RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 1:

Reference(s): **Exhibit 1B, Tab 1, Schedule 1, page 1**
Exhibit 1B, Tab 1, Schedule 3 and
Ontario Energy Board ***Filing Requirements For Electricity Distribution Rate Applications – 2014 Edition for 2015 Rate Applications,*** **Chapter 3 Incentive Regulation, July 25, 2014, pp.15-16**

In the first reference, THESL states that it is applying to the Board for electricity distribution rates and other charges effective May 1, 2015 and custom Price Cap Index framework to set distribution rates for the period January 1, 2016 to December 31, 2019.

In the second reference, THESL discusses its proposed Custom Capital Factor for the years 2016 to 2019.

In the third reference, the Board discusses its ICM materiality threshold which is applied when determining incremental capital expenditures eligible for recovery in IRM years.

Please state whether or not THESL took into account any kind of materiality threshold in developing its proposed Custom Capital Factor and if not, why not.

RESPONSE:

No, Toronto Hydro did not use the Incremental Capital Module (“ICM”) materiality threshold in developing the Custom Capital (“C”) Factor. The C-factor is intended to reconcile Toronto Hydro’s significant, multi-year capital investment requirements within

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

a price cap framework. That framework is, in Toronto Hydro's view, concordant with the Board's policy as outlined in the *Renewed Regulatory Framework for Electricity* (RRFE). The C-factor is not intended to replicate an ICM mechanism. As the OEB stated in the RRFE Report (page 20): "There will not be an ICM in the Custom IR method."

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INTERROGATORY 2:

Reference(s): Exhibit 1B, Tab 1, Schedule 3, p. 6, line 3

Please provide citations or other information in the public domain that supports the claim in footnote 9 that "PEG suggests that a 10-year horizon is the minimum required for TFP indexing."

RESPONSE:

The quotation above is in reference to the discussion on page 13 of the following: Pacific Economics Group (2013), *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario*, (corrected January 24, 2014).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 3:

Reference(s): Exhibit 1B, Tab 1, Schedule 3, p. 6, lines 9-23

THESL states that, in its view, the zero productivity factor adopted by the Board for Price Cap IR contains an implicit "stretch" of 0.33 per cent since Ontario electricity distributors' TFP grew at an average rate of -0.33% over the 2002-2012 period.

a) Please state whether or not in Price Cap IR, the Board's selected inflation factor grows at the same average, annual rate as input prices for Ontario's electricity distributors, as presented in PEG's November 2013 TFP and Benchmarking report;
b) If not, please compute the historical "input price differential" (i.e. the difference between average inflation in the selected inflation factor and average inflation in industry input prices) that is implicit in the rate adjustment formula in Price Cap IR;
c) Please calculate the sum of the "input price differential" and the "implicit productivity stretch factor" in the rate adjustment formula in Price Cap IR;
d) Please state whether or not the calculation in part c implies that the "implicit" input price and productivity terms reflected in the Price Cap IR formula make it more difficult, or less difficult, for utilities to recover their cost changes over the term of an IR plan. Please explain.

RESPONSE (PREPARED BY PSE):

a) Based on the PEG November report and the Board's selected 2-Factor inflation measure, the historical 2002 to 2012 Board inflation measure did not grow at the same average annual rate as the historical 2002 to 2012 average annual growth rate of PEG's industry input price measure.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

b) The November 21, 2013 Report of the Board (page 10) shows the average annual historical growth rate from 2002 to 2012 of the 2-Factor inflation measure as 2.1%. In the PEG November 2013 report (page 22), PEG calculates input price inflation at 1.1%. The difference between these two numbers is approximately 1.0%. However, PSE disagrees with the premise of the question that this is an "implicit" input price differential in the Price Cap IR. On page 18 of PEG's November report, PEG shows that the weighted average cost of capital ("WACC") declined by an average annual growth rate of 2.86%. This decline is the primary reason for the difference in the two historical inflation measures. Only if one assumes this precipitous decline in interest rates will continue during the life of the Price Cap IR plan, should the difference be considered an "implicit" input price differential. If WACC increases over the Price Cap IR plan, then we would likely see the opposite situation, where industry input prices rise more rapidly than the Board's 2-Factor inflation index.

c) The sum of these two is 0.67%. However, as stated in part b, PSE disagrees with the premise that the historical difference of the inflation measures constitutes an "input price differential" for the rate adjustment formula in the Price Cap IR formula. This difference was driven by the decline in WACC from 2002 to 2012, which is unlikely to continue through the life of the Price Cap IR plan.

d) If industry input prices rise faster than the Price Cap IR inflation measure, then distributors will find it more difficult to recover their cost changes in the plan. Conversely, if industry input prices rise slower than the Price Cap IR inflation measure, then distributors will find it less difficult to recover their cost changes in the plan. It would not be prudent to assume the decline in interest rates seen from 2002

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to 2012 is likely to continue indefinitely. If interest rates increase from current levels, it is likely that industry input price inflation will be higher than the Price Cap IR inflation measure, making cost recovery more difficult for distributors. If interest rates decline, the opposite is true. THESL's statement referenced in the beginning of this interrogatory assumes no input price differential, which basically assumes interest rates and WACC remains constant throughout the Price Cap IR plan.

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INTERROGATORY 4:

Reference(s): **Exhibit 1B, Tab 1, Schedule 3, pages 8-13 and Ontario Energy Board, EB-2014-0219 Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module, September 18, 2014**

At the first reference, THESL discusses its proposal for a Custom Capital Factor stating that:

> The premise of the inclusion of a custom capital factor ("CCF" or "C-factor") is to reconcile the OEB's guidance that the CIR framework is best suited for utilities with significant, multi-year capital investment requirements as it is clear that the standard 4th Generation IR framework is not.

Subsequent to the filing of THESL's application, the Board introduced the Advanced Capital Module (ACM) as a new policy option for the funding of capital investments. At the second reference, the Board described the ACM as:

> a new funding mechanism that would enable review during a cost of service application for the need and prudence of any proposed incremental capital module funding requests for discrete projects that are part of a distributor's Distribution System Plan, and that are planned to come into service during the IRM period (the Advanced Capital Module or "ACM").

Please state whether or not THESL believes the ACM could replace its proposed Custom Capital Factor and why or why not this would be the case.

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RESPONSE:

In Toronto Hydro's view, the ACM is not a substitute for the Custom Capital ("C") Factor. Toronto Hydro notes the following from page 14 of the *Report of the Board, New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*:

> "[T]here must be a clear distinction between a cost of service application under the Price Cap IR option (with ACM proposals beyond the test year), and the Custom IR method. The use of an ACM is most appropriate for a distributor that:
>
> - Does not have multiple discrete projects for each of the four IR years for which it requires incremental capital funding;
> - Is not seeking funding for a series of projects that are more related to recurring capital programs for replacements or refurbishments (i.e., "business as usual" type projects); or,
> - Is not proposing to use the entire eligible incremental capital envelope available for a particular year."

Toronto Hydro's Distribution System Plan ("DSP", Exhibit 2B) comprises many "business as usual" projects that include replacing or refurbishing assets over the entire five-year CIR period. There are 22 projects in the System Renewal section of the DSP and many programs that fall under the other investment categories involve non-discretionary on-going asset replacement or refurbishment. The criteria listed above that indicate the OEB envisions that the ACM will be used in circumstances that are substantially different than those of Toronto Hydro.

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INTERROGATORY 5:

Reference(s): Exhibit 1B, Tab 1, Schedule 3, page 9, lines 1-10

a) Please state whether or not the computation of Cn depends in any way on changes in billing determinants between 2015 and 2016. Please explain;

b) If not, please state whether or not the computed Cn value of 5.15% would yield the same amount of revenue for THESL in 2016 if all of its billing determinants grew by 1% in that year compared with a scenario where all of its billing determinants grew by 2% in that year. Please explain;

c) Please explain how a C factor adjustment to allowed prices will exactly recover the Company's change in capital-related revenue requirements if the C factor does not also take account of changes in billing determinants between years.

RESPONSE:

a) Billing determinants are not an input in the calculation of C_n.

b) Irrespective of the value of $C_{n,}$ revenue generated by Toronto Hydro's proposed custom Price Cap Index ("PCI") will vary with changes in billing determinants in much the same way that revenue generated under the OEB's 4th Generation IR PCI varies with changes in billing determinants.

c) It is reasonable to expect that a utility's costs will tend to correlate with changes in billing determinants (e.g., costs tend to increase as the number of customers increases). It is therefore critical that the proposed PCI retain the characteristic of

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varying with billing determinants, which it shares with the Board's 4^{th} Generation IR PCI.

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INTERROGATORY 6:

Reference(s): **Exhibit 1B, Tab 1, Schedule 3, page 12, line 9 and Ontario Energy Board Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach October 18, 2012.**

a) Please confirm that this line is mathematically equivalent to the following:

$$PCI = (1 – Scap) * (I – X) + Cn;$$

b) Since (1 - Scap) is the share of OM&A expenses in THESL's revenue requirements, please state whether or not the formula in part a) is identical to indexing of OM&A expenses only and a cost tracker for capital expenses. Please explain;

c) Since I – X indexing applies only to the recovery of OM&A costs, please state whether or not it would be more appropriate to use OM&A partial factor productivity (PFP) trends rather than TFP trends as the basis for the X factor. Please explain;

d) In its RRFE Report, the Board (p. 8) defined "targeted rate-setting" as treating OM&A and capital separately and distinguished this from "a comprehensive approach to rate-setting" (p. 9) that recognizes the interrelationship between capital expenditures and OM&A expenditures. The RRFE report also found (p. 9) "rate-setting that is comprehensive creates stronger and more balanced incentives and is more compatible with the Board's implementation of an outcome-based framework." Table 1 on page 13 of the RRFE Report also shows that the Custom IR option must have comprehensive (i.e. capital and OM&A) coverage:

   i) Given the formula presented above in part a, please state whether or not THESL's Custom IR plan is more akin to what the Board describes in the

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RRFE Report as a targeted rather than comprehensive approach to rate-setting? Please explain;

ii) Please explain in detail how the Custom IR plan recognizes the interrelationship between capital expenditures and OM&A expenditures when the formula specifies different cost recovery mechanisms for changes in capital and OM&A costs.

RESPONSE:

a) Yes.

$PCI = I – X + C_n – S_{cap} * (I – X) = (1 – S_{cap}) * (I – X) + C_n$

b) Please see Toronto Hydro's reply to interrogatory 3-BOMA-24 on how $(1 – S_{cap})$ is not equal to S_{OMA}.

Toronto Hydro disagrees with Board Staff's characterization of the custom Price Cap Index ("PCI") as an expense/cost index. Please see further Toronto Hydro's reply to part (d) of this interrogatory on how Toronto Hydro's custom PCI is a comprehensive price cap.

With specific regard to the suggestion that Toronto Hydro's custom PCI formula "is identical to indexing OM&A expenses", Toronto Hydro notes that the Board's 4th Generation IR PCI can also be expressed in a fashion that contains a "$S_{OMA} * (I – X)$" term:

$$PCI_{4GIRM} = I – X = S_{cap} * (I – X) + S_{OMA} * (I – X) + S_{RO} * (I – X)$$

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c) Please see Toronto Hydro's reply to interrogatory 3-BOMA-24. Toronto Hydro notes that partial factor productivity is not contemplated in the OEB's report on Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors,[1] nor in the immediately preceding Pacific Economics Group report.[2] Absent further study, the appropriateness of using such an approach cannot be assessed.

d) Toronto Hydro disagrees with the suggestion that the proposed rate framework specifies different cost recovery mechanisms for changes in capital and OM&A costs. Toronto Hydro believes that the custom PCI it proposed is a comprehensive approach to rate-making in that, like the OEB's 4th Generation IR PCI, the value that is determined by the formula is applied directly to base rates. Toronto Hydro's proposed custom PCI provides for rate increases incremental to "I – X" on the basis that its capital needs require funding in excess of what "I – X" rate increases provide.

[1] Issued on November 21, 2013 and as corrected on December 4, 2013. [See EB-2010-0379]
[2] Issued on November 21, 2012 and as corrected on December 19, 2013 and January 24, 2014. [See EB-2010-0379]

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INTERROGATORY 7:

Reference(s): Exhibit 1B, Tab 2, Schedule 4, p. 8, lines 4-9

a) Please provide all available empirical support for THESL's claim that "high-value programs such as Feeder Automation and Design Enhancement…are expected to deliver significant improvements in system performance and operational efficiency for a level of annual investment that is relatively small compared to the typical renewal program;"

b) Please identify all "typical renewal programs" that THESL is referencing in this claim;

c) Please state whether or not THESL has undertaken, or is aware of, any benchmarking analysis that examines the reliability impacts resulting from its capital expenditure programs compared with similar programs undertaken in the industry. If so, please provide copies of all such benchmarking analyses.

RESPONSE:

a) System performance and operational efficiency improvements for Feeder Automation and Design Enhancement are further described in detail below:

Feeder Automation

- **System Performance:** Feeder Automation improves system performance by reducing the impact of outages to the average customer; by installing automating switches on the trunk circuit in the horseshoe system, and remote operated switches in the URD. Figure 4 in Section E7.3.2.1 of Toronto Hydro's

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Distribution System Plan (Exhibit 2B, Section E7.3, Page 11, Figure 4) illustrates that a potential savings of 54% CI and 49% CHI can be achieved if feeder automation was implemented on the associated feeders contained within the program. Table 5 within Section E7.3.3.1 of the Distribution System Plan (Exhibit 2B, Section E7.3, Page 26, Table 5) illustrates that the URD has the longest average outage duration in Toronto Hydro's distribution system mainly because the system is underground making it difficult to detect faults as field crews are required to manually perform these tasks. Automation is expected to improve this by providing the control room the ability to detect and isolate the fault, and restore service to the remaining (non-isolated) portions of the feeder.

- **Operational Efficiency:** Feeder automation would automatically fault detect, isolate, and restore the feeder in under a minute, providing more efficient use of control room resources, and reducing rollout times for field crews by narrowing down the fault location. This can be seen in section E7.3.3.1 Page 19 Table 4.

__Design Enhancement__

- **System Performance:** Installing fuses on redundant trunks prevents unnecessary breaker lockouts and limits the impact of a sustained outage to a localized set of customers (i.e., decreases number of customers interrupted). Upgrading of undersized fusing prevents the premature operation of an undersized fuse, which will result in a sustained interruption downstream that would have typically been cleared by a momentary breaker re-closure (i.e., decreases sustained lateral interruptions). Alignment of mis-coordinated laterals would reduce the number of customer affected during an outage by containing faults downstream of a sub-fuse (i.e., decreases number of customers interrupted). Finally, the installation of tree-

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proof conductor can reduce the frequency of momentary and sustained tree contact interruptions.

- **Operational Efficiency:** By installing fuses on redundant trunks, complications associated with the restoration of trunk outages in terms of fault locating and switching operations can be reduced. Upgrading undersized fuses eliminates the need for Toronto Hydro field crew workers to be called out for an otherwise unnecessary fuse unit replacement. Tree proof conductor installed along feeder trunk circuits that are located in heavily treed areas can prevent complications associated with sustained outage restoration in terms of fault locating and switching operations (especially during adverse weather conditions).

Since the initial deployment of Feeder Automation on ten feeders, the scheme has been able to mitigate over 6,000 CHI and over 25,000 CI.

b) "Typical" renewal programs would include Overhead and Underground Circuit Renewal respectively.

c) Toronto Hydro has not undertaken, nor is it aware of, any benchmarking analysis with respect to these capital investment programs.

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INTERROGATORY 8:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, p. 11, line 4

Please provide all evidence where "the OEB acknowledged the outlier status of Toronto Hydro in the Ontario context." Please provide specific citations to Board Reports or other official documents.

RESPONSE:

Please see the following passage (emphasis added, footnote location, content and sequencing preserved; however, the original footnote numbering could not be replicated).

Reference: Ontario Energy Board, Report of the Board: *Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*, (Issued on November 21, 2013 and as corrected on December 4), 2013, at page 14:

> As detailed in the May 2013 Updated PEG Report, PEG calculated TFP trends using an index-based approach on Ontario data for the period 2002-2011.[1] PEG noted the results of the analysis were being materially impacted by ***outliers*** [2], Toronto Hydro and Hydro One, and recommended that the data for the two companies be excluded from the industry

[1] PEG has subsequently updated this analysis to include 2012 data, and those results are presented further below.

[2] An outlier is a value that "lies outside" (is much smaller or larger than) most of the other values in a set of data.

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> calculation. ***The Board agrees with PEG that an industry productivity measure reflective of 73*** [3] ***distributors operating in Ontario should not be materially impacted by only two distributors, and therefore will exclude the two outliers in the industry calculation***. Furthermore, the Board is of the view that for ***as long as they remain outliers***, these distributors should be excluded from the Industry TFP data set. [emphasis added]

[3] Four distributors are excluded from PEG's analysis because their RRR data is not available: Attawapiskat First Nation; Fort Albany First Nation; Kashechewan First Nation; and Hydro One Remote Communities Inc.

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INTERROGATORY 9:

Reference(s): **Exhibit 1B, Tab 2, Schedule 5, p. 14 lines20-23**

a) Please provide a citation to the section(s) of the PSE report that "confirmed" the amount of productivity/efficiency gains achieved by THESL in the years preceding the Custom IR application;

b) Please provide the quantitative values of THESL's productivity/efficiency gains, by year, as confirmed by PSE.

RESPONSE:

a) Please see page 34, Table 5 of the updated PSE Report (Exhibit 1B, Tab 2, Schedule 5). The referenced table showcases the 2010-2012 average of Toronto Hydro's actual historical costs, as compared to the average of model-predicted costs for Toronto Hydro for the same years. The difference (-21.5%) between Toronto Hydro's actual costs and those predicted by the model are the productivity/efficiency gains referenced in the cited passage.

b) Please see page 34, Table 6 of the updated PSE report (Exhibit 1B, Tab 2, Schedule 5).

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INTERROGATORY 10:

Reference(s): **Exhibit 1B, Tab 2, Schedule 5, App. B, p. 6**

At the above reference, PSE says that it "gathered U.S. data on utilities' non-normalized reliability indexes and their sustained outage definitions from publicly-available regulatory filings."

a) Please identify the data source (e.g., the precise "regulatory filing" or report) for SAIFI and SAIDI data for each year, for every US utility, in PSE's US reliability benchmarking sample;
b) Please identify all SAIFI and SAIDI data in PSE's US reliability database that were interpolated, adjusted or otherwise modified compared to what was reported in the publicly-available regulatory filings. Please also explain the rationale for each such adjustment of the source data.

RESPONSE (PREPARED BY PSE):

a) Please see the file named 1B-OEBStaff-10.zip provided separately on a disk along with other large size files related to PSE requests (1B-BOMA-87.zip and 1B-OEBSTAFF-14.zip). Please note that not all data sources continue to be available on websites or could be located by PSE, in the limited time to respond.

b) PSE did not interpolate, adjust, or otherwise modify data compared to what was reported in the publically available regulatory filings. In some cases, PSE did calculate SAIDI if only SAIFI and CAIDI were reported using the equation SAIDI = SAIFI * CAIDI.

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INTERROGATORY 11:

Reference(s): **Exhibit 1B, Tab 2, Schedule 5, App. B, p. 8**

Footnote 9 of the above reference states regarding Toronto Hydro's proposed capital spending program that "…reliability is a large portion of the rationale, and is the 'output' of the capital spending program that most readily lends itself to be benchmarked and evaluated."

a) Please state whether or not PSE has ever undertaken any analysis that benchmarks reliability as an "output of the capital spending program" of an electric utility;
b) If so, please provide a copy of all such analyses (report, dataset, computer programs, spreadsheets, and testimony) that evaluate the cost effectiveness of reliability projects that PSE has undertaken and/or testified in support of;
c) Please state whether or not the reliability performance of Toronto Hydro's capital spending plan (e.g. the expected SAIDI improvement resulting from Toronto Hydro's 2015-2019 capital spending) can be benchmarked using these models. Please explain in detail;
d) If so, please use the PSE model(s) to project:
   i) The expected change in SAIDI resulting from Toronto Hydro's 2015-2019 capital spending program;
   ii) The expected change in SAIFI resulting from Toronto Hydro's 2015-2019 capital spending program;
e) Given the output from part d, please provide PSE's estimate of:
   iii) The expected cost per minute of SAIDI change from Toronto Hydro's 2015-2019 capital spending program;

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iv) The expected cost per change in SAIFI from Toronto Hydro's 2015-2019 capital spending program.

RESPONSE (PREPARED BY PSE):

a) Yes, PSE has undertaken an analysis that benchmarks reliability as an "output of the capital spending program". This analysis was conducted and testified to by Mr. Steve Fenrick in rebuttal testimony in the Application of Wisconsin Public Service Corporation for its System Modernization and Reliability Project. The case number is 6690-CE-198.

b) A copy of the testimony in this case is provided as Appendix A to this response (Pre-filed Rebuttal Testimony of Steven A. Fenrick, dated April 23, 2013). The computer code, datasets, and spreadsheets contain confidential information. PSE signed a confidentiality agreement that does not permit us to share these items with outside parties.

c) It is certainly possible that a similar modeling approach could be used to benchmark the reliability benefit of Toronto Hydro's plan, although the models themselves might change. PSE's modeling approach in the WPS testimony focused on SAIDI improvement, while Toronto Hydro's capital spending plan has other reasons beyond improving SAIDI, notably SAIFI and safety improvement.

d) PSE's scope of work involved fulfilling the Board's RRFE requirements of providing external benchmarking of the historical and forecasted cost levels of Toronto Hydro's costs. PSE also provided reliability benchmarking to provide the Board with an

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accurate depiction of Toronto Hydro's reliability metrics against those of other utilities. PSE did not conduct the modeling referred to in this question for Toronto Hydro. Toronto Hydro was not included in the models put together for WPS, and properly inserting Toronto Hydro and conducting the analysis for the company would require several weeks' worth of effort.

e) Please see the response to part d.

BEFORE THE
PUBLIC SERVICE COMMISSION
OF WISCONSIN

Application of Wisconsin Public Service Corporation for its System Modernization and Reliability Project — 6690-CE-198

PRE-FILED REBUTTAL TESTIMONY OF

STEVEN A. FENRICK

FOR
WISCONSIN PUBLIC SERVICE CORPORATION

April 23, 2013

INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven A. Fenrick. My business address is 1532 West Broadway, Madison, Wisconsin 53713.

Q. By whom are you employed and in what capacity?

A. I am employed by Power System Engineering, Inc. Power System Engineering was founded in 1974 and is a full-service consulting firm serving the utility industry. My title at Power System Engineering is "Leader, Benchmarking & Economic Studies." I supervise the cost and reliability benchmarking and statistical cost research practice areas at Power System Engineering.

Q. What are your responsibilities with Power System Engineering?

A. I am responsible for energy utility performance benchmarking, productivity analysis, value-based reliability planning, statistical cost modeling, and demand side management economic analysis. The group I head works with regulatory commissions, utilities, and consumer advocate clients to provide economic and statistical analysis. Our benchmarking practice has examined the cost and reliability performance of over a hundred utilities. Part of our benchmarking research includes examining the trade-offs and proper balancing of reliability and cost levels for electric utilities.

Q. Please briefly describe your educational and professional background as it relates to this project.

A. I have a B.S. degree in Economics from the University of Wisconsin-Madison. I also received an M.S. degree in Agriculture and Applied Economics from the University of Wisconsin-Madison. I have worked at Power System Engineering since 2009. I initiated the benchmarking and statistical cost research practice areas at the company. Before starting at Power System Engineering, I was at Pacific Economics Group from 2001 until 2009, where I served as an Economist and later as a Senior Economist. I have published a number of academic journal articles on reliability benchmarking and statistical cost research. I regularly work with utilities, regulators, and consumer advocacy groups in conducting benchmark evaluations. These evaluations are used both for regulatory purposes and for internal management improvement initiatives.

Q. What is the purpose of your testimony?

A. I am responding to points made by Mr. Hahn in his pre-filed direct testimony. More specifically, Wisconsin Public Service Corporation (WPS) asked me to conduct a capital cost performance analysis related to the SMRP, and I am providing the results of that analysis.

Q. On Direct-CUB-Hahn-8c, Mr. Hahn states that SMRP will cost "more than $2.6 million per minute of outage reduced" and goes on to note that "[t]his seems like an extraordinarily high figure." Do you agree?

A. No. The cost per minute of outage reduced is not high by industry standards. In fact, the opposite is true. SMRP is less expensive on a cost per minute of outage reduced basis when compared to industry-wide metrics.

Q. What is your opinion based upon?

A. My opinion is based on the SAIDI impact benchmark result. This result is derived from a model I developed to address and evaluate the cost-effectiveness of reliability projects. I have used similar models in a number of different settings to estimate reliability and cost performance and to assist in the evaluation of the cost-effectiveness of utility reliability-driven projects.

Q. Please generally explain how you conducted your analysis.

A. The process involved a comparison of the estimated SMRP capital cost and expected SAIDI performance to industry-wide benchmark levels determined using two econometric models. The first, a SAIDI econometric model, examines the impact of utilities' capital cost levels on SAIDI values after controlling for the effects of other factors that influence SAIDI. These factors include the level of forestation of a service territory, customer density and weather conditions. Utilities that have high capital costs relative to the industry-wide benchmark values tend to have better SAIDI values. The capital cost levels used in the SAIDI model are actually capital cost performance scores obtained from another econometric model, which we call the capital cost model. The capital cost model develops capital cost performance scores by considering factors that affect cost but are outside the control of utilities.

Q. Are the models based on industry-wide data?

A. Yes. The capital cost benchmark model includes data from 96 U.S. investor owned utilities (IOUs) for the years 2002-2011. The SAIDI impact model includes data from 52 IOUs for the years 2002-2011. These utilities were the ones for which the requisite data were available. The capital cost data is mostly gathered from FERC Form 1s filed annually by IOUs. The SAIDI data is gathered by Power System Engineering through publicly-available regulatory filings of reliability.

Q. What inputs do your models generally consider?

A. In general, model inputs consider business conditions that are known to affect capital cost of electricity distribution and SAIDI. Three categories of variables are considered for the capital cost model: output, prices and "other" business condition variables. These include the number of customers served, line miles and retail deliveries; the price of capital; and the level of vertical integration and output diversification. The variables considered for the SAIDI model include the level of service territory forestation, customer density, weather and the capital cost performance scores.

