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.

ENERGY PROBE RESEARCH FOUNDATION
("ENERGY PROBE")
CROSS-EXAMINATION COMPENDIUM

PANEL 2B Part 1

Each year's funding request represents THESL's current plans for rear lot conversions in that year and the funding approved will be used for this purpose. These jobs represent incremental capital spending that is above and beyond that anticipated when current rates were approved.

2. Why the Project is Needed Now

THESL believes that the rear lot conversion work is non-discretionary for the reasons that follow.

If no action is taken, outages, safety risks, and costs resulting from rear lot equipment will likely accelerate to unacceptable levels. In addition to the acceleration in failure rates of the rear lot equipment, studies have shown that underground assets are more reliable and reduce maintenance costs compared to their overhead counterparts.[1] Typical outage restoration times for rear lot plant outages are more than twice those of front lot outages. Thus, customers supplied via the rear lot may experience outage durations that are much longer than normal. Additionally, for a typical rear lot outage, the likelihood of an outage occurring is significantly /C
higher for the overhead system. The graph below presents the levels of the typical outages of /C
overhead (OH) construction versus underground (UG) construction.

[1] Fenrick, S.A., and Lullit Getachew. "Cost and Reliability Comparisons of Underground and Overhead Power Lines". *Utilities Policy*, Volume 20, Issue 1, March 2012, pages 31-37.

I EXECUTIVE SUMMARY

1. Project Description

THESL is requesting approximately $45.57million in ICM funding to finance non-discretionary /UF, US civil and infrastructure jobs related to rear lot conversion between 2012 to2013. This amount is broken into discrete jobs, totalling approximately $24.15 million in 2012, and $21.42 million in /UF, US 2013. A detailed description of all the jobs, by year, is provided in Part V below. /UF, US

The rear lot conversion segment responds to the critical need to move the distribution service currently located in backyards to the street, for reasons of safety, reliability and cost.

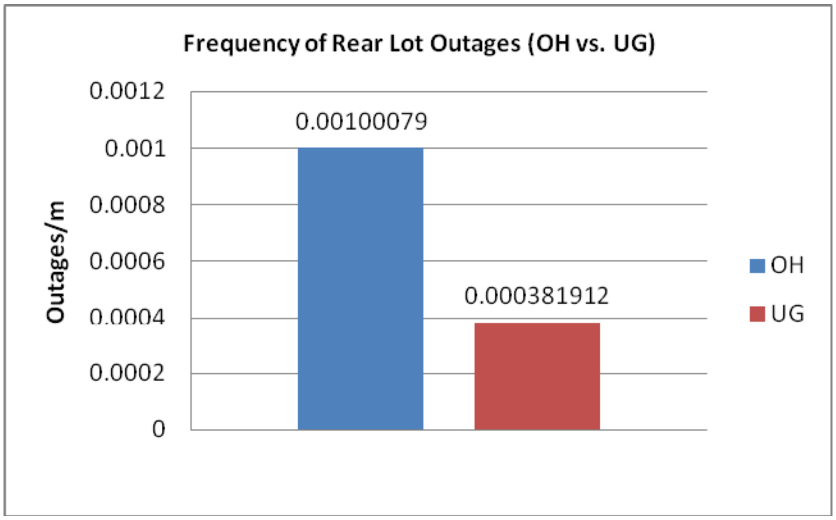
Rear lot service was implemented in certain Toronto neighbourhoods in the 1950s and 1960s. The equipment providing rear lot service is past its useful life and difficult to access and repair. As a result of its age and condition, THESL expects that this equipment will continue to fail at an increasing rate and when it does, efforts to repair it create safety, equipment availability and cost issues.

This segment will remove rear lot service in targeted areas that currently pose potential safety risks, greater reliability concerns and higher repair costs. It will be replaced with standard underground service constructed to current specifications. The result of the move to standard service will be reduced safety risks, improved reliability, and reduced costs to repair.

The work to be undertaken in each year covered by this application has been selected based on two factors:

(a) The priority associated with each specific rear lot conversion job; the need to undertake work in a logical sequence that reflects good planning, distribution contingencies and the local impacts of construction; and

(b) The amount of work THESL can complete in a given year.



/c

Figure 1: Frequency of Typical Rear Lot Outages (OH vs. UG) /c

This segment is necessary to address the many critical issues inherent in rear lot service due to its location, and the age and condition of the equipment providing this service. The nature of these issues requires that they be addressed immediately or they will continue to pose potential safety risks to THESL crews and the public. Failure to address rear lot construction would also perpetuate ongoing cost and reliability issues, as THESL will be required to undertake expensive and time-consuming repairs on equipment that is past its useful life and difficult to access and maintain.

The specific reasons that require this segment to be undertaken now are:

- Operational constraints – THESL field crews are constantly challenged to access customers' rear lot plant due to physical inability to use the machinery typically employed for distribution system repairs (e.g., bucket trucks, cranes and drilling machines). As a result, crews are at times required to hand-carry heavy assets such as poles and transformers to effect repairs. This increases potential physical risks to the crews, particularly at night and in winter, and extends the time necessary to repair and replace failed equipment. Additional evidence on the operational constraints related to rear lot service can be found in Part III, Section 2 below.

- Asset condition - there are many rear lot distribution assets which are past their useful service lives, in very poor condition and surrounded by heavy vegetation which is challenging and expensive to manage.[2] Additional evidence on the asset condition and vegetation issues concerns related to rear lot service can be found in Part III, Sections 1 and 3 below.
- Crew safety risks – THESL crews at times have to work on poles that have rotted at the bases, making them unstable and imposing potential safety risks. Securing these poles, to the extent possible, delays restoration. Additional evidence regarding crew safety risk can be found in Part II, Section 2 below.
- Public safety risks – energized conductors and poles with associated equipment are in close proximity to residential structures and back yard activities imposing potential contact risk to the public. Additional evidence regarding public safety risk can be found in Part III, Section 4 below.
- Lengthy power restoration times – due to operational constraints, it is estimated that it takes two and a half times longer to restore power to customers compared to a typical front lot outage; during 2010 and 2011, the average CAIDI for THESL overall was 48 minutes. For a sample of rear lot related outages, the average CAIDI for these outages was 109 minutes. Additional information regarding the reliability and customer service concerns related to rear lot service can be found in Part III, Section 5 below.

