variances between the estimates filed in the ICM Application and the actual cost of the completed jobs. Most variances were due to changes that occurred between the high-level estimates filed in the ICM and the detailed design work for the job as discussed in Section 1 below. Changes that emerged during job execution due to field conditions encountered or construction requirements were another prominent variance cause, as discussed in Section 2 below. On occasion, jobs changed because of requirements or constraints imposed by third parties such as Hydro One, the City of Toronto, and other utilities as discussed in Section 3 below. Finally, certain jobs saw cost changes due to differences between the actual cost amounts for road cuts and other centrally accumulated costs and the averages used in preparing high-level estimates as explained in Section 4 below.

1. HIGH-LEVEL TO DETAILED DESIGN VARIANCE

The estimates that underpinned the ICM Application were largely high-level planning estimates. The most significant driver of job-level variances in the Underground Infrastructure segment were changes that occurred as jobs moved from these high-level planning estimates to detailed designs. As the detailed design work was completed on jobs, changes were made to the labour and materials required to execute them. The changes between the high-level estimate and project design usually involved changes in the design configuration required by the actual conditions at the project site or changes in project scope.

The most frequent source of scope change leading to material cost variances was a change in Toronto Hydro's technical design standards with respect to the secondary cables and secondary services that connect customers to the distribution system in neighbourhoods with underground distribution configurations. Prior to the ICM Application, Toronto Hydro's technical standard was to reuse the existing directly buried service connection from the customer lot demarcation line to the meter base. As Toronto Hydro ramped up the replacement of direct buried primary underground cables with equipment housed in concrete-encased ducts, the existing service connections, which were typically nearing or beyond end-of-life, often were disturbed and sustained damage that was an unavoidable part of working with the existing legacy direct-buried infrastructure. Toronto Hydro found that even after replacing the direct buried primary cable, faults in the direct buried service connection would continue to require reactive repair and remediation. In light of these developments, and consistent with the 2009 revision of the standard for placing new primary underground cables into concrete-encased ducts, Toronto Hydro revised its standard for the manner of construction of secondary cables and services in underground residential rebuilds, requiring that the secondary bus be placed in concrete-encased ducts up to the lot demarcation line and that service cables be placed in direct-buried ducts from the lot line to the meter base. Apart from addressing the emerging issue of service cables being damaged in the process of primary civil work, the utility's decision to adopt a new technical standard was driven by the following considerations:

- enhancing service reliability by replacing the aged infrastructure and placing it in a protective duct;
- execution efficiency by completing all requisite work in the area concurrently;

and

- reduced intervention timelines for future outage restoration and replacement activities.

Given that the new design standard was not released until late in 2011, some of the earlier cost estimates presented in the Phase 1 filing, which would have been created in the years prior to and including 2011, would not have included the additional costs of labour and material associated with replacing the service connections. The reasoning behind Toronto Hydro's decision to revise the standard and incur these costs was consistent with the rationale for placing the primary circuits into concrete-encased ducts, which the Board found to be the most effective way of replacing the direct-buried cables in the Phase 1 Decision. Implementing the revised technical standard for the replacement of service wires was a prudent decision that was necessary to achieve the sustainable reliability benefits that are the goal of this infrastructure renewal segment.

The extent to which the addition of secondary service rebuilds increased the cost of a given job in this segment was largely dependent on site-specific conditions. For example, in some instances the presence of mature trees may have necessitated tunnelling as an alternative to open trenching in order to leave root systems undisturbed, and the need to dig trenches where customers had installed decorative finishes such as interlocking brick significantly increased restoration costs in a number of jobs.

These field conditions, which affect underground construction in particular and are difficult to fully anticipate at the high-level estimating stage, were also a source of variance when constructing primary duct banks. Generally, restoration costs following road cuts and trenching, whether on private property or in the public road allowance, can vary substantially between neighbourhoods and properties and can be difficult to estimate in the absence of detailed field inspections by design and construction personnel.

Other changes in job scope occurred as designers conducted prospective site visits, identifying that additional assets or fewer assets were required to execute the job based on asset condition and configuration. This type of change in project scope as it progresses from high-level planning estimates to detailed design is typically based on differences between the data available to the engineer at the time of high-level planning and the information gathered through site inspections that occur in conjunction with detailed design preparation. For example, negative project cost variances can be driven by scope changes in instances where some replacement work was undertaken on a reactive basis following asset failure, thereby reducing the work requirements for the project.

It should be noted that in the scenarios above, the job as originally scoped has not gone over or under cost, but has in fact expanded or retracted to address more or fewer assets in need of replacement, in accordance with the core drivers of work in the segment.

Other instances of scope changes occurred as the control room operators requested certain modifications to project scopes to improve system reliability and operability. These typically entailed requests to install SCADA equipment or load interrupter switches, performing circuit transfers to balance the system loading in particular areas, and/or expanding capacity ratings of specific assets to improve operational flexibility of the system and minimize the impact of contingencies. Since system controllers review the project scopes during the advanced stages of the design process (where their review can provide the most value), these modifications were not included in the high-level estimates underlying the ICM Application. However, given that these modifications are implemented in the course of the work that was found necessary and prudent on its own merit, Toronto Hydro submits that the costs of these modifications are themselves prudent in light of the system operation benefits produced, and the efficiency gained from performing this work concurrently with the core project activities.

Another source of scope changes was the advancement of the latter phases of a job that were originally planned for construction after the ICM Period. This typically occurred where contractors performing civil work on site had additional capabilities and resources to complete the electrical work as well. Advancing the electrical work allowed Toronto Hydro to realize execution efficiencies and avoid future disruptions in the area by completing all requisite work at once. Similar to the replacement of additional assets not originally identified in the high-level estimates, the advancement of latter stages of the required work does not strictly represent a cost overrun relative to the original estimate, as the final costs reflect the additional work that would have been required to complete the project in the future less any efficiency gains from having the work done by crews already on-site.[4]

2. FIELD CONDITIONS AND EXECUTION REQUIREMENTS

Some variances occurred at the execution stage because site conditions, operational constraints or other factors caused costs to change during construction. The most common scenario involved material modifications to account for the particular conditions of each project site and/or equipment targeted for replacement. Given that the segment largely consists of below-grade work, it is often difficult for Toronto Hydro's designers to anticipate potential challenges to the asset positioning and configurations used in the design based on available asset records. As such, a number of job variances, involving both cost increases and decreases, are driven by the modifications to the original designs that only became apparent following the actual commencement of the jobs, after the targeted equipment and its positioning were physically visible to the crews.

The typical modifications involved partial or complete relocation of the ductwork based on the specific location of the existing assets relative to the sidewalk/roadway, non-

[4] While much less typical, on occasion the electrical phases of a job were deferred, rather than advanced, to make better use of available resources during periods when the weather is unsuitable for concrete work.

standard equipment configurations, presence of other utilities' infrastructure, or the design requirements that could not be accommodated within the confines of the existing asset locations. For example, the discovery during construction of abandoned utilities or an unforeseen water main can make it necessary to increase the depth at which a duct bank is constructed, which raises the cost of a job.

Project variances also occur at the execution stage due to the fact that the work was originally estimated on the assumption that it would be completed by Toronto Hydro's internal crews, but the projects were ultimately assigned to the external contractors for execution. Unlike the internal construction cost estimates that are based on unburdened work execution rates, the contractor costs charged to the projects are fully burdened, as they are intended to recover all costs incurred by the third-party contractor, including the administrative overhead costs, costs of contractor vehicles and equipment and other related drivers, which are typically accounted for separately at Toronto Hydro (e.g., through OM&A costs).[5] In a similar manner, cost variances between projects assumed to be constructed "in house", which are delivered by third-party contractors also attract the incremental costs of mandatory construction audit performed by an independent assessor, which cannot be reliably predicted at the high-level scope estimation.

3. THIRD PARTY REQUIREMENTS AND CONSTRAINTS

Toronto Hydro's ability to work in road ways and on customer premises is often constrained by the City of Toronto or customers' requirements. Restrictions placed on construction activities by the City in certain areas required scope changes for Underground Infrastructure jobs. Examples include road cut moratoria that forced Toronto Hydro to re-define job scopes, and specific instructions from the City's planners,

[5] The issue of cost comparisons between Toronto Hydro's internal and third party construction costs was explored in depth during the 2015-2019 CIR Application (EB-2014-0116). For an adjusted "like-for-like" comparison of contractor costs to fully burdened internal Toronto Hydro cost please see EB-2014-0116, Interrogatory Response 2B-CUPE-02.

such as the denial of a request to install above-ground switches, resulting in the need to amend job scopes by including additional cable chambers and ductwork to accommodate below-grade equipment installation. As the municipal permitting process is based on detailed estimates, the specific modifications required by the permitting process were not included as part of the high-level estimates.

4. VARIANCE IN ALLOCATED COSTS

A number of costs are compiled centrally by Toronto Hydro and then attributed to individual jobs at project closeout. Examples include costs for road cut repairs billed by the City of Toronto and centralized costs for design and engineering services. These costs are then attributed to specific jobs based on the cost and nature of the completed work. Variances can occur when the amount of these allocated costs at close out are greater or less than the average amounts assumed in the high-level estimates. Road cut restorations exemplify this type of cost in the Underground Infrastructure segment. The actual number of road cuts required and their associated cost can vary significantly from the averages used in the high-level estimate and even from the amounts included in the detailed design depending on actual conditions encountered.

In several instances, allocated costs were the source of some of the most significant percentage variances in the Underground Infrastructure segment. For example, in some jobs the work was largely completed prior to the filing of the ICM Application, with only minor remaining portions included in the ICM Application. Since Toronto Hydro's approach to accounting for allocated costs in the ICM Application was to apply a consistent adder based on a percentage of the project's filed costs, the amounts included in the filing for these activities was based only on the small amount of remaining cost included in the ICM Application. At project closeout, however, the amounts actually allocated to these jobs were based on the jobs' entire scope of work. These amounts were far more than those that had been previously included, creating a major cost variance. It should be noted that these variances do not reflect major changes to job costs but are merely a consequence of the manner in which Toronto Hydro's allocated costs interacted with several jobs that spanned the 2011 to 2012 timeframe.

ICM Segment **B1 Underground Infrastructure**

Estimate	Description	ISAs	Rationale/Driver for Inclusion
EST16873_002EST25422_001	W10335 BLAKETON MS PCI -W10335 Blaketon MS F2/F4	$211,486.14	The project involved replacing outdated air-insulated PMH switchgears with modern SCADA technology. The project began in 2011 and was completed in December 2012, with the estimate for this job being limited to installation of communication devices such as antennas. This project was necessary as the older switches presented significant reliability and safety risks. Air-insulated PMH switchgears are one of the assets targetted by Segment B1 due to the likelyhood of contamination over time which can lead to flashover, which can pose a serious safety risk to crews and can affect supply to approximately 1,400 customers on average. This cost represents the remaining ICM Period expenditures for a job that was substantially complete prior to 2012. The full cost of the job was $843K, with the remainder captured separately as pre-2012 CWIP coming into service in the ICM Period. (As established in the ICM Application, pre-2012 CWIP contributes to the non-ICM eligibile amounts below the ICM Materiality Threshold).
EST18275_003	E11217 Celeste Drive Rebuild NA47M15	$311,283.11	This project was required to replace the single phase distribution for the Celeste Drive townhome complex. The distribution was built in 1977 with direct buried cables which had failed a number of times in the past. This single phase distribution was established off the supplying feeder through approximately 430 meters of TRXLPE cable. The supplying feeder NA47M14 was the second worst performing feeder in 2010 and continued to be a poor performer.
EST20728_002	E11640-FESI SubmTxmr Replmt NYSS68-F9	$626,026.66	This job was necessary to replace non-standard submersible transformers on feeder NYSS68-F9. This feeder had experienced 10 outages in the previous year and was 26th on the worst performing feeder list. The non-switchable submersible transformers were deemed to be a significant risk to future reliability performance and were replaced in order to reduce restoration time in the event of future failures on this poor performing feeder. This feeder had experienced 730,718 customer minutes interrupted and 7,075 customer interruptions the year prior to job initiation.
EST20473_002	PCI W12293 Finch TS Sub Loop cable Rplmt	$133,665.93	This job was part of mitigation efforts related to a feeder experiencing multiple sustained interruptions. The specific underground direct-buried cable loop that this job addressed had experienced three failures. Toronto Hydro replaced 100m of single phase primary failing cable with new tree-retardant XLPE cable in concrete encased ducts and replaced end-of-life transformers on the loop.
EST22941_003	PCI - E14118 Ugrade Lawrence Pharmacy	$557,344.45	This job addressed a feeder that had experienced an average of four outages per year for 10 years. Toronto Hydro replaced old and failing direct-buried cable on Lawrence Ave. and Pharmacy Ave. with cable in concrete-encased duct. Some sections of the cable were also undersized, which restricted Toronto Hydro's ability to maintain service to customers under contingency situations. Overal, the assets replaced included 150 3-phase 1000 kcmil cable, 150 meters concrete ducts, 2 SCADA pad switches, 2 overhead SCADA switches and 2 poles.
EST24035_003	PCI - E12726 Agincourt Mall Rebuild	$557,166.36	This was an urgent job to repair a leaking transformer and end-of-life switchgear feeding the Agincourt Mall. The work was required to avoid extended service interruptions and potential safety hazards due to catastrophic failure.

ICM Segment **B1 Underground Infrastructure**

Estimate	Description	ISAs	Rationale/Driver for Inclusion
EST22503_001	PCI E11371 FINCHDENE SUBD UG RBLD CIVIL	$5,154,091.29	This job was the civil construction phase to the job "E11401 & E11426 Finchdene UG Electrical Ph1/2 (SC26M31)" which was filed in Segment B1 in the Phase 2 filing as a job intended to commence in 2014. The 2014 job could not have proceeded without the civil portion being complete. The civil job had already started at the time of the Phase 1 filing and its omissions was an oversight. The objective of this job was to proactively replace underground assets on 27.6 kV feeder SCNAR26M31 in order to improve reliability of service and mitigate potential safety risks. As demonstrated in the Phase 2 evidence for the electrical phase, the job area had experienced deteriorating reliability from 2010 through 2012, with a total of 1,847 customer interruptions and 844 customer hours interrupted in that period. The area serves primarily industrial and commercial customers who experienced direct financial consequences as a result of poor reliability. The work performed included replacement of a concrete pad PMH switch and 2.5KM concrete encased ducts.
EST20496_003	PCI W12307 FESI Downsview Dells Rebuild	$67,425.55	This job was necessary to address a section of obsolete underground XLPE cable that had experienced multiple failures and was a source of deteriorating reliability on feeder 55M25. This job replaced 400 meters of cable and two underground transformers.
EST26148_003	PCI E13286 SALINGER SANWIN SUBM. TRANSF.	$589,475.85	This job was necessary to replace two non-standard submersible transformers with switchable transformers. The non-standard transformers were found to be defective during inspections and presented a significant risk of failure. The poor condition and inadequate height of the existing vaults necessitated construction of two new vaults for the replacement transformer units. This in turn required additoinal civil and electric construction related to primary and secondary cabling. This job relates to feeder NYSS68-F9, which was a FESI-10 feeder when the job was initiated and ranked 26th on the worst performing feeder list.
EST18723_002	PCI E11445 - Tineta-Kimroy UG Rebuild	$1,560,413.11	The concerned project area distribution was built in 1969 with direct buried cables which were failing repeatedly. The voltage conversion rebuild project was critical for the improvement of reliability. At the time that the project was issued, the area had experienced 60 customer interruptions and 385 customer hours interrupted in the previous year. The civil installation work performed included 1,269m of new trench and duct and 9 new submersible transformer vaults.
EST20402_003	PCI W12298 FINCH TS STN EGRESS	$2,869,922.47	The scope of work for this project was to replace the critical egress cables from XLPE 1000 kcmil AL to TRXLPE 1000 kcmil Cu on multiple 27.6kV feeders.The job replaced the egress cable of the feeders 55M25, 55M30, 55M28 and 55M3 to improve operational flexibility and mitigate cable de-rating. Failure of egress cables can cause widespread outages at the station level. The egress cable at this stations was direct buried from the station to the first chamber. Toronto Hydro determined that it was vital to replace the direct-buried cable with a new duct structure in order to mitigate the exceptionally high risk of failure should the direct buried cable fail. In total, 18,264m of 1000kcmil feeder cable and 48m of duct was installed.

ICM Segment **B1 Underground Infrastructure**

Estimate	Description	ISAs	Rationale/Driver for Inclusion
EST26751_001EST26064_003	PCI-E13045_Wilfred UG Rebuild_ELECTRICAL	$646,951.63	This underground rebuild job was assigned urgent priorty after repeated cable faults occurred in the area of Gypsy Roseway (Scarborough) in late 2012 and 2013. Planned units based on high level estimates are as follows: 10 poles, 4 underground transformers, 7,500 meters of underground cable, 20 overhead switches and 1355 meters of civil infrastructure.
EST18781_003EST26830_003	E12082 BAYLAWN/ PETWORTH UG REPL. ELECT	$347,406.63	The concerned project area distribution was built in 1971 with direct buried cables which were failing repeatedly. The voltage conversion rebuild project was critical for the improvement of reliability. At the time the job was created, the project area had experienced 228 customer interruptions and 292 customer hours interrupted in the previous year. Non-switchable, submersible transformers and 1/0 vintage XLPE cables were replaced with switchable submersible transformers and new TR-XLPE cables in concrete encased ducts. 1,465m of direct buried primary cable was replaced. In addition, 2 new poles were installed for the riser, each with a single overhead fused switch.
EST26936_002	PCI - W12860 JANE MS EGRESS CIVIL	$796,885.81	To support the urgent and non-discretionary switchgear replacement at Jane MS (completed in 2014), egress cable replacement was required to remove old vintage XLPE cable, which is unreliable and was undersized, and to install standard 500 MCM, 15 kV stranded copper between the circuit breaker and the primary riser pole.This specific job built the civil infrastructure to replace the existing direct buried egress cable of all five feeders out of Jane MS from the circuit breaker to the riser pole. The Jane MS project was required because the non-standard, legacy configuration of the existing bus bars had caused a circuit breaker to fail, with risk of additional failures remaining. The civil infrastructure work performed included: 4 cable chambers, 7 poles and 580m of civil infrastructure.
EST27119_001EST27162_001	E13500 - FESI - 27.6kV Sub TX Replace E13500 - FESI - 4.16 kV Sub TX Replace	$77,440.68	The project replaced eight transformers which were identified to be in poor condition (leaking oil) by the maintenance group and posed high risk for catastrophic failure and long outages. The transformers were on multiple 27.6 kV feeders covered by Ellesmere TS or Scarborough TS.
EST27253_001	PCI W12367 FESI-Lat Cable Repl Jane Ph 2	$855,489.25	This job proactively replaced the underground cable on the laterals of 55M8 to improve reliability and mitigate outages due to underground cable failure. The feeder had experienced multiple cable failures within the job area. These underground loops were affected by nine underground failures between 2010 and 2013. The loops were direct buried and were replaced with cable in concrete-encased ducts. The following assets were installed as part of this job: 1330m duct structure, 10 tap boxes and 1 foundation for padmount transformer.
EST25111_003	PCI E12845 155 Morningside PT171226	$92,381.45	Field inspections determined that the padmount transformer at 155 Morningside was heavily rusted. The base needed to be replaced and the cabinet was beyond repair. The padmount was relocated 8.5m north on customer's property. A new pole was installed to provide a primary service riser and required 99m of TRXLPE-CN-PEJ cable and 3 loadbreak elbows.

ICM Segment **B1 Underground Infrastructure**

Estimate	Description	ISAs	Rationale/Driver for Inclusion
EST29036_002	PCI E11570 Sheppard-Neilson Swgr repl	$442,563.53	This job was requested by system operations to address the high failure risk posed by an obsolete air-insulated PMH switchgear on feeder NT47M3. These switches are vulnerable to contamination leading to faults. This switch connected three feeders and operations was particularly concerned about the risk of flashover that could cause a significant outage on all three feeders. The three-feeder configuration was a non-standard design and could not be replaced with a like-for-like solution. The new design involved two SCADA enabled SF6 PMH-11 switches. At the time the job was originally scoped, feeder NT47M3 had been the worst performing for six consecutive years. The feeder had experienced 22 outages resulting in 47,353 customer interruptions and 1,467,345 customer minutes interrupted in the previous year.

B2 – PAPER INSULATED LEAD COVERED CABLES SEGMENT

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro uses Paper Insulated Lead Covered ("PILC") cables extensively in the downtown core to connect commercial and industrial customers to either 13.8 kV terminal stations or 4.16 kV substations. Historically, Toronto Hydro's normal operating procedure had been to work around energized and leaking PILC cables. Safety considerations led Toronto Hydro to revise its work practices and it now considers leaking PILC cables defective, posing safety hazards to workers and the environment. Leaking PILC cables have a high likelihood of failure, including electrical flashovers that are a significant safety risks to personnel working in the chamber. Leaks occur along the cable itself or on the lead sleeves encapsulating cable splices. Work in this segment included repairing leaking cables that presented significant potential safety and reliability risks. Cables that had deteriorated beyond repair were replaced with a new section running to the adjacent cable chamber. Work in this segment also included remedying unsafe cable chamber congestion by placing and racking cables in such a way that the center of the cable chamber remained clear of cable for safe access.

2. OEB DECISION

The OEB found that the nature of the work in the PILC Piece Outs and Leakers segment, as filed, qualified for ICM treatment.[1] Having found that the work was both necessary and prudent, the OEB made no reduction to Toronto Hydro's funding request.[2] Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto

[1] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p. 25.
[2] Ibid.

Hydro's forecast of approximately $3.4 million of ISAs in 2012 and 2013. Toronto Hydro forecasted an additional $2.1 million in 2014 ISAs related to work proposed in Phase 1 of EB-2012-0064 (i.e., jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the Initial ICM Rate Rider. The OEB also approved an additional $1.4 million in ISAs that Toronto Hydro forecasted in Phase 2 for jobs commencing in 2014, but these were not funded through the Initial ICM Rate Rider or any rate adder.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $2.8 million, which is $4.1 million less than the overall forecasted amounts in this segment and $0.6 million less than the amounts on which the Initial ICM Rate Rider was based. To the extent that the Initial Rate Rider for this segment recovered revenue in excess of the actual three-year revenue requirement, the surplus amount is offset against any additional recoveries for other segments in the ICM True-up Rate Rider calculation.[3]

B. SEGMENT OVERVIEW

Toronto Hydro included this segment in the ICM Application to address the potential safety and reliability risks associated with damaged equipment. With age and load cycling, the lead covering on aged PILC equipment has become cracked and developed multiple oil leaks, which created the risk of electrical contact hazards, faults and arc flashes.

Furthermore, system growth has resulted in the addition of circuits to existing rights of way. Multiple cable chambers have become congested to the extent that safe clearances from energized equipment could no longer be maintained during work. To address this

[3] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.

issue, Toronto Hydro crews extended the length of cables within the chambers by splicing additional cable segments into the existing cables, which allowed for proper racking along the walls of the chamber. This work occasionally required addressing the size and/or structural integrity of the cable chamber itself. Where feasible from the system operation perspective, this work required that all cables in the chamber be de-energized as the splicing and racking took place. This significantly limited the available times of the day and year where such work could be performed without causing extensive customer outages, and underscored the importance of doing the work proactively, rather than on a reactive or emergency basis where extensive customer outages may be unavoidable and reactive labour costs could substantially increase the cost of completing the work.

Toronto Hydro filed 14 discrete jobs to repair and replace PILC cables during the ICM Period, with associated ISAs of approximately $6.9 million. The utility expected these jobs to be completed, partially completed or in progress by the end of the ICM Period.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the variance between forecast ISAs and the actual ISAs over the ICM Period. Toronto Hydro put into service $4.1 million less than forecasted. As described further below, this was largely due to project postponement as a result of limited crew resources due to competing projects deemed higher priority, system operation restrictions that significantly reduced the available intervention opportunities, and delays associated with the involvement of third parties.

Table 1: Forecast vs. Actual In-service Additions

	Forecast ISAs				Actual ISAs				Variance
	2012	2013	2014	Total	2012	2013	2014	Total	Total
ISAs ($M)	0.0	3.3	3.5	**6.9**	-	0.13	2.7	**2.8**	**(4.1)**

Table 2 summarizes the job-level accomplishments for this segment during the ICM Period. Twelve of the 14 filed jobs were completed, partially completed or in progress by the end of 2014. Of the remaining two forecasted jobs, one of the jobs was completed reactively due to equipment failure, resulting in cancellation of the redundant planned work. The remaining job was deferred to 2016 due to resource constraints. Toronto Hydro also initiated the civil phase of one analogous job in this segment. This job remained in progress, with no ISAs, as of the beginning of 2015.

Table 2: 2012-2014 Job-level Accomplishments

Segment Jobs Breakdown	Number of Jobs
Total Forecasted Jobs	**14**
Less: Deferred or Canceled Jobs	(2)
Add: Analogous Jobs	1
Total Segment Jobs	**13**
Less: In Progress Jobs	(8)
Total Jobs with ISAs	**5**
Breakdown of Total Jobs with ISAs	**Number of Jobs**
Completed Jobs	3
Partially Completed Jobs	2
Total Jobs with ISAs	**5**

As anticipated in the ICM Phase 1 Application, Toronto Hydro faced certain constraints when scheduling and executing PILC jobs. These constraints were generally related to feeder availability and difficulty working on the underground system in the city's dense urban core. For example, work needed to be scheduled for evenings or weekends during shoulder seasons, when loading was lower, in order to switch customers onto alternate feeders. Work was subject to postponement when forecast loading conditions did not materialize. Moreover, jobs were affected by Toronto Hydro's prioritization across the work program, where other jobs targeting the same feeders or requiring the crews with the same skillsets (e.g., Copeland TS, stations support, and customer-initiated work) were deemed more urgent.

Toronto Hydro also notes that two "In Progress" jobs were in fact completed by the end of the 2014, but were not recognized as in service by the year-end due to the timing of Toronto Hydro's financial closeout processes.

D. REVIEW OF VARIANCES

All three of the forecasted and completed jobs had minor variances, the largest of which was a job that came in approximately $70,000 lower than the forecast cost. In general, Toronto Hydro expects its final costs to vary to some extent from its high-level estimates, which are based on high-level information and are intended for program budgeting purposes only.

B3 – HANDWELL REPLACEMENT SEGMENT

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro proposed the Handwell Replacement segment to protect the public from the potential safety risk posed by electric shocks from contact voltage. Handwells are electrical junction boxes embedded in sidewalks or other pavement in which the connection is made between the secondary distribution system and street lighting or unmetered scattered loads. Owing to their location, which exposes them to corrosion from salt, water and construction damage, the handwells themselves may become a source of contact voltage and damage to the wires and connections within them may allow other equipment, such as streetlight poles to become energized. Toronto Hydro proposed to replace existing handwells with non-conductive handwells and lids.

2. OEB DECISION

The OEB found that the nature of the work in the Handwell Replacement segment, as filed, qualified for ICM treatment.[1] Having found that the work was both necessary and prudent, the Board made no reductions to Toronto Hydro's funding request.[2] Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an ICM rate rider in the Phase 1 Decisions, which was based on Toronto Hydro's forecasts of approximately $23.8 million of ISAs in 2012 and 2013. Toronto Hydro forecasted an additional $6.5 million in 2014 ISAs related to work proposed in Phase 1 of EB-2012-0064 (i.e., jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the Initial ICM Rate Rider. The OEB also approved an additional $7.2 million in ISAs that Toronto Hydro forecasted in Phase 2 for jobs

[1] EB-2012-0064, Ontario Energy Board, Partial Decision and Order (April 2, 2013) at p. 27.
[2] Ibid.

commencing in 2014, but these were not funded through the Initial ICM Rate Rider or any rate adder.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $36.4 million, which is $1.1 million less than the overall forecasted amount for this segment but $12.6 million more than the amounts on which the Initial ICM Rate Rider was based. Revenue requirement associated with the ISAs that were not sufficiently funded through the Initial ICM Rate Rider for this segment remain to be recovered through the ICM True-Up Rate Rider.[3]

B. SEGMENT OVERVIEW

Handwells are among the top three structures with the highest number of contact voltage hits as assessed by mobile scanning inspections. This poses a potential safety risk of electric shock to the public. Common causes include damage from the elements, as handwells are exposed to harsh environmental conditions, third party damage whenever the sidewalk is rebuilt or repaired, degradation of cable insulation, and substandard installation of connections.

The Handwell Replacement program was originally proposed following the Level III emergency declared in 2009 after members of the public and household pets received shocks from energized equipment. Existing handwells were replaced with new non-conductive handwells and lids.

By the end of 2011, Toronto Hydro had replaced almost 5,600 existing handwells with new, non-conducting composite handwells. In Phase 1 of the ICM Application, Toronto

[3] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.

Hydro proposed to replace approximately 4,665 units in 2012 and 2013. In Phase 2 of the ICM Application, Toronto Hydro proposed an additional 2,500 units for replacement. Toronto Hydro estimated these replacement projects, taken together, would result in replacement of approximately 90% of the total population of handwells.

Toronto Hydro forecasted approximately $37.5 million of in-service additions for this program during the three-year ICM Period.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the variance between the forecast in-service additions and the actual in-service additions during the ICM Period. Toronto Hydro replaced, remediated or abandoned 7,264 handwells with associated in-service amounts of $36.4 million.

Table 1: Forecast In-service Additions vs. Actual In-service Additions

	Forecast ISAs				**Actual ISAs**				**Variance**
	2012	**2013**	**2014**	**Total**	**2012**	**2013**	**2014**	**Total**	**Total**
ISAs ($M)	6.1	17.7	13.7	**37.5**	5.4	16.6	14.4	**36.4**	**(1.1)**

Actual in-service additions were $1.1 million lower than forecasted. The reasons for variance are discussed in the following section.

The small number of jobs that Toronto Hydro filed in this segment were intended as ‘bucket’ estimates to capture high volumes of identical discrete units forecasted for replacement. As a result, this segment is discussed in terms of dollars invested and units, rather than jobs, completed.

D. REVIEW OF VARIANCES

Toronto Hydro addressed a greater number of units than forecasted while spending $1.1 million less than forecasted on an ISAs basis. The primary reason for this variance in unit cost was due to requirements discovered during the detailed design phase that could not have been known until on-site inspections were conducted. For example, at the high-level budgeting phase, Toronto Hydro planners assume that all handwells will require full replacement. However, as explained in Phase 2 of the ICM Application, if the designer discovers that the handwell has been abandoned (i.e., no street lighting assets are connected), Toronto Hydro will remove the handwell instead of implementing the more expensive replacement option.[4] On average, over the 2012-2014 timeframe the handwell removals accounted for about 10% of all handwells addressed through this segment.

Toronto Hydro also discovered a number of additional handwells during field inspections that were not reflected in asset records. In many cases these handwells were in areas under a City road moratorium and could not be replaced in the short-term. In these instances, Toronto Hydro performed a less expensive partial remediation by replacing the internal connections and handwell lids only. For clarity, it is Toronto Hydro's intent to return to the areas where preliminary work took place and complete the remaining elements of replacement work, once necessary intervention activities are again permitted.

[4] EB-2012-0064, Toronto Hydro Electric-System Limited Response to Association of Major Power Consumers in Ontario on Phase 2 (November 22, 2013), Tab 10G, Schedule 2-9.

B4 – OVERHEAD INFRASTRUCTURE SEGMENT

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro proposed the Overhead Infrastructure segment to replace aged, deteriorated and non-standard equipment including wood poles, overhead conductor, Completely Self-Protected ("CSP") transformers, porcelain switches and hardware and open bus secondary lines. This work was necessary to address safety, reliability and system efficiency issues. The aged, poor condition and non-standard equipment addressed in this segment posed safety risks to Toronto Hydro crews and the public, significantly contributed to decreasing reliability in the overhead system and limited Toronto Hydro's ability to operate the system.

2. OEB DECISION

The OEB found that the nature of the work in the Overhead Infrastructure segment, as filed, qualified for ICM treatment.[1] Having found that the work was both necessary and prudent, the OEB made no reduction to Toronto Hydro's funding request.[2] Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto Hydro's forecast of approximately $43.1 million of ISAs in 2012 and 2013. Toronto Hydro forecasted an additional $21.9 million in 2014 ISAs related to work proposed in Phase 1 (i.e., jobs that were forecasted to commence in 2012 or 2013, but not come into service until 2014), but these amounts did not inform the Initial ICM Rate Rider.

As detailed below, Toronto Hydro's actual ISAs in this segment total about

[1] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p.28.
[2] Ibid.

$83.7 million. In addition to the forecasted ISAs of approximately $65.0 million from Phase 1, this total includes:

- approximately $14.8 million in ISAs that Toronto Hydro forecasted in Phase 2 for jobs commencing in 2014, which were approved in the Phase 2 Decision but not funded through the Initial ICM Rate Rider (or any other rate adder); and
- about $4.0 million in additional prudent and non-discretionary ISAs associated with both filed and analogous jobs as described below.

The revenue recovered through the Initial ICM Rate Rider for this segment did not sufficiently cover the revenue requirement of all necessary and prudent work performed as part of this project segment. Revenue requirement associated with the ISAs that were not sufficiently funded through the Initial ICM Rate Rider remain to be recovered through the ICM True-Up Rate Rider.[3]

B. SEGMENT OVERVIEW

The primary drivers for the proposed work in the Overhead Infrastructure segment were safety and reliability. Wood poles in poor condition, CSP transformers and legacy porcelain switches and hardware all presented documented safety hazards to Toronto Hydro crews and the public. These hazards included the risk of falling wood poles, CSP transformers placing workers at risk due to their lacking external fuses and broken porcelain equipment sending shards to the ground.[4]

In terms of reliability, Defective Overhead Equipment accounted for about 15 percent of system-wide System Average Interruption Frequency Index ("SAIFI") and about 14

[3] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.
[4] For further details of these hazards and pictures see EB-2012-0064, Toronto Hydro Electric-System Limited Application (filed May 10, 2012, updated October 31, 2012), Tab 4, Schedule B4 at pp. 1-9.

percent of system wide System Average Interruption Duration Index ("SAIDI") in 2011. "From a SAIFI perspective, overhead outages account for 46 percent, 56 percent and 39 percent of the Defective Equipment-related outages in 2009, 2010 and 2011, respectively. In terms of SAIDI, overhead outages account for 41 percent, 44 percent and 34 percent of the Defective Equipment-related outages for 2008, 2009 and 2010, respectively."[5]

To address these safety and reliability issues, Toronto Hydro undertook area-based jobs that replaced aged and obsolete overhead equipment in locations throughout Toronto. The areas were selected because they contained significant numbers of the equipment types discussed above requiring replacement due to age, condition and obsolescence. Job areas were also selected to facilitate the retirement of obsolete 4 kV substations by rebuilding the areas they served to permit connection to 13.8 or 27.6 kV substations. In each area, Toronto Hydro addressed all of the overhead equipment types requiring replacement at the same time. This approach allowed Toronto Hydro to use its crews and equipment productively by addressing the overhead equipment issues in an area in a coordinated fashion. This approach also minimized job setup time and disruption in the area where the jobs were undertaken.

Toronto Hydro forecasted 112 discrete jobs to address anticipated safety and reliability concerns in this segment during ICM Period. Toronto Hydro expected these jobs to be completed, partially completed or in progress by the end of the ICM Period.

[5] EB-2012-0064, Toronto Hydro Electric-System Limited Application (filed May 10, 2012, updated October 31, 2012), Tab 4, Schedule B4 at p. 13.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the variance between the forecast ISAs and the actual ISAs over the ICM Period. Over the three ICM years, Toronto Hydro completed $83.7 million in ISAs, $4.0 million (or 5%) above the forecast amount for this segment. Higher than forecasted ISAs in this segment were a result of both job-level variances and the addition of several analogous jobs to the work program. These analogous jobs were urgent and necessary to address equipment performance, asset condition, and other considerations described below.

Table 1: Forecast vs. Actual In-service Additions

	Forecast ISAs				Actual ISAs				Variance
	2012	**2013**	**2014**	**Total**	**2012**	**2013**	**2014**	**Total**	**Total**
ISAs ($M)	4.0	39.1	36.7	**79.7**	0.5	33.1	50.2	**83.7**	**4.0**

Table 2, below, summarizes the job-level accomplishments for this segment during the ICM Period. The vast majority of the originally forecasted jobs (107 out of 112, or almost 96%) were completed, partially completed or in progress by the end of 2014. Five jobs in this segment were deferred or cancelled because of resource constraints, including crew availability and switching capacity, or due to their being combined with other related jobs. Cancellation of these jobs provided some of the resources that were used to complete other analogous jobs. As shown in Table 2, Toronto Hydro completed ten analogous jobs in the period.

Table 2: 2012-2014 Job-level Accomplishments

Segment Jobs Breakdown	Number of Jobs
Total Forecasted Jobs	**112**
Less: Deferred or Canceled Jobs	(5)
Add: Analogous Jobs	10
Total Segment Jobs	**117**
Less: In Progress Jobs	(27)
Total Jobs with ISAs	**90**
Breakdown of Total Jobs with ISAs	**Number of Jobs**
Completed Jobs	81
Partially Completed Jobs	9
Total Jobs with ISAs	**90**

Two of the analogous jobs were, in fact, included in the original Phase 1 ICM Application, but were subsequently deferred to Phase 2 of the ICM Application at the time of Toronto Hydro's evidentiary update in October 2012. Despite being deferred to 2014 in the October 2012 forecast, these priority projects were ultimately executed during the Phase 1 timeframe (i.e., 2013) to maximize the utilization of available resources. As such, the funding requirements for these projects (i.e., $1.4 million in ISAs) were not captured in either of the ICM Application phases.

The remaining eight analogous jobs were completed as urgent capital work given the need to execute them quickly, driven by such considerations as the reliability performance of the affected feeders (e.g., projects on the Worst Performing Feeder ("FESI-7") list), voltage conversion of the surrounding electrical areas that necessitated concurrent conversion of the project areas themselves, or identified equipment deficiencies (e.g., irreversible structural damage of the wood poles, insufficient guying, etc.) that posed immediate safety and reliability risks and mandated replacement without delay.

Complete information regarding the investment drivers, scope of work and final costs for all analogous jobs can be found in the Appendix to this Schedule.

D. REVIEW OF VARIANCES

Differences between the cost estimates filed in the ICM Application and the actual costs of the completed jobs were generally due to four variance causes. The vast majority of variances were due to changes that occurred between the high-level estimates filed in the ICM Application and the detailed design work for the job as discussed below in Section 1. Another, less common, reason for variance was changes that emerged during job execution due to field conditions encountered or construction requirements as covered below in Section 2. Certain jobs saw costs changes due to differences between the actual amounts for design, road cuts and other centrally accumulated costs, and the averages used in preparing high-level estimates as explained below in Section 3. Finally, in a few cases variances were due to errors in the high-level estimates or the ICM filing as discussed below in Section 4.