Q. What did the models find relative to the interaction between SAIDI improvement and capital spending?

A. The capital cost elasticity of SAIDI is -0.285, such that a one percent increase in the capital score (increased capital spending of one percent) results in a 0.285 percent reduction in SAIDI. In other words, when a utility increases its capital spending by one percent, it is expected to see a SAIDI improvement equal to approximately 0.285%. This finding is quite logical and is statistically significant at a 90 percent confidence level. In the context of the SMRP, WPS is proposing to increase its distribution capital costs by approximately 43 percent. Our models predict that the industry-wide average SAIDI improvement associated with such spending would be approximately 12%. Yet WPS is expecting a SAIDI improvement of around 20 to 25 percent (which is between 67 and 84 minutes). Put another way, the industry-wide average cost per minute of outage reduction for a project of this size would be $5 million, and SMRP ranges from about $2.6 - $3.3 million per minute of outage reduction. SMRP is therefore very cost-effective and is expected to deliver twice the benefit that our industry-wide model predicts. The SMRP offers strong reliability benefits for the money spent.

Q. Mr. Hahn also argues that the project should be conducted over a ten year period rather than a five year period, do you agree?

A. Given WPS's current need for improved reliability and the cost-effectiveness of the SMRP based on our SAIDI improvement benchmark analysis, it is my opinion that the project should be implemented as soon as possible. Spreading out the project over a longer time frame would delay the realization of cost-effective reliability improvements to the customers of WPS.

Q. Does this complete your rebuttal testimony?

A. Yes.

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INTERROGATORY 12:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, App. B, page 16

a) Please state whether or not kWh was statistically significant but with a negative sign in any of PSE's benchmarking models;

b) If so, please state whether or not this result raised any concerns about PSE's benchmarking approach. Please explain.

RESPONSE (PREPARED BY PSE):

a) kWh was positive in both the combined data and U.S.-only data models. It was not, however, found to be statistically significant in the combined total cost model, but was positive and statistically significant in the U.S.-only model.

b) This finding raises no concerns about PSE's benchmarking approach. The kWh variable is not featured because it was not statistically significant in the combined model, and we wanted consistency in outputs between models; furthermore, PSE believes that peak demand (kW) captures the cost impact of energy use far better than volume (kWh). As PSE states on page 16 of the PSE Report, "PSE believes that energy delivered will have minimal to no impact on distribution total costs." PSE's models support that belief.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 13:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, App. B, pp. 16-17

a) Please state whether or not PSE expressed non-labour OM&A prices in a common currency (using PPP exchange rates) but expressed labour prices for Ontario electricity distributors in Canadian dollars and labour prices for US electricity distributors in US dollars;

b) If so, please state whether or not PSE is concerned about the asymmetric treatment of labour and non-labour OM&A prices in its study. Please explain why or why not in detail;

c) Please provide all other calculations PSE involved, if any, to create a "price patch" linking input price levels in Ontario to input prices in the US.

RESPONSE (PREPARED BY PSE):

a) All input prices are stated in the same currency as the corresponding cost data. In the case of the non-labour OM&A input price, PSE used the PPP exchange rates to put input prices in terms of Canadian dollars for the Canadian distributors in the sample. All Canadian distributors have input prices (non-labour, labour, and capital) stated in Canadian dollars. All U.S. distributors have input prices (non-labour, labour, and capital) stated in U.S. dollars. The currency for costs matches the input prices for each distributor to assure consistency in the study.

b) As stated in part a, there is no asymmetric treatment of labour and non-labour OM&A prices in the study.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

c) No other calculations are used.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 14:

Reference(s): **Exhibit 1B, Tab 2, Schedule 5, App. B, p. 19**

For each of the variables listed on Table 2 of the PSE report, please provide in electronic form the following information:

a) The source data necessary to construct the values PSE provided for each company in the US sample. For the purpose of this request, "source data" is meant to be account level FERC Form 1 data or other data that is employed prior to any calculations or data manipulations by PSE;

b) The formulas used to calculate each variable from the source data. This can be provided in either a spreadsheet or program code;

c) Information to allow the identification of companies, variables, and mapping of companies to geographical regions where applicable;

d) If not provided above, please provide in electronic form the data (and identified data sources) and formulas used to adjust the Prices of Capital and OM&A inputs to reflect differences in US and Canadian currencies.

RESPONSE (PREPARED BY PSE):

a) All of the source data files are provided in the file named 1B-OEBStaff-14.zip.

a) The SST computer program produces the variable calculations for each variable. The SST code used can be found in the file named 1B-OEBStaff-14.zip; it is named "TH2012_update.prg" (due to its size and format, this attachment is being filed separately along with other large size files related to PSE requests (1B-OEBStaff-

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

10.zip and 1B-BOMA-87.zip). Due to its proprietary nature, this information is being filed confidentially, in accordance with the OEB's *Rules of Practice and Procedure*, and the OEB's *Practice Direction on Confidential Filings.*

b) Two ID identification maps are included in the folder referenced in part a). The first one named "US_map.xls" provides the identification of the U.S. utilities by SNL ID. The second map is named "Ontario_map.xls" and provides the identification of the Ontario utilities by the same "pegid" used by PEG in the 4th Generation IR proceeding (EB-2010-0379). The data elements used to construct the variables in the study can be found in "Data_Descriptions"; this file can be found in the same folder referenced in part a), 1B-OEBStaff-14.zip.

c) All data and formulas are included in the SST code and source data.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 15:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, App. B, p. 29

PSE states that it was provided with projections of non-coincident peaks at the substation level but they were adjusted based on the ratio of the coincident peak demand of the THESL system and the sum of the non-coincident substation peak demands. Please provide a spreadsheet showing all the details of this calculation, including supplementary analyses that may enter into this computation.

RESPONSE (PREPARED BY PSE):

Please see the included spreadsheet "2015 to 2019 peak load final (filename 1B_OEBStaff_15.xlsx) showing the details of this calculation.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 16:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, App. B, p. 31

Table 4 of the above reference includes estimates of cost function parameters with two outputs, estimated using the US-Ontario sample. The cost elasticity for the customers output is 0.967 and the cost elasticity for the peak demand output is 0.114. The sum of the two cost elasticities is therefore 1.081.

a) Please confirm that when the sum of all output elasticities in an econometric cost model exceeds a value of 1 it indicates that there are *diseconomies* of scale for the mean firm in the sample;

b) Please also confirm that, all else equal, when diseconomies of scale exist for the mean sample firm, unit costs of production for that firm would be decreased if its output decreased;

c) Please state whether or not it is reasonable to conclude that there are diseconomies of scale for a US-Ontario sample of electricity distributors. Please explain, particularly with respect to the magnitude of output for the average Ontario distributor;

d) Please state whether or not the finding of diseconomies of scale for a US-Ontario sample evidence would be an indication of deeper problems with PSE's econometric model and its ability to provide rigorous inferences on distributor efficiency. Please explain.

RESPONSE (PREPARED BY PSE):

a) Yes, the model coefficients would indicate diseconomies of scale at the sample mean when the sum of the first order output coefficients is greater than one.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

b) All else being equal, that is what the model coefficients would indicate.

c) The fact that the mean firm shows diseconomies of scale does not by itself necessarily indicate that any particular utility or subset of utilities within the sample shows diseconomies of scale.

d) This finding does not constitute evidence for any type of deeper problems with the model. The translog cost function is a flexible functional form that allows the data to "speak for itself" on this issue.[1] The Board preferred the translog cost function when benchmarking distributors.[2] In the 4th Generation Incentive Regulation proceeding (EB-2010-0379) the issue of functional forms arose. In some cases PEG's estimated translog cost model produced non-intuitive results, such as negative output cost elasticities (i.e., if an output increased the model coefficients inferred cost would actually decrease). Despite these results, the Board preferred this approach, which is why PSE used that same approach in the PSE study.

[1] Similar views were expressed by the Board Staff's expert witness, Dr. Kaufmann, in EB-2010-0379. Please see the transcript of the stakeholder conference on May 28, 2013, volume 2, starting on page 77.
[2] Please see the Report of the Board dated November 21, 2013 in EB-2010-0379, pages 23 and 24.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 17:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, App. B, p. 33

PSE states at the above reference that "…prior to 2007 the company was consistently near 30% below benchmark expectations. This is suggestive that the company's capital was in need of investment."

a) Please state whether or not the purpose of PSE's cost benchmarking model is to make valid inferences on the cost efficiency of Toronto Hydro;
b) If so, please state why actual costs being consistently below benchmark costs are "suggestive" that Toronto Hydro is not investing enough, rather than a finding that Toronto Hydro is highly efficient. Please explain in detail;
c) Please state the criteria PSE would use to discriminate between the hypotheses that management has 1) under-invested; or 2) been highly cost versus efficient; when its cost benchmarking analysis finds the actual costs of a distributor are below its expected costs. Please explain in detail;
d) Please state whether or not PSE has applied those criteria in this report. Please explain with specific reference to PSE's econometric benchmarking results (i.e. actual versus predicted costs) for Toronto Hydro in: 1) 2007; 2) 2013; and 3) 2019.

RESPONSE (PREPARED BY PSE):

a) As stated on page 1 of the referenced PSE report: "The purpose of PSE's benchmarking analysis is to evaluate the reasonableness of Toronto Hydro's historical and projected total cost amounts and system reliability metrics."

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

b) This question presents a false dichotomy; a utility could be efficient and at the same time have a need for more capital investment. The combination of the total cost benchmarking result and the SAIFI benchmarking result does suggest the need for more capital investment. Toronto Hydro's total costs are below benchmark model expectations and the frequency of outages is higher than benchmark model expectations. Capital investment should move Toronto Hydro closer to benchmark expectations in both of those categories.

c) PSE was not tasked with explicitly evaluating Toronto Hydro's efficiency. PSE has only concluded that capital investment is likely to move Toronto Hydro closer to benchmark expectations in total costs and frequency of outages. Please also refer to the response for part b) of this question.

d) PSE did benchmark the reliability performance of Toronto Hydro along with the cost benchmarking in all of the years requested. Please see page 50, Table 15, of the PSE Report for those results.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 18:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, App. B, p. 37

Table 7 of the above reference includes estimates of cost function parameters with two outputs, estimated using the US plus THESL sample. The cost elasticity for the customers output is 0.732 and the cost elasticity for the peak demand output is 0.220. The sum of the two cost elasticities is therefore 0.952.

a) The sum of the output elasticities (0.952) in the US plus Toronto Hydro sample is lower than the sum of output elasticities (1.081) in the US plus Ontario sample. Please state whether all else being equal, this result implies that there are greater economies of scale at the sample mean in a US plus THESL sample than in the US plus all Ontario sample. Please explain;

b) Please state whether or not the result in part a) is reasonable given that the average size of most Ontario distributors is much smaller than the average size of utilities in the US sample. Please explain.

RESPONSE (PREPARED BY PSE):

a) Yes, the model coefficients imply this.

b) Please see response to interrogatory 1B-OEBStaff-16.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 19:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, App. B, page 37

a) Please state why the U.S.-Toronto sample does not include customer density as an independent variable. Please explain in detail;

b) In the context of a), please discuss whether or not Toronto Hydro's rationale for expanding its benchmarking sample to include U.S. utilities depended largely on the issue of customer density, particularly the need to include more utilities (like Toronto Hydro) that served very dense urban areas. Please explain;

c) If the answer to b) is yes, please state whether or not customer density is at least as important a cost driver in the U.S. sample as in the U.S.-Ontario sample. Please explain.

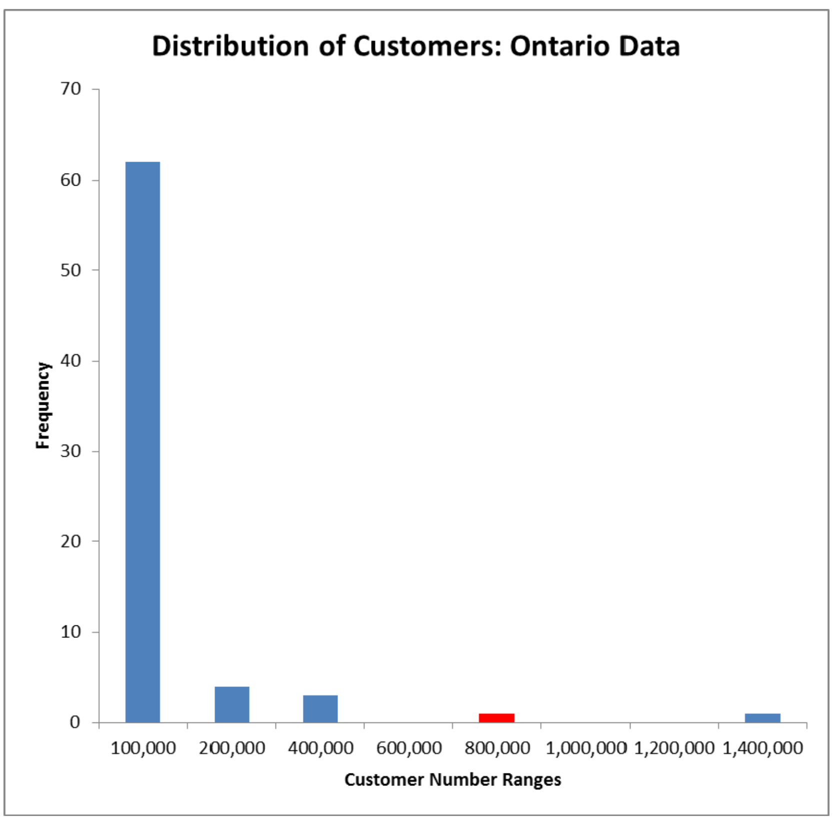
RESPONSE (PREPARED BY PSE):

a) The U.S.-Toronto model does not include the customer density variable because it has the wrong sign; the coefficient is positive, which does not align with a priori theory that it should have a negative sign.

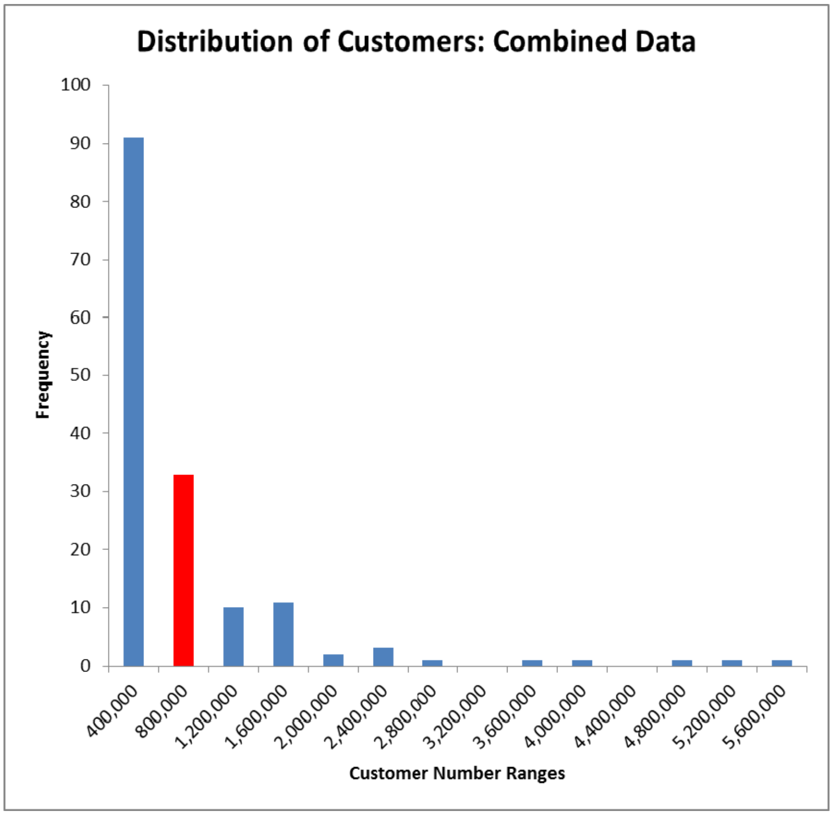
b) The rationale for expanding the sample was not dependent on customer density. PSE used data from U.S. utilities in order to include: (1) utilities that serve very dense urban core areas, and (2) those that are similarly sized in terms of both the number of customers served and peak demand. Thus, while the U.S. sample includes utilities that serve dense urban cores, it also includes those that are large both in terms of the number of customers they serve and the peak demand that they meet. For a further

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

explanation of why the U.S. utilities are necessary for an accurate benchmarking evaluation of Toronto Hydro please refer to Chapter 6 in the PSE Report entitled, "Importance of U.S. Data for Benchmarking Toronto Hydro." In this chapter PSE shows a number of graphs comparing the total costs, number of customers, and peak demands of Toronto Hydro, the U.S. data, and Ontario data. Toronto Hydro is an obvious outlier when compared only to Ontario data (see first graphic below, Toronto Hydro denoted in red). These differences are addressed when U.S. data is included in the analysis (see second graphic). Similar results occur when peak demand is examined.



RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES



c) As stated in part b, the rationale for including U.S. utilities in the benchmarking sample is not dependent on customer density.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 20:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, App. B, p. 42

It is well-known that electric utilities often underground assets in an effort to reduce outages. PSE's cost benchmarking model also included the percentage of plant underground as an independent variable in its US-THESL sample.

a) Please state whether or not PSE investigated whether the share of electricity distribution plant underground was a statistically significant driver of measured SAIDI in its US-THESL sample. If so, please provide the relevant econometric results;

b) Please state whether or not PSE investigated whether the share of electricity distribution plant underground was a statistically significant driver of measured SAIFI in its US-THESL sample. If so, please provide the relevant econometric results;

c) If PSE did not investigate whether an undergrounding variable was statistically significant in its reliability benchmarking models, please state whether or not it would be concerned that those models are characterized by omitted variable bias, since they would not take into account one of the most important business decisions utilities make to reduce outages. Please explain in detail.

RESPONSE (PREPARED BY PSE):

a) PSE investigated the "percent underground" variable, but PSE could not include it in the combined sample due to the unavailability of data regarding underground plant in service for all of the Ontario utilities. PSE hesitated to include it as an explanatory

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

variable, because it can be seen as a management decision variable rather than an externally-derived condition. Given that including the variable did not directionally change results (in fact, including it made the need capital spending to address SAIFI increase), PSE decided to remain conservative and avoid including a controversial variable. However, we have performed the econometric runs and provided results below for both models. When percent underground plant is included in the U.S. models for SAIFI and SAIDI, the results are quite similar to the PSE report. With either the original models or the ones with percent undergrounding included, THESL's SAIFI is considerably higher than benchmarks, with a convergence towards the benchmarks during the Custom IR period. Likewise, both models show SAIDI performance being considerably below benchmark values for most years, including the Custom IR period. Regardless of which model was determined to be the most appropriate, it would not change PSE's conclusions. The U.S. reliability models with percent plant undergrounding included are provided for review. The SAIDI model is titled "1B_01_OEBStaff_020 SAIDI with PCTUG" and the SAIFI model is titled "1B_01_OEBStaff_020 SAIFI with PCTUG"; these are provided as Appendices A and B to this response. The table below shows the original % difference in SAIFI and SAIDI using both models.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

Year	SAIDI % Difference (Underground Model)	SAIDI % Difference (Original Model)	SAIFI % Difference (Underground Model)	SAIFI % Difference (Original Model)
2005	-22%	-48%	+80%	+63
2006	-45%	-70%	+96%	+80
2007	-34%	-56%	+97%	+83
2008	-80%	-103%	+69%	+54
2009	+5%	-19%	+76%	+62
2010	-46%	-71%	+85%	+74
2011	-72%	-100%	+54%	+37
2012	-73%	-106%	+56%	+38
2013	+177%	+145%	+113%	+95
2014	-113%	-145%	+51%	+33
2015	-116%	-145%	+48%	+31
2016	-126%	-155%	+40%	+24
2017	-136%	-163%	+33%	+18
2018	-145%	-171%	+25%	+11
2019	-156%	-181%	+18%	+4

b) Please see answer to part a.

c) Both the original models and models with percent undergrounding provide similar results and lead to the same conclusions. In both models, THESL's SAIFI is consistently above benchmark expectations and the Custom IR investments are projected to move THESL's SAIFI towards benchmark values (closer to 0.0% in the table above). If the models with undergrounding are deemed to be more appropriate, this would only enhance the need for investment to address SAIFI deficiencies. Furthermore, in both models, THESL's SAIDI is considerably below benchmarks, and this remains the case throughout the Custom IR period.

```
» run C:\work\THESL2\Specification\SAIDI.prg;
********************************************************************************

                RELIABILITY MODELS

10/22/2014      OUTPUT FILE: C:\work\THESL2\results\SAIDI          15:06:40

                Output using the data set C:\work\THESL2\th_benchb_July7_orig.xlsx

********************************************************************************

                                DEFINITIONS OF VARIABLES:

                                        var1 is const

                                        var2 is Retail Customers (yn)

                                        var3 is sum of wind days base 10kts

                                        var4 is customer/dx miles (UDI)

                                        var5 is % forestation using GIS area1

                    Time period used: 2002 through 2012


   391.000
                    REGRESSION WITH GROUPWISE HETEROSKEDASTICITY

Valid cases:                      384      Dependent variable:           LSAIDI_A
Total SS:                     386.507      Degrees of freedom:                373
R-squared:                      0.242      Rbar-squared:                    0.222
Residual SS:                  292.893      Std error of est:                0.886
F(11,373):                     10.838      Probability of F:                0.000
Durbin-Watson:                  1.692      Number of Firms:                47.000

                           Standard                    Prob   Standardized  Cor with
Variable     Estimate       Error      t-value        >|t|     Estimate    Dep Var
--------------------------------------------------------------------------------
CONST        5.274122    0.083280   63.329889      0.000    0.965585    0.989449
LYN          0.087492    0.036213    2.416037      0.016    0.016447   -0.300647
LWDD10       0.258075    0.087113    2.962532      0.003    0.028829   -0.258033
LDENSITY     0.351446    0.099452    3.533817      0.000    0.027489   -0.304720
LPFGIS1      0.340408    0.115168    2.955748      0.003    0.034851   -0.341361
LPCTUG      -0.847851    0.119022   -7.123510      0.000   -0.092254   -0.465222
LWDD10SQ     0.272945    0.145036    1.881915      0.061    0.023046    0.367507
LDENSQ      -2.089994    0.348854   -5.991036      0.000   -0.054367    0.602588
LPFGISSQ    -0.188426    0.301355   -0.625264      0.532   -0.009353    0.531964
LPCTUG2     -0.145946    0.197559   -0.738747      0.461   -0.008496    0.585582
TREND        0.052587    0.010353    5.079302      0.000    0.063882    0.896600


        OUT-OF-SAMPLE PREDICTION OF RELIABILITY LEVEL PERFORMANCE LAST THREE YEARS


    Actual     Predicted Difference  t_ratio     p_value    Utility

  4.469494   5.787882  -1.318388  -2.563080   0.005383        Indianapolis Power & Light Co
  5.026624   6.191716  -1.165092  -2.232282   0.013094        Southern California Edison Co
  4.496515   5.625676  -1.129161  -2.145987   0.016259        Florida Power & Light Co
  4.687669   5.671246  -0.983578  -1.542131   0.061944        Tampa Electric Co
  4.733827   5.714127  -0.980300  -1.097476   0.136570        Florida Power Corp
  5.302734   6.161111  -0.858377  -1.628762   0.052103        Gulf Power Co
  4.394298   5.134801  -0.740503  -1.410076   0.079674        Wisconsin Electric Power Co
(WEPCO)
  5.158899   5.831033  -0.672134  -1.276897   0.101215        AmerenUE
  3.981867   4.634143  -0.652276  -1.270195   0.102402        Madison Gas and Electric Co
  4.517652   5.152865  -0.635213  -1.169907   0.121392        TORONTO HYDRO-ELECTRIC SYSTEM
LIMITED
```

4.860706	5.419517	-0.558811	-1.086376	0.139006	Rochester Gas and Electric Corp
5.353206	5.848806	-0.495600	-0.962652	0.168172	Pacific Gas and Electric Co
5.603710	6.068234	-0.464524	-0.886431	0.187978	Ohio Edison Co (First Energy)
5.240363	5.641710	-0.401347	-0.765992	0.222082	Portland General Electric Co
5.287357	5.678407	-0.391050	-0.744947	0.228386	Entergy Arkansas Inc
5.759316	6.007254	-0.247938	-0.472625	0.318378	Cleveland Electric Illuminating Co (First Energy)
5.711924	5.932199	-0.220275	-0.420798	0.337072	Green Mountain Power Corp
4.946763	5.125701	-0.178939	-0.348358	0.363884	Wisconsin Power and Light Co
5.292851	5.408159	-0.115308	-0.219838	0.413059	Niagara Mohawk Power Corp (National Grid)
5.697999	5.782127	-0.084128	-0.163442	0.435129	PSI Energy Inc (Duke Energy IN)
6.697521	6.753901	-0.056380	-0.107485	0.457231	Central Maine Power Co
5.276219	5.254235	0.021983	0.042688	0.482987	Southern Indiana Gas and Electric Co (Vectern)
6.290832	6.255495	0.035337	0.068692	0.472636	Consumers Energy Company
5.109422	4.959376	0.150046	0.290522	0.385789	Avista Corp
5.175708	5.011278	0.164430	0.313298	0.377115	Kansas City Power & Light Co (MO)
6.066628	5.845391	0.221236	0.429547	0.333886	Northern Indiana Public Service Co
6.227470	5.966896	0.260574	0.503015	0.307625	Orange and Rockland Utilities Inc (O&R)
6.360216	6.086725	0.273491	0.521629	0.301119	Ohio Power Co (AEP)
5.814559	5.489611	0.324948	0.619005	0.268145	Virginia Electric and Power Co
6.053607	5.694377	0.359230	0.697841	0.242855	Wisconsion Public Service Co
5.933163	5.558114	0.375049	0.712288	0.238365	Dayton Power & Light Co
6.212301	5.814274	0.398027	0.774942	0.219432	Detroit Edison
6.877696	6.386068	0.491629	0.954965	0.170106	new York State Electric & Gas Corp (NYSEG)
6.259686	5.618052	0.641634	1.223512	0.110953	Cincinnati Gas & Electric Co (Duke Energy OH)
5.764104	4.959228	0.804876	1.566015	0.059095	Commonwealth Edison Co
6.340216	5.487071	0.853145	1.617590	0.053297	Louisville Gas and Electric Co
6.074367	5.065304	1.009064	1.959735	0.025385	Consolidated Edison Co of new York Inc (CONED)
6.422220	5.409598	1.012622	1.964854	0.025086	Western Massachusetts Electric Co (Northeast Utilities)
6.978886	5.942888	1.035997	1.960503	0.025339	Kentucky Power Co (AEP)
6.302029	5.263760	1.038269	1.977773	0.024344	Potomac Electric Power Co
5.002443	3.604162	1.398281	2.651786	0.004174	San Diego Gas & Electric Co
6.913967	5.461669	1.452298	2.766188	0.002977	Baltimore Gas & Electric Co
7.154407	5.701188	1.453219	2.757841	0.003052	Empire District Electric Co (MO)
7.379586	5.879848	1.499738	2.908323	0.001925	Central Hudson Gas & Electric Corp (CHGE)
7.093782	5.334222	1.759560	3.419815	0.000348	United Illuminating Co
6.775079	4.944567	1.830512	3.486316	0.000274	Oklahoma Gas and Electric Co
7.658442	5.825560	1.832882	3.561097	0.000208	Connecticut Light & Power Co