3. Why the Proposed Project is the Preferred Alternative

Four options were evaluated to address existing rear lot risks:

(a) Option 1: Remediation – only repair/replace aged rear lot assets on an as-needed basis.

(b) Option 2: Rebuild – construct new rear lot distribution so that facilities meet current safety regulations.

[2] The same constraints that make it difficult to use heavy equipment such as bucket trucks for repairs often limit the access for the machinery typically used in pruning such as bucket trucks and chippers.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 30:

Reference(s): **Tab 4, Sch. B6 Rear Lot Construction**

Lines 11-16 on Page 6 and 1-22 on Page 7 describe the specific reasons for undertaking rear lot conversion. The first category is Operational Constraints on Page 6.

a) Has THESL investigated the use of sectional fibre glass or composite poles that can be more easily carried into backyards and assembled in place? Would this mitigate the safety issue of field crews carrying heavier full length wood poles into backyards and the issue of limited manoeuvring room for full length poles in backyards?

RESPONSE:

a) THESL has investigated the use of sectional composite poles. Crew safety would remain an issue since there would still be restricted access and restricted available space in backyards of customer premises for the crews to assemble and set the poles. Risks due to slips, trips, and falls would still remain due to limited working space and difficult access (e.g., ice, snow and obstructions) compared to that typically afforded in a front lot installation. These potential safety risks are particularly prominent when restoration work is undertaken at night time and in winter months.

b) Has THESL considered using compact backhoes capable of accessing rear lots and digging pole holes in confined areas to set poles? If not why not?

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

RESPONSE:

b) THESL has not considered this since many of the safety issues discussed above and in the evidence will necessarily persist as long as rear lot service continues. Furthermore, even compact backhoes may not be able to achieve access due to obstructions on customer property such as landscape, fences, gates, sheds, and pools.

c) Has THESL attempted to develop compact equipment capable of transporting heavy assets such as transformers into backyards? If not why not?

RESPONSE:

c) THESL uses compact equipment such as dollies where practical. Due to varying locations of outages and depending on layout and obstructions at the customer premises, use of this equipment is not possible in all cases.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 31:

Reference(s): Tab 4, Sch. B6 Rear Lot Construction

Lines 11-16 on Page 6 and 1-22 on Page 7 describe the specific reasons for undertaking rear lot conversion. The second category is asset condition on Page 7.

a) Do THESL's easements give it the right to access backyards to maintain plant and control vegetation that might grow into equipment? If yes, has THESL regularly done this kind of maintenance? If not, why not?

RESPONSE:

a) Yes. THESL does asset maintenance as required and schedules tree trimming as per THESL's tree trimming model.

b) Please provide a copy of the typical easement agreement THESL has with rear lot fed customers (with appropriate redactions to eliminate personal information where necessary).

RESPONSE:

b) Please see a sample of a typical easement agreement THESL has with rear lot fed customers provided as Attachment A to this Schedule (Rear Lot Easement Document).

THIS AGREEMENT made in duplicate this 9th day of November, A.D. 1960.

Toronto Hydro-Electric System Limited
EB-2012-0064
Tab 6F
Schedule 7-31
Attachment A
Filed: 2012 Oct 5
(4 pages)

B E T W E E N:

[redacted]

hereinafter called the "GRANTOR"

OF THE FIRST PART:

- and -

THE HYDRO-ELECTRIC COMMISSION OF THE TOWNSHIP OF NORTH YORK

hereinafter called the "COMMISSION"

OF THE SECOND PART:

WHEREAS the Grantor is the owner in fee simple and in possession of the land described in Schedule "A" hereto.

AND WHEREAS the Commission has erected, or is about to erect a wood pole line, together with the necessary wires, cables, and accessories for the transmission of electrical energy on this land.

NOW THIS INDENTURE WITNESSETH that in consideration of other good and valuable consideration and the sum of TWO AND 00/100 ($2.00) DOLLARS of lawful money of Canada, now paid by the Commission to the Grantor, the receipt whereof is hereby acknowledged, the Grantor HEREBY GRANTS AND CONVEYS to the Commission, its successors and assigns, the free, uninterrupted right and easement in perpetuity:

(a) To enter on and construct, maintain, repair, replace and operate on the lands described in Schedule "A" herein Poles, Transformers and Anchors, with guys and braces and to string wires, cables and accessories thereon (all or any of which works are herein called "the line");

(b) To keep the land for a distance of five feet (5') on each side of the centre line of the pole (herein called the strip) clear of all trees and brush, and to cut or trim from time to time such trees outside the strip as the Commission may consider necessary for the safe and efficient operation of the line;

(c) For the servants, agents, contractors and workmen of the Commission, at all times to pass and repass with any equipment along the strip to examine, repair and renew the line;

2. THE GRANTOR COVENANTS and agrees not to erect on the strip any buildings, structures or other obstructions of any nature whatsoever.

3. THE GRANTOR COVENANTS with the Commission that it has the right to convey the easement over the said land, and that the Commission shall quietly possess and enjoy the said easement, and that it will execute such further assurances of the said easement as may be requisite.

4. All the covenants herein contained shall be construed to be several as well as joint, and wherever the singular is used in this Grant of Easement, the same shall be construed as including the plural where the context or the parties hereto so require.

5. The burden and benefit of this Grant of Easement shall run with the land, and shall extend to, be binding on and enure to the benefit of the parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF the Grantor has hereunto affixed its Corporate Seal under the hands of its proper officers duly authorized in that behalf.

