TORONTO
HYDRO ELECTRIC SYSTEM LIMITED

EB-2012-0064
Ontario Energy Board
IN THE MATTER OF the *Ontario Energy Board Act, 1998*,
S.O. 1998, c. 15, (Schedule B);
AND IN THE MATTER OF an application by **TORONTO HYDRO ELECTRIC SYSTEM LIMITED** for an order approving just and reasonable rates and other charges for electricity distribution to be effective
June 1, 2012, May 1, 2013 and May 1, 2014.

AMPCO
CROSS-EXAMINATION COMPENDIUM
PANEL 2B

Summary of Capital Program

Schedule Number	Projects	Segments	Cost Estimates ($M) 2012	2013	2014	Total
B1	Underground Infrastructure and Cable	Underground Infrastructure	46.94	53.02	74.92	174.88
B2		Paper Insulated Lead Covered Cable - Piece Outs and Leakers	17.32	5.18	1.47	23.97
B3		Handwell Replacement	12.01	14.45	7.17	33.63
B4	Overhead Infrastructure and Equipment	Overhead Infrastructure	29.43	53.02	20.11	102.56
B5		Box Construction	10.20	20.54	27.76	58.50
B6		Rear Lot Construction	34.37	20.73	11.03	66.13
B7		Polymer SMD-20 Switches	3.06	2.95	2.94	8.94
B8		SCADA-Mate R1 Switches	2.86	2.80	2.69	8.36
B9	Network Infrastructure and Equipment	Network Vault & Roofs	13.57	12.31	15.57	41.45
B10		Fibertop Network Units	8.59	8.78	9.36	26.73
B11		Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)	3.27	3.30	3.23	9.80
B12	Station Infrastructure and Equipment	Stations Power Transformers	1.30	2.56	0.87	4.73
B13.1 & 13.2		Stations Switchgear - Muncipal and Transformer Stations	19.35	18.76	20.31	58.41
B14		Stations Circuit Breakers	1.37	1.08	1.38	3.83
B15		Stations Control & Communicaton Systems	1.15	2.15	1.34	4.64
B16		Downtown Station Load Transfers	1.75	1.59	3.59	6.93
B17	Bremner TS	Bremner Transformer Station	31.73	69.38	23.02	124.13
B18	Hydro One Capital Contributions	Hydro One Capital Contributions	25.28	52.12	36.00	113.40
B19	Feeder Automation	Feeder Automation	7.82	16.30	7.38	31.50
B20	Metering	Metering	5.62	7.21	10.03	22.85
B21	Plant Relocations	Externally-Initiated Plant Relocations and Expansions	24.27	17.67	13.34	55.28
B22	Grid Solutions	Grid Solutions	2.40	3.60	0.96	6.95
C1	Operations Portfolio Capital		121.70	121.60	121.60	364.90
C2	Information Technology Capital		15.00	15.00	15.00	45.00
C3	Fleet Capital		2.00	2.00	2.00	6.00
C4	Buildings and Facilities Capital		5.00	5.00	5.00	15.00
	Allowance for Funds Used During Construction		1.40	1.40	1.40	4.20
Total			**448.74**	**534.48**	439.47	**1,422.70**

Summary of Capital Program

Schedule Number	Projects	Segments	Cost Estimates ($M) 2012 Forecast *	2013 Budget	2014	Total for 2012 and 2013 **	
B1	Underground Infrastructure and Cable	Underground Infrastructure	28.75	58.94	~~74.92~~	87.70	/UF, US
B2		Paper Insulated Lead Covered Cable - Piece Outs and Leakers	0.08	5.42	~~1.47~~	5.50	/UF, US
B3		Handwell Replacement	13.65	16.65	~~7.17~~	30.30	/UF, US
B4	Overhead Infrastructure and Equipment	Overhead Infrastructure	9.07	55.88	~~20.11~~	64.95	/UF, US
B5		Box Construction	0.58	23.04	~~27.76~~	23.62	/UF, US
B6		Rear Lot Construction	16.36	29.43	~~11.03~~	45.78	/UF, US
B7		Polymer SMD-20 Switches	-	1.53	~~2.94~~	1.53	/UF, US
B8		SCADA-Mate R1 Switches	-	1.43	~~2.69~~	1.43	/UF, US
B9	Network Infrastructure and Equipment	Network Vault & Roofs	2.84	18.76	~~15.57~~	21.60	/UF, US
B10		Fibertop Network Units	1.48	7.71	~~9.36~~	9.19	/UF, US
B11		Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)	-	3.26	~~3.23~~	3.26	/UF, US
B12	Station Infrastructure and Equipment	Stations Power Transformers	0.38	3.48	~~0.87~~	3.86	/UF, US
B13.1 & 13.2		Stations Switchgear - Muncipal and Transformer Stations	1.73	21.81	~~20.31~~	23.54	/UF, US
B14		Stations Circuit Breakers	0.76	0.55	~~1.38~~	1.31	/UF, US
B15		Stations Control & Communicaton Systems	0.14	1.00	~~1.34~~	1.14	/UF, US
B16		Downtown Station Load Transfers	0.68	2.14	~~3.59~~	2.82	/UF, US
B17	Bremner TS	Bremner Transformer Station	8.50	81.00	~~23.02~~	89.50	/UF, US
B18	Hydro One Capital Contributions	Hydro One Capital Contributions	22.98	48.12	~~36.00~~	71.10	/UF, US
B19	Feeder Automation	Feeder Automation	2.30	20.66	~~7.38~~	22.97	/UF, US
B20	Metering	Metering	4.74	8.40	~~10.03~~	13.14	/UF, US
B21	Plant Relocations	Externally-Initiated Plant Relocations and Expansions	10.16	24.84	~~13.34~~	35.00	/UF, US
B22	Grid Solutions	Grid Solutions	-	-	~~0.96~~	-	/UF, US
C1	Operations Portfolio Capital		120.51	121.63	~~121.60~~	242.14	/UF, US
C2	Information Technology Capital		22.00	15.00	~~15.00~~	37.00	/UF, US
C3	Fleet Capital		0.80	2.00	~~2.00~~	2.80	/UF, US
C4	Buildings and Facilities Capital		5.00	5.00	~~5.00~~	10.00	/UF, US
	Allowance for Funds Used During Construction		1.20	1.40	~~1.40~~	2.60	/UF, US
Total			**274.68**	**579.09**	~~439.47~~	**853.78**	/UF, US

* The sum of actual spending to August 31, 2012 and estimated spending to year end.

** THESL has asked the OEB to consider the work programs identified for 2012 and 2013 together, and to defer consideration of the work program for 2014 to a later date.

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Network Units replacement over the course of the next three years. The segment cost schedule is shown below in Table-1. Complete job listings are shown in Appendix A.

Table-1: Project Budget Details

Project Title	Project Year	Estimated Cost ($M)	
Fibertop Changeouts	2012	$1.69	/UF, /US
Fibertop Changeouts	2013	$7.44	/UF, /US
~~Fibertop Changeouts~~	~~2014~~	~~$9.36~~	
	Total 2013/2014	**$9.13**	/UF, /US

Figure 1 below shows the locations of the Fibertop Network Units that are scheduled to be replaced. Most are located in downtown Toronto and parts of East York, particularly along the Yonge Street corridor where dense commercial load requires reliable distribution equipment.

