Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #2 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D1-3-3/Appendix A/Table 4/Item #D17

a) Please explain why the customer capital contribution for Bremner TS constitutes 100% of the gross total cost. What assumptions underpin this conclusion?

Response

a) Hydro One has calculated the capital cost contributions based on the incremental load forecast provided by THESL. The discounted cash flow (DCF) analysis showed that a 100% capital contribution is required as there was insufficient incremental load growth to offset this cost, and this was conveyed to THESL.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #3 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D2/Tab 2/Sch 3/ p74

a) Please explain the impact of the Bremner TS line connection on the current transfer capability between John TS and Esplanade TS. In Hydro One's response, please indicate how 115kV transfer capability will be maintained.

Response

a) The through transfer capability between John TS and Esplanade TS will be reduced by the amount of load on Bremner TS. The only way to maintain existing transfer capability, during such transfer scenarios, is to move the Bremner TS load to other transformer stations in Toronto via the THESL distribution network.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #4 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D2/Tab 2/Sch 3/ p74

a) Please provide a detailed cost breakdown of the $60M gross cost for building the Bremner TS line connection.

Response

a) As mentioned in Exhibit D2, Tab 2, Schedule 3, ISD #D17 the project is in a preliminary stage and Hydro One is working with THESL to finalize the scope.

The $60M gross cost for the work is based on the preliminary scope discussed with THESL and budgetary costs for equipment and installation is as follows:

i) Station: Gas Insulated Switchgear (GIS) (230kV rated, operated at 115kV) ~ $30M
ii) Cables: Four 115kV circuits (230kV rated, operated at 115kV) ~ $15M
iii) Protections: ~ $5M
iv) Other costs (interest/overhead/contingencies): ~ $10M

Hydro One will be advising THESL of the detailed project costs when the project scope is finalized, the preliminary engineering and estimating work are complete, and the tender bids for outsourced work have been reviewed.

Toronto Hydro-Electric System Limited (THESL) INTERROGATORY #5 List 1

Issue 11 Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Interrogatory

Ref: Exhibit D2/Tab 2/Sch 3/ p74

a) Has Hydro One considered any alternate designs for the Bremner TS line connection project? If so, please identify any alternative designs that have been considered, and the status of those alternatives.

Response

a) Yes, Hydro One did suggest to THESL potential alternatives for Bremner TS and its line connection. The alternatives were as follows:

- Build station facilities at Esplanade TS and connect to the John to Esplanade 115kV circuits.
- Build station facilities at Bremner TS and install 115kV underground cables between Bremner TS and Esplanade TS.
- Build station facilities at Bremner TS and install 115kV underground cables between Bremner TS and John TS.
- Install low voltage switchgear facilities at Bremner TS and install transformers at another location.

These alternatives were discussed with THESL but THESL indicated that the current Bremner proposal better meets their timeline needs.

This document details the work that is planned over the 2012-2014 period on each of the aforementioned types of stations assets. For the long-term investment plan for stations assets, please refer to the 2012-2021 Electrical Distribution Capital Plan found at Exhibit D1, Tab 7, Schedule 6.

THE STATIONS WORK PROGRAM

Table 1 below illustrates actual, bridge and test year spending for the Stations Sustaining portfolio.

Table 1: Stations Sustaining Capital Summary ($ millions)

	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test	2013 Test	2014 Test
Stations	16.8	14.1	17.0	19.1	24.5	24.1	24.0

An increase in capital investments for Stations portfolio during 2011, 2012, 2013 and 2014 is required mainly due to the following:

- Increase from the 2010 Actual to 2011 Bridge years is mainly due to increasing the number of units and costs for station transformers, KSO circuit breakers, MS switchgear, partially offset by a cost decrease due to deferral of TS switchgear replacement.
- Increase from 2011 Bridge to 2012-2014 test years is mainly due to:
  - Increases in the number of MS switchgear replacements and materials and labour costs due to the construction of a new MS building, and replacement of a 13.8kV MS switchgear in deteriorated condition.
  - Replacement of TS switchgear continues during 2012-2014.
  - Replacement of KSO oil circuit breakers continues during 2012-2014.
  - Increase of SCADA RTU replacements due to lack of parts for repair and technical support on software from supplier, increase in installation of

SCADA system for stations that do not have SCADA yet and upgrade of fiber-optic SONET system to increase bandwidth to support future initiatives.

- Increase in station activities such as preparing switchgear circuit breakers to support distribution projects to connect new customers or to carry out load transfer projects and replace protection relays to support grid modernization efforts.