1. HIGH-LEVEL TO DETAILED DESIGN VARIANCE

The estimates that underpinned the ICM filing were largely high-level planning estimates. The most significant driver of job-level variances were changes that occurred as jobs moved from these high-level planning estimate to detailed designs. As the detailed design work was completed on jobs, changes were made to the labour and materials required to execute them. The changes between the high-level estimate and project design usually involved changes in the project scope or the design required by the actual conditions at the project site.

Project scope changes occurred as designers conducted prospective site visits, identifying additional assets in need of replacement based on their condition, physical proximity to and electrical interdependence with the assets within the original scope, and opportunities for prudent reliability improvements through reconfiguration. In a few instances, the scope of a project decreased when some assets were found to be in better condition than anticipated, which led to a decrease in the number of poles and transformers to be replaced. In these cases, the job as originally scoped has not gone over or under cost, but has in fact expanded or retracted to address more or fewer assets in need of replacement, in accordance with the core drivers of work in the segment.

These types of changes are expected as jobs mature. When creating the high-level estimates, engineers rely primarily on existing field patrol and asset condition information and geographical information system data to approximate the number of assets that require replacement in an overhead area and the cost of building the replacement assets. The information that the engineer uses is a snapshot in time and can evolve significantly between the time when the information was originally gathered and detailed job design. Field personnel who inspect the job site prior to design and construction generally perform a more thorough and detailed assessment of pole and other asset condition, and through on-site inspection and testing will often find that greater or fewer assets need to be addressed in coordination with the already planned work. Furthermore, while the engineer is aware of standard design practices and applies them to every feasible extent in the high-level estimate, it is not until the detailed design stage that these standards are fully implemented in the creation of a new overhead plant design. For example, it is not until the point where design and construction personnel have determined the exact location for the new poles that they are then be able to assess specific needs related to the tensile forces placed on the overhead equipment.

Scope changes between the high-level estimate and the design also occurred where planners or designers determined that certain elements of one job would be better addressed as a part of another ICM job, due to work execution efficiency considerations, timing of projects, or additional analysis that was determined to be necessary to address particularly complex asset installations. As these scope transfers occurred between different ICM jobs, they produced variances in the relevant individual jobs, but did not impact the overall segment variance (subject to other potential variance drivers) as a reduction in the cost of one job was typically offset by an equivalent increase in another. Where scope was transferred to jobs coming into service outside the ICM Period, however, the transfer would contribute to the overall ICM segment variance.

2. FIELD CONDITIONS AND EXECUTION REQUIREMENTS

Some variances occurred at the execution stage because of site conditions, operational constraints or other factors. For example, high-level estimates for certain jobs assumed that scheduled customer outages, which require comparatively small amounts of switching work, would be relied upon during execution. In some instances Toronto Hydro revaluated these planned outages for and attempted to reduce customer impacts by instead using more labour-intensive switching arrangements.

Some 2014 jobs had variances that were not in fact variances in the overall job cost but were merely the result of changes in scheduling relative to the estimate filed in the Phase 2 ICM Application. For example, in the financial tables that were used to calculate forecast ISAs for 2014, for jobs that spanned 2014 and 2015, Toronto Hydro only included the portion of the job that was forecast to be spent in 2014. Where a job was eventually rescheduled and completed in its entirety in 2014, the variance shown was the result of the full cost of the job being placed into service during the ICM Period rather than an increase in the job's overall cost.

3. Variance in Allocated Cost

A number of costs are compiled centrally by Toronto Hydro and then attributed to individual jobs at project closeout. Examples include costs for road cut repairs billed by the City of Toronto and centralized costs for design and engineering services. These costs are then attributed to specific jobs based on the cost and nature of the completed work. Variances can occur when the amount of these allocated costs at closeout are greater or less than the average amounts assumed in the high-level estimates.

In a few jobs in the Overhead Infrastructure segment, allocated costs were materially higher than the assumed amounts. Design costs incurred to prepare the final design can vary from averages due to the need for redesign following site visits, or the need for greater design work if the scope of the job expands. Road cut costs associated with pole and riser work can also be higher than the averages used in the high-level estimate depending on actual conditions encountered.

4. Errors

In several instances, variances are attributable to errors in the original estimates or in the ICM Application. Two notable extreme variances were the result of these administrative errors. For example, one estimate shows a job as being millions of percent overspent. Toronto Hydro identified that a clerical error had resulted in the inclusion of a $1 estimate for this job when calculating the forecasted ISAs by segment in the Phase 2 Application.

ICM Segment **B4 Overhead Infrastructure**

Estimate	Description	ISAs	Rationale/Driver for Inclusion
EST17186_003	W10365-RICHVIEW TS 88M1-16 Stdzn	$208,946.91	The scope of work addressed in this project was to install primary fusing on feeders being supplied by Richview TS in Etobicoke. Three of these feeders had very poor reliability and each had over 10 outages each affecting between 6,000 to 22,000 customers. Proper fusing was required to localize the outage to a few customers and reduce patrol time to locate the outage source. Prior to this scope there was a lack of primary fusing to isolate lateral circuits in the event of a fault. Without the additional fusing the interrupting device would be the station breaker causing the entire feeder to experience the fault. The feeders from Richview TS are on average quite large and outages at the breaker can affect thousands of customers. Furthermore, installation of these fuses shortens fault location time and as a result shortens outage duration. This job replaced 71 fuse locations on eight feeders.
EST20956_003	W12463-FESI-Insulator Replacement	$225,127.22	Objective of the project was to replace glass insulators along the route of 80M2, specifically along Bathurst and Cactus.Feeder NY80M2 was a FESI 7 feeder when this scope was issued to replace glass insulators with polymer type. Glass insulators are prone to tracking and flashover when dirty. This is identified as one of the causes of power outages on overhead feeders.
EST24137_002	W12750 Emergency Pole & TX Replacement	$228,674.43	This job was initiated to replace 17 poles that were identified through inspections as suffering from irreversible damage and loss of strength, posing the risk of catastrophic failure. The job also remedied poles that were found to have insufficient guying support and therefore presented a failure risk.
EST20893_003	ICM X12461 O/H Flamborough Drive	$741,161.90	This job was filed in the original Phase 1 filing for 2013 execution but was flagged for deferral to 2014 in the Phase 1 Oct 2012 update. However, the job was ultimately completed in 2013, and was therefore not filed in the Phase 2 2014 application, meaning that it was not included in the overall CAPEX forecast for Segment B4 in 2014. The purpose of this job was to rebuild the existing overhead distribution system in the Flamborough area with standardized equipment. This project was necsssary as outages in this portion of the distribution system were directly attributable to overhead equipment failures and animal contact. The primary overhead distribution plant required rehabilitation in order to address reliability concerns. The following work was performed: 49 poles, 9 switches, 819m cable, and 5 transformers.
EST25755_003	PCI W12902 - POLE REPLACEMENT	$204,538.96	This job was initiated to replace 12 poles that were identified as suffering from irreversible damage and loss of strength, which posed a risk of collapsing and other safety risks. Replacement of these poles was necessary for maintaining reliable service.

ICM Segment **B4 Overhead Infrastructure**

Estimate	Description	ISAs	Rationale/Driver for Inclusion
EST26827_002	ICM W12992 FESI - Lomar Dr OH Reb 55M-25	$610,633.03	This job was identified as deferred to 2014 in the Phase 1 ICM filing update (October 2012). However, the job was ultimately completed in 2013 and therefore did not appear in the total CAPEX amounts filed in the Phase 2 ICM filing for 2014. Therefore, this job, while appearing in the original filing, did not form part of the funding request. The purpose of this job was to rebuild sections of the distribution feeder 55M25 in the Lomar area. The primary overhead distribution plant on 55M25 required short-term targeted rehabilitation in order to address reliability concerns. 55M25 experienced nine sustained interruptions in 2011.
EST26014_004	ICM W12921 CAUTION POLE SPOT REPLACEMENT	$101,995.46	This project was initiated to replace 3 poles that were identified as suffering from irreversible damage and loss of strength, which posed a risk of collapsing and other safety risks. Replacement of these poles were necessary for maintaining reliable service.
EST28229_001	PCI-E13479 P03 Batch Pole Replacement	$168,708.99	This project was initiated to replace 18 poles that were identified as suffering from irreversible damage and loss of strength, which posed a risk of collapsing and other safety risks. Replacement of these poles were necessary for maintaining reliable service.
EST27986_002	ICM E14547 OWEN BLVD OH RBLD	$344,045.64	This additional work was identified and proposed by field crew after construction of E12227 has started. The additional work would improve the switching and restoration flexibility of the distribution in the event of outage in the future. Since work was already taking place in the area and poles in the additional proposed work area were also in poor condition, it was determined that it would be prudent to do the additional work to minimize disruption to the residents and maximize resource efficiency. Work involved replacement of: - 22 poles; - 4 OH transformers; - 660m 3 phase 3/0 27.6kV OH line; and - 8 single phase disconnect switches.
EST27665_002	PCI E13633-Switch Automation SCNAH9M30	$298,300.46	An investigation following prolonged outages on feeder H9M30 in December 2012 revealed deficiencies with respect to feeder switching capabilities. To mitigate the short-term risk of additional prolonged outages on this part of the overhead system, Toronto Hydro elected to install three fully automated SCADA-Mate switches.

B5 – BOX CONSTRUCTION SEGMENT

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro proposed the Box Construction segment to proactively replace an obsolete type of 4 kV overhead feeder design with 13.8 kV feeders built to contemporary design specifications. A majority of the box construction assets identified for replacement were beyond end-of-life and could support less than a third of a standard 13.8 kV feeder's loading capacity, constraining the utility's ability to accommodate concentrated load growth in areas with significant new developments. Furthermore, the configuration of box construction feeders, whereby a number of circuits were located within a concentrated space, created a potential safety hazard for crews working on the assets, limited bucket truck access and limited the utility's ability to maintain clearance standards from nearby buildings. Finally, circuits with box construction configuration have generally experienced worse reliability and do not support the use of automated switches, necessitating manual switching efforts and further complicating system operation and outage restoration efforts.

2. BOARD DECISION

The OEB found that the nature of the work in the Box Construction segment, as filed, qualified for ICM treatment.[1] Having found that the work was both necessary and prudent, the OEB made no reduction to Toronto Hydro's funding request.[2] Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto Hydro's forecast of approximately $14.6 million of ISAs in 2012 and 2013. Toronto

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[1] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p.29.
[2] Ibid.

Hydro forecasted an additional $9.0 million in 2014 ISAs related to work proposed in Phase 1 (i.e., jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the Initial ICM Rate Rider. The OEB also approved an additional $5.7 million in ISAs that Toronto Hydro forecasted in Phase 2 for jobs commencing in 2014, but these were not funded through the Initial ICM Rate Rider or any rate adder.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $23.0 million, which is $6.4 million less than the overall forecasted amounts in this segment but $8.4 million more than the amounts on which the Initial ICM Rate Rider was based. Revenue requirement associated with the ISAs that were not sufficiently funded through the Initial ICM Rate Rider remain to be recovered through the ICM True-Up Rate Rider.[3]

B. SEGMENT OVERVIEW

The primary driver for the proposed work in the Box Construction segment was safety. The high concentration of multiple circuits in the legacy box construction design presented three potential safety risk to field crews. Firstly, some circuits were inaccessible with bucket trucks due to the physical arrangement of the feeders running through a single box pole, which forced line crews to climb the poles. Secondly, the position and configuration of box construction equipment created situations where field crews would have difficulty conforming to the electrical clearance standards requiring a 15 cm gap between people/tools and energized conductors as defined in the Electrical Utility Safety Rules ("EUSR"). Lastly, box construction feeders utilized certain obsolete equipment that was installed prior to the adoption of current safe work practices, such as the 'Positect' switches that were operable by hand, and consequently exposed field crews

[3] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.

to the flash zone of the switch.

A secondary driver for the segment was reliability. Box construction infrastructure, which was predominantly constructed in the 1950s and 1960s, included a significant number of assets that were either approaching or had already passed the end of their useful lives, thereby increasing the likelihood of outages driven by asset failure. Moreover, in addition to safety concerns addressed above, the manually operated switching equipment installed on the box construction feeders prolonged restoration timelines. In general, 4 kV box construction feeders had historically demonstrated worse reliability compared to standard 13.8 kV overhead feeders.

The jobs selected for conversion over the ICM Period were a part of the utility's longer-term plan to convert all box construction feeders to standard 13.8 kV configuration. Toronto Hydro forecasted 22 discrete jobs to convert legacy 4 kV box construction feeders to standard 13.8 kV overhead feeders to address anticipated reliability, safety and operational efficiency concerns in the segment during the ICM Period. Toronto Hydro anticipated that these jobs would be completed, partially completed or in progress by the end of the ICM Period.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the variance between the forecast ISAs and the actual ISAs in this segment over the ICM Period. Toronto Hydro placed into service $6.4 million less than forecast. ISAs in 2012 and 2013 were lower than forecasted, partially offset by higher than forecasted additions in 2014. Segment variance is a function of both job-specific variances and broader factors that affected Toronto Hydro's work program, including timing adjustments driven by external factors, such as dependency on the timing of upstream capital projects undertaken by Hydro One Networks Inc. ("HONI").

Table 1: Forecast In-service Additions vs. Actual In-service Additions

	Forecast ISAs				Actual ISAs				Variance
	2012	2013	2014	Total	2012	2013	2014	Total	Total
ISAs ($M)	0.3	14.4	14.7	**29.3**	0.1	5.7	17.2	**23.0**	**(6.4)**

Table 2 summarizes the job-level accomplishments for this segment during the ICM Period. Of the 22 originally forecasted jobs, 18 were completed or in progress by the end of 2014. Toronto Hydro deferred three forecasted jobs in order to align with the anticipated timing of upstream HONI projects. A fourth job was cancelled following efforts to address scheduling conflicts and streamline the overall conversion and station decommissioning efforts in the Junction MS area.

Toronto Hydro made investments in six analogous jobs that were identified as critical during the course of the ICM Period. Four of these additional jobs were completed in the ICM Period, with the remaining two being in progress as of the end of 2014.

Toronto Hydro's decision to include the analogous jobs was driven by safety and reliability concerns associated with equipment age and condition, along with deteriorating performance of the affected feeders and system efficiency considerations associated with other planned and ongoing work in the vicinity of project areas.

Complete information regarding the investment drivers, scope of work and final costs for all analogous jobs can be found in the Appendix to this Schedule.

Table 2: Job-level Accomplishments

Segment Jobs Breakdown	Number of Jobs
Total Forecasted Jobs	**22**
Less: Deferred or Cancelled Jobs	(4)
Add: Analogous Jobs	6
Total Segment Jobs	**24**
Less: In Progress Jobs	(8)
Total Jobs with ISAs	**16**
Breakdown of Total Jobs with ISAs	**Number of Jobs**
Completed Jobs	11
Partially Completed Jobs	5
Total Jobs with ISAs	**16**

D. REVIEW OF VARIANCES

Differences between the cost estimates filed in the ICM Application and the actual costs of the completed jobs were generally due to three variance causes. The most common reasons for variance were changes between the high-level estimates filed in the ICM Application and the detailed design work for the job as discussed in Section 1 below, and changes that emerged during job execution due to field conditions and execution requirements discussed in Section 2. One job had a variance caused by an error in the estimate as discussed in Section 3.

1. HIGH-LEVEL TO DETAILED DESIGN VARIANCE

The estimates underlying the ICM filing materials were primarily high-level planning estimates. As jobs advanced from the high-level design stage towards more detailed design work that better reflected site-specific considerations, changes were made to the labour and materials required to complete the underlying work. These changes were largely dictated by the actual conditions and equipment configurations at the project site, or amendments to the scope of the project, driven by efficiency considerations or further findings in the field.

Occasionally Toronto Hydro had the opportunity to increase efficiency by completing the second phase of work in a job area ahead of schedule and in coordination with the ongoing first phase. In certain instances the original high-level estimate filed in the ICM Application only included the cost of phase one of the project, with phase two, driven by the same considerations, forecasted for completion after 2014. However, leveraging available resources and suitable work conditions to advance the second phase of the job facilitated service improvements in the adjacent areas, increased system operation efficiency, and reduced disruption in the general area by avoiding the need to return at a later date to complete phase two. Given that more assets were replaced than originally forecasted, this variance does not reflect a cost overrun, but is instead a function of completing more work.

Other variances in this category were a function of the need for additional infrastructure that was discovered during the detailed design stage and the use of external contractors versus internal crews to complete the job. Unlike the internal construction cost estimates that are based on unburdened work execution rates, the contractor costs charged to the projects are fully-burdened, as they are intended to recover all costs incurred by the third-party contractor, including the administrative overhead costs, costs of contractor vehicles and equipment and other related drivers, which are typically accounted for separately at

Toronto Hydro (e.g., through OM&A costs).[4] In a similar manner, cost variances between projects assumed to be constructed "in house", which are delivered by third-party contractors also attract the incremental costs of mandatory construction audit performed by an independent assessor, which cannot be reliably predicted at the high-level scope estimation.

2. FIELD CONDITIONS AND EXECUTION REQUIREMENTS

Some variances occurred at the execution stage because site conditions, operational constraints or other factors caused costs to change during construction. In one such instance, the aftermath of the 2013 winter ice storm increased workload for system operators, which led to longer than expected execution times and higher labour costs associated with delays in obtaining hold-offs from the control centre (i.e., permission to proceed with work on safely de-energized assets).

In some instances, unforeseen site-specific considerations within the vicinity of a project caused significant cost variances. This included situations in which a designer or construction supervisor identified the need to hire paid-duty police officers to manage the traffic around a work site. Increased labour costs also occurred in relation to assets that were located on a narrow street or in close proximity to Toronto Transit Commission tracks and overhead lines. Completing the requisite work safely and efficiently under these conditions sometimes required additional time and effort on the part of field crews.

3. ERRORS

One variance was due to work that was inadvertently omitted from the original estimate, which led to underestimated costs.

[4] The issue of cost comparisons between Toronto Hydro's internal and 3rd party construction costs was explored in depth during the 2015-2019 CIR Application (EB-2014-0116). For an adjusted "like-for-like" comparison of contractor costs to fully-burdened internal Toronto Hydro cost please see Interrogatory Response 2B-CUPE-02.

ICM Segment **B5 Box Construction**

Estimate	Description	Actual ISA	Rationale/Driver for Inclusion
EST16466_005	W10246_EGLINTON MS 4KV OH STAGE#2 PH#1	$230,417.55	The 4 kV box construction feeders associated with Eglinton MS were prioritized for conversion in order to facilitate the timely decommissioning of the station, which was approaching end-of-life. Both feeders were beyond end-of-life and were of box construction. The station assets were over 60 years old. The work performed included the following: replacement of 125 poles, 39 overhead transformers, and 12 primary switches. The costs incurred during the ICM period represent a small remaining portion of a larger job that was substantially complete prior to 2012. The total cost of the job was $2.62M. Amounts that were invested prior to 2012 had already been placed into service and are therefore omitted from pre-2012 CWIP coming into service during the ICM period.
EST16470_003	W10247 Eglinton MS VC Stage 2 B71EG	$77,606.37	The 4 kV box construction feeders associated with Eglinton MS were prioritized for conversion in order to facilitate the timely decommissioning of the station, which was approaching end-of-life. Both feeders were beyond end-of-life and were of box construction. The station assets were over 60 years old. The following work was performed: 93 wood poles, 57 concrete poles, 45 overhead transformers, 14,374m overhead primary conductor and 24 overhead switches. The costs incurred during the ICM period represent a small remaining portion of a larger job that was substantially complete prior to 2012. The total cost of the job was $2.60M. The majority of amounts that were invested prior to 2012 had already been placed into service and are therefore omitted from pre-2012 CWIP coming into service during the ICM period. Approximately $64,000 of pre-2012 spending did not come into srevice prior to 2012 and is therefore captured as pre-2012 CWIP coming into service in the ICM period.
EST20027_001EST19157_003	X12056 B2CD VC ADVANCE POLE INSTALL	$1,257,783.75	It was determined that the outdated box construction needed to be replaced with 13.8KV feeders as it would improve safety, reliability and system efficiency. The job was a high-priority box construction conversion project that was necessary to improve reliability and avoid future maintenance costs associated with College MS, which was nearing decommissioning. This replacement enabled the conversion of the feeder allowing obsolete assets to be removed from the system. The following assets were addressed: 175 poles, 689 km of overhead conductors, 49 overhead transformers, 25 overhead switches, and 1 gang operated switch. The costs incurred during the ICM period represent the remaining portion of a larger job that was partially complete prior to 2012. The total cost of the job was about $3M. $1.2M of the pre-2012 expenditures are recognized as pre-2012 CWIP coming into service in the ICM period. Remaining amounts had already been placed into service prior to 2012.
EST19412_002	PCI- X11513 B3DA Conversion	$287,840.58	As described in the original pre-filed evidence, prudent investment in conversion of the existing Box Construction system involves converting 4 kV feeders in a planned and staged manner in order to facilitate decommissioning of existing 4 kV municipal stations in time to avoid future maintenance and refurbishment costs. This job was required to convert a small amount of remaining customer load supplied by feeder B3DA to allow for timely decommisioning of the associated station.
EST30261_002	111 BATHURST ST.(O/H CONVERSION) WBS-CCM RC4330 CAPEX for IFRS	$0.00	In Progress

ICM Segment **B5 Box Construction**

Estimate	Description	Actual ISA	Rationale/Driver for Inclusion
EST27656_003	X13173 conversion B1-2W	$0.00	In Progress

B6 – REAR LOT CONSTRUCTION SEGMENT

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro proposed the Rear Lot Construction segment to address the critical need to move distribution service currently located in customers' backyards to the street, for reasons of safety, reliability and cost. This work involved constructing front lot underground service to current standards, connecting customers to it, and removing the electrical distribution equipment located in the rear lots. Toronto Hydro prioritized the replacement of rear lot equipment because of its age, condition and the difficulty and cost of accessing it for repairs, which leads to longer outages for customers and higher repair costs. Typical outage restoration times for rear lot plant outages are more than twice those of front lot outages.

2. OEB DECISION

The OEB found that the nature of the work in the Rear Lot Construction segment, as filed, qualified for ICM treatment.[1] Having found that the work was both necessary and prudent, the OEB made no reduction to Toronto Hydro's funding request.[2] Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto Hydro's forecast of approximately $34.3 million of ISAs in 2012 and 2013. Toronto Hydro forecasted an additional $11.5 million in 2014 ISAs related to work proposed in Phase 1 (i.e., jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the Initial ICM Rate Rider.

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[1] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p.30.
[2] Ibid.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $58.0 million. In addition to the forecasted ISAs of $45.8 million from Phase 1, this amount includes:

- $5.0 million in ISAs that Toronto Hydro forecasted in Phase 2 for jobs commencing in 2014, which were approved in the Phase 2 Decision but not funded through the Initial ICM Rate Rider (or any other rate adder); and
- about $7.2 million in additional prudent and non-discretionary ISAs associated with both forecasted and analogous jobs as described in the sections below.

The revenue recovered through the Initial ICM Rate Rider for this segment did not sufficiently cover the revenue requirement of all necessary and prudent work performed as part of this project segment. The revenue requirement associated with the ISAs that were not sufficiently funded through the Initial ICM Rate Rider remains to be recovered through the ICM True-Up Rate Rider.[3]

B. SEGMENT OVERVIEW

Safety and reliability were the primary drivers for the proposed work in the Rear Lot Construction segment. Many rear lot distribution assets are past their useful service lives, in poor condition and surrounded by heavy vegetation that is difficult and costly to manage.[4] Occasionally, Toronto Hydro crews must perform work on rear lot poles that have rotted at the base. These poles can be unstable and may impose safety risks. Securing these poles to the extent possible prior to beginning restoration work can extend outage durations. Furthermore, access to rear lot poles is typically limited, which precludes the use of mechanical equipment to make repairs, requiring crews to carry

[3] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.
[4] For further details of these hazards and pictures see EB-2012-0064, Toronto Hydro Electric-System Limited Application (filed May 10, 2012, updated October 31, 2012), Tab 4, Schedule B6 at pp. 16-28.

replacement poles, transformers and conductor into the rear lot, all of which increases safety risks, extends restoration time and leads to higher repair costs.

Energized conductors and poles with associated equipment are often in close proximity to residential structures and backyard activities, imposing potential safety risks to the public. These risks have worsened over time, as customers have constructed pools, sheds and other structures near the legacy distribution infrastructure.

To address these safety and reliability issues, Toronto Hydro proposed replacing the existing rear lot plant with new standard underground plant at the street. Toronto Hydro forecasted 31 discrete jobs to accomplish the work in this segment during the ICM Period. These jobs were expected to be completed, partially completed or in progress by the end of the ICM Period.

C. 2012-2014 ACCOMPLISHMENTS

Table 1, below, summarizes the variance between the forecast ISAs and the actual ISAs over the ICM Period. Toronto Hydro put into service $7.2 million more than forecasted. While ISAs in 2012 were lower than forecasted, higher than forecast additions in both 2013 and 2014 produced the additional in-service amount. Higher than forecast ISAs in this segment are the result of both job-level variances and the addition of two analogous jobs that Toronto Hydro determined to be necessary in light of the equipment's performance, condition, and other considerations described below.

Table 1: Forecast vs. Actual Segment In-service Additions

	Forecast				Actuals				Variance
	2012	2013	2014	Total	2012	2013	2014	Total	Total
ISAs ($M)	7.3	27.0	16.5	**50.8**	3.0	28.6	26.4	**58.0**	**7.2**

Table 2 summarizes the job-level accomplishments for this segment during the ICM Period. All but one of the forecasted jobs in this segment were completed, partially completed or in progress by the end of 2014, with 26 jobs fully attained. One job was deferred to 2015 in order to better utilize available resources.

Table 2: 2012-2014 Job-level Accomplishments

Segment Jobs Breakdown	Number of Jobs
Total Forecasted Jobs	**31**
Less: Deferred or Cancelled Jobs	(1)
Add: Analogous Jobs	2
Total Segment Jobs	**32**
Less: In Progress Jobs	(3)
Total Jobs with ISAs	**29**
Breakdown of Total Jobs with ISAs	**Number of Jobs**
Completed Jobs	28
Partially Completed Jobs	1
Total Jobs with ISAs	**29**

The primary consideration driving Toronto Hydro’s decision to complete the two analogous jobs was the urgent need to convert rear lot customers that were supplied from three aging and obsolete 4 kV stations. Toronto Hydro prioritized these stations for decommissioning in order to avoid anticipated maintenance and refurbishment costs. Conversion of the rear lot load addressed by these two jobs enabled decommissioning by ensuring that the stations would have enough spare capacity to avoid lengthy outages during contingency situations. These jobs addressed aging and obsolete rear lot plant and were therefore categorically identical to other jobs in the Rear Lot Construction segment.

Complete information regarding the investment drivers, scope of work and final costs for all analogous jobs can be found in the Appendix to this Schedule.

D. REVIEW OF VARIANCES

Of the 26 forecasted and competed jobs in the Rear Lot Construction segment, 11 had negative variances while the remainder had positive variances. Three types of variance causes explain the cost differences between the estimates filed in the ICM filing and the actual cost of the completed jobs for those jobs with significant differences. Nearly all variances were due to changes that occurred between the high-level estimates filed in the ICM filing and the detailed design work for the job as discussed in Section 1 below. In one instance, a job changed because of requirements or constraints imposed by City of Toronto, as described in Section 2. Finally, in one case a variance was due to an error in the ICM filing as discussed in Section 3.

1. High-level to Detailed Design Variance

The estimates that underpinned the ICM filing were largely high-level planning estimates. The most significant driver of job-level variances were changes that occurred as jobs moved from these high-level planning estimates to detailed designs. As the detailed design work was completed on jobs, changes were made to the labour and materials required to execute them. The changes between the high-level estimate and project design usually involved changes in the design configuration required by the actual conditions at the project site or project scope. Project scope changes occurred as designers conducted prospective site visits, identifying that additional assets or fewer assets were required to execute the job based on asset condition and configuration.

A number of rear lot areas included a small number of front lot customers supplied from the same 4 kV lateral supplies that were the subject of rear lot conversion. Since rear lot conversion involves converting the lateral to a higher voltage – typically 27.6 kV – Toronto Hydro included work in the forecasted rear lot jobs to convert these front lot service customers in coordination with the implementation of the broader rear lot plan. These jobs were necessary in order to continue supplying the existing front lot customers without inefficiently maintaining a separate 4 kV lateral and/or a 4 kV under-build circuit along the 27.6 kV trunk circuit. Several of these smaller jobs addressing front-lot customers experienced significant scope changes as they moved through the detailed design stage. For example, jobs that the high-level plan assumed would address only the primary electrical equipment were necessarily revised to include direct-buried secondary services that were found to be in poor condition.

These are not cases of cost increasing to complete the work within the original scope; rather the job was expanded to address significantly more assets in need of replacement and in accordance with the reliability driver for this segment. The movement from high-level estimates to job-specific designs also produced scope changes that resulted in the reduction of project costs, such as where the originally targeted assets were found to be in an adequate condition upon further inspection. This occurred in another job that did in fact anticipate the need to replace secondary services to a small, front-lot supplied townhome complex. The secondary services were found to be in good condition and remained in service.

Other changes occurred as the designer implemented a more efficient design configuration than that anticipated by the engineer during the less detailed high-level estimating phase. For example, in one instance instead of routing a main trunk circuit through two streets, the designer was able to route the circuit exclusively along a single street and was able to supply some of the new lateral loops from existing nearby overhead poles. This reduced the number of padmounted switches required and removed a significant amount of the originally anticipated main loop construction.

Changes between the high-level estimate and the design also occurred where planners or designers determined that certain elements of one job would be better addressed as a part of another ICM job, due to work execution efficiency considerations, timing of projects, or additional analysis that was determined to be necessary to address particularly complex asset installations. For example, in one phased job all of the rear lot equipment removal work was transferred to the final phase to improve execution efficiency. When these scope transfers occurred between different ICM jobs, they produced variances in both the relevant individual jobs, but may not have impacted the overall segment variance (subject to other potential variance drivers) as a reduction in the cost of one job was typically offset by an equivalent increase in another during the ICM Period. Where scope was transferred to jobs coming into service outside the ICM Period, however, the transfer does contribute to the overall ICM segment variance.

2. THIRD PARTY REQUIREMENTS AND CONSTRAINTS

Toronto Hydro’s work often must be coordinated with Hydro One and other utilities. This coordination imposes additional costs as jobs schedules are impacted by the work schedules of other entities. Similarly, Toronto Hydro’s ability to work in road ways and on customer premises is often constrained by the City’s or customers’ requirements. Work on one rear lot project was accelerated during the ICM Period so that the project could be completed before the City undertook unforeseen road repairs in the same area.

The City had indicated that once the road work was complete, a road cut moratorium until 2018 would be instituted. As the condition of the assets did not permit waiting until 2018 to replace them, the project was accelerated to complete it before the City started work.

3. ERRORS

A clerical error led to one forecasted job being included in the ICM filing with a cost estimate that was significantly higher than the actual estimated job cost.

ICM Segment B6 Rear Lot Construction

Estimate	Description	Actual ISA	Rationale/Driver for Inclusion
EST23111_003	E11778 BANBURY / LARKFIELD RL PH.2	$260,044.86	After an irreparable failure inside the Lesmill M.S., the customers were transferred to supply by the following neighbouring stations: Northdale, Winfield and Don Mills West. This project was needed to convert aged and unreliable overhead rear lot distribution to the underground front yard distribution. The following assets were installed: 8 fused switches, 1 overhead transformer, 15 padmount transformers (single phase), 1 padmount transformer (three phase), 2846m of underground conductor cable (single phase) and 681m of underground conductor cable (three phase). This job has an additional $1.9M in spending that was completed prior to 2012 and is included in pre-2012 CWIP amounts coming into service in 2012-2014.
EST18240_003	E12437 LesMill MS F2 Rear Lot V. C.-Elec	$1,367,634.45	After an irreparable failure inside Lesmill MS in the mid 2000s, the customers were transferred to the neighboring municipal stations: Northdale, Winfield and Don Mills West. Due to age and condition these stations are now in the process of planned conversion and decommissioning. The added load from Lesmill MS limited the ability to decommission these stations without raising the risk of lengthy outages during contingency situations. Therefore, to prudently decommission the obsolete stations, it was necessary to convert the Lesmill MS 4 kV rear lot distribution to front lot, 27.6 kV distribution on a priority basis.

B9 – NETWORK VAULTS AND ROOFS

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro proposed the Network Vaults and Roofs segment to address critical structural issues that posed potential safety risks to the public and Toronto Hydro workers and reliability risks to the distribution system. Network vaults on the secondary network system were constructed in the 1950s and 1960s, mainly beneath the sidewalks in the busy downtown core of Toronto. Toronto Hydro proposed to rebuild vaults and/or vault roofs or decommission vaults that were in “poor” or “very poor” condition during the ICM Period.

2. OEB DECISION

The OEB found that the nature of the work in the Network Vaults and Roofs segment, as filed, qualified for ICM treatment.[1] Having found that the work was both necessary and prudent, the OEB made no reduction to Toronto Hydro’s funding request.[2] Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto Hydro’s forecast of approximately $14.3 million of ISAs in 2012 and 2013. Toronto Hydro forecasted an additional $7.3 million in 2014 ISAs related to work proposed in Phase 1 of EB-2012-0064 (i.e., jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the Initial ICM Rate Rider. The OEB also approved an additional $0.9 million in ISAs that Toronto Hydro forecasted in Phase 2 for jobs commencing in 2014, but these were not funded through the Initial ICM Rate Rider or any rate rider at all.

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[1] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p.33.
[2] Ibid.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $17.3 million, which is $5.2 million less than the overall forecast amounts in this segment but $3.0 million more than the amounts on which the Initial ICM Rate Rider was based. Revenue requirement associated with the ISAs that were not sufficiently funded through the Initial ICM Rate Rider for this segment remain to be recovered through the ICM True-Up Rate Rider.[3]

B. SEGMENT OVERVIEW

The primary driver for the proposed work in the Network Vaults and Roofs segment was safety. The condition of the vaults exposed crews to potential safety risks from falling concrete and debris, and exposed the public to potential tripping hazards where vault roofs collapsed leaving sidewalks uneven or sunken.

The secondary driver for the proposed work in the Network Vaults and Roofs segment was reliability. Leaks and falling debris in vaults and roofs directly and indirectly contributed to damage to vault equipment resulting in reliability risks, including the risk of catastrophic failures from vault fires.

Of the 1,064 vaults that were in service at the time of the ICM Application, 60% of vaults would be past their useful life of 60 years by 2022. Toronto Hydro proposed to repair or replace 50 vaults that were in "poor" or "very poor" condition. The vast majority of these vaults had reached or were approaching the end of their useful lives.

Toronto Hydro proposed to undertake the following activities:

- Roof rebuild (15 vaults): install a temporary false room to protect the

[3] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.

distribution assets, remove asbestos, install new primary and secondary cable, rebuild the vault roof and the adjoining sidewalk.

- Vault rebuild (27): inspect and test contingency equipment in adjacent vaults, rebuild civil infrastructure in same location or decommission and construct in new location, install new network units (transformer and protector) and cables, repair the adjoining sidewalk.
- Vault decommissioning (8): remove all distribution assets, backfill space with gravel and rebuild adjoining sidewalk.

Toronto Hydro filed 19 discrete jobs to address 50 vaults in "poor" or "very poor" condition. Each of the 19 filed jobs was forecast to be complete, partially complete, or in progress by the end of 2014, with estimated ISAs of $22.5 million over the ICM Period.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the variance between the forecast ISAs and the actual ISAs over the ICM Period. Actual ISAs were $5.2 million less than the forecast amount, and almost all ISAs occurred in 2013. Job-level variances for this segment are further explained in the section below.

Table 1: Forecast vs. Actual In-service Additions

	Forecast ISAs				Actual ISAs				Variance
	2012	**2013**	**2014**	**Total**	**2012**	**2013**	**2014**	**Total**	**Total**
ISAs ($M)	1.3	13.0	7.3	**22.5**	0.1	14.7	2.4	**17.3**	**(5.2)**

Table 2 summarizes the job-level accomplishments for this segment during the ICM Period. Of the originally forecasted jobs, 11 are complete or partially complete (i.e., partially in service). Toronto Hydro deferred nine forecasted jobs to 2015 and 2016. One of the nine deferred jobs was rescheduled for the 2015-2019 period in order to better address complex design requirements, while the remainder were deferred largely in order to enable the attainment of other analogous jobs that were identified as more critical during the course of the ICM Period. As shown in Table 2, Toronto Hydro added nine of these priority jobs, all of which were completed in the period.

One forecasted job was cancelled as Toronto Hydro clarified that the required vault rebuild would be the customer's responsibility.

Table 2: 2012-2014 Job-level Accomplishments

Segment Jobs Breakdown	Number of Jobs
Total Forecasted Jobs	**29**
Less: Deferred or Canceled Jobs	(10)
Add: Analogous Jobs	9
Total Segment Jobs	**28**
Less: In Progress Jobs	(4)
Total Jobs with ISAs	**24**
Breakdown of Total Jobs with ISAs	**Number of Jobs**
Completed Jobs	23
Partially Completed Jobs	1
Total Jobs with ISAs	**24**

Toronto Hydro completed the nine analogous jobs in this segment for two primary reasons:

- the vaults or vault roofs had deteriorated to the point that they posed immediate potential safety and reliability risks; or

- the vault experienced a fire from failed electrical equipment, which in turn triggered the need to undertake a planned rebuild in the near-term.

Generally, network vaults are highly sensitive to the level of vehicle and foot traffic experienced in a given location as well as site-specific environmental conditions (e.g., the amount of salt used in that location during the winter). For this reason, all of Toronto Hydro's network vaults are inspected and/or maintained multiple times per year. These inspections can sometimes reveal the rapid deterioration of a vault over a relatively short period, causing that vault location to be prioritized for intervention over other planned vault rebuilds.

Complete information regarding the investment drivers, scope of work and final costs for all analogous jobs can be found in the Appendix to this Schedule.

D. REVIEW OF VARIANCES

A majority of forecasted and completed jobs in the Network Vaults and Roofs segment had only minor cost variances. For larger variances, two types of variance causes explain the cost differences between the estimates filed in the ICM Application and the actual cost of the completed jobs. Most of these variances are due to changes that occurred between the high level estimates filed in the ICM Application and the detailed design work for the job, as discussed in Section 1 below. In one case a significant variance was due to an error in the ICM filing as discussed in Section 2.

1. HIGH LEVEL TO DETAILED DESIGN VARIANCE

The estimates that underpinned the ICM filing were largely high level planning estimates. Changes that occurred as jobs moved from high level planning estimates to detailed designs were the most significant driver of job-level variances. As the detailed design work was completed on jobs, changes were made to the labour and materials required to execute them. The changes between the high level estimate and project design usually involved changes in the design configuration required by the actual conditions at the project site or changes in project scope.

In some instances, changes in design or project scope occurred where designers or construction supervisors performed on-site inspections of vaults and vault roofs and determined that more assets or less assets were required to execute the job based on the condition or configuration in the system of the vault or vault roof. In certain cases, scope changes resulted in lower than forecasted project costs, such as when the site inspections revealed that certain assets slated for replacement were in better condition than originally anticipated and did not require replacement (e.g., the electrical equipment within the vault), or configured in such a manner that the job could not be completed in its entirety.