In the recent past THESL has replaced 40 to 60 Network units annually due to corrosion. Leaking transformers and fibertops have made up a significant portion of these replacements (40% in 2009 and 60% in 2010). The proposed segment would be an increase to the existing replacement strategy as more units would be replaced annually.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 15:

Reference(s): Tab 4, Schedule B10, Page 1

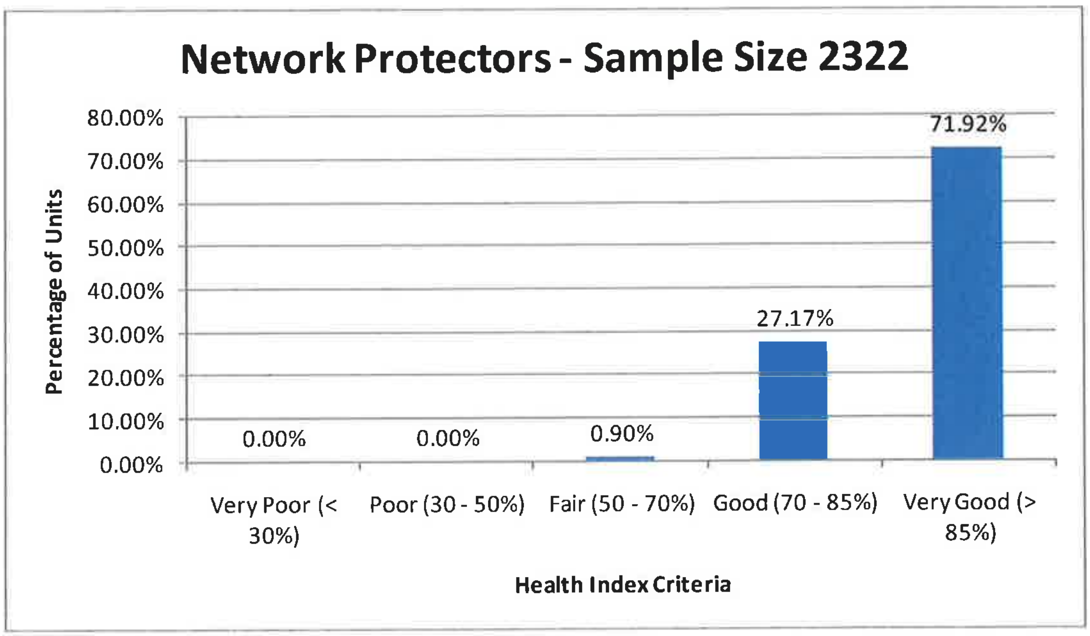
The assets selected for replacement have been identified as possessing the highest probability of failure, based on inspection of all THESL units.

a) Please confirm this finding is reflected in THESL's Asset Condition Assessment.

RESPONSE:

a) The Asset Condition for the network protector class can be found in the following graph. The graph indicates that the majority of network protectors are in good and very good condition. As discussed in the evidence (Tab 4, Schedule B10, pages 6 to 14), however, Fibertop protectors, particularly those outdoors below public thoroughfares, have a much higher probability of catastrophic failure because of deficiencies inherent in their design.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES ON ISSUE 2.2



The units identified as possessing the highest probability of catastrophic failure are Fibertop Network Units that are located in public pedestrian walkways under the sidewalk. These outdoor locations are typically affected in the winter with de-icing salts that contaminate network equipment. Fibertop protectors are particularly susceptible to this contamination because of their design. Therefore they are viewed as having the highest probability of failure.

Recently there has been an increase in maintenance for these Fibertop Units to mitigate the possibility of a catastrophic failure. Annual cleaning for all Fibertop Units is preformed in an attempt to remove contaminants that may cause vault fires. Although the increased cleaning has helped improved the overall condition of the Fibertop Network Units, the underlying flaws still exist.

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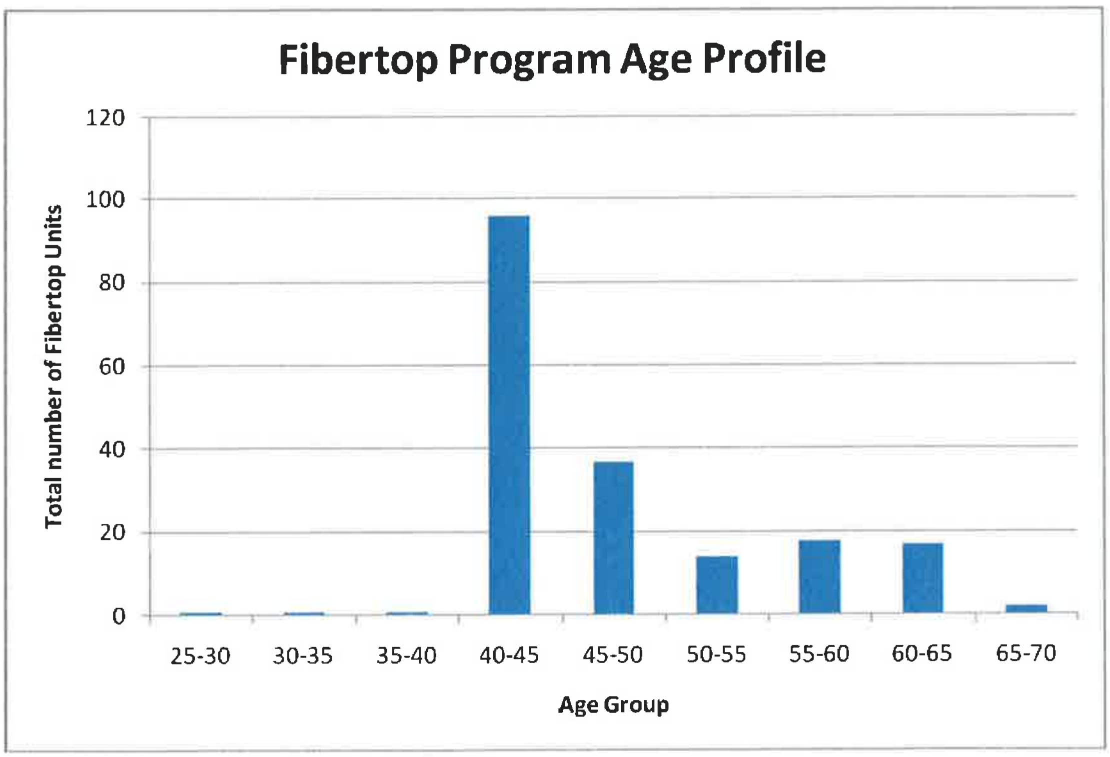
RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES ON ISSUE 2.2

The following graph shows that the population of Fibertop Network Units is generally over 40 years old. As stated in the Reference (Tab 4, Schedule B10, page 2) the useful life of these assets is 20 years. Therefore, although the ACA shows a good condition asset, THESL has determined that these assets require replacement because of their age and the risk and nature of their failure.



b) Please provide a breakdown of the 187 Fibertop Network Units between poor and very poor.

RESPONSES TO ASSOCIATION OF MAJOR POWER CONSUMERS IN ONTARIO INTERROGATORIES ON ISSUE 2.2

RESPONSE:

b) There are no Fibertop network units in the poor and very poor ACA category. As described in the response to part a) above, although the ACA shows a good condition asset, THESL has determined that these assets require replacement because of their age and the risk and nature of their failure.

I EXECUTIVE SUMMARY

1. Project Description

Automatic Transfer Switches (ATS) automatically switch a customer to a designated standby feeder in the event the normal primary feeder fails. Reverse Power Breakers (RPB) automatically open primary feeder supplies to customers in the event of feeder outages to prevent dangerous backfeed conditions. ATS and RPB assets are generally used to supply medium size customers that require a reliable supply, such as schools, supermarkets, seniors' homes, and other mid- sized buildings (See Section II, 1).

Both ATS and RPB assets have degraded rapidly in 2010 and 2011. THESL's Asset Condition Assessment (ACA) results indicate that approximately 30 ATS assets will need to be replaced over the next three years (See Section III, 1 and Appendix 1). In addition, based on physical inspection data, a further six RPB assets have been identified as requiring immediate replacement. The proposed ATS and RPB Segment will replace these assets with Stand Alone Network Protectors or Standard Network Equipment at a total cost of $3.25M over 2012 and 2013. /UF, /US

Table 1: ATS and RPB Segment Capital Cost

Description	Year	Design Estimate ($M)	Estimated Total Cost ($M)	
Replace 10 ATS Locations	2013	$2.54	$2.54	/UF, /US
~~Replace 10 ATS Locations~~	~~2014~~	~~$2.52~~		
Replace 2 RPB Locations	2013	$0.71	$0.71	
~~Replace 2 RPB Locations~~	~~2014~~	~~$0.71~~		
Total 2012-2013:			**$3.25**	/UF