OUT-OF-SAMPLE PREDICTION OF RELIABILITY LEVEL PERFORMANCE BY YEAR

THESL2:

Year	Actual	Predicted	%Difference	t_ratio	p_value
2005.000	104.893	130.865	-0.221	-0.245	0.403
2006.000	94.063	148.021	-0.453	-0.499	0.309
2007.000	117.000	164.307	-0.340	-0.373	0.355
2008.000	74.400	165.168	-0.798	-0.879	0.190
2009.000	174.169	166.271	0.046	0.051	0.480
2010.000	99.596	157.805	-0.460	-0.510	0.305
2011.000	85.800	175.672	-0.717	-0.792	0.214
2012.000	90.000	186.535	-0.729	-0.805	0.211
2013.000	1271.400	217.126	1.767	1.735	0.042
2014.000	71.400	221.624	-1.133	-1.113	0.133
2015.000	73.800	234.391	-1.156	-1.135	0.129
2016.000	70.200	247.726	-1.261	-1.237	0.108
2017.000	67.200	261.698	-1.360	-1.333	0.092
2018.000	64.800	276.332	-1.450	-1.420	0.078

2019.000	61.200	291.636	-1.561	-1.527	0.064

»

» run C:\work\THESL2\Specification\SAIFI.prg;

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RELIABILITY MODELS

10/22/2014 OUTPUT FILE: C:\work\THESL2\results\SAIFI 15:12:27

Output using the data set C:\work\THESL2\th_benchb_July7_orig.xlsx

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DEFINITIONS OF VARIABLES:

var1 is const

var2 is Retail Customers (yn)

var3 is customer/dx miles (UDI)

var4 is % forestation using GIS area1

var5 is elevation stdev

var6 is lightning strikes/service territory

Time period used: 2002 through 2012

391.000

REGRESSION WITH GROUPWISE HETEROSKEDASTICITY

Valid cases:	384	Dependent variable:	LSAIFI_A
Total SS:	98.189	Degrees of freedom:	371
R-squared:	0.394	Rbar-squared:	0.375
Residual SS:	59.475	Std error of est:	0.400
F(13,371):	18.577	Probability of F:	0.000
Durbin-Watson:	1.299	Number of Firms:	47.000

Variable	Estimate	Standard Error	t-value	Prob >|t|	Standardized Estimate	Cor with Dep Var
CONST	0.177037	0.041097	4.307770	0.000	0.359612	0.644496
LYN	-0.027146	0.015907	-1.706581	0.089	-0.052413	-0.355881
LDENSITY	0.092852	0.040503	2.292452	0.022	0.080553	-0.357671
LPFGIS1	0.215825	0.050504	4.273380	0.000	0.221393	0.025434
LELEVSTD	0.097981	0.029219	3.353353	0.001	0.219188	-0.386935
LLIGHT1	0.205010	0.022193	9.237522	0.000	0.464864	0.021121
LPCTUG	-0.450537	0.038816	-11.607114	0.000	-0.614980	-0.750915
LDENSQ	-0.928365	0.125305	-7.408824	0.000	-0.266533	0.307507
LPFGISSQ	0.607103	0.120338	5.044998	0.000	0.282151	0.324274
LELEVSQ	0.053510	0.026618	2.010301	0.045	0.106703	0.360895
LLIGHTSQ	0.084954	0.015851	5.359710	0.000	0.265833	0.161082
LPCTUG2	-0.020474	0.057413	-0.356603	0.722	-0.017806	0.640740
TREND	0.011753	0.004279	2.746693	0.006	0.155824	0.593316

OUT-OF-SAMPLE PREDICTION OF RELIABILITY LEVEL PERFORMANCE LAST THREE YEARS

Actual	Predicted	Difference	t_ratio	p_value	Utility
-1.261445	-0.304199	-0.957246	-4.103244	0.000025	Consolidated Edison Co of new York Inc (CONED)
-0.112624	0.782173	-0.894797	-3.730855	0.000110	Portland General Electric Co
-0.405241	0.147388	-0.552629	-2.163647	0.015564	Wisconsin Electric Power Co (WEPCO)
-0.009508	0.534283	-0.543791	-2.318606	0.010479	Southern California Edison Co
-0.523162	0.008602	-0.531764	-2.279345	0.011606	Madison Gas and Electric Co
0.134937	0.572788	-0.437851	-1.521679	0.064470	Tampa Electric Co

0.081452	0.455814	-0.374361	-1.580905	0.057375	AmerenUE
-0.066965	0.260878	-0.327843	-1.381498	0.083978	Kansas City Power & Light Co (MO)
-0.024127	0.263100	-0.287227	-1.230626	0.109620	Indianapolis Power & Light Co
-0.090105	0.140564	-0.230668	-0.990976	0.161171	Rochester Gas and Electric Corp
0.609312	0.758913	-0.149601	-0.631619	0.264012	Gulf Power Co
0.139903	0.266594	-0.126691	-0.542249	0.293986	Detroit Edison
0.616739	0.736057	-0.119318	-0.498152	0.309336	Entergy Arkansas Inc
0.331404	0.426314	-0.094910	-0.406247	0.342397	Northern Indiana Public Service Co
0.535264	0.620314	-0.085050	-0.358718	0.360005	Green Mountain Power Corp
0.449423	0.526357	-0.076934	-0.324144	0.373006	Ohio Power Co (AEP)
0.491131	0.557973	-0.066842	-0.285786	0.387601	Orange and Rockland Utilities Inc (O&R)
0.401763	0.465025	-0.063262	-0.267072	0.394781	Dayton Power & Light Co
0.335007	0.394337	-0.059330	-0.253719	0.399926	Southern Indiana Gas and Electric Co (Vectern)
0.127263	0.162228	-0.034965	-0.147309	0.441484	Niagara Mohawk Power Corp (National Grid)
0.384417	0.413847	-0.029430	-0.126031	0.449888	Consumers Energy Company
0.705650	0.704415	0.001235	0.005308	0.497884	new York State Electric & Gas Corp (NYSEG)
0.587787	0.581367	0.006420	0.015914	0.493656	Florida Power Corp
1.171141	1.140783	0.030359	0.127208	0.449422	Kentucky Power Co (AEP)
0.173500	0.137370	0.036130	0.152222	0.439547	Florida Power & Light Co
0.328138	0.259598	0.068540	0.288948	0.386391	Cleveland Electric Illuminating Co (First Energy)
0.429047	0.350963	0.078084	0.329015	0.371165	Ohio Edison Co (First Energy)
-0.021767	-0.100179	0.078412	0.335633	0.368668	Wisconsin Power and Light Co
0.222808	0.135064	0.087744	0.375755	0.353657	Pacific Gas and Electric Co
0.479624	0.358652	0.120972	0.510238	0.305094	Louisville Gas and Electric Co
0.534561	0.404981	0.129580	0.548820	0.291729	PSI Energy Inc (Duke Energy IN)
0.443139	0.255396	0.187743	0.805573	0.210502	Wisconsion Public Service Co
0.849303	0.649773	0.199531	0.858385	0.195616	Central Hudson Gas & Electric Corp (CHGE)
0.555870	0.309751	0.246119	1.037434	0.150104	Oklahoma Gas and Electric Co
0.368462	0.110778	0.257684	1.103661	0.135227	United Illuminating Co
1.118035	0.841388	0.276647	1.165999	0.122181	Central Maine Power Co
0.292006	-0.005152	0.297158	1.266369	0.103087	Commonwealth Edison Co
0.538521	0.233759	0.304762	1.301474	0.096951	Western Massachusetts Electric Co (Northeast Utilities)
0.232960	-0.078709	0.311669	1.334271	0.091466	Avista Corp
0.707572	0.295585	0.411987	1.761150	0.039517	Connecticut Light & Power Co
0.728100	0.264637	0.463463	1.953274	0.025768	Virginia Electric and Power Co
1.032380	0.541089	0.491290	2.072581	0.019450	Empire District Electric Co (MO)
0.641705	0.134977	0.506727	2.131316	0.016859	Baltimore Gas & Electric Co
0.809632	0.291462	0.518169	2.183672	0.014805	Cincinnati Gas & Electric Co (Duke Energy OH)
-0.129984	-0.774531	0.644547	2.723619	0.003381	San Diego Gas & Electric Co
0.539364	-0.110231	0.649595	2.727058	0.003346	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
0.852212	0.039123	0.813089	3.423925	0.000343	Potomac Electric Power Co

OUT-OF-SAMPLE PREDICTION OF RELIABILITY LEVEL PERFORMANCE BY YEAR

Year	Actual	Predicted	%Difference	t_ratio	p_value
THESL2:					
2005.000	2.007	0.904	0.798	1.974	0.025
2006.000	2.169	0.835	0.955	2.361	0.009
2007.000	2.270	0.857	0.974	2.410	0.008
2008.000	1.760	0.885	0.687	1.700	0.045
2009.000	1.863	0.871	0.760	1.881	0.030
2010.000	1.946	0.829	0.853	2.107	0.018
2011.000	1.620	0.947	0.537	1.326	0.093
2012.000	1.600	0.914	0.559	1.382	0.084
2013.000	2.910	0.936	1.134	1.145	0.126
2014.000	1.580	0.946	0.513	0.518	0.303

2015.000	1.550	0.956	0.483	0.488	0.313
2016.000	1.440	0.965	0.400	0.404	0.343
2017.000	1.360	0.975	0.333	0.336	0.369
2018.000	1.270	0.985	0.254	0.257	0.399
2019.000	1.190	0.994	0.180	0.182	0.428

»

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 21:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, App. B, p. 42

PSE's SAIDI and SAIFI benchmarking samples include 2012, which was the year Hurricane Sandy created massive, multi-day outages along much of the US east coast. PSE also used unadjusted SAIDI and SAIFI data, so the 2012 reliability data for many US utilities in its sample would have overwhelmingly reflected the impact of Hurricane Sandy.

a) Please state whether or not it is appropriate to project SAIDI and (to a lesser extent) SAIFI for the 2015-2019 period using data that reflects the impact of Hurricane Sandy. Please explain;

b) Please provide an updated SAIDI econometric model estimated with the US-Toronto sample but excluding data for the 2012 year.

RESPONSE (PREPARED BY PSE):

a) It is appropriate, as the findings are not substantially affected by Hurricane Sandy. PSE did not wish to make any exclusions to the data. However, PSE did test our SAIDI and SAIFI results against weather-normalized U.S. data, where major events (such as Hurricane Sandy) would have been excluded. PSE found similar results that were directionally unchanged. Thus PSE's same conclusions remained.

b) PSE performed a SAIDI and a SAIFI econometric run, both of which have a cut-off date of 2011 (pre-Hurricane Sandy). Please see 1B_01_OEBStaff_021_SAIDI and 1B_01_OEBStaff_021_SAIFI for the SAIDI and SAIFI runs, respectively; these are

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

provided as Appendices A and B to this response. The results are provided in the table below.