For example, the filed estimate may have anticipated special provisions for securing and protecting an adjacent customer-owned building during the vault roof rebuild. However, during construction it was determined that the adjacent building did not require any extensive reinforcement.

2. ERRORS

The only notable positive variance in this segment was attributable to a clerical error in the ICM filing which caused an incorrect estimate version to be filed.

ICM Segment **B9 Network Vaults and Roofs**

Estimate	Description	ISAs	Rationale/Driver for Inclusion
EST18912_003	X11390 Vault Loc 4407 Rebd-Yonge-Delisle	$690,908.82	Field inspection of this 60 year old vault revealed concrete spalling on the walls. The vault also contained a 40 year old network unit with fibretop protector, an asset type with a high risk of catastrophic failure resulting in vault fires. Due to the high risk of failure, the vault and network unit were prioritized for replacement.
EST24715_003	PCI-X11581.V.#4588.Cumberland & Bellair	$163,383.29	Field inspections identified potential safety and structural issues with the network vault. The roof and wall were cracked and the electrical equipment was rusted from water and salt ingress. The vault was over 40 years old and required replacement.
EST18913_003	PCI-X06394 Network Replacement, Loc#4792	$1,458,516.76	The original scope of work was to replace an obsolete fibretop network unit at risk of catastrophic failure. Inspections showed that the vault which housed the protector was beginning to crack and for safety and reliability purposes needed to be rebuilt.
EST20406_003	PCI X12314 LOC 4557 VAULT REBUILD	$492,693.87	The vault roof and wall sustained significant structural damage (cracks) following a fire, and required timely remediation to ensure public safety (e.g. elimination of trip hazards) and prevent further damage to equipment and support structures (e.g. through corrosion caused by water leakage).
EST24000_003	PCI W11874 REBUILD VAULT ROOF #00001	$84,522.24	Asset inspection identified severely corroded steel I-beams that provide structural support for the vault. The vault roof was considered to be in very poor condition. This was a potential safety hazard for the public as well as crews working in the cable chamber. Remediation (installation of steel plates to stabilize the civil structure) was required to prevent further damage and prevent a complete collapse of the roof. The vault roof was then rebuilt.
EST19687_003EST27251_001	PCI X11560 Loc#4313 Reb Vault Eglin Ph1	$1,318,979.57	Asset inspection identified structural damage to the roof and wall of the vault (cracking) that required timely remediation to prevent vault collapse, prevent further equipment/support structure corrosion due to water and salt ingress and eliminate a public safety hazard. The following work was performed: rebuild of vault in front of 150 Eglinton Avenue, rebuild of two cable chambers, installation of 28.5m of conduit, installation of two transformers and protectors, installation of 450m of primary cables and installation of 636m of secondary cable.
EST25128_003	PCI - X11747 URGENT REBUILD 3441 A71CS	$231,511.44	The vault roof at the job location failed and was supported by a temporary roof with wooden beams. This job was necessary to rebuild the vault.
EST28429_003	X14589 Vlt Roof Rlbd Loc #4443 Bay_Irwin	$90,755.80	While executing a network transformer changeout, the vault roof cracked while lifting the roof slab, posing a significant public safety and structural integrity hazard. A temporary solution (steel plates) was implemented immediately. The permanent ramediation work was ultimately completed in 2014 as soon as resources could be made available.
EST30717_003	X14754 LOC 4481 ROOF REHAB A51DX	$139,824.72	Immediate remediation was required due to a roof collapse on a vault that was not included into the ICM filing. Project completion addressed public safety and structural integrity risks.

B10 – FIBERTOP NETWORK UNITS SEGMENT

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro proposed this segment to replace Fibertop Network Units with Submersible Network Units. Due to their obsolete design, Fibertop Network Units were prone to catastrophic failure resulting in vault fires. Toronto Hydro concluded that all Fibertop Network Units presented significant potential reliability and safety risks and needed to be replaced on a planned basis. The equipment replaced in this segment was well beyond its expected useful life and possessed the highest probability of failure based on frequent network vault inspections.

2. OEB DECISION

The OEB found that the nature of the work in the Fibertop Network Units segment, as filed, qualified for ICM treatment. [1] Having found that the work was both necessary and prudent, the OEB made no reduction to Toronto Hydro's funding request.[2] Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto Hydro's forecast of approximately $6.2 million of ISAs in 2012 and 2013. Toronto Hydro forecasted an additional $3.0 million in 2014 ISAs related to work proposed in Phase 1 of EB-2012-0064 (i.e., jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the Initial ICM Rate Rider.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $13.6 million. In addition to the approved and partially funded ISAs of $9.2 million from

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[1] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p.34.
[2] Ibid.

Phase 1, this includes:

- approximately $2.8 million in ISAs that Toronto Hydro forecasted in Phase 2 for jobs commencing in 2014, which were approved in the Phase 2 Decision but not funded through the Initial ICM Rate Rider or any rate adder; and
- approximately $1.6 million in additional prudent and non-discretionary ISAs associated with both filed and analogous jobs as described in Sections III and IV below.

The revenue recovered through the Initial ICM Rate Rider for this segment did not sufficiently cover the revenue requirement of all necessary and prudent work performed as part of this project segment. Revenue requirement associated with the ISAs that were not sufficiently funded through the Initial ICM Rate Rider remain to be recovered through the ICM True-Up Rate Rider.[3]

B. SEGMENT OVERVIEW

The primary driver for the proposed work in the Fibertop Network Units segment was safety. Vault fires caused by the design of the Fibertop Network Units posed safety risks to Toronto Hydro crews, firefighters and the general public as these assets were often located in high traffic pedestrian areas.

Network Units are comprised of a network transformer and protector and are connected together to form a grid. The top of a Fibertop Network Unit's protector, where interconnections were made to a secondary grid, was highly susceptible to moisture and contamination. The interconnections themselves were spaced very close together. This design increased the probability of inter□phase tracking occurring between these

[3] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.

connections, potentially igniting a vault fire. Additional hazards were introduced because these assets were often connected to the secondary grid using Asbestos-Insulated Lead-Covered ("AILC") secondary cables.

The secondary driver for the proposed work in the Fibertop Network Units segment was reliability. Vault fires caused by malfunctions in the Fibertop Network Units resulted in extensive damage, the de-energization of the entire network grid, and outages affecting a large number of customers.

Toronto Hydro filed 68 jobs in this segment. These jobs were expected to be completed, partially completed or in progress by the end of the ICM Period with forecast ISAs of $12.0 million for the segment overall.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the variance between the forecast ISAs and the actual ISAs over the ICM Period. Toronto Hydro put into service $1.6 million more than forecast. Higher than forecast ISAs in this segment resulted from job-level variances and the addition of analogous jobs that Toronto Hydro determined were necessary in light of the equipment's performance, condition, and other considerations as described below.

Table 1: Forecast vs. Actual In-service Additions

	Forecast ISAs				Actual ISAs				Variance
	2012	**2013**	**2014**	**Total**	**2012**	**2013**	**2014**	**Total**	**Total**
ISAs ($M)	0.7	5.5	5.9	**12.0**	2.4	6.4	4.9	**13.6**	**1.6**

Table 2 summarizes the job-level accomplishments for this segment during the ICM Period. Of the 68 originally forecasted jobs, 43 were completed, partially completed or in progress by the end of 2014.

The utility cancelled or deferred 21 of the forecast jobs in the ICM Application. Two of these jobs were cancelled because the work was completed in coordination with a different planned job, and three jobs were cancelled because the units were replaced reactively, either due to failure or imminent failure as assessed through regular network vault inspections. The remaining sixteen jobs were filed in the Phase 2 Application for initiation in 2014 but were deferred to 2015, largely so that Toronto Hydro could complete other analogous jobs that were identified as more critical or more opportune during the course of the ICM Period. Toronto Hydro added 17 of these analogous jobs, all of which were completed during the ICM Period.

The analogous jobs completed in this segment were categorically identical to other jobs in the segment. The jobs addressed additional Fibertop Network Units that were deteriorating and past the end of their useful lives. The entire population of Fibertops were considered defective, beyond end-of-life and at high risk of catastrophic failure resulting in possible vault fires and extensive and costly outages to the network system. As previously established in Toronto Hydro's ICM Application, work force and grid operation limitations constrained the utility's ability to replace all Fibertops over the ICM Period. Working within these constraints, Toronto Hydro occasionally re-prioritized its Fibertop jobs based on the following three factors.

Table 2: 2012-2014 Job-level Accomplishments

Segment Jobs Breakdown	Number of Jobs
Total Forecasted Jobs	**68**
Less: Deferred or Canceled Jobs	(21)
Add: Analogous Jobs	17
Total Segment Jobs	**64**
Less: In Progress Jobs	(6)
Total Jobs with ISAs	**58**
Breakdown of Total Jobs with ISAs	**Number of Jobs**
Completed Jobs	57
Partially Completed Jobs	1
Total Jobs with ISAs	**58**

1) **Condition:** Generally, network vaults and the equipment within them are highly sensitive to the level of vehicle and foot traffic experienced in a given location as well as site-specific environmental conditions (e.g., the amount of salt used in that location during the winter and the amount of debris that accumulates over time). For this reason, all of Toronto Hydro's network vaults are inspected and/or maintained multiple times per year. These inspections sometimes revealed the rapid deterioration of vault conditions and/or Fibertop asset health (e.g., unit leaking), which often resulted in the reprioritization of Fibertop Network Units for replacement.

2) **Loading:** Some areas of the network system are more heavily loaded and are therefore at greater risk in terms of both the likelihood of failure and the potential customer impact of failure. While relative loading conditions are unlikely to

change significantly in the very short-term, loading is nonetheless an overarching criteria for prioritization and was taken into consideration in conjunction with evolving condition information.

3) **Efficiency:** Some analogous jobs were prioritized for replacement over forecasted jobs in order to take advantage of outage coordination opportunities. For example, Toronto Hydro took advantage of pre-scheduled outages on certain feeders to simultaneously replace Fibertops on those feeders, which avoided the need to have a second scheduled outage at a later date.

All of the analogous jobs in this segment were completed in accordance with the prioritization considerations listed above. Table 3 lists all of the analogous jobs that were completed in 2012-2014. The average cost of these jobs during the ICM Period was approximately $213,000, which is slightly higher than the average final cost of the forecasted and completed jobs in this segment (i.e. approximately $183,000). This was due to the fact that several analogous jobs replaced more than one fibertop unit. For example, the most costly analogous job (estimate number 23268 in Table 3 below) replaced four fibertop units for a total cost of $668,728, or an average of $167,182 per unit, which is within the normal cost range for a Fibertop Network Unit replacement segment.

D. REVIEW OF VARIANCES

Fibertop Network Unit jobs are targeted asset replacements that lack the complexity of feeder-based jobs such as those in the Box Construction segment. As a result, nearly all of the jobs in this segment were completed without any significant variances in cost. Larger variances were due to unforeseen changes in field conditions that occurred during the movement from High-level to Detailed Design (e.g., asset failure resulting in greater complexity of work), or, in one instance, an Error that duplicated the costs within an estimate, resulting in final costs that were significantly lower than forecast.

Table 3: List of Analogous Jobs

Estimate Number	Job Title
18794	X11402 NETWORK UNIT REPL LOC#4484 A46GD
22031	X11759 LOC4164 - N/W CHANGEOUTS
22682	X11792 LOC4657 - N/W CHANGEOUTS
22685	X11793 LOC4426 - N/W CHANGEOUTS
22688	X11795 LOC4106 - N/W CHANGEOUTS
22689	X11796 LOC4768SV - N/W CHANGEOUTS
22676	X11787 LOC4198 - N/W CHANGEOUTS
22678	X11790 LOC4709 - N/W CHANGEOUTS
23268	X12262 Bridgeman TS LOCN. #4789 & 4648
23617	X11837 LOC4719 - N/W CHANGEOUTS
19875	X12192 Network Replacement Loc#4177
21842	X12548 Network Replacement - Cecil
28154	ICM-X14453 Loc4529WV/N1083NW
28192	ICM X14458 LOC4736NV - N/W CHANGEOUTS
32885	X11507 NETWORK C/O LOC#4845 A44 & A42CE

B11 – AUTOMATIC TRANSFER SWITCHES AND REVERSE POWER BREAKSERS SEGMENT

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro uses Automatic Transfer Switches ("ATS") to automatically switch a customer to a designated standby feeder in the event that the normal primary feeder fails. Reverse Power Breakers ("RPB") are used to automatically open primary feeder supplies to customers in the event of feeder outages to prevent dangerous back feed conditions.

Both ATS and RPB assets degraded rapidly in 2010 and 2011. Toronto Hydro's Asset Condition Assessment ("ACA") results indicated that approximately 30 ATS assets would need to be replaced during the 2012-2014 period. In addition, based on physical inspection data, a further six RPB assets were identified as requiring immediate replacement. Jobs in this segment replaced ATS and RPB assets with stand-alone network protectors or standard network equipment.

2. OEB DECISION

The OEB found that the nature of the work in the ATS and RPB segment, as filed, qualified for ICM treatment.[1] Having found that the work was both necessary and prudent, the OEB made no reduction to Toronto Hydro's funding request.[2] Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto Hydro's forecast of approximately $2.0 million of ISAs for 2013. Toronto Hydro forecasted an additional $1.3 million in 2014 ISAs related to work proposed in Phase 1

1 EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p. 34.
2 Ibid.

(i.e., jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the Initial ICM Rate Rider. The OEB also approved an additional $0.1 million in ISAs that Toronto Hydro forecasted in Phase 2 for jobs commencing in 2014, but these were not funded through the Initial ICM Rate Rider or any rate adder.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $1.9 million, which is $1.5 million less than the overall forecasted amounts in this segment and about $100,000 less than the amounts on which the Initial ICM Rate Rider was based. To the extent that the Initial Rate Rider for this segment recovered revenue in excess of the actual three-year revenue requirement, that surplus amount is offset against any additional recoveries in the ICM True-Up Rate Rider calculation.[3]

B. SEGMENT OVERVIEW

ATS and RPB assets were generally used to supply medium size customers that required a reliable supply, such as schools, supermarkets, seniors' homes, and other mid-sized buildings. ATS and RPB assets were purchased from many different manufacturers over many different vintages, which made each unit unique. These units became obsolete and the manufacturer support and spare parts have become unavailable, rendering them unrepairable and largely unmaintainable. Many ATS and RPB assets are degraded and in poor condition.

The primary drivers of investment in this segment were potential risks to safety and reliability. For instance, an ATS vault fire incident at 33 Princess Street (January 16, 2012) affected a daycare centre, a seniors' home and the St. James Campus of George Brown College. Similarly, an RPB failure at 50 Marlborough (January 10, 2010) resulted

[3] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.

in an explosion and damage to equipment in other locations, and an extended interruption to the entire neighbouring grid network.

Toronto Hydro filed 11 discrete jobs to replace ATS and RPB assets with stand-alone network protectors or standard network equipment. These jobs were forecasted to be completed, partially completed or in progress by the end of the ICM Period. The forecasted ISAs associated with this work were approximately $3.4 million over the ICM Period.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the variance between the forecast ISAs and the actual ISAs during the ICM Period. Toronto Hydro spent $1.5 million less than forecasted on an ISAs basis. Underspending at the segment level was due to underspending on completed jobs and the cancellation of planned jobs that were completed reactively.

Table 1: Forecast vs. Actual In-service Additions

	Forecast ISAs				Actual ISAs				Variance
	2012	**2013**	**2014**	**Total**	**2012**	**2013**	**2014**	**Total**	**Total**
ISAs ($M)	-	2.0	1.4	**3.4**	0.1	1.5	0.3	**1.9**	**(1.5)**

Table 2 summarizes the job-level accomplishments for this segment during the ICM Period. Six of the forecasted jobs in this segment were completed by the end of 2014. Five forecasted jobs were cancelled as the work was ultimately performed on a reactive basis due to deteriorating asset condition as identified via frequent inspections of the vaults.

Table 2: 2012-2014 Job-level Accomplishments

Segment Jobs Breakdown	Number of Jobs
Total Forecasted Jobs	**11**
Less: Deferred or Canceled Jobs	(5)
Add: Analogous Jobs	1
Total Segment Jobs	**7**
Less: In Progress Jobs	0
Total Jobs with ISAs	**7**
Breakdown of Total Jobs with ISAs	**Number of Jobs**
Completed Jobs	7
Partially Completed Jobs	0
Total Jobs with ISAs	**7**

In addition to the six completed forecasted jobs, Toronto Hydro also completed one analogous job that was deemed critical for execution during the ICM Period. This job replaced two modular ATS switches that had failed in the recent past and were considered a significant reliability risk if left in-service.

Complete information regarding the investment drivers, scope of work and final costs for all analogous jobs can be found in the Appendix to this Schedule.

D. REVIEW OF VARIANCES

Of the six forecasted and completed jobs in this segment, all but two came in under the forecast cost. The largest of these negative variances was a -31% variance that was responsible for approximately $270K worth of underspending in the segment. Prior to undertaking this job, some equipment in the vault was replaced on a reactive basis due to failure, thereby reducing the necessary scope of work and cost for the planned part of the project. This is an example a typical High Level to Detailed Design Variance that would result from a designer gaining additional information from detailed inspections of underground equipment.

One of the two overspent jobs had a significant positive variance which was also due to additional information gathered during the detailed design phase. In this case, field inspections concluded that both of the transformers in the vault (as opposed to just the one identified in the original scope of work) needed to be replaced as both were in poor condition. This job also had higher than anticipated restoration costs as the vault roof was paved with decorative stones, which would not have been included in the original high-level estimate used for segment budgeting purposes.

ICM Segment **B11 Automatic Transfer Switches and Reverse Power Breakers**

Estimate	Description	ISAs	Rationale/Driver for Inclusion
EST18831_003	X11414 ATS Rplmt. Locn #D9010 Richmond	$86,350.68	Two modular ATS switches at the job location had failed in the past and required replacement. These ATS switches are considered obsolete and are prone to failure due to their obsolete design. An additional $22.5K was spent on this job prior to 2012 and is captured in pre-2012 CWIP amounts coming into service in 2012-2014.

B12 – STATIONS POWER TRANSFORMERS SEGMENT

A. INTRODUCTION

1. SEGMENT OVERVIEW

Toronto Hydro proposed the Stations Power Transformers segment to address municipal station ("MS") power transformers that are beyond the end of their useful lives, have exhibited incidences of oil leakage, or where the risk of transformer failure was high due to deteriorating insulating materials. The units selected for replacement in this segment exhibited significant symptoms of degradation, as determined by the asset condition and dissolved gas analysis ("DGA") oil tests that were used to prioritize unit replacement.

2. OEB DECISION

The OEB found that the nature of the work in the Stations Power Transformers segment, as filed, qualified for ICM treatment.[1] Having found that the work was both necessary and prudent, the OEB made no reduction to Toronto Hydro's funding request.[2] Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto Hydro's forecast of approximately $2.5 million of ISAs in 2012 and 2013. Toronto Hydro forecasted an additional $1.4 million in 2014 ISAs related to work proposed in Phase 1 of EB-2012-0064 (i.e., jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the Initial ICM Rate Rider. Toronto Hydro did not propose additional jobs for this segment in the Phase 2 Application.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $5.0 million. In addition to the forecasted ISAs of $3.9 million from Phase 1, this includes about

[1] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p.36.
[2] Ibid.

$1.1 million in additional prudent and non-discretionary ISAs associated with both forecasted and analogous jobs as described in the sections below.

The revenue recovered through the Initial ICM Rate Rider for this segment did not sufficiently cover the revenue requirement of all necessary and prudent work performed as part of this project segment. Revenue requirement associated with the ISAs that were not sufficiently funded through the Initial ICM Rate Rider remain to be recovered through the ICM True-Up Rate Rider.[3]

B. SEGMENT OVERVIEW

The primary driver for this segment was reliability. Power transformers are critical municipal station assets from the perspective of both financial and operational risk. A significant portion of these assets were installed in the 1950s to 1970s and had surpassed their typical useful life of 43 years.[4] As transformers aged, the pressboard and paper insulation of the energized components deteriorated, increasing the likelihood of insulation failure and electrical faults.

Transformer failures carry the risk of causing long duration outages for thousands of customers. Catastrophic failures could also result in collateral damage to other transformers and station equipment. Moreover, in addition to the direct impact on the customers connected to a specific transformer, the failure of a single station transformer could increase the risk of further outages in the surrounding area, as the adjacent transformers absorb the load of the failed unit, thereby increasing the risk of their own failure due to increased loading. Leaking transformers also present an environmental risk, as the mineral oil could have entered the area surrounding the station.

[3] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.
[4] EB-2010-0178, Kinectrics Inc. Asset Depreciation Study for the Ontario Energy Board (July 8, 2010).

Another driver of power transformer replacement was safety, as catastrophic damage sustained by failed transformers could endanger Toronto Hydro personnel working in the vicinity of the assets.

Toronto Hydro filed ten discrete jobs to replace power transformers during the ICM Period. These jobs were forecasted to be completed, partially completed, or in progress by the end of the ICM Period.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the forecast ISAs and the actual ISAs in this segment over the ICM Period. Toronto Hydro put into service $1.1 million more than forecasted in this segment. ISAs in 2012 and 2014 were higher than forecasted, partially offset by lower than forecasted additions in 2013. Higher than forecast ISAs in this segment were a result of both job-level variances and the addition of five analogous jobs that Toronto Hydro determined to be urgent in light of the equipment's performance, condition, and other considerations as described below.

Table 1: Forecast vs. Actual In-service Additions

	Forecast ISAs				Actual ISAs				Variance
	2012	**2013**	**2014**	**Total**	**2012**	**2013**	**2014**	**Total**	**Total**
ISAs ($M)	0.2	2.3	1.4	**3.9**	2.3	0.9	1.8	**5.0**	**1.1**

Table 2 summarizes the job-level accomplishments for this segment during the ICM Period. All of the originally forecasted jobs in this segment were completed or in progress by the end of 2014. As shown below, Toronto Hydro also added five analogous priority jobs, all of which were completed during the ICM Period.

Table 2: 2012-2014 Job-level Accomplishments

Segment Jobs Breakdown	Number of Jobs
Total Forecasted Jobs	**10**
Less: Deferred or Canceled Jobs	(0)
Add: Analogous Jobs	5
Total Segment Jobs	**15**
Less: In Progress Jobs	(4)
Total Jobs with ISAs	**11**
Breakdown of Total Jobs with ISAs	**Number of Jobs**
Completed Jobs	11
Partially Completed Jobs	0
Total Jobs with ISAs	**11**

Toronto Hydro's decision to complete the five analogous jobs during the ICM Period was driven primarily by:

- irreversible deterioration of the assets, as confirmed through field inspection, particularly the dissolved gas analysis of the transformer oil; and
- advanced age and the resultant increased risk of failure of the equipment (all transformers replaced were between 40 and 55 years old).

Complete information regarding the investment drivers, scope of work and final costs for all analogous jobs can be found in the Appendix to this Schedule.

D. REVIEW OF VARIANCES

All six of the forecasted and completed jobs in this segment were within approximately 10% of their forecast cost.

ICM Segment **B12 Stations Power Transformers**

Estimate	Description	ISAs	Rationale/Driver for Inclusion
EST14189_003	S10109 University MS: Replace 4 Trans.	$499,445.85	Independent transformer oil tests indicated paper insulation deterioration in all four of University MSs transformers. Toronto Hydro determined that near-term replacement was required to avoid transformer failure. The transformers were each 55 years old when this job was originally planned in 2010. Due to scheduling constraints, this job was not completed until 2012.
EST20904_003	S11656 Sherbourne MS: Replace TR3	$604,537.61	Dissolved gas and fluid analysis reports indicated that TR3 at Sherbourne MS, which serves 2,629 customers, exhibited high acetylene and carbon monoxide levels, which demonstrated frequent arcing activities inside the transformer. The transformer (54 years old in 2011) was also beyond the end of service life. Toronto Hydro determined that it was necessary to replace this transformer on an urgent basis in order to avoid significant customer interruptions.
EST20537_003	S11099 Centennial D'arcy MS: Replace TR	$660,225.34	Centenial D'Arcy Magee MS was 42 years old in 2011 and had reached its end-of-life. Testing had revealed that it was in poor condition. Therefore, the transformer had to be replaced to avoid catastrophic failure that would directly impact the 1,628 customers it supplied.
EST17686_002	S11029 Highlevel MS -Replace TR#4	$602,122.49	The TR4 transformer at High Level MS was 54 years old in 2011, and dissolved gas analysis oil test results accumulated from 1997 to 2008 indicated deterioration requiring replacement in the near-term. Failure of this transformer would have had a direct impact to 7,008 customers connected to the 4 kV bus, and may have caused further collateral damage-related outages to 5633 customers on 13.8 kV buses.
EST17920_002	S11150 Highlevel MS -Replace TR#3	$509,373.98	TR3 transformer was 40 years old and oil testing revealed that it was in deteriorated condition and needed to be replaced in order to avoid catastrophic failure. High Level TR3 failure will have a direct impact to 7,008 customers connected to 4kV bus, and could cause further collateral damage outage to 5,633 customers on 13.8kV buses. This transformer is indoor and is sharing the same building space with 3 other 4kV transformers, 1 of 4 kV bus, and 3 of 13.8 kV buses.

B13 – STATIONS SWITCHGEAR SEGMENT

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro proposed the Stations Switchgear segment to replace switchgear in municipal substations and transformer stations that were past the end of their useful lives and relied on obsolete technology such as non-arc-resistant designs with oil circuit breakers and mechanical relays. The switchgear selected for replacement in this segment were chosen from 181 switchgear across 170 municipal substations based on advanced equipment age, equipment obsolescence, lack of arc-resistant design and safety related equipment issues.

The proposed Segment B13 included two components:

- Segment 13.1 for the replacement of aging and obsolete switchgear in municipal substations (“MSs”); and
- Segment 13.2 for the replacement of aging and obsolete switchgear in high-voltage transformer stations (“TSs”).

2. OEB DECISION

The OEB found that the nature of the work in the Stations Switchgear segment, with the exception of MS switchgears that were considered to be in “Fair” condition according to inspection data, qualified for ICM treatment.[1] The Board ultimately approved the renewal of four MS switchgears from the Phase 1 filing (2012-2013) that had specific auto-reclose issues and all proposed work related to the renewal of TS switchgears.[2]

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[1] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p.38.

[2] For additional clarification regarding the final interpretation of this decision as it was applied in the final rate order, please refer to EB-2012-0064, Toronto Hydro Electric-System Limited Draft Rate Order (Filed: April 12, 2012) at p.7.

Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto Hydro's forecast of approximately $9.9 million of ISAs in 2012 and 2013. Toronto Hydro forecasted an additional $5.4 million in 2014 ISAs related to work proposed in Phase 1 of EB-2012-0064 (i.e., jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the Initial ICM Rate Rider.

Toronto Hydro included additional MS switchgear jobs in the Phase 2 filing (2014) based on the specific criteria for the Board's Phase 1 approvals. The OEB approved the additional $1.4 million in ISAs associated with these Phase 2 jobs commencing in 2014, but these were not funded through the Initial ICM Rate Rider or any rate adder.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $5.0 million, which is $11.7 million less than the overall forecasted amounts in this segment and $5.0 million less than the amounts on which the Initial ICM Rate Rider was based. To the extent that the Initial Rate Rider for this segment recovered revenue in excess of the actual three-year revenue requirement, that surplus amount is offset against any additional recoveries in the ICM True-Up Rate Rider calculation.[3]

B. SEGMENT OVERVIEW

1. SEGMENT 13.1 – MUNICIPAL SUBSTATIONS

The primary driver for the proposed work in the 13.1 Stations Switchgear segment was reliability as many Municipal Substations ("MS") located outside of downtown Toronto employed switchgear that were past the end of their useful lives and relied on obsolete technology such as non-arc resistant designs with oil circuit breakers and mechanical

[3] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.

relays. As their asset condition deteriorated and risk of failure increased, maintaining them became unsustainable.

A secondary driver for this segment was safety. Toronto Hydro experienced two substation fires in the years leading up to the ICM period due to faults in substation equipment that was at the end of its useful life. In both cases, the substations were over 50 years old and the fire was attributable to faults in the substations switchgear. Switchgear that is beyond useful life (50 years) can fail catastrophically at any time.

There were additional operational constraints that posed potential safety risks to the operating personnel. The circuit breakers in some of these substations had auto re closure problems, i.e., when a circuit breaker was taken out of service for maintenance and put back, it would auto reclose instead of locking, even though the circuit breaker was on open position and the auto re-closure was blocked by control authority.

2. Segment 13.2 – Transformer Stations

The primary driver for the proposed work in the 13.2 Stations Switchgear segment was reliability as switchgear operating at 13.8 kV in many downtown Transformer Stations ("TS") were past the end of their useful lives and relied on obsolete technology such as brick and mortar enclosures, non-arc-resistant designs with air blast or air magnetic circuit breakers and mechanical relays and were in poor condition. The existing non-arc-resistant switchgear did not channel the energy released during an internal arc fault to minimize potential injury to personnel and damage to surrounding equipment. As a result, this switchgear could cause damage that could have impacted the entire station, interrupting service to thousands of customers. This equipment had been kept in service via increased maintenance, custom fabrication and harvesting parts from spares.

A secondary driver for the proposed work within this segment was safety. Toronto Hydro experienced several incidents of internal arc faults in its non-arc-resistant switchgear. For instance, an internal arc fault at Terauley TS in 2007 resulted in an explosion in the circuit breaker compartment and caused the front door to fly away from its mounts. In addition to the consequences of in-service failures, the existing circuit breakers in all of the switchgear, except Duplex TS, were air blast circuit breakers, which are obsolete.

Toronto Hydro filed a number of jobs related to the replacement of switchgear at 11 municipal stations and four transformer stations to address anticipated reliability, safety and operational concerns during the ICM Period. The forecasted ISAs associated with this work were $20.4 million over the three-year period. These jobs were selected based on age, equipment obsolescence, lack of arc-resistant design and safety related equipment issues and were forecasted to be completed, partially completed or in progress by the end of the ICM Period. As discussion in the section above, the OEB ultimately approved forecasted ISAs in the amount of $16.7 million for the ICM Period.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the variance between the forecast ISAs and the actual ISAs that took place over the ICM Period. Toronto Hydro placed into service $11.7 million less than forecasted.

Table 1: Forecast vs. Actual In-service Additions

	Forecast ISAs				Actual ISAs				Variance
	2012	2013	2014	Total	2012	2013	2014	Total	Total
ISAs ($M)	0.8	9.2	6.8	**16.7**	0.8	0.00	4.1	**5.0**	**(11.7)**

Table 2 summarizes the job-level accomplishments for this segment during the ICM Period. Out of the 17 forecasted jobs, about half (nine or 53%) were completed or in progress by the end of 2014. The utility cancelled or deferred eight of the forecasted jobs in the ICM Application. Switchgear replacement jobs and associated load transfer jobs are significant undertakings that require long lead times, specialized resources and extensive coordination with Hydro One. During the execution ramp-up following the Phase 1 Decision, Toronto Hydro faced significant challenges securing timely resources to execute the planned switchgear jobs on schedule. These difficulties, combined with some coordination challenges involving Hydro One's station assets, caused many of the filed jobs to be deferred until later in the ICM Period or until the subsequent 2015-2019 CIR period. The significant underspending on an ISAs basis was due to these scheduling delays, and was magnified by the fact that this segment addresses large, discrete assets as opposed to geographical jobs that can be brought into service in stages. The fact that the segment was only underspent by $3.57 million on a capital expenditures basis as opposed to $11.73 million on an ISAs basis illustrates this point. Unlike an Underground Infrastructure job, no part of a switchgear renewal job can be placed in-service until the entire job is complete.

Toronto Hydro also invested in five analogous jobs with primary drivers identical to the jobs originally included in this segment. These additional jobs were completed during the ICM Period on a priority basis and contributed to the deferral of other, lower-priority forecasted jobs.

Four of the five analogous jobs completed in this segment included final commissioning and feeder transfer work that was necessary to complete following the replacement of certain switchgear prior to 2012. Feeder transfers are required in order to bring load to the new switchgear and to decommission old switchgear, and commissioning efforts are required in order to ensure safe and efficient operation of the equipment prior to energization.

One other job addressed a non-arc-resistant 45-year-old switchgear at Jane MS that had failed in 2008 and needed to be replaced on a priority basis.

Complete information regarding the investment drivers, scope of work and final costs for all analogous jobs can be found in the Appendix to this Schedule.

Table 2: 2012-2014 Job-level Accomplishments

Segment Jobs Breakdown	Number of Jobs
Total Forecasted Jobs	**17**
Less: Deferred or Canceled Jobs	(8)
Add: Analogous Jobs	5
Total Segment Jobs	**14**
Less: In Progress Jobs	(7)
Total Jobs with ISAs	**7**
Breakdown of Total Jobs with ISAs	**Number of Jobs**
Completed Jobs	7
Partially Completed Jobs	0
Total Jobs with ISAs	**7**

D. REVIEW OF VARIANCES

Of the two forecasted and completed jobs in the Stations Switchgear segment, one job had a notable High-level to Detailed Design variance that resulted in a cost increase from a forecast of approximately $254,000 to $757,000. This variance related to the need to complete a stations support job at Porterfield MS, which replaced direct-buried PILC station egress cables with standard primary cables in concrete-encased ducts. The PILC cables required replacement because they were not compatible with the new switchgear that was to be installed. Some overhead work was also required in relation to the replacement of the station egress cable.

During the execution of this job, Toronto Hydro determined that the actual switchgear replacement could not be completed on time due to resource constraints. The inability to do the stations work in conjunction with the supporting distribution project required the distribution project to be redesigned in order to maintain system operability until the switchgear replacement could be rescheduled. The new design necessitated a new cable chamber. Field Conditions and Execution Requirements were a secondary factor for this job, as during construction a Bell duct bank was discovered which required relocation of Toronto Hydro's poles.

ICM Segment **B13 Stations Switchgear**

Estimate	Description	ISAs	Rationale/Driver for Inclusion
EST14232_003	S09346 Commission New A5-6GD SWGR (2009)	$240,260.77	This job was the final commissioning phase for a new switchgear that had been installed in a separate job. The old A5-6GD switchgear was 59 years old in 2009 and past end-of-ife. The new switchgear has a larger capacity to meet increasing customer load demands in the region. This job invloved verifing proper functioning of the equipment after installation, verifing that performance of the installed equipment meets the specified design intent, and capturing and recording performance data of the whole installation as the baseline for future operation and maintenance. Commissioning of a switchgear ensures that all components and systems installed are in a satisfactory and safe condition before start up.
EST15450_005	S10157 GlengroveTS:Repl A5-A6 with A7-A8	$172,554.03	The A5-6GL switchgear at Glengrove TS was 53 years old and beyond its useful life, necessitating replacement to mitigate risk of failure. Replacement parts for the obsolete switchgear and circuit breakers were no longer manufactured. The switchgear was also non-arc resistant and limited to 2000A, which constrained the capacity for growth in the area. The $173K of ISAs for this job represented a small remaining portion of the total job cost and was related to the final efforts of switchgear commissioning.The total cost for this job was closer to $5M, with the vast majority of those expenditures coming into service prior to 2012.
EST18244_003	W11203 A3-4T STRACHAN FEEDER TRANS- IFRS	$332,999.85	The purpose of this job was to transfer the load from A3-4T Switchgear to the newly installed A9-10T Switchgear at Strachan TS. This job enabled the removal of de-energized A3-4T Switchgear to make space available for future Switchgear installations.
EST18745_003	S11446 Strachan A9-10T Feeder Transfer	$98,878.52	The objective of this job was to make the necessary load transfers to facilitate the replacement of the A3-4T switchgear at Strachan TS. The job transfered load from A3-4T to the newly installed A9-10T switchgear. This enabled the removal of the A3-4T Switchgear to make space available for future projects. The stations work involved in this job included: 1. Terminate the new feeder cables at the A9-10T bus. 2. Commission new feeders and protection. 3. Update Strachan TS bus drawings. The non-arc resistant A3-4T Switchgear at Strachan TS was 56 years old and beyond its useful life, necessitating replacement to mitigate risk of failure. This switchgear housed air-blast type circuit breakers, which were 56 years old and past their useful lives of 42 years. The original manufacturer no longer produced this device, and spare parts were difficult to obtain and in many cases needed to be custom manufactured. This made the maintenance cost high and unsustainable over the long term. Since the switchgear was of non-arc resistant design, it was vulnerable to internal arc faults. This increased the risk of collateral damage and personnel injury during a catastrophic failure.

ICM Segment **B13 Stations Switchgear**

Estimate	Description	ISAs	Rationale/Driver for Inclusion
EST19121_003	S11458 Jane MS: Replace 13.8kV SWGR	$3,211,067.13	Jane MS and Sentinel MS were sister stations constructed in the late 1960s The non-arc resistant Switchgear at Jane MS was manufactured in 1968 and was 45 years old during its replacement. This Switchgear housed obsolete air-magnetic circuit breaker, which were past their useful lives of 40 years. The switchgear was made up of two housing sections, the north section contained the F1, F2 and F3 feeders, and the south section contained the F4 and F5 feeders. After a major

B20 – METERING SEGMENT

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro proposed the Metering segment to comply with the metering requirements mandated by Measurement Canada and the Independent Electricity System Operator ("IESO"). Completed and ongoing jobs in this segment have addressed these requirements. Work performed within this segment included the following:

- Wholesale Metering Market Settlement Compliance;
- Seal Expiring Meters; and
- Wireless Collector Upgrade.

2. OEB DECISION

The OEB accepted Toronto Hydro's Phase 1 evidence that Wholesale Metering and Seal Expiring Meters replacements were necessary for compliance with IESO and Measurement Canada requirements, and therefore must be undertaken during the ICM Period.[1] Having found that the work was both necessary and prudent, the OEB made no reductions to Toronto Hydro's funding request.[2]

Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto Hydro's forecast of approximately $9.8 million of ISAs in 2012 and 2013. Toronto Hydro forecasted an additional $3.3 million in 2014 ISAs related to work proposed in Phase 1 of EB-2012-0064 (i.e., jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the initial ICM Rate Rider.

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[1] EB-2012-0064, Toronto Hydro Electric-System Limited Partial Decision and Order (April 2, 2013) at p.59.
[2] Ibid.

Toronto Hydro introduced the Wireless Collector Upgrade initiative in its Phase 2 evidence update as an urgent and non-discretionary investment requirement.[3] This work was required to safeguard the utility's ability to collect meter readings from customers who collectively account for over $800 million in annual revenue. The OEB approved the associated ISAs as part of its Phase 2 Decision.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $18.2 million. In addition to the forecasted ISAs of $13.1 million from Phase 1, this includes:

- approximately $3.8 million in ISAs that Toronto Hydro forecasted in Phase 2 for activities commencing in 2014 (including the Wireless Collector Upgrade), which were approved in the Phase 2 Decision but not funded through the Initial ICM Rate Rider or any rate adder; and
- about $1.2 million in additional prudent and non-discretionary ISAs associated with both filed and analogous jobs as described in the sections below.