Table 2: ATS Replacement Jobs

Job Estimate Number	Job Title	Job Year	Cost Estimate ($M)	
19381	D9012 – Near 654 Castlefield, Toronto	2013	$0.32	
23252	D3031 - 2108 Queen St East, Toronto	2013	$0.21	/US
24544	4862 - 77 Ryerson Ave, Toronto	2013	$0.14	
24546	4023 - Near 142 Pears Ave, Toronto	2013	$0.36	/UF, /US
24548	D9010 - 205 Richmond St W, Toronto	2013	$0.14	
24549	D3022 – 75 Dowling Ave, Toronto	2013	$0.14	
24550	4064 – 295 College St, Toronto	2013	$0.37	
24634	D3002 – 70 Elmsthorpe, Toronto	2013	$0.14	
24634	D9013 - 2727 Dundas W, Toronto	2013	$0.36	/US
24634	4063 - 645 Adelaide St W, Toronto	2013	$0.36	
~~24952~~	~~4027 - 14 Spadina Road~~	~~2013~~	~~$0.32~~	
~~24952~~	~~4046 - Near 130 EGLINTON, Toronto~~	~~2013~~	~~$0.32~~	
~~24952~~	~~4129 - Heath Street East~~	~~2013~~	~~$0.32~~	
~~24952~~	~~4158 - Duncan Ave~~	~~2013~~	~~$0.32~~	
~~24953~~	~~4817 - ADJ. to 330 GERRARD~~	~~2014~~	~~$0.36~~	
~~24953~~	~~D9007 – 658 to 668 Danforth Ave, Toronto~~	~~2014~~	~~$0.14~~	
~~24953~~	~~D3014 – 2001 Bloor St W, Toronto~~	~~2014~~	~~$0.14~~	
~~24953~~	~~4157 – 175 Elm, Toronto~~	~~2014~~	~~$0.36~~	
~~24953~~	~~D3041 – 1141 Bloor St W, Toronto~~	~~2014~~	~~$0.14~~	/US
~~24953~~	~~D3003 – 75 Eglinton Ave W, Toronto~~	~~2014~~	~~$0.14~~	
~~24953~~	~~4118 – 197 Wellesley St E, Toronto~~	~~2014~~	~~$0.36~~	
~~24953~~	~~4763 – 700 Ontario St, Toronto~~	~~2014~~	~~$0.14~~	
~~24953~~	~~4121 – 36 Earl, Toronto~~	~~2014~~	~~$0.36~~	
~~24953~~	~~4861 – 165 Grange Ave, Toronto~~	~~2014~~	~~$0.36~~	

/C

1 **Table 3: RPB Replacement Jobs**

Job Estimate Number	Job Title	Job Year	Cost Estimate ($M)
24905	4515 - 25 Lascelles Blvd, Toronto	2013	$0.35
24905	D3039 – 186 Cowan, Toronto	2013	$0.35
~~24955~~	~~4175 – 160 John St, Toronto~~	~~2014~~	~~$0.35~~
~~24955~~	~~4669 – 200 Balliol, Toronto~~	~~2014~~	~~$0.35~~

/US

1 **Table 1: Job Cost Estimate**

Job Estimate Number	Job Title	Year Installed	Job Year	Cost Estimate ($M)	
20427	S12320 Leslie MS Switchgear Replacement	1978	2013	4.08	/US
20427	S12320 Leslie MS Switchgear Replacement (Continuation	1978	2013	1.04	
20560	S11032 Lawrence Golf Switchgear Replacement	1957	2012	0.82	
20561	S11031 Brian Elinor MS Replace switchgear	1954	2012	0.83	
22620	S11642 York MS Replace Switchgear	1954	2012	1.39	
20544	S11040 Brimley Bernadine MS Replace Switchgear	1959	2012	1.09	
20750	S12416 Porterfield MS Replace Switchgear	1956	2013	1.23	/US
21338	S13090 Greencedar Lawrence MS Replace Switchgear	1960	2013	0.22	/UF
21581	S13126 Neilson Dr MS Replace Switchgear	1954	2013	0.30	/UF
21339	S14044 Midland Lawrence MS Replace switchgear	1960	2013	0.24	
~~21339~~	~~S14044 Midland Lawrence MS Replace switchgear (Continuation)~~	~~1960~~	~~2014~~	~~0.62~~	
~~20779~~	~~S14048 Pharmacy CPR MS Replace switchgear~~	~~1961~~	~~2014~~	~~0.94~~	
~~22804~~	~~S14068 Islington MS Replace Switchgear~~	~~1955~~	~~2014~~	~~1.51~~	

Job Estimate Number	Job Title	Year Installed	Job Year	Cost Estimate ($M)
22805	S14070 Thornton MS Replace Switchgear (pre-work)	1955	2013	0.11
~~22805~~	~~S14070 Thornton MS Replace Switchgear (pre-work)~~		~~2014~~	~~0.86~~
Jobs Total 2012-2013				**11.35**
Reconciliation for budget changes < $100,000 and rounding				**$0.05**
TOTAL				**$11.40**

/US

/UF, US

2. Why the Project is Needed Now

All the Municipal Substation switchgear proposed to be replaced are over 50 years (with the exception of Leslie MS) and have reached the end of their useful life. The switchgear employ obsolete technology, such as non arc-resistance design, oil circuit breakers and mechanical relays. Non arc-resistant switchgear does not have the ability to channel the energy released during an internal arc fault in ways that minimize the potential injury to personnel and damage to equipment in the surrounding area, including damaging the entire substation.

THESL experienced two substation fires in recent years due to faults in substation equipment that were at their end of service life; one was in 2007 at Lesmil MS in North York area and the second one was in 2009 at station J, in East York area. Both substations were over 50 years old and the fire was attributed to faults in the substation switchgears. Switchgear which is over its useful design life (50 years) can fail catastrophically at any time. Lesmil MS was severely damaged as a result of the fire created due to the fault and Station J was burned down as a result of the fire created by the arc fault in the switchgear and there was no substation equipment left to repair.

The load of both of the above substations was temporarily transferred to their respective adjacent substations. Lesmil MS was ultimately converted to 27.6kV because the station was lightly loaded and replacing or repairing the aging switchgear was not cost effective. Station J MS was also lightly loaded as a result of previous load conversion so converting substation was more cost effective than replacing and/or repairing the aging switchgear. Load conversion also

Table 1: Summary of values used in the determination of Avoided Estimated Risk Cost

Business Case Element	Estimated Cost (in Millions)	
Present Value of Project Net Cost in 2015 (PV(PROJECT$_{NET_COST}$(2015))	$2.810	/C
Project Net Cost in 2012 (PROJECT$_{NET_COST}$(2012))	$2.155	
Avoided Estimated Risk Cost = (PV(PROJECT$_{NET_COST}$(2015)) – PROJECT$_{NET_COST}$(2012))	**$ 0.655**	/C

When this avoided estimated risk cost is calculated as a positive value, it means that estimated risk costs for the job assets in 2015 will exceed the estimated risks that exist today. By performing the work immediately as opposed to waiting until 2015, THESL can eliminate these estimated risks. Therefore, these avoided estimated risk costs represent the benefits of job execution.

Table 1: Summary of values used in the determination of Avoided Estimated Risk Cost

Business Case Element	**Estimated Cost (in Millions)**
Present Value of Project Net Cost in 2015 ($PV(PROJECT_{NET\_COST}(2015))$)	$2.355
Project Net Cost in 2012 ($PROJECT_{NET\_COST}(2012)$)	$2.155
Avoided Estimated Risk Cost = ($PV(PROJECT_{NET\_COST}(2015)) - PROJECT_{NET\_COST}(2012)$)	**$ 0.200**

When this avoided estimated risk cost is calculated as a positive value, it means that estimated risk costs for the job assets in 2015 will exceed the estimated risks that exist today. By performing the work immediately as opposed to waiting until 2015, THESL can eliminate these estimated risks. Therefore, these avoided estimated risk costs represent the benefits of job execution.

ICM Project | Stations Switchgear – Transformer Stations Segment

I EXECUTIVE SUMMARY

1. Project Description

Switchgear operating at 13.8kV in many downtown Transformer Stations (TS) are past the end of their useful lives and rely 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 are in poor condition (See Section II, 3). The existing non arc-resistant switchgear does not channel the energy released during an internal arc fault to minimize potential injury to personnel and minimize damage to surrounding equipment. As a result, this switchgear can cause damage that impacts the entire station, interrupting service to thousands of customers. This equipment has been kept in service via increased maintenance, custom fabrication and harvesting parts from spares. The asset condition continues to deteriorate and safety concerns are increasing.