Year	SAIDI % Difference (2011 end date)	SAIDI % Difference (Original Model)	SAIFI % Difference (2011 end date)	SAIFI % Difference (Original Model)
2005	-51%	-48%	+65%	+63%
2006	-75%	-70%	+82%	+80%
2007	-62%	-56%	+85%	+83%
2008	-109%	-103%	+55%	+54%
2009	-26%	-19%	+63%	+62%
2010	-77%	-71%	+74%	+74%
2011	-108%	-100%	+37%	+37%
2012	Excluded	-106%	Excluded	+38%
2013	+134%	+145%	+94%	+95%
2014	-156%	-145%	+32%	+33%
2015	-158%	-145%	+30%	+31%
2016	-168%	-155%	+22%	+24%
2017	-177%	-163%	+16%	+18%
2018	-186%	-171%	+9%	+11%
2019	-196%	-181%	+2%	+4%

```
» run C:\work\THESL2\Specification\SAIDI.prg;
********************************************************************************

                RELIABILITY MODELS

10/22/2014      OUTPUT FILE: C:\work\THESL2\results\SAIDI          16:23:17

                Output using the data set C:\work\THESL2\th_benchb_July7_orig.xlsx

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                                DEFINITIONS OF VARIABLES:

                                        var1 is const

                                        var2 is Retail Customers (yn)

                                        var3 is sum of wind days base 10kts

                                        var4 is customer/dx miles (UDI)

                                        var5 is % forestation using GIS area1


                    Time period used: 2002 through 2011


   365.000
                    REGRESSION WITH GROUPWISE HETEROSKEDASTICITY

Valid cases:                      358      Dependent variable:           LSAIDI_A
Total SS:                     353.225      Degrees of freedom:                349
R-squared:                      0.135      Rbar-squared:                    0.115
Residual SS:                  305.548      Std error of est:                0.936
F(9,349):                       6.051      Probability of F:                0.000
Durbin-Watson:                  1.664      Number of Firms:                47.000

                         Standard                     Prob   Standardized  Cor with
Variable     Estimate      Error      t-value        >|t|     Estimate    Dep Var
--------------------------------------------------------------------------------
CONST        5.388718    0.085455   63.059036      0.000    1.000028    0.992144
LYN          0.013656    0.036138    0.377886      0.706    0.002483   -0.239040
LWDD10       0.202582    0.093722    2.161522      0.031    0.025556   -0.491745
LDENSITY    -0.178904    0.080024   -2.235619      0.026   -0.016085   -0.365023
LPFGIS1      0.433019    0.112610    3.845295      0.000    0.040953   -0.149256
LWDD10SQ     0.213689    0.152264    1.403410      0.161    0.019412    0.437098
LDENSQ      -2.219198    0.314688   -7.052068      0.000   -0.070296    0.654109
LPFGISSQ    -0.425546    0.289936   -1.467725      0.143   -0.019660    0.489696
TREND        0.057454    0.011600    4.952912      0.000    0.063704    0.906512


        OUT-OF-SAMPLE PREDICTION OF RELIABILITY LEVEL PERFORMANCE LAST THREE YEARS


    Actual     Predicted Difference  t_ratio     p_value    Utility

  4.656831   6.043683  -1.386853  -2.552407   0.005561        Rochester Gas and Electric Corp
  4.394298   5.755091  -1.360793  -2.446701   0.007454        Wisconsin Electric Power Co
(WEPCO)
  4.608804   5.875118  -1.266314  -2.326732   0.010275        Consolidated Edison Co of new
York Inc (CONED)
  4.547588   5.626250  -1.078662  -1.985807   0.023917        Indianapolis Power & Light Co
  4.409526   5.453523  -1.043996  -1.866390   0.031411        Florida Power & Light Co
  4.733827   5.646774  -0.912946  -0.967154   0.167067        Florida Power Corp
  3.911079   4.676647  -0.765569  -1.412213   0.079388        Madison Gas and Electric Co
  4.687669   5.441906  -0.754238  -1.117377   0.132300        Tampa Electric Co
  4.737723   5.440982  -0.703259  -1.245669   0.106860        TORONTO HYDRO-ELECTRIC SYSTEM
LIMITED
  5.240363   5.842680  -0.602317  -1.085896   0.139136        Portland General Electric Co
  4.832967   5.415632  -0.582664  -1.072831   0.142043        Wisconsin Power and Light Co
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5.019363	5.600613	-0.581250	-1.068425	0.143033	Southern California Edison Co
5.488121	5.985239	-0.497118	-0.910547	0.181580	Pacific Gas and Electric Co
5.759316	6.187226	-0.427910	-0.769250	0.221132	Cleveland Electric Illuminating Co (First Energy)
5.215415	5.507567	-0.292152	-0.523628	0.300434	Gulf Power Co
5.509433	5.781641	-0.272208	-0.486875	0.313326	AmerenUE
5.711924	5.949971	-0.238047	-0.435841	0.331610	Green Mountain Power Corp
5.603710	5.838634	-0.234924	-0.423453	0.336112	Ohio Edison Co (First Energy)
5.287357	5.499977	-0.212619	-0.388004	0.349124	Entergy Arkansas Inc
5.165736	5.378276	-0.212541	-0.391198	0.347945	Avista Corp
5.175708	5.358149	-0.182441	-0.328764	0.371265	Kansas City Power & Light Co (MO)
5.292851	5.445641	-0.152790	-0.278970	0.390216	Niagara Mohawk Power Corp (National Grid)
5.814559	5.863200	-0.048641	-0.087440	0.465186	Virginia Electric and Power Co
5.694134	5.515943	0.178191	0.327003	0.371931	Northern Indiana Public Service Co
6.227470	5.991561	0.235910	0.434229	0.332195	Orange and Rockland Utilities Inc (O&R)
5.903640	5.612656	0.290984	0.535018	0.296489	Wisconsion Public Service Co
5.799631	5.507865	0.291765	0.534319	0.296730	PSI Energy Inc (Duke Energy IN)
6.162818	5.823320	0.339498	0.625216	0.266118	Consumers Energy Company
6.284303	5.881461	0.402842	0.741152	0.229549	new York State Electric & Gas Corp (NYSEG)
6.302029	5.829957	0.472072	0.862562	0.194485	Potomac Electric Power Co
6.202797	5.670324	0.532474	0.959050	0.169098	Baltimore Gas & Electric Co
5.531375	4.978617	0.552758	1.016867	0.154960	Commonwealth Edison Co
6.259686	5.701772	0.557914	1.004799	0.157844	Cincinnati Gas & Electric Co (Duke Energy OH)
6.576970	6.006431	0.570539	1.049638	0.147304	Western Massachusetts Electric Co (Northeast Utilities)
6.360216	5.716590	0.643626	1.159779	0.123465	Ohio Power Co (AEP)
6.067837	5.398989	0.668847	1.230705	0.109630	Detroit Edison
5.933163	5.258858	0.674305	1.207209	0.114084	Dayton Power & Light Co
5.966856	5.193159	0.773697	1.421896	0.077974	United Illuminating Co
6.697521	5.772718	0.924803	1.662397	0.048664	Central Maine Power Co
6.340216	5.400155	0.940061	1.680018	0.046923	Louisville Gas and Electric Co
6.881385	5.914226	0.967158	1.778453	0.038099	Connecticut Light & Power Co
6.345049	5.314690	1.030360	1.890895	0.029732	Southern Indiana Gas and Electric Co (Vectern)
5.014746	3.882615	1.132131	2.055877	0.020268	San Diego Gas & Electric Co
6.933960	5.798819	1.135141	2.083439	0.018968	Central Hudson Gas & Electric Corp (CHGE)
7.154407	5.598152	1.556254	2.784555	0.002826	Empire District Electric Co (MO)
6.978886	5.384151	1.594734	2.854362	0.002285	Kentucky Power Co (AEP)
6.775079	5.162829	1.612250	2.896733	0.002004	Oklahoma Gas and Electric Co

OUT-OF-SAMPLE PREDICTION OF RELIABILITY LEVEL PERFORMANCE BY YEAR

Year	Actual	Predicted	%Difference	t_ratio	p_value
THESL2:					
2005.000	104.893	175.239	-0.513	-0.539	0.295
2006.000	94.063	198.454	-0.747	-0.782	0.217
2007.000	117.000	217.866	-0.622	-0.650	0.258
2008.000	74.400	221.874	-1.093	-1.145	0.127
2009.000	174.169	224.782	-0.255	-0.268	0.395
2010.000	99.596	215.161	-0.770	-0.811	0.209
2011.000	85.800	253.770	-1.084	-1.141	0.127
2013.000	1271.400	332.390	1.342	1.331	0.092
2014.000	71.400	340.014	-1.561	-1.549	0.061
2015.000	73.800	357.499	-1.578	-1.565	0.059
2016.000	70.200	375.383	-1.677	-1.661	0.049
2017.000	67.200	394.870	-1.771	-1.752	0.040
2018.000	64.800	415.091	-1.857	-1.835	0.034
2019.000	61.200	436.016	-1.964	-1.937	0.027

»

» run C:\work\THESL2\Specification\SAIFI.prg;

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RELIABILITY MODELS

10/22/2014 OUTPUT FILE: C:\work\THESL2\results\SAIFI 16:16:19

Output using the data set C:\work\THESL2\th_benchb_July7_orig.xlsx

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DEFINITIONS OF VARIABLES:

var1 is const

var2 is Retail Customers (yn)

var3 is customer/dx miles (UDI)

var4 is % forestation using GIS area1

var5 is elevation stdev

var6 is lightning strikes/service territory

Time period used: 2002 through 2011

365.000

REGRESSION WITH GROUPWISE HETEROSKEDASTICITY

Valid cases:	358	Dependent variable:	LSAIFI_A
Total SS:	93.732	Degrees of freedom:	347
R-squared:	0.188	Rbar-squared:	0.165
Residual SS:	76.071	Std error of est:	0.468
F(11,347):	7.324	Probability of F:	0.000
Durbin-Watson:	1.330	Number of Firms:	47.000

Variable	Estimate	Standard Error	t-value	Prob >|t|	Standardized Estimate	Cor with Dep Var
CONST	0.430782	0.044428	9.696076	0.000	0.949695	0.716772
LYN	-0.027813	0.016076	-1.730075	0.085	-0.064053	-0.218280
LDENSITY	-0.161755	0.034247	-4.723188	0.000	-0.160227	-0.231907
LPFGIS1	0.199655	0.048396	4.125447	0.000	0.248843	-0.040832
LELEVSTD	0.126418	0.026212	4.822963	0.000	0.389118	-0.428901
LLIGHT1	0.212882	0.022819	9.329341	0.000	0.592105	0.111405
LDENSQ	-0.993377	0.110986	-8.950472	0.000	-0.343223	0.292665
LPFGISSQ	0.108493	0.123898	0.875665	0.382	0.065306	0.315800
LELEVSQ	0.048614	0.020380	2.385323	0.018	0.161541	0.445692
LLIGHTSQ	0.052388	0.015091	3.471550	0.001	0.205076	0.189675
TREND	0.010745	0.004818	2.230393	0.026	0.148709	0.666778

OUT-OF-SAMPLE PREDICTION OF RELIABILITY LEVEL PERFORMANCE LAST THREE YEARS

Actual	Predicted	Difference	t_ratio	p_value	Utility
-1.674675	0.282541	-1.957216	-7.192995	0.000000	Consolidated Edison Co of new York Inc (CONED)
-0.405241	0.306427	-0.711668	-2.589490	0.005008	Wisconsin Electric Power Co (WEPCO)
-0.162679	0.542051	-0.704730	-2.594836	0.004932	Rochester Gas and Electric Corp
-0.112624	0.539390	-0.652015	-2.379325	0.008941	Portland General Electric Co
-0.066965	0.445450	-0.512415	-1.873461	0.030921	Kansas City Power & Light Co (MO)
0.133337	0.621773	-0.488436	-1.782059	0.037806	AmerenUE
-0.524222	-0.076061	-0.448161	-1.648245	0.050102	Madison Gas and Electric Co

0.134937	0.495613	-0.360676	-1.083192	0.139737	Tampa Electric Co
-0.005783	0.322032	-0.327815	-1.203723	0.114757	Southern California Edison Co
-0.067963	0.243527	-0.311490	-1.133529	0.128886	Wisconsin Power and Light Co
-0.005431	0.305803	-0.311234	-1.141760	0.127169	Indianapolis Power & Light Co
0.127263	0.253122	-0.125859	-0.460530	0.322712	Niagara Mohawk Power Corp (National Grid)
0.328138	0.445943	-0.117805	-0.430397	0.333587	Cleveland Electric Illuminating Co (First Energy)
0.050015	0.155122	-0.105107	-0.381908	0.351381	Detroit Edison
0.167245	0.263898	-0.096653	-0.354016	0.361771	Northern Indiana Public Service Co
0.491131	0.561614	-0.070482	-0.259879	0.397555	Orange and Rockland Utilities Inc (O&R)
0.587787	0.637939	-0.050153	-0.106739	0.457529	Florida Power Corp
0.535264	0.568797	-0.033533	-0.123542	0.450875	Green Mountain Power Corp
0.249049	0.282334	-0.033285	-0.121640	0.451627	Florida Power & Light Co
0.616739	0.610809	0.005930	0.021781	0.491317	Entergy Arkansas Inc
0.578927	0.566358	0.012569	0.046121	0.481620	Western Massachusetts Electric Co (Northeast Utilities)
0.086710	0.045811	0.040899	0.150009	0.440422	United Illuminating Co
0.555870	0.509531	0.046340	0.169472	0.432762	Oklahoma Gas and Electric Co
0.275127	0.227359	0.047768	0.175737	0.430301	Pacific Gas and Electric Co
0.346061	0.293568	0.052493	0.192837	0.423600	Consumers Energy Company
0.449423	0.390678	0.058745	0.214856	0.415003	Ohio Power Co (AEP)
0.429047	0.354876	0.074171	0.271305	0.393159	Ohio Edison Co (First Energy)
0.556072	0.471440	0.084632	0.309683	0.378494	Gulf Power Co
0.479624	0.387535	0.092089	0.337095	0.368124	Louisville Gas and Electric Co
0.352334	0.249641	0.102693	0.378304	0.352718	Wisconsion Public Service Co
0.401763	0.296966	0.104797	0.383275	0.350875	Dayton Power & Light Co
0.506550	0.393572	0.112978	0.413143	0.339878	Baltimore Gas & Electric Co
0.242068	0.127369	0.114699	0.419808	0.337443	Commonwealth Edison Co
0.583429	0.432657	0.150772	0.552595	0.290448	PSI Energy Inc (Duke Energy IN)
0.728100	0.571859	0.156241	0.572178	0.283786	Virginia Electric and Power Co
0.568472	0.403651	0.164821	0.604482	0.272958	Connecticut Light & Power Co
0.576639	0.393448	0.183191	0.669319	0.251868	Southern Indiana Gas and Electric Co (Vectern)
0.629009	0.444052	0.184957	0.682298	0.247752	new York State Electric & Gas Corp (NYSEG)
0.816234	0.565446	0.250788	0.922508	0.178451	Central Hudson Gas & Electric Corp (CHGE)
0.298149	0.030260	0.267889	0.982897	0.163171	Avista Corp
-0.124403	-0.465367	0.340964	1.248619	0.106322	San Diego Gas & Electric Co
0.809632	0.425211	0.384420	1.405820	0.080335	Cincinnati Gas & Electric Co (Duke Energy OH)
0.852212	0.411428	0.440784	1.622397	0.052812	Potomac Electric Power Co
1.032380	0.542422	0.489958	1.792121	0.036991	Empire District Electric Co (MO)
0.590024	0.008233	0.581791	2.116903	0.017489	TORONTO HYDRO-ELECTRIC SYSTEM LIMITED
1.171141	0.487209	0.683933	2.502128	0.006402	Kentucky Power Co (AEP)
1.118035	0.380930	0.737105	2.695371	0.003686	Central Maine Power Co

OUT-OF-SAMPLE PREDICTION OF RELIABILITY LEVEL PERFORMANCE BY YEAR

THESL2:

Year	Actual	Predicted	%Difference	t_ratio	p_value
2005.000	2.007	1.048	0.650	1.379	0.084
2006.000	2.169	0.957	0.819	1.737	0.042
2007.000	2.270	0.976	0.845	1.792	0.037
2008.000	1.760	1.014	0.551	1.169	0.122
2009.000	1.863	0.991	0.631	1.338	0.091
2010.000	1.946	0.924	0.744	1.577	0.058
2011.000	1.620	1.119	0.370	0.785	0.216
2013.000	2.910	1.135	0.941	0.985	0.163
2014.000	1.580	1.143	0.324	0.338	0.368
2015.000	1.550	1.148	0.300	0.314	0.377
2016.000	1.440	1.152	0.223	0.233	0.408
2017.000	1.360	1.157	0.161	0.169	0.433

2018.000	1.270	1.162	0.089	0.092	0.463
2019.000	1.190	1.167	0.020	0.020	0.492

»

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 22:

Reference(s): **Exhibit 1B, Tab 2, Schedule 5, App. B, pp. 42-44**

Please state for Table 10 of the above reference whether or not the reported three year average SAIDI and SAIFI values are computed using geometric rather than arithmetic averages of reported annual SAIDI and SAIFI indices.

If the answer to a) is geometric averages, please explain the rationale for PSE's decision.

RESPONSE (PREPARED BY PSE):

They were computed using geometric averages, but there was no particular rationale for doing so. It is a method that PSE uses routinely.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 23:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, App. B, p. 55

At the above reference, PSE writes "if the average efficiency embodied in the benchmark value is generated using firms that are very dissimilar than the utility being benchmarked (i.e., the benchmarked utility is an outlier), then its performance evaluation has a high chance of being inaccurate."

a) Please state whether or not in PSE's benchmarking model, the measure of efficiency (not cost) for each utility is independent of the external business conditions used in the cost model. Please explain in detail;

b) If the answer to part a is yes, please state how efficiency measures can depend in any way on whether or not the business conditions for any given utility are "dissimilar" to other utilities in the sample. Please explain in detail.

RESPONSE (PREPARED BY PSE):

a) The efficiency scores and the external business conditions are not independent of one another. It is true that the efficiency scores are uncorrelated with the explanatory variables of the models. While this does get a bit technical in nature, the efficiency scores are uncorrelated with the explanatory variables, they are not, however, independent of them. Statistically speaking, if the scores and explanatory variables are independent, then they are uncorrelated. But, if they are uncorrelated (which is the case for properly specified and estimated models), they do not have to be independent.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

b) As stated above, the efficiency measures are not independent of model variables. PSE or any other benchmarking professional is always at the mercy of the data set chosen to determine how the external business condition variables impact cost. For accurate results, the dataset requires observations that include and encompass the variable values of the studied firm. That is to say, the studied utility must not be an outlier relative to the rest of the sample. While the efficiency scores should be uncorrelated with those external business condition variables, the benchmark costs and thus the efficiency scores will be dependent on the coefficient values derived from the chosen data set.

This alternative explanation may also be useful. In the field of econometrics, the typical label for the left hand side variable (total costs in this application) is the "dependent" variable. It is named the "dependent" variable because its value depends on the values of the explanatory variables (or external business conditions in this context) and the estimated coefficients. The efficiency scores are calculated as the percentage difference in the dependent variable relative to observed cost which is calculated prior to econometric modeling. Therefore, the efficiency scores are not independent of the model coefficients but rather dependent on them, which is why a data set that can properly capture the cost impacts of the variables for the data ranges of the studied utility is essential.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 24:

Reference(s): **Exhibit 1B, Tab 2, Schedule 5, App. B**

Please provide the following information on a spreadsheet:

a) The account level data used in calculating the OM&A cost for THESL for the year 2012;

b) The formulas used to calculate OM&A for THESL for the year 2012.

RESPONSE:

a) As discussed on page 16 of the PSE Report (Exhibit 1B, Tab 2, Schedule 5, Appendix B), PSE sourced the historic OM&A and capital costs for Ontario distributors from a dataset prepared by Pacific Economics Group ("PEG") for the purposes of the empirical work supporting the 4th Generation IRM proceedings. PSE adopted PEG's calculations value to facilitate data consistency with the approach used by the OEB. Accordingly, PSE sourced Toronto Hydro's 2012 OM&A costs from the dataset entitled Working Papers – Part II, posted on the OEB Website on September 6, 2013 (please see the link below). The specific value is located in Tab "OM&A Calculation," Cell D727.[1]

b) Please see response to part (a).

[1] http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Policy%20Initiatives%20and%20Consultations/Renewed%20Regulatory%20Framework/Measuring%20Performance%20of%20Electricity%20Distributors

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 25:

Reference(s): Exhibit 1B, Tab 2, Schedule 5, App. B

Please provide the following information on a spreadsheet:

a) All data used to calculate the capital cost of THESL. It is expected that these data will necessarily go back to the benchmark year of 1989.This information should include the relevant price indexes, gross additions, rates of return and any other data used by PSE in the calculation of capital cost;

b) If gross additions were calculated from other data sources, please provide the formulas and data from these sources.

RESPONSE (PREPARED BY PSE):

a) Please see the Excel spreadsheet entitled, “1B_OEBStaff_25.xls”.

b) Gross additions were calculated using the same PEG method employed in their November 2013 report. The gross plant in service numbers are provided in the spreadsheet referenced in part (a). Please refer to page 21 of the PSE Report regarding the formulas used to translate gross plant numbers to additions. For THESL’s projected gross additions, PSE received that information directly from THESL.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 26:

Reference(s): **Exhibit 1B, Tab 2, Schedule 5, App. B**

Please state whether or not the calculation of the benchmark year capital quantity for THESL included a reduction in plant due to customer contributions (CIAC) reported in account 1995.

RESPONSE (PREPARED BY PSE):

Yes, this was done for all Ontario distributors including Toronto Hydro.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 27:

Reference(s): **Exhibit 1B, Tab 2, Schedule 5, App. B**

The following questions relate to the reliability data contained in the study;

a) Please explain why there are no SAIFI or SAIDI data for the following utilities in the following years:

	2002	2003	2005	2006	2009	2010	2011	2012
Florida Power and Light				X				
Gulf Power Co.				X	X		X	
Wisconsin Electric Power Co.	X		X			X	X	X
All New York Utilities	X							
Kansas City Power & Light	X					X	X	X
Cincinnati Gas & Electric/								
Duke Energy Ohio						X	X	X
Kentucky Power Co.							X	X
Louisville Gas and Electric								X
Niagara Mohawk Power Co.		X						X
Orange and Rockland Utilities								X
Portland General Electric Co.	X					X	X	X
Potomac Electric Power Co.	X						X	X
Virginia Electric Power Co.	X	X				X	X	X

b) Please explain why Florida Power Corporation has only one year of SAIDI and SAIFI data (2007);

c) Please explain why Tampa Electric Company has SAIDI and SAIFI data in only 2007 and 2011;

d) Since all the FirstEnergy companies in Ohio file their reliability reports together to the Commission, please explain why Toledo Edison was excluded from the sample;

e) Please explain why Duke Energy Kentucky was excluded from the sample;

f) Please confirm that, in the data sources used for your study:

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

   i) the values of Central Maine Power Company's SAIDI and SAIFI indices in 2009 are identical to their values in 2008;
   ii) the values of Cincinnati Gas & Electric/Duke Energy Ohio's SAIDI and SAIFI indices in 2003 are identical to their values in 2004;
   iii) the values of Green Mountain Power Company's SAIDI and SAIFI indices in 2009 are identical to their values in 2008;

g) Please provide the source table for the following:
   i) Western Massachusetts Electric Company's SAIDI and SAIFI values in 2012;
   ii) Portland General Electric's SAIDI and SAIFI values in 2009;
   iii) Kansas City Power & Light's SAIDI and SAIFI values in 2009;
   iv) Wisconsin Public Service Corporation's SAIDI and SAIFI values in 2012;
   v) Southern California Edison's SAIDI and SAIFI values in 2002;

h) Please provide the table numbers for Potomac Electric and Power Company's SAIDI and SAIFI values in 2003 and 2010;

i) Please provide the table numbers where the data used to derive Commonwealth Edison's SAIDI values in 2002, 2008-2010, and 2012 and its SAIFI values in 2008-2010 and 2012 are reported, as well as the calculations used to derive them;

j) Please provide the table number for Dayton Power and Light's SAIDI value in 2009;

k) Please provide the chart numbers or source table for Connecticut Power and Light's SAIDI and SAIFI values for 2002-2012;

l) Please provide the chart numbers or source table for United Illuminating's SAIDI and SAIFI values for 2002-2012;

m) Please provide the table numbers where the data used to derive Florida Power and Light's SAIDI and SAIFI values for 2008-2012 are reported, as well as the calculations used to derive them;

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

n) Please provide the table numbers where the data used to derive Gulf Power Company's SAIDI and SAIFI values for 2008, 2010, and 2012 are reported, as well as the calculations used to derive them;

o) Please provide the source data as well as the calculations used to derive New York State Electric and Gas Corp's SAIDI and SAIFI values for 2008-2010;

p) Please explain why companies with fewer than three years of SAIDI and SAIFI data are included in your service reliability benchmarking sample;

q) Please explain how three year average SAIDI and SAIFI values were calculated for companies with three or fewer years of data;

r) Please provide the source data as well as the calculations used to derive Central Hudson Gas and Electric Corp's SAIDI and SAIFI values for 2007-2010.

RESPONSE (PREPARED BY PSE):

a) **Florida Power & Light:** Given no uniform reliability data source exists for U.S. data, internet searches for individual reliability reports are necessary. PSE did not locate data sources for Florida Power & Light major event day ("MED") inclusive reliability data for years prior to 2007 when compiling the data set.

Gulf Power: Given no uniform reliability data source exists for U.S. data, internet searches for individual reliability reports are necessary. PSE did not locate data sources for Gulf Power MED inclusive reliability data for years 2006, 2009, and 2011 when compiling the data set.

Wisconsin Electric Power: The years 2002 and 2005 were excluded due to those observations not being included in the total cost benchmarking dataset. PSE did not

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

want to introduce new observations for the reliability benchmarking that were not available for the total cost benchmarking. For years 2010-2012, PSE did find the reliability reports necessary but excluded the observations because PSE initially believed they only reported Wisconsin territory data and not Wisconsin Electric Power's Michigan territory. Upon further review, it appears the data source is inclusive of both the Wisconsin and Michigan territories.

All New York Utilities: Given no uniform reliability data source exists for U.S. data, internet searches for individual reliability reports are necessary. PSE did not locate data sources for all the New York utilities MED inclusive reliability data for the year 2002 when compiling the data set.

Kansas City Power & Light: Given no uniform reliability data source exists for U.S. data, internet searches for individual reliability reports are necessary. PSE did not locate data sources for Kansas City Power & Light MED inclusive reliability data for the year 2002, 2010, 2011, and 2012 when compiling the data set.

Duke Energy Ohio: Given no uniform reliability data source exists for U.S. data, internet searches for individual reliability reports are necessary. PSE did not locate data sources for Duke Energy Ohio MED inclusive reliability data for the year 2010, 2011, and 2012 when compiling the data set.

Kentucky Power: Given no uniform reliability data source exists for U.S. data, internet searches for individual reliability reports are necessary. PSE did not locate data sources for Kentucky Power MED inclusive reliability data for the year 2011 and 2012 when compiling the data set.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

Louisville Gas & Electric: For 2012, the reliability report PSE located did not appear to disaggregate Louisville Gas & Electric and Kentucky Utilities, whereas in prior years the data was clearly disaggregated.

Niagara Mohawk Power: The years 2003 and 2012 were excluded due to those observations not being included in the total cost benchmarking dataset. PSE did not want to introduce new observations for the reliability benchmarking that were not available for the total cost benchmarking.

Orange & Rockland Utilities: The year 2012 was excluded due to the observation not being included in the total cost benchmarking dataset. PSE did not want to introduce new observations for the reliability benchmarking that were not available for the total cost benchmarking.

Portland General Electric: Given no uniform reliability data source exists for U.S. data, internet searches for individual reliability reports are necessary. PSE did not locate data sources for Portland General Electric MED inclusive reliability data for the year 2002, 2010, 2011, and 2012 when compiling the data set.

Potomac Electric Power: Given no uniform reliability data source exists for U.S. data, internet searches for individual reliability reports are necessary. PSE did not locate data sources for Potomac Electric Power MED inclusive reliability data for the year 2002, 2011, and 2012 when compiling the data set. PSE did locate Maryland service territory data but could not locate District of Columbia data.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

Virginia Electric Power: Given no uniform reliability data source exists for U.S. data, internet searches for individual reliability reports are necessary. PSE did not locate data sources for Virginia Electric Power MED inclusive reliability data for the year 2002, 2003, 2010, 2011, and 2012 when compiling the data set.

b) Given no uniform reliability data source exists for U.S. data, internet searches for individual reliability reports are necessary. PSE did not locate data sources for Florida Power MED inclusive reliability data for the years other than 2007 when compiling the data set.

c) Given no uniform reliability data source exists for U.S. data, internet searches for individual reliability reports are necessary. PSE did not locate data sources for Tampa Electric MED inclusive reliability data for the years other than 2007 and 2011 when compiling the data set.

d) Toledo Edison was excluded due to those observations not being included in the total cost benchmarking dataset for years prior to 2012. PSE did not want to introduce new observations for the reliability benchmarking that were not available for the total cost benchmarking. For the 2012 observation PSE did not locate MED inclusive reliability data for the company.

e) Duke Energy Kentucky was excluded due to those observations not being included in the total cost benchmarking dataset. PSE did not want to introduce new observations for the reliability benchmarking that were not available for the total cost benchmarking.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

f) Please see specific subparts below.

i) The data is not identical. PSE has revised the 2009 observation in the data set to 535.2 for SAIDI and 2.46 for SAIFI. Please see the data source file found in PSE's response to Interrogatory 1B-OEBStaff-10 named, "23.2009.pdf".

ii) PSE is unable to locate the reliability data sources for 2003 and 2004 for Duke Energy Ohio.

iii) PSE is unable to locate the reliability data sources for 2008 and 2009 for Green Mountain Power.

g)

i) Please see response to Interrogatory 1B-OEBStaff-10 for the file named, "198.2012".

ii) Please see response to Interrogatory 1B-OEBStaff-10 for the file named, "148.2003-2009.pdf". SAIDI has been revised to 193.2 and SAIFI to 0.96.