[redacted]

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 33:

Reference(s): Tab 4, Sch. B6 Rear Lot Construction

Lines 11-16 on Page 6 and 1-22 on Page 7 describe the specific reasons for undertaking rear lot conversion. The fourth category is Public Safety Risks.

a) How does the risk of proximity to energized equipment and conductors in backlot construction compare to the risks of proximity in front lot O/H systems?

RESPONSE:

a) The risk of proximity to energized equipment and conductors in backlot construction is greater than in front lot O/H systems. Although the impact is similar, the probability of contact is greater in the rear lot. This is due to close proximity of existing rear lot assets to houses, pools, out buildings and patios.

b) How much (on a % basis) of the THESL residential supply system is O/H (both front and rear lot) and how much is U/G?

RESPONSE:

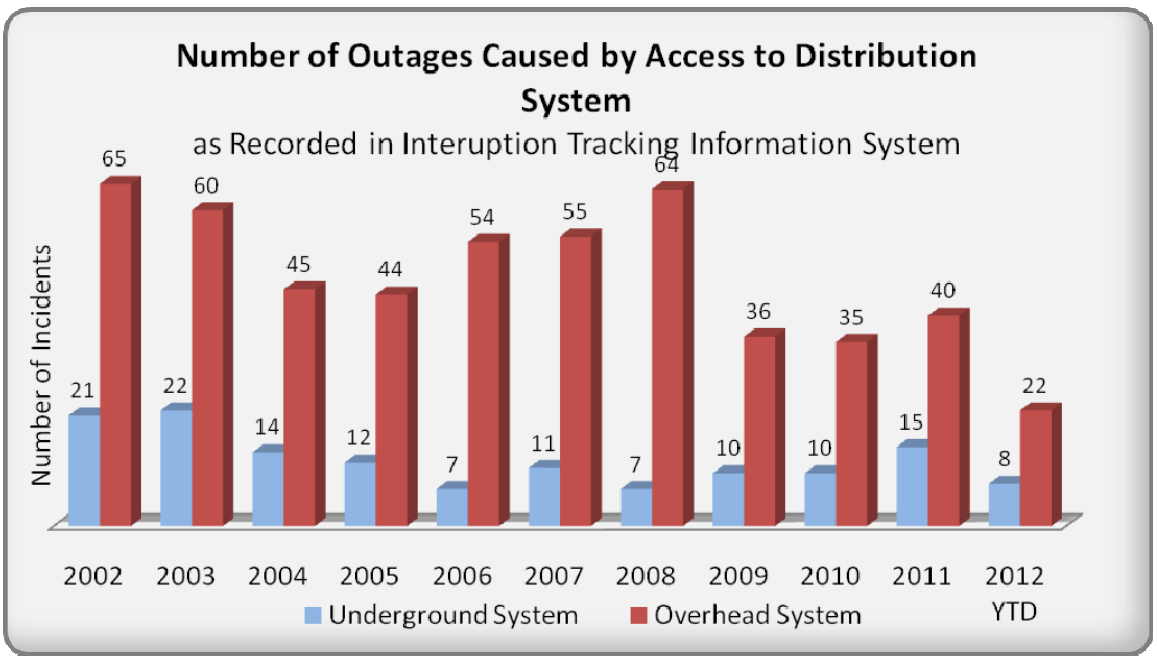
b) THESL currently does not maintain O/H versus U/G based upon customer class (e.g., residential). However THESL's system is comprised of approximately 15,100 kilometres of overhead wires and approximately 10,900 kilometres of underground wires.

c) Please provide a chart showing public electrical contact incidents in the last ten years for rear lot residential systems, for front lot residential systems and for

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

front lot underground systems (including contractor dig ins and overhead contacts).

c) The incidents related to the electrical contact (vehicle contact, dig-in, etc) can be classified in underground or overhead incidents. THESL does not track differentiation between front and rear lots. Below is a graph that summarizes the incidents during the past ten years.



RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 34:

Reference(s): Tab 4, Sch. B6 Rear Lot Construction

Lines 11-16 on Page 6 and 1-22 on Page 7 describe the specific reasons for undertaking rear lot conversion. The fifth category is Power Restoration Times.

a) Is the restoration comparison citing two and one half times restoration time for rear lot service compared to front lot derived from the CAIDI averages in lines 18-19? If not, please explain how it was arrived at?

RESPONSE:

a) Yes, it was derived from the CAIDI averages.

b) How was the sample of rear lot outages selected?

RESPONSE:

b) Since THESL does not specifically track outages specific to rear lot, THESL conducted a study whereby outages on feeders supplying rear lot rear lot areas were plotted in order to determine whether the outage actually originated within an area with rear lot service. Data collected in these rear lot areas from outages that occurred during 2010 and early 2011 was used in the analysis.

c) Please provide a chart comparing the durations of all outages on rear lot residential construction to all outages on front lot O/H and on front lot U/G for the past five years.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

RESPONSE:

c) THESL does not track outages specific to rear lot. The table below provides a summary of the durations of all OH and all UG outages for the past five years:

	2006	2007	2008	2009	2010	2011
OH Outage Durations (minutes)	126,780	112,583	126,151	118,532	107,856	130,019
UG Outage Durations (minutes)	113,125	113,442	125,614	114,127	119,285	117,715

MR. FAYE: So then schedule 7-24 -- or 7-34 shows the outage durations for the overhead and the underground systems for the years 2006 to 2011. And if you sum them up so that you have a total for those years, the total duration minutes are almost the same, 720,000 for overhead and 701,000 for underground. And this despite the fact that there is 50 percent more overhead.

So we would look at that and conclude: Well, at least in terms of duration of outages, the overhead system appears to be much more reliable than the underground system.

Is that a fair conclusion to draw? Or would you like to comment on that?

MR. KERR: Yeah. I don't think that is a fair conclusion to draw from that evidence.

When we're speaking about the length of overhead in the system, we're talking about the numbers we're referring to, the length of circuit kilometres, but what we weren't speaking to is the number of customers fed by those circuit kilometres.