Switchgear requiring replacement in 2012, and 2013, ~~and 2014~~ include the A7-8T switchgear at Strachan TS, A6-7E switchgear at Carlaw TS, A3-4W ~~and A5-6W~~ switchgear at Wiltshire TS, ~~A5-6WR switchgear at Windsor TS~~ and A5-6DX at Duplex TS. All but one of these are more than 55 years old. The total cost of this segment is approximately $12.14 million for the jobs shown in Table 1 /UF, US

Table 1: Job Costs

Estimate Number	Job Title	Year Installed	Customer Load Served (MVA)	Job Year	Cost Estimate ($M)
18591	Strachan TS A7-8 switchgear replacement preparation	1956	34	2012	0.34
25425	Strachan TS A7-8 switchgear replacement	1956	34	2013	3.41

/UF

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ICM Project | Stations Switchgear – Transformer Stations Segment

Estimate Number	Job Title	Year Installed	Customer Load Served (MVA)	Job Year	Cost Estimate ($M)	
~~24972~~	~~S14406 Strachan TS Load Transfer from A7-8T to A11-12T Switchgear~~	~~1956~~	~~34~~	~~2014~~	~~0.30~~	
22025	Carlaw TS A6-7E switchgear replacement	1968	26	2013	1.45	/UF, US
20877	Wiltshire TS A3-4W switchgear replacement	1954	20	2012	6.71	/UF, US
~~22719~~	~~Wiltshire TS A5-6W switchgear replacement~~	~~1954~~	~~22~~	~~2014~~	~~7.67~~	
~~21735~~	~~Windsor TS A5-6WR switchgear replacement~~	~~1956~~	~~56~~	~~2014~~	~~8.41~~	
20492	Duplex TS A5-6DX switchgear replacement	1954	42	2013	0.23	/UF
2012-2013 Total					**12.14**	/UF, US

These switchgear were selected for replacement based on the following considerations:

- Obsolescence (brick structures, non-arc resistant design, obsolete breakers)
- Age
- Condition
- Space available for transition switchgear, and
- Station egress for cabling

All the switchgear listed are to be replaced with 3,000A air-insulated, arc-resistant type C switchgear with double-bus, double-breaker or breaker-and-half configuration except Duplex

Table 1: Summary of values used in the determination of Avoided Estimated Risk Cost

Business Case Element	Estimated Cost (in Millions)	
Present Value of Project Net Cost in 2015 (PV(PROJECT$_{NET_COST}$(2015))	$ 42.037	/C
Project Net Cost in 2012 (PROJECT$_{NET_COST}$(2012))	$ 0.0298	
Avoided Estimated Risk Cost = (PV(PROJECT$_{NET_COST}$(2015)) – PROJECT$_{NET_COST}$(2012))	**$ 42.007**	/C

When this avoided estimated risk cost is calculated as a positive value, it means that estimated risk costs for the job assets in 2015 will exceed the estimated risks that exist today. By performing the work immediately as opposed to waiting until 2015, we can eliminate these estimated risks. Therefore, these avoided estimated risk costs represent the benefits of job execution.

1 **Table 1: Summary of values used in the determination of Avoided Estimated Risk Cost**

Business Case Element	Estimated Cost (in Millions)
Present Value of Project Net Cost in 2015 (PV(PROJECT$_{NET_COST}$(2015))	\$ 35.235
Project Net Cost in 2012 (PROJECT$_{NET_COST}$(2012))	\$ 0.0298
Avoided Estimated Risk Cost = (PV(PROJECT$_{NET_COST}$(2015)) – PROJECT$_{NET_COST}$(2012))	**\$ 35.205**

When this avoided estimated risk cost is calculated as a positive value, it means that estimated risk costs for the job assets in 2015 will exceed the estimated risks that exist today. By performing the work immediately as opposed to waiting until 2015, we can eliminate these estimated risks. Therefore, these avoided estimated risk costs represent the benefits of job execution.

ICM Project | Stations Circuit Breakers Segment

I EXECUTIVE SUMMARY

1. Description

Station circuit breaker work proposed for 2012 consists of replacing 9 oil circuit breakers /UF, US (27.6kV) mounted outdoors and associated control boxes with vacuum circuit breakers at five Terminal Stations (TS). The estimated cost for the work is $1.38 M as shown in Table 1: /UF, US

Table 1: Job Cost Estimates

Job Estimate Number	Job Title	Job Year	Cost Estimate ($M)
17662	S11118 Finch TS: Replace KSO CB (55M27)	2012	$0.07
17669	S11121 Finch TS: Replace KSO CB (55M28)	2012	$0.07
17654	S11130 Bathurst TS: Replace KSO CB (85M24)	2012	$0.07
18403	S12001 Leslie TS: Replace KSO OCB (51M4 and 51M6)	2012	$0.39
18233	S12036 Fairchild TS: Replace KSO CB (80M1)	2012	$0.19
18237	S12037 Fairchild TS: Replace KSO CB (80M3)	2012	$0.19
18262	S12043 Fairchild TS: Replace KSO CB (80M5)	2012	$0.20
18263	S12044 Fairchild TS: Replace KSO CB (80M9)	2012	$0.20
~~22693~~	~~S14052 Finch TS: Replace KSO CB (55M24)~~	~~2014~~	~~$0.19~~
~~22694~~	~~S14054 Finch TS: Replace KSO CB (55M25 and 55M8)~~	~~2014~~	~~$0.41~~
~~22695~~	~~S14055 Bathurst TS : Replace 85M1 KSO CB~~	~~2014~~	~~$0.19~~
~~22698~~	~~S14056 Bathurst TS: Replace 85M4 KSO CB~~	~~2014~~	~~$0.20~~
~~22699~~	~~S14057 Bathurst TS: Replace 85M2 KSO CB~~	~~2014~~	~~$0.19~~
~~22700~~	~~S14059 Bathurst TS: Replace 85M25 KSO CB~~	~~2014~~	~~$0.19~~
Jobs Total 2012-2013:			**$1.38**
Reconciliation for budget changes < $100,000 and rounding			**($0.07)**
TOTAL			**$1.31**

/UF

Job Estimate Number	Job Title	Job Year	Cost Estimate ($M)
22700	S14059 Bathurst TS: Replace 85M25 KSO CB	2014	$0.19
		Total:	**$3.83**

2. Why the Project is Needed Now

Circuit breakers are automated switching devices that can carry and interrupt electrical currents under normal and abnormal conditions. Distribution circuit breakers at THESL are commonly used at transmission or distribution stations for switching 27.6, 13.8 or 4.16 kV feeders. Circuit breakers operate infrequently. When an electrical fault occurs however, it is important that breakers operate reliably and with adequate speed to minimize damage. Circuit breaker designs have evolved over the years and many different types are currently in use. Commonly used circuit breaker types include oil circuit breakers (OCB), vacuum breakers, magnetic air circuit breakers and SF_6 circuit breakers. Circuit breakers may be mounted indoors or outdoors.

For OCBs, the interruption of load and fault currents involves the reaction of high pressure with large volumes of hydrogen gas and other arc decomposition products. Thus, both contacts and oil degrade more rapidly in OCBs than they do in either SF_6 or vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, four to eight interruptions with contact erosion and oil carbonization will lead to the need for maintenance, including oil filtration. Oil breakers can also experience re-strike when switching low load or line charging currents with high recovery voltage values. Sometimes this can lead to catastrophic breaker failures. Outdoor circuit breakers may experience adverse environmental conditions that influence their rate and severity of degradation. For outdoor-mounted circuit breakers, the following represent additional degradation factors:

- Corrosion;
- Effects of moisture;
- Bushing/insulator deterioration; and
- Mechanical.

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I EXECUTIVE SUMMARY

1. Description

THESL relies on an extensive Supervisory Control and Data Acquisition System (SCADA) for control and monitoring of distribution equipment. THESL uses various types of communication (SONET fibre optics, copper lines, radio system and leased telephone lines) to convey information between station assets and distribution system assets. This communication system is vital for operating the system and re-routing electrical supply during planned outages and emergency situations.

Station control and communication work proposed for 2012 and 2013 ~~and 2014~~ consists of improving SONET communication redundancy, upgrading SONET system communication capacity and installing SCADA RTUs. The estimated cost for the work is $1.13M, which consists of $0.51M for improving SONET system and $0.62M for replacing / installing SCADA RTUs, as presented in Table 1 and Table 2 below. Jobs were selected for inclusion in this segment based upon need and execution capacity, and in coordination with other projects. /US /UF, US /UF, US

Table 1: Job Cost Estimates for SONET System Redundancy/Upgrading

Job Title	Job Year	Cost Estimate ($M)
Improve SONET Redundancy: 14 Carlton to George and Duke MS and Esplanade TS	2012	$0.23
Improve SONET Redundancy: Malvern TS to Sheppard TS	2012	$0.22
Improve SONET Redundancy: Split Toronto SONET ring	2013	$0.06
~~Improve SONET Redundancy: Duplex TS to Fairbank TS and Warden TS to Bermondsey TS~~	~~2014~~	~~$0.39~~
Jobs Total 2012-2013:		**$0.51**
Reconciliation for budget changes < $100,000 and rounding		**$0.01**
TOTAL		**$0.52**

/US
/UF, US

Table 2: Job Cost Estimates for SCADA RTUs Replacing/Installing

Job Title	Job Year	Cost Estimate ($M)	
Replace 15 MOSCAD RTUs in Etobicoke	2012	$0.28	/UF
Install 5 MS SCADA RTUs	2013	$0.34	
~~Replace 14 MOSCAD RTUs in Etobicoke~~	~~2014~~	~~$0.59~~	
~~Install 5 MS SCADA RTUs~~	~~2014~~	~~$0.36~~	
	Subtotal:	**$0.62**	

2. Why This Work is Needed Now

Elements of the SONET system and the radio system have developed reliability and maintenance issues that require immediate attention. This segment will address the communication issues that pose risks for THESL's continued ability to remotely monitor and control the distribution grid.