The revenue recovered through the Initial ICM Rate Rider for this segment did not sufficiently cover the revenue requirement of all necessary and prudent work performed as part of this project segment. Revenue requirement associated with the ISAs that were not sufficiently funded through the Initial ICM Rate Rider remain to be recovered through the ICM True-Up Rate Rider.[4]

[3] EB-2012-0064, Toronto Hydro Electric-System Limited Application-Evidence Update for 2014 (August 19, 2013), Tab 9, Schedule B20 at p.3.
[4] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.

B. SEGMENT OVERVIEW

To maintain compliance with Measurement Canada and IESO requirements, Toronto Hydro was required to perform the following work:

1. WHOLESALE METERING MARKET SETTLEMENT COMPLIANCE

Wholesale metering is the term used to describe the meters installed at delivery points in the distribution grid. These are locations where electricity is delivered from the Ontario transmission system to either a local distribution company ("LDC") or a major power consumer. As the Metered Market Participant for 106 legacy metering points located at 35 different stations across the City of Toronto, Toronto Hydro is responsible for ensuring that every meter and instrument transformer used in a metering installation for settlement purposes has been approved for use by Measurement Canada. In addition, all wholesale meter installations are required to be compliant with the Market Rules administered by the IESO.

Toronto Hydro was required to replace certain legacy transformers with new transformers during the ICM Period in order to remain in compliance with the IESO Market Rules and Measurement Canada requirements for accuracy. Toronto Hydro proposed to upgrade 65 wholesale metering locations during the ICM Period.

2. SEAL EXPIRING METERS

Toronto Hydro is required to comply with the metering requirements set out by Measurement Canada in Sections 9, 11 and 12 of the *Electricity and Gas Inspection Act*. These requirements state that all customer meters must be resealed at specific intervals in order to ensure that a customer's electricity use is being metered accurately.

Toronto Hydro proposed to replace 6,408 meters with expired seals during the ICM Period in order to comply with the *Electricity and Gas Inspection Act*.

3. WIRELESS COLLECTOR UPGRADE

Collector technology is required to collect interval data for the purposes of billing time-of-use rates. Toronto Hydro's first generation phone line-based collectors were experiencing a high failure rate and the manufacturer had discontinued production of these types of collectors. Toronto Hydro proposed to replace the failing and obsolete modem-based collectors with wireless, second generation collectors in 2014.

Toronto Hydro forecasted ISAs for the Metering segment totalling approximately $17.0 million during the ICM Period.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the variance between the forecast ISAs and the actual ISAs that took place over the ICM Period. Toronto Hydro put into service $1.2 million more than forecasted. While ISAs in 2012 and 2013 were lower than forecasted, higher than forecast additions in 2014 produced the additional ISAs.

Table 1: Forecast vs. Actual In-service Additions

	Forecast ISAs				Actual ISAs				Variance
	2012	**2013**	**2014**	**Total**	**2012**	**2013**	**2014**	**Total**	**Total**
ISAs ($M)	2.1	7.8	7.1	**17.0**	0.1	7.1	11.0	**18.2**	**1.2**

Toronto Hydro created a small number of estimates to capture the forecasted costs for this segment during the ICM Period. These estimates were intended to provide a level of detail that was consistent with jobs in other segments. For true-up purposes, Toronto Hydro has summarized its discussion of accomplishments in this segment at the activity level. This is necessary due to the actual nature of the activities in the Metering segment, which are generally based on units rather than geographical areas. As a result, this segment is discussed in terms of dollars invested and units, rather than jobs, completed.

Table 2 summarizes the forecasted and actual capital expenditures for each of the three major activities carried-out in this segment. Capital expenditures are used instead of ISAs because Toronto Hydro did not establish ISA forecasts at any level below the overall segment level in any of the ICM segments.

Table 2: Forecast Capital Expenditures vs. Actual Segment Capital Expenditures by Activity

	Forecast CAPEX ($M)				Actual CAPEX ($M)				Variance
	2012	**2013**	**2014**	**Total**	**2012**	**2013**	**2014**	**Total**	**Total**
Wholesale Metering	1.0	6.3	6.1	**13.4**	1.2	2.5	7.6	**11.3**	**(2.1)**
Seal Expiring Meters	3.8	2.1	0.5	**6.4**	4.6	2.0	1.0	**7.5**	**1.1**
Wireless Collector Upgrade	-	-	2.9	**2.9**	-	0.2	3.6	**3.9**	**0.9**
TOTAL	4.7	8.4	9.5	**22.7**	5.8	4.7	12.1	**22.7**	**(0.0)**

While Toronto Hydro was overspent by $1.2 million on an ISAs basis, on a capital expenditures basis the Metering segment was on budget. It is important to note that the ISA forecasts in all segments were calculated by applying historical ISA-to-CAPEX ratios to the forecasted CAPEX amounts at the segment level in each of the ICM years; the segment-level approximations were not based on specific schedules for activity completion. Thus the primary reason for overspending in this segment on an ISAs basis was faster than expected financial recognition of capital expenditures during the ICM period. Reasons for CAPEX variances in each of the three spending categories are discussed independently in the following section.

D. REVIEW OF VARIANCES

1. WHOLESALE METERING

The wholesale metering upgrades originally planned for 2012 were all completed in 2012 for an amount slightly under budget. Toronto Hydro also received a schedule notification from Hydro One for a full upgrade of the Ellesmere TS ahead of schedule, with work commencing in 2012 instead of 2013 as originally planned. Since this work had to be completed in accordance with Hydro One's construction schedules, a portion of the Ellesmere station upgrade planned for 2013 was moved forward and completed in 2012. This acceleration resulted in wholesale metering upgrades expenditures being overspent by approximately $220,000 in 2012.

Spending in 2013 was significantly lower than forecasted due to changes in Hydro One's outage schedules. While Toronto Hydro was able to partially complete the engineering, design and construction for these transformers, the utility was not able to fully complete any of the projects until 2014. This resulted in underspending in 2013. The planned 2013 transformer stations that were addressed in 2014 included:

- Bermondsey;
- Scarborough;
- Dufferin; and
- Fairbank.

These deferrals had a cascading effect on the plan for 2014, resulting in the necessary deferral of three transformer stations (Gerrard, Main and Warden) to 2015. All other transformer work originally scheduled for 2014 was completed in that year.

Overall, for the reasons specified above, the net wholesale metering budget from 2012 to 2014 was underspent by about $2 million on a capital expenditures basis.

2. Seal Expiring Meters

Toronto Hydro planned to replace 6,408 seal expiring meters, of which 5,989 were conventional meters. A total of 846 seal expiring meters were mounted on asbestos backer boards.[5] In the years 2012 and 2014, Toronto Hydro's actual capital expenditures were above forecasts. For 2013, Toronto Hydro was able to complete all scheduled jobs within the forecasted costs. Overall, Toronto Hydro spending exceeded forecast spending by approximately $1 million in this category.

There are two areas that contributed to higher than forecast spending in this category. The first was related to the Province's requirement to install Smart Meters on all residential and small commercial accounts to enable Time of Use ("TOU") billing. To accomplish this, Toronto Hydro was required to include additional activities, such as hiring bailiff services to provide access to the meters, in its standard processes. The costs for these additional activities were higher than anticipated and were added to the 2012 budget.

The second area that contributed to higher than forecast spending was related to the QuadLogic meters that are installed for suite metered accounts. In the 2014 evidence update, Toronto Hydro reduced the number of QuadLogic Meters due for replacement in

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[5] Asbestos is a designated substance covered under Ontario Regulation 278/05 made under the *Occupational Health and Safety Act* which presents potential safety risks.

2014 from 4,703 to 970, and correspondingly lowered its costs for the seal expiring meters activity from $1 million to $0.50 million. This was a result of Measurement Canada extending the replacement period for a type of QuadLogic meter from six to ten years. However, it was later clarified that Measurement Canada's extension was applicable only to meters that were sealed after 2007. This increased the number of QuadLogic meters that needed to be replaced by 3,730, resulting in the higher than forecast spending in 2014.

3. WIRELESS COLLECTOR UPGRADE

Toronto Hydro incurred non-discretionary costs related to wireless collectors in 2013. These expenditures were necessary in order to maintain the current network of phone line gatekeepers. As the obsolete phone line gatekeepers failed, they required upgrades to sustain the collection of hourly meter reads for TOU billing.

In addition, the original estimate for this category anticipated installing collectors at customers' meter base locations. However, following the ice-storm in 2013, Toronto Hydro determined that its network of gatekeeper collectors should be installed on poles instead of meter base locations to ensure that the equipment would be robust and able to withstand severe weather. Gatekeeper installation on poles would improve communication and allow for the collectors to be equipped with battery backup to enable communication during power outages, which in turn would improve restoration efforts. The cost of installing the gatekeepers on poles increased the 2014 cost of this category by approximately $900,000, with an additional $704,000 carried over into the 2015 test year of Toronto Hydro's 2015-2019 CIR Application.

B21 – EXTERNALLY-INITIATED PLANT RELOCATIONS SEGMENT

A. INTRODUCTION

1. SEGMENT DESCRIPTION

Toronto Hydro proposed the Externally-Initiated Plant Relocations segment to account for projects that were required as a direct result of, or were uniquely enabled by, work undertaken by governments or their agencies. Because these projects are linked to third-party activities, no single type or class of assets was specifically targeted through this program. The timing of the work in this segment was beyond Toronto Hydro's control and its completion could not be deferred.

2. OEB DECISION

The OEB found that the nature of the work in the Externally-Initiated Plant Relocations segment, as filed, qualified for ICM treatment. Having found that the work was both necessary and prudent, the OEB made no reduction to Toronto Hydro's funding request. Pending the revenue reconciliation process, the OEB provided for interim funding of this work through an Initial ICM Rate Rider in the Phase 1 Decisions, which was based on Toronto Hydro's forecast of approximately $25.3 million of ISAs in 2012 and 2013. Toronto Hydro forecasted an additional $9.7 million in 2014 ISAs related to work proposed in Phase 1 of EB-2012-0064 (i.e. jobs that were forecasted to commence in 2012 or 2013), but these amounts did not inform the Initial ICM Rate Rider. The OEB also approved an additional $1.9 million in ISAs that Toronto Hydro forecasted in Phase 2 for jobs commencing in 2014, but these were not funded through the initial ICM Rate Rider or any rate adder.

As detailed below, Toronto Hydro's actual ISAs in this segment total about $34.4 million, which is $2.5 million less than the overall forecasted amount for this segment but

$9.1 million more than the amounts on which the initial ICM Rate Rider was based. Revenue requirement associated with the ISAs that were not sufficiently funded through the Initial ICM Rate Rider for this segment remain to be recovered through the ICM True-Up Rate Rider.[1]

B. SEGMENT OVERVIEW

Third-party agencies, such as the City of Toronto, GO Metrolinx and the Ontario Ministry of Transportation, regularly maintain, upgrade, expand or otherwise improve public infrastructure such as roads, bridges, highways and rail crossings. This work is usually undertaken in close proximity to Toronto Hydro's infrastructure, requiring relocation of its existing plant. These construction projects often provide an opportunity for Toronto Hydro to expand its infrastructure for future needs in conjunction with a relocation project.

Under the *Public Service Works on Highways Act* ("PSWHA"), Toronto Hydro is obligated to relocate its facilities that are located within a public road right-of-way in a cooperative fashion with the Road Authority, for either the City of Toronto or the Ontario Ministry of Transportation. The PSWHA includes a cost sharing mechanism and the right to appeal cost allocations to the Ontario Municipal Board.

Toronto Hydro facilities located on private property are not subject to the PSWHA and are typically governed by individual agreements, such as with railway authorities for rail right-of-way crossings or GO Transit for their right-of-way crossings. Toronto Hydro aims to retain existing distribution system capacity, so relocation projects are often executed on a "like-for-like" basis.

[1] See Exhibit 3 for a detailed calculation of the ICM True-Up Rate Rider, which accounts for the timing of ISAs and the amount of ICM-eligible ISAs that were dropped below the ICM Materiality Threshold.

In some instances, "like-for-like" relocations are not the appropriate or prudent course of action. For example, projects initiated as a result of Waterfront Toronto's Central Revitalization Project called for system expansion to accommodate future development opportunities that emerge out of the renewal of that part of the city. Performing this expansion work at the time of Waterfront Toronto's project work was the most cost effective and least disruptive approach, rather than re-excavating in the same area when developments occur. Moreover, road cutting/trenching moratoria limited the prospects of performing future Toronto Hydro construction activity following the completion of the Waterfront Toronto work.

Toronto Hydro's forecast included 27 jobs to address externally-initiated plant relocation requests during the ICM Period. These jobs were forecast to be completed, partially completed or in progress by the end of the ICM Period.

C. 2012-2014 ACCOMPLISHMENTS

Table 1 summarizes the variance between the forecast ISAs and the actual ISAs in this segment during the ICM Period. Toronto Hydro put into service $34.4 million, which was $2.5 million or 7% less than forecast. Less than forecast ISAs at the segment level was the result of job-level cost variances, many of which were outside of the utility's control, and the deferral or cancellation of certain jobs by third-parties.

Table 1: Forecast vs. Actual In-service Additions

	Forecast ISAs				Actual ISAs				Variance
	2012	**2013**	**2014**	**Total**	**2012**	**2013**	**2014**	**Total**	**Total**
ISAs ($M)	4.5	20.8	11.6	**36.9**	2.6	7.4	24.4	**34.4**	**(2.5)**

Table 2 summarizes the job-level accomplishments for this segment during the ICM Period. Out of the 27 originally forecasted jobs, 21 were complete, partially complete or in progress by the end of 2014. Toronto Hydro cancelled or deferred six of the forecasted jobs in the ICM application as a result of third party delays or requests that were outside of the utility’s control. As shown in Table 2, 24 analogous jobs were added to this segment at the request of third-parties. Twelve of the analogous jobs were completed in the ICM Period while the remaining 12 were in progress as of the end of 2014.

Table 2: 2012-2014 Job-level Accomplishments

Segment Jobs Breakdown	Number of Jobs
Total Forecasted Jobs	**27**
Less: Deferred or Canceled Jobs	(6)
Add: Analogous Jobs	24
Total Segment Jobs	**45**
Less: In Progress Jobs	(16)
Total Jobs with ISAs	**29**
Breakdown of Total Jobs with ISAs	**Number of Jobs**
Completed Jobs	28
Partially Completed Jobs	1
Total Jobs with ISAs	**29**

A majority of the analogous jobs were initiated by the City of Toronto, with several jobs initiated by Metrolinx and the remainder by the provincial Road Authority and the TTC. All of the jobs involved non-discretionary or mandatory relocation work in response to initiatives such as road alignment changes, sidewalk elevation changes, bridge rehabilitation, transit corridor expansion, and Toronto Water projects.

Complete information regarding the investment drivers, scope of work and final costs for all analogous jobs can be found in the Appendix to this Schedule.

D. REVIEW OF VARIANCES

Within the Externally-Initiated Plant Relocations segment, four types of variance causes account for the cost differences between the forecasted job estimates in the ICM application and the actual cost of the completed jobs. As Toronto Hydro's ability to undertake work within this segment is constrained by the work being done by other agencies, one of the main causes of variance in this segment was third party requirements and constraints (see Section 1 below). Variances within this segment were also the result of changes that occurred between the high level estimates filed in the ICM Period and the detailed design work for the jobs, as discussed in Section 2 below. Less common reasons for variance included cost changes due to differences between the actual amount of cost for road cuts and other centrally accumulated costs and the averages used in preparing high level estimates, as explained in Section 3 below, and, in one case, an error in the filed estimate itself, as discussed in Section 4 below.

1. THIRD PARTY REQUIREMENTS AND CONSTRAINTS

As the work in this segment is driven by the schedules and requirements of third-parties, a number of cost variances experienced at the job level were the result of third-party decisions that were outside of Toronto Hydro's control. For example, Toronto Hydro saw significant negative variances due to deviations from the anticipated cost-sharing agreements. In one instance, it was necessary for Toronto Hydro to defer a Metrolinx initiated job as part of the general ramp-down of work following the OEB's decision on Toronto Hydro's 2012-2014 Cost of Service application. To ensure that the project moved forward in a timely manner, Metrolinx elected to make a one-time exception to the cost-sharing agreement and pay the full cost of the job, which brought Toronto Hydro's costs effectively $0. In another instance, at the time of the filing a project was considered to be a relocation project requested by a Road Authority, the City of Toronto. However, during the detailed design stage, Toronto Hydro was notified that this was not a relocation request by the City but rather a beautification request. Legislation does not require Toronto Hydro to pay for beautification projects so the City of Toronto was asked to pay for the full amount of the project. The cost of the project was reduced accordingly.

Third party requirements also resulted in positive variances. For example, Toronto Hydro's costs for a highway relocation project increased primarily due to the Ontario Ministry of Transportation's ("MTO") requirement to complete the work during off-peak hours, which led to higher labour costs. In addition, MTO required engineering reports, the cost of which had not been considered in preparing the high level estimates.

2. HIGH LEVEL TO DETAILED DESIGN VARIANCE

The estimates that underpinned the ICM filing were largely high level planning estimates. The most significant driver of job-level variances were changes that occurred as jobs moved from high-level planning estimates to detailed designs. As the detailed design work was completed on jobs, changes were made to the labour and materials required to execute them. The changes between the high level estimate and project design usually involved changes in the design configuration required by the actual conditions at the project site or changes in project scope.

In some instances, the variances were the result of Toronto Hydro gaining a more complete knowledge of construction requirements for a job during the detailed design or construction phase. For instance, in one of the jobs, Toronto Hydro planners had anticipated the need to relocate telecom related assets and the possibility of incurring costs related to leaking paper-insulated lead-covered cables. When neither of these costs materialized, the cost of the job decreased. In another instance, the designer determined that a greater amount of underground assets would need to be relocated than anticipated in the high-level estimate as Toronto Hydro was unable to obtain an easement for its overhead installation.

Another example was the City of Toronto's north-west PATH relocation project. The City of Toronto, which was responsible for hiring the contractors who would execute the job, ultimately accepted a bid that, due to the complexities of work, specific field conditions, and the City's specific scheduling considerations and other requirements, was significantly higher that Toronto Hydro's estimate. The final cost of the job included significant costs incurred due to shift premiums for night work, complexity of work and congestion of utilities, and asbestos removal.

3. VARIANCE IN ALLOCATED COSTS

One job experienced a significant variance related to design, engineering capital and road cut repair costs, which are typically allocated to a job after it is complete and are proportional to the overall job cost. The filed estimate was intended to capture the amount of remaining expenditures in 2012 for a much larger job that was substantially complete in 2011. The significant variance in this instance was due to the allocation of road cut repairs, design costs and engineering capital, all of which are finalized at the job close-out and are generally proportional to the full cost of the job.

4. ERRORS

A clerical error in the ICM filing produced a material variance for one job. The estimate for this job was incorrectly filed at about half of the expected cost, resulting in the appearance of a significant positive variance. In fact, the job was completed at a lower than forecast cost.

ICM Segment **B21 Externally Initiated Plant Relocations**

Estimate	Description	Actual ISA	Rationale/Driver for Inclusion
EST20651_002	X11633 Roncesvalles Dundas St W TTC	$237,783.99	The TTC requested attachment of streetcar strands to Toronto Hydro poles on the west side of Roncesvalles and Dundas streets. The existing poles were unable to support the attachment, so three new steel poles were installed. The total cost of this job was $526K, with part of the expenditures occuring prior to 2012. These amounts did not come into service before the ICM period are therefore captured in the pre-2012 CWIP amounts coming into service in the ICM period.
EST20975_003EST21411_003	E11664 Duncan Mills Bridge	$96,358.30	To facilitate rehabilitation of the Duncan Mills bridge by the road authority, Toronto was obligated to relocate ducts located under the bridge. The total cost of this job was $403K, with part of the expenditures occuring prior to 2012. These amounts did not come into service before the ICM period are therefore captured in the pre-2012 CWIP amounts coming into service in the ICM period.
EST20587_003	X11627 Tra A10T-12T to A54-57-58T	$298,248.07	As part of Metrolinx's Strachan Ave. grade separation project, Toronto Hydro was obligated to relocate all feeders crossing CN rail tracks along Strachan Ave. This job started prior to 2012. The total cost of this job was $300K, with a small portion of the expenditures occuring prior to 2012. These amounts did not come into service before the ICM period are therefore captured in the pre-2012 CWIP amounts coming into service in the ICM period.
ESTAS12016_001	E12667 Reconfig distrib R2634 Tapscott	$83,488.08	Toronto Hydro was obligated to reconfigure single-phase distribution to accomodate City of Toronto rehabilitation work associated with the Tapscott Road Underpass.
EST24212_003	PCI - W12756 EDENBRIDGE DR EXPANSION/ PO	$64,308.42	To facilitate City of Toronto roadwork, water main and sewer replacement near Bearwood Drive, Toronto Hydro was obligated to relocate three poles and one guy wire.
EST21468_003	PCI W11825 CARLINGVIEW OH PLANT RELOC	$220,443.04	This job involved relocating 15 poles carrying primary feeders in order to accomodate work on the Metrolinx GO expansion at Carlingview Drive in near the Pearson Airport.
EST26317_003	PCI-X13514 FRONT AND JARVIS RELOCATION	$91,855.99	This job involved relocating distribution assets to accomodate City of Toronto watermain repairs at Front St and Jarvis Rd.
EST27658_001	ICM-W13629 Ext Init Knightwood UG Relc	$148,808.40	This job relocated underground road crossings in three locations on Knightswood Road to allow for City of Toronto storm sewer construction.
EST29920_003	X14725-VAULT LOC.4761 ROOF REB.	$77,789.43	This job involved raising a vault roof in order to match a proposed city sidewalk elevation.
EST31038_001	W13501 Park Lawn StLt Pole Relocation	$93,127.20	The City of Toronto proposed a road widening of Park Lawn Rd. north of Lakeshore Blvd W. on the west side. To facilitate this project, Toronto Hydro was obligated to relocate five poles and associated underground ducts.
EST29748_003	X13750 York ST cable p/o	$143,858.04	This project was intitiated when the TTC came across Toronto Hydro's cable chambers while replacing their trackbeds. Toronto Hydro's cable chambers included large holes were identified for repair. Toronto Hydro was called to investigate and remediate the situation. This project had to be completed as soon as possible as it involved closing York street from Front street to Queen street.

ICM Segment **B21 Externally Initiated Plant Relocations**

Estimate	Description	Actual ISA	Rationale/Driver for Inclusion
EST30437_003	W14765 - GO Transit Expansion Creation Date: October 1, 2010	$160,624.85	GO Transit is expanding their service to Milton and west of Toronto in a project called Georgetown expansion. There were numerous Toronto Hydro poles and underground structures along the way that required modification. Failure to relocate poles in a timely manner could have delayed the completion of GO service upgrade. This could have delayed the opening of Union Pearson Express line.
EST27118_001	PCI Queens Quay Ph 1_2_3 ELECTRICAL WBS-CCM RC4330 CAPEX for IFRS	$0.00	In Progress
EST28276_003	ICM W12851 Eglinton Crosstown Part 1 - 5 Eglinton Ave W and Blackthorn	$0.00	In Progress
EST28283_003	ICM W12854 EGLINTON CROSSTOWN Part 4-5 Eglinton Between Park Hill and Flanders	$0.00	In Progress
EST28320_003	ICM W12852 EGLINTON CROSSTOWN Part 2 - 5 Eglinton and Little	$0.00	In Progress
EST28547_003	ICM W12853 EGLINTON CROSSTOWN Part 3 - 5 Eglinton and Dufferin	$0.00	In Progress
EST30541_003	S14748 EsplanadeTS Cable Suprt "Dis Sup" Terminate Two Neutral Cables 2014	$0.00	In Progress
EST29932_003	X12998 TTC Leslie St. Connection Track Created Oct 2010	$0.00	In Progress
EST31635_003	W14818 Metrolinx Weston Underpass OH Restoration	$0.00	In Progress
EST32087_003	W14850 TTC Bakersfield poles relocation Creation Date: February 18,2014	$0.00	In Progress
EST33647_001	X13750 York ST cable p/o - Electrical Transfer from DPC to DCW	$0.00	In Progress
EST33163_003	E14904 #2740 Lawrence HONI Interference E5-1M23	$0.00	In Progress
P0091683	O/H Sec Bus Upgrds & Reloc To Ttc Poles	$0.00	In Progress

Power System Engineering, Inc.
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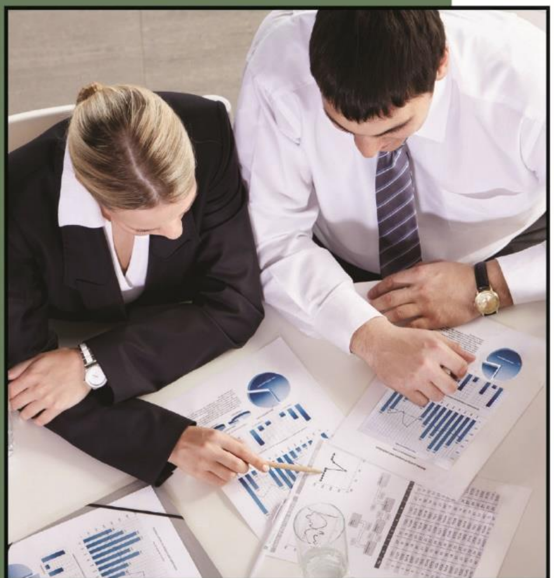

Toronto Hydro ICM Variance Evaluation

Prepared by:

Power System Engineering, Inc.

January 29, 2016

Toronto Hydro ICM Variance Evaluation

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1 Executive Summary

In 2012, Toronto Hydro-Electric System Limited ("Toronto Hydro"), as part of its 2012-2014 Incentive Regulation Mechanism application, requested Incremental Capital Module ("ICM") funding for critical capital projects, expected to be performed during 2012 to 2014. Torys LLP retained Power System Engineering, Inc. ("PSE") to provide an opinion on the reasonableness of variances between the Ontario Energy Board-approved expenditures and actual expenditures, at a segment level.

First, PSE reviewed and considered cost estimation literature to determine an appropriate "expected variance range" for estimates made at the point of the process which Toronto Hydro performed the estimates contained in its ICM application. Based on this analysis, and having regard to the early stage of the planning process during which the estimates were prepared, PSE concludes that an expected estimation variance range of -30% to +50% is appropriate for Toronto Hydro's segment estimations.

PSE then reviewed the variances for 13 segments identified in Toronto Hydro's ICM. This review was done at the segment level. Further review of variances was conducted at the job level where notable segment-level variances were identified. Overall, based on a comparison of forecasted vs. actual in-service additions ("ISAs") at the segment level, PSE finds the variance ranges for the segments to be reasonable, given the stage at which the estimates were made, and the conditions (as described by Toronto Hydro) that led to variances outside of the expected range.

PSE compared the forecasted ISAs to actual ISAs for each segment. Ten of the thirteen segments were found to be within the expected estimation variance range of -30% to +50%. The remaining three segments were outside the expected range, all falling below the -30% variance threshold (meaning actual ISAs were lower than projected ISAs).

PSE also reviewed completed jobs for eleven out of thirteen segments[1], and ten of those segments were found to be within the expected estimation variance range. Only one segment was outside the expected range, falling above the +50% variance threshold (meaning that actual ISAs were outside the projected ISAs variance range).

For the segments that had variances outside the expected estimation variance range, for either the overall ISAs analysis or completed jobs analysis, PSE examined the relevant narrative explanations from an engineering perspective. PSE also looked at the narrative explanations for select segments that were within the expected estimation variance range, but close to the thresholds.

[1] Toronto Hydro did not provide job level accomplishment details for two segments, which instead were presented on an overall ISAs basis. Toronto Hydro distinguished these two segments from the others because they are not based on specific job-level activities but, instead, are 'bucket' estimates to capture high volumes of identical discrete units.

Based on its analysis of the explanations provided by Toronto Hydro for the variances in these outlier segments, PSE concludes that the variances for such outlier segments are reasonable from an engineering perspective. In other words, the drivers of variances in the outlier segments are the types of conditions that cause such outlier variances, and are also the types of conditions that cannot always be reliably foreseen at the estimation stage at which Toronto Hydro created the estimates.

2 Background

2.1 Toronto Hydro's ICM Filing

In 2012, Toronto Hydro-Electric System Limited ("Toronto Hydro") applied to the Ontario Energy Board ("OEB" or the "Board") for Incremental Capital Module ("ICM") funding for a variety of capital improvement projects. The OEB approved funding for certain Toronto Hydro capital projects of various types (also known as "segments"). Each segment is composed of a number of discrete jobs that are similar in nature. For example, one segment involved replacing Fibertop Network Units with Submersible Network Units. Each job consisted of the replacement of one or more Fibertop units; all the Fibertop replacement jobs put together constitute the segment.

The OEB approved specific levels of in-service additions ("ISAs") for each segment, and required Toronto Hydro to "true-up" the OEB-approved amounts at the segment level after 2014. This true-up is to be performed in Toronto Hydro's 2012-2014 ICM True-up Application (the "Application").

Torys LLP ("Torys") retained Power System Engineering, Inc. ("PSE") to provide an opinion on the reasonableness of variances between the OEB-approved ISAs and actual ISAs, at a segment level. This report (the "PSE Report") represents PSE's opinion on the segment variances from an engineering perspective.

2.2 Brief Description of ICM Process and PSE Evaluation Approach

From 2011 to 2014, Toronto Hydro operated under an Incentive Regulation Mechanism ("IRM") framework, which had a first year of rates based on cost-of-service, followed by three years of rates using a formula set by the OEB. The ICM provided a mechanism by which extraordinary spending could be approved during the IRM period. In 2012, Toronto Hydro requested ICM funding for critical capital projects, expected to be performed during 2012 to 2014. The OEB approved ICM funding for 13 project segments; this approval was completed over two phases of the proceeding. Each segment was composed of jobs of a similar type.

In projects of this magnitude, as construction is commenced, jobs may sometimes have to be deferred or cancelled, due to logistical, engineering, and other reasons. Therefore some Toronto Hydro ICM segments have jobs that were expected, but not started—they were deferred or cancelled. Furthermore, some jobs were commenced but not completed, and are designated as "in progress" (i.e. underway but with no ISAs) or "partially complete" (i.e. underway with partial ISAs) as of the end of 2014. Thus the five main categories of Toronto Hydro ICM jobs from a progress standpoint are:

1. Completed
2. In-progress
3. Partially complete
4. Deferred
5. Cancelled

In addition, some jobs may be added, for example when newly discovered jobs turn out to be more urgent than the originally contemplated jobs. Toronto Hydro refers to these jobs as "analogous" jobs. Analogous jobs may be either completed, in-progress, or partially complete.

2.3 Objective of PSE Report

The objective of the PSE Report is to review the *Requests and Rationale: True-up of the 2012-2014 Incremental Capital Module Application* ("Exhibit 1" or the "True-up Summary"), and the individual ICM Project True-up narratives ("Exhibit 2" or the "Narratives") for each ICM segment and provide an independent analysis of the reasonableness of variances in the ICM segments.

2.4 Scope of PSE Report

PSE utilized the information and data in Exhibits 1 and 2 to develop a commentary on the reasonableness of the established variances based on industry experience, taking into account the size and complexity of the segments.

PSE generally focused on completed jobs as an aggregate group. It is difficult to evaluate variances for in-progress jobs and partially completed jobs, as they do not yet have a final cost. Obviously, deferred or cancelled jobs do not have a final cost either. Thus, one of the bases for PSE's evaluations was to compile the completed jobs within each segment, and take the aggregate forecasted ISAs as compared to the aggregate final ISAs.

2.5 PSE Methodology

PSE used the following methodology as applied to the information and data supplied to PSE in Exhibits 1 and 2.

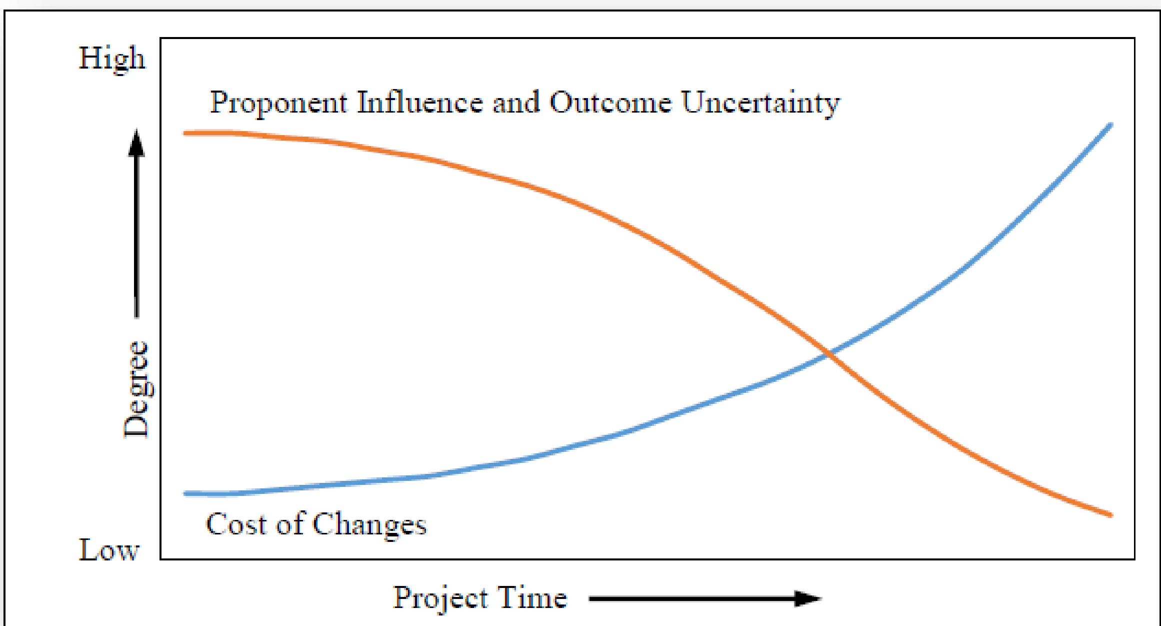
1. Identify relevant organizations which have developed estimation classification frameworks that include a baseline metric for reasonable variance expectations. Review and consider these estimation frameworks, which divide such initiatives into different project stages and which have different expected accuracy for estimations. As the project stage progresses toward construction, the accuracy expected becomes more precise.
2. Ascertain the planning stage in the researched frameworks that is most similar to the stage in the ICM process at which Toronto Hydro made its estimates; this will produce an "expected" variance range for ICM forecast estimate accuracy.
3. Apply the "expected" or baseline metric variance expectations to the ICM actual variances; compare/contrast the actual ICM segment variances with the variance expectations.
4. Comment on the reasonableness of the actual ICM segment variances relative to the baseline variance expectations, at the segment level.
5. Comment on the reasonableness of Toronto Hydro's explanations for the actual ICM segment variances, relative to variance explanations common in the industry.

3 Estimation Processes for Utility Projects

3.1 Introduction

Distribution utility capital program and project costs are dependent on many factors, such as project definitions, scope of work, material and commodity prices, labor rates, field settings, impact on other systems and vice versa, physical constraints due to geography, project timeframe, and weather conditions. As shown in Figure 3-1, the level of proponent influence and outcome uncertainty of the above mentioned factors are greatest at the start of a project, while the ability to influence the final characteristics of a project's objective, without significantly impacting cost, is lowest toward the end of a project's life. These factors and project management control characteristics directly tie the stage of a project to the accuracy of forecast cost estimates as they relate to the final costs.

Figure 3-1 Proponent Influence/Uncertainty vs. Cost of Changes



For this purpose, it is important to first establish an understanding of the various stages (alternatively called "phases") of a project's life. Once these phases are known, they can then be used to quantify an "estimate class" in relative terms. For example, an estimate made at the concept phase of a project will most likely be different than an estimate made at the design phase. Although the terms used can vary from utility to utility, conceptually there are similarities in "stages" or "phases" of a project. The approximated "estimate class" can then be used to establish the range of reasonable variance expectations.

3.2 Estimating Costs of Capital Programs

PSE has worked with many electric distribution utilities over the last 40 years developing, monitoring, and completing capital programs. Our involvement has ranged from developing comprehensive plans that outline and define all projects within a multi-year program, to taking on smaller roles of designing and managing individual projects, and roles in between. We have experienced various processes used by utilities for accomplishing an entire capital program life, but a common progression is found across the industry.

Large scale capital programs carried out by electric distribution utilities move through various stages from initiation to completion. Significant planning and study work is performed at the beginning stage of a program, identifying distribution infrastructure needs driven by demand growth, reliability, safety and other planning criteria standards. The planning and study efforts typically result in a two- to five-year timeline, by proposing a collection of capital projects varying by type and magnitude. From the planning and study level, the identified capital projects next typically go through an approval process, where authorization is given to go ahead with the program. The PSE-defined major stages or phases of a capital project are shown below.

Figure 3-2 Phases of a Capital Project

PSE classifies the planning and study level as a "screening" phase, and once a proposed program has been approved, the collection of projects within the program are further refined by going through a "conceptual" phase that puts a group of projects into motion on a yearly budget schedule. From here, projects are further defined in a "definition" phase to assure that, based on actual conditions, the anticipated results can be achieved and refined costs aligned with the yearly budget or an approved change order. Upon approval of the definition phase, projects are typically "committed" and proceed through the final design and construction phases. Figure 3-2 illustrates the phase progression a project goes through in a capital program. Again, although not all utilities or engineers would use identical terminology, in our opinion the description of these high-level phases would be recognizable to most practitioners in the field.