So from our point of view, if you have one system serving the same number of people and another system which is 50 percent larger serving the same number of people, essentially the density of customers on the feeder is higher on the system which serves more people with less.

So when we look at the SAIDI and SAIFI and CAIDI numbers, those are actually coming from how many customers were interrupted, not just by how many circuit kilometres

TECHNICAL CONFERENCE UNDERTAKING RESPONSE
INTERVENOR 7 – ENERGY PROBE RESEARCH FOUNDATION

UNDERTAKING NO. JT1.4:

Reference(s): Tab 6F, Schedule 7-33 and 7-34

Provide a rough approximation of how many customers are fed off overhead vs underground primaries.

RESPONSE:

THESL has approximately 475,000 customers fed from overhead primary and approximately 243,000 customers fed from underground primary. Note that customers fed from the secondary network in the downtown area are included in the customer count for customers fed from underground primary.

1 **Table A1: Status Quo (Remediation on an as-needed basis)**

Business Case Element	Estimated Cost ($, millions)
OPTION 1 – Status Quo (Remediation on an as-needed basis)	
Cost of Ownership of Existing Rear Lot Construction (COO_E)	
Projected risk cost of existing rear lot (NPV)	$7.95
Projected non-asset risk cost of existing rear lot (NPV)	$102.48
Maintenance cost of existing rear lot	$0.68
TOTAL (COO_E)	**$111.11**

/C

2 **Table A2: Like-for-Like Replacement of Existing O/H Rear Lot with New O/H Rear Lot**

Business Case Element	Estimated Cost ($, millions)
OPTION 2 – Like-for-Like Replacement of Existing O/H Rear Lot with New O/H Rear Lot	
Cost of Ownership of New Standardized Rear Lot Construction (COO_N)	
Projected risk cost of new overhead rear lot (NPV)	$2.37
Projected non-asset risk cost of new overhead rear lot (NPV)	$102.48
Maintenance cost of new overhead rear lot	$0.68
TOTAL (COO_N)	**$105.53**
Option 2 Project Net Benefit	
TOTAL (COO_E)	**$111.11**
TOTAL (COO_N)	**$105.53**
PROJECT COST	**$7.36**
PROJECT NPV: ((COO_E – COO_N) – PROJECT COST)	**-$1.78**

/C

/C

Table A3: Replacement of Existing O/H Rear Lot with New U/G Front Lot

Business Case Element	Estimated Cost ($, millions)
OPTION 4 – Replacement of Existing O/H Rear Lot with New U/G Front Lot	
Cost of Ownership of New Standardized Underground Front Lot Construction (COO_N)	
Projected risk cost of underground front lot (NPV)	$11.55
Projected non-asset risk cost of underground front lot (NPV)	$0
Maintenance cost of underground front lot	$0.43
TOTAL (COO_N)	**$11.98**
Option 4 Project Net Benefit	
TOTAL (COO_E)	**$111.11**
TOTAL (COO_N)	**$11.98**
PROJECT COST	**$66.14**
PROJECT NPV: ((COO_E – COO_N) – PROJECT COST)	**$32.99**

To further illustrate the relationship between Non-Asset Risk and Asset Risk, a comparison was made against historically tracked CHI over the last ten-year period due to asset and non-asset causes for the rear lot feeders.

Table A4: NPV and CHI ratios of Non-Asset to Asset Risk for Existing Rear Lot

	NPV ($ in Millions)	CHI (hrs)
Asset Risk	7.95	784.45
Non-Asset Risk (NAR)	102.48	6193.21
Ratio (NAR/Asset Risk)	12.89	7.90

The difference between the two ratios is attributed to the increasing trend of non-asset related outages. The graph includes outages from tree contacts, animal contacts, lightning, and adverse weather. Over the last five years, there has been an increasing trend in the amount of non-asset related failures. This is further illustrated in Figure A4. The 12.89 ratio represents a value that /C will be held constant over the next three years, even though the expected number of non-asset

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.

I EXECUTIVE SUMMARY

1. Project Description

This segment includes 27 discrete jobs to replace approximately $87.7 million of direct buried /UF, US cable with cable in concrete-encased ducts, and air-insulated pad-mounted switchgear units with SF_6-insulated pad-mounted switchgear units in 2012~~,~~ and 2013~~, and 2014~~. The cost breakdown by year is $61.1 million in 2012~~,~~ and $26.6 million in 2013~~, and $74.92 million in 2014~~. The jobs address both direct buried cable and air-insulated pad-mounted switchgear units /UF, US collectively, as this is the most efficient and cost-effective approach. Table 1 below lists the proposed jobs, in order of the number of unplanned sustained outages[1] experienced by the feeder in 2011 (with the exception of the last job in the table because it addresses a number of feeders). Each job is described in section II.

Table 1: List of jobs to be executed in 2012~~,~~ and 2013 ~~and 2014~~

Job Title	Year	Estimated Cost ($M)	
Underground Rehabilitation of Feeder NY80M29	2012, 2013	$2.90	
Underground Rehabilitation of Feeder SCNAR26M34	2012, 2013~~, 2014~~	$2.33	/US
Underground Rehabilitation of Feeder NY55M8	2013	$2.50	/UF, US
Underground Rehabilitation of Feeder YK35M10	2012	$2.32	/US
~~Underground Rehabilitation of Feeder SCNT63M4~~	~~2014~~	~~$3.16~~	
Underground Rehabilitation of Feeder SCNA47M14	2012, 2013	$4.43	
Underground Rehabilitation of Feeder NY51M6	2012	$2.91	/UF, US
~~Underground Rehabilitation of Feeder NY80M8~~	~~2014~~	~~$9.51~~	
~~Underground Rehabilitation of Feeder NY85M6~~	~~2014~~	~~$2.01~~	
Underground Rehabilitation of Feeder NY51M8	2013~~, 2014~~	$1.26	/US
Underground Rehabilitation of Feeder SCNA502M22	2012, 2013~~, 2014~~	$2.78	/UF, US

[1] A sustained outage is an outage lasting more than one minute.