The SONET fibre optic communication system is normally designed as a redundant ring system between station assets and the Control Centre, but some segments lack redundancy and as these fibre optic lines age or are damaged by adjacent construction, there is a risk of a complete SONET system failure (Section III, 1). Failure of the SONET system would likely result in:

- No communication to support SCADA system, which would prevent system operators from monitoring and controlling vital substation equipment. The result would be longer outages as manual, rather than remote, switching would be required.
- No information to/from the T1 data circuits used for the protection and control of HONI 115kV transmission feeders that supply THESL (i.e., loss of system security and redundancy at HONI supply points and possibly longer outages from poor coordination with HONI).
- No transfer trip protection for HONI 230kV transmission in the Scarborough area, resulting in loss of system security and redundancy at HONI supply points and possibly

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Ontario

ONTARIO ENERGY BOARD

Transmission System Code

June 10, 2010

10. PROTECTION SYSTEM REQUIREMENTS

10.1 TELECOMMUNICATIONS

10.1.1 A transmitter shall ensure that telecommunication facilities used for protection purposes have a level of reliability consistent with the required performance of the protection system.

10.1.2 A transmitter shall specify to all customers telecommunication channel media and protective systems.

10.1.3 A transmitter shall ensure that telecommunication circuits used for the protection and control of the transmission system are dedicated to that purpose.

10.1.4 Where each of the dual protections protecting the same system element requires communication channels, a transmitter shall ensure that the equipment and channel for each protection is separated physically and designed to minimize the risk that both protections might be disabled simultaneously by a single contingency.

10.1.5 A transmitter shall ensure that telecommunication systems are:

(a) designed to prevent unwanted operations such as those caused by equipment or personnel,

(b) powered by the station's batteries or other sources independent from the power system, and

(c) monitored in order to assess equipment and channel readiness.

10.1.6 Major disturbances caused by telecommunication failures shall have annual frequency of less than 0.002 per year from the dependability aspect and less than 0.002 per year from the security aspect.

10.1.7 A transmitter shall ensure that telecommunication protection for a single transmission system circuit shall be unavailable for no more than 42 minutes per year, and for two circuits, no more than four minutes per year.

10.1.8 A transmitter shall ensure that the telecommunication false trip rate used as part of a protection system for a single transmission system circuit is no more than 0.1 false trips per year, and for two circuits, no more than 0.001 false trips per year.

10.1.9 A transmitter shall ensure that total transmission system circuit trips coincident with telecommunications failure are no more than 0.001 per year.

10.2 TEST SCHEDULE FOR RELAYING COMMUNICATION CHANNELS

10.2.1 A transmitter shall test communication channels associated with protective relaying at periodic intervals to verify that the channels are operational and that their characteristics are within specific tolerances. Testing should include signal adequacy tests and channel performance tests.

10.2.2 Signal adequacy testing for unmonitored channels shall be done at one month intervals. Signal adequacy testing for monitored channels shall be done at twelve month intervals.

10.2.3 Channel performance testing on leased communication circuits shall be conducted at 24 month intervals, while intervals for testing power line carrier equipment shall be equipment specific.

10.3 VERIFICATION AND MAINTENANCE PRACTICES

10.3.1 A transmitter shall use the maximum verification intervals established by reliability organizations and in accordance with applicable reliability standards: (a) four years for most 115kV elements, most transformer stations, and certain 230kV elements: (b) two years for all other high voltage elements. All newly commissioned protection systems shall be verified within six months of the initial in service date of the system.

10.3.2 Routine verification shall ensure with reasonable certainty that the protection systems respond correctly to fault conditions.

10.3.3 A transmitter shall use an electrically initiated simulated fault clearing check to verify new protection systems, after any wiring or component changes are made to an existing protection system, and for the routine verification of a protection system.

longer outages from poor coordination with HONI. Operational flexibility in re-routing loads also would be impacted.

The Motorola radio communication system used in the Etobicoke area (DARCOM radio system and MOSCAD Terminals) has reached the end of its useful life and the equipment is obsolete. As a result, when the communication between the substations in Etobicoke and the SCADA system fails, control for switching restoration is unavailable, increasing the risk of longer customer outages (Section III, 2). This job will ensure reliable communication by adding redundancy to the SONET system and replacing the radio communication system.

The impacts of the deferral are increased risk of prolonged outages to customers served by these communication systems. For example, on December 22, 2011 all control and monitoring capability to 64 substations and 155 overhead Remote Terminal Units (collectively serving 51,937 customers) was lost for 6.5 hours. Although no outages occurred during this event, the loss of SCADA control put the system at risk for longer restoration time. Without remote switching capability, restoration time would move from a few minutes to a few hours, due to the time it takes to send field crews to perform manual switching.

Without SCADA control and system monitoring, control personnel do not have access to the following critical information to minimize outage impacts on customers:

- Alarm for circuit breaker trip (feeder outage)
- Alarm on loss of transformer voltage (transformer outage)
- Alarm on cable overloading
- Alarm on transformer pressure
- Alarm on transformer oil level
- Alarm on transformer temperature
- Alarm on battery system (loss of battery power will prevent protection relay to trip a fault feeder).

ICM Project | Downtown Station Load Transfer Facilities Segment

I EXECUTIVE SUMMARY

1. Project Description

This segment includes the completion of the Dufferin – Bridgman feeder tie work in 2012 that was largely completed in 2011, and two new jobs for 2013 that are required to provide feeder ties between Basin and George and Duke stations; and Basin and Carlaw stations, where no such facilities present exist (See Section II). /US

About 21% of the $9.4M Dufferin-Bridgman feeder ties work remains for 2012 which includes completion of electrical work, feeder transfers, some feeder capacity upgrades and commissioning (See Section II). This job plus the other two proposed jobs for 2013 combine for a total cost of $2.8M. None of the proposed work is included in existing rates. /UF /UF, US

Table 1: Proposed Feeder Ties

Job Number	Job Identifier	Cost Estimate ($M)	Year of Execution	
X11620	Feeder Tie Dufferin to Bridgman	1.94	2012	/UF
X11424	Feeder Tie A203BN to A240GD	0.48	2013	/US
X12086	A204BN tie to new Carlaw feeder	0.39	2013	
~~X12340~~	~~Feeder Tie A36DN to A67W~~	~~1.78~~	~~2014~~	
~~X12342~~	~~Feeder Tie A13DN to A35W~~	~~1.81~~	~~2014~~	
	Total	**2.82**		/UF, US