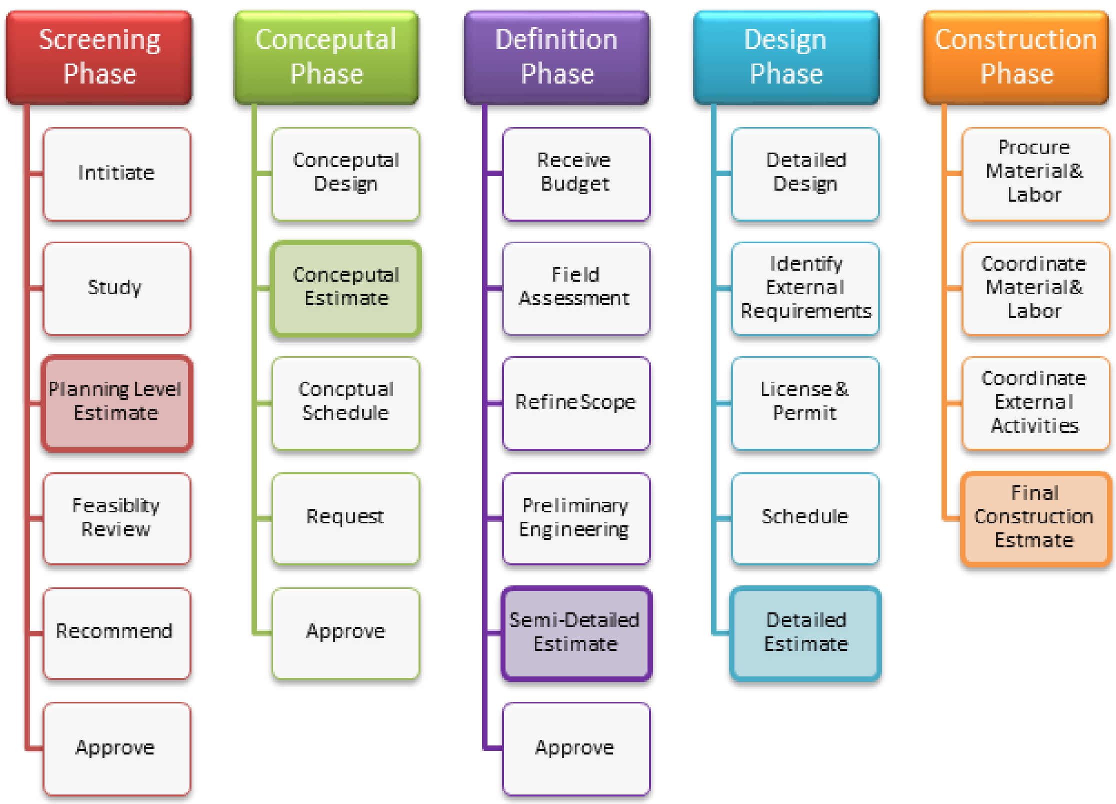
This phased type process is an efficient, effective and practical approach. It allows system planners to compare, evaluate and recommend (or oppose) capital project alternatives using high level estimates based on general assumptions of project parameters and experiences aligned with historical undertakings. Developing detailed estimates at this stage is not prudent as it would result in establishing futile designs of discarded project alternatives as well as adversely extending the overall planning process timeline. The advantage of the phased process allows for subsequent stages to further refine selected projects through additional and substantial efforts, such as detailed designs and corresponding estimates, built upon earlier planning exertions. Control checks can be inserted during subsequent stages to ensuring project objectives will be realized and fulfill the intentions of system planners.

3.3 Cost Estimate Phases and Anticipated Accuracy (General)

Throughout the various phases of a capital program, cost estimates are developed and refined for assessing project feasibility, control and approval. The accuracy range of the estimates are closely related to the amount of detail known about a project at the time of the estimate. As a project progresses through the phases of a capital program, more information on factors influencing costs is obtained, allowing the accuracy of cost estimates to be refined.

The progression of the PSE defined phases for a capital project is shown again in Figure 3-3, which illustrates a list of efforts that fall within each stage of the framework. Some utilities merge the listed efforts into fewer project phases; however, the below illustration provides a more granular view. Within each phase a cost estimate is developed and refined. At the screening phase, a planning level estimate is established based on a high-level project scope definition. In the next phase, a conceptual estimate can be established based on a conceptual design of a specific project, using representative assumptions and applying utility standards. Conceptual estimates are typically used for the development of annual budgets.

Figure 3-3 Phases of a Capital Project (detailed)



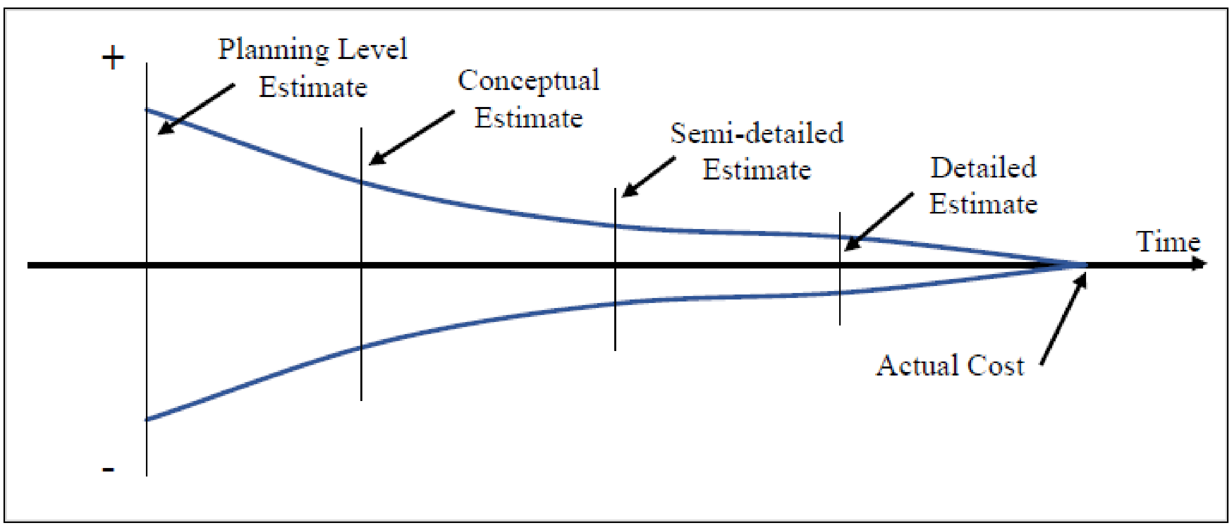
Field conditions for a specific project are assessed in the definition phase. Based on this assessment, the project scope may be refined due to field conditions and physical constraints. Preliminary engineering of the refined scope allows for a semi-detailed estimate to be established and used as a control for the final project advancement approval. Following the approval at this definition phase, a project is typically committed.

In the design phase, a detailed design is established upon which construction will be based. External requirements, such as involvement of other utilities and public entities, are identified. Material and labor is procured. Licenses and permits are obtained. The construction schedule is developed. Only at this point can a detailed construction estimate be developed.

The final phase of progression for a capital project is actual construction. Even during this phase, a number of factors can surface causing the final cost to deviate from a detailed estimate. These factors include weather, equipment malfunction, unknown underground obstructions, and other unpredictable impediments.

Figure 3-4 illustrates how the accuracy of cost estimates improve over the phase and time progression of a capital project. Estimates are dependent upon the available information, time demands, purpose of the estimate, and technique used. In all cases observed by PSE, cost estimates of capital projects start off at a higher level of inaccuracy, compared to subsequent estimates, which are developed and refined until the actual cost is known.

Figure 3-4 Accuracy of Estimates

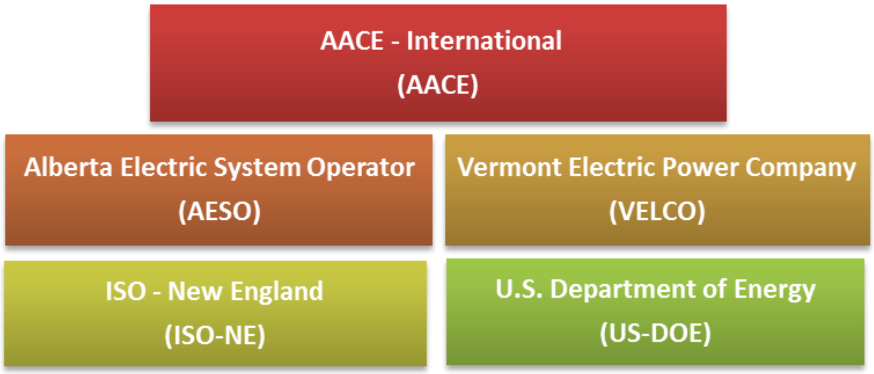


3.4 Cost Estimate Phases and Anticipated Accuracy (Specific Industry Examples)

PSE reviewed and considered numerous sources to establish guidelines around a reasonable variance expectation of project cost estimates within the electric utility industry. Our findings indicated that there are alternative viewpoints and that not one standard is accepted by all. However, we also recognize relative consistency between published guidelines that are applicable to the electric utility industry. Through the course of our research, we identified a total of five sources applicable to the electric utility industry that provided guidance in establishing and understanding the expected variances for forecast cost estimates at different stages of a project sequence compared to final costs. These sources are shown in the following figure, and included AACE International ("AACE"), Alberta Electric System Operator ("AESO"), Vermont Electric

Power Company ("VELCO"), ISO New England ("ISO-NE"), and the U.S. Department of Energy ("US-DOE").[2][3]

Figure 3-5 Cost Estimate Phases--Sources



Each of these sources has recognized a framework identifying various characteristics such as the level of project definition, purpose of the estimate, methodology used develop the estimate, expected accuracy range of the estimate and the amount of effort behind the estimate preparation. For example, the AACE International provides a cost estimate classification matrix summarizing the framework of estimate classes based on primary and secondary characteristics as seen in Figure 3-6.

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[2] The source documents and associated web links are identified the Appendix to this Report.

[3] AACE International was previously known as the American Association of Cost Engineering, and then the Association for the Advancement of Cost Engineering.

Figure 3-6 AACE Estimation Classification Matrix

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.
[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

The sources reviewed typically divide estimations into classes. Although the classes generally correspond to the PSE-defined stages of a project previously shown in Figure 3-2, in some instances, the estimation classes identified in the sources do not align precisely.

Figure 3-6 shows the AACE estimation for illustrative purposes. Referencing the AACE table suggests that a capital project at the concept screening phase, when only up to 2% of the project design and "complete in service" definition is known, can be categorized as a Class 5 estimate. The table further suggests that the expected variation of actual in service cost of a given capital project scope, after the application of contingency, can vary as low as -50% and as high as +100%. The estimation matrices for the remaining sources are provided in the Appendix of this report.

Of the five sources identified and reviewed by PSE, AACE is qualitatively given a greater weighting due to the nature of the organization. AACE is non-profit association serving the total cost management community since 1956. The association consists of over 9,000 members world-wide and serves total cost management professionals in a variety of disciplines and across all industries. PSE also recognized during our research, that AACE is commonly referenced by other organizations and companies.

Using the AACE framework as a starting point, PSE compared the other four sources and developed a summary matrix, shown in Table 3-1. This comparison matrix identifies five cost estimate classes and compares the definition level, estimate type and expected accuracy for each reference. By blending all sources, and giving AACE a higher qualitative weighting, PSE developed characteristics that correspond with PSE defined project phases in Figure 3-3.

The expected accuracy corresponding to the PSE-defined estimate was set to the AACE source. For reasons previously explained, PSE gave AACE the highest qualitative weighting compared to all sources. The AACE expected accuracy range also falls within the majority of other sources' expected accuracy ranges. The definition level corresponding to the PSE-defined estimate is a mix of all sources with AACE given the highest weighting. The distinguishing difference between the AACE and the PSE definition levels is that the PSE levels do not overlap. Where overlap occurs in the AACE definition levels, other sources were considered along with PSE's experience of project definition levels to establish a more definitive transition from one project definition to the next.

Table 3-1 **Summary of Estimate Classifications Sources Reviewed**

		Class 5 Estimate	Class 4 Estimate	Class 3 Estimate	Class 2 Estimate	Class 1 Estimate
AACE	Definition Level	0 – 2%	1% - 15%	10% - 40%	30% - 70%	50% - 100%
	Estimate Type	Screening	Feasibility	Budget	Detail Control	Construct
	Expected Accuracy	+100% / -50%	+50% / -30%	+30% / -20%	+20% / -15%	+15% / -10%
AESO	Definition Level	0 – 2%	1% - 15%	10% - 40%	30% - 70%	65% - 100%
	Estimate Type	Screening	Concept	Budget	Control	Construct
	Expected Accuracy	+50% / -30%	+30% / -20%	+20% / -15%	+15% / -10%	+10% / -5%
VELCO	Definition Level	1% – 15%		10% - 40%	30% - 70%	50% - 100%
	Estimate Type	Study/Simplified		Budget	Detail Control	Final
	Expected Accuracy	+120% / -60%		+60% / -30%	+30% / -15%	+10% / -5%
ISO-NE	Definition Level	0 – 15%		15% - 40%	40% - 70%	70% - 90% / 80% - 100%
	Estimate Type	Order of Magnitude		Conceptual	Planning	Eng. / Const.
	Expected Accuracy	+200% / -50%		+50% / -25%	+25% / -25%	+10% / -10%
US-DOE	Definition Level	0 – 2%	1% - 15%	10% - 40%	30% - 70%	70% - 100%
	Estimate Type	Screening	Feasibility	Budget	Control	Construct
	Expected Accuracy	+100% / -50%	+50% / -30%	+30% / -20%	+20% / -15%	+15% / -10%
PSE	**Definition Level**	**0 – 2%**	**2% - 15%**	**15% - 40%**	**40% - 70%**	**70% - 100%**
	Estimate Type	**Screening**	**Conceptual**	**Definition**	**Design**	**Construct**
	Expected Accuracy	**+100% / -50%**	**+50% / -30%**	**+30% / -20%**	**+20% / -15%**	**+15% / -10%**

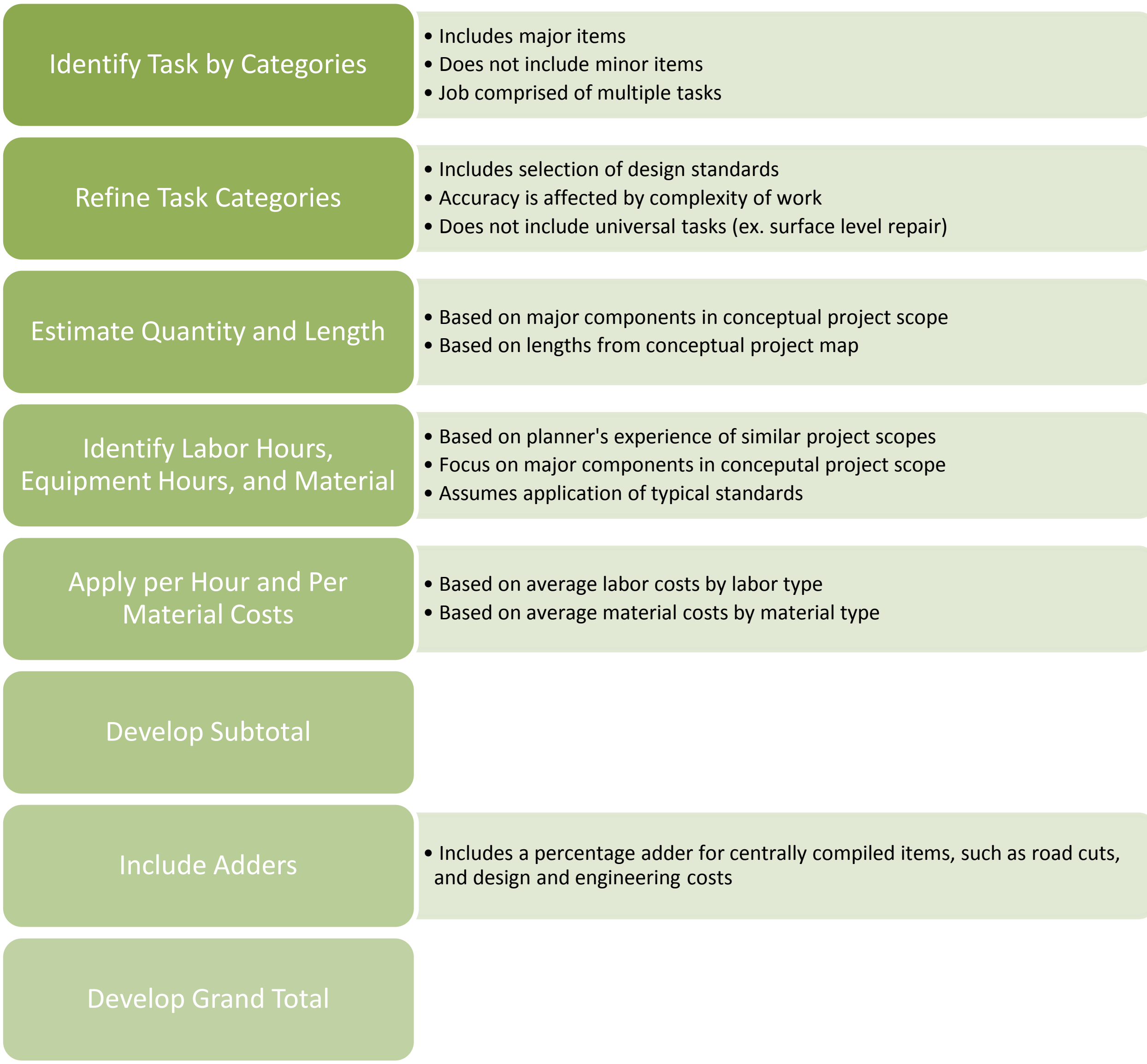
3.5 Toronto Hydro's High-Level Estimation Process

The capital projects costs in Toronto Hydro's 2012 ICM filing were based on a high-level estimating process. From a big picture perspective, this process identified typical tasks needed to complete each job within a segment using a conceptual design approach. This conceptual design approach consisted of the following characteristics:

- Referenced planning and study level job scopes.
- Based on typical planning standards, typical construction standards and generalized local conditions.
- Generally based on maps and records assessed from the office.
- In some cases, a basic field review was performed to confirm the conceptual design scope.
- Identified major components required for a job.
- Did not include research or efforts required to identify all complications that would cause a detailed design to deviate from typical standards, generalized assumptions, or normal construction steps. For example, the presence of overly congested underground utilities in an underground job area would not typically be known at the time of the conceptual design.

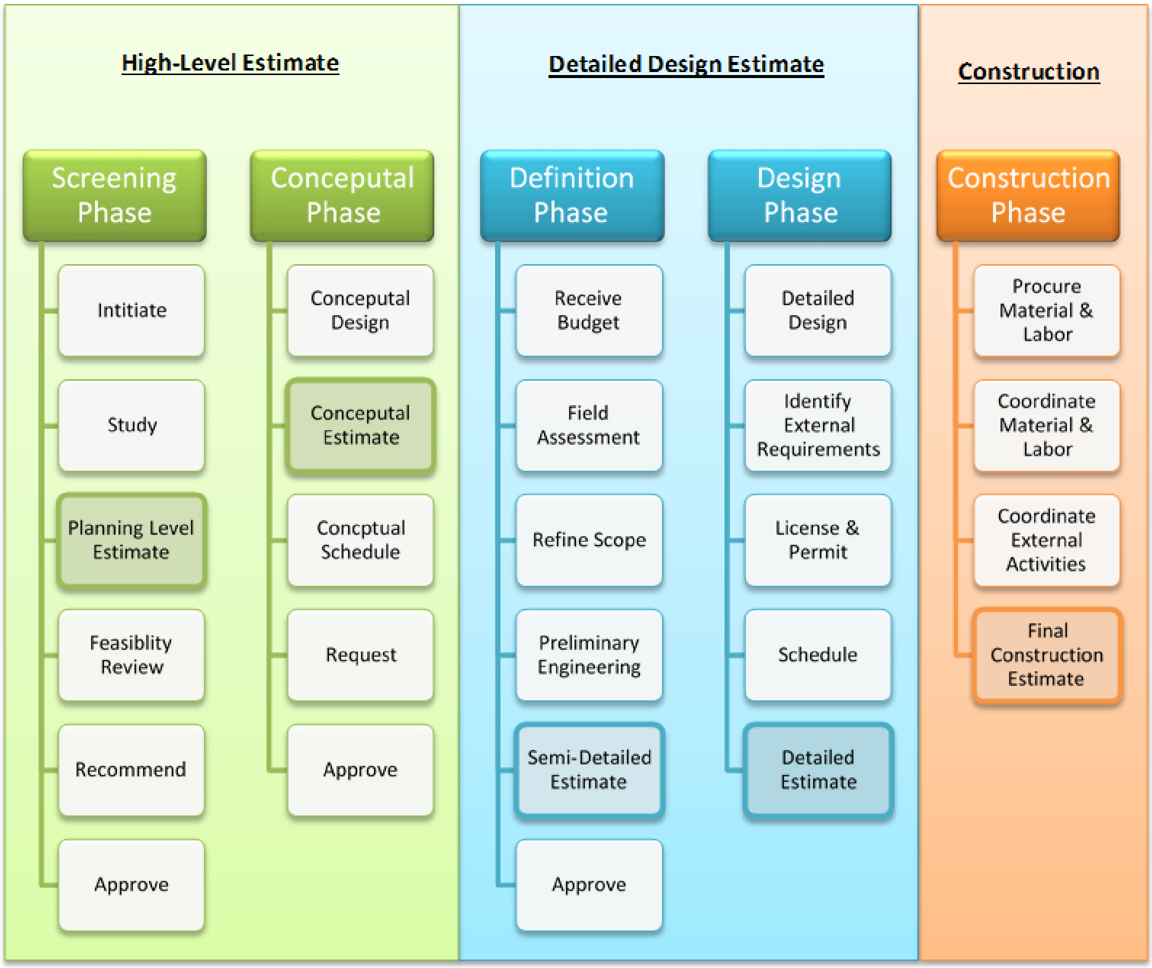
In order to establish a more definitive understanding of Toronto Hydro's high-level cost estimating process, a closer examination of the approach used in their underground infrastructure job (segment B1) was conducted. This approach was broken down into the following eight steps.

Figure 3-7 Summary of Toronto Hydro's High-Level Estimation Process



Referring to the high-level estimating process identified above, as well as knowledge gained through interviews, PSE characterizes Toronto Hydro's capital project estimation process as being comprised of three phases: (1) high-level, (2) detailed design, and (3) construction. Toronto Hydro's high-level estimation phase is a combination of the PSE-defined screening and conceptual phases and Toronto Hydro's detailed design estimation phase is a combination of PSE-defined definition and design phases. This association is further illustrated in Figure 3-8.

Figure 3-8 Toronto Hydro's Estimation Process



3.6 Application of Industry Ranges to Toronto Hydro's ICM Estimation Process

Aligning the Toronto Hydro capital project process with the PSE cost classification matrix results in an association illustrated in Table 3-2.

Table 3-2 Toronto Hydro's Estimates

		Class 5 Estimate	Class 4 Estimate	Class 3 Estimate	Class 2 Estimate	Class 1 Estimate
PSE	Definition Level	0 – 2%	2% - 15%	15% - 40%	40% - 70%	70% - 100%
	Estimate Type	Screening	Conceptual	Definition	Design	Construct
	Expected Accuracy	+100% / -50%	+50% / -30%	+30% / -20%	+20% / -15%	+15% / -10%
Toronto Hydro	Definition Level	**0 – 15%**		**15% - 70%**		**70% - 100%**
	Estimate Type	**High Level**		**Detailed Design**		**Construct**
	Expected Accuracy	**+50% / -30%**		**+20% / -15%**		**+15% / -10%**

Given the above description of the Toronto Hydro high level estimation process, PSE has assigned Toronto Hydro's ICM estimates an estimation phase of "Class 4" based on when the ICM projections were made. Based on this "Class 4" designation, and based on data from industry practices and association guides, it is reasonable to expect ICM variances in each segment to have a variance of +50% to -30%. Percent variances within that window would be considered appropriate for the originally intended accuracy level of the forecasted estimate.

3.7 General Comments Regarding Segment Types

It is widely accepted in the industry that certain types of projects tend to produce larger variances than other types. For example, a program to replace analog residential meters with smart meters may have costs that are somewhat well-defined in advance of actual replacement. Other projects, such as undergrounding, may run into unforeseeable problems (e.g. the discovery of underground equipment from another utility, traffic issues, weather issues, etc.). The natural planning/ construction evolution of large complex initiatives identifies "new and better" information, changes resource alignments, improves inspection and testing methods, and reorders job priorities. All of these factors and others contribute to larger variances for highly complex projects relative to smaller scale efforts with more definitive job definitions.

Furthermore, variation in accuracy and precision occurs on a segment to segment basis. For example, segments such as Underground Infrastructure (B1) and Paper Insulated Lead Covered Cable (B2) exhibit greater variation due to the limited inspection and testing methods available for pre-assessing actual in-service conditions.

Moreover, each segment is comprised of numerous jobs and variation in accuracy will occur on a job to job basis within a segment. While each job in a given segment would have similar basic requirements consisting of material, labor, equipment, and indirect cost allocations, there are other factors which also affect the variance outcome.

These “difficult to quantify” factors involve site specific conditions, operational conditions, interface conditions, and unforeseeable conditions. Many of these factors are dynamic and change over time, further increasing the estimating as well as the execution challenges. Exhibit 1, Section 4 (“Variance Explanations”) details the common drivers for the cost variances, and the various Exhibit 2 Narratives discuss variances for specific jobs experienced in the ICM initiative.

4 Variance Evaluation

4.1 Forecasted ISAs vs. Actual ISAs: Segment Level

In this section, comparisons are drawn from forecasted ISAs to actual ISAs at the segment level. Application of the accuracy boundaries of +50% and -30% established in Section 3.6 identifies segments with percent variances outside the normal expectations. We also consider the magnitude of the dollar variance relative to the other segments.

The forecast and actual ISA data for each segment were provided in the True-up Summary (Exhibit 1) of the 2012-2014 Incremental Capital Module Application. The variances are shown in the table below (numbers may differ slightly from Exhibit 1 due to rounding).

Table 4-1 Forecast ISAs vs. Actual ISAs

Segment Number	Segment Description	2012-2014 Forecasted ISA ($M)	2012-2014 Actual ISA ($M)	Variance ($M)	Percent Variance
B1	Underground Infrastructure	124.4	180.0	55.6	44.7%
B2	PILC	6.9	2.8	(4.1)	-59.9%
B3	Handwell Replacement	37.5	36.4	(1.1)	-3.0%
B4	Overhead Infrastructure	79.7	83.7	4.0	5.0%
B5	Box Construction	29.3	23.0	(6.4)	-21.7%
B6	Rear Lot Construction	50.8	58.0	7.2	14.3%
B9	Network Vault & Roofs	22.5	17.3	(5.2)	-23.2%
B10	Fibertop Network Units	12.0	13.6	1.6	13.3%
B11	ATSs and RPBs	3.4	1.9	(1.5)	-43.1%
B12	Stations Power Transformers	3.9	5.0	1.1	29.5%
B13	Stations Switchgear	16.7	5.0	(11.7)	-70.2%
B20	Metering	17.0	18.1	1.2	7.0%
B21	Plant Relocations and Expansions	36.9	34.4	(2.5)	-6.7%
Total		**441.0**	**479.3**	**38.3**	**8.7%**

The percent variances and the established percent variance expectation bands were combined into a bar chart to identify outliers (see Figure 4-1 following). In addition, a bar chart was created to show the ISA dollar variances by segment (Figure 4-2).

Figure 4-1 Percentage of ISAs Variance (Overall)

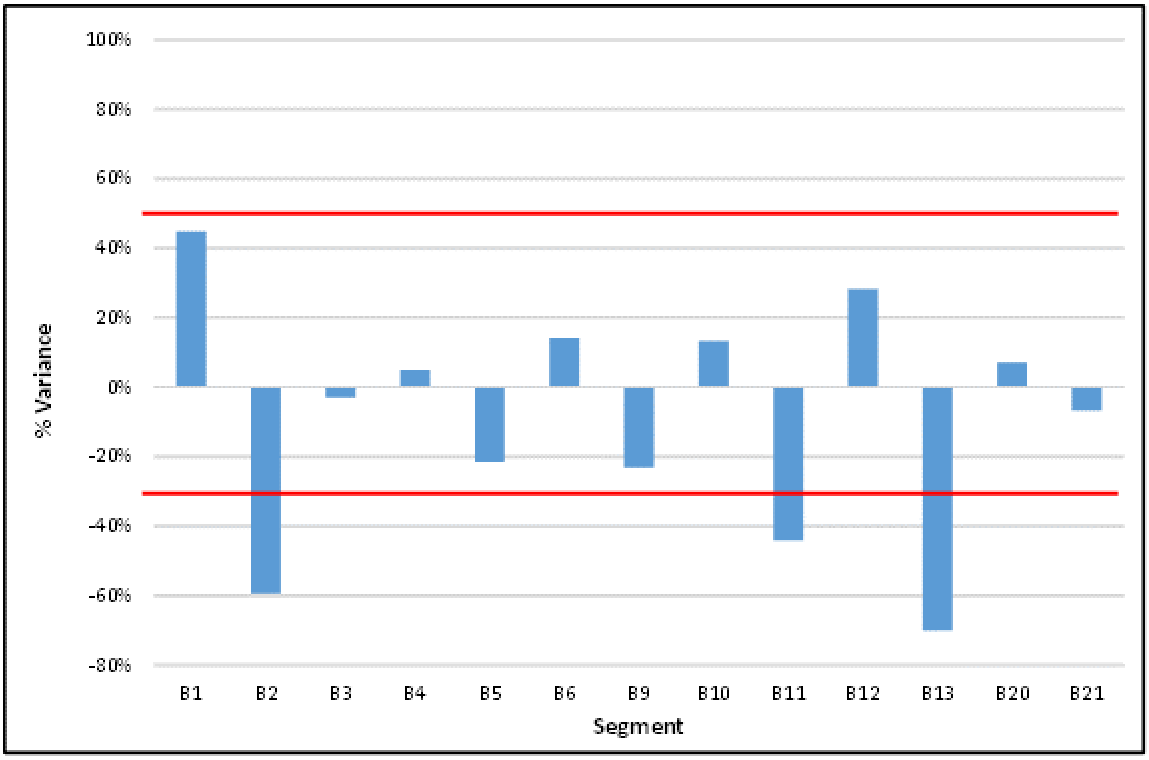
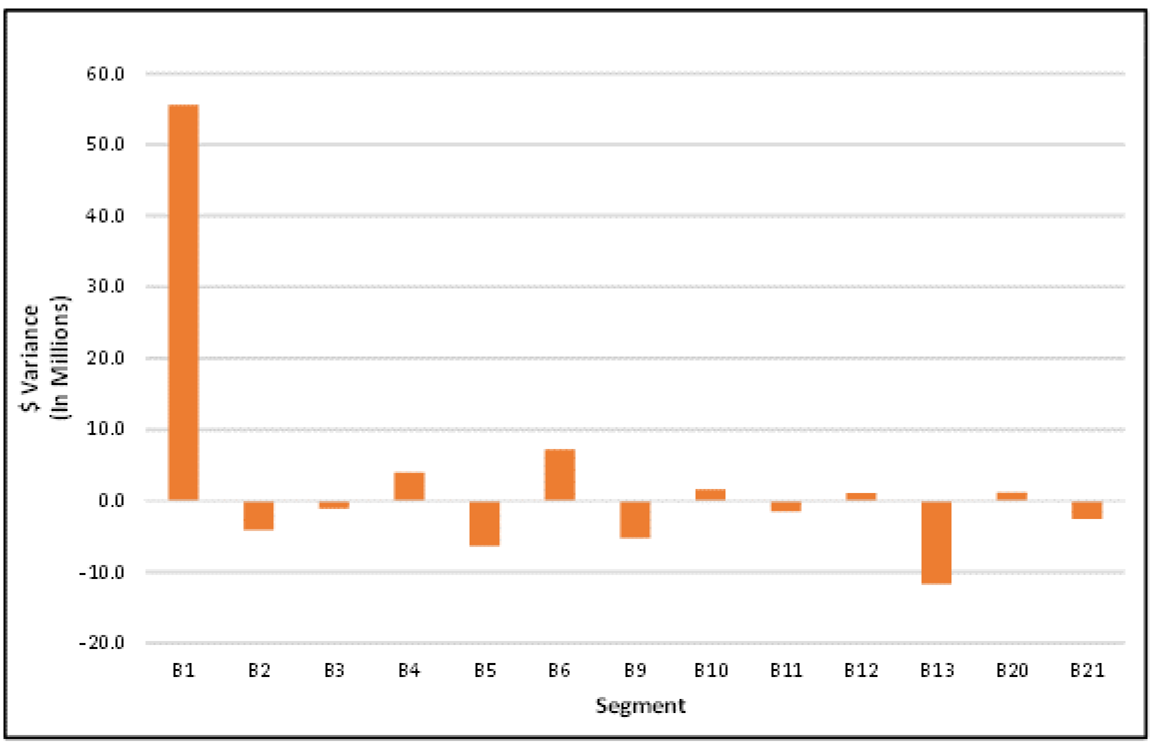


Figure 4-2 Dollar Amount of ISAs Variances (Overall)



As illustrated in Figure 4-1, the majority of segments are within the expected range of variance. Only three segments produced variances which exceeded the +50%/-30% thresholds; these segments warrant further review.

1. ICM Segment B2: PILC Piece Outs and Leakers
2. ICM Segment B11: Automatic Transfer Switches and Remote Power Breakers
3. ICM Segment B13: Stations and Switchgear

Furthermore, B1 (Underground Infrastructure) was close to the upper limit of +50%. B1 also warrants further review because it is the largest segment in terms of ISAs. With that being said, it is also important to note that the variance decreases when looking only at completed jobs as illustrated in Figure 4-2.

Segments B1, B2, B11, and B13 are furthered reviewed in Section 4.4.

4.2 Forecasted ISAs vs. Actual ISAs of Completed Jobs

Next, PSE focused on the completed jobs only (not including analogous jobs), and compared forecasted ISAs to actual ISAs. These completed jobs are the only jobs for which both final actual ISAs, and forecasted ISAs are available for comparison. The deferred and cancelled jobs have forecasted ISAs, but no actual ISAs. The in-progress jobs and the partially complete jobs have forecasted ISAs, but do not yet have final actual ISAs. Analogous jobs have final ISAs in many cases, but not forecasted ISAs.

The number of completed jobs within the majority of segments, in comparison to the total forecasted jobs, provides a significant representative sample. Therefore, PSE makes the assumption that the completed jobs serve as the best available proxy for an aggregated representation of all jobs within a segment. In other words, the representative sample of completed jobs variances provides a point of reference for the jobs that have a status of in progress, partially completed, deferred, or cancelled. Table 4-2 shows the forecasted ISAs vs. completed ISAs.

As illustrated in Table 4-2, all segments except B13 (Stations and Switchgear) are within the expected range of variance.

Table 4-2 Forecasted ISAs vs. Actual ISAs of Completed Work (not including analogous jobs)

Segment Number	Segment Description	2012-2014 Forecasted ISA ($M)	2012-2014 Actual ISA ($M)	Variance ($M)	Percent Variance
B1	Underground Infrastructure	107.5	147.4	39.9	37.1%
B2	PILC	0.6	0.6	0.0	2.8%
B3	Handwell Replacement	Analyzed separately--See Chapter 4.2.1			
B4	Overhead Infrastructure	53.0	71.7	18.7	35.3%
B5	Box Construction	9.9	12.8	2.9	29.6%
B6	Rear Lot Construction	46.3	52.6	6.4	13.8%
B9	Network Vault & Roofs	14.1	12.2	(1.9)	-13.6%
B10	Fibertop Network Units	7.0	7.7	0.7	9.7%
B11	ATSs and RPBs	2.1	1.8	(0.3)	-12.6%
B12	Stations Power Transformers	2.1	2.1	0.1	3.3%
B13	Stations Switchgear	0.4	0.9	0.5	136.9%
B20	Metering	Analyzed separately--See Chapter 4.2.1			
B21	Plant Relocations and Expansions	18.2	16.3	(1.9)	-10.4%
		261.1	**326.2**	**65.1**	**24.9%**

With the exception of B13, the variances for the completed jobs range from -13.6% for B9 (network vaults and roofs), to 37.1% for B1 (Underground). Segment B13, with variance of 137%, is the only segment not within the expected range of -30% to 50%. These variances are shown in graphic format in Figure 4-3.

Toronto Hydro's narrative for segment B13 indicates the variance occurred due to third party requirements and constraints as well as field conditions and execution issues. While the percent variance for completed jobs was large, the dollar variance was small (see Table 4-2 and Figure 4-4) and this segment did not significantly contribute to the variance of the segments in total. B13 is discussed further in Section 4.4.

Figure 4-3 Percentage of ISAs Variance (Completed Projects)

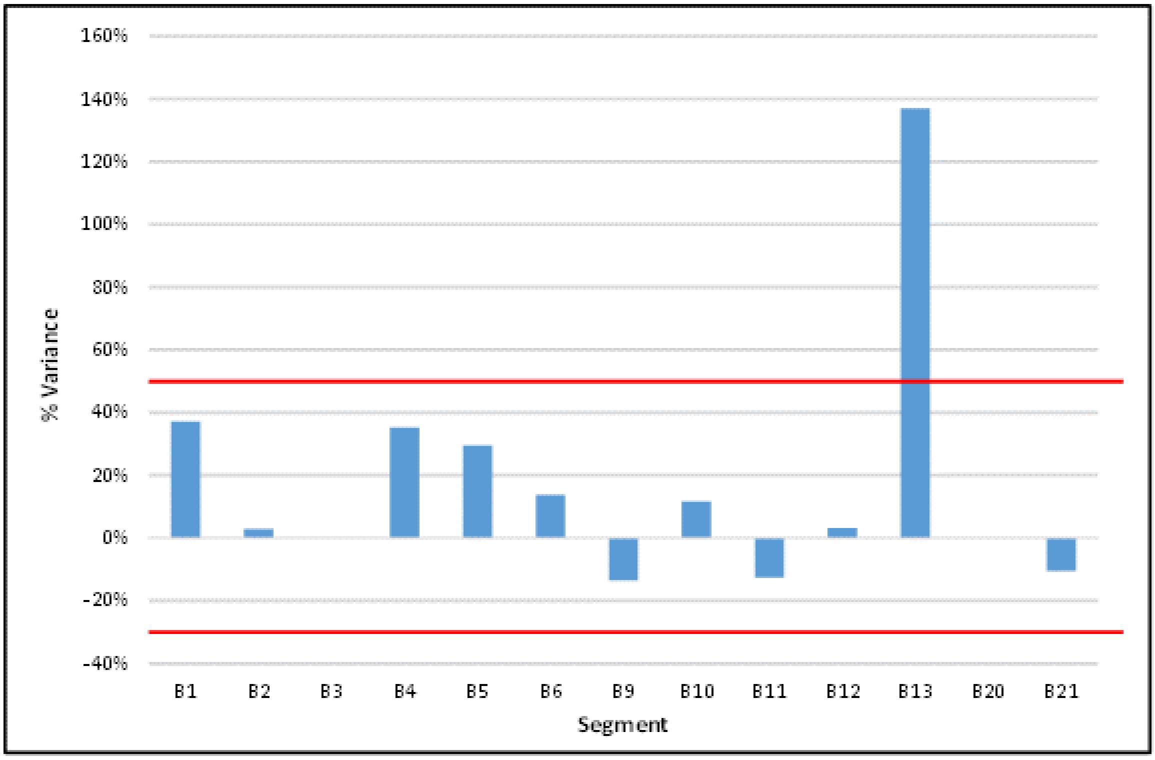
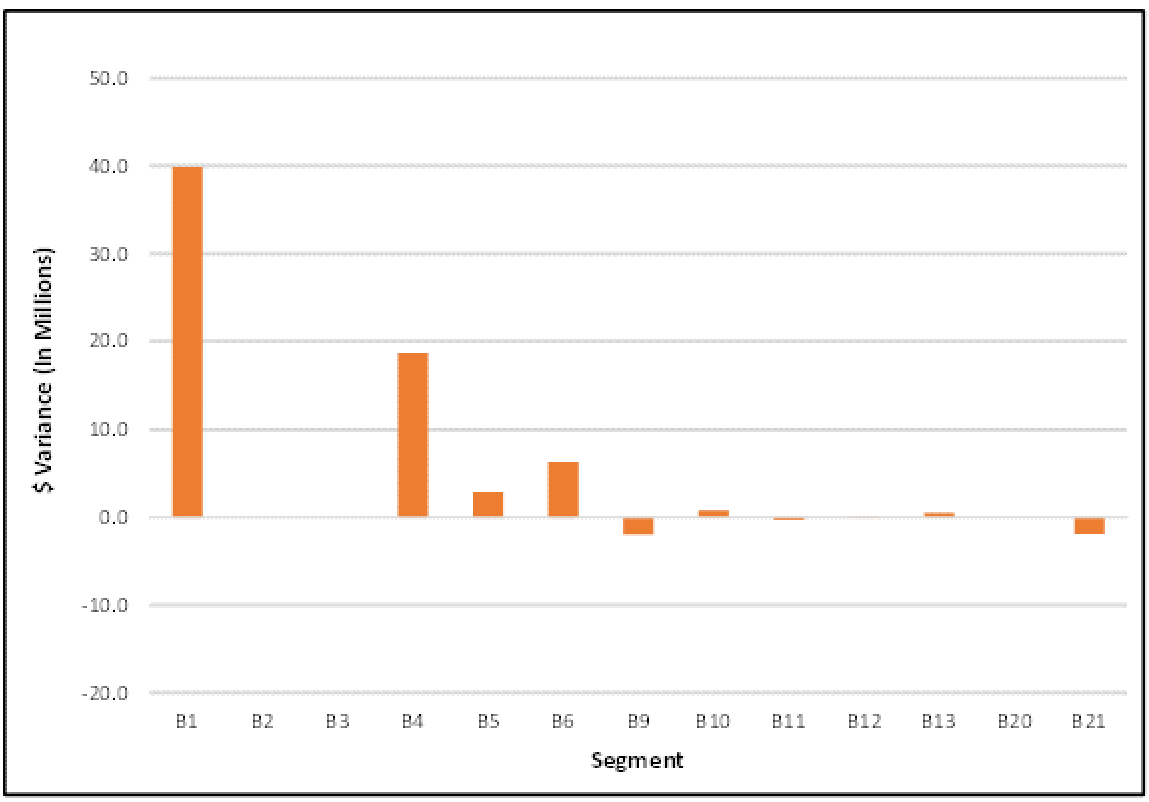


Figure 4-4 Dollar Amounts of ISAs Variances (Completed Projects)



In summary, the segments listed below were selected for further review of the variance drivers in Section 4.4, based on either exceeding the expected variance window or being a large dollar variance overall relative to the dollar variance of the other segments.