Due to numerous operational issues associated with rejuvenation including the planned outage time required and the fact that splicing/repair activities would need to continue as part of outage remediation, THESL has concluded that cable rejuvenation is not a viable option (See Section IV, 1, Option 2). The same conclusion was reached for replacing direct buried XLPE cables with new direct buried TR-XLPE cables (See Section IV, 1, Option 3). With both of these options, there would be a continuing probability of failure due to the fact that the cables remain direct buried and the remediation costs would still be significant due to digging and splicing activities required.

Replacement of direct buried XLPE cables with new strand-blocked TR-XLPE cables in concrete-encased conduit is the preferred alternative (See Section IV, 1, Option 4). The conduit provides mechanical protection against external factors and moisture from the surrounding soil. Moreover, an entire cable segment can be pulled out from the conduit and replaced with a new cable segment during remediation procedures. This is in stark contrast to outage remediation for direct buried cables, in which case cables are spliced and will therefore continue deteriorating along their existing life cycle from the time of failure onwards. The life cycle will be further shortened due to the fact that the splice in itself may become a point of failure.

There are also a number of intervention options available for existing air-insulated pad-mounted switches (See Section IV, 2, Options 1 through 5). Maintenance activities, including CO_2 cleaning, can be accelerated for this asset class, but it has been noted that these cleaning activities are also resulting in further degradation of the asset over time (See Section IV, 2, Option 1).

A pilot study was carried out to install a moisture barrier within an air-insulated pad-mounted switch to isolate the below-grade contaminants from the above-grade electrical parts (See Section IV, 2, Option 3). However, the vast majority of contamination occurs through the ventilation louvers of the asset, which are above this barrier. Furthermore, the barrier provides an additional medium for water and contamination to settle upon, thus increasing the probability of a flashover occurrence.

current design and procurement practices in order to have standardized equipment and to reduce the dependence on one-of-a-kind devices, which may be hard to procure.

Rear to Front Lot Conversions

Few companies are actively relocating overhead lines to front or roadside locations, as lines along property frontage or roadways usually need to be relocated underground at significant cost. Some companies are relocating overhead lines to underground, but only when needed for reliability or lack of access. Virtually all primary and secondary relocations include use of conduit, either concrete-encased duct banks for primary three-phase lines and directional boring and flexible conduit for single-phase laterals. Direct buried cable, while discouraged, is sometimes used for replacement of secondary cable due to cost or when replacing small segments of line.

Specific findings include:

- The preferred method for single-phase lines is to use directional boring in combination with the installation of flexible conduit. THESL practice is to install concrete-encased conduit for single- and three-phase cable.
- Those relocating lines underground have formalized policies that also mandate the use of padmounted transformers (as opposed to submersibles); this has caused some difficulties in obtaining easements as property owners are reluctant to grant easements when installation of underground cables is conditioned upon the installation of padmount transformers.
- One company has established a policy to only install pad mount transformers when submersible devices fail or need to be replaced due to deterioration.
- Where relocations are single-phase only, directional boring with flexible conduit is most often used. However, where three-phase main line primary distribution is relocated, concrete-encased duct bank is installed in trenches dug by backhoes. The use of conduit also includes single phase lines that may later be upgraded to three-phase.
- One utility reports that it pays for electric panel replacements if the utility has chosen to relocate the line.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

Please refer to the response to interrogatory EP 22 (Tab 6F, Schedule 7-22) for further information on the benefits of underground infrastructure over overhead infrastructure, and the response to interrogatory EP 23 (Tab 6F, Schedule 7-23) for further information on directional boring.

b) Please provide an expanded Table 3 on Page 134 showing comparable costs for two additional options:

1. **Directional boring with flexible duct to house cable, and**
2. **O/H primary with pole mounted transformers and U/G secondaries. (Please update the installation costs in Option 4 of existing Table 3 to include submersible transformers, transformer vaults and cable chambers and secondaries.)**

RESPONSE:

c) Table 2 below is an expanded and updated version of Table 3 in Tab 4, Schedule B1, and includes the costs of replacing existing direct buried cable through planned work and outage restoration with overhead conductors and poles as well as new cable in direct buried duct via directional boring.

Important notes pertaining to Table 2 below:

- Options 1, 2, 3, 4 and 6 in Table 4 below are for a length of 100 metres of cable. Option 5 is for a length of 114 metres of overhead poles and conductors (based on three spans of 38 metres).
- #1/0 Al TR-XLPE cable is used in Options 1, 2, 3, 4 and 6. #3/0 ACSR conductor is used in Option 5.
- The costs for cable/conductor are for one phase only.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

- Options 4 and 6 assume a typical 2x3 duct configuration.
- Options 1 and 3 assume a typical trench depth of 1.2m.
- All options (1-6) assume a straight stretch of local road without any bends.
- All costs do not include transformers or switchgear. Including these components would not provide a realistic picture of the associated costs since not all projects proposed by THESL require transformers or switchgear. To this end, only the common components of all projects have been included for the purposes of this analysis.

As noted by footnote 3 to Table 2, some of these costs are corrections to those previously included in Table 3 in Tab 4, Schedule B1.