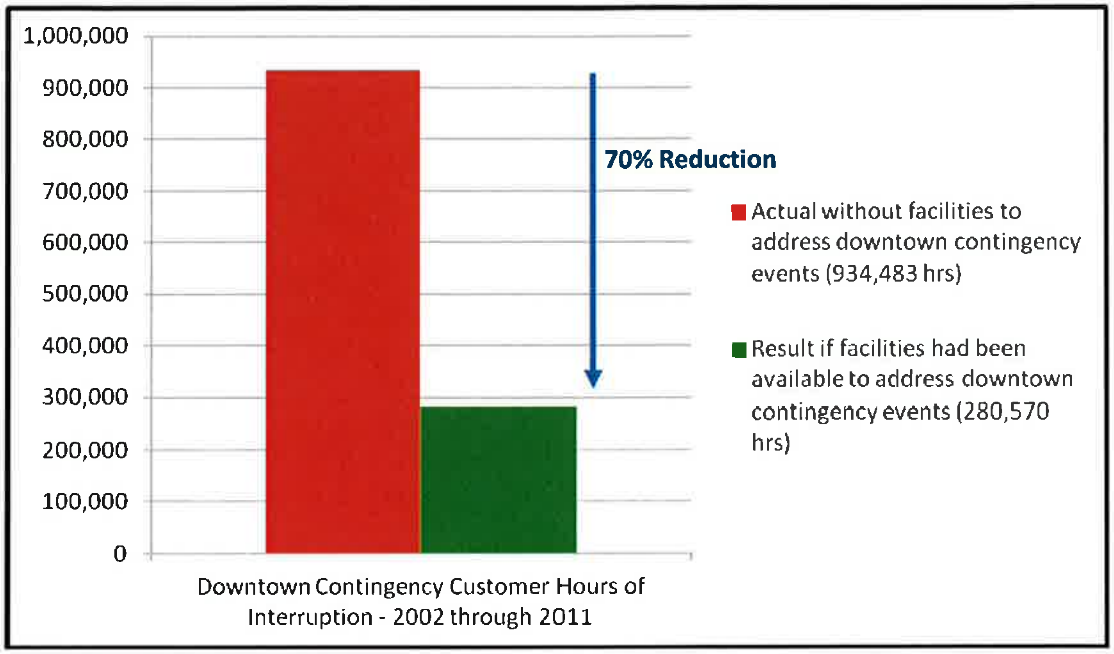

Figure 4: Reliability Impact of Downtown Station Load Transfer Implementation

All four major station outage events in downtown Toronto's history occurred in the last decade. This experience indicates that the conditions in and around the 15 downtown stations are worsening as time progresses, and as a result the risks are increasing. Each of these historical events resulted from causes external to THESL that negatively impacted the station distribution equipment. Therefore, the only certain way to address such failures is to provide a back-up supply to customers.

The purpose of this segment is to provide distribution load transfer capability from one station area to another station area in order to manage the risks of partial, or complete, station outages.

An investment of $2.8M over the period of 2012 through 2013 is expected to complete the work necessary to provide feeder-to-feeder tie capability for six feeder pairs. This work is expected to allow rapid transfer of customer loads on these feeder pairs should mitigate virtually any loss-of-supply incident occur at any of these stations. /UF, US

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ICM Project | Feeder Automation

Table 1: Business Case Evaluation of Job Areas

Project Location	**Project Cost Allocated ($ M)**	**Project Net Benefit ($ M)**	**Option Benefit/Cost Ratio**
Horner TS and Manby TS	$3.40	$358.39	**118.81**
Fairchild TS	$2.78	$211.58	**84.38**
Cavanagh TS and Agincourt TS	$7.82	$861.34	**111.14**
Scarborough East TS	$7.66	$416.55	**57.47**

/C

The general scope of work for these jobs consists of two phases. The first phase involves choosing feeders that will benefit from automation. The second phase is effectively sectionalizing the feeder. Feeder selection was based on reliability, network configuration, and restoration capacity. Feeders were first selected on based on their reliability and focusing on the number of outages that occurred on the trunk. Since this project builds on the existing FA implementation, feeder selection also was based on designing a system that could connect into the existing FA implementation through interconnection with other FA feeders. Non-automated tie-points will be included where considered necessary to backfeed into established FA feeders. Each feeder selected must be able to backfeed into a section and resupply a faulted feeder.

The number of feeders that can be addressed in an area at any one time is limited to maintain operational flexibility in the case of an outage. Power system controllers require a sufficient number of feeders available to ensure adequate flexibility to restore an area in the event of an outage. One method used to maximize the amount of FA deployment is to work in multiple areas of the system, the east, west and north areas of the city, at the same time.

By focusing on trunk feeders and effectively deploying an FA scheme to specific areas, THESL has prepared a focused project that is expected to have a significant positive impact on SAIDI and SAIFI.

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 90:

Reference(s): **Tab 4, Schedule B19, pages 2-3**

a) Please explain more fully why this project is considered to be non-discretionary (i.e., must be done now).

RESPONSE:

a) Feeder Automation is non-discretionary on the basis that it introduces a new technology into the system that will significantly reduce the impact of trunk related outages on targeted at risk feeders. This is explained in greater detail as demonstrated on Tab 4, Schedule B19, page 3 to 4, in the section "Why the Project is Needed Now", and on Tab 4, Schedule B19, page 13 to 18, in the section "Need".

b) Has THESL used FA to improve the reliability in specific areas over the past 5 years (2007-2011)? If not, why not? If yes, please provide a schedule setting out the annual spending.

RESPONSE:

b) Yes, THESL used FA to improve the reliability in specific areas. The summary of spending on FA in previous years is shown below:

Project	Year	Location	Status	Cost
Feeder Automation Pilot Project	2010	Fairbanks TS and Bathurst TS	Online Oct. 2010	$3,597,479

Panel: Parts a) and b) Capital Projects
Panel: Part c) Rates and Revenue Requirement

RESPONSES TO VULNERABLE ENERGY CONSUMERS COALITION INTERROGATORIES ON ISSUE 2.2

c) In THESL's view does a favourable Benefit/Cost ratio demonstrate that a project is prudent or that it is non-discretionary or does it demonstrate both?

RESPONSE:

c) By itself a positive Benefit/Cost ratio supports the prudence of a proposed project, not its non-discretionary character. However, as explained in the Manager's Summary at page 17, where alternative timings or stagings of a project would generate materially different costs, THESL considers it non-discretionary to pursue the lower cost alternative, assuming that all requirements are met.

2. Why the Project is Needed Now

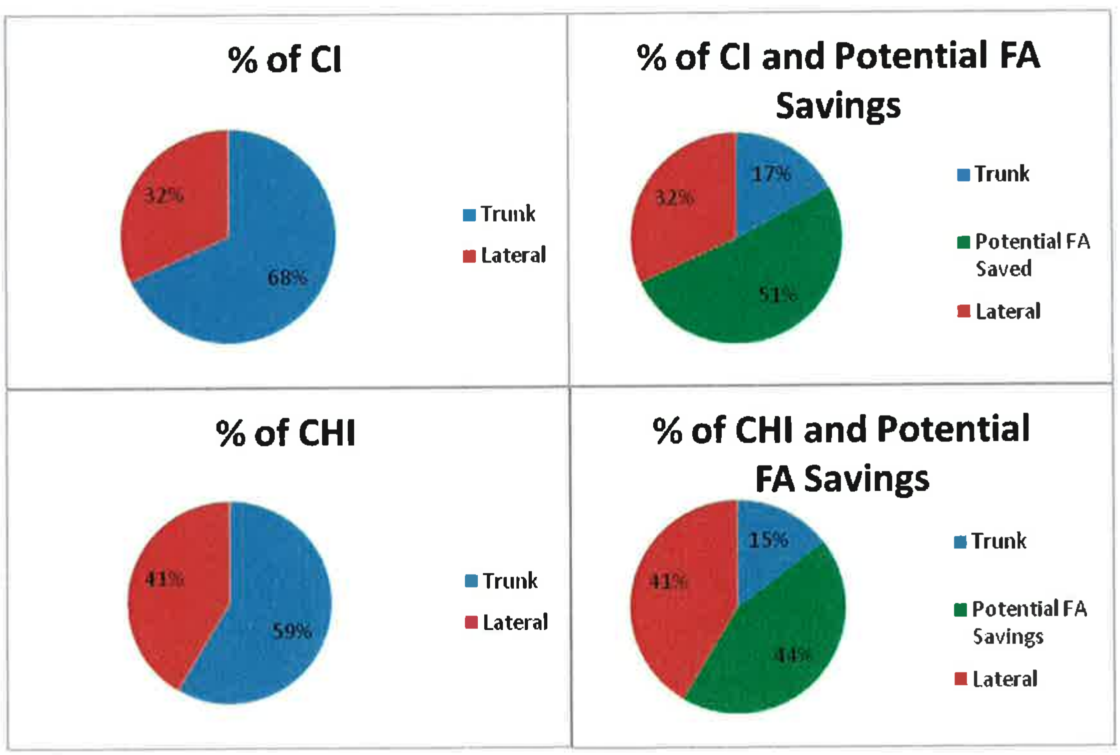
The project needs to be constructed on the selected feeders now for three reasons:

(a) to reduce the current reliability impact of feeder trunk outages,

(b) to reduce the risk of future outages due to the high probability of equipment failure, and

(c) to ensure effective FA saturation on the system.

Of the customer interruptions (CI) on the selected feeders, 68% are attributable to the trunk /C
portions these feeders; for customer hours interrupted (CHI), 58% are attributable to the feeder
trunk (See Figure 1). By deploying FA on these feeders a potential reliability savings of 51% for /C
CI and 44% of CHI on the feeders can be achieved (See Section III). /C



/C

Figure 1: Reliabilty Impact and FA Savings on Selected Feeders

III NEED

This project is necessary to help THESL maintain reliability by reducing the impact of feeder trunk related outages on SAIDI and SAIFI. As discussed above, FA helps limit the number of customers impacted by trunk outages and reduces the duration of these outages. In the face of aging infrastructure and financial and physical limitations on the pace of capital replacement, FA is a cost effective method of addressing reliability performance.