Table 2 below illustrates the major station equipment units planned for the period of 2012-2014.

Table 2: Planned Investment Schedule

	2012	2013	2014
TS Switchgear Replacements	2	2	2
MS Switchgear Replacements	4	3	4
Station Transformer Replacements	4	6	6
KSO Oil Circuit Breaker Replacements	6	6	6
SCADA RTU Replacements	18	22	20
Station Battery System Replacements	14	16	16

TS Switchgear Replacement Program

THESL has a program to replace TS switchgear that is at end of its useful life and employs obsolete technology. This TS switchgear is mostly concentrated in downtown Toronto. Under the program, targeted switchgear such as Glengrove A1-2GL, Carlaw A1-2W, and Terauley A7-8A have been recently replaced. THESL will continue to replace switchgear at the end of its useful life and obsolete switchgear over the next ten years.

During the 2012, 2013 and 2014 years, replacements of two TS switchgear units per year are planned, as shown in Table 3 below.

Table 3: Planned TS Switchgear Replacements for 2012-2014

Switchgear Name	Enclosure Type	Circuit Breaker Type	Planned Year
Wiltshire TS A3-4W	Brick and Mortar	Airblast	2012
Strachan TS A7-8T	Metal	Air Magnetic	2012
Carlaw TS A4-5E	Brick and Mortar	Airblast	2013
Duplex A5-6DX	Metal	Air Magnetic	2013
Strachan TS 5-6T	Metal	Air Magnetic	2014
Wiltshire TS A3-4W	Brick and Mortar	Airblast	2014

The TS switchgear replacement work generally consists of the preparation of floor space, switchgear design, specification and procurement, delivery and installation, testing and commissioning, energizing, feeder transfer from old switchgear to the new switchgear, removal of obsolete switchgear and its old structure and coordination with HONI for replacement of the associated incoming supply circuit breakers.

MS Switchgear Replacement Program

During the 2012, 2013 and 2014 test years, replacements of three or four MS switchgear units per year are planned as shown in Table 4 below.

The MS switchgear replacement work is less complex than TS switchgear replacement due to a much smaller scope of civil work for floor preparation. The work generally consists of switchgear design, specification and procurement, delivery and installation, testing and commissioning, energizing, feeder transfer from old switchgear to the new switchgear and removal of obsolete switchgear.

Table 4
Load Customer Connection: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions)									In-Service Years
						Historical			Bridge	Test	Test	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	
						2009	2010	2011	2012	2013	2014				
D13	Tremaine TS: Build New Transformer Station	Development, Non-Discretionary	Category 1	Completed	Not Required	0.3	0.9	3.6	19.2	6.3	0.0	30.5	11.7	18.8	Q1 2013
D14	Barwick TS: Build new Transformer Station	Development, Non-Discretionary	Category 1	Completed	Not Required	0.4	0.4	2.6	4.3	16.1	0.0	23.8	0.0	23.8	Q4 2013
D15	Nebo TS: Increase Capacity of 230/27.6kV DESN	Development, Non-Discretionary	Category 2	Not Required	Not Required	0.0	0.0	0.2	7.0	12.0	0.0	19.2	9.2	10.0	Q4 2013
D16	Orleans TS: Build new Transformer Station	Development, Non-Discretionary	Category 2	Not Required	Not Required	0.0	0.0	0.1	3.1	11.3	19.0	33.4	20.2	13.2	Q2 2014
D17	Bremner TS: Build Line Connection for Toronto Hydro	Development, Non-Discretionary	Category 2	Completed	Not Required	0.0	0.0	0.2	2.6	20.2	37.0	60.0	60.0	0.0	Q4 2014
D18	Chalk River CTS: Build 115kV Switching Facilities and connect new Customer Station	Development, Non-Discretionary	Category 2	Not Required	Not Required	0.0	0.0	0.0	1.0	4.0	5.0	10.0	10.0	0.0	Q2 2014
D19	Nelson TS: Replace T1/T2 DESN with new DESN	Development, Non-Discretionary	Category 2	Not Required	Not Required	0.0	0.0	0.3	2.0	12.0	15.5	29.8	14.8	15.0	Q4 2014
	Other Capital Projects (<$3M) with 2013-14 Cashflows[4]					0.9	1.0	11.5	23.8	20.0	18.9	369.7[6]	143.4	226.3	
	Other Historical Projects (pre-2013)[5]					69.2	42.3	49.6	37.1	0.0	0.0	321.5	63.7	257.8	
	Total					**70.8**	**44.6**	**68.1**	**100.1**	**101.9**	**95.4**				

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2013 and after 2014 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 4: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2013 or 2014.
Note 5: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2013 or 2014.
Note 6: The Gross Total Cost consists of several major multi-year projects under consideration for beyond 2014, which have some minimal cashflow in 2013 and/or 2014 in order to perform preliminary studies and engineering.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D17	Bremner TS: Build Line Connection for Toronto Hydro	$60.0M	Q4 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To provide connection to Toronto Hydro's proposed Municipal Transformer Station, Bremner MTS. Hydro One is obligated under the Transmission System Code to meet customer supply needs when requested by the area customers.