iii) Please see response to Interrogatory 1B-OEBStaff-10 for the file named, "89.2009.pdf". Prior numbers were for Kansas-only, SAIDI has been revised to 134.2 and SAIFI to 0.82 for the combined Kansas and Missouri territories.

iv) Please see response to Interrogatory 1B-OEBStaff-10 for the file named, "203.2012.pdf".

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

v) Please see response to Interrogatory 1B-OEBStaff-10 for the file named, "169.2002-2011".

h) Please see response to Interrogatory 1B-OEBStaff-10 for the file named, "150.2003". This data source was for the Maryland operations only. PSE has revised their data set to no longer include this observation. Please see response to Interrogatory 1B-OEBStaff-10 for the file named, "150.2004-2010". The 2010 observation is through November. PSE has bumped up the reliability data by dividing by 11/12ths.

i) Please see response to Interrogatory 1B-OEBStaff-10 for the files named, "32.2002", "32.2008", "32.2009", "32.2010", and "32.2012".

j) Please see response to Interrogatory 1B-OEBStaff-10 for the file named, "44.2009". PSE has revised its dataset and bumped up the SAIDI value to 113.4.

k) Please see response to Interrogatory 1B-OEBStaff-10 for the files named, "36.2002-2010(a)", "36.2011(a)", "36.2012(a)".

l) Please see response to Interrogatory 1B-OEBStaff-10 for the files named, "186.2002-2010(b)", "186.2011(b)", "186.2012(b)".

m) Please see response to Interrogatory 1B-OEBStaff-10 for the files named, "62.2008(a)", "62.2010(a)", "62.2011(a)", and "62.2012". PSE has revised its data set to reflect data in these sources for 2008-2012.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

n) Please see response to Interrogatory 1B-OEBStaff-10 for the files named, "68.2008(c)", "68.2010(c)", and "68.2012". PSE has revised its data set to reflect data in these sources for 2008, 2010, and 2012.

o) Please see response to Interrogatory 1B-OEBStaff-10 for the files named, "124.2006-2010(c)".

p) PSE chose not to exclude utilities if fewer than three years were available.

q) For companies with fewer than three years, an average of the available one or two years was taken.

r) Please see response to Interrogatory 1B-OEBStaff-10 for the files named, "21.2006-2010(a)".

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 28:

Reference(s): **Exhibit 1C, Tab 4, Schedule 2, p.22, Financial Statements 2013**

With respect to the first reference in note 13, THESL discloses a liability for OPEBs as at December 31, 2013 of $238,792,000.

a) Please state how much of this liability has been recovered through rates since 2000. THESL may wish to refer to undertaking TCJ1.19 in the Hydro One proceeding EB-2013-0416 for a suggestion as to how to complete its response;

b) Please provide the actuarial valuations used in the preparation of the year-end financial statements for the years 2010 through 2012.

RESPONSE:

a) From 2000 to 2013, approximately $114,542 of the liability for OPEBs has been recovered through rates.

b) Please refer to Appendices A to C to this Schedule. Please note that the OPEB liabilities associated with Energy Services Incorporated and LDC Unregulated as noted in the appendices are accounted for within the OPEB liability on the balance sheet of THESL. However, the OPEB costs associated with Toronto Hydro Corporation, Energy Services Incorporated and LDC Unregulated are accounted for in the income statements of the subsidiaries and are therefore not taken into account when calculating THESL rates.

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TORHYD.4011

January 24, 2011

CONFIDENTIAL

Ms. Celine Arsenault-Smith
Toronto Hydro
14 Carlton Street
Toronto, ON M5B 1K5

Dear Celine:

RE: Fiscal 2010 Year-End Disclosure and Expense of the Post-Retirement Benefits for Employees of Toronto Hydro (the "Company") - Final

Further to your request, we have prepared updated year-end financial figures relating to Toronto Hydro's post-retirement benefits for reporting in its 2010 financial statements, including schedules with disclosures required under Section 3461 and accounting appendices G and H. The year-end financial figures presented herein were updated to reflect benefit payments made during Fiscal 2010 in respect of permanent LTD employees. **This letter replaces our initial letter dated January 14, 2010.**

It is our understanding that the Company has the following non-pension post-employment benefits: a sick leave program, life insurance, OMERS top-up pension, and extended health and dental benefits. There are no other non-pension post-employment benefits that we are aware of that would be subject to accounting treatment under CICA 3461.

We have enclosed the following:

Appendix G: Accounting Schedule for each of the four companies and Consolidated
Appendix H: CICA 3461 Disclosures for each of the four companies and Consolidated

Assumptions and Methods

All figures have been calculated using the same assumptions as those used in the valuation performed as at January 1, 2010 (and described in Appendix A of our report dated August 2010). Based on our discussions with the Company, we understand these assumptions still represent management's best estimates of future experience. The 2010 expense is based upon a 6.0% discount rate and the accrued benefit obligations ("ABO") at December 31, 2010 are based on a 5.75% discount rate, as instructed by the Company.

To determine the ABO at December 31, 2010, we re-ran our valuation at January 1, 2010 at a 5.75% discount rate, and projected forward the ABO and service cost figures with interest at 5.75% per annum, reflecting the actual benefit payments in Fiscal 2010.

Changes in Plan Provisions

We understand that there have not been any changes to the post-retirement non-pension benefits as outlined in Appendix D of our actuarial valuation report.

Expense Results Summary

A summary of the Fiscal 2010 expense, the balance sheet accrued benefit liability and the accrued benefit obligation as at December 31, 2010 is as follows:

	Fiscal 2010 Expense ($)	Accrued Benefit Liability at December 31, 2010 ($)	Accrued Benefit Obligation at December 31, 2010 ($)
Toronto Hydro-Electric System Limited	15,346,000	164,229,000	195,753,000
Toronto Hydro Corporation	133,000	3,107,000	1,397,000
Toronto Hydro-Energy Service Incorporation	184,000	1,841,000	2,080,000
Toronto Hydro – LDC Unregulated	83,000	720,000	797,000
Toronto Hydro-Consolidated	15,746,000	169,897,000	200,027,000

Representation

1. The most recent actuarial valuation of the Plan for accounting purposes was performed as at January 1, 2010. Extrapolations to December 31, 2010 have been performed in accordance with Section 3461 of the CICA Handbook.

   We have not been asked to provide an opinion nor have we provided an opinion regarding the actuarial assumptions. Emerging experience, differing from assumptions, will result in gains or losses that will be revealed in future actuarial valuations.

2. As is commonly the case in Canada for benefits other than pensions, there are no assets associated with the Company's Plans.

3. The expense figures for the year ending December 31, 2010 have been determined using the projected benefits method pro-rated on service, applied in conformity with Section 3461 of the CICA Handbook. These figures were extrapolated from the results of the valuation.

4. We understand that the Company elected the retroactive approach in adopting CICA Handbook Section 3461. The Company has adopted the Corridor Method for recognizing experience gains and losses. Under this accounting policy, the portion of the experience gains and losses that exceeds 10% of the accrued benefit obligation is amortized over the average remaining service period of active employees and recognized in future years' expense.

5. The plan provisions are unchanged from those described in our actuarial valuation report dated August 2010. Please see Appendix D of that report for more details.

6. The results of the actuarial valuation and extrapolation have been based on the membership data as of January 1, 2010. Please refer to Appendix C of our report dated August 2010 for a summary of the membership data.

7. We are not aware of any matters or events between the date of our August 2010 valuation report and the date of this letter which would have a significant effect on the figures contained herein.

8. This letter has been prepared, and our opinions given, in accordance with accepted actuarial practice.

9. I am a member in good standing of the Canadian Institute of Actuaries. I understand that this letter will be used for audit evidence.

Should you have any questions or need further clarification, please call me.

Yours truly,

Gary E. Stoller

Gary E. Stoller, F.C.I.A.
(416) 383-6440

c.c. Nelsha Nanji, Morneau Sobeco

This letter and enclosures have been peer-reviewed by Philip Fosu, F.C.I.A.

Toronto Hydro - Consolidated
Post Retirement Benefits
APPENDIX G
Historial Expense Summary

	Estimated Fiscal 2012	*Estimated* Fiscal 2011	Fiscal 2010	Fiscal 2009
Starting values at BOY				
Accrued benefits	207,817,000	200,027,000	177,144,000	137,451,000
Experience (gain) loss			8,013,000	
Adjustment due to January 1, 2010 district changes			0	
Adjusted Accrued benefits at BOY	207,817,000	200,027,000	185,157,000	
Plan assets	0	0	0	0
Assumed discount rate on liabilities at BOY	5.75%	5.75%	6.00%	7.50%
Assumed discount rate on liabilities at EOY	5.75%	5.75%	5.75%	6.00%
Assumed salary increase	4.00%	4.00%	4.00%	4.00%
Accrual for service (normal cost) (employer)	4,133,000	3,908,000	3,485,000	2,539,000
Expected contributions (employer)	8,101,000	7,625,000	7,197,000	6,891,000
Contributions (employee)			0	0
Benefit payments	8,101,000	7,625,000	7,197,000	6,891,000
Average Remaining Service Period (ARSP)	13.0	13.0	13.0	16.0
Average Remaining Service Period to full eligibility	9.0	9.0	9.0	10.0
Exhibit I - Interest on accrued benefits				
Opening balance	207,817,000	200,027,000	185,157,000	137,451,000
Accrual for service	4,133,000	3,908,000	3,485,000	2,539,000
Benefit payments (mid-year)	(4,052,000)	(3,813,000)	(3,600,000)	0
Total	207,898,000	200,122,000	185,042,000	139,990,000
Interest	11,954,000	11,507,000	11,102,000	10,240,000
Exhibit II - Experience gains/ losses - accrued benefits				
Opening balance	207,817,000	200,027,000	185,157,000	137,451,000
Accrual for service	4,133,000	3,908,000	3,485,000	2,539,000
Interest on accrued benefits	11,954,000	11,507,000	11,102,000	10,240,000
Benefit payments	(8,101,000)	(7,625,000)	(7,197,000)	(6,891,000)
Expected value at EOY	215,803,000	207,817,000	192,547,000	143,339,000
Actual value at EOY	215,803,000	207,817,000	200,027,000	177,144,000
Experience gain (loss)	0	0	7,480,000	(33,805,000)
Exhibit III - Unamortized experience				
Experience gain/(loss) at BOY	(27,319,000)	(27,952,000)	(12,654,000)	21,680,000
Other changes at BOY	0	0	(8,013,000)	0
Amortization amount	526,000	633,000	195,000	(529,000)
Changes during year	0	0	(7,480,000)	(33,805,000)
Experience gain/(loss) at EOY	(26,793,000)	(27,319,000)	(27,952,000)	(12,654,000)
Exhibit IV - Post employment benefits expense				
Accrual for services (total)	4,133,000	3,908,000	3,485,000	2,539,000
Interest on accrued benefits	11,954,000	11,507,000	11,102,000	10,240,000
Interest on plan assets	0	0	0	0
Amortization of July 1, 2000 amendment	(5,000)	(156,000)	(296,000)	(296,000)
Amortization of Jan 1, 2001 amendment	5,000	182,000	195,000	195,000
Amortization of Jan 1, 2003 amendment	1,065,000	1,065,000	1,065,000	1,065,000
Amortization of experience (gains)/losses	526,000	633,000	195,000	(529,000)
Net expense	17,678,000	17,139,000	15,746,000	13,214,000
Exhibit V - Calculation of accrual: accrued (prepaid) expense				
Opening balance at BOY	179,411,000	169,897,000	161,348,000	155,025,000
Adjustment due to January 1, 2010 district changes	0	0	0	0
Expense (Income) for the year	17,678,000	17,139,000	15,746,000	13,214,000
Funding contributions (total)	(8,101,000)	(7,625,000)	(7,197,000)	(6,891,000)
Closing balance at EOY	188,988,000	179,411,000	169,897,000	161,348,000
Exhibit VI - Reconciliation				
Accrued benefits at EOY	215,803,000	207,817,000	200,027,000	177,144,000
Plan assets at EOY	0	0	0	0
(Surplus)/Deficit at EOY	215,803,000	207,817,000	200,027,000	177,144,000
Less: Unamortized (gains)/losses				
July 2000 past service cost	(5,000)	(10,000)	(166,000)	(462,000)
Jan 2001 past service cost	0	5,000	187,000	382,000
Jan 2003 past service cost	27,000	1,092,000	2,157,000	3,222,000
Experience (gains)/losses	26,793,000	27,319,000	27,952,000	12,654,000
	188,988,000	179,411,000	169,897,000	161,348,000

Toronto Hydro - Electric System Limited
Post Retirement Benefits
APPENDIX G
Historial Expense Summary

	Estimated Fiscal 2012	*Estimated* Fiscal 2011	Fiscal 2010	Fiscal 2009
Starting values at BOY				
Accrued benefits	203,341,000	195,753,000	172,280,000	134,026,000
Experience (gain) loss			7,511,000	
Adjustmeht due to January 1, 2010 district changes			1,518,000	
Adjusted Accrued benefits at BOY	203,341,000	195,753,000	181,309,000	134,026,000
Plan assets	0	0	0	0
Assumed discount rate on liabilities at BOY	5.75%	5.75%	6.00%	7.50%
Assumed discount rate on liabilities at EOY	5.75%	5.75%	5.75%	6.00%
Assumed salary increase	4.00%	4.00%	4.00%	4.00%
Accrual for service (normal cost) (employer)	3,992,000	3,775,000	3,367,000	2,419,000
Expected contributions (employer)	7,987,000	7,446,000	7,083,000	6,797,000
Contributions (employee)	0	0	0	0
Benefit payments	7,987,000	7,446,000	7,083,000	6,797,000
Average Remaining Service Period (ARSP)	13.0	13.0	13.0	14.0
Average Remaining Service Period to full eligibility	9.0	9.0	9.0	8.0
Exhibit I - Interest on accrued benefits				
Opening balance	203,341,000	195,753,000	181,309,000	134,026,000
Accrual for service	3,992,000	3,775,000	3,367,000	2,419,000
Benefit payments (mid-year)	(3,994,000)	(3,723,000)	(3,542,000)	(3,399,000)
Total	203,339,000	195,805,000	181,134,000	133,046,000
Interest	11,692,000	11,259,000	10,868,000	9,978,000
Exhibit II - Experience gains/ losses - accrued benefits				
Opening balance	203,341,000	195,753,000	181,309,000	134,026,000
Accrual for service	3,992,000	3,775,000	3,367,000	2,419,000
Interest on accrued benefits	11,692,000	11,259,000	10,868,000	9,978,000
Benefit payments	(7,987,000)	(7,446,000)	(7,083,000)	(6,797,000)
Expected value at EOY	211,038,000	203,341,000	188,461,000	139,626,000
Actual value at EOY	211,038,000	203,341,000	195,753,000	172,280,000
Experience gain (loss)	0	0	7,292,000	32,654,000
Exhibit III - Unamortized experience				
Experience gain/(loss) at BOY	(29,022,000)	(29,809,000)	(15,372,000)	17,580,000
Other changes at BOY	0	0	(7,511,000)	0
10% Corridor	20,334,100	19,575,300	18,130,900	13,402,600
Total amount to be amortized	8,687,900	10,233,700	4,752,100	4,177,400
Amortization amount	668,000	787,000	366,000	(298,000)
Changes during year	0	0	(7,292,000)	(32,654,000)
Experience gain/(loss) at EOY	(28,354,000)	(29,022,000)	(29,809,000)	(15,372,000)
Exhibit IV - Post employment benefits expense				
Accrual for services (total)	3,992,000	3,775,000	3,367,000	2,419,000
Interest on accrued benefits	11,692,000	11,259,000	10,868,000	9,978,000
Interest on plan assets	0	0	0	0
Amortization of July 1, 2000 amendment	0	(135,000)	(275,000)	(275,000)
Amortization of Jan 1, 2001 amendment	0	168,000	180,000	180,000
Amortization of Jan 1, 2003 amendment	840,000	840,000	840,000	840,000
Amortization of experience (gains)/losses	668,000	787,000	366,000	(298,000)
Net expense	17,192,000	16,694,000	15,346,000	12,844,000
Exhibit V - Calculation of accrual: accrued (prepaid) expense				
Opening balance at BOY	173,477,000	164,229,000	154,448,000	148,401,000
Adjustment due to January 1, 2010 district changes	0	0	1,518,000	0
Expense (Income) for the year	17,192,000	16,694,000	15,346,000	12,844,000
Funding contributions (total)	(7,987,000)	(7,446,000)	(7,083,000)	(6,797,000)
Closing balance at EOY	182,682,000	173,477,000	164,229,000	154,448,000
Exhibit VI - Reconciliation				
Accrued benefits at EOY	211,038,000	203,341,000	195,753,000	172,280,000
Plan assets at EOY	0	0	0	0
(Surplus)/Deficit at EOY	211,038,000	203,341,000	195,753,000	172,280,000
Less: Unamortized (gains)/losses				
July 2000 past service cost	0	0	(135,000)	(410,000)
Jan 2001 past service cost	0	0	168,000	348,000
Jan 2003 past service cost	2,000	842,000	1,682,000	2,522,000
Experience (gains)/losses	28,354,000	29,022,000	29,809,000	15,372,000
	182,682,000	173,477,000	164,229,000	154,448,000

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following impact for 2010:

1% Increase	**$ Change**
Total of service and interest cost	2,493,000
Accrued benefit obligation as at December 31, 2010	29,415,000

1% Decrease	**$ Change**
Total of service and interest cost	(1,720,000)
Accrued benefit obligation as at December 31, 2010	(22,645,000)

Toronto Hydro Corporation
Post Retirement Benefits
APPENDIX G
Historial Expense Summary

	Estimated Fiscal 2012	*Estimated* Fiscal 2011	Fiscal 2010	Fiscal 2009
Starting values at BOY				
Accrued benefits	1,416,000	1,397,000	2,347,000	1,738,000
Experience (gain) loss			300,000	
Adjustment due to January 1, 2010 district changes			(1,285,000)	
Adjusted Accrued benefits at BOY	1,416,000	1,397,000	1,362,000	
Plan assets	0	0	0	0
Assumed discount rate on liabilities at BOY	5.75%	5.75%	6.00%	7.50%
Assumed discount rate on liabilities at EOY	5.75%	5.75%	5.75%	6.00%
Assumed salary increase	4.00%	4.00%	4.00%	4.00%
Accrual for service (normal cost) (employer)	17,000	16,000	14,000	40,000
Expected contributions (employer)	79,000	76,000	109,000	92,000
Contributions (employee)	0	0	0	0
Benefit payments	79,000	76,000	109,000	92,000
Average Remaining Service Period (ARSP)	13.0	13.0	13.0	16.0
Average Remaining Service Period to full eligibility	9.0	9.0	9.0	11.0
Exhibit I - Interest on accrued benefits				
Opening balance	1,416,000	1,397,000	1,362,000	1,738,000
Accrual for service	17,000	16,000	14,000	40,000
Benefit payments (mid-year)	(40,000)	(38,000)	(55,000)	(46,000)
Total	1,393,000	1,375,000	1,321,000	1,732,000
Interest	80,000	79,000	79,000	130,000
Exhibit II - Experience gains/ losses - accrued benefits				
Opening balance	1,416,000	1,397,000	1,362,000	1,738,000
Accrual for service	17,000	16,000	14,000	40,000
Interest on accrued benefits	80,000	79,000	79,000	130,000
Benefit payments	(79,000)	(76,000)	(109,000)	(92,000)
Expected value at EOY	1,434,000	1,416,000	1,346,000	1,816,000
Actual value at EOY	1,434,000	1,416,000	1,397,000	2,347,000
Experience gain (loss)	0	0	51,000	531,000
Exhibit III - Unamortized experience				
Experience gain/(loss) at BOY	1,988,000	2,142,000	2,664,000	3,396,000
Other changes at BOY	0	0	(300,000)	0
10% Corridor	141,600	139,700	136,200	173,800
Total amount to be amortized	1,846,400	2,002,300	2,227,800	3,222,200
Amortization amount	(142,000)	(154,000)	(171,000)	(201,000)
Changes during year	0	0	(51,000)	(531,000)
Experience gain/(loss) at EOY	1,846,000	1,988,000	2,142,000	2,664,000
Exhibit IV - Post employment benefits expense				
Accrual for services (total)	17,000	16,000	14,000	40,000
Interest on accrued benefits	80,000	79,000	79,000	130,000
Interest on plan assets	0	0	0	0
Amortization of July 1, 2000 amendment	(2,000)	(18,000)	(18,000)	(18,000)
Amortization of Jan 1, 2001 amendment	5,000	12,000	12,000	12,000
Amortization of Jan 1, 2003 amendment	217,000	217,000	217,000	217,000
Amortization of experience (gains)/losses	(142,000)	(154,000)	(171,000)	(201,000)
Net expense	175,000	152,000	133,000	180,000
Exhibit V - Calculation of accrual: accrued (prepaid) expense				
Opening balance at BOY	3,183,000	3,107,000	4,368,000	4,280,000
Adjustment due to January 1, 2010 district changes	0	0	(1,285,000)	0
Expense (Income) for the year	175,000	152,000	133,000	180,000
Funding contributions (total)	(79,000)	(76,000)	(109,000)	(92,000)
Closing balance at EOY	3,279,000	3,183,000	3,107,000	4,368,000
Exhibit VI - Reconciliation				
Accrued benefits at EOY	1,434,000	1,416,000	1,397,000	2,347,000
Plan assets at EOY	0	0	0	0
(Surplus)/Deficit at EOY	1,434,000	1,416,000	1,397,000	2,347,000
Less: Unamortized (gains)/losses				
July 2000 past service cost	0	(2,000)	(20,000)	(38,000)
Jan 2001 past service cost	0	5,000	17,000	29,000
Jan 2003 past service cost	1,000	218,000	435,000	652,000
Experience (gains)/losses	(1,846,000)	(1,988,000)	(2,142,000)	(2,664,000)
	3,279,000	3,183,000	3,107,000	4,368,000

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following impact for 2010:

1% Increase	**$ Change**
Total of service and interest cost	15,000
Accrued benefit obligation as at December 31, 2010	201,000

1% Decrease	**$ Change**
Total of service and interest cost	(12,000)
Accrued benefit obligation as at December 31, 2010	(159,000)

Toronto Hydro - Energy Services Incorporated
Post Retirement Benefits
APPENDIX G
Historial Expense Summary

	Estimated Fiscal 2012	*Estimated* Fiscal 2011	Fiscal 2010	Fiscal 2009
Starting values at BOY				
Accrued benefits	2,176,000	2,080,000	2,517,000	1,687,000
Experience (gain) loss			166,000	
Adjustment due to January 1, 2010 district changes			(870,000)	
Adjusted Accrued benefits at BOY	2,176,000	2,080,000	1,813,000	
Plan assets	0	0	0	0
Assumed discount rate on liabilities at BOY	5.75%	5.75%	6.00%	7.50%
Assumed discount rate on liabilities at EOY	5.75%	5.75%	5.75%	6.00%
Assumed salary increase	4.00%	4.00%	4.00%	4.00%
Accrual for service (normal cost) (employer)	76,000	72,000	64,000	80,000
Expected contributions (employer)	22,000	97,000	5,000	2,000
Contributions (employee)	0	0	0	0
Benefit payments	22,000	97,000	5,000	2,000
Average Remaining Service Period (ARSP)	13.0	13.0	13.0	18.0
Average Remaining Service Period to full eligibility	9.0	9.0	9.0	12.0
Exhibit I - Interest on accrued benefits				
Opening balance	2,176,000	2,080,000	1,813,000	1,687,000
Accrual for service	76,000	72,000	64,000	80,000
Benefit payments (mid-year)	(11,000)	(49,000)	(3,000)	(1,000)
Total	2,241,000	2,103,000	1,874,000	1,766,000
Interest	129,000	121,000	112,000	132,000
Exhibit II - Experience gains/ losses - accrued benefits				
Opening balance	2,176,000	2,080,000	1,813,000	1,687,000
Accrual for service	76,000	72,000	64,000	80,000
Interest on accrued benefits	129,000	121,000	112,000	132,000
Benefit payments	(22,000)	(97,000)	(5,000)	(2,000)
Expected value at EOY	2,359,000	2,176,000	1,984,000	1,897,000
Actual value at EOY	2,359,000	2,176,000	2,080,000	2,517,000
Experience gain (loss)	0	0	(96,000)	(620,000)
Exhibit III - Unamortized experience				
Experience gain/(loss) at BOY	(208,000)	(208,000)	54,000	704,000
Other changes at BOY	0	0	(166,000)	0
10% Corridor	217,600	208,000	181,300	168,700
Total amount to be amortized	0	0	0	535,300
Amortization amount	0	0	0	(30,000)
Changes during year	0	0	(96,000)	(620,000)
Experience gain/(loss) at EOY	(208,000)	(208,000)	(208,000)	54,000
Exhibit IV - Post employment benefits expense				
Accrual for services (total)	76,000	72,000	64,000	80,000
Interest on accrued benefits	129,000	121,000	112,000	132,000
Interest on plan assets	0	0	0	0
Amortization of July 1, 2000 amendment	(3,000)	(3,000)	(3,000)	(3,000)
Amortization of Jan 1, 2001 amendment	0	2,000	3,000	3,000
Amortization of Jan 1, 2003 amendment	8,000	8,000	8,000	8,000
Amortization of experience (gains)/losses	0	0	0	(30,000)
Net expense	210,000	200,000	184,000	190,000
Exhibit V - Calculation of accrual: accrued (prepaid) expense				
Opening balance at BOY	1,944,000	1,841,000	2,532,000	2,344,000
Adjustment due to January 1, 2010 district changes	0	0	(870,000)	0
Expense (Income) for the year	210,000	200,000	184,000	190,000
Funding contributions (total)	(22,000)	(97,000)	(5,000)	(2,000)
Closing balance at EOY	2,132,000	1,944,000	1,841,000	2,532,000
Exhibit VI - Reconciliation				
Accrued benefits at EOY	2,359,000	2,176,000	2,080,000	2,517,000
Plan assets at EOY	0	0	0	0
(Surplus)/Deficit at EOY	2,359,000	2,176,000	2,080,000	2,517,000
Less: Unamortized (gains)/losses				
July 2000 past service cost	(5,000)	(8,000)	(11,000)	(14,000)
Jan 2001 past service cost	0	0	2,000	5,000
Jan 2003 past service cost	24,000	32,000	40,000	48,000
Experience (gains)/losses	208,000	208,000	208,000	(54,000)
	2,132,000	1,944,000	1,841,000	2,532,000

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following impact for 2010:

1% Increase	**$ Change**
Total of service and interest cost	39,000
Accrued benefit obligation as at December 31, 2010	429,000

1% Decrease	**$ Change**
Total of service and interest cost	(29,000)
Accrued benefit obligation as at December 31, 2010	(318,000)

Toronto Hydro - LDC Unregulated
Post Retirement Benefits
APPENDIX G
Historial Expense Summary

	Estimated Fiscal 2012	*Estimated* Fiscal 2011	Fiscal 2010	Fiscal 2009
Starting values at BOY				
Accrued benefits	884,000	797,000	0	0
Experience (gain) loss			36,000	
Adjustment due to January 1, 2010 district changes			637,000	
Adjusted Accrued benefits at BOY	884,000	797,000	673,000	0
Plan assets	0	0	0	0
Assumed discount rate on liabilities at BOY	5.75%	5.75%	6.00%	7.50%
Assumed discount rate on liabilities at EOY	5.75%	5.75%	5.75%	6.00%
Assumed salary increase	4.00%	4.00%	4.00%	4.00%
Accrual for service (normal cost) (employer)	48,000	45,000	40,000	0
Expected contributions (employer)	13,000	6,000	0	0
Contributions (employee)	0	0	0	0
Benefit payments	13,000	6,000	0	0
Average Remaining Service Period (ARSP)	13.0	13.0	13.0	14.0
Average Remaining Service Period to full eligibility	9.0	9.0	9.0	8.0

	Fiscal 2012	Fiscal 2011	Fiscal 2010	Fiscal 2009
Exhibit I - Interest on accrued benefits				
Opening balance	884,000	797,000	673,000	0
Accrual for service	48,000	45,000	40,000	0
Benefit payments (mid-year)	(7,000)	(3,000)	0	0
Total	925,000	839,000	713,000	0
Interest	53,000	48,000	43,000	0

	Fiscal 2012	Fiscal 2011	Fiscal 2010	Fiscal 2009
Exhibit II - Experience gains/ losses - accrued benefits				
Opening balance	884,000	797,000	673,000	0
Accrual for service	48,000	45,000	40,000	0
Interest on accrued benefits	53,000	48,000	43,000	0
Benefit payments	(13,000)	(6,000)	0	0
Expected value at EOY	972,000	884,000	756,000	0
Actual value at EOY	972,000	884,000	797,000	0
Experience gain (loss)	0	0	41,000	0

	Fiscal 2012	Fiscal 2011	Fiscal 2010	Fiscal 2009
Exhibit III - Unamortized experience				
Experience gain/(loss) at BOY	(77,000)	(77,000)	0	0
Other changes at BOY	0	0	(36,000)	0
10% Corridor	88,400	79,700	67,300	0
Total amount to be amortized	0	0	0	0
Amortization amount	0	0	0	0
Changes during year	0	0	(41,000)	0
Experience gain/(loss) at EOY	(77,000)	(77,000)	(77,000)	0

	Fiscal 2012	Fiscal 2011	Fiscal 2010	Fiscal 2009
Exhibit IV - Post employment benefits expense				
Accrual for services (total)	48,000	45,000	40,000	0
Interest on accrued benefits	53,000	48,000	43,000	0
Interest on plan assets	0	0	0	0
Amortization of July 1, 2000 amendment	0	0	0	0
Amortization of Jan 1, 2001 amendment	0	0	0	0
Amortization of Jan 1, 2003 amendment	0	0	0	0
Amortization of experience (gains)/losses	0	0	0	0
Net expense	101,000	93,000	83,000	0

	Fiscal 2012	Fiscal 2011	Fiscal 2010	Fiscal 2009
Exhibit V - Calculation of accrual: accrued (prepaid) expense				
Opening balance at BOY	807,000	720,000	0	0
Adjustment due to January 1, 2010 district changes	0	0	637,000	0
Expense (Income) for the year	101,000	93,000	83,000	0
Funding contributions (total)	(13,000)	(6,000)	0	0
Closing balance at EOY	895,000	807,000	720,000	0

	Fiscal 2012	Fiscal 2011	Fiscal 2010	Fiscal 2009
Exhibit VI - Reconciliation				
Accrued benefits at EOY	972,000	884,000	797,000	0
Plan assets at EOY	0	0	0	0
(Surplus)/Deficit at EOY	972,000	884,000	797,000	0
Less: Unamortized (gains)/losses				
July 2000 past service cost	0	0	0	0
Jan 2001 past service cost	0	0	0	0
Jan 2003 past service cost	0	0	0	0
Experience (gains)/losses	77,000	77,000	77,000	0
	895,000	807,000	720,000	0

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following impact for 2010:

1% Increase	**$ Change**
Total of service and interest cost	21,000
Accrued benefit obligation as at December 31, 2010	186,000

1% Decrease	**$ Change**
Total of service and interest cost	(16,000)
Accrued benefit obligation as at December 31, 2010	(139,000)

Appendix H

Post-Retirement Benefits other than Pension for Toronto Hydro - Consolidated CICA 3461 Disclosures

	Estimate 2011	2010	2009	2008
Accrued benefit obligation:				
Balance at beginning of year	200,027,000	177,144,000	137,451,000	176,269,000
Experience (gain) loss at beginning of year	0	8,013,000	0	0
Reduction in ABO due to sale of Telecom July 31, 2008	0	0	0	(294,000)
Current service cost	3,908,000	3,485,000	2,539,000	3,613,000
Past Service Cost	0	0	0	0
Interest cost	11,507,000	11,102,000	10,240,000	9,721,000
Benefits paid	(7,625,000)	(7,197,000)	(6,891,000)	(5,671,000)
Actuarial (gains)/losses	0	7,480,000	33,805,000	(46,187,000)
Plan amendments	0	0	0	0
Balance at end of year	207,817,000	200,027,000	177,144,000	137,451,000
Reconciliation of accrued benefit obligation to accrued benefits liability:				
Accrued benefit obligation	207,817,000	200,027,000	177,144,000	137,451,000
Less: Unamortized net actuarial (gain)/loss	27,319,000	27,952,000	12,654,000	(21,680,000)
Unamortized past service costs	1,087,000	2,178,000	3,142,000	4,106,000
Post-employment benefits liability	179,411,000	169,897,000	161,348,000	155,025,000
Components for net periodic defined benefit costs:				
Current service cost	3,908,000	3,485,000	2,539,000	3,613,000
Interest cost	11,507,000	11,102,000	10,240,000	9,721,000
Actuarial (gains)/ losses	0	15,493,000	33,805,000	(46,187,000)
Plan amendments	0	0	0	0
Elements of defined benefit costs before adjustment recognized in:	15,415,000	30,080,000	46,584,000	(32,853,000)
Adjustments to recognize the long-term nature of employee future benefit costs:				
- Difference between actuarial (gain) loss recognized for period and actuarial (gain) loss on accrued benefits obligation for the period	633,000	(15,298,000)	(34,334,000)	46,787,000
- Difference between amortization of past service costs for the period and the actual plan amendments for the period	1,091,000	964,000	964,000	964,000
Defined benefit costs recognized	**17,139,000**	**15,746,000**	**13,214,000**	**14,898,000**
Significant assumptions				
Accrued benefit obligation as of December 31:				