Examining the impacts of trunk related outages throughout the THESL system demonstrates the potential benefits of FA to improve reliability. Figures 4, 5 and 6 illustrate the reliability of the THESL distribution system over the last ten years using CI, SAIDI and SAIFI metrics. These figures show that trunk feeders have a much greater impact on overall reliability than lateral feeders. Figure 4 shows that in terms of the number of interruptions, trunk feeders cause more than twice as many as lateral feeders. This difference translates into more than 500,000 additional customer interruptions due to outages on trunk feeders. Figure 5 compares SAIDI over the last ten years for trunk and lateral feeders. In most years the SAIDI for trunk feeders is more than twice the SAIDI for lateral feeders, but in 2011, it is more than three time higher. Figure 6 shows that SAIFI is also several times higher for trunk feeders.

The reason for the greater reliability impacts of feeder trunks is that faults on lateral feeders affect relatively few customers compared to those on feeder trunks. Lateral feeder faults only affect the small number of customers that are protected by the fuse on that lateral. By comparison, faults on the feeder trunk cause the feeder's circuit breaker to open and disrupt power to all customers served by the feeder.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 23:

Reference(s): **Tab 4/B21**

With respect to Externally – Initiated Plant Relocations and Expansions:

a) [p.4] Please breakdown each job into a) relocation costs and b) expansion costs.

RESPONSE:

a)

Job Title	Agency	Total Estimated Project Cost	Project Breakdown			
		($M)	Relocation (%)	Expansion (%)	Relocation ($M)	Expansion ($M)
Queens Quay Rebuild Phase 1	Waterfront Toronto	$4.67	13%	87%	$0.60	$4.07
Queens Quay Rebuild Phase 2	Waterfront Toronto	$5.30	11%	89%	$0.60	$4.70
Queens Quay Rebuild Phase 3	Waterfront Toronto	$3.42	18%	82%	$0.60	$2.82
Queens Quay Rebuild Phase 4	Waterfront Toronto	$12.43	22%	78%	$2.70	$9.73
Queens Quay Rebuild Phase 5	Waterfront Toronto	$7.98	13%	87%	$1.00	$6.98

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

Job Title	Agency	Total Estimated Project Cost ($M)	Project Breakdown			
			Relocation (%)	Expansion (%)	Relocation ($M)	Expansion ($M)
Metrolinx West of Hwy 27	GO Transit	$0.23	100%	0%	$0.23	$0.00
GTS Bridge – Hwy 27	GO Transit	$0.14	100%	0%	$0.14	$0.00
Weston Tunnel	GO Transit	$0.47	100%	0%	$0.47	$0.00
Martin Grove Bridge	GO Transit	$0.12	100%	0%	$0.12	$0.00
Black Creek and Weston UG Reinstatement	GO Transit	$0.09	100%	0%	$0.09	$0.00
GO Strachan UG Crossing Civil	GO Transit	$0.26	100%	0%	$0.26	$0.00
GO Strachan UG Crossing Civil	GO Transit	$0.13	100%	0%	$0.13	$0.00
Strachan Electrical Relocation Part 1	GO Transit	$1.98	100%	0%	$1.98	$0.00
Strachan Electrical Relocation Part 2	GO Transit	$1.73	100%	0%	$1.73	$0.00

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

Job Title	Agency	Total Estimated Project Cost	Project Breakdown			
		($M)	Relocation (%)	Expansion (%)	Relocation ($M)	Expansion ($M)
Strachan Electrical Relocation Part 3	GO Transit	$1.34	100%	0%	$1.34	$0.00
Strachan Electrical Relocation Part 4	GO Transit	$0.92	100%	0%	$0.92	$0.00
Keele St and Hwy 401-PH2-Tunnelling Under Hwy 401	MTO	$1.69	100%	0%	$1.69	$0.00
Eglinton Ramp Onto Hwy 427	MTO	$0.24	100%	0%	$0.24	$0.00
Dunn Ave Directional Drilling	City of Toronto	$0.72	100%	0%	$0.72	$0.00
Dundas Street Overhead to Underground Phase 1 - Design	City of Toronto	$0.64	100%	0%	$0.64	$0.00
Dundas Street Overhead to Underground Phase 2	City of Toronto	$8.77	100%	0%	$8.77	$0.00

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

Job Title	Agency	Total Estimated Project Cost	Project Breakdown			
		($M)	Relocation (%)	Expansion (%)	Relocation ($M)	Expansion ($M)
Dundas Street Overhead to Underground Phase 3	City of Toronto	$8.01	100%	0%	$8.01	$0.00
North West PATH Addition Phase 1	City of Toronto	$1.62	95%	5%	$1.54	$0.08
North West PATH Addition Phase 2	City of Toronto	$1.38	90%	10%	$1.24	$0.14
Front Street Streetscape Improvement	City of Toronto	$0.52	100%	0%	$0.52	$0.00
Beecroft OH Reconfiguration	City of Toronto	$1.07	100%	0%	$1.07	$0.00
Lawrence Avenue Relocation	City of Toronto	$0.15	100%	0%	$0.15	$0.00

b) Have any of the requesting Agencies/Governments made official requests to date? If so, for which projects?

b) Yes. Official requests have been made for all projects.

RESPONSES TO SCHOOL ENERGY COALITION INTERROGATORIES ON ISSUE 2.2

c) Between 2008 and 2010, how many externally – initiated plant relocations and expansions jobs (and there costs) were i) budgeted and ii) actual incurred in the year budgeted.

RESPONSE:

c)

Year	Number of Projects Budgeted	Amount Budgeted ($M)	Number of Projects Completed in Budget Year	Actual Costs Incurred in Budgeted Year ($M)
2008	7	2.97	2	0.73
2009	0	0	1	2.24
2010	17	3.57	7	3.18

Note: Projects typically require 12-18 months to complete.

If only the required infrastructure for relocation is built at the present time, THESL will be limited by the existing civil infrastructure along Queens Quay Boulevard. This civil infrastructure, as detailed in Figure 6, is undersized and insufficient to accommodate existing circuits plus the additional feeders required to serve the loads anticipated along Queens Quay Boulevard shown in Figure 2.

The restrictions and possible lack of space along the new revitalized Queens Quay Boulevard from Yo Yo Ma Lane to Parliament Street would prevent THESL from utilizing that route unless new ducts and chambers are added as part of the Queens Quay refurbishment. Otherwise, additional capital funds will have to be spent in future years for THESL to install the necessary new civil infrastructure for new feeders to supply customers via Bremner TS.

This new civil infrastructure would, in turn, require new trenching along major routes such as York Street and Lakeshore Boulevard in order to access the high growth areas. This work would be significantly more costly because while the distance to be covered along Lakeshore is similar to that for Queens Quay Boulevard, additional work would be required on York Street. Moreover, Lakeshore is a higher traffic route resulting in more complex construction and maintenance restrictions. Overall, the long term costs associated with this approach are significantly higher than the costs associated with installing the necessary facilities as part of the expansion along Queens Quay Boulevard.

1.2. Business Case Evaluation (BCE) Results

The total cost for THESL to perform the relocations as requested by Waterfront Toronto and increase the duct capacity and civil infrastructure for future requirements is estimated at $25.53M. This estimate can be divided into two portions. Portion 1, to be funded one hundred /UF
percent by Waterfront Toronto, is estimated at $4.50M and includes the civil and electrical plant /UF
relocation based on preliminary design during project development and alignments proposed by Waterfront Toronto. Portion 2, required by THESL estimated at $21.32M and includes the /UF
expansion to a 32-duct 3.2 kilometre duct bank along Queens Quay Boulevard from Yo Yo Ma Lane to Parliament Street, approximately 55 cable chambers, all associated structure stabilization and all required road crossings.

Alternatively, the total cost involved for THESL to perform only the relocations required, and then in future years construct new infrastructure to meet demand is an estimated $35.32M. /UF Similar to the scenario described above, this estimate includes a $4.50M portion to be fully paid /UF for by Waterfront Toronto for the proposed civil and electrical relocation. In addition, it also includes an estimated $30.82M THESL portion for a 24-duct 3.2 kilometre duct bank along /UF Lakeshore Boulevard from Yo Yo Ma Lane to Parliament Street, approximately 45 cable chambers, all associated structure stabilization and all required road crossings, plus the rebuild of approximately 150 metres and 300 metres of civil infrastructure on York Street and Parliament Street respectively for distribution customer servicing.