Summary:
Toronto Hydro is proposing to build a new municipal transformer station on the west side of the Roundhouse at Bremner Blvd and Rees Street in downtown Toronto. It is proposed to connect the new station to the 115kV cable circuits that span between John TS to Esplanade TS.

The connection will require extending and looping the existing 115kV circuits through Bremner MTS and building a high voltage switching facility at the station to connect Toronto Hydro's step down transformers. The 115kV circuit extensions will be installed in a tunnel to be built by Toronto Hydro. Toronto Hydro has requested that high voltage gas insulated switching (GIS) facilities be provided for the connection of the 115kV cables and the stepdown transformers. The high voltage switching facilities will be installed inside the Toronto Hydro Bremner MTS building. Both the cable extensions and the high voltage switching facilities will be owned and operated by Hydro One.

The project is in the preliminary planning stage. A new facility such as the one proposed will require Environmental Assessment approval from the Ministry of Environment in accordance with the provincial Environmental Assessment Act (Class EA for minor Transmission Facilities) which will be undertaken by Toronto Hydro.

The project cost will be fully recoverable through capital contribution from the customer Toronto Hydro, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The project costs and capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
To provide connection to the new Toronto Hydro Bremner MTS in downtown Toronto.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to satisfy customers' supply requirements.

Amanda Klein
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October 1, 2012

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

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

Dear Ms. Walli:

RE: Toronto Hydro-Electric System Limited ("THESL") 2011 Annual CDM Report
OEB File Number: EB-2010-0215

THESL writes in respect of the above-noted matter.

In accordance with the Conservation and Demand Management Code for Electricity Distributors, please find attached THESL's 2011 CDM Annual Report. The report has been filed in the manner set out in Appendix C.

For the 2011 reporting period, THESL achieved 49.8 MW in peak demand savings and 172.9 GWh in energy savings. The savings achieved by THESL represent 23% and 29% of the provincial conservation results respectively.

While these results are considerable, the updated forecast prepared for this report shows that there will be a shortfall of approximately 90 MW versus THESL's 2014 peak demand reduction target. Although the peak demand savings are below target, THESL expects to achieve the electricity energy savings 2014 target. Given the expected shortfall, THESL continues to work actively with the Ontario Power Authority ("OPA") and the Electrical Distribution Association ("EDA") to improve program effectiveness, however it is THESL's position that in itself will not fully overcome the forecasted peak demand savings shortfall.

As the 2011-2014 program term end date is approaching, THESL submits to the Board that the peak demand savings shortfall will need to be addressed quickly through the introduction of new programs in 2012 and consideration be given to an extension of the program delivery timeframe.

In presenting its results and revising its savings forecast, THESL has analyzed various options that could help reduce its shortfall and mitigate the risk of failing to achieve the peak demand savings target. THESL would be pleased to discuss these options with the OEB.

If further information regarding the Annual Report is required or the OEB wishes to discuss the options mentioned above please contact Mr. Chris Tyrrell, Vice-President, Customer Care and Chief Conservation Officer directly at 416-542-3143 or at ctyrrell@torontohydro.com.

Sincerely,

[original signed by]

Amanda **Klein**
Director, Regulatory Affairs
Toronto Hydro-Electric System Limited
regulatoryaffairs@torontohydro.com

:AK/TP/acc

cc: Chris Tyrrell, Vice-President, Customer Care

4 Combined CDM Reporting Elements

4.1 Progress Towards CDM Targets

The summary of THESL's progress towards meeting its CDM targets is provided in the tables below. The data comes from the 2011 final results released by OPA on August 31, 2012. The cells highlighted in yellow reference the CDM Strategy submitted by THESL in 2010.