- Discount rate	5.75%	5.75%	6.00%	7.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Benefit costs for the years ended December 31:				
- Discount rate	5.75%	6.00%	7.50%	5.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Assumed health care cost trend rates at December 31:				
- Rate of increase in dental costs	4.00%	4.00%	4.00%	4.00%
- Rate of increase in health costs (pre July 2000 retirements)	7.00%	7.50%	8.00%	8.50%
- Ultimate rate in health costs (pre July 2000 retirements)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (pre July 2000 retirements)	2016	2016	2016	2016
- Rate of increase in health costs (other members)	8.50%	9.00%	8.00%	8.50%
- Ultimate rate in health costs (other members)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (other members)	2019	2019	2016	2016

Sensitivity Analysis - Extended Health & Dental Care

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2010:

	Increase $	Decrease $
Total of current service and interest cost (at 6.00%)	2,568,000	(1,777,000)
Accrued benefit obligation as at December 31, 2010 (at 5.75%)	30,231,000	(23,262,000)

Sensitivity Analysis - Discount Rate for Disclosure Purposes

Assumed interest rates have a significant effect on the amounts reported for the total accrued benefit obligation and expense.
A one-percentage-point change in assumed interest rates would have the following effects for 2010:

	Increase $	Decrease $
Accrued benefit obligation as at December 31, 2010	(27,096,000)	35,140,000
Estimated expense for Fiscal 2011	(1,449,000)	3,197,000

Appendix H

Post-Retirement Benefits other than Pension for Toronto Hydro Electric System Limited CICA 3461 Disclosures

	Estimate 2011	2010	2009	2008
Accrued benefit obligation:				
Balance at beginning of year	195,753,000	172,280,000	134,026,000	171,382,000
Experience (gain) loss at beginning of year	0	7,511,000	0	0
Adjustment due to January 1 district changes	0	1,518,000	0	0
Current service cost	3,775,000	3,367,000	2,419,000	3,433,000
Interest cost	11,259,000	10,868,000	9,978,000	9,461,000
Benefits paid	(7,446,000)	(7,083,000)	(6,797,000)	(5,592,000)
Actuarial (gains)/losses	0	7,292,000	32,654,000	(44,658,000)
Plan amendments	0	0	0	0
Balance at end of year	203,341,000	195,753,000	172,280,000	134,026,000

Reconciliation of accrued benefit obligation to accrued benefits liability:

	Estimate 2011	2010	2009	2008
Accrued benefit obligation	203,341,000	195,753,000	172,280,000	134,026,000
Less: Unamortized net actuarial (gain)/loss	29,022,000	29,809,000	15,372,000	(17,580,000)
Unamortized past service costs	842,000	1,715,000	2,460,000	3,205,000
Post-employment benefits liability	173,477,000	164,229,000	154,448,000	148,401,000

Components for net periodic defined benefit costs:

164,229,000
+1,841,000
+720,000 =
166,790,000

	Estimate 2011	2010	2009	2008
Current service cost		3,367,000	2,419,000	3,433,000
Interest cost		10,868,000	9,978,000	9,461,000
Actuarial (gains)/ losses		14,803,000	32,654,000	(44,658,000)
Plan amendments		0	0	0
Elements of defined benefit costs before adjustment recognized in:		29,038,000	45,051,000	(31,764,000)
Adjustments to recognize the long-term nature of employee future benefit costs:				
- Difference between actuarial (gain) loss recognized for period and actuarial (gain) loss on accrued benefits obligation for the period		(14,437,000)	(32,952,000)	45,423,000
- Difference between amortization of past service costs for the period and the actual plan amendments for the period	873,000	745,000	745,000	745,000
Defined benefit costs recognized	**16,694,000**	**15,346,000**	**12,844,000**	**14,404,000**

Significant assumptions

	Estimate 2011	2010	2009	2008
Accrued benefit obligation as of December 31:				
- Discount rate	5.75%	5.75%	6.00%	7.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Benefit costs for the years ended December 31:				
- Discount rate	5.75%	6.00%	7.50%	5.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Assumed health care cost trend rates at December 31:				
- Rate of increase in dental costs	4.00%	4.00%	4.00%	4.00%
- Rate of increase in health costs (pre July 2000 retirements)	7.00%	7.50%	8.00%	8.50%
- Ultimate rate in health costs (pre July 2000 retirements)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (pre July 2000 retirements)	2016	2016	2016	2016
- Rate of increase in health costs (other members)	8.50%	9.00%	8.00%	8.50%
- Ultimate rate in health costs (other members)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (other members)	2019	2019	2016	2016

Sensitivity analysis

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2010:

	Increase $	Decrease $
Total of current service and interest cost (at 6.00%)	2,493,000	(1,720,000)
Accrued benefit obligation as at December 31, 2009 (at 5.75%)	29,415,000	(22,646,000)

Appendix H

Post-Retirement Benefits other than Pension for Toronto Hydro Corporation CICA 3461 Disclosures

		Estimate 2011	2010	2009	2008
Accrued benefit obligation:					
	Balance at beginning of year	1,397,000	2,347,000	1,738,000	2,299,000
	Experience (gain) loss at beginning of year	0	300,000	0	0
	Adjustment due to January 1 district changes	0	(1,285,000)	0	0
	Current service cost	16,000	14,000	40,000	59,000
	Interest cost	79,000	79,000	130,000	128,000
	Benefits paid	(76,000)	(109,000)	(92,000)	(60,000)
	Actuarial (gains)/losses	0	51,000	531,000	(688,000)
	Plan amendments	0	0	0	0
	Balance at end of year	1,416,000	1,397,000	2,347,000	1,738,000
Reconciliation of accrued benefit obligation to accrued benefits liability:					
	Accrued benefit obligation	1,416,000	1,397,000	2,347,000	1,738,000
Less	Unamortized net actuarial (gain)/loss	(1,988,000)	(2,142,000)	(2,664,000)	(3,396,000)
	Unamortized past service costs	221,000	432,000	643,000	854,000
	Post-employment benefits liability	3,183,000	3,107,000	4,368,000	4,280,000
Components for net periodic defined benefit costs:					
	Current service cost	16,000	14,000	40,000	59,000
	Interest cost	79,000	79,000	130,000	128,000
	Actuarial (gains)/ losses	0	351,000	531,000	(688,000)
	Plan amendments	0	0	0	0
	Elements of defined benefit costs before adjustment recognized in:	95,000	444,000	701,000	(501,000)
	Adjustments to recognize the long-term nature of employee future benefit costs:				
	- Difference between actuarial (gain) loss recognized for period and actuarial (gain) loss on accrued benefits obligation for the period	(154,000)	(522,000)	(732,000)	523,000
	- Difference between amortization of past service costs for the period and the actual plan amendments for the period	211,000	211,000	211,000	211,000
	Defined benefit costs recognized	**152,000**	**133,000**	**180,000**	**233,000**
Significant assumptions					
	Accrued benefit obligation as of December 31:				
	- Discount rate	5.75%	5.75%	6.00%	7.50%
	- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
	Benefit costs for the years ended December 31:				
	- Discount rate	5.75%	6.00%	7.50%	5.50%
	- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
	Assumed health care cost trend rates at December 31:				
	- Rate of increase in dental costs	4.00%	4.00%	4.00%	4.00%
	- Rate of increase in health costs (pre July 2000 retirements)	7.00%	7.50%	8.00%	8.50%
	- Ultimate rate in health costs (pre July 2000 retirements)	5.00%	5.00%	5.00%	5.00%
	- Ultimate year (pre July 2000 retirements)	2016	2016	2016	2016
	- Rate of increase in health costs (other members)	8.50%	9.00%	8.00%	8.50%
	- Ultimate rate in health costs (other members)	5.00%	5.00%	5.00%	5.00%
	- Ultimate year (other members)	2019	2019	2016	2016

Sensitivity analysis

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2010:

	Increase $	Decrease $
Total of current service and interest cost (at 6.00%)	15,000	(12,000)
Accrued benefit obligation as at December 31, 2009 (at 5.75%)	201,000	(159,000)

Appendix H

Post-Retirement Benefits other than Pension for
Toronto Hydro-Energy Service Incorporation
CICA 3461 Disclosures

	Estimate 2011	2010	2009	2008
Accrued benefit obligation:				
Balance at beginning of year	2,080,000	2,517,000	1,687,000	2,294,000
Experience (gain) loss at beginning of year	0	166,000	0	0
Adjustment due to January 1 district changes	0	(870,000)	0	0
Current service cost	72,000	64,000	80,000	121,000
Interest cost	121,000	112,000	132,000	132,000
Benefits paid	(97,000)	(5,000)	(2,000)	(19,000)
Actuarial (gains)/losses	0	96,000	620,000	(841,000)
Plan amendments	0	0	0	0
Balance at end of year	**2,176,000**	**2,080,000**	**2,517,000**	**1,687,000**
Reconciliation of accrued benefit obligation to accrued benefits liability:				
Accrued benefit obligation				
Less: Unamortized net actuarial (gain)/loss	2,176,000	2,080,000	2,517,000	1,687,000
Unamortized past service costs	208,000	208,000	(54,000)	(704,000)
Post-employment benefits liability	24,000	31,000	39,000	47,000
	1,944,000	1,841,000	2,532,000	2,344,000
Components for net periodic defined benefit costs:				
Current service cost	72,000	64,000	80,000	121,000
Interest cost	121,000	112,000	132,000	132,000
Actuarial (gains)/ losses	0	262,000	620,000	(841,000)
Plan amendments	0	0	0	0
Elements of defined benefit costs before adjustment recognized in:	193,000	438,000	832,000	(588,000)
Adjustments to recognize the long-term nature of employee future benefit costs:				
- Difference between actuarial (gain) loss recognized for period and actuarial (gain) loss on accrued benefits obligation for the period	0	(262,000)	(650,000)	841,000
- Difference between amortization of past service costs for the period and the actual plan amendments for the period	7,000	8,000	8,000	8,000
Defined benefit costs recognized	**200,000**	**184,000**	**190,000**	**261,000**
Significant assumptions				
Accrued benefit obligation as of December 31:				
- Discount rate	5.75%	5.75%	6.00%	7.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Benefit costs for the years ended December 31:				
- Discount rate	5.75%	6.00%	7.50%	5.50%
- Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Assumed health care cost trend rates at December 31:				
- Rate of increase in dental costs	4.00%	4.00%	4.00%	4.00%
- Rate of increase in health costs (pre July 2000 retirements)	7.00%	7.50%	8.00%	8.50%
- Ultimate rate in health costs (pre July 2000 retirements)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (pre July 2000 retirements)	2016	2016	2016	2016
- Rate of increase in health costs (other members)	8.50%	9.00%	8.00%	8.50%
- Ultimate rate in health costs (other members)	5.00%	5.00%	5.00%	5.00%
- Ultimate year (other members)	2019	2019	2016	2016

Sensitivity analysis

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans.
A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2010:

	Increase $	Decrease $
Total of current service and interest cost (at 6.00%)	39,000	(29,000)
Accrued benefit obligation as at December 31, 2009 (at 5.75%)	429,000	(318,000)

Appendix H

Post-Retirement ~~Benefits other~~ than Pension for
LDC Unregulated
CICA 3461 Disclosures

	Estimate 2011	2010
Accrued benefit obligation:		
Balance at beginning of year	797,000	0
Experience (gain) loss at beginning of year	0	36,000
Adjustment due to January 1 district changes	0	637,000
Current service cost	45,000	40,000
Interest cost	48,000	43,000
Benefits paid	(6,000)	0
Actuarial (gains)/losses	0	41,000
Plan amendments	0	0
Balance at end of year	884,000	797,000
Reconciliation of accrued benefit obligation to accrued benefits liability:		
Accrued benefit obligation	884,000	797,000
Less: Unamortized net actuarial (gain)/loss	77,000	77,000
Unamortized past service costs	0	0
Post-employment benefits liability	807,000	720,000
Components for net periodic defined benefit costs:		
Current service cost	45,000	40,000
Interest cost	48,000	43,000
Actuarial (gains)/ losses	0	77,000
Plan amendments	0	0
Elements of defined benefit costs before adjustment recognized in:	93,000	160,000
Adjustments to recognize the long-term nature of employee future benefit costs:		
- Difference between actuarial (gain) loss recognized for period and actuarial (gain) loss on accrued benefits obligation for the period	0	(77,000)
- Difference between amortization of past service costs for the period and the actual plan amendments for the period	0	0
Defined benefit costs recognized	**93,000**	**83,000**
Significant assumptions		
Accrued benefit obligation as of December 31:		
- Discount rate	5.75%	5.75%
- Rate of compensation increase	4.00%	4.00%
Benefit costs for the years ended December 31:		
- Discount rate	5.75%	6.00%
- Rate of compensation increase	4.00%	4.00%
Assumed health care cost trend rates at December 31:		
- Rate of increase in dental costs	4.00%	4.00%
- Rate of increase in health costs (pre July 2000 retirements)	7.00%	7.50%
- Ultimate rate in health costs (pre July 2000 retirements)	5.00%	5.00%
- Ultimate year (pre July 2000 retirements)	2016	2016
- Rate of increase in health costs (other members)	8.50%	9.00%
- Ultimate rate in health costs (other members)	5.00%	5.00%
- Ultimate year (other members)	2019	2019

Sensitivity analysis

Assumed health and dental care cost trend rates have a significant effect on the amounts reported for the health and dental care plans. A one-percentage-point change in assumed health and dental care cost trend rates would have the following effects for 2010:

	Increase $	Decrease $
Total of current service and interest cost (at 6.00%)	21,000	(16,000)
Accrued benefit obligation as at December 31, 2009 (at 5.75%)	186,000	(139,000)

TOWERS WATSON

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February 5, 2012

Ms. Celine Arsenault-Smith
Toronto Hydro
14 Carlton Street
Toronto, ON
M5B 1K5

Dear Celine:

POST-RETIREMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2011 YEAR END DISCLOSURES AND ESTIMATED 2012 AND 2013 NET PERIODIC COST

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-retirement and post-employment benefits:

- Extended health benefits for retirees and members on long-term disability;
- Dental benefits for retirees and members on long-term disability;
- Life insurance benefits for retirees;
- Sick leave benefits; and
- OMERS top up pension.

This letter and appendices have been prepared for the Company for the following purposes:

- Determining the final calculation of the 2011 net periodic expense to be reported in the Company's 2011 financial statements;
- Providing the required information for year-end disclosure purposes as of December 31, 2011 to be reported in the Company's 2011 financial statements; and
- Determining an estimate of 2012 and 2013 net periodic benefit cost.

The information contained in this letter and appendices is presented in thousands of Canadian dollars and is in respect of the benefits mentioned above only.

All valuation results and accounting calculations presented in this letter and appendices were prepared in accordance with the following accounting standards:

- 2011 net periodic expense and year-end disclosures – in accordance with Canadian GAAP (Canadian Institute of Chartered Accountants Handbook Section 3461)
- Estimated net period benefit cost for 2012 and 2013 – in accordance with US GAAP (FASB Accounting Standards Codification 715)

The year-end disclosure obligations are based on the January 1, 2010 actuarial valuation conducted by Morneau Shepell.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Please refer to the January 1, 2010 actuarial valuation report prepared by Morneau Shepell (dated August 2010) for the summaries of the plan provisions, the membership data and the actuarial basis used in the valuation.

ACTUARIAL ASSUMPTIONS AND METHODS

- Results are based on the most recent valuation of the post-retirement and post-employment benefit programs. The valuation was performed as at January 1, 2010 by the previous actuarial consultants, Morneau Shepell, and we have relied on all the data and information including plan provisions and membership data, as being complete and accurate. We have not independently verified the accuracy or completeness of the data or information used for the January 1, 2010 actuarial valuation.

- The measurement date used for fiscal 2011 year-end disclosure is December 31, 2011.

- The 2011 benefit cost is based upon discount rate of 5.75% per annum and the accrued benefit obligation (“ABO”) at December 31, 2011 is based upon discount rate of 4.75% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2010 and at December 31, 2011, respectively.

- With the exception of the discount rate, the actuarial methods and assumptions used for the determination of the 2011 net periodic benefit cost and December 31, 2011 obligation are consistent with those used for the 2010 disclosures.

- Service costs and ABO as of December 31, 2011 were extrapolated from the full January 1, 2010 valuation results assuming that there are no experience gains and losses other than from actual benefit payments being different from expected and from changes in the assumptions during the extrapolation period such as changes in the discount rate.

DISCLOSURE RESULTS SUMMARY

The summary of Fiscal 2011 net periodic benefit costs, the balance sheet accrued benefit liability and the ABO as at December 31, 2011, under Canadian GAAP are as follows (in $000s):

	Fiscal 2011 Net Periodic Benefit Costs	*Accrued Benefit Asset/(Liability) at December 31, 2011*	*ABO at December 31, 2011*
Toronto Hydro-Electric System Limited	$ 16,694	$ (173,542)	$ 239,064
Toronto Hydro Corporation	152	(3,171)	1,665
Toronto Hydro-Energy Service Incorporation	200	(2,017)	2,558
Toronto Hydro-LDC Unregulated	93	(811)	1,039
Toronto Hydro – Consolidated	17,139	(179,541)	244,326

- Actual benefit payments for 2011 of $7,495,000 are based on information provided by the Company on January 26, 2012. We have projected 2012 and 2013 benefit payments based on the valuation assumptions.

TRANSITION TO US GAAP

- We understand that the transition to US GAAP will result in all actuarial gains and losses and prior service costs to be fully recognized immediately in other comprehensive income as at the transition date, January 1, 2011. We understand that US GAAP will be adopted for financial reporting effective January 1, 2012 (with a provision of Fiscal 2011 comparative figures).

- On an ongoing basis, actuarial gains and losses will be reflected in the statement of comprehensive income. To the extent that they exceed 10% of the accumulated benefit obligation, these gains and losses will be recognized over the expected average remaining service period of active employees participating in the plans.

- On an ongoing basis, prior service costs will be reflected in the statement of comprehensive income, and recognized through expense over a straight line basis over the average service period (to full eligibility) of employees active at the date of amendment.

- As instructed by Toronto Hydro, we have assumed that all accounting methods and policies under US GAAP will be consistent with those applied under current Canadian GAAP. Additional disclosure items under US GAAP include a split of current and non-current liability.

OTHER COMMENTS

- We understand that the post-retirement benefit plan is not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.

- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2010 that would materially affect the results of our valuations.

* * * * *

ACTUARIAL CERTIFICATION

The consulting actuaries are members of the Canadian Institute of Actuaries and Society of Actuaries and other professional actuarial organizations and meets their "General Qualification Standard for Statements of Actuarial Opinions" relating to pension and other postretirement benefit plans.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are not other subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

The calculations for the 2011 disclosures have been made in accordance with Section 3461 of the CICA Handbook, with which we are familiar. This report has been prepared in accordance with the reporting requirements of the CIA/CICA Joint Policy Statement.

In preparing the results presented in this letter (including the attached appendices), we have relied upon information provided to us regarding plan provisions, postretirement welfare plan costs, plan participants, plan assets and actuarial results prepared by Morneau Shepell. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this letter is dependent upon the accuracy and completeness of the underlying information.

The actuarial assumptions and the accounting policies and methods employed in the development of the pension cost have been selected by the Toronto Hydro management as representing their best estimates of future contingent events. As is required under the CICA accounting standards, the assumptions are not intended to include any provision for adverse deviations and we do not express any opinion on them. FASB ASC 715 requires that each significant assumption "individually represent the best estimate of a particular future event."

The results shown in this letter have been developed based on actuarial assumptions that are considered to be reasonable and within the "best-estimate range" as described by the Actuarial Standards of Practice. Other actuarial assumptions could also be considered to be reasonable and within the best-estimate range. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

* * * * *

The information contained in this report was prepared for Toronto Hydro, for its internal use and for the preparation of its periodic financial disclosures, and its auditors, for the preparation of its periodic financial disclosures. It is neither intended nor necessarily suitable for other purposes. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited with Towers Watson's prior written consent.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Towers Watson

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Enclosures

cc: Diane Low, Shirley Powell, Alex Park — Toronto Hydro
Olga Baliakina, Ken Chapman — Towers Watson

Post-Employment Benefits Plans - 2011 CICA 3461 Disclosures ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)	December 31, 2010				
Funded status	(195,753)	(1,397)	(2,080)	(797)	(200,027)
Unamortized prior service costs					
July 2000 past service costs	(135)	(20)	(11)	-	(166)
Jan 2001 past service costs	168	17	2	-	187
Jan 2003 past service costs	1,682	435	40	-	2,157
Unamortized net actuarial (gains)/losses	29,809	(2,142)	208	77	27,952
Accrued benefit asset (liability)	(164,229)	(3,107)	(1,841)	(720)	(169,897)
Change in accrued benefit obligation	2011				
Accrued benefit obligation at beginning of year	195,753	1,397	2,080	797	200,027
Service cost	3,775	16	72	45	3,908
Interest cost	11,259	79	121	48	11,507
Actuarial (gain) loss	35,658	261	309	151	36,379
Benefits paid	(7,381)	(88)	(24)	(2)	(7,495)
Accrued benefit obligation at end of year	239,064	1,665	2,558	1,039	244,326
Change in plan assets	2011				
Fair value of plan assets at beginning of year	-	-	-	-	-
Actual return on plan assets	-	-	-	-	-
Employer contribution	7,381	88	24	2	7,495
Plan participants' contributions	-	-	-	-	-
Benefits paid	(7,381)	(88)	(24)	(2)	(7,495)
Fair value of plan assets at end of year	-	-	-	-	-
Net Periodic Benefit Cost	2011				
Service cost	3,775	16	72	45	3,908
Interest cost	11,259	79	121	48	11,507
Actuarial (gain)/loss during current period	35,658	261	309	151	36,379
Other adjustments to Allocate Costs to Period in which Service is Rendered:					
- Amortization of net (gain) loss	(34,871)	(415)	(309)	(151)	(35,746)
- Amortization of prior service cost					-
July 2000 past service costs	(135)	(18)	(3)	-	(156)
Jan 2001 past service costs	168	12	2	-	182
Jan 2003 past service costs	840	217	8	-	1,065
Total Net periodic benefit cost	16,694	152	200	93	17,139
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)	December 31, 2011				
Funded status	(239,064)	(1,665)	(2,558)	(1,039)	(244,326)
Unamortized prior service costs					
July 2000 past service costs	-	(2)	(8)	-	(10)
Jan 2001 past service costs	-	5	-	-	5
Jan 2003 past service costs	842	218	32	-	1,092
Unamortized net actuarial (gains)/losses	64,680	(1,727)	517	228	63,698
Accrued benefit asset (liability)	(173,542)	(3,171)	(2,017)	(811)	(179,541)
Additional information at December 31, 2011					
Average future working lifetime	13.0	13.0	13.0	13.0	13.0
Expected benefit payments for 2012	7,987	79	22	13	8,101

sum = (176,370)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Key Assumptions					
Discount rate as at December 31, 2011 (for Dec 31, 2011 ABO)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate as at December 31, 2010 (for 2011 Benefit Cost)	5.75%	5.75%	5.75%	5.75%	5.75%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%	4.00%
Assumed medical and dental cost trend rate at December 31, 2011					
Dental care cost trend rate assumed for next year	4.00%	4.00%	4.00%	4.00%	4.00%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	7.00%	7.00%	7.00%	7.00%	7.00%
Rate that the cost trend gradually declines to	5.00%	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Health care cost trend rate assumed for next year	8.50%	8.50%	8.50%	8.50%	8.50%
Rate that the cost trend gradually declines to	5.00%	5.00%	5.00%	5.00%	5.00%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2011					
1% point increase	2,651	15	43	24	2,733
1% point decrease	(1,818)	(12)	(33)	(17)	(1,880)
Effect on accrued benefit obligation at December 31, 2011					
1% point increase	35,923	240	528	242	36,933
1% point decrease	(27,655)	(190)	(391)	(181)	(28,417)
Sensitivity to Changes in Discount Rate Assumption					
Effect on estimated 2012 Net Periodic Benefit Cost					
1% point increase	(2,950)	(21)	(37)	(22)	(3,030)
1% point decrease	3,355	25	46	23	3,449
Effect on accrued benefit obligation at December 31, 2011					
1% point increase	(32,384)	(226)	(347)	(141)	(33,098)
1% point decrease	41,998	293	449	183	42,923

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January 13, 2013

Ms. Aida Cipolla
Toronto Hydro
14 Carlton Street
Toronto, ON
M5B 1K5

Dear Aida:

POST-EMPLOYMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2012 YEAR END DISCLOSURES AND ESTIMATED 2013 AND 2014 NET PERIODIC COST UNDER US GAAP

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-employment benefits plans ("the Plans"):

- Extended health benefits for retirees and members on long-term disability;
- Dental benefits for retirees and members on long-term disability;
- Life insurance benefits for retirees;
- Sick leave benefits; and
- OMERS top up pension.

This letter and appendices have been prepared for the Company for the following purposes:

- Determining the final calculation of the 2012 net periodic benefit cost to be reported in the Company's 2012 financial statements;

- Providing the required information for year-end disclosure purposes as of December 31, 2012 to be reported in the Company's 2012 financial statements; and

- Determining an estimate of 2013 and 2014 net periodic benefit cost.

The information contained in this letter and appendices is presented in thousands of Canadian dollars and is in respect of the benefits mentioned above only.

All valuation results and accounting calculations presented in this letter and appendices were prepared in accordance with US GAAP (FASB Accounting Standards Codification 715).

The 2012 net periodic benefit cost is consistent with the 2012 net periodic benefit cost provided in our 2011 disclosure letter dated February 5, 2012. The 2012 year-end disclosure obligations and extrapolations for 2013 and 2014 are based on the January 1, 2012 actuarial valuation conducted by Towers Watson.

In 2012, the Company implemented exit programs resulting in the termination of employees in 2012 and 2013. As directed by the company, the impact of the programs was treated as actuarial gains/losses as at December 31, 2012 in the financial accounting for the Plans under US GAAP.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Please refer to the January 1, 2012 actuarial valuation report prepared by Towers Watson for the summaries of the plan provisions, the membership data and the actuarial basis used in the valuation.

ACTUARIAL ASSUMPTIONS AND METHODS

- The measurement date used for fiscal 2012 year-end disclosure is December 31, 2012.
- The 2012 benefit cost is based on a discount rate of 4.75% per annum and the accrued benefit obligation ("ABO") at December 31, 2012 is based on a discount rate of 4.25% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2011 and at December 31, 2012, respectively.
- The actuarial methods and assumptions used for the determination of the 2012 net periodic benefit cost are consistent with those used for the 2011 disclosures.
- With the exception of the discount rate, the actuarial methods and assumptions used to determine the December 31, 2012 obligation are consistent with those used for the January 1, 2012 valuation presented on December 12, 2012.
- The obligation as of December 31, 2012 and the 2013 and 2014 expense estimates are based on extrapolations from the January 1, 2012 valuation results, assuming that there are no experience gains and losses other than from actual benefit payments being different from expected, and reflecting changes in the assumptions during the extrapolation period such as changes in the discount rate.

DISCLOSURE RESULTS SUMMARY

The summary of Fiscal 2012 net periodic benefit costs, the ABO and accumulated other comprehensive income ("AOCI") as at December 31, 2012, under US GAAP are as follows (in $000s):

	Fiscal 2012 Net Periodic Benefit Costs	***ABO at December 31, 2012***	***AOCI at December 31, 2012***
Toronto Hydro-Electric System Limited	$ 20,354	$ 247,777	$ 61,823
Toronto Hydro Corporation	199	2,076	(1,194)
Toronto Hydro-Energy Service Incorporation	245	2,928	675
Toronto Hydro-LDC Unregulated	121	1,109	195
Toronto Hydro – Consolidated	20,919	253,890	61,499

- Actual benefit payments for 2012 of $8,069,000 are based on information provided by the Company on January 8, 2013. We have projected 2013 and 2014 benefit payments based on the valuation assumptions.

ACCOUNTING METHODS

- Actuarial gains and losses will be reflected in the statement of comprehensive income. To the extent that they exceed 10% of the accumulated benefit obligation, these gains and losses will be recognized over the expected average remaining service period of active employees participating in the plans.