Table 2: Direct buried cable replacement cost comparison

	Estimated Installation / Rejuvenation Costs				Repair Due to Outage			
Option	**Material / Injection Cost (per metre)**	**Electrical Labour Cost (per segment)**	**Civil Cost (per metre)**	**Total Installation/ Rejuvenation Cost (1)**	**Electrical Material and Labour Cost**	**Civil Cost**	**Total Costs**	**Total Costs per metre**
1. Performing reactive work on the feeder (i.e., replace XLPE with strand-filled TR-XLPE)	$13.41 (per metre) [3]	$1,822.24 [3]	$240.18 (per trench metre) [3]	$27,181.33 [3]	$4,922.37 [3,4]	$1,244 (per splice-pit) [5]	$6,166.04 [3]	$6,166.04 [3]

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

	Estimated Installation / Rejuvenation Costs				**Repair Due to Outage**			
Option	**Material / Injection Cost (per metre)**	**Electrical Labour Cost (per segment)**	**Civil Cost (per metre)**	**Total Installation/ Rejuvenation Cost (1)**	**Electrical Material and Labour Cost**	**Civil Cost**	**Total Costs**	**Total Costs per metre**
2. Rejuvenate existing XLPE direct buried cables via cable injection	$20.01 (per metre)	$3,352.08	$522.50 (per metre)	$57,603.08	$4,922.37 (3,4)	$1,244 (per splice-pit) (5)	$6,166.04 (3)	$6,166.04 (3)
3. Replace existing XLPE direct buried cables with new strand-filled TR-XLPE direct buried cables	$13.41 (per metre) (3)	$1,822.24 (3)	$240.18 (per trench metre) (3)	$27,181.33 (3)	$4,922.37 (3,4)	$1,244 (per splice-pit) (5)	$6,166.04 (3)	$6,166.04 (3)
4. Replace existing XLPE direct buried cables with new strand-filled TR-XLPE cables in concrete-encased ducts	$13.41 (per metre) (3)	$2,162.90 (3)	$380.40 (per metre) (3)	$41,544.32 (3)	$6,171.12 (3)	N/A	$6,171.12 (3)	$61.71 (3)

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

	Installation / Rejuvenation Costs				Repair Due to Outage			
Option	**Material / Injection Cost (per metre)**	**Electrical Labour Cost (per segment)**	**Civil Cost (per metre)**	**Total Installation/ Rejuvenation Cost (1)**	**Electrical Material and Labour Cost**	**Civil Cost**	**Total Costs**	**Total Costs per metre**
5. Replace existing XLPE direct buried cables with overhead conductors and poles	$350.00 (per 38m span)	$8,912.08 (1)	$24,203.30 (2)	$34,165.38	$5,625.86 (6)	N/A	$5,625.86	$56.26
6. Replace existing XLPE cables with strand-filled TR-XLPE cables in flexible ducts via directional boring	$13.41 (per metre)	$2,162.90	$307.34 (per metre)	$32,896.57	$6,171.12 (7)	N/A	$6,171.12	$61.71

Notes to the Table:

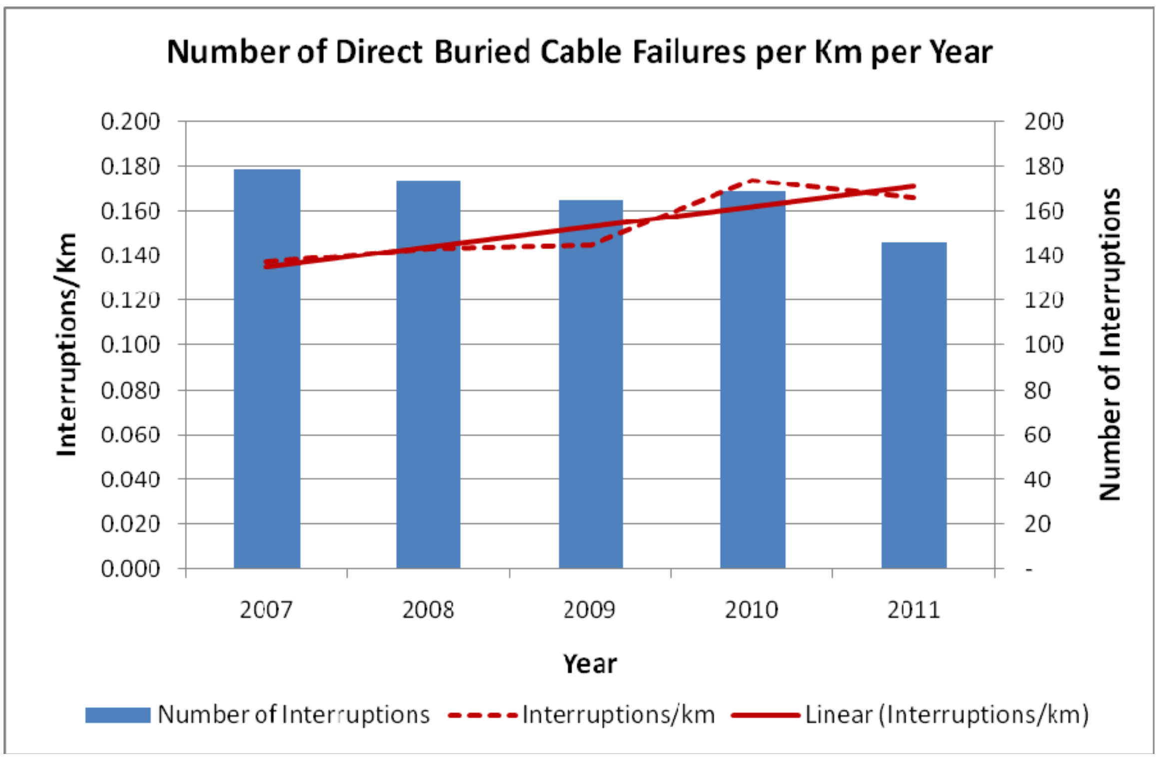
1) The Electrical Labour Cost for option 5 includes grounding and abandoning existing direct buried cable, switching, conductor stringing, primary risers and pole framing and guying.
2) The Civil Labour Cost for option 5 includes splice pits required for grounding and abandoning direct buried cable, tree trimming, pole holes, 45’ poles, delivery of poles to site, and pole installation and anchoring.