Table 8: Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	49.83	37.08	36.69	35.19
Verified Net Annual Peak Demand Savings Persisting in 2014				35.19
THESL 2014 Annual CDM Capacity Target				286.27
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%)				12.29%
LDC Milestone submitted for 2011				49.56
Variance				0.3

The summer peak demand savings for 2011 are 49.8 MW, which is consistent with the predicted savings in the CDM Strategy of 49.6 MW. Of the total demand reduction, 36% was attributable to transition projects (i.e. programs that ended prior to the launch of the OPA Programs). The decline in demand savings noted in years 2012 to 2014 is due to the demand savings persistence with regard to DR 3 contracts. However, at this point in time THESL assumes that the current aggregate of contracts will persist until 2014. Based on this assumption, the contribution from the 2011 results to the 2014 target will be 17.4% as reported by OPA.

Table 9: Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	172.92	172.13	171.02	166.90	682.97
Verified Net Cumulative Energy Savings 2011-2014					682.97
THESL 2011-2014 Cumulative CDM Energy Target					1,303.99
Verified Portion of Cumulative Energy Target Achieved (%)					52.38%
LDC Milestone submitted for 2011					284.84
Variance					-111.92

Energy savings in 2011 are lower than the target in the CDM Strategy due to higher achievement from demand response initiatives that do not contribute to energy savings. However, taking into account the persistence of savings, THESL has achieved 52% of the four year energy savings target. Of this total, transition projects (i.e. programs that ended prior to the launch of the OPA Programs) represented 55% of the energy savings for 2011 and clearly demonstrate the importance of the OPA Program stability on achieving results.

Generator customers

6.5.1 Where a transmitter modifies a transmitter-owned connection facility to meet the needs of a generator customer, the transmitter shall require the generator customer to pay the fully allocated cost of the minimum design required to meet the customer's needs. The transmitter shall include the capital cost of equipment installed on transmitter-owned connection facilities by the transmitter for monitoring the performance of the generation facility and for verification testing of fault protection equipment associated with the generation facility. If the generator customer elects to have verification testing costs included in the economic evaluation rather than paying such costs on an "as incurred" basis over time, the transmitter shall also include the present value of the estimated cost of doing periodic verification testing of its monitoring and testing equipment and, if necessary, of similar equipment owned by the generator customer. The transmitter shall not include costs associated with incremental operation and maintenance.

6.5.1A Where a transmitter constructs an enabler facility, the cost to be attributed to generator customers under section 6.3.14A shall be the fully allocated cost of the enabler facility. The transmitter shall include the capital cost of equipment installed on transmitter-owned connection facilities by the transmitter for monitoring the performance of the generation facilities and for verification testing of fault protection equipment associated with the generation facilities. If any generator customer elects to have verification testing costs included in the economic evaluation rather than paying such costs on an "as incurred" basis over time, the transmitter shall also include the present value of the estimated cost of doing periodic verification testing of its monitoring and testing equipment and, if necessary, of similar equipment owned by the generator customer. The transmitter shall include the present value of the operation and maintenance costs associated with an enabler facility.

Load customers

6.5.2 A transmitter shall establish in its connection procedures referred to in section 6.1.4 and implement an economic evaluation procedure that sets out how the transmitter will carry out an economic evaluation of a proposed new or modified connection of a load customer to determine what capital contribution is to be made by the load customer. The economic evaluation procedure shall:

(a) include the methodology that will be used by the transmitter in determining the financial risk associated with a proposed connection of a

load customer, which methodology shall meet the requirements of and be consistent with Appendix 4;

(b) provide that the economic evaluation period will be 5 years for a high risk connection, 10 years for a medium-high risk connection, 15 years for a medium-low risk connection, and 25 years for a low risk connection;

(c) be based on the discounted cash flow calculation set out in Appendix 5 using the forecast connection rate revenues from the connection facilities and the fully allocated capital cost, operating and maintenance cost and administrative cost of the minimum design required to meet the customer's needs. The costs shall include the transmitter's cost of transmitter-owned equipment for monitoring and testing installed on connection facilities on either side of the connection point, and the cost of carrying out verification testing on that equipment;

(d) establish that the cost used in the economic evaluation is limited to the advancement costs where the transmitter had planned a new or modified connection facility and moves the planned date forward to accommodate a customer;

(e) use a discount rate that is based on the transmitter's current deemed debt-to-equity ratio, debt and preference share costs and Board-approved rate of return on equity;

(f) require that discounting reflect the true timing of expenditures so that up-front capital expenditures are treated as occurring at the beginning of the first year of operation, and future capital expenditures, annual connection rate revenues and average operation and maintenance costs will be treated as occurring at the mid-point of the year in which they occur;

(g) take into account all relevant tax amounts, adjusted by any applicable capital cost allowance;

(h) exclude network facility costs and network rate revenues;

(i) exclude historic revenues and sunk costs;