1. Segment B1: Underground Infrastructure
2. Segment B2: PILC Piece Outs and Leakers
3. Segment B4: Overhead Infrastructure
4. Segment B11: Automatic Transfer Switches and Remote Power Breakers
5. Segment B13: Stations and Switchgear

4.2.1 Segments B3 and B20

Segments B3 (handwells) and B20 (metering) were not included in the completed jobs only analysis because Toronto Hydro did not provide job level accomplishment details for these two segments but rather were presented on an overall ISAs basis. Toronto Hydro distinguished these two segments differently from the others in that they are not based on specific job-level activities, but are instead 'bucket' estimates to capture high volumes of identical discrete units. This reflects the fundamental nature of the work, which, internally, is not executed on a job basis in the same way as a job would be established and executed under another segment such as underground infrastructure.

For Segment B3, Toronto Hydro proposed to replace 7,165 handwells.[4] It replaced, remediated, or abandoned 7,264 handwells, at an ISAs cost of $1.1 million (-2.9%) below forecast. When evaluated on an average cost per job, the variance drops to -4.3%. This is summarized in the table below. Toronto Hydro's narrative states that approximately 10% of the 7,264 handwells addressed were removed. Toronto Hydro has stated to PSE that around 430 handwells were remediated. In PSE's opinion, the overall ISAs variance and average cost per job variance for this segment are well within expected tolerances. Reasons for the remediations and abandonments, as described by Toronto Hydro, are also reasonable in PSE's opinion.

Table 4-3 Handwell Summary

Forecast			Actual			Projected Average Cost vs. Actual Average Cost
Jobs	Cost	Average Cost	Jobs	Cost	Average Cost	
7165	$37,500,000	$5,234	7264	$36,400,000	$5,011	-4.3%

For Segment B20 (metering), there are many different types of upgrades including:

- Wholesale metering upgrades
- Customer meters
    - Conventional

[4] See ICM Project True-up B3 Handwell Replacement, p. 2, lines 22-23 (4,655 units in 2012 and 2013, and 2,500 units in 2014).

  - General service > 50 kW
  - RIMS
  - Quadlogic
  - Smart and other meters
- Wireless collectors

PSE was not able to evaluate the average cost per job because the forecasted and actual costs of the various types of meters, along with forecasted vs. actual numbers of jobs, were not available. Therefore, PSE is unable to form an opinion on the reasonableness of the completed cost per job variances in a similar fashion to the other segments. However, since the overall ISAs variance for the segment was at 7.1%, in addition to a relatively small dollar magnitude, PSE believes that the metering segment variance is reasonable.

4.3 Total Committed Jobs

In Section 4.2, PSE looked at the forecasted ISAs vs. actual ISAs of the completed jobs (excluding analogous jobs). Section 4.2 did not consider partially completed jobs or in-progress jobs, as the final ISAs for those jobs was not available. PSE also did not include the analogous jobs, as those did not have forecasted ISAs.

This raises the question of whether the total number of jobs forecasted was similar to the number of jobs "committed". For the purpose of our analysis, "committed" jobs means any job that Toronto Hydro completed (whether originally forecasted or analogous), as well as in-progress jobs and partially completed jobs. These jobs are all jobs for which Toronto Hydro has committed resources and commenced work. If forecasted jobs are similar in number to committed jobs, then that is one measure of the work forecasted vs. actual work performed. This is an imperfect measure; however, it is a solution based on the available information and is consistent with the manner in which jobs were filed in Toronto Hydro's ICM application.[5] The comparison of the number of jobs is shown in the following table.

[5] As noted throughout Exhibit 2 of the ICM application, Toronto Hydro did not intend to complete every job originally forecasted in the ICM application. For example, in the B1 Underground Infrastructure Segment true-up narrative (Exhibit 2, Tab 1, Schedule 1), Toronto Hydro explains that they "filed 172 discrete [Underground Infrastructure] jobs to address anticipated reliability, safety and operational efficiency concerns in this segment during the ICM Period. The utility anticipated that these jobs would be complete or in progress by the end of the ICM Period. (emphasis added)"

Table 4-4 Forecasted vs. "Committed" Jobs

Segment Number	Segment Description	Forecasted Jobs	Completed Jobs	Partially Completed Jobs	In Progress Jobs	Total Committed Jobs	% of Forecasted Jobs Committed
B1	Underground Infrastructure	**172**	129	11	37	**177**	103%
B2	PILC	**14**	3	2	8	**13**	93%
B3	Handwell Replacement	Analyzed separately--See Chapter 4.2.1					
B4	Overhead Infrastructure	**112**	81	9	27	**117**	104%
B5	Box Construction	**22**	11	5	8	**24**	109%
B6	Rear Lot Construction	**31**	28	1	3	**32**	103%
B9	Network Vault & Roofs	**29**	23	1	4	**28**	97%
B10	Fibertop Network Units	**68**	57	1	4	**62**	91%
B11	ATSs and RPBs	**11**	7	0	0	**7**	64%
B12	Stations Power Transformers	**10**	11	0	4	**15**	150%
B13	Stations Switchgear	**17**	7	0	7	**14**	82%
B20	Metering	Analyzed separately--See Chapter 4.2.1					
B21	Plant Relocations and Expansions	**27**	28	1	16	**45**	167%
Total		**513**	385	31	118	**534**	104%

As illustrated in Table 4-4, Toronto Hydro committed to 104% of the number of forecasted jobs during the ICM period. On a segment level, in 10 of 11 segments Toronto Hydro has committed to over 80% of the number of forecasted jobs (9 of 11 are over 90%).

The segment with the lowest number of committed jobs (on a percentage basis) is B11 ATS/RPB. It was noted that this segment had an overall ISAs cost variance of -44.1% and a completed job ISAs variance of -13%. Therefore, the lower number of completed jobs is expected and reasonable.

The two segments B3 (handwells) and B20 (metering) were left out of this analysis for reasons previously discussed.

4.4 Toronto Hydro's Five Primary Reasons for Variance as Applied to Outliers

Exhibits 1 and 2 provided narrative around the variances associated with the ICM initiative. The narratives outlined the primary drivers, provided an explanation, and are supported with detailed examples which are summarized in Table 4-5.

Based on industry experience the variance drivers explained by Toronto Hydro are not unusual for initiatives like ICM which are complex and span over several years. Generally speaking, the uncertainty associated with the elements used to develop the high level forecasts are challenging to quantify and forecast into the future. Not all parameters and conditions concerning a project are known or fully defined when cost estimates are prepared. Even when parameters and conditions are fully defined, uncontrollable issues such as impacts from other projects and third party constraints can surface driving costs upward.

Table 4-5 Toronto Hydro Variance Drivers

ICM Variance Primary Driver	ICM Variance Explanation	ICM Variance Job Specific Example Excerpts
High Level to Detail Design Variance	Variances attributable to the move from the high level planning estimates that form the basis of the ICM application to the detailed designs contained in the final Execution Work Plan. They are due to changes in: operational elements requested by Toronto Hydro's control room such as additional SCADA switches; job scope; design elements; and applicable standards.	(B1) Underground Infrastructure: Project scope changes due to changes in technical design standards. Change in assets due to detail inspection conditions. System operations SCADA requests. Tunneling instead of open air trenching. Replacement of assets on reactive failure basis. Additional assets needing replacement which met core drivers of work in the segment. Advancement of future ICM work to maximize crew alignment and utilization resulting in fewer operational outages. (B2) PILC: Replacement of equipment on reactive basis due to failure. (B4) Overhead Infrastructure: Changes in asset conditions over time between high level plan and EWP. Realignment of work with other project work: efficiency, timing, additional analysis required. (B11) ATSs and RPBs: Replacement of equipment on reactive basis due to failure. Additional information gathered from detailed inspections. (B13) Stations Switchgear: Switchgear, cable, overhead interface and compatibility issues. Alignment of resources resulting in additional design/work for maintaining system operations until all work could be completed.

Table 4-5 Toronto Hydro Variance Drivers (continued)

ICM Variance Primary Driver	ICM Variance Explanation	ICM Variance Job Specific Example Excerpts
Field Conditions and Execution Requirements	Variances that arise due to site conditions encountered during the construction phase. These include site conditions, operational constraints (e. g. loading and switching restrictions), and labor and equipment costs that arise during construction.	(B1) Underground Infrastructure: Changes in UG material due to UG relocation of ductwork relative to other structures, non-standard configurations, unforeseen UG facilities as well as use of external crews. Use of external contractors when initial estimate based on cost of internal crew. (B2) PILC: Postponements due to crew resources and competing priorities, system operating restrictions. Feeder availability and difficulties associated with work in dense urban core. (B4) Overhead Infrastructure: Shifting work to premium periods to minimize customer impact, outages and maintain reliability. Cost shifting due to variation in planned/actual schedule. (B13) Stations Switchgear: Colocation issues.
Third Party Requirements and Constraints	Variances due to third party requirements arising from collaborative agreements and coordination issues with the city of Toronto, Hydro One or other utilities.	(B1) Underground Infrastructure: City of Toronto restrictions on work in particular areas, road cut moratoriums, denial of request to install overhead switches. Coordination of work with other parties. (B2) PILC: Postponements due to third party delays.
Variance in Allocated Costs	Variances due to differences between the average overhead costs (e.g. design costs, road cuts) allocated to individual jobs in the high level planning estimates and the actual overhead costs incurred for each individual job as calculated at the project close out.	(B1) Underground Infrastructure: Estimated using consistent adder based on percentage of project costs, actual costs compiled centrally and allocated at project closeout, example, number of road cuts. (B4) Overhead Infrastructure: Same as B1. Examples: additional site visits, job scope expansion, road cuts and riser costs.
Errors	Variances due to errors made in the high level planning estimates or in the ICM filing.	(B4) Overhead Infrastructure: Clerical errors in original estimates.

The variance drivers for the segments identified as outliers or which have large magnitude ISAs were reviewed.

Segment B1, Underground Infrastructure, was on the edge of being an outlier on a percent ISAs variance basis and had the largest ISAs dollar cost variance. In addition, B1 was the largest segment in actual ISAs dollars. The main variance driver was changes in Toronto Hydro's technical design standards which were implemented after the estimates for the ICM initiative were developed. Furthermore, site detailed inspections identified changes in the number of assets relative to the ICM segment criteria. Additional scope changes were required to accommodate additional modifications from System Operations to improve operability and reliability. Lastly field and execution issues, third party constraints, as well as variance in allocated costs added to the final variance. Based on industry experience these types of variance drivers are reasonable.

Segment B13, Stations Switchgear, was identified as an outlier on a percent ISAs variance basis as well as being the second largest ISAs dollar cost variance. It is worth noting the dollar cost variance was very small when viewed on a "Jobs Completed" basis. The narratives explained the scheduling and coordination issues associated with the specialized resources and interfacing work groups resulted in deferments. The total ISAs for the segment was underspent due to these deferments. Based on industry experience these types of variance drivers are reasonable.

Segment B4, Overhead Infrastructure, was within the expected percent ISAs variance window, however, the segment did have the second largest dollar cost variance on a "Jobs Completed" basis. Moreover, B4 was the second largest segment in actual ISAs dollars. The main variance driver identified in the narrative was the high level planning estimates which relied on existing field conditions at the time of the forecast. The field conditions changed over time and the detailed inspection information used to create the refined project estimate was different from the initial high level planning estimate. Based on industry experience these types of variance drivers are reasonable.

While segment B2, PILC Piece Outs and Leakers, as well as segment B11, Automatic Transfer Switches and Remote Power Breakers, were outside the expected ISAs variance window, the magnitude of the dollar cost variances were not significant compared to the total cost variance. Therefore, no further variance analysis was deemed necessary by PSE.

Overall, the reasons for variances as defined by Toronto Hydro, and discussed above, are understandable and can be found across the industry.

Appendix—Estimation Classification Matrices

This Appendix provides links for estimation sources reviewed for this Report.

AACE International

AACE International				
Secondary Characteristic	***Primary Characteristic***	***Secondary Characteristic***	***Secondary Characteristic***	
EXPECTED ACCURACY RANGE Typical variation in low and high ranges [a]	**LEVEL OF PROJECT DEFINITION Expressed as % of complete definition**	**END USAGE Typical purpose of estimate**	**METHODOLOGY Typical estimating method**	**ESTIMATE CLASS**
L: -20% to -50% H: +30% to +100%	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	Class 5
L: -15% to -30% H: +20% to +50%	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	Class 4
L: -10% to -20% H: +10% to +30%	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	Class 3
L: -5% to -15% H: +5% to +20%	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	Class 2
L: -3% to -10% H: +3% to +15%	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take- Off	Class 1
[a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope. [b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.				

Adapted from a chart taken from AACE's website at http://www.aacei.org/ (membership required).

A copy of the chart can be found at: http://purchasing.borough.kenai.ak.us/docs/AACE_CLASSIFICATION_SYSTEM.pdf

Alberta Electric System Operator

AESO BASIS OF COST ESTIMATE FRAMEWORK				
ACCURACY RANGE	**LEVEL OF PROJECTION DEFINITION**	**END USAGE/ INDUSTRY USAGE**		**ESTIMATE CLASS**
-30%/+50%	0% to 2%	Screening or Feasibility; Long Term Plan Feasibility Assessment Screening Alternatives		Class 5
-20%/+30%	1% to 15%	Concept Study of Feasibility; Need Assessment Study Scope Preferred Option		Class 4
-15%/+20%	10% to 40%	Design Development Budget Authorization; Proposal to Provide Service Facility Application Preferred Option		Class 3
-10%/+15%	30% to 75%	Control or Bid/Tender; Post Permit & License Revised Budget (180 day PPS)		Class 2
0%		Approved Cost Estimate (ACE)		
-5%/+10%	65 to 100%	Bid Tender; Fixed Price Contracts		Class 1

Adapted from chart in: *Review of the Cost Status of Major Transmission Projects in Alberta*, JUNE 2014 REPORT. Available at: http://www.ucahelps.alberta.ca/documents/ABE_TFCMC_Report_7_WEB_-_June_2014.pdf

Vermont Electric Power Company

VT Transco VELCO VETCO / Vermont Electric Power Company				
EXPECTED ACCURACY RANGE Typical variation in low and high ranges	LEVEL OF PROJECT DEFINITION Expressed as % of complete definition	Descriptive (AACE / EPRI)		Estimate Type
L: -15% to -60% H: +30% to +120%	1% to 15%	Study / Simplified Estimate		A
L: -10% to -30% H: +20% to +60%	10% to 40%	Budget, Authorization or Control / Preliminary Estimate		B
L: -5% to -15% H: +10% to +30%	30% to 70%	Control or Bid / Detailed Estimate		C
L: -5% to -5% H: +10% to +10%	50% to 100%	Check Estimate or Bid / Finalized Estimated		D
Source: Derived from Association for Advancement of Cost Engineering (AACE) and Electric Power Research Institute (EPRI).				

Available at:
http://www.state.vt.us/psb/rules/proposed/5400/2008-07-24_VELCO_presentation.pdf

ISO New England ("ISO-NE")

Attachment D to Planning Procedure 4 (NE ISO)				
RSP Listing Target Accuracy	Level of Project Definition	Estimate Type		Estimate Class
-50% to +200%	0% to 15%	Order of Magnitude		-
-25% to +50%	15% to 40%	Conceptual Estimate		A
-25% to +25%	40% to 70%	Planning Estimate		B
-10% to +10%	70% to 90%	Engineering Estimate		C
-10% to +10%	80% to 100%	Construction Estimate		D

Adapted from: *ISO New England Planning Procedure No. 4 Procedure for Pool-Supported PTF Cost Review* (Attachment D to Planning Procedure 4) (uses AACE adapted for transmission)

http://www.iso-ne.com/rules_proceds/isone_plan/pp04_0/pp4_0_attachment_d.pdf

US-DOE

U.S. Department of Energy				
	Level of Definition (% of Complete Definition)	Cost Estimate Classification	Cost Estimating Description (Techniques)	Cost Estimate Classification
	0% to 2%	Concept Screening	Stochastic, most parametric, judgment (parametric, specific analogy, expert opinion, trend analysis)	Class 5
	1% to 15%	Study or Feasibility	Various, more parametric (parametric, specific analogy, expert opinion, trend analysis)	Class 4
	10% to 40%	Preliminary, Budget Authorization	Various, including combinations (detailed, unitcost, or activity-based; parametric; specific analogy; expert opinion; trend analysis)	Class 3
	30% to 70%	Control or Bid/Tender	Various, more definitive (detailed, unit-cost, or activity-based; expert opinion; learning curve)	Class 2
	50% to 100%	Check Estimate or Bid/Tender	Deterministic, most definitive (detailed, unit-cost, or activity-based; expert opinion; learning curve)	Class 1

Adapted from: *Life Cycle Cost Handbook: Guidance for Life Cycle Cost Estimation and Analysis*, Office of Acquisition and Project Management U.S. Department of Energy, September 2014, Table 2-1 “Generic Cost Estimate Classifications and Primary Characteristics”

Available at:
http://energy.gov/sites/prod/files/2014/10/f18/LCC%20Handbook%20Final%20Version%209-30-14.pdf

ICM TRUE-UP REVENUE REQUIREMENT AND RATE RIDERS

1. ICM REVENUES

Toronto Hydro implemented the Initial ICM Rate Rider on June 1, 2013. The Initial ICM Rate Rider was designed by the OEB to provide funding for ICM Segments based on forecast ISAs that were above the ICM materiality threshold in 2012 or 2013. The forecast 2012 ISAs did not exceed the threshold; therefore, the Initial ICM Rate Rider did not include any funding for 2012 ICM Segments. The forecast 2013 ISAs did exceed the threshold; therefore, the Initial ICM Rate Rider did include funding for 2013 ICM Segments.

The Initial ICM Rate Rider as applied to each rate class is summarized in the following table. The rider for each class was billed until April 30, 2015.

Table 1: Approved ICM Rate Riders

	Residential	CSMUR	GS<50kW	GS 50-999kW	GS 1000-4999kW	Large Use	Street-lighting	USL
Fixed ($/30 days)	0.73	0.68	0.97	1.42	27.34	119.83	0.05	0.02 / 0.19
Variable ($/kWh or kVA)	0.00061	0.00103	0.00090	0.2225	0.1771	0.1887	1.1439	0.00245

The Phase 2 Decision, which approved a settlement agreement in respect of forecast 2014 ISAs, did not modify or supplement the Initial ICM Rate Rider.

The total amount collected from the Initial ICM Rate Rider over the June 2013 to May 2015 period was $41.2 million. It was booked monthly to Account 1508, Subaccount Incremental Capital Expenditures – ICM Rate Rider Revenue, per the Accounting Order. Monthly carrying charges were calculated and booked to Account 1508, Subaccount

Incremental Capital Expenditures – Carrying Charges – ICM Rate Rider Revenue, with a total balance in this account of $0.6 million as of April 30, 2015.

2. ICM TRUE-UP REVENUE REQUIREMENT

The following table shows the actual ISAs, amortization expense and capital cost allowance ("CCA") amounts by ICM Segment and in total for each of 2012, 2013 and 2014. These amounts reflect actual ISAs which were above the materiality thresholds each year.[1]

Table 2: Closing Net Fixed Assets, Amortization Expense and CCA by Segment

		2012 ($ millions)	2013 ($ millions)	2014 ($ millions)
01 Underground Infrastructure	ISA	5.533	66.816	48.891
	Amortization Expense	0.182	2.120	1.592
	CCA	0.443	5.345	3.911
02 Paper Insulated Lead Covered Cable - Piece Outs and Leakers	ISA	-	0.128	1.251
	Amortization Expense	-	0.002	0.029
	CCA	-	0.010	0.100
03 Handwell Replacement	ISA	3.093	16.614	6.787
	Amortization Expense	0.128	0.739	0.302
	CCA	0.247	1.329	0.543
04 Overhead Infrastructure	ISA	0.285	33.073	23.690
	Amortization Expense	0.008	0.890	0.619
	CCA	0.023	2.646	1.895

[1] The ICM materiality thresholds were $173.3 million, $163.8 million, and $211.1 million for each of 2012, 2013 and 2014 respectively.

		2012 ($ millions)	2013 ($ millions)	2014 ($ millions)
05 Box Construction	ISA	0.069	5.650	8.121
	Amortization Expense	0.002	0.142	0.212
	CCA	0.006	0.452	0.650
06 Rear Lot Construction	ISA	1.737	28.557	12.486
	Amortization Expense	0.053	0.821	0.369
	CCA	0.139	2.285	0.999
09 Network Vault & Roofs	ISA	0.072	14.728	1.143
	Amortization Expense	0.004	0.447	0.038
	CCA	0.006	1.178	0.091
10 Fibertop Network Units	ISA	1.371	6.366	2.295
	Amortization Expense	0.061	0.309	0.100
	CCA	0.110	0.509	0.184
11 Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)	ISA	0.035	1.535	0.149
	Amortization Expense	0.001	0.066	0.005
	CCA	0.003	0.123	0.012
12 Stations Power Transformers	ISA	1.295	0.914	0.857
	Amortization Expense	0.040	0.029	0.027
	CCA	0.104	0.073	0.069
13.1 & 13.2 Stations Switchgear -Municipal and Transformer Stations	ISA	0.475	0.001	1.955
	Amortization Expense	0.012	0.000	0.051
	CCA	0.038	0.000	0.156

		2012 ($ millions)	2013 ($ millions)	2014 ($ millions)
20 Metering	ISA	0.005	7.128	5.200
	Amortization Expense	(0.001)	0.320	0.222
	CCA	0.000	0.570	0.416
21 Externally-Initiated Plant Relocations and Expansions	ISA	1.467	7.426	11.537
	Amortization Expense	0.039	0.187	0.284
	CCA	0.117	0.594	0.923
	Total ISA	15.436	188.935	124.363
	Total Amortization Expense	0.528	6.073	3.852
	Total CCA	1.235	15.115	9.949

As directed by the OEB (Appendix B to the EB-2012-0064 Decision and Rate Order), the calculation of the actual revenue requirement for each ICM year uses the inputs as provided in the original ICM Workforms (i.e. cost of capital rates and tax rates). The only changes are for the actual ISAs, associated depreciation and CCA amounts. The revenue requirement for 2014 reflects the half-year rule applied to actual ISAs and depreciation. The annual ICM Workforms for 2012 to 2014 are filed in Tab 2 of this Exhibit as Schedules 1 to 3.

The total variance amount for ICM True-up is calculated as the difference for the 2012 to 2014 ICM period between total revenues received from the Initial ICM Rate Rider, which was based on forecast ISAs, and total Actual ICM Revenue Requirement associated with the actual ISAs. Carrying charges have been calculated on the Actual ICM Revenue Requirement. (These charges are based on monthly revenues assuming rate riders were put in place reflecting the actual ICM revenue requirements. See Tab 2, Schedule 5 of this Exhibit.) Carrying charges on Actual ICM Revenue Requirement are netted against the carrying charges calculated on the revenue received. The total ICM True-up requires an $11.2 million debit to customers.

Table 3: Calculation of True-up Amount ($ millions)

	2012	2013	2014	Total
Revenue Received	0.0	19.830	21.334	41.164
Carrying Charges	0.0	0.122	0.461	0.583
Actual Revenue Requirement[2]	1.514	19.544	31.226	52.284
Carrying Charges	0.010	0.155	0.464	0.629
True-up	1.524	-0.253	9.896	11.167

3. ALLOCATION AND RATE RIDER DESIGN

Toronto Hydro proposes to allocate the ICM True-up Revenue Requirement among rate classes according to the same methodology as was accepted by the OEB in setting the Initial ICM Rate Rider. The allocated ICM True-up Revenue Requirement is shown in the following table.

Table 4: Allocation of ICM True-up Revenue Requirement ($ millions)

Residential	CSMUR	GS<50kW	GS 50-999kW	GS 1000-4999kW	Large Use	Street-lighting	USL	Total
4.321	0.161	1.419	3.299	1.084	0.535	0.249	0.099	11.167

The allocated ICM True-up Revenue Requirement is then divided by billing determinants and the disposition period to calculate the ICM True-up Rate Rider for each customer

[2] Each year's revenue requirement reflects the revenue requirement associated with the actual ISAs for that year, plus the revenue requirement related to previous year's actual ISAs. For example, in 2013, the $19.544M revenue requirement reflects the revenue requirement associated with actual 2013 ISAs ($18.030M), plus the revenue requirement associated with actual 2012 ISAs ($1.514M).

class. The billing determinants used are the 2016-2017 forecast billing determinants as approved by the OEB in EB-2014-0116. The disposition period being proposed by Toronto Hydro is for 14 months. Rate riders for all classes except the Residential and CSMUR classes include both fixed and variable components and reflect the same fixed/variable split as current distribution rates. For the Residential and CSMUR classes, Toronto Hydro proposes a fully fixed rate, which is in line with the Board's recent rate design policy (EB-2012-0410). Detailed calculations showing the derivation of the ICM True-up Rate Rider are included in Tab 3 of this Exhibit.

4. IMPLEMENTATION AND BILL IMPACTS

Toronto Hydro proposes to implement the ICM True-up Rate Rider over a 14-month period from November 1, 2016 through December 31, 2017. The start of the rate rider period will coincide with the Time-of-Use ("TOU") Regulatory Price Plan ("RPP") rate change. The conclusion of the rate rider period will coincide with the 2018 distribution rate change.

The proposed ICM True-up Rate Rider by class and summary bill impacts are as follows:

Table 5: Proposed Rates and Bill Impacts

	Residential	CSMUR	GS<50kW	GS 50-999kW	GS 1000-4999kW	Large Use	Street-lighting	USL
Fixed ($/30 days)	0.49	0.16	0.41	0.67	14.21	50.45	0.02	0.01 / 0.16
Variable ($/kWh or kVA)	n/a	n/a	0.00042	0.1024	0.0790	0.0800	0.5069	0.00150
Bill Impact ($/30 days)	0.49	0.16	1.25	40.40	154.67	805.17	0.10	0.72

Ontario Energy Board

Incremental Capital Workform

Legend: DROP-DOWN MENU | INPUT FIELD | CALCULATION

Applicant Name	**Toronto Hydro-Electric System Limited**
Application Type	**IRM3**
LDC Licence Number	**ED-2002-0497**
Applied for Effective Date	**May 1, 2012**
Stretch Factor Group	**III**
Stretch Factor Value	**0.6%**
Last COS Re-based Year	**2011**
Last COS OEB Application Number	**EB-2010-0142**
ICM Billing Determinants for Growth - Numerator	**2011 Re-Based Forecast**
ICM Billing Determinants for Growth - Denominator	**2010 Audited RRR**

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Incremental Capital Workform

Table of Contents

Sheet Name	Purpose of Sheet
A1.1 LDC Information	Enter LDC Data
A2.1 Table of Contents	Table of Contents
B1.1 Re-Based Bill Det & Rates	Set Up Rate Classes and enter Re-Based Billing Determinants and Tariff Rates
B1.2 Removal of Rate Adders	Removal of Rate Adders
B1.3 Re-Based Rev From Rates	Calculated Re-Based Revenue From Rates
B1.4 Re-Based Rev Req	Detailed Re-Based Revenue From Rates
C1.1 Ld Act-Mst Rcent Yr	Enter Billing Determinants for most recent actual year
D1.1 Current Revenue from Rates	Enter Current Rates to calculate current rate allocation
E1.1 Threshold Parameters	Shows calculation of Price Cap and Growth used for incremental capital threshold calculation
E2.1 Threshold Test	Input sheet to calculate Threshold and Incremental Capital
E3.1 Summary of I C Projects	Summary of Incremental Capital Projects
E4.1 IncrementalCapitalAdjust	Shows Calculation of Incremental Capital Revenue Requirement
F1.1 Incr Cap RRider Opt A FV	Option A - Calculation of Incremental Capital Rate Rider - Fixed & Variable Split
F1.2 Incr Cap RRider Opt B Var	Option B - Calculation of Incremental Capital Rate Rider - Variable Allocation
Z1.0 OEB Control Sheet	Not Shown

Rate Class and Re-Based Billing Determinants & Rates

Select the appropriate Rate Groups and Rate Classes from the drop-down menus in Columns C and D respectively. Following your selection, all appropriate input cells will be shaded green.

Last COS Re-based Year	**2011**
Last COS OEB Application Number	**EB-2010-0142**

Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Re-based Tariff Service Charge D	Re-based Tariff Distribution Volumetric Rate kWh E	Re-based Tariff Distribution Volumetric Rate kW F
RES	Residential	Customer	kWh	598,508	4,886,977,489		18.25	0.0151	
RES	Residential Urban	Customer	kWh	24,898	99,791,184		17.00	0.0257	
GSLT50	General Service Less Than 50 kW	Customer	kWh	65,792	2,139,318,076	0	24.30	0.0225	
GSGT50	General Service 50 to 999 kW	Customer	kW	13,067	10,116,374,153	26,935,191	35.56		5.5956
GSGT50	General Service 1,000 to 4,999 kW	Customer	kW	514	4,626,928,262	10,587,119	686.46		4.4497
LU	Large Use	Customer	kW	47	2,376,778,323	4,993,733	3,009.11		4.7406
SL	Street Lighting	Connection	kW	162,777	110,165,016	322,023	1.30		28.7248
USL	Unmetered Scattered Load	Connection	kWh	1,130	56,231,585		4.84	0.0607	
USL	Unmetered Scattered Load	Connection	kWh	21,729	0		0.49		
NA	Rate Class 10	NA	NA						
NA	Rate Class 11	NA	NA						
NA	Rate Class 12	NA	NA						
NA	Rate Class 13	NA	NA						
NA	Rate Class 14	NA	NA						
NA	Rate Class 15	NA	NA						
NA	Rate Class 16	NA	NA						
NA	Rate Class 17	NA	NA						
NA	Rate Class 18	NA	NA						
NA	Rate Class 19	NA	NA						
NA	Rate Class 20	NA	NA						
NA	Rate Class 21	NA	NA						
NA	Rate Class 22	NA	NA						
NA	Rate Class 23	NA	NA						
NA	Rate Class 24	NA	NA						
NA	Rate Class 25	NA	NA						

Removal of Rate Adders

Last COS Re-based Year 2011

Last COS OEB Application Number EB-2010-0142

Rate Class	Re-based Tariff Service Charge A	Re-based Tariff Distribution Volumetric Rate kWh B	Re-based Tariff Distribution Volumetric Rate kW C	Service Charge Rate Adders D	Distribution Volumetric kWh Rate Adders E	Distribution Volumetric kW Rate Adders F	Re-based Base Service Charge H = A - D	Re-based Base Distribution Volumetric Rate kWh I = B - E	Re-based Base Distribution Volumetric Rate kW J = C - F
Residential	18.25	0.0151	0.0000	0.00	0.0000	0.0000	18.25	0.0151	0.0000
Residential Urban	17.00	0.0257	0.0000	0.00	0.0000	0.0000	17.00	0.0257	0.0000
General Service Less Than 50 kW	24.30	0.0225	0.0000	0.00	0.0000	0.0000	24.30	0.0225	0.0000
General Service 50 to 999 kW	35.56	0.0000	5.5956	0.00	0.0000	0.0000	35.56	0.0000	5.5956
General Service 1,000 to 4,999 kW	686.46	0.0000	4.4497	0.00	0.0000	0.0000	686.46	0.0000	4.4497
Large Use	3,009.11	0.0000	4.7406	0.00	0.0000	0.0000	3,009.11	0.0000	4.7406
Street Lighting	1.30	0.0000	28.7248	0.00	0.0000	0.0000	1.30	0.0000	28.7248
Unmetered Scattered Load	4.84	0.0607	0.0000	0.00	0.0000	0.0000	4.84	0.0607	0.0000
Unmetered Scattered Load	0.49	0.0000	0.0000	0.00	0.0000	0.0000	0.49	0.0000	0.0000

Calculated Re-Based Revenue From Rates

Last COS Re-based Year 2011

Last COS OEB Application Number EB-2010-0142

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Re-based Base Service Charge D	Re-based Base Distribution Volumetric Rate kWh E	Re-based Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates J = G + H + I	Service Charge % Revenue K = G / J	Distribution Volumetric Rate % Revenue kWh L = H / J	Distribution Volumetric Rate % Revenue kW M = I / J	Total % Revenue N = J / R
Residential	598,508	4,886,977,489	0	18.25	0.0151	0.0000	131,073,252	73,646,751	0	204,720,003	64.0%	36.0%	0.0%	38.8%
Residential Urban	24,898	99,791,184	0	17.00	0.0257	0.0000	5,079,192	2,559,644	0	7,638,836	66.5%	33.5%	0.0%	1.4%
General Service Less Than 50 kW	65,792	2,139,318,076	0	24.30	0.0225	0.0000	19,184,993	48,070,477	0	67,255,470	28.5%	71.5%	0.0%	12.7%
General Service 50 to 999 kW	13,067	10,116,374,153	26,935,191	35.56	0.0000	5.5956	5,575,758	0	150,718,556	156,294,314	3.6%	0.0%	96.4%	29.6%
General Service 1,000 to 4,999 kW	514	4,626,928,262	10,587,119	686.46	0.0000	4.4497	4,234,085	0	47,109,505	51,343,590	8.2%	0.0%	91.8%	9.7%
Large Use	47	2,376,778,323	4,993,733	3,009.11	0.0000	4.7406	1,697,138	0	23,673,292	25,370,430	6.7%	0.0%	93.3%	4.8%
Street Lighting	162,777	110,165,016	322,023	1.30	0.0000	28.7248	2,539,322	0	9,250,042	11,789,364	21.5%	0.0%	78.5%	2.2%
Unmetered Scattered Load	1,130	56,231,585	0	4.84	0.0607	0.0000	65,611	3,413,257	0	3,478,868	1.9%	98.1%	0.0%	0.7%
Unmetered Scattered Load	21,729	0	0	0.49	0.0000	0.0000	127,767	0	0	127,767	100.0%	0.0%	0.0%	0.0%
							169,577,117 O	127,690,129 P	230,751,395 Q	528,018,642 R				100.0%

Detailed Re-Based Revenue From Rates

Last COS Re-based Year	**2011**
Last COS OEB Application Number	**EB-2010-0142**

Applicants Rate Base		**Last Rate Re-based Amount**				
Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	4,183,572,075	A			
Add: CWIP Re-based Opening	$	204,719,106	B			
Re-based Capital Additions	$	376,263,596	C			
Re-based Capital Disposals			D			
Re-based Capital Retirements			E			
Deduct: CWIP Re-based Closing	-$	232,060,508	F			
Gross Fixed Assets - Re-based Closing	$	4,532,494,269	G			
Average Gross Fixed Assets				$	4,358,033,172	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	2,285,733,698	I			
Re-based Depreciation Expense	$	138,815,781	J			
Re-based Disposals	$	2,807,234	K			
Re-based Retirements			L			
Accumulated Depreciation - Re-based Closing	$	2,427,356,713	M			
Average Accumulated Depreciation				$	2,356,545,206	N = (I + M) / 2
Average Net Fixed Assets				**$**	**2,001,487,967**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	2,479,952,766	P			
Working Capital Allowance Rate		12.0%	Q			
Working Capital Allowance				**$**	**296,739,314**	R = P * Q
Rate Base				**$**	**2,298,227,281**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	91,929,091	W = S * T
Deemed Long Term Debt %		56.00%	U	$	1,287,007,277	X = S * U
Deemed Equity %		40.00%	V	$	919,290,912	Y = S * V
Short Term Interest		2.46%	Z	$	2,261,456	AC = W * Z
Long Term Interest		5.37%	AA	$	69,112,291	AD = X * AA
Return on Equity		9.58%	AB	$	88,068,069	AE = Y * AB
Return on Rate Base				**$**	**159,441,816**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	231,014,224	AG			
Amortization	$	138,815,781	AH			
Ontario Capital Tax (F1.1 Z-Factor Tax Changes)	$	6,802,382	AI			
Grossed Up PILs (F1.1 Z-Factor Tax Changes)	$	11,791,223	AJ			
Low Voltage			AK			
Transformer Allowance	$	11,479,842	AL			
	$	-	AM			
			AN			
			AO			
				$	**399,903,452**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	7,580,526	AQ			
Late Payment Charges	-$	4,900,000	AR			
Other Distribution Income	-$	7,240,556	AS			
Other Income and Deductions	-$	6,300,000	AT	**-$**	**26,021,082**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**533,324,186**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (B1.1 Re-based Revenue - Gen)				$	528,018,642	AW
Difference				$	5,305,544	AZ = AV - AW
Difference (Percentage - should be less than 1%)					1.00%	BA = AZ / AW

Load Actual - Most Recent Year

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections A	Billed kWh B	Billed kW C	Base Service Charge D	Base Distribution Volumetric Rate kWh E	Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D * 12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Total Revenue by Rate Class J = G + H + I
Residential	Customer	kWh	591,496	5,105,974,275	0	$18.25	$0.0151	$0.0000	$129,537,624	$76,947,032	$0	$206,484,656
Residential Urban	Customer	kWh	24,898	99,791,184	0	$17.00	$0.0257	$0.0000	$5,079,192	$2,559,644	$0	$7,638,836
General Service Less Than 50 kW	Customer	kWh	65,799	2,095,343,918	0	$24.30	$0.0225	$0.0000	$19,186,988	$47,082,378	$0	$66,269,366
General Service 50 to 999 kW	Customer	kW	12,873	10,189,051,346	26,712,248	$35.56	$0.0000	$5.5956	$5,493,167	$0	$149,471,055	$154,964,221
General Service 1,000 to 4,999 kW	Customer	kW	509	4,828,382,733	10,972,419	$686.46	$0.0000	$4.4497	$4,192,898	$0	$48,823,974	$53,016,871
Large Use	Customer	kW	47	2,263,227,585	5,267,224	$3,009.11	$0.0000	$4.7406	$1,697,138	$0	$24,969,801	$26,666,940
Street Lighting	Connection	kW	162,964	112,727,603	321,995	$1.30	$0.0000	$28.7248	$2,542,238	$0	$9,249,232	$11,791,471
Unmetered Scattered Load	Connection	kWh	1,107	52,097,299	0	$4.84	$0.0607	$0.0000	$64,295	$3,162,306	$0	$3,226,601
Unmetered Scattered Load	Connection	kWh	12,159	0	0	$0.49	$0.0000	$0.0000	$71,495	$0	$0	$71,495
									$167,865,035	**$129,751,360**	**$232,514,062**	**$530,130,457**

This sheet is used to determine the applicants most current allocation of revenues (after the most recent revenue cost ratio adjustment, if applicable) to be used to calculate the incremental capital rate riders.