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

3) These costs are different from what was included in Table 3 in Tab 4, Schedule B1. The costs in these cells in Table 3 in Tab 4, Schedule B1 are incorrect.
4) Each faulted cable will require two splices; this price reflects the cost of two splices plus labour.
5) This is assuming that the fault is located on the first try and only one splice pit is required, otherwise multiple pits may be needed and accounted for in the repair calculations.
6) This price assumes reactive work due to a typical outage caused by pole damage due to a vehicle.
7) This repair assumes ducts are intact. If ducts have been damaged, the cost of trenching, replacing duct and cable must be added to the replacement costs noted above.

While options 1 and 3 involve lower total costs than the other options, THESL does not consider these options to be prudent, as discussed in Tab 4, Schedule B1. Options 5 and 6 have lower costs than option 4, but THESL considers option 4 to be more prudent as discussed in the responses to EP 22 (Tab 6F, Schedule 7-22) and EP 23 (Tab 6F, Schedule 7-23), as well as in Table 1 above.

The number of sustained interruptions due to direct buried cable failures has exhibited a slightly decreasing trend since 2000, mainly due to the direct buried replacement projects that have been completed since 2007. However, the number of sustained interruptions (due to direct buried cable) per kilometer of direct buried cable remaining in the system has been increasing since 2007. This is illustrated in Figure 1, and highlights the need to continue to replace direct buried cable. Approximately 887 conductor kilometres of direct buried cable remain in THESL's system, representing approximately 7% of all underground primary cable in THESL's distribution grid. Of the 887 conductor kilometres, approximately 580 conductor kilometres require immediate attention.



/C

Figure 1: Number of sustained interruptions, attributed to direct buried cable failures, per kilometer of direct buried cable remaining in the system.

In 2011, Customers Interrupted (CI) and Customer Hours Interrupted (CHI) values for direct buried cables accounted for 57% and 43% respectively of the CI and CHI for the entire underground distribution system.

- One utility reports that it does not replace service cable for underground residential distribution ("URD")[9] due to cost, unless the cable is obviously deteriorated.
- Where secondaries and services are replaced, these are usually in duct as directional boring is applied where possible.
- Utilities report that concrete-encased duct bank systems are installed for three-phase primary trunk lines or where street crossings exist. This is consistent with THESL practices.

Where concrete encased duct banks are installed to accommodate three-phase primary cable, these typically are 1x4 ducts, configured horizontally. If additional feeders are in the planning horizon, 2x4 duct bank systems may be installed. For major street crossings with three-phase lines, typically 4x4 duct banks (or larger) are installed.

One utility reports that it is installing spare conduits at road crossings when other utilities (e.g., communications utilities) are installing new lines or replacing existing communications cable. THESL has adopted a similar practice, as the impact on electric infrastructure is reviewed and coordinated with City departments, provincial agencies or other utilities when new construction is proposed or where new lines are to be installed.

[9] Often referred to as underground rural distribution by some utilities.

Table 1: Summary of Segment Costs

Project Estimate Number	Project Title	Year	Cost Estimate ($M)	
20178	Handwell Standardization and Remediation	2012	$15.84	/UF
25009	Handwell Standardization and Remediation	2013	$14.45	
~~25011~~	~~Handwell Standardization and Remediation~~	~~2014~~	~~$ 7.17~~	
Total:			**$30.3**	/UF, US

2. Why the Project is Needed Now

Handwells are among the top three structures with the highest number of contact voltage hits as assessed by mobile scanning inspections (See Section III). 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. If left untreated, the public may be exposed to the potential safety risk posed by electric shock through contact voltage from the following sources:

- Contact of exposed conductor with metallic plates and covers;
- Direct contact with exposed conductor; or
- Indirect contact through another medium
    - Concrete structures (including sidewalks)
    - Conductive salt water saturates concrete and a voltage gradient forms
    - Metallic poles

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

INTERROGATORY 27:

Reference(s): Tab 4, Sch. B3 Handwell replacements

Page 1 Lines 26-28 refer to City Moratoriums on excavating sidewalks and pavement thereby preventing THESL from replacing handwells.

a) Please provide a map showing where these moratoriums are in effect.

RESPONSE:

a) Please see the attached spreadsheet provided by the City of Toronto. The City does not provide the information in a map format.

b) How long does THESL expect the moratoriums to last?

RESPONSE:

b) Please see the Municipal Consent Requirements document, which is Appendix A to the response to EP interrogatory 22 (Tab 6F, Schedule 7-22), at pages 7 and 8 for the duration of road moratoriums.

c) Is the Electrical Safety Authority aware that THESL cannot address a potential public safety issue? If yes, what was the ESA's response and/or advice to THESL. If not, shouldn't THESL make the ESA aware?

RESPONSES TO ENERGY PROBE RESEARCH FOUNDATION INTERROGATORIES ON ISSUE 2.2

RESPONSE:

c) The Electrical Safety Authority is aware both that THESL has a handwell replacement program and that THESL is also using other mitigation measures to ensure public safety is maintained during the duration of the handwell replacement program. The ESA has not made any comment to THESL on the schedule for handwell replacement.

d) What measures can THESL take to mitigate the risks of contact voltage in areas where the handwells cannot be replaced?

RESPONSE:

d) THESL is undertaking measures such as the use of mobile surveying described on Tab 4, Schedule B3, page 9, lines 25-29.