The projected savings of an estimated $10.79M arise because of the cost savings from not /UF executing construction on Lakeshore Boulevard as well as the elimination of new facilities on York Street and Parliament Street. Compared to Queens' Quay, Lakeshore Boulevard is a main roadway with work restrictions that would result in escalated costs and complex construction requirements. In addition, by performing its civil infrastructure activities in alignment with external parties' required work, potential customer disruptions can be minimized.

The requested funds for the THESL expansion in both scenarios are initially driven from third parties as a result of their relocation activities which are performed at their expense. THESL, in turn, must respond to these third-party investments performing immediate expansion of THESL-owned infrastructure located in these same locations to address future growth considerations. If THESL does not take immediate action to address these assets, due to restrictions that are placed by the third parties (such as Waterfront Toronto) following the execution of their projects, THESL risks being unable to address the immediate load growth concerns and future source of supply for customers.

All costs identified above for both scenarios include work required for relocation as requested by Waterfront Toronto and work associated to additional expansion required by THESL. Only the incremental capital required by THESL is being justified in this Business Case and does not include the portion of relocation work to be one hundred percent funded by Waterfront Toronto.

Given that THESL must undertake the relocation and expansion work on Queens Quay Boulevard, installing sufficient duct capacity to meet future needs is the most prudent approach for ratepayers. In addition, it will result in strategically located facilities that are optimally integrated with the planned Bremner TS. It will also minimize construction disruption for the neighbourhood area. In contrast, if future needs are not addressed, THESL will have insufficient ducts and associated facilities to supply new customers along Queens Quay Boulevard and will be forced to construct more expensive facilities in undesirable locations that will not support or strengthen THESL's distribution system.

1.3. Detailed Descriptions of Specific Central Waterfront Revitalization Jobs

Table 2: Waterfront Revitalization Jobs and Cost Estimates (2012-2013~~2014~~) /US

Estimate Number	Job Title	THESL Cost Estimate ($M)	
22851	Queens Quay Rebuild Phase 1 (2012)	$3.78	/UF
22853	Queens Quay Rebuild Phase 2 (2013)	$4.70	/US
22854	Queens Quay Rebuild Phase 3 (2013)	$2.82	/US
24729	Queens Quay Rebuild Phase 4 (2013)	$9.73	
~~24731~~	~~Queens Quay Rebuild Phase 5 (2014)~~	~~$6.98~~	
	TOTAL	**$21.03**	/UF, US

The scope of work for this entire expansion project includes constructing a new 32-duct 3.2 kilometre duct bank along the south side of Queens Quay Boulevard from Yo Yo Ma Lane to Parliament Street. The duct bank to be constructed will be designed as two 4x4 duct banks with associated cable chambers required for splicing and jointing. Approximately 55 cable chambers and structure stabilization material, such as Helix Anchors and piles for cable chamber installation, will be required as a part of this project.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 27:

Reference(s): **T2/App. 4, T4/S B11/pp. 22-23 and T4/S B16/pp. 10-11**

The first reference explains in detail the theoretical constructs of the "Feeder Investment Model" ("FIM"), and the theoretical constructs of the Model for the "Cost of Ownership" ("COO").

The second reference discusses an_outage cost based on $30 per customer per interruption and $15 per kWh interrupted.

The third reference discusses an outage cost based on $30/kW outage event cost and $15 per kWh outage duration cost.

a) **Please explain the apparent differences between the basis of the two referenced customer interruption costs.**

RESPONSE:

a) The two references use consistent customer interruption costs. In both cases the applied customer interruption costs (CICs) are as follows:

   i. CIC = Event Cost + Duration Cost

   ii. Event Cost = ($SAIFI_{EFFECT}$)(Total Load)
   Where:
   - $SAIFI_{EFEECT}$ ($30) represents the cost associated with the occurrence of the interruption.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

- Total Load represents the peak load in kVA that will be interrupted due to the outage event.

iii. Duration Cost = ($SAIDI_{EFFECT}$)(Total Load)(Outage Duration)

Where:

- $SAIDI_{EFEECT}$ (\$15) represents the cost associated with the duration of the interruption.
- Total Load represents the peak load in kVA that will be interrupted due to the outage event.
- Outage Duration represents the average duration of the outage event in hours.

b) Please clarify whether or not a fixed set of referenced customer interruption costs are used for all customer interruptions in all the FIM and COO type business case evaluations, and if so please provide that fixed set.

RESPONSE:

b) As noted in (a), THESL has adopted the use of a \$30/kVA (peak load) customer interruption cost value to represent the outage occurring (The "Event") and a \$15/kVA-hour (peak load) customer interruption cost value to represent the length of the outage (The "Duration"). These costs are adopted within every FIM and COO business case evaluation presented within the ICM filing.

c) Please provide supporting evidence/calculations justifying this cost.

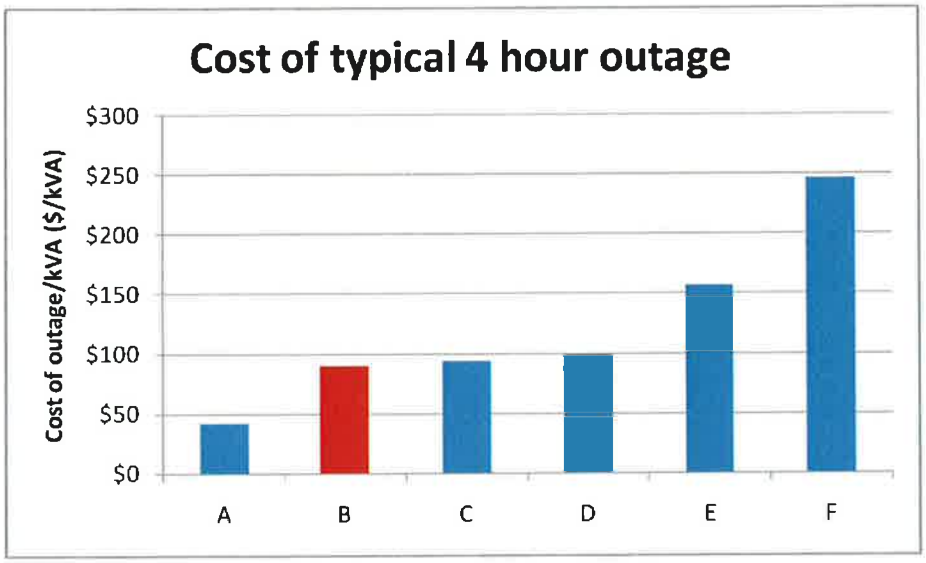
RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2

RESPONSE:

c) The customer interruption costs applied by THESL as part of every FIM and COO business case were developed with consultants, who have worked with other utilities in establishing similar parameters. Reliability valuation studies, such as those from Roy Billinton, were used to aid in the development of these parameters, which are applied consistently to quantify power interruptions to all types of customers.

Figure 1 and chart 1 illustrate how THESL's customer interruption costs compare to those established via reliability valuation studies. Figure 1 illustrates the total cost of a four-hour outage using these various customer interruption costs. Those employed by THESL are shown in red. Table 1 shows the Event Cost per Customer and Duration Cost per Customer-Hour using each of these customer interruption costs, including those employed by THESL. The chart also contains the source of the information shown in the blue bars in Figure 1, and in Table 1, THESL's customer interruption costs are within the range of the other sampled costs. In addition, THESL has also confirmed that the current customer duration cost employed by THESL is within the range of customer duration costs used by Hydro One Networks Inc.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES ON ISSUE 2.2



1 **Figure 1 – Cost of a Typical 4-Hour Outage**

2 **Table 1 – Customer Interruption Cost Breakdown**

	Study Name	Duration Cost ($/kVA)	Event Cost ($/kVA)	Reference	Page Number on PDF
A	Interruption Costs Netherlands	8.721	6.579	N/A	4
B	THESL	15	30	N/A	N/A
C	The Use of Customer Outage Cost Surveys in Policy Decision-Making	14.436	35.982	N/A	5
D	Consumer Expectations of DNOs and WTP for Improvements in Service	22.539	8.769	Table 29	35
E	Economic Valuation of Electrical Service Reliability	17.631	86.652	N/A	9
F	How to Estimate the Value of Service Reliability Improvements	50.94	42.93	Table 1	3