Current Revenue from Rates

Rate Class	Fixed Metric	Vol Metric	Current Base Service Charge A	Current Base Distribution Volumetric Rate kWh B	Current Base Distribution Volumetric Rate kW C	Re-based Billed Customers or Connections D	Re-based Billed kWh E	Re-based Billed kW F
Residential	Customer	kWh	18.25	0.0151		598,508	4,886,977,489	0
Residential Urban	Customer	kWh	17.00	0.0257		24,898	99,791,184	0
General Service Less Than 50 kW	Customer	kWh	24.30	0.0225		65,792	2,139,318,076	0
General Service 50 to 999 kW	Customer	kW	35.56		5.5956	13,067	10,116,374,153	26,935,191
General Service 1,000 to 4,999 kW	Customer	kW	686.46		4.4497	514	4,626,928,262	10,587,119
Large Use	Customer	kW	3,009.11		4.7406	47	2,376,778,323	4,993,733
Street Lighting	Connection	kW	1.30		28.7248	162,777	110,165,016	322,023
Unmetered Scattered Load	Connection	kWh	0.49	0.0607		1,130	56,231,585	0
Unmetered Scattered Load	Connection	kWh	4.84			21,729	0	0

Rate Class	Current Base Service Charge Revenue G = A * D *12	Current Base Distribution Volumetric Rate kWh Revenue H = B * E	Current Base Distribution Volumetric Rate kW Revenue I = C * F	Total Current Base Revenue J = G + H + I	Service Charge % Total Revenue L = G / $K	Distribution Volumetric Rate % Total Revenue M = H / $K	Distribution Volumetric Rate % Total Revenue N = I / $K	Total % Revenue O = J / $K
Residential	131,073,252	73,646,751	0	204,720,003	24.8%	13.9%	0.0%	38.7%
Residential Urban	5,079,192	2,559,644	0	7,638,836	1.0%	0.5%	0.0%	1.4%
General Service Less Than 50 kW	19,184,993	48,070,477	0	67,255,470	3.6%	9.1%	0.0%	12.7%
General Service 50 to 999 kW	5,575,758	0	150,718,556	156,294,314	1.1%	0.0%	28.5%	29.5%
General Service 1,000 to 4,999 kW	4,234,085	0	47,109,505	51,343,590	0.8%	0.0%	8.9%	9.7%
Large Use	1,697,138	0	23,673,292	25,370,430	0.3%	0.0%	4.5%	4.8%
Street Lighting	2,539,322	0	9,250,042	11,789,364	0.5%	0.0%	1.7%	2.2%
Unmetered Scattered Load	6,642	3,413,257	0	3,419,900	0.0%	0.6%	0.0%	0.6%
Unmetered Scattered Load	1,262,025	0	0	1,262,025	0.2%	0.0%	0.0%	0.2%
	170,652,407	127,690,129	230,751,395	529,093,932	32.3%	24.1%	43.6%	100.0%
				K				

Ontario Energy Board

Incremental Capital Workform

Threshold Parameters

Price Cap Index

Price Escalator (GDP-IPI)	2.00%		
Less Productivity Factor	-0.72%		
Less Stretch Factor	-0.60%		
Price Cap Index		**0.68%**	

Growth

ICM Billing Determinants for Growth - Numerator : 2011 Re-Based Forecast	$ 528,018,642	A
ICM Billing Determinants for Growth - Denominator : 2010 Audited RRR	$ 530,130,457	B
Growth	**-0.40%**	C = A / B

Threshold Test

Year		**2011**	
Price Cap Index		**0.68%**	**A**
Growth		**-0.40%**	**B**
Dead Band		**20%**	**C**
Average Net Fixed Assets			
Gross Fixed Assets Opening		$4,183,572,075	
Add: CWIP Opening		$ 204,719,106	
Capital Additions		$ 376,263,596	
Capital Disposals		$ -	
Capital Retirements		$ -	
Deduct: CWIP Closing		-$ 232,060,508	
Gross Fixed Assets - Closing		$4,532,494,269	
Average Gross Fixed Assets		$4,358,033,172	
Accumulated Depreciation - Opening		$2,285,733,698	
Depreciation Expense		$ 138,815,781	**D**
Disposals		$ 2,807,234	
Retirements			
Accumulated Depreciation - Closing		$2,427,356,713	
Average Accumulated Depreciation		$2,356,545,206	
Average Net Fixed Assets		$2,001,487,967	**E**
Working Capital Allowance			
Working Capital Allowance Base		$2,479,952,766	
Working Capital Allowance Rate		12%	
Working Capital Allowance		$ 296,739,314	**F**
Rate Base		**$2,298,227,281**	**G = E + F**
Depreciation	**D**	**$ 138,815,781**	**H**
Threshold Test		**124.62%**	**I = 1 + (G / H) * (B + A * (1 + B)) + C**
Threshold CAPEX		$ 172,989,465	**J = H *I**

Summary of Incremental Capital Projects (ICPs)

Number of ICPs

1

Project ID #	Incremental Capital Non-Discretionary Project Description	Incremental Capital CAPEX	Amortization Expense	CCA
ICP 1	Summary of Projects (please see Table XXX)	15,436,160	528,412	1,234,893
		15,436,160	528,412	1,234,893

Incremental Capital Adjustment

Current Revenue Requirement				
Current Revenue Requirement - Total			$533,324,186	**A**
Return on Rate Base				
Incremental Capital CAPEX			$ 15,436,160	**B**
Depreciation Expense			$ 528,412	**C**
Incremental Capital CAPEX to be included in Rate Base			$ 14,907,748	**D = B - C**
Deemed ShortTerm Debt %	4.0%	**E**	$ 596,310	**G = D * E**
Deemed Long Term Debt %	56.0%	**F**	$ 8,348,339	**H = D * F**
Short Term Interest	2.46%	**I**	$ 14,669	**K = G * I**
Long Term Interest	5.37%	**J**	$ 448,306	**L = H * J**
Return on Rate Base - Interest			$ 462,975	**M = K + L**
Deemed Equity %	40.0%	**N**	$ 5,963,099	**P = D * N**
Return on Rate Base -Equity	9.58%	**O**	$ 571,265	**Q = P * O**
Return on Rate Base - Total			$ 1,034,240	**R = M + Q**
Amortization Expense				
Amortization Expense - Incremental		**C**	$ 528,412	**S**
Grossed up PIL's				
Regulatory Taxable Income		**O**	$ 571,265	**T**
Add Back Amortization Expense		**S**	$ 528,412	**U**
Deduct CCA			$ 1,234,893	**V**
Incremental Taxable Income			-$ 135,216	**W = T + U - V**
Current Tax Rate (F1.1 Z-Factor Tax Changes)	26.4%	**X**		
PIL's Before Gross Up			-$ 35,697	**Y = W * X**
Incremental Grossed Up PIL's			-$ 48,501	**Z = Y / (1 - X)**
Ontario Capital Tax				
Incremental Capital CAPEX			$ 15,436,160	**AA**
Less : Available Capital Exemption (if any)			$ -	**AB**
Incremental Capital CAPEX subject to OCT			$ 15,436,160	**AC = AA - AB**
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.000%	**AD**		
Incremental Ontario Capital Tax			$ -	**AE = AC * AD**
Incremental Revenue Requirement				
Return on Rate Base - Total		**Q**	$ 1,034,240	**AF**
Amortization Expense - Total		**S**	$ 528,412	**AG**
Incremental Grossed Up PIL's		**Z**	-$ 48,501	**AH**
Incremental Ontario Capital Tax		**AE**	$ -	**AI**
Incremental Revenue Requirement			$ 1,514,150	**AJ = AF + AG + AH + AI**

Calculation of Incremental Capital Rate Rider - Option A Fixed and Variable

Rate Class	Service Charge % Revenue A	Distribution Volumetric Rate % Revenue kWh B	Distribution Volumetric Rate % Revenue kW C	Service Charge Revenue D = $N * A	Distribution Volumetric Rate Revenue kWh E = $N * B	Distribution Volumetric Rate Revenue kW F = $N * C	Total Revenue by Rate Class G = D + E + F	Billed Customers or Connections H	Billed kWh I	Billed kW J	Service Charge Rate Rider K = D / H / 12	Distribution Volumetric Rate kWh Rate Rider L = E / I	Distribution Volumetric Rate kW Rate Rider M = F / J
Residential	24.8%	13.9%	0.0%	$ 375,102.83	$ 210,760.81	$ -	$ 585,863.64	598,508	4,886,977,489	0	$0.052227	$0.000043	
Residential Urban	1.0%	0.5%	0.0%	$ 14,535.53	$ 7,325.14	$ -	$ 21,860.67	24,898	99,791,184	0	$0.048650	$0.000073	
General Service Less Than 50 kW	3.6%	9.1%	0.0%	$ 54,903.23	$ 137,567.14	$ -	$ 192,470.37	65,792	2,139,318,076	0	$0.069541	$0.000064	
General Service 50 to 999 kW	1.1%	0.0%	28.5%	$ 15,956.59	$ -	$ 431,323.37	$ 447,279.96	13,067	10,116,374,153	26,935,191	$0.101765	$0.000000	$0.016013
General Service 1,000 to 4,999 kW	0.8%	0.0%	8.9%	$ 12,117.02	$ -	$ 134,817.04	$ 146,934.07	514	4,626,928,262	10,587,119	$1.964498	$0.000000	$0.012734
Large Use	0.3%	0.0%	4.5%	$ 4,856.84	$ -	$ 67,747.76	$ 72,604.59	47	2,376,778,323	4,993,733	$8.611411	$0.000000	$0.013567
Street Lighting	0.5%	0.0%	1.7%	$ 7,266.98	$ -	$ 26,471.59	$ 33,738.57	162,777	110,165,016	322,023	$0.003720	$0.000000	$0.082204
Unmetered Scattered Load	0.0%	0.6%	0.0%	$ 19.01	$ 9,767.99	$ -	$ 9,787.00	1,130	56,231,585	0	$0.001402	$0.000174	
Unmetered Scattered Load	0.2%	0.0%	0.0%	$ 3,611.64	$ -	$ -	$ 3,611.64	21,729	0	0	$0.013851		
				$ 488,369.67	$ 365,421.07	$ 660,359.76	$ 1,514,150.50						
							-						

Enter the above rate riders onto "Sheet 14. Proposed Rate_Riders" in the 2012 OEB IRM3 Rate Generator as an "Rate Rider for Incremental Capital"

Calculation of Incremental Capital Rate Rider - Option B Variable

Rate Class	Total Revenue $ by Rate Class A	Total Revenue % by Rate Class B = A / $H	Total Incremental Capital $ by Rate Class C = $I * B	Billed kWh D	Billed kW E	Distribution Volumetric Rate kWh Rate Rider F = C / D	Distribution Volumetric Rate kW Rate Rider G = C / E
Residential	$204,720,003	38.69%	$585,864	4,886,977,489	0	$0.0001	
Residential Urban	$7,638,836	1.44%	$21,861	99,791,184	0	$0.0002	
General Service Less Than 50 kW	$67,255,470	12.71%	$192,470	2,139,318,076	0	$0.0001	
General Service 50 to 999 kW	$156,294,314	29.54%	$447,280	10,116,374,153	26,935,191		$0.0166
General Service 1,000 to 4,999 kW	$51,343,590	9.70%	$146,934	4,626,928,262	10,587,119		$0.0139
Large Use	$25,370,430	4.80%	$72,605	2,376,778,323	4,993,733		$0.0145
Street Lighting	$11,789,364	2.23%	$33,739	110,165,016	322,023		$0.1048
Unmetered Scattered Load	$3,419,900	0.65%	$9,787	56,231,585	0	$0.0002	
Unmetered Scattered Load	$1,262,025	0.24%	$3,612	0	0		
	$529,093,932	100.00%	$1,514,150				
	H		I				

Enter the above rate riders onto "Sheet 14. Proposed Rate_Riders" in the 2012 OEB IRM3 Rate Generator as an "Rate Rider for Incremental Capital"

Ontario Energy Board

Incremental Capital Workform

Legend: DROP-DOWN MENU | INPUT FIELD | CALCULATION

Applicant Name	**Toronto Hydro-Electric System Limited**
Application Type	**IRM3**
LDC Licence Number	**ED-2002-0497**
Applied for Effective Date	**May 1, 2012**
Stretch Factor Group	**III**
Stretch Factor Value	**0.6%**
Last COS Re-based Year	**2011**
Last COS OEB Application Number	**EB-2010-0142**
ICM Billing Determinants for Growth - Numerator	**2011 Re-Based Forecast**
ICM Billing Determinants for Growth - Denominator	**2010 Audited RRR**

Table of Contents

Sheet Name	Purpose of Sheet
A1.1 LDC Information	Enter LDC Data
A2.1 Table of Contents	Table of Contents
B1.1 Re-Based Bill Det & Rates	Set Up Rate Classes and enter Re-Based Billing Determinants and Tariff Rates
B1.2 Removal of Rate Adders	Removal of Rate Adders
B1.3 Re-Based Rev From Rates	Calculated Re-Based Revenue From Rates
B1.4 Re-Based Rev Req	Detailed Re-Based Revenue From Rates
C1.1 Ld Act-Mst Rcent Yr	Enter Billing Determinants for most recent actual year
D1.1 Current Revenue from Rates	Enter Current Rates to calculate current rate allocation
E1.1 Threshold Parameters	Shows calculation of Price Cap and Growth used for incremental capital threshold calculation
E2.1 Threshold Test	Input sheet to calculate Threshold and Incremental Capital
E3.1 Summary of I C Projects	Summary of Incremental Capital Projects
E4.1 IncrementalCapitalAdjust	Shows Calculation of Incremental Capital Revenue Requirement
F1.1 Incr Cap RRider Opt A FV	Option A - Calculation of Incremental Capital Rate Rider - Fixed & Variable Split
F1.2 Incr Cap RRider Opt B Var	Option B - Calculation of Incremental Capital Rate Rider - Variable Allocation
Z1.0 OEB Control Sheet	Not Shown

Rate Class and Re-Based Billing Determinants & Rates

Select the appropriate Rate Groups and Rate Classes from the drop-down menus in Columns C and D respectively. Following your selection, all appropriate input cells will be shaded green.

Last COS Re-based Year	**2011**
Last COS OEB Application Number	**EB-2010-0142**

Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Re-based Tariff Service Charge D	Re-based Tariff Distribution Volumetric Rate kWh E	Re-based Tariff Distribution Volumetric Rate kW F
RES	Residential	Customer	kWh	598,508	4,886,977,489		18.25	0.0151	
RES	Residential Urban	Customer	kWh	24,898	99,791,184		17.00	0.0257	
GSLT50	General Service Less Than 50 kW	Customer	kWh	65,792	2,139,318,076	0	24.30	0.0225	
GSGT50	General Service 50 to 999 kW	Customer	kW	13,067	10,116,374,153	26,935,191	35.56		5.5956
GSGT50	General Service 1,000 to 4,999 kW	Customer	kW	514	4,626,928,262	10,587,119	686.46		4.4497
LU	Large Use	Customer	kW	47	2,376,778,323	4,993,733	3,009.11		4.7406
SL	Street Lighting	Connection	kW	162,777	110,165,016	322,023	1.30		28.7248
USL	Unmetered Scattered Load	Connection	kWh	1,130	56,231,585		4.84	0.0607	
USL	Unmetered Scattered Load	Connection	kWh	21,729	0		0.49		
NA	Rate Class 10	NA	NA						
NA	Rate Class 11	NA	NA						
NA	Rate Class 12	NA	NA						
NA	Rate Class 13	NA	NA						
NA	Rate Class 14	NA	NA						
NA	Rate Class 15	NA	NA						
NA	Rate Class 16	NA	NA						
NA	Rate Class 17	NA	NA						
NA	Rate Class 18	NA	NA						
NA	Rate Class 19	NA	NA						
NA	Rate Class 20	NA	NA						
NA	Rate Class 21	NA	NA						
NA	Rate Class 22	NA	NA						
NA	Rate Class 23	NA	NA						
NA	Rate Class 24	NA	NA						
NA	Rate Class 25	NA	NA						

Removal of Rate Adders

Last COS Re-based Year 2011

Last COS OEB Application Number EB-2010-0142

Rate Class	Re-based Tariff Service Charge A	Re-based Tariff Distribution Volumetric Rate kWh B	Re-based Tariff Distribution Volumetric Rate kW C	Service Charge Rate Adders D	Distribution Volumetric kWh Rate Adders E	Distribution Volumetric kW Rate Adders F	Re-based Base Service Charge H = A - D	Re-based Base Distribution Volumetric Rate kWh I = B - E	Re-based Base Distribution Volumetric Rate kW J = C - F
Residential	18.25	0.0151	0.0000	0.00	0.0000	0.0000	18.25	0.0151	0.0000
Residential Urban	17.00	0.0257	0.0000	0.00	0.0000	0.0000	17.00	0.0257	0.0000
General Service Less Than 50 kW	24.30	0.0225	0.0000	0.00	0.0000	0.0000	24.30	0.0225	0.0000
General Service 50 to 999 kW	35.56	0.0000	5.5956	0.00	0.0000	0.0000	35.56	0.0000	5.5956
General Service 1,000 to 4,999 kW	686.46	0.0000	4.4497	0.00	0.0000	0.0000	686.46	0.0000	4.4497
Large Use	3,009.11	0.0000	4.7406	0.00	0.0000	0.0000	3,009.11	0.0000	4.7406
Street Lighting	1.30	0.0000	28.7248	0.00	0.0000	0.0000	1.30	0.0000	28.7248
Unmetered Scattered Load	4.84	0.0607	0.0000	0.00	0.0000	0.0000	4.84	0.0607	0.0000
Unmetered Scattered Load	0.49	0.0000	0.0000	0.00	0.0000	0.0000	0.49	0.0000	0.0000

Calculated Re-Based Revenue From Rates

Last COS Re-based Year 2011

Last COS OEB Application Number EB-2010-0142

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Re-based Base Service Charge D	Re-based Base Distribution Volumetric Rate kWh E	Re-based Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates J = G + H + I	Service Charge % Revenue K = G / J	Distribution Volumetric Rate % Revenue kWh L = H / J	Distribution Volumetric Rate % Revenue kW M = I / J	Total % Revenue N = J / R
Residential	598,508	4,886,977,489	0	18.25	0.0151	0.0000	131,073,252	73,646,751	0	204,720,003	64.0%	36.0%	0.0%	38.8%
Residential Urban	24,898	99,791,184	0	17.00	0.0257	0.0000	5,079,192	2,559,644	0	7,638,836	66.5%	33.5%	0.0%	1.4%
General Service Less Than 50 kW	65,792	2,139,318,076	0	24.30	0.0225	0.0000	19,184,993	48,070,477	0	67,255,470	28.5%	71.5%	0.0%	12.7%
General Service 50 to 999 kW	13,067	10,116,374,153	26,935,191	35.56	0.0000	5.5956	5,575,758	0	150,718,556	156,294,314	3.6%	0.0%	96.4%	29.6%
General Service 1,000 to 4,999 kW	514	4,626,928,262	10,587,119	686.46	0.0000	4.4497	4,234,085	0	47,109,505	51,343,590	8.2%	0.0%	91.8%	9.7%
Large Use	47	2,376,778,323	4,993,733	3,009.11	0.0000	4.7406	1,697,138	0	23,673,292	25,370,430	6.7%	0.0%	93.3%	4.8%
Street Lighting	162,777	110,165,016	322,023	1.30	0.0000	28.7248	2,539,322	0	9,250,042	11,789,364	21.5%	0.0%	78.5%	2.2%
Unmetered Scattered Load	1,130	56,231,585	0	4.84	0.0607	0.0000	65,611	3,413,257	0	3,478,868	1.9%	98.1%	0.0%	0.7%
Unmetered Scattered Load	21,729	0	0	0.49	0.0000	0.0000	127,767	0	0	127,767	100.0%	0.0%	0.0%	0.0%
							169,577,117	127,690,129	230,751,395	528,018,642				100.0%
							O	P	Q	R				

Detailed Re-Based Revenue From Rates

Last COS Re-based Year	**2011**
Last COS OEB Application Number	**EB-2010-0142**

Applicants Rate Base		**Last Rate Re-based Amount**				
Average Net Fixed Assets						
Gross Fixed Assets - Re-based Opening	$	4,183,572,075	A			
Add: CWIP Re-based Opening	$	204,719,106	B			
Re-based Capital Additions	$	376,263,596	C			
Re-based Capital Disposals			D			
Re-based Capital Retirements			E			
Deduct: CWIP Re-based Closing	-$	232,060,508	F			
Gross Fixed Assets - Re-based Closing	$	4,532,494,269	G			
Average Gross Fixed Assets				$	4,358,033,172	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$	2,285,733,698	I			
Re-based Depreciation Expense	$	138,815,781	J			
Re-based Disposals	$	2,807,234	K			
Re-based Retirements			L			
Accumulated Depreciation - Re-based Closing	$	2,427,356,713	M			
Average Accumulated Depreciation				$	2,356,545,206	N = (I + M) / 2
Average Net Fixed Assets				**$**	**2,001,487,967**	O = H - N
Working Capital Allowance						
Working Capital Allowance Base	$	2,479,952,766	P			
Working Capital Allowance Rate		12.0%	Q			
Working Capital Allowance				**$**	**296,739,314**	R = P * Q
Rate Base				**$**	**2,298,227,281**	S = O + R
Return on Rate Base						
Deemed ShortTerm Debt %		4.00%	T	$	91,929,091	W = S * T
Deemed Long Term Debt %		56.00%	U	$	1,287,007,277	X = S * U
Deemed Equity %		40.00%	V	$	919,290,912	Y = S * V
Short Term Interest		2.46%	Z	$	2,261,456	AC = W * Z
Long Term Interest		5.37%	AA	$	69,112,291	AD = X * AA
Return on Equity		9.58%	AB	$	88,068,069	AE = Y * AB
Return on Rate Base				**$**	**159,441,816**	AF = AC + AD + AE
Distribution Expenses						
OM&A Expenses	$	231,014,224	AG			
Amortization	$	138,815,781	AH			
Ontario Capital Tax (F1.1 Z-Factor Tax Changes)	$	6,802,382	AI			
Grossed Up PILs (F1.1 Z-Factor Tax Changes)	$	11,791,223	AJ			
Low Voltage			AK			
Transformer Allowance	$	11,479,842	AL			
	$	-	AM			
			AN			
			AO			
				$	**399,903,452**	AP = SUM (AG : AO)
Revenue Offsets						
Specific Service Charges	-$	7,580,526	AQ			
Late Payment Charges	-$	4,900,000	AR			
Other Distribution Income	-$	7,240,556	AS			
Other Income and Deductions	-$	6,300,000	AT	**-$**	**26,021,082**	AU = SUM (AQ : AT)
Revenue Requirement from Distribution Rates				**$**	**533,324,186**	AV = AF + AP + AU
Rate Classes Revenue						
Rate Classes Revenue - Total (B1.1 Re-based Revenue - Gen)				$	528,018,642	AW
Difference				$	5,305,544	AZ = AV - AW
Difference (Percentage - should be less than 1%)					1.00%	BA = AZ / AW

Load Actual - Most Recent Year

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections A	Billed kWh B	Billed kW C	Base Service Charge D	Base Distribution Volumetric Rate kWh E	Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D * 12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Total Revenue by Rate Class J = G + H + I
Residential	Customer	kWh	591,496	5,105,974,275	0	$18.25	$0.0151	$0.0000	$129,537,624	$76,947,032	$0	$206,484,656
Residential Urban	Customer	kWh	24,898	99,791,184	0	$17.00	$0.0257	$0.0000	$5,079,192	$2,559,644	$0	$7,638,836
General Service Less Than 50 kW	Customer	kWh	65,799	2,095,343,918	0	$24.30	$0.0225	$0.0000	$19,186,988	$47,082,378	$0	$66,269,366
General Service 50 to 999 kW	Customer	kW	12,873	10,189,051,346	26,712,248	$35.56	$0.0000	$5.5956	$5,493,167	$0	$149,471,055	$154,964,221
General Service 1,000 to 4,999 kW	Customer	kW	509	4,828,382,733	10,972,419	$686.46	$0.0000	$4.4497	$4,192,898	$0	$48,823,974	$53,016,871
Large Use	Customer	kW	47	2,263,227,585	5,267,224	$3,009.11	$0.0000	$4.7406	$1,697,138	$0	$24,969,801	$26,666,940
Street Lighting	Connection	kW	162,964	112,727,603	321,995	$1.30	$0.0000	$28.7248	$2,542,238	$0	$9,249,232	$11,791,471
Unmetered Scattered Load	Connection	kWh	1,107	52,097,299	0	$4.84	$0.0607	$0.0000	$64,295	$3,162,306	$0	$3,226,601
Unmetered Scattered Load	Connection	kWh	12,159	0	0	$0.49	$0.0000	$0.0000	$71,495	$0	$0	$71,495
									$167,865,035	**$129,751,360**	**$232,514,062**	**$530,130,457**

This sheet is used to determine the applicants most current allocation of revenues (after the most recent revenue cost ratio adjustment, if applicable) to be used to calculate the incremental capital rate riders.

Current Revenue from Rates

Rate Class	Fixed Metric	Vol Metric	Current Base Service Charge A	Current Base Distribution Volumetric Rate kWh B	Current Base Distribution Volumetric Rate kW C	Re-based Billed Customers or Connections D	Re-based Billed kWh E	Re-based Billed kW F	Current Base Service Charge Revenue G = A * D *12	Current Base Distribution Volumetric Rate kWh Revenue H = B * E	Current Base Distribution Volumetric Rate kW Revenue I = C * F	Total Current Base Revenue J = G + H + I	Service Charge % Total Revenue L = G / $K	Distribution Volumetric Rate % Total Revenue M = H / $K	Distribution Volumetric Rate % Total Revenue N = I / $K	Total % Revenue O = J / $K
Residential	Customer	kWh	18.25	0.0151		598,508	4,886,977,489	0	131,073,252	73,646,751	0	204,720,003	24.8%	13.9%	0.0%	38.7%
Residential Urban	Customer	kWh	17.00	0.0257		24,898	99,791,184	0	5,079,192	2,559,644	0	7,638,836	1.0%	0.5%	0.0%	1.4%
General Service Less Than 50 kW	Customer	kWh	24.30	0.0225		65,792	2,139,318,076	0	19,184,993	48,070,477	0	67,255,470	3.6%	9.1%	0.0%	12.7%
General Service 50 to 999 kW	Customer	kW	35.56		5.5956	13,067	10,116,374,153	26,935,191	5,575,758	0	150,718,556	156,294,314	1.1%	0.0%	28.5%	29.5%
General Service 1,000 to 4,999 kW	Customer	kW	686.46		4.4497	514	4,626,928,262	10,587,119	4,234,085	0	47,109,505	51,343,590	0.8%	0.0%	8.9%	9.7%
Large Use	Customer	kW	3,009.11		4.7406	47	2,376,778,323	4,993,733	1,697,138	0	23,673,292	25,370,430	0.3%	0.0%	4.5%	4.8%
Street Lighting	Connection	kW	1.30		28.7248	162,777	110,165,016	322,023	2,539,322	0	9,250,042	11,789,364	0.5%	0.0%	1.7%	2.2%
Unmetered Scattered Load	Connection	kWh	0.49	0.0607		1,130	56,231,585	0	6,642	3,413,257	0	3,419,900	0.0%	0.6%	0.0%	0.6%
Unmetered Scattered Load	Connection	kWh	4.84			21,729	0	0	1,262,025	0	0	1,262,025	0.2%	0.0%	0.0%	0.2%
									170,652,407	127,690,129	230,751,395	529,093,932 **K**	32.3%	24.1%	43.6%	100.0%

Ontario Energy Board

Incremental Capital Workform

Threshold Parameters

Price Cap Index

Price Escalator (GDP-IPI)	2.00%	
Less Productivity Factor	-0.72%	
Less Stretch Factor	-0.60%	
Price Cap Index		**0.68%**

Growth

ICM Billing Determinants for Growth - Numerator : 2011 Re-Based Forecast	$528,018,642	A
ICM Billing Determinants for Growth - Denominator : 2010 Audited RRR	$530,130,457	B
Growth	**-0.40%**	C = A / B

Threshold Test

Year		**2011**	
Price Cap Index		**0.68%**	**A**
Growth		**-0.40%**	**B**
Dead Band		**20%**	**C**
Average Net Fixed Assets			
Gross Fixed Assets Opening		$4,183,572,075	
Add: CWIP Opening		$ 204,719,106	
Capital Additions		$ 376,263,596	
Capital Disposals		$ -	
Capital Retirements		$ -	
Deduct: CWIP Closing		-$ 232,060,508	
Gross Fixed Assets - Closing		$4,532,494,269	
Average Gross Fixed Assets		$4,358,033,172	
Accumulated Depreciation - Opening		$2,285,733,698	
Depreciation Expense		$ 138,815,781	**D**
Disposals		$ 2,807,234	
Retirements			
Accumulated Depreciation - Closing		$2,427,356,713	
Average Accumulated Depreciation		$2,356,545,206	
Average Net Fixed Assets		$2,001,487,967	**E**
Working Capital Allowance			
Working Capital Allowance Base		$2,479,952,766	
Working Capital Allowance Rate		12%	
Working Capital Allowance		$ 296,739,314	**F**
Rate Base		**$2,298,227,281**	**G = E + F**
Depreciation	**D**	**$ 138,815,781**	**H**
Threshold Test		**124.62%**	**I = 1 + (G / H) * (B + A * (1 + B)) + (**
Threshold CAPEX		$ 172,989,465	**J = H *I**

Ontario Energy Board

Incremental Capital Workform

Summary of Incremental Capital Projects (ICPs)

Number of ICPs

1

Project ID #	Incremental Capital Non-Discretionary Project Description	Incremental Capital CAPEX	Amortization Expense	CCA
ICP 1	Summary of Projects (please see Table XXX)	188,935,099	6,073,091	####
		188,935,099	6,073,091	####

Incremental Capital Adjustment

Current Revenue Requirement				
Current Revenue Requirement - Total			$533,324,186	**A**
Return on Rate Base				
Incremental Capital CAPEX			$188,935,099	**B**
Depreciation Expense			$ 6,073,091	**C**
Incremental Capital CAPEX to be included in Rate Base			$182,862,008	**D = B - C**
Deemed ShortTerm Debt %	4.0%	**E**	$ 7,314,480	**G = D * E**
Deemed Long Term Debt %	56.0%	**F**	$102,402,724	**H = D * F**
Short Term Interest	2.46%	**I**	$ 179,936	**K = G * I**
Long Term Interest	5.37%	**J**	$ 5,499,026	**L = H * J**
Return on Rate Base - Interest			$ 5,678,963	**M = K + L**
Deemed Equity %	40.0%	**N**	$ 73,144,803	**P = D * N**
Return on Rate Base -Equity	9.58%	**O**	$ 7,007,272	**Q = P * O**
Return on Rate Base - Total			$ 12,686,235	**R = M + Q**
Amortization Expense				
Amortization Expense - Incremental		**C**	$ 6,073,091	**S**
Grossed up PIL's				
Regulatory Taxable Income		**O**	$ 7,007,272	**T**
Add Back Amortization Expense		**S**	$ 6,073,091	**U**
Deduct CCA			$ 15,114,808	**V**
Incremental Taxable Income			-$ 2,034,445	**W = T + U - V**
Current Tax Rate (F1.1 Z-Factor Tax Changes)	26.4%	**X**		
PIL's Before Gross Up			-$ 537,093	**Y = W * X**
Incremental Grossed Up PIL's			-$ 729,747	**Z = Y / (1 - X)**
Ontario Capital Tax				
Incremental Capital CAPEX			$188,935,099	**AA**
Less : Available Capital Exemption (if any)			$ -	**AB**
Incremental Capital CAPEX subject to OCT			$188,935,099	**AC = AA - AB**
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.000%	**AD**		
Incremental Ontario Capital Tax			$ -	**AE = AC * AD**
Incremental Revenue Requirement				
Return on Rate Base - Total		**Q**	$ 12,686,235	**AF**
Amortization Expense - Total		**S**	$ 6,073,091	**AG**
Incremental Grossed Up PIL's		**Z**	-$ 729,747	**AH**
Incremental Ontario Capital Tax		**AE**	$ -	**AI**
Incremental Revenue Requirement			$ 18,029,579	**AJ = AF + AG + AH + AI**

Calculation of Incremental Capital Rate Rider - Option A Fixed and Variable

Rate Class	Service Charge % Revenue A	Distribution Volumetric Rate % Revenue kWh B	Distribution Volumetric Rate % Revenue kW C	Service Charge Revenue D = $N * A	Distribution Volumetric Rate Revenue kWh E = $N * B	Distribution Volumetric Rate Revenue kW F = $N * C	Total Revenue by Rate Class G = D + E + F	Billed Customers or Connections H	Billed kWh I	Billed kW J	Service Charge Rate Rider K = D / H / 12	Distribution Volumetric Rate kWh Rate Rider L = E / I	Distribution Volumetric Rate kW Rate Rider M = F / J
Residential	24.8%	13.9%	0.0%	$ 4,466,495.32	$ 2,509,610.95	$ -	$ 6,976,106.27	598,508	4,886,977,489	0	$0.621893	$0.000514	
Residential Urban	1.0%	0.5%	0.0%	$ 173,080.22	$ 87,223.27	$ -	$ 260,303.49	24,898	99,791,184	0	$0.579298	$0.000874	
General Service Less Than 50 kW	3.6%	9.1%	0.0%	$ 653,754.13	$ 1,638,065.42	$ -	$ 2,291,819.55	65,792	2,139,318,076	0	$0.828055	$0.000766	
General Service 50 to 999 kW	1.1%	0.0%	28.5%	$ 190,001.36	$ -	$ 5,135,935.19	$ 5,325,936.55	13,067	10,116,374,153	26,935,191	$1.211754	$0.000000	$0.190678
General Service 1,000 to 4,999 kW	0.8%	0.0%	8.9%	$ 144,282.09	$ -	$ 1,605,319.00	$ 1,749,601.09	514	4,626,928,262	10,587,119	$23.392037	$0.000000	$0.151629
Large Use	0.3%	0.0%	4.5%	$ 57,832.24	$ -	$ 806,698.90	$ 864,531.14	47	2,376,778,323	4,993,733	$102.539424	$0.000000	$0.161542
Street Lighting	0.5%	0.0%	1.7%	$ 86,530.76	$ -	$ 315,207.49	$ 401,738.25	162,777	110,165,016	322,023	$0.044299	$0.000000	$0.978836
Unmetered Scattered Load	0.0%	0.6%	0.0%	$ 226.35	$ 116,311.28	$ -	$ 116,537.63	1,130	56,231,585	0	$0.016697	$0.002068	
Unmetered Scattered Load	0.2%	0.0%	0.0%	$ 43,005.19	$ -	$ -	$ 43,005.19	21,729	0	0	$0.164929		
				$ 5,815,207.66	$ 4,351,210.91	$ 7,863,160.58	$ 18,029,579.14						
							-						

Enter the above rate riders onto "Sheet 14. Proposed Rate_Riders" in the 2012 OEB IRM3 Rate Generator as an "Rate Rider for Incremental Capital"

Calculation of Incremental Capital Rate Rider - Option B Variable

Rate Class	Total Revenue $ by Rate Class A	Total Revenue % by Rate Class B = A / $H	Total Incremental Capital $ by Rate Class C = $I * B	Billed kWh D	Billed kW E	Distribution Volumetric Rate kWh Rate Rider F = C / D	Distribution Volumetric Rate kW Rate Rider G = C / E
Residential	$204,720,003	38.69%	$6,976,106	4,886,977,489	0	$0.0014	
Residential Urban	$7,638,836	1.44%	$260,303	99,791,184	0	$0.0026	
General Service Less Than 50 kW	$67,255,470	12.71%	$2,291,820	2,139,318,076	0	$0.0011	
General Service 50 to 999 kW	$156,294,314	29.54%	$5,325,937	10,116,374,153	26,935,191		$0.1977
General Service 1,000 to 4,999 kW	$51,343,590	9.70%	$1,749,601	4,626,928,262	10,587,119		$0.1653
Large Use	$25,370,430	4.80%	$864,531	2,376,778,323	4,993,733		$0.1731
Street Lighting	$11,789,364	2.23%	$401,738	110,165,016	322,023		$1.2475
Unmetered Scattered Load	$3,419,900	0.65%	$116,538	56,231,585	0	$0.0021	
Unmetered Scattered Load	$1,262,025	0.24%	$43,005	0	0		
	$529,093,932	100.00%	$18,029,579				
	H		I				

Enter the above rate riders onto "Sheet 14. Proposed Rate_Riders" in the 2012 OEB IRM3 Rate Generator as an "Rate Rider for Incremental Capital"

Ontario Energy Board

Incremental Capital Workform

Legend | DROP-DOWN MENU | INPUT FIELD | CALCULATION

Applicant Name	Toronto Hydro-Electric System Limited
Application Type	IRM3
LDC Licence Number	ED-2002-0497
Applied for Effective Date	May 1, 2012
Stretch Factor Group	III
Stretch Factor Value	0.6%
Last COS Re-based Year	2011
Last COS OEB Application Number	EB-2010-0142
ICM Billing Determinants for Growth - Numerator	2011 Re-Based Forecast
ICM Billing Determinants for Growth - Denominator	2010 Audited RRR

Table of Contents

Sheet Name	Purpose of Sheet
A1.1 LDC Information	Enter LDC Data
A2.1 Table of Contents	Table of Contents
B1.1 Re-Based Bill Det & Rates	Set Up Rate Classes and enter Re-Based Billing Determinants and Tariff Rates
B1.2 Removal of Rate Adders	Removal of Rate Adders
B1.3 Re-Based Rev From Rates	Calculated Re-Based Revenue From Rates
B1.4 Re-Based Rev Req	Detailed Re-Based Revenue From Rates
C1.1 Ld Act-Mst Rcent Yr	Enter Billing Determinants for most recent actual year
D1.1 Current Revenue from Rates	Enter Current Rates to calculate current rate allocation
E1.1 Threshold Parameters	Shows calculation of Price Cap and Growth used for incremental capital threshold calculation
E2.1 Threshold Test	Input sheet to calculate Threshold and Incremental Capital
E3.1 Summary of I C Projects	Summary of Incremental Capital Projects
E4.1 IncrementalCapitalAdjust	Shows Calculation of Incremental Capital Revenue Requirement
F1.1 Incr Cap RRider Opt A FV	Option A - Calculation of Incremental Capital Rate Rider - Fixed & Variable Split
F1.2 Incr Cap RRider Opt B Var	Option B - Calculation of Incremental Capital Rate Rider - Variable Allocation
Z1.0 OEB Control Sheet	Not Shown

Rate Class and Re-Based Billing Determinants & Rates

Select the appropriate Rate Groups and Rate Classes from the drop-down menus in Columns C and D respectively. Following your selection, all appropriate input cells will be shaded green.