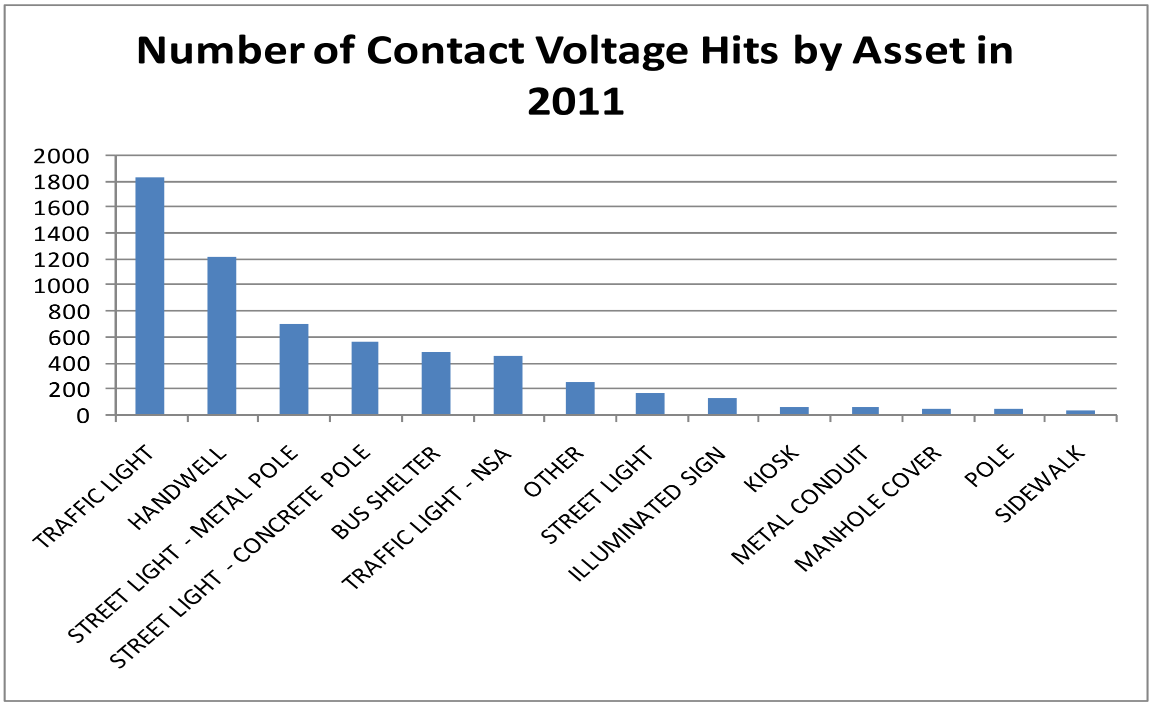


Figure 8 – 2011 Results by Asset Class

Additionally, Table 2 shows the number of energized (greater than 1 volt) handwells detected in THESL's service territory. /c

Table 2 – Number of Energized Handwells /c

Year	Numberof Energized Handwells Detected (>1 Volt)
2009	777 (Note: scanning commenced partway through 2009)
2010	1,219
2011	1,226
2012	524 (Note: includes results up to the end of March 2012)

/c

Any contact voltage occurrences that are not proactively detected through mobile scanning have the potential to harm members of the public. In 2011, there were eight recorded handwell

I EXECUTIVE SUMMARY

1. Project Description

The handwell replacement segment described in this document is required to protect the public from the potential safety risk posed by electric shocks from contact voltage. Handwells are essentially 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 and 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.

There are approximately 11,700 handwells on the THESL system. Following the Level III emergency that THESL declared in 2009 after children and pets received shocks from energized equipment, THESL began handwell replacement (See Section II, 1). By the end of 2011, THESL had replaced almost 5,600 existing handwells with new, non-conducting composite handwells (See Section II, 2). These replacements were concentrated in the downtown core because that is where both the number of handwells and the potential exposure to contact voltage are greatest.

The segment proposed in this application is to replace the remaining handwells not addressed in prior years. This segment will first target the remaining handwells in the downtown core and then replace handwells located in the surrounding areas of North York, East York, York, Etobicoke, and Scarborough. By the end of 2014, when this segment is complete, some 90 percent of handwells in the City of Toronto are expected to have been replaced. The handwells that remain to be replaced are primarily located in areas where City moratoriums prevent THESL from excavating the sidewalks or other pavement.

The following Table 1 summarizes the cost of the segment.

2. Project Scope and Cost

Handwell replacement typically involves the following tasks:

- Excavation and removal of legacy handwells
- Replacement of active handwells with non-conductive units
- Replacement of underground secondary mains cable with a superior, dual-insulation cable
- Remaking all connections in handwells to the current standard

Forecast costs are based on an average a handwell replacement cost of approximately $6,900 per unit and do not include unforeseen locations requiring remediation.

Table 4: Handwells - Summary of Project Costs /C

Project Estimate Number	Project Title	Project Year	Cost Estimate ($M)	
20178	Handwell Standardization and Remediation	2012	$15.84	/UF
25009	Handwell Standardization and Remediation	2013	$14.45	
~~25011~~	~~Handwell Standardization and Remediation~~	~~2014~~	~~$7.17~~	
Total:			**$30.3**	/UF, US

IV PREFERRED ALTERNATIVE

1. Project Description

The Handwell Replacement program will replace the above components which were installed based on previous standards with new components meeting the current standards. This work is intended to enhance public-safety by mitigating the potential risk of contact voltage through ongoing handwell replacements. This approach is preferred, as opposed to deferring the required work to some later date and not mitigating potential safety risks.

This work begins by addressing the highest risk areas in the downtown core due to higher pedestrian traffic and a greater number of handwells with a resulting concentration of contact voltage occurrences. THESL will then begin replacement in other areas of the City with handwells that are identified as not being constructed to current standards. The cost of this approach is an estimated $30.3 million to remediate about 4,665 handwells. This is expected to /UF result in replacement of the vast majority of metal handwells, thereby reducing the potential safety risk of contact voltage to the public.

The alternative to the proposed replacement program would be to replace handwells reactively when specific instances of contact voltage are identified, or if they fall within the scope of a related distribution project. While this option would defer capital expenditures, it will also result in a higher potential public safety risk. As the existing handwells continue to age and the condition of the cables within them continues to deteriorate, an increase in contact voltage occurrences is expected, further compounding the risk.

Moreover, even if this work is deferred in the short term, the existing handwells eventually will require replacement due to their deteriorated condition. Reactive replacement costs may also be higher for locations identified during contact voltage scans due to the costs of after-hours work and delays in permitting. THESL believes that it is prudent to complete this work in the near term in order to address the potential safety risk.