Last COS Re-based Year	**2011**
Last COS OEB Application Number	**EB-2010-0142**

Rate Group	Rate Class	Fixed Metric	Vol Metric	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Re-based Tariff Service Charge D	Re-based Tariff Distribution Volumetric Rate kWh E	Re-based Tariff Distribution Volumetric Rate kW F
RES	Residential	Customer	kWh	598,508	4,886,977,489		18.25	0.0151	
RES	Residential Urban	Customer	kWh	24,898	99,791,184		17.00	0.0257	
GSLT50	General Service Less Than 50 kW	Customer	kWh	65,792	2,139,318,076	0	24.30	0.0225	
GSGT50	General Service 50 to 999 kW	Customer	kW	13,067	10,116,374,153	26,935,191	35.56		5.5956
GSGT50	General Service 1,000 to 4,999 kW	Customer	kW	514	4,626,928,262	10,587,119	686.46		4.4497
LU	Large Use	Customer	kW	47	2,376,778,323	4,993,733	3,009.11		4.7406
SL	Street Lighting	Connection	kW	162,777	110,165,016	322,023	1.30		28.7248
USL	Unmetered Scattered Load	Connection	kWh	1,130	56,231,585		4.84	0.0607	
USL	Unmetered Scattered Load	Connection	kWh	21,729	0		0.49		
NA	Rate Class 10	NA	NA						
NA	Rate Class 11	NA	NA						
NA	Rate Class 12	NA	NA						
NA	Rate Class 13	NA	NA						
NA	Rate Class 14	NA	NA						
NA	Rate Class 15	NA	NA						
NA	Rate Class 16	NA	NA						
NA	Rate Class 17	NA	NA						
NA	Rate Class 18	NA	NA						
NA	Rate Class 19	NA	NA						
NA	Rate Class 20	NA	NA						
NA	Rate Class 21	NA	NA						
NA	Rate Class 22	NA	NA						
NA	Rate Class 23	NA	NA						
NA	Rate Class 24	NA	NA						
NA	Rate Class 25	NA	NA						

Removal of Rate Adders

Last COS Re-based Year 2011

Last COS OEB Application Number EB-2010-0142

Rate Class	Re-based Tariff Service Charge A	Re-based Tariff Distribution Volumetric Rate kWh B	Re-based Tariff Distribution Volumetric Rate kW C	Service Charge Rate Adders D	Distribution Volumetric kWh Rate Adders E	Distribution Volumetric kW Rate Adders F	Re-based Base Service Charge H = A - D	Re-based Base Distribution Volumetric Rate kWh I = B - E	Re-based Base Distribution Volumetric Rate kW J = C - F
Residential	18.25	0.0151	0.0000	0.00	0.0000	0.0000	18.25	0.0151	0.0000
Residential Urban	17.00	0.0257	0.0000	0.00	0.0000	0.0000	17.00	0.0257	0.0000
General Service Less Than 50 kW	24.30	0.0225	0.0000	0.00	0.0000	0.0000	24.30	0.0225	0.0000
General Service 50 to 999 kW	35.56	0.0000	5.5956	0.00	0.0000	0.0000	35.56	0.0000	5.5956
General Service 1,000 to 4,999 kW	686.46	0.0000	4.4497	0.00	0.0000	0.0000	686.46	0.0000	4.4497
Large Use	3,009.11	0.0000	4.7406	0.00	0.0000	0.0000	3,009.11	0.0000	4.7406
Street Lighting	1.30	0.0000	28.7248	0.00	0.0000	0.0000	1.30	0.0000	28.7248
Unmetered Scattered Load	4.84	0.0607	0.0000	0.00	0.0000	0.0000	4.84	0.0607	0.0000
Unmetered Scattered Load	0.49	0.0000	0.0000	0.00	0.0000	0.0000	0.49	0.0000	0.0000

Calculated Re-Based Revenue From Rates

Last COS Re-based Year 2011

Last COS OEB Application Number EB-2010-0142

Rate Class	Re-based Billed Customers or Connections A	Re-based Billed kWh B	Re-based Billed kW C	Re-based Base Service Charge D	Re-based Base Distribution Volumetric Rate kWh E	Re-based Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D *12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Revenue Requirement from Rates J = G + H + I	Service Charge % Revenue K = G / J	Distribution Volumetric Rate % Revenue kWh L = H / J	Distribution Volumetric Rate % Revenue kW M = I / J	Total % Revenue N = J / R
Residential	598,508	4,886,977,489	0	18.25	0.0151	0.0000	131,073,252	73,646,751	0	204,720,003	64.0%	36.0%	0.0%	38.8%
Residential Urban	24,898	99,791,184	0	17.00	0.0257	0.0000	5,079,192	2,559,644	0	7,638,836	66.5%	33.5%	0.0%	1.4%
General Service Less Than 50 kW	65,792	2,139,318,076	0	24.30	0.0225	0.0000	19,184,993	48,070,477	0	67,255,470	28.5%	71.5%	0.0%	12.7%
General Service 50 to 999 kW	13,067	10,116,374,153	26,935,191	35.56	0.0000	5.5956	5,575,758	0	150,718,556	156,294,314	3.6%	0.0%	96.4%	29.6%
General Service 1,000 to 4,999 kW	514	4,626,928,262	10,587,119	686.46	0.0000	4.4497	4,234,085	0	47,109,505	51,343,590	8.2%	0.0%	91.8%	9.7%
Large Use	47	2,376,778,323	4,993,733	3,009.11	0.0000	4.7406	1,697,138	0	23,673,292	25,370,430	6.7%	0.0%	93.3%	4.8%
Street Lighting	162,777	110,165,016	322,023	1.30	0.0000	28.7248	2,539,322	0	9,250,042	11,789,364	21.5%	0.0%	78.5%	2.2%
Unmetered Scattered Load	1,130	56,231,585	0	4.84	0.0607	0.0000	65,611	3,413,257	0	3,478,868	1.9%	98.1%	0.0%	0.7%
Unmetered Scattered Load	21,729	0	0	0.49	0.0000	0.0000	127,767	0	0	127,767	100.0%	0.0%	0.0%	0.0%
							169,577,117	127,690,129	230,751,395	528,018,642				100.0%
							O	P	Q	R				

Detailed Re-Based Revenue From Rates

Last COS Re-based Year	**2011**
Last COS OEB Application Number	**EB-2010-0142**

Applicants Rate Base

	Last Rate Re-based Amount				
Average Net Fixed Assets					
Gross Fixed Assets - Re-based Opening	$ 4,183,572,075	A			
Add: CWIP Re-based Opening	$ 204,719,106	B			
Re-based Capital Additions	$ 376,263,596	C			
Re-based Capital Disposals		D			
Re-based Capital Retirements		E			
Deduct: CWIP Re-based Closing	-$ 232,060,508	F			
Gross Fixed Assets - Re-based Closing	$ 4,532,494,269	G			
Average Gross Fixed Assets			$	4,358,033,172	H = (A + G) / 2
Accumulated Depreciation - Re-based Opening	$ 2,285,733,698	I			
Re-based Depreciation Expense	$ 138,815,781	J			
Re-based Disposals	$ 2,807,234	K			
Re-based Retirements		L			
Accumulated Depreciation - Re-based Closing	$ 2,427,356,713	M			
Average Accumulated Depreciation			$	2,356,545,206	N = (I + M) / 2
Average Net Fixed Assets			**$**	**2,001,487,967**	O = H - N
Working Capital Allowance					
Working Capital Allowance Base	$ 2,479,952,766	P			
Working Capital Allowance Rate	12.0%	Q			
Working Capital Allowance			**$**	**296,739,314**	R = P * Q
Rate Base			**$**	**2,298,227,281**	S = O + R

Return on Rate Base

Deemed ShortTerm Debt %	4.00%	T	$	91,929,091	W = S * T
Deemed Long Term Debt %	56.00%	U	$	1,287,007,277	X = S * U
Deemed Equity %	40.00%	V	$	919,290,912	Y = S * V
Short Term Interest	2.46%	Z	$	2,261,456	AC = W * Z
Long Term Interest	5.37%	AA	$	69,112,291	AD = X * AA
Return on Equity	9.58%	AB	$	88,068,069	AE = Y * AB
Return on Rate Base			**$**	**159,441,816**	AF = AC + AD + AE

Distribution Expenses

OM&A Expenses	$ 231,014,224	AG			
Amortization	$ 138,815,781	AH			
Ontario Capital Tax (F1.1 Z-Factor Tax Changes)	$ 6,802,382	AI			
Grossed Up PILs (F1.1 Z-Factor Tax Changes)	$ 11,791,223	AJ			
Low Voltage		AK			
Transformer Allowance	$ 11,479,842	AL			
	$ -	AM			
		AN			
		AO			
			$	**399,903,452**	AP = SUM (AG : AO)

Revenue Offsets

Specific Service Charges	-$ 7,580,526	AQ			
Late Payment Charges	-$ 4,900,000	AR			
Other Distribution Income	-$ 7,240,556	AS			
Other Income and Deductions	-$ 6,300,000	AT	**-$**	**26,021,082**	AU = SUM (AQ : AT)

Revenue Requirement from Distribution Rates			**$**	**533,324,186**	AV = AF + AP + AU

Rate Classes Revenue

Rate Classes Revenue - Total (B1.1 Re-based Revenue - Gen)			$	528,018,642	AW

Load Actual - Most Recent Year

Rate Class	Fixed Metric	Vol Metric	Billed Customers or Connections A	Billed kWh B	Billed kW C	Base Service Charge D	Base Distribution Volumetric Rate kWh E	Base Distribution Volumetric Rate kW F	Service Charge Revenue G = A * D * 12	Distribution Volumetric Rate Revenue kWh H = B * E	Distribution Volumetric Rate Revenue kW I = C * F	Total Revenue by Rate Class J = G + H + I
Residential	Customer	kWh	591,496	5,105,974,275	0	$18.25	$0.0151	$0.0000	$129,537,624	$76,947,032	$0	$206,484,656
Residential Urban	Customer	kWh	24,898	99,791,184	0	$17.00	$0.0257	$0.0000	$5,079,192	$2,559,644	$0	$7,638,836
General Service Less Than 50 kW	Customer	kWh	65,799	2,095,343,918	0	$24.30	$0.0225	$0.0000	$19,186,988	$47,082,378	$0	$66,269,366
General Service 50 to 999 kW	Customer	kW	12,873	10,189,051,346	26,712,248	$35.56	$0.0000	$5.5956	$5,493,167	$0	$149,471,055	$154,964,221
General Service 1,000 to 4,999 kW	Customer	kW	509	4,828,382,733	10,972,419	$686.46	$0.0000	$4.4497	$4,192,898	$0	$48,823,974	$53,016,871
Large Use	Customer	kW	47	2,263,227,585	5,267,224	$3,009.11	$0.0000	$4.7406	$1,697,138	$0	$24,969,801	$26,666,940
Street Lighting	Connection	kW	162,964	112,727,603	321,995	$1.30	$0.0000	$28.7248	$2,542,238	$0	$9,249,232	$11,791,471
Unmetered Scattered Load	Connection	kWh	1,107	52,097,299	0	$4.84	$0.0607	$0.0000	$64,295	$3,162,306	$0	$3,226,601
Unmetered Scattered Load	Connection	kWh	12,159	0	0	$0.49	$0.0000	$0.0000	$71,495	$0	$0	$71,495
									$167,865,035	**$129,751,360**	**$232,514,062**	**$530,130,457**

This sheet is used to determine the applicants most current allocation of revenues (after the most recent revenue cost ratio adjustment, if applicable) to be used to calculate the incremental capital rate riders.

Current Revenue from Rates

Rate Class	Fixed Metric	Vol Metric	Current Base Service Charge A	Current Base Distribution Volumetric Rate kWh B	Current Base Distribution Volumetric Rate kW C	Re-based Billed Customers or Connections D	Re-based Billed kWh E	Re-based Billed kW F	Current Base Service Charge Revenue G = A * D *12	Current Base Distribution Volumetric Rate kWh Revenue H = B * E	Current Base Distribution Volumetric Rate kW Revenue I = C * F	Total Current Base Revenue J = G + H + I	Service Charge % Total Revenue L = G / $K	Distribution Volumetric Rate % Total Revenue M = H / $K	Distribution Volumetric Rate % Total Revenue N = I / $K	Total % Revenue O = J / $K
Residential	Customer	kWh	18.25	0.0151		598,508	4,886,977,489	0	131,073,252	73,646,751	0	204,720,003	24.8%	13.9%	0.0%	38.7%
Residential Urban	Customer	kWh	17.00	0.0257		24,898	99,791,184	0	5,079,192	2,559,644	0	7,638,836	1.0%	0.5%	0.0%	1.4%
General Service Less Than 50 kW	Customer	kWh	24.30	0.0225		65,792	2,139,318,076	0	19,184,993	48,070,477	0	67,255,470	3.6%	9.1%	0.0%	12.7%
General Service 50 to 999 kW	Customer	kW	35.56		5.5956	13,067	10,116,374,153	26,935,191	5,575,758	0	150,718,556	156,294,314	1.1%	0.0%	28.5%	29.5%
General Service 1,000 to 4,999 kW	Customer	kW	686.46		4.4497	514	4,626,928,262	10,587,119	4,234,085	0	47,109,505	51,343,590	0.8%	0.0%	8.9%	9.7%
Large Use	Customer	kW	3,009.11		4.7406	47	2,376,778,323	4,993,733	1,697,138	0	23,673,292	25,370,430	0.3%	0.0%	4.5%	4.8%
Street Lighting	Connection	kW	1.30		28.7248	162,777	110,165,016	322,023	2,539,322	0	9,250,042	11,789,364	0.5%	0.0%	1.7%	2.2%
Unmetered Scattered Load	Connection	kWh	0.49	0.0607		1,130	56,231,585	0	6,642	3,413,257	0	3,419,900	0.0%	0.6%	0.0%	0.6%
Unmetered Scattered Load	Connection	kWh	4.84			21,729	0	0	1,262,025	0	0	1,262,025	0.2%	0.0%	0.0%	0.2%
									170,652,407	127,690,129	230,751,395	529,093,932	32.3%	24.1%	43.6%	100.0%
												K				

Ontario Energy Board

Incremental Capital Workform

Threshold Parameters

Price Cap Index

Price Escalator (GDP-IPI)	2.00%	
Less Productivity Factor	-0.72%	
Less Stretch Factor	-0.60%	
Price Cap Index		**0.68%**

Growth

ICM Billing Determinants for Growth - Numerator : 2011 Re-Based Forecast	$528,018,642	A
ICM Billing Determinants for Growth - Denominator : 2010 Audited RRR	$530,130,457	B
Growth	**-0.40%**	C = A / B

Ontario Energy Board

Incremental Capital Workform

Threshold Test

Year		**2011**	
Price Cap Index		**0.68%**	**A**
Growth		**-0.40%**	**B**
Dead Band		**20%**	**C**
Average Net Fixed Assets			
Gross Fixed Assets Opening		$4,183,572,075	
Add: CWIP Opening		$ 204,719,106	
Capital Additions		$ 376,263,596	
Capital Disposals		$ -	
Capital Retirements		$ -	
Deduct: CWIP Closing		-$ 232,060,508	
Gross Fixed Assets - Closing		$4,532,494,269	
Average Gross Fixed Assets		$4,358,033,172	
Accumulated Depreciation - Opening		$2,285,733,698	
Depreciation Expense		$ 138,815,781	**D**
Disposals		$ 2,807,234	
Retirements			
Accumulated Depreciation - Closing		$2,427,356,713	
Average Accumulated Depreciation		$2,356,545,206	
Average Net Fixed Assets		$2,001,487,967	**E**
Working Capital Allowance			
Working Capital Allowance Base		$2,479,952,766	
Working Capital Allowance Rate		12%	
Working Capital Allowance		$ 296,739,314	**F**
Rate Base		**$2,298,227,281**	**G = E + F**
Depreciation	**D**	**$ 138,815,781**	**H**
Threshold Test		**124.62%**	**I = 1 + (G / H) * (B + A * (1 + B)) + (**
Threshold CAPEX		$ 172,989,465	**J = H *I**

Ontario Energy Board

Incremental Capital Workform

Summary of Incremental Capital Projects (ICPs)

Number of ICPs
1

Project ID #	Incremental Capital Non-Discretionary Project Description	Incremental Capital CAPEX	Amortization Expense	CCA
ICP 1	Summary of Projects (please see Table XXX)	124,363,009	3,852,404	9,949,040
		124,363,009	3,852,404	9,949,040

Incremental Capital Adjustment

Current Revenue Requirement				
Current Revenue Requirement - Total			$533,324,186	**A**

Return on Rate Base				
Incremental Capital CAPEX			$124,363,009	**B**
Depreciation Expense			$ 3,852,404	**C**
Incremental Capital CAPEX to be included in Rate Base			$120,510,605	**D = B - C**
Deemed ShortTerm Debt %	4.0%	**E**	$ 4,820,424	**G = D * E**
Deemed Long Term Debt %	56.0%	**F**	$ 67,485,939	**H = D * F**
Short Term Interest	2.46%	**I**	$ 118,582	**K = G * I**
Long Term Interest	5.37%	**J**	$ 3,623,995	**L = H * J**
Return on Rate Base - Interest			$ 3,742,577	**M = K + L**
Deemed Equity %	40.0%	**N**	$ 48,204,242	**P = D * N**
Return on Rate Base -Equity	9.58%	**O**	$ 4,617,966	**Q = P * O**
Return on Rate Base - Total			$ 8,360,544	**R = M + Q**

Amortization Expense				
Amortization Expense - Incremental		**C**	$ 3,852,404	**S**

Grossed up PIL's				
Regulatory Taxable Income		**O**	$ 4,617,966	**T**
Add Back Amortization Expense		**S**	$ 3,852,404	**U**
Deduct CCA			$ 9,949,040	**V**
Incremental Taxable Income			-$ 1,478,670	**W = T + U - V**
Current Tax Rate (F1.1 Z-Factor Tax Changes)	26.4%	**X**		
PIL's Before Gross Up			-$ 390,369	**Y = W * X**
Incremental Grossed Up PIL's			-$ 530,392	**Z = Y / (1 - X)**

Ontario Capital Tax				
Incremental Capital CAPEX			$124,363,009	**AA**
Less : Available Capital Exemption (if any)			$ -	**AB**
Incremental Capital CAPEX subject to OCT			$124,363,009	**AC = AA - AB**
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	0.000%	**AD**		
Incremental Ontario Capital Tax			$ -	**AE = AC * AD**

Incremental Revenue Requirement				
Return on Rate Base - Total		**Q**	$ 8,360,544	**AF**
Amortization Expense - Total		**S**	$ 3,852,404	**AG**
Incremental Grossed Up PIL's		**Z**	-$ 530,392	**AH**
Incremental Ontario Capital Tax		**AE**	$ -	**AI**
Incremental Revenue Requirement			$ 11,682,555	**AJ = AF + AG + AH + AI**

Calculation of Incremental Capital Rate Rider - Option A Fixed and Variable

Rate Class	Service Charge % Revenue A	Distribution Volumetric Rate % Revenue kWh B	Distribution Volumetric Rate % Revenue kW C	Service Charge Revenue D = $N * A	Distribution Volumetric Rate Revenue kWh E = $N * B	Distribution Volumetric Rate Revenue kW F = $N * C	Total Revenue by Rate Class G = D + E + F	Billed Customers or Connections H	Billed kWh I	Billed kW J	Service Charge Rate Rider K = D / H / 12	Distribution Volumetric Rate kWh Rate Rider L = E / I	Distribution Volumetric Rate kW Rate Rider M = F / J
Residential	24.8%	13.9%	0.0%	$ 2,894,137.37	$ 1,626,142.71	$ -	$ 4,520,280.08	598,508	4,886,977,489	0	$0.402966	$0.000333	
Residential Urban	1.0%	0.5%	0.0%	$ 112,150.11	$ 56,517.72	$ -	$ 168,667.83	24,898	99,791,184	0	$0.375365	$0.000566	
General Service Less Than 50 kW	3.6%	9.1%	0.0%	$ 423,610.49	$ 1,061,410.79	$ -	$ 1,485,021.28	65,792	2,139,318,076	0	$0.536551	$0.000496	
General Service 50 to 999 kW	1.1%	0.0%	28.5%	$ 123,114.43	$ -	$ 3,327,911.68	$ 3,451,026.11	13,067	10,116,374,153	26,935,191	$0.785176	$0.000000	$0.123553
General Service 1,000 to 4,999 kW	0.8%	0.0%	8.9%	$ 93,489.89	$ -	$ 1,040,192.23	$ 1,133,682.12	514	4,626,928,262	10,587,119	$15.157246	$0.000000	$0.098251
Large Use	0.3%	0.0%	4.5%	$ 37,473.33	$ -	$ 522,713.51	$ 560,186.83	47	2,376,778,323	4,993,733	$66.442066	$0.000000	$0.104674
Street Lighting	0.5%	0.0%	1.7%	$ 56,069.00	$ -	$ 204,243.75	$ 260,312.75	162,777	110,165,016	322,023	$0.028704	$0.000000	$0.634252
Unmetered Scattered Load	0.0%	0.6%	0.0%	$ 146.67	$ 75,365.76	$ -	$ 75,512.43	1,130	56,231,585	0	$0.010819	$0.001340	
Unmetered Scattered Load	0.2%	0.0%	0.0%	$ 27,865.90	$ -	$ -	$ 27,865.90	21,729	0	0	$0.106869		
				$ 3,768,057.18	$ 2,819,436.98	$ 5,095,061.16	$ 11,682,555.33						
							-						

Enter the above rate riders onto "Sheet 14. Proposed Rate_Riders" in the 2012 OEB IRM3 Rate Generator as an "Rate Rider for Incremental Capital"

Calculation of Incremental Capital Rate Rider - Option B Variable

Rate Class	Total Revenue $ by Rate Class A	Total Revenue % by Rate Class B = A / $H	Total Incremental Capital $ by Rate Class C = $I * B	Billed kWh D	Billed kW E	Distribution Volumetric Rate kWh Rate Rider F = C / D	Distribution Volumetric Rate kW Rate Rider G = C / E
Residential	$204,720,003	38.69%	$4,520,280	4,886,977,489	0	$0.0009	
Residential Urban	$7,638,836	1.44%	$168,668	99,791,184	0	$0.0017	
General Service Less Than 50 kW	$67,255,470	12.71%	$1,485,021	2,139,318,076	0	$0.0007	
General Service 50 to 999 kW	$156,294,314	29.54%	$3,451,026	10,116,374,153	26,935,191		$0.1281
General Service 1,000 to 4,999 kW	$51,343,590	9.70%	$1,133,682	4,626,928,262	10,587,119		$0.1071
Large Use	$25,370,430	4.80%	$560,187	2,376,778,323	4,993,733		$0.1122
Street Lighting	$11,789,364	2.23%	$260,313	110,165,016	322,023		$0.8084
Unmetered Scattered Load	$3,419,900	0.65%	$75,512	56,231,585	0	$0.0013	
Unmetered Scattered Load	$1,262,025	0.24%	$27,866	0	0		
	$529,093,932	100.00%	$11,682,555				
	H		I				

Enter the above rate riders onto "Sheet 14. Proposed Rate_Riders" in the 2012 OEB IRM3 Rate Generator as an "Rate Rider for Incremental Capital"

2012, 2013 and 2014 ICM True-Up

	2012			2013			2014		
	Net Fixed Asset	Amort. Exp	CCA	Net Fixed Asset	Amort. Exp	CCA	Net Fixed Asset	Amort. Exp	CCA
01 Underground Infrastructure	5,532,938	181,834	442,635	66,816,313	2,119,715	5,345,305	48,890,725	1,592,427	3,911,258
02 Paper Insulated Lead Covered Cable - Piece Outs and Leakers	-	-	-	128,199	2,276	10,256	1,251,332	28,985	100,107
03 Handwell Replacement	3,092,536	127,921	247,403	16,613,719	739,310	1,329,098	6,787,380	302,358	542,990
04 Overhead Infrastructure	284,925	7,995	22,794	33,073,032	890,052	2,645,843	23,689,595	619,169	1,895,168
05 Box Construction	69,165	1,683	5,533	5,649,973	141,885	451,998	8,120,856	211,922	649,668
06 Rear Lot Construction	1,737,342	53,338	138,987	28,557,004	821,303	2,284,560	12,485,955	369,314	998,876
07 Polymer SMD - 20 Fuses				-	-	-	-	-	-
08 Scadamate R1 Switches				-	-	-	-	-	-
09 Network Vault & Roofs	71,813	3,591	5,745	14,727,912	447,279	1,178,233	1,143,224	37,785	91,458
10 Fibertop Network Units	1,370,583	60,927	109,647	6,366,000	309,397	509,280	2,295,328	100,499	183,626
11 Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)	35,035	1,168	2,803	1,535,186	65,705	122,815	149,485	5,458	11,959
12 Stations Power Transformers	1,294,908	40,326	103,593	913,537	29,005	73,083	857,448	26,720	68,596
13.1 & 13.2 Stations Switchgear -Municipal and Transformer Stations	475,469	11,941	38,037	1,130	28	90	1,954,951	51,029	156,396
15 Stations Control & Communication Systems				-	-	-	-	-	-
16 Downtown Station Load Transfers				-	-	-	-	-	-
17 Bremner Transformer Station				-	-	-	-	-	-
18 Hydro One Capital Contributions				-	-	-	-	-	-
19 Feeder Automation				-	-	-	-	-	-
20 Metering	4,944	(990)	396	7,127,528	319,863	570,202	5,199,941	222,352	415,995
21 Externally-Initiated Plant Relocations and Expansions	1,466,502	38,678	117,320	7,425,566	187,273	594,045	11,536,791	284,386	922,943
Total	**15,436,160**	**528,412**	**1,234,893**	**188,935,099**	**6,073,091**	**15,114,808**	**124,363,009**	**3,852,404**	**9,949,040**
Values Above Threshold for ICM Model	**15,436,160**	**528,412**	**1,234,893**	**188,935,099**	**6,073,091**	**15,114,808**	**124,363,009**	**3,852,404**	**9,949,040**

Return on Rate Base										
Incremental Capital CAPEX			$ 15,436,160			$ 188,935,099			$ 124,363,009	B
Depreciation Expense			$ 528,412			$ 6,073,091			$ 3,852,404	C
Incremental Capital CAPEX to be included in Rate Base			$ 14,907,748			$ 182,862,008			$ 120,510,605	D = B - C
Deemed ShortTerm Debt %	4.0%	E	$ 596,310	4.0%	E	$ 7,314,480	4.0%	E	$ 4,820,424	G = D * E
Deemed Long Term Debt %	56.0%	F	$ 8,348,339	56.0%	F	$ 102,402,724	56.0%	F	$ 67,485,939	H = D * F
Short Term Interest	2.46%	I	$ 14,669	2.46%	I	$ 179,936	2.46%	I	$ 118,582	K = G * I
Long Term Interest	5.37%	J	$ 448,306	5.37%	J	$ 5,499,026	5.37%	J	$ 3,623,995	L = H * J
Return on Rate Base - Interest			$ 462,975			$ 5,678,963			$ 3,742,577	M = K + L
Deemed Equity %	40.0%	N	$ 5,963,099	40.0%	N	$ 73,144,803	40.0%	N	$ 48,204,242	P = D * N
Return on Rate Base -Equity	9.58%	O	$ 571,265	9.58%	O	$ 7,007,272	9.58%	O	$ 4,617,966	Q = P * O
Return on Rate Base - Total			$ 1,034,240			$ 12,686,235			$ 8,360,544	R = M + Q

Amortization Expense										
Amortization Expense - Incremental		C	$ 528,412		C	$ 6,073,091		C	$ 3,852,404	S

Grossed up PIL's										
Regulatory Taxable Income		O	$ 571,265		O	$ 7,007,272		O	$ 4,617,966	T
Add Back Amortization Expense		S	$ 528,412		S	$ 6,073,091		S	$ 3,852,404	U
Deduct CCA			$ 1,234,893			$ 15,114,808			$ 9,949,040	V
Incremental Taxable Income			-$ 135,216			-$ 2,034,445			-$ 1,478,670	W = T + U - V
Current Tax Rate (F1.1 Z-Factor Tax Changes)	26.4%	X		26.4%	X		26.4%	X		
PIL's Before Gross Up			-$ 35,697			-$ 537,093			-$ 390,369	Y = W * X
Incremental Grossed Up PIL's			-$ 48,501			-$ 729,747			-$ 530,392	Z = Y / (1 - X)

Ontario Capital Tax										
Incremental Capital CAPEX		$	15,436,160		$	188,935,099		$	124,363,009	AA
Less : Available Capital Exemption (if any)		$	-		$	-		$	-	AB
Incremental Capital CAPEX subject to OCT		$	15,436,160		$	188,935,099		$	124,363,009	AC = AA - AB
Ontario Capital Tax Rate (F1.1 Z-Factor Tax Changes)	AD			0.000% AD			0.000% AD			
Incremental Ontario Capital Tax		$	-		$	-		$	-	AE = AC * AD

Incremental Revenue Requirement											
Return on Rate Base - Total	Q	$	1,034,240	Q	$	12,686,235	Q	$	8,360,544	AF	
Amortization Expense - Total	S	$	528,412	S	$	6,073,091	S	$	3,852,404	AG	
Incremental Grossed Up PIL's	Z	-$	48,501	Z	-$	729,747	Z	-$	530,392	AH	
Incremental Ontario Capital Tax	AE	$	-	AE	$	-	AE	$	-	AI	
Incremental Revenue Requirement		**$**	**1,514,150**		**$**	**18,029,579**		**$**	**11,682,555**	AF + AG + AH +	
To Be Collected			**4,542,451**			**36,059,158**		**$**	**11,682,555**		**52,284,165**

ICM Carrying Charges

	Revenues Received from ICM Rate Rider				Revenues Based on Actual ICM Revenue Requirements			
Date	Opening Balance	Closing Balance	Interest	Carrying Charges	Opening Balance	Closing Balance	Interest	Carrying Charges
May-12						-		-
Jun-12					124,544	125,105	0.12%	153.25
Jul-12					138,319	249,650	0.12%	305.82
Aug-12					131,692	387,968	0.12%	475.26
Sep-12					120,369	519,660	0.12%	636.58
Oct-12					120,980	640,029	0.12%	784.04
Nov-12					117,922	761,009	0.12%	932.24
Dec-12					125,101	878,930	0.12%	1,076.69
Jan-13					128,304	1,004,032	0.12%	1,229.94
Feb-13					111,935	1,132,336	0.12%	1,387.11
Mar-13					125,657	1,244,271	0.12%	1,524.23
Apr-13					116,640	1,369,927	0.12%	1,678.16
May-13					1,616,050	1,486,567	0.12%	1,821.04
Jun-13					1,606,873	3,102,617	0.12%	3,800.71
Jul-13	(1,773,368)	(3,714,611)	0.12%	(2,172.38)	1,809,810	4,709,490	0.12%	5,769.13
Aug-13	(3,714,611)	(5,560,525)	0.12%	(4,550.40)	1,699,853	6,519,300	0.12%	7,986.14
Sep-13	(5,560,525)	(7,322,319)	0.12%	(6,811.64)	1,590,962	8,219,153	0.12%	10,068.46
Oct-13	(7,322,319)	(9,081,780)	0.12%	(8,969.84)	1,597,497	9,810,115	0.12%	12,017.39
Nov-13	(9,081,780)	(10,814,114)	0.12%	(11,125.18)	1,557,128	11,407,612	0.12%	13,974.32
Dec-13	(10,814,114)	(12,632,229)	0.12%	(13,247.29)	1,708,687	12,964,740	0.12%	15,881.81
Jan-14	(12,632,229)	(14,576,753)	0.12%	(15,474.48)	1,768,444	14,673,427	0.12%	17,974.95
Feb-14	(14,576,753)	(16,270,510)	0.12%	(17,856.52)	1,483,333	16,441,872	0.12%	20,141.29
Mar-14	(16,270,510)	(18,144,521)	0.12%	(19,931.37)	1,671,292	17,925,205	0.12%	21,958.38
Apr-14	(18,144,521)	(19,829,930)	0.12%	(22,227.04)	1,515,002	19,596,498	0.12%	24,005.71
May-14	(19,829,930)	(21,533,311)	0.12%	(24,291.66)	2,544,925	21,111,500	0.12%	25,861.59
Jun-14	(21,533,311)	(23,313,409)	0.12%	(26,378.31)	2,575,038	23,656,425	0.12%	28,979.12
Jul-14	(23,313,409)	(25,149,081)	0.12%	(28,558.93)	2,691,695	26,231,462	0.12%	32,133.54
Aug-14	(25,149,081)	(26,974,385)	0.12%	(30,807.62)	2,686,216	28,923,157	0.12%	35,430.87
Sep-14	(26,974,385)	(28,712,628)	0.12%	(33,043.62)	2,554,028	31,609,373	0.12%	38,721.48
Oct-14	(28,712,628)	(30,441,345)	0.12%	(35,172.97)	2,518,558	34,163,401	0.12%	41,850.17
Nov-14	(30,441,345)	(32,185,999)	0.12%	(37,290.65)	2,508,092	36,681,959	0.12%	44,935.40
Dec-14	(32,185,999)	(33,986,049)	0.12%	(39,427.85)	2,649,426	39,190,051	0.12%	48,007.81
Jan-15	(33,986,049)	(35,871,887)	0.12%	(41,632.91)	2,740,138	41,839,477	0.09%	38,352.85
Feb-15	(35,871,887)	(37,660,093)	0.12%	(43,943.06)	2,464,936	44,579,615	0.09%	40,864.65
Mar-15	(37,660,093)	(39,461,613)	0.12%	(46,133.61)	2,646,020	47,044,551	0.09%	43,124.17
Apr-15	(39,461,613)	(41,165,011)	0.12%	(36,173.14)	2,432,917	49,690,571	0.09%	45,549.69
May-15	(41,165,011)	(41,163,832)	0.12%	(37,734.59)				
Total				**(582,955.08)**				**629,393.99**

	2012 Revenue Requirement A		2013 Revenue Requirement B		2014 Revenue Requirement C		Total to be Recovered D = A + B + C		Amt collected from ICM Rate Rider (ending May 2015) E		Over / (Under) Recovered E - D	
ICM TRUE UP	$	4,552,635	$	36,214,558	$	12,146,367	$	52,913,559	$	41,746,787	$	(11,166,772)	Under Recovered

Rate Design

	Service Charge %	Distribution Volumetric kWh %	Distribution Volumetric kVa %	% of Revenue Adjustment
Residential	100.0%	0.0%	0.0%	38.7%
CSMUR	100.0%	0.0%	0.0%	1.4%
General Service Less Than 50 kW	28.5%	71.5%	0.0%	12.7%
General Service 50 to 999 kW	3.6%	0.0%	96.4%	29.5%
General Service 1,000 to 4,999 kW	8.2%	0.0%	91.8%	9.7%
Large Use - Regular	6.7%	0.0%	93.3%	4.8%
Street Lighting	21.5%	0.0%	78.5%	2.2%
Unmetered Scattered Load	0.2%	99.8%	0.0%	0.6%
Unmetered Scattered Load	100.0%	0.0%	0.0%	0.2%

Nov 2016 to Dec 2017 Load Forecast

	Billed Customers or Connections	Billed kWh	Billed kVA	Service Charge (per 30 Days)	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kVA (per 30 days)	
Residential	616,501	5,681,547,376	-	$ 4,320,710	$ -	$ -	$ 4,320,710
CSMUR	73,248	334,626,462	-	$ 161,221	$ -	$ -	$ 161,221
General Service Less Than 50 kW	69,390	2,415,024,888	-	$ 404,908	$ 1,014,550	$ -	$ 1,419,458
General Service 50 to 999 kW	12,397	-	30,627,099	$ 117,679	$ -	$ 3,180,985	$ 3,298,664
General Service 1,000 to 4,999 kW	443	-	12,412,624	$ 89,362	$ -	$ 994,268	$ 1,083,630
Large Use - Regular	50	-	6,158,909	$ 35,819	$ -	$ 499,636	$ 535,455
Street Lighting	164,621	-	379,688	$ 53,594	$ -	$ 195,226	$ 248,820
Unmetered Scattered Load	898	48,006,528	-	$ 140	$ 72,038	$ -	$ 72,179
Unmetered Scattered Load	11,720	-	-	$ 26,636	$ -	$ -	$ 26,636
				$ 5,210,069	**$ 1,086,588**	**$ 4,870,115**	**$ 11,166,772**
	13.05						

ICM TRUE UP Rate Rider (14 Months Recovery)	Service Charge (per 30 Days)	Distribution Volumetric Rate kWh	Distribution Volumetric Rate kVA (per 30 days)
Residential	**0.49**		
CSMUR	**0.16**		
General Service Less Than 50 kW	**0.41**	**0.00042**	
General Service 50 to 999 kW	**0.67**		**0.1024**
General Service 1,000 to 4,999 kW	**14.21**		**0.0790**
Large Use - Regular	**50.45**		**0.0800**
Street Lighting	**0.02**		**0.5069**
Unmetered Scattered Load	**0.01**	**0.00150**	
Unmetered Scattered Load	**0.16**		