- Prior service costs will be reflected in the statement of comprehensive income, and recognized through expense over a straight line basis over the average service period (to full eligibility) of employees active at the date of amendment.

OTHER COMMENTS

- The Company transitioned to US GAAP from Canadian GAAP for financial reporting effective January 1, 2012. Please refer to the 2011 disclosure letter dated February 5, 2012 for additional details.

- We understand that the post-retirement benefit plan is not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.

- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2012 that would materially affect the results of our valuations.

* * * * *

ACTUARIAL CERTIFICATION

The consulting actuaries are members of the Canadian Institute of Actuaries and Society of Actuaries and other professional actuarial organizations and meets their "General Qualification Standard for Statements of Actuarial Opinions" relating to pension and other postretirement benefit plans.

In preparing the results presented in this letter (including attached exhibits), we have relied upon information provided to us regarding plan provisions, actual benefit payments, historical plan costs and plan participants. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this letter is dependent upon the accuracy and completeness of the underlying information.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are no other subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

The actuarial assumptions and the accounting policies and methods employed in the development of the pension and postretirement plan costs have been selected by the Toronto Hydro management as representing their best estimates of future contingent events. The assumptions are not intended to include any provision for adverse deviations, and we do not express any opinion of them. FASB ASC 715 requires that each significant assumption "individually represent the best estimate of a particular future event."

The results shown in this letter have been developed based on actuarial assumptions that are considered to be reasonable and within the "best-estimate range" as described by the Actuarial Standards of Practice. Other actuarial assumptions could also be considered to be reasonable and within the best-estimate range. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

* * * * *

The information contained in this report was prepared for Toronto Hydro, for its internal use and for the preparation of its periodic financial disclosures, and its auditors, for the preparation of its periodic financial disclosures. It is neither intended nor necessarily suitable for other purposes. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited with Towers Watson's prior written consent.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Towers Watson

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Enclosures

cc: Lance Lugsdin, Shirley Powell, Helen Macdonald — Toronto Hydro
Olga Baliakina, Mitchell Coviensky — Towers Watson

Post-Employment Benefits Plan - US GAAP - 2012 Disclosure ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Funded status			January 1, 2012		
Funded status	(239,064)	(1,665)	(2,558)	(1,039)	(244,326)
Current vs. Non-Current OPEB Liability			January 1, 2012		
Current	(7,804)	(77)	(21)	(13)	(7,915)
Non-Current Liability	(231,260)	(1,588)	(2,537)	(1,026)	(236,411)
Total	(239,064)	(1,665)	(2,558)	(1,039)	(244,326)
Amounts Recognized in Accumulated Other Comprehensive Income			January 1, 2012		
Prior service (credit)/cost					
July 2000 past service costs	-	(2)	(8)	-	(10)
Jan 2001 past service costs	-	5	-	-	5
Jan 2003 past service costs	842	218	32	-	1,092
Net actuarial (gain)/loss	64,680	(1,727)	517	228	63,698
Total	65,522	(1,506)	541	228	64,785
Change in Accumulated Benefit Obligation (ABO)			2012		
Accumulated benefit obligation at beginning of year	239,064	1,665	2,558	1,039	244,326
Service cost	4,976	21	95	59	5,151
Interest cost	11,402	78	125	52	11,657
Actuarial (gain) loss	277	412	159	(23)	825
Benefits paid	(7,942)	(100)	(9)	(18)	(8,069)
Accumulated benefit obligation at end of year	247,777	2,076	2,928	1,109	253,890
Change in Plan Assets			2012		
Fair value of plan assets at beginning of year	-	-	-	-	-
Actual return on plan assets	-	-	-	-	-
Employer contribution	7,942	100	9	18	8,069
Plan participants' contributions	-	-	-	-	-
Benefits paid	(7,942)	(100)	(9)	(18)	(8,069)
Fair value of plan assets at end of year	-	-	-	-	-
Net Periodic Benefit Cost			2012		
Service cost	4,976	21	95	59	5,151
Interest cost	11,402	78	125	52	11,657
Amortization of prior service cost					-
July 2000 past service costs	-	(2)	(3)	-	(5)
Jan 2001 past service costs	-	5	-	-	5
Jan 2003 past service costs	840	217	8	-	1,065
Amortization of net (gain) loss	3,136	(120)	20	10	3,046
Net periodic benefit cost	20,354	199	245	121	20,919
Funded status			December 31, 2012		
Funded status	(247,777)	(2,076)	(2,928)	(1,109)	(253,890)
Current vs. Non-Current OPEB Liability			December 31, 2012		
Current	(9,790)	(79)	(37)	(19)	(9,925)
Non-Current Liability	(237,987)	(1,997)	(2,891)	(1,090)	(243,965)
Total	(247,777)	(2,076)	(2,928)	(1,109)	(253,890)
Amounts Recognized in Accumulated Other Comprehensive Income			December 31, 2012		
Prior service (credit)/cost					
July 2000 past service costs	-	-	(5)	-	(5)
Jan 2001 past service costs	-	-	-	-	-
Jan 2003 past service costs	2	1	24	-	27
Net actuarial (gain)/loss	61,821	(1,195)	656	195	61,477
Total	61,823	(1,194)	675	195	61,499
Additional information					
Average future working lifetime as at December 31, 2012	18	15	13	15	
Average future working lifetime as at December 31, 2011	13	13	13	13	
Key Assumptions					
Discount rate as at December 31, 2012 (used for Dec 31/12 ABO)	4.25%	4.25%	4.25%	4.25%	4.25%
Discount rate as at December 31, 2011 (used for 2012 Benefit Costs)	4.75%	4.75%	4.75%	4.75%	4.75%
Rate of compensation increase	4.0%	4.0%	4.0%	4.0%	4.0%
Assumed medical and dental cost trend rate at December 31, 2012					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Medical cost trend rate assumed for next year	6.5%	6.5%	6.5%	6.5%	6.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Medical cost trend rate assumed for next year	8.0%	8.0%	8.0%	8.0%	8.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2012					
1% point increase	2,461	12	39	22	2,534
1% point decrease	(2,164)	(9)	(33)	(17)	(2,223)
Effect on accrued benefit obligation at December 31, 2012					
1% point increase	31,479	221	477	170	32,347
1% point decrease	(27,614)	(198)	(417)	(151)	(28,380)
Sensitivity to Changes in Discount Rate Assumption					
Effect on estimated 2013 Net Periodic Benefit Cost					
1% point increase	(2,546)	(39)	(51)	(17)	(2,653)
1% point decrease	4,595	22	68	34	4,719
Effect on accrued benefit obligation at December 31, 2012					
1% point increase	(38,334)	(307)	(545)	(196)	(39,382)
1% point decrease	47,039	372	682	251	48,344
Projection of Benefit Payments					
2013	9,996	81	38	19	10,134
2014	8,039	82	40	22	8,183
2015	8,238	85	44	25	8,392
2016	8,912	85	51	28	9,076
2017	9,354	83	57	30	9,524
2018-2022	54,821	450	461	180	55,912

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 29:

Reference(s): Exhibit 2A, Tab 1, Schedule 2, App. 2-BA, pp.5-6

In the above reference, retirements and derecognition of gross costs are shown for 2014 and 2015 under MIFRS. Retirements are shown as $3.6 million in 2014 and $32.4 million in 2015. Derecognition is shown as $83.1 million in 2014 and $101.9 million in 2015.

a) Please explain how THESL differentiates between the two categories of retirements and derecognition;
b) Please identify and describe the capital projects that give rise to these retirements and derecognition of fixed assets which are or were presumably in service;
c) Please state where in the application the cost recovery of these amounts is shown;
d) Please state whether or not it is expected that more than $100 million of fixed assets will be stranded per year during the test period 2015-2019;
e) In these schedules, additions and transfers of gross cost are shown. Please explain what are the transfers and to whom or to what they are transferred.

RESPONSE:

a) Retirements relate to the disposal of rolling stock and properties. The gain or loss on disposition is calculated as the difference between the net disposal proceeds and the carrying amount of the item of PP&E and any related asset retirement obligation. The gains from the disposition of rolling stock and properties are recorded in profit or loss. The expected gain on disposition in 2015 has been deferred on the balance sheet.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

Derecognition relates to the disposition of assets that are not individually identifiable.[1] Toronto Hydro does not expect any proceeds from the disposition of these assets. Losses resulting from the disposition of assets with a carrying amount are recorded as depreciation expense as shown in Exhibit 4B, Tab 1, Schedule 1, Appendix A.

b) In 2014, the retirement amounts relate to the disposal of two properties, 10 Gamble Avenue and 1255 York Mills Rd, and the reversal of the Asset Remediation Obligation assets for certain properties ($1.7 million) and wooden poles ($1.2 million). As part of ongoing efforts to improve operational efficiency, Toronto Hydro determined that the effort required to maintain Asset Remediation accounting for these assets does not justify the results obtained. Toronto intends to charge minor remediation costs to OM&A as they are incurred going forward. Large value and long-term remediation costs continue to be accrued.

In 2015, the retirement amounts relate to the forecasted disposal of two properties, 5800 Yonge Street and 28 Underwriters Road.

Please refer to Toronto Hydro's response to interrogatory 9-OEBStaff-92 part (a) for a description of capital projects that give rise to derecognition of fixed assets.

[1] Accounting Procedure Handbook ("APH") Article 410: Accounting for Specific Items – Property, Plant & Equipment and Intangible Assets, Pages 13-17.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

c) The expected gain from the retirements of land and buildings has been deferred on the balance sheet. The derecognition loss is recorded as depreciation expense as shown in Exhibit 4B, Tab 1, Schedule 1.

d) It is not expected that more than $100 million of fixed assets will be stranded per year during the test period 2015-2019. Please refer to Exhibit 4B, Tab 1, Schedule 2, Table 1 for the forecasted losses on derecognition for the years 2014 to 2019.

e) The 2014 transfers relate to the reclassification of ICM in-service assets from PP&E to Regulatory Assets. In 2015, the transfers relate to the reclassification from PP&E to Regulatory Assets of Eligible Investments and Hydro One Capital Contributions. For more information regarding all of these accounts, please refer to Exhibit 9, Tab 1, Schedule 1, Sections 5.9 (Hydro One Capital Contributions), 6.2 (GEA / eligible investments), and 6.5 (ICM Assets).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 30:

Reference(s): **EB-2009-0180/-0181/-0182/-0183, Decision and Order, August 3, 2011, pp. 14-15 and**
Exhibit 2A, Tab 5, Schedule 1, pp. 17-19

The first reference is from the Board's findings in what THESL refers to as the "Valuation Decision". In that Decision, the Board found that the proposed transfer price for streetlighting assets of $28.938 million was reasonable and that the rate base, revenue requirement and rate consequences of the subject transfer should be determined in the context of THESL's next cost of service based rates application. The Board does not appear to make reference to any further revaluation of these assets in the Decision.

In the second reference, THESL explains why it believes that it is appropriate that the proposed 2014 NBV of the former streetlighting assets of $39.8 million be used rather than the original amount approved by the Board in the Valuation Decision of $28.9 million and states that:

> …it is still the case that the proxy value of $28.9 million provided at the time was the result of two simplifying assumptions that had to be made due to the lack of more precise information. .. However, the detailed analysis does not increase the value of the overall asset; rather, it changes the proportion of the unchanged total amount that is transferred to Toronto Hydro.

a) Please state whether or not and why THESL would view its detailed analysis as a revision of the asset valuation, rather than an update of the Board approved level given its comments related to the two simplifying assumptions in the second reference above;

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

b) If THESL views its detailed analysis as a revision of the asset valuation, please state why it believes its proposed approach would be in compliance with the Valuation Decision;

c) Please provide further explanation of the statement above that the detailed analysis does not increase the value of the overall asset.

RESPONSE:

a) Toronto Hydro views its detailed analysis as an <u>update</u> to the OEB-approved level. The OEB concluded in the Valuation Decision that the rate base, revenue requirement, and rate consequences of the street lighting transfer would be determined in the context of Toronto Hydro's next cost of service based rate application.[1] Because Toronto Hydro's 2012 cost of service application (EB-2011-0144) was dismissed, the OEB has not made final determinations of the amounts and assets to be transferred. All of these determinations are directly connected to and dependant on the value of the transferred assets, which was updated by Toronto Hydro to: 1) address the simplifying assumptions that had to be made in the context of the Valuation Decision, using better information that became available to Toronto Hydro through the detailed analysis, and 2) account for the natural evolution of the assets since the Valuation Decision.

b) Toronto Hydro views the detailed analysis as an update to the asset valuation, and believes that the updated value better adheres to the principles of the OEB's Decisions.[2] In particular, Toronto Hydro considers that the new information derived

[1] EB-2009-0180 et al., Decision and Order (August 3, 2011), at page 15 ["Valuation Decision"].
[2] EB-2009-0180, et al., Decision and Order (February 11, 2010) ["Classification Decision"]; and the Valuation Decision, *supra* note 1.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

from the detailed analysis described in Exhibit 2A, Tab 5, Schedule 1, provides a better approximation for the depreciated historic cost method ("DHC") of the transferred assets, which the OEB found to be a more appropriate valuation methodology.[3] This conclusion was independently confirmed by PricewaterhouseCoopers LLP ("PWC") in the report filed at Exhibit 2A, Tab 5, Schedule 2.

c) Toronto Hydro refers to the combined Net Book Value (NBV) of both the transferred and un-transferred assets as the '*value of the overall assets*'. The purpose of the detailed analysis was to decompose the value of the overall assets into transferrable and non-transferrable amounts, consistent with the OEB's Decisions and the additional information that became available to Toronto Hydro through the detailed analysis. The overall value of the assets was held constant throughout, and therefore did not change as a result of the detailed analysis.

[3] Valuation Decision, *supra* note 1, at page 14.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 31:

Reference(s): **Exhibit 2A, Tab 5, Schedule 1, p. 22**

Table 4 of the above reference "Revenue Requirement from Streetlighting Assets ($ millions)" shows a service revenue requirement for the 2015 Test year of $8.1 million, which is offset by a "Revenue Offset – Contract Revenue" amount of $8.1 million producing a base revenue requirement of zero.

THESL's explanation of this adjustment is that:

> Under existing agreements between TH Energy and the City of Toronto, TH Energy receives service fees for the maintenance and operation of the street lighting assets. Given the transfer of a portion of these assets into Toronto Hydro's rate base as distribution assets, Toronto Hydro proposes to allocate a portion of the revenue that it expects to receive to exactly offset the revenue requirement impacts arising from the transfer. Consequently, there is no overall change to the Base Revenue requirement for 2015 as a result of these assets being transferred into the utility's rate base.

a) Please state whether the existing agreements between TH Energy and the City of Toronto will be transferred over to THESL and, if so, whether they will be transferred unchanged, or if any modifications will be made. If modifications are anticipated, please state what they will be;
b) THESL states that it proposes to allocate a portion of the revenue it expects to receive. Please state what the anticipated total amount of expected revenue would be;

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c) If THESL was not to make the revenue offset shown in Table 7, please state what the impact would be.

RESPONSE:

a) The existing agreements between TH Energy and the City of Toronto will not be transferred to Toronto Hydro. Rather, to meet its obligations under the existing agreements, insofar as they relate to the transferred portion of the assets, TH Energy has sub-contracted the performance of the services to Toronto Hydro.

b) The total amount of revenue that Toronto Hydro expects to receive from the City Contract is $8.1 million, consistent with the revenue requirement calculation outlined in Exhibit 2A, Tab 5, Schedule 1, Table 7. For greater clarity, the $8.1 million figure represents a portion of the total revenue under TH Energy's contract with the City of Toronto. Toronto Hydro proposes to allocate this entire $8.1 million amount to offset the revenue requirement costs associated with the transferred assets.

c) If Toronto Hydro did not include $8.1M from the Streetlighting contract as a directly allocated revenue offset, then $8.1M of additional Base Revenue requirement would need to be collected through Base Distribution Rates charged to all customers.

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INTERROGATORY 32:

Reference(s): **Exhibit 2A, Tab 8**

As per the Filing Requirements for Electricity Rate Applications for 2015 Rate Applications, section 2.5.2.5, relating to renewable enabling investments, provincial rate recovery, please provide a draft accounting order for the requested variance account to track IESO payment revenues against the actual spending.

RESPONSE:

Please see Appendix A.

Renewable Enabling Investments Provincial Rate Protection Variance Account – Draft Accounting Order

Toronto Hydro is planning a number of Renewable Generation Connection investments which may be eligible for rate protection under the provisions of O. Reg. 330/09 (Cost Recovery Re Section 79.1 of the [OEB] Act. Eligible investments are as described under section 79.1 of the Ontario Energy Board Act, 1998.

In accordance with the Board's Filing Requirements for Electricity Distribution Rate applications (dated July 17, 2013) Chapter/Section 2.5.25 and Appendices 2-FA, 2-FB and 2-FC regarding Costs of Eligible Investments for the Connection of Qualifying Generation Facilities, Toronto Hydro shall establish a variance account to track the variance between Toronto Hydro's revenue requirement required to support the portion of the investments that are eligible for rate protection, and the rate protection payments collected from the Independent Electricity Systems Operator (IESO).

Toronto Hydro will calculate and record as a debit to the variance account, the revenue requirement associated with the portion of the capital costs that are eligible for provincial rate protection, as incurred by the utility for eligible renewable enabling investments for the period of 2015 through 2019.

Toronto Hydro will record as a credit to the variance account, the amounts collected from the IESO as a result of any OEB order directing such payments from the IESO to Toronto Hydro.

The balance in the account will not attract carrying charges.

Toronto Hydro will establish the following variance account to record the amounts described above:

- Account XXXX (TBD upon OEB approval, note 1) - Renewable Enabling Investments (REI) Provincial Rate Protection Variance Account

The sample accounting entries for the Variance Account are provided below.

a. To record the Renewable Enabling Investments (REI) capital expenditures:
    - DR 2055 Construction Work in Progress - Electric
    - CR 1005 Cash

b. To transfer the REI expenditures to Property, Plant and Equipment (PP8E) (Electric Plant in Service) :
    - DR Various Accounts Property, Plant and Equipment - Renewable Enabling Investments (PP*E)
    - CR 2055 Construction Work in Progress – Electric

c. To record amortization for the Renewable Energy Investments PP*E capital costs:
    - DR 5705 Depreciation Expense – Property, Plant and Equipment
    - CR 2105 Accumulated depreciation of Electric Utility Plant – Property, Plant and Equipment (REI)

d. To record amounts collected from the IESO for the Provincial Rate Protection Payments, to fund the Renewable Enabling Investments:
    - DR 1005 Cash
    - CR 4080 Distribution Services Revenue – Sub-account, REI Revenue Requirement

e. To record the annual true-up for the Renewable Enabling Investments Provincial Rate Protection revenue requirement variance: (the variance as defined in note 2. below)
    - DR/CR XXXX (TBD, note 1) REI Provincial Rate Protection Variance Account
    - CR/DR 4080 Distribution Services Revenue – Sub-account, REI Revenue Requirement

Notes:

1. There is no OEB prescribed Variance Account in the OEB APH for the "Renewable Enabling Investments (REI) Provincial Rate Protection Variance Account, specifically defined for the purpose described above. The OEB account is TBD upon OEB approval.

2. REI Provincial Rate Protection Variance Account calculation:
   Record the net of:
    i. The revenue requirement associated with the portion of the capital costs that are eligible for provincial rate protection, as incurred by the utility for eligible renewable enabling investments;
       AND
    ii. The amounts collected from the IESO as a result of any OEB order directing such payments from the IESO to Toronto Hydro.

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INTERROGATORY 33:

Reference(s): **Exhibit 2B, Section 00, p. 8 and**
Exhibit 2B, Section A, p. 4, lines 28-30

In the first reference, the histograms on this page show "proposed CIRs" for 2019 as: SAIDI 1.02 and SAIFI 1.19.

The numbers provided in the above references are summarized in the table below. There is a difference in the starting year for the quoted reliability numbers in each reference but the reference 2 numbers are not consistent with the histogram in reference 1. Furthermore, the end year for the comparison is the same but the Reference 2 numbers do not match the numbers in reference 1 histograms.

Reference		**2014**	**2015**	**2019**
1. Exhibit 2B, Section 00, p. 8 (histograms)	SAIDI		1.23	1.02
	SAIFI		1.55	1.19
2. Exhibit 2B Section A, p. 4, lines 28-30	SAIDI	1.21		0.97
	SAIFI	1.53		1.13

a) Please explain why there are different numbers in the two references;
b) Please provide a table showing the correct forecast SAIDI and SAIFI numbers for years 2014-2019 for the scenario for i) Run-to-fail and ii) with proposed requested renewals capital expenditures.

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RESPONSE:

a) The differences are a result of an editing mistake. The numbers provided in Exhibit 2B Section A, page 4, lines 28-30 are incorrect. The correct projections are shown in Exhibit 2B, Section 00, page 8 (see also part b for the projection values.)

b) Please see the table below:

		2014	2015	2016	2017	2018	2019
SAIDI	Run To Fail	1.21	1.26	1.31	1.37	1.43	1.50
	Proposed CIR		1.23	1.17	1.12	1.08	1.02
SAIFI	Run To Fail	1.53	1.67	1.74	1.81	1.90	1.99
	Proposed CIR		1.55	1.44	1.36	1.27	1.19

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INTERROGATORY 34:

Reference(s): Exhibit 2B, Section 00, p. 38, lines 30-31

It is stated that "The projected budgets from 2016 to 2019 for System O&M are expected to increase in line with inflation."

a) Please expand on the above statement, indicating relationships to construction material indices, labour rates and any other variables which THESL considers important;
b) Please discuss the expected effect of the asset renewal program on O&M as the health index of assets improves;
c) Please state the efficiencies that are expected to be implemented in O&M that are expected to reduce O&M costs. Please relate these efficiencies to the programs for the respective Asset Access, Renewal and Service, and General Plant.

RESPONSE:

a) Inflationary pressures on System O&M work are predominantly attributed to increases in internal labour rates and increases in market rates for external service providers. From an internal perspective, Toronto Hydro operates in a unionized environment where staff is represented by either CUPE or the Society of Energy Professionals. Pursuant to the collective agreements with these unions, Toronto Hydro will experience the following increases in wage rates:

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- a 1.75% average annual wage rate increase for CUPE employees pursuant to the current collective agreements that expire in January of 2018 (Exhibit 4A, Tab 4, Schedule 5, pages 9-10); and
- a 2% annual wage rate increase for Society employees during 2014 and 2015 pursuant to the current collective agreement that expires in December of 2015 and that will require renegotiation (Exhibit 4A, Tab 4, Schedule 5, page 10).

From an external perspective, Toronto Hydro routinely enters into competitively sourced agreements with third parties to provide various O&M services (e.g., cable locates, tree trimming, line patrols, vault inspections). External service providers are subject to their own cost pressures, which are reflected in increased prices submitted to Toronto Hydro.

b) Toronto Hydro expects the system renewal investments and improvements in asset health to have the following impacts on O&M, as noted in Exhibit 2B, Section 00, page 38:

i) No Impact on a Large Subset of the Expenditures: A significant portion of Predictive and Preventive Maintenance expenditures are for activities that are not directly related to particular planned capital programs and asset health indices. For these programs, asset renewal is not expected to impact maintenance. Examples include:
   - vegetation management to maintain minimum clearance requirements for overhead conductors and equipment;
   - fixed-cycle patrols and asset inspections undertaken to comply with minimum Distribution System Code requirements;

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- other preventive and corrective maintenance and overhaul activities to maintain equipment function; and
- emergency response following asset failure, in particular failures caused by severe weather and storm damage, and other abnormal system events.

ii) Reduce Expenditures in Some Areas: As the asset base is renewed, corrective maintenance activities and costs related to deteriorated asset health and increased asset can be expected to decrease as can costs related to specific asset classes that are eliminated from the system such as porcelain insulators (e.g., insulator washing) and fibertop network protectors (e.g., fibertop cleaning).

iii) Increase Expenditures in Some Areas: Any planned capital program that results in an increase in asset count will necessitate a corresponding increase in the maintenance programs required for those assets.

c) Efficiencies that are proposed to be implemented across Toronto Hydro's maintenance programs include standardizing station maintenance cycles to eliminate multiple scheduled outages, implementing "find and fix" protocols to reduce follow-up visits and associated mobilization costs, issuance of longer-term inspection maintenance contracts to third party service providers for improved cost stability, and introducing new tools to improve inspection efficiency and data quality. Cost savings arising from these efficiencies are expected to reduce corrective maintenance costs over time; the impact can be quantified once these initiatives are fully implemented. The use of new tools and technologies is expected to improve condition-based maintenance practises, and provide more accurate asset health and condition information to Toronto Hydro's capital plans. Other examples of Toronto Hydro's

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ongoing and planned productivity and efficiency initiatives are discussed in the Exhibit 1B, Tab 2, Schedule 5. Consistent with its CIR rate framework proposal, Toronto Hydro expects to manage its overall OM&A envelope expenditures over the 2016-2019 period by identifying and implementing productivity and efficiency initiatives throughout the CIR period.

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INTERROGATORY 35:

Reference(s): **Exhibit 2B, Section D, App. A, Kinectrics Report**

At page 9 of the above reference in the first paragraph of the section entitled "Changes in Sample Size", it is indicated that for a particular asset to be included "60% of required condition data must be available in order to be included into the sample size."

In the fourth paragraph it states: "Generally, a minimum sample size of 10% is required to extrapolate ACA results over an entire population."

On page 10, Table 1 provides "Summary Change in Population and Sample Size" and indicates that the minimum percentage sample size in 2014 is 32%.

a) Based on the minimum sample size of 32%, please state whether or not it would be correct to infer that one could theoretically extrapolate over an entire population with just 32%x60%=19.2% of the ACA data points;

b) Please state how THESL utilizes the extrapolations, including discussion of the questions below:

   i) If THESL has a sample size of 32% for an asset, what does the extrapolation to the whole population allow THESL to do? Is planning based on the extrapolated population distribution?

   ii) Would THESL use the extrapolated number for assets which are at or beyond end-of-life as the number of devices that need to be replaced?

   iii) If a sample size of 25% of the population shows that half is beyond end of life, would THESL assume the same holds true for the extrapolated population, and then plan to replace half the entire population?

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c) Using the example in Table 1 of the Asset "7", "SF6 CB", please describe the selection procedure according to which the samples were selected, including answering the following:

Please discuss how THESL would describe the process of sample data collection stating whether or not it was consciously randomized, or "convenience" or "opportunity" sampling.

If the process was not consciously randomized, please state whether the samples were taken from breakers that had been a) routinely serviced, or b) breakers that had to be repaired.

If the data was taken from breakers that had been serviced, please state the procedure according to which it was decided to service those breakers including whether or not servicing of breakers was done by a random selection.

Please comment on the importance of using randomized data in order to extrapolate information from a sample to an entire population.

RESPONSE:

a) A sample size of 32% does not equate to knowing only 19.2% of ACA data points. Toronto Hydro employs a 60% Data Availability Rule. According to this, 60% of an asset's ACA data must be available for the asset to be included in the sample. This is based on the premise that the health of an asset can be reasonably estimated if 60% or more of its data is available . It then follows that every asset in the sample has, at a

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minimum, 60% of its ACA data. A Sample Size of 32% would mean that for the 32% of the asset population that constitutes the sample, each asset has at least 60% of its ACA data. Please refer to page 76 of the Kinectrics Report found in Exhibit 2B, Section D, Appendix A for detailed definitions.

b) Responses below:

i) Toronto Hydro uses ACA as a consideration/indicator for a given asset class and assists in guiding the overall priority and pace of replacement, but is not the only tool used in making Asset Management decisions. If ACA scores for a given asset class are generally poor, but it has a smaller sample size, it will prompt further investigation by the Asset Management planning team. As an example, age and equipment manufacturer data of equipment without HI scores will be compared against similar assets with HI scores available.

ii) Note that 'end-of-life' is an age-based assessment of assets, whereas ACA is a condition-based assessment (see response to Interrogatory 1B-BOMA-31part (b)). As stated in (i), if a small sample size exists for an asset class with poor ACA scores, it will prompt further investigation from the Asset Management planning group.

iii) No. While poor ACA results would prompt concern, Toronto Hydro will investigate the condition of assets without HI scores prior to issuing capital work to replace them.

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c) Maintenance of these assets is done on a fixed cycle. As a result, the inspection data is ‘consciously randomized’, as opposed to ‘convenience’ or ‘opportunity’ sampling.

As noted above, inspection data is generally collected during periodic maintenance activities. However, abnormal system events (such as failure of adjacent equipment) could generate an inspection outside of the normal planned cycle.

In general, randomized data is important to provide meaningful and accurate statistical information when sampling a diverse population.

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INTERROGATORY 36:

Reference(s): **Exhibit 2B, Section D3**
Exhibit 2B, Section E6.14
Exhibit 2B, Section D4, App. A

Board staff notes that in regard to the process for determining which devices are to be replaced and when they are to be optimally replaced, a key concept is the end-of-life of the particular asset. Board staff wants to understand the end-of-life concept as it is used in the application, and how critical this factor is in deciding how many units of an asset should be replaced.

a) Please provide a copy of the following documents discussed at page 1 of Reference 3:
   i) the 2006 full Asset Condition Assessment (ACA) conducted by Kinectrics, or if there is a more recent full ACA the most recent one;
   ii) the stand-alone ACAs of Network Transformers, Network Vaults and Network Protectors by Kinectrics;
   iii) the 2012 condition assessments conducted internally by THESL;
b) Please explain the step by step descriptive process of determining the end-of-life for an asset, using the System Renewal program E6.14, “Stations Power Transformer Renewals” as an illustrative numerical example. Also provide flow diagrams if this would assist in the explanation;
c) Please confirm that the “Optimal Intervention Time” (in years), as described in Reference 1, page 8, figure 3, is in fact the “end-of-life” criteria for determining when a particular asset should be replaced;
d) Please explain how, in practice, the curves of figure 3 are determined;

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e) Please explain how the end-of-life for the asset is combined with the Health Index for the asset to determine that a particular asset should be replaced;

f) For the asset reference 2 it is stated at page 2 that "By 2015, an estimated 51.6% of in-service station power transformers will be beyond their expected useful lives of 45 years…" Please indicate:

   i) The depreciation life of these transformers for accounting purposes.
   ii) The population of transformers under consideration and how many transformers are represented by the 51.6%.
   iii) The sensitivity of the data, by determining what percent (and how many) of the transformers would be beyond their expected useful lives if the useful life had been calculated as 50 years.

RESPONSE:

a) Please see Appendices A, B and C to this Schedule.

b) The end-of-useful life for an asset, also known as useful life or mean life of the asset, is determined by identifying the exact mid-point between the minimum useful life ("UL") and maximum UL as defined by Kinectrics within their "Useful Life of Assets" report, which was filed in the EB-2010-0142 application (Exhibit Q1, Tab 2). For Stations Power Transformers, the minimum UL is 32 years and the maximum UL is 55 years. Therefore, the exact midpoint would be 43.5 years, rounded up to 44 years, which represents the statistical mean or useful life of the asset in question. In this instance, the Stations Power Transformer Renewal program references the Typical UL value provided within the Kinectrics report of 45 years, since this value is very close to the statistical mean or useful life value.

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c) The "Optimal Intervention Time" represents the economic end-of-life of an asset – not the end-of-useful-life explained in part (b) above. The economic end-of-life is established via the risk-based optimization approach (further explained in Section D3.1.2, pages 13-16), balancing the risk of asset failure against the capital cost of intervention. As such, the economic end-of-life takes into account the impact of asset failure to both Toronto Hydro and its customers. As part of the Investment Planning process explained in Section D3.1.1.3, age (or end-of-useful-life criteria), economic end-of-life criteria, asset condition and historical reliability results are collectively used as prioritization factors to identify assets across the system for renewal programs.

d) The curves in Figure 3 are determined by annualizing the capital cost and risk cost of an asset and summing the curves to produce a life cycle cost curve. Please see Exhibit 2B, Section D3.1.2.1 (i) (pages 6-9) for more details on these values.

e) The end-of-life (i.e., end-of-useful life) values that are available for the various asset classes are a key factor in identifying assets for replacement based on the age of the asset. The end-of-useful life provides an indication of the age based deterioration of the asset. The Health Index information provides an indication of the asset's condition in the field, allowing Toronto Hydro to isolate assets that are deteriorating faster than would be expected based on the age of the asset alone. Toronto Hydro uses age, condition and other factors (historical reliability, economic end-of-life criteria, etc.) as part of the investment planning process in order to prioritize assets within asset renewal programs. This process is further detailed in Exhibit 2B, Section D3.1.1.3.

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f)

i) For accounting purposes, Toronto Hydro uses a depreciation life of 32 years. This depreciation life was adopted January 1, 2011, based on the independent detailed review of useful lives conducted by Kinectrics. Refer to Exhibit 4B, Tab 1, Schedule 1 for background information on Toronto Hydro's depreciation and amortization policies. The 32 years depreciation life was selected for accounting purposes to align with the lower-end expected life identified by Kinectrics. This decision was made based on a commonly held industry perception that, due to a persistent incentive for suppliers to minimize cost, a newly designed and manufactured power transformer is not as robust and "over-engineered" as units built in the past. In development of the Distribution System Plan ("DSP"), Toronto Hydro decided to use the midpoint from the Kinectrics typical life study (45 years) because the DSP deals with lifecycle management of transformers that were designed and manufacturer multiple decades ago.

ii) The population of 248 power transformers is shown on page 16, line 22 of Exhibit 2B, Section E6.14. It is also shown at the bottom right corner of Figure 8 on page 17 of Exhibit 2B, Section E6.14. The 51.6% is derived by dividing the 128 transformers over 45 years old (typical useful life) by the total population of 248 transformers.

iii) For sensitivity analysis, if the useful life of a power transformer is changed to a theoretical value of 50 years old, then the percentage of power transformers exceeding the theoretical useful life would be 36.3% – equivalent to 90 power transformers.

DISTRIBUTION ASSET CONDITION ASSESSMENT FOR TORONTO HYDRO ELECTRICAL SYSTEMS LIMITED

Kinectrics Inc. Report No.: K-012905-RA-0002-R00

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DISTRIBUTION ASSET CONDITION ASSESSMENT
FOR
TORONTO HYDRO ELECTRICAL SYSTEMS LIMITED

Kinectrics Inc. Report No.: K-012905-RA-0002-R00

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Dated: Friday, February 2, 2007

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Toronto Hydro Electric Systems Limited.

REVISIONS

Revision Number	Date	Comments	Approved
Draft 0	**June 20, 2006**		
Draft 1	**October 12, 2006**		
Final 0	**January 25, 2007**		

EXECUTIVE SUMMARY

Arising from the 2006 rate application, the Ontario Energy Board requested that THESL submit an Asset Condition Assessment report in support of future rate applications. The Asset Condition Assessment is fundamental in developing maintenance plans and long-term asset replacement and capital investment plans. It is expected that knowledge of the asset condition will assist in defining immediate and then longer term programs and expenditures to ensure that assets are well managed and future rate shocks due to uneven capital replacements can be avoided.

THESL retained the services of Kinectrics Inc., experts on the technical aspects of the distribution utility business and particularly in the subject of condition assessment and Health Indices, to conduct an asset condition assessment and a field audit of asset condition.

This report provides an assessment of THESL's distribution asset condition based on existing available documentation, an audit of the assets, and an estimate of how many assets will require replacement within the next year and the next ten years.

A considerable portion of this work was devoted to the development of Health Indices that are uniquely tailored to THESL's assets and the condition information available. The report presents the Health Indices derived for the asset classes and provides some comparison of these indices with the previously used age-based method of asset condition assessment. The Health Index method provides THESL with a tool for improved tracking of asset condition, and managing and budgeting for asset replacement. The project has provided spreadsheets that implement the Health Index formulation.

The findings of Kinectrics review of asset condition at THESL are detailed in the balance of this report. In the majority of cases, the condition of the assets was within the range expected for distribution assets that are well maintained. Subject to the clarifications provided in this report, in general, Kinectrics found that the available records of assets provided by THESL accurately reflected the condition of the equipment in service.

In the case of a few specific assets classes at THESL, there are indications that assets may be deteriorating faster than they are being replaced and these require actions beyond routine maintenance. Indications of this include the increasing failure rates and the poor Health Indices of some classes of asset. For example, direct buried underground cables are a major component that suffers from this deterioration.

The prime results of the condition assessment for each asset class, based on existing condition data, are shown in the following Table ES-1. This is an ultimate best estimate of the condition of each asset class determined using the Health Index method, or the age-based method where sufficient condition data was not yet available at THESL. The percentage of the total population for each asset class in each condition category, "very good", "good", "fair", "poor", and "very poor", is shown in the "Asset Condition" column. The results show that most assets are in very good or good condition. This indicates in general that the maintenance and capital replacement programs at THESL have been well designed and executed.

The final column on the right hand side indicates the number of assets that are expected to require replacement within the next ten years and the percentage of the total asset class that this represents. It is recommended that the assets in "very poor" condition be planned for replacement in the next year, assets in "poor" condition be planned for years 2 and 3, and assets in "fair" condition be planned for replacement in 4 to 10 years. It is anticipated that the assets now in "fair" condition will be in "very poor" condition by the end of the ten years.

Table ES-1 Summary of Asset Condition

Asset Group	Asset Condition					Total Population	EOL within 10 years
	Very Good	Good	Fair	Poor	Very Poor		Units (%)
Station Transformers	49	92	114	30	2	287	146 (50%)
Circuit Breakers	823	822	60	18	9	1732	87 (5%)
Switchgear Assemblies	135	134	2	1	0	272	3 (1%)
Buildings	0	0	0	0	0	16	0 (0%)
Network Trans./Protectors	701	700	459	130	65	2,055	654 (32%)
Pole Mounted Transformers	10,000	10,000	7490	2140	1070	30,709	10,700 (35%)
Submersible Transformers	3095	3094	1470	420	210	8,289	2,100 (25%)
Vault Transformers	7178	3900	1330	11	0	12,409	1,341 (11%)
Pad Mounted Transformers	4950	4950	770	220	110	5,609	1,100 (20%)
Wood Poles	63,880	63,880	22,358	6388	3194	159,700	31,940 (20%)
Overhead Switches – Remote Operated	72	330	103	0	0	505	103 (20%)
Overhead Switches – Manual	506	404	36	0	0	946	36 (4%)
Pad Mounted Switchgear	341	341	42	12	6	742	60 (8%)
Automatic Transfer Switches	28	14	71	0	0	113	71 (63%)
Underground Cable – XLPE in Ducts	N/A	2497	0%	0%	N/A	2,497	0 km (0%)
Underground Cable – PILC in Ducts	N/A	862	308	74	N/A	1,243	382 km (31%)
Underground Cable – XLPE Direct Buried	N/A	494	479	298	N/A	1,271	777 km (61%)
Network Vaults	498	497	52	1	0%	1,048	53 (5%)
Cable Chambers	4985	4985	71	20	10	10,071	101 (1%)

Note: NA indicates no data was available

The assets that require the most significant replacement programs in the next ten years are:

- Direct buried underground cable (61% of the population)
- Automatic transfer switches (63%)
- Station transformers (50%).
- Pole mounted transformers (35%)
- Network transformer/protector units (32%)

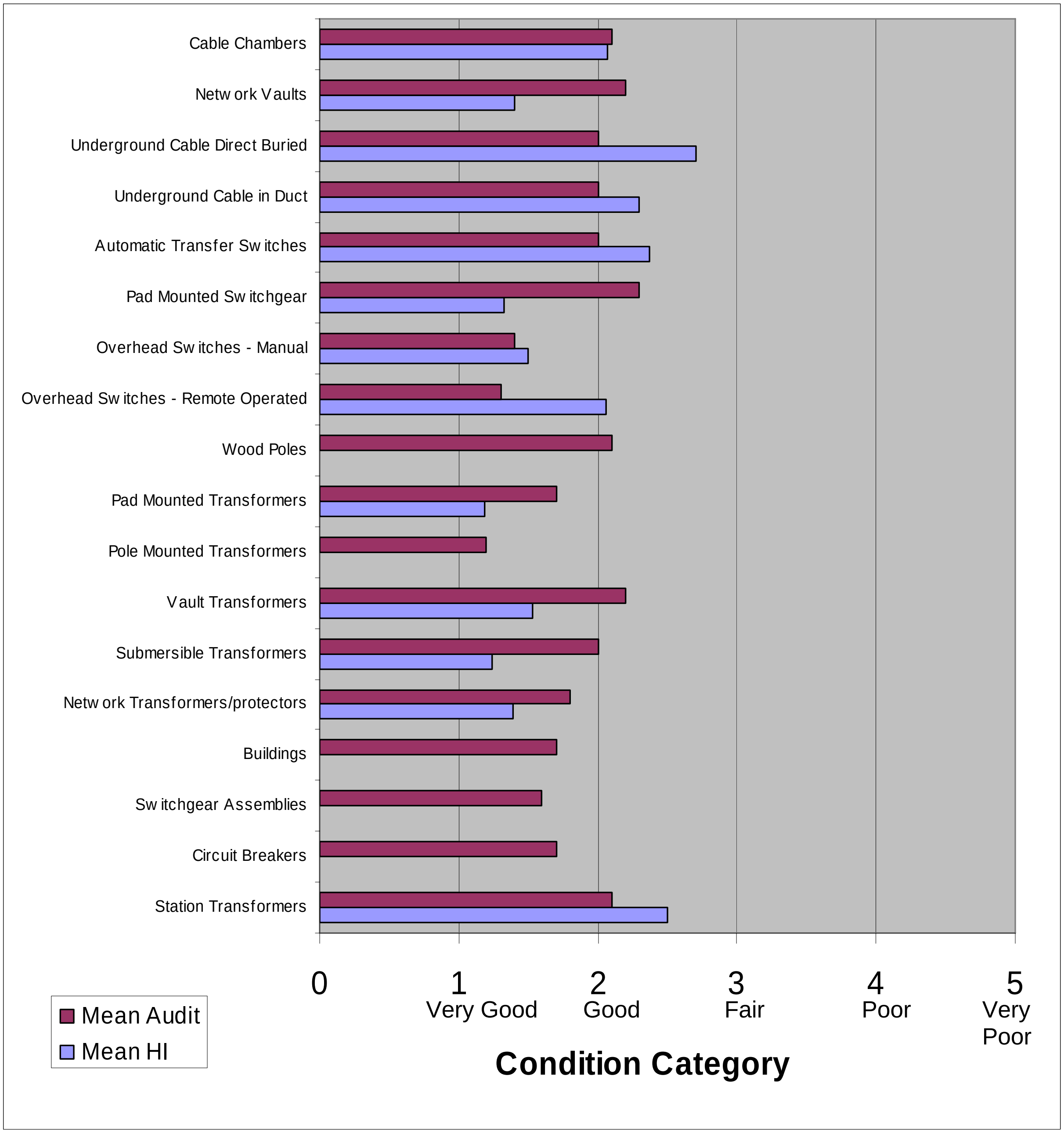
The assets requiring replacement and with the largest impact on reliability and cost are the direct buried underground cable and the station transformers. A formal risk assessment is recommended to prioritize the required asset replacements.

A field audit of asset condition was conducted to confirm the results of the asset condition assessment based on existing information. A comparison of the average condition determined by the audit with the average condition based on existing condition data is shown in the bar chart of Figure ES-1. The field audit verified the Health Index results for most assets. Some differences are expected between the two methods of assessing asset condition due to the different condition criteria used in the two methods. The Health Index method is considered to be more accurate in cases where condition data existed in adequate quantity and quality. All equipment was found to be in “good” condition on average, except for underground cables where the Health Index method indicated only “fair” condition on average.

There was insufficient available data on which to base a Health Index for wood poles, pole mounted transformers, buildings, switchgear assemblies, and circuit breakers. However, Health Index methods were developed for these assets so that, in the future, when data has been collected to support the Health Index calculation, these assets can be assessed more accurately with the Health Index method.

The asset condition data used in this study was collected by THESL primarily to guide maintenance decisions rather than to provide the input for Health Index calculations. Health Indices have now been formulated for all major asset classes and in the future data can be collected specifically designed to provide a more comprehensive indication of condition. There was enough overlap between the two sets of data (the set for guiding maintenance and the set for calculating Health Indices) that the Health Indices could be calculated for eight classes of equipment, including the most critical, underground cables and station transformers. It is recommended that the data required for the Health Index method be collected in the future.

Figure ES-1 Comparison of Health Index and Audit Results



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DISTRIBUTION ASSET CONDITION ASSESSMENT FOR TORONTO HYDRO ELECTRIC SYSTEM LIMITED

1 INTRODUCTION

Toronto Hydro-Electric System Limited (THESL) is the regulated electric distribution utility affiliate of Toronto Hydro Corporation. It is the largest municipal electric distribution utility in Canada, delivering electricity to a broadly diversified, residential, commercial and industrial customer base in the City of Toronto. The utility serves more than 676,000 customers. It achieved its present structure in 1998 upon the amalgamation of six municipal utilities.

THESL distributes approximately 18 percent of the electricity consumed in Ontario. In 2005, THESL sold 5,724,299 residential megawatt-hours and 20,647,870 commercial/industrial megawatt-hours. Peak load was 5,005 megawatts in July 2005. Load growth at the utility is estimated at 1% per year. The utility's annual revenue is approximately $2.6 Billion. THESL employs 1,313 people in a variety of trades and professions.

In general, the subject of this report concerns the distribution system assets of THESL and their life-cycle management to end-of-life and replacement. THESL operates $1.585 billion of capital assets comprised primarily of an electricity distribution system located in the City of Toronto. The utility utilizes 35 transmission stations and a single control center. In approximate numbers THESL's major assets include 280 station transformers, 159,000 poles, 10,000 cable chambers, 8,400 km of overhead conductor, 7,500 km of underground cable, 31,000 primary switches, and 58,000 distribution transformers.

THESL maintains and replaces assets in accordance with an asset management model. THESL is organizationally structured with its Asset Manager functionally separated within the company from the service providers. The Asset Manager develops long-term asset management strategies and policies, develops all distribution plant capital investment programs, develops all distribution plant maintenance programs and ensures execution of programs by the internal and external service providers.

THESL distribution plant maintenance uses a Reliability Centered Maintenance methodology. Maintenance programs are derived from Reliability Centered Maintenance (RCM) analyses. This includes preventive, predictive, corrective and emergency maintenance programs. RCM is designed to establish the optimal maintenance required to achieve a desired operational performance.

At this point, investments to rebuild and sustain THESL's existing plant form the largest pool of distribution plant capital investments. Despite performing maintenance according to developed plans, distribution assets will reach a point where no reasonable amount will maintain the reliability or safety of the equipment and it may fail if not replaced.

Age of assets is one indicator that THESL has applied to anticipate the end of life of an asset class. In various recent reports THESL has estimated that 25% to 40% of their power system assets have exceeded age-based end-of-life criteria. THESL is cognizant that age data used was not precise as for some assets the age was based on general assumptions regarding the time of installation of equipment in grid blocks of the system. While age profiling provides some useful guidance, it has been recognized that not all older assets are necessarily in poor condition and not all newer assets are immune from degradation and failure.

Condition monitoring is a method that can be used to achieve more effective management of the end of life of distribution assets. The concept of a Health Index is being adopted in the power distribution industry to provide a qualitative indication of the condition of an asset and asset populations. Condition monitoring is more data intensive than tracking age to determine the timing of replacement for an asset. Different condition criteria are required to assess the various assets on the distribution system. Inspection and testing of assets is one source of condition information. Reliability statistics such as failure frequency can also be used as input to condition assessment. Ultimately the condition of the asset must be combined with the impact or consequence of failure of an asset to develop a replacement program.

In early 2006, THESL appeared before the Ontario Energy Board with a rate application. Arising from the 2006 rate application, the Ontario Energy Board has requested that THESL submit an Asset Condition Assessment report in support of future rate applications. The Asset Condition Assessment forms a significant input into long term capital planning and is fundamental in defending long-term capital investment plans. THESL intends to prepare a 10 Year Capital Investment Plan in part based on the findings of the asset condition assessment results. It is expected that knowledge of the asset condition will assist in defining immediate and then longer term programs and expenditures to ensure that assets are at a sustainable level and future rate shocks due to peaking replacements can be avoided. Questions exist as to whether existing reactive maintenance and replacement programs must be accelerated to keep up with the impending end of life of assets. The reliability impact and risk of losing major assets is also a prime concern at THESL.

THESL retained the services of Kinectrics Inc., who are experts on the technical aspects of the distribution utility business, and particularly in the subject of condition assessment and Health Indices, to conduct an asset condition assessment audit.

This report presents the findings of the review of THESL’s assets. The report provides an assessment of the asset condition based on existing available documentation, an audit of the assets themselves, and review of historic maintenance and capital programs and budgets. A considerable portion of this work was devoted to the development of Health Indices uniquely tailored to THESL’s assets and the condition information available. The report presents the Health Indices derived for the asset classes and provides some comparison of these indices with the aged based approach of asset assessment.

1.1 Objective

The objective of the work discussed in this report was to conduct an asset condition assessment (ACA) for THESL for key distribution plant assets within the limitations of schedule defined by THESL. The asset condition assessment was designed to quantify the extent of degradation and provide a recommendation as to the number of assets that would likely require replacement within future time horizons.

1.2 Scope of Work

The scope of the work in this asset condition assessment included:

- prioritization of an identified set of asset classes based upon the number and reliability impact they represent to THESL.
- definition of the information needed to determine and evaluate asset condition against condition indicators for the high priority asset classes.
- providing information on industry best practices and understanding of the asset deterioration process and the failure modes and consequences and defining the asset end-of-life criteria for high priority asset classes
- reviewing the adequacy of existing asset condition information and decision criteria for high priority asset classes and determining additional condition information required
- collecting available asset condition information from existing databases including information from regular testing, surveys and inspections.
- defining condition criteria and coordinating with THESL staff to collect statistically relevant population samples of asset condition information
- creating asset condition Health Indices for asset classes
- analyzing the asset condition and performance information to identify population condition, and risks and impacts of asset condition
- conducting spot audits to verify that the asset condition assessment results reflect actual field conditions

The scope of this study was confined to a predefined set of THESL's major assets. This study did not have the mandate to review the cost consequences and impacts associated with the loss of assets. The work was also not intended to produce a Capital Investment Plan.

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2 METHODOLOGY

2.1 Asset Classes Assessed

THESL operates $1.585 billion of capital assets comprised primarily of an electricity distribution system located in the City of Toronto. The utility utilizes 35 transmission stations and a single control center. Of the 35 transformer stations; 19 are owned by Hydro One, 15 are jointly owned by Hydro One and THESL, and one is owned solely by THESL. Seventeen of the stations are supplied at 115 kV and the other 18 are supplied at 230 kV. At 20 of the transformer stations voltage is stepped down to 27.6 kV, and at the other 15 it is stepped down to 13.8 kV.

In addition to the terminal stations at 27.6 kV and 13.8 kV, THESL has a substantial 4.16 kV system involving 188 stations that are located in various parts of the City of Toronto. In total, power is distributed at 27.6 kV, 13.8 kV and 4.16 kV through approximately 268, 642, and 631 feeders respectively. THESL distributes electricity through a network of over 9,100 kilometers of overhead wires supported by over 159,000 poles as well as over 7,600 kilometers of underground wires installed in cable chambers and duct systems. Voltage is further stepped down to intermediate levels for the use of customers in the City of Toronto via 59,000 distribution transformers. These transformers are located in buildings, below grade vaults, surface mounted pads or mounted on the poles. Power is distributed throughout the city via radial, loop, and network systems both in underground and overhead plant configurations.

A particular sub-set of THESL's assets were selected for the purpose of this asset condition assessment. The asset categories and classes that are addressed in this assessment are listed in Table 2-1 along with the population in each class. The following provides a brief description of the particular assets in the class with some of their significant characteristics.

It is important to note that the asset classes are large enough that they do not always represent a homogenous set of equipment. Beside the variance in age there are variations in model, types, ratings, installations, environments, etc. All of these factors can potentially have impact on the condition of the individual assets, the ultimate Health Indices and the estimated replacement timing.

Table 2-1 Assets Included in the Condition Assessment

Asset Group	Asset Class	Population
Transformer Stations	230-27.6 kV power transformers	2
	27.6 kV circuit breakers	120
	13.8 kV circuit breakers	743
	27.6 kV switchgear assemblies	2
	13.8 kV switchgear assemblies	50
	Buildings	16
Distribution Stations	27.6 kV-13.8 kV power transformers	34
	27.6 kV-4.16 kV power transformers	166
	13.8 kV-4.16kV power transformers	85
	13.8kV switchgear assemblies	37
	4.16 kV switchgear assemblies	183
Overhead Distribution	Poles, wood and concrete	159,700
Network Distribution	Transformer/protector units	2,055
Radial Distribution	27.6 kV, 13.8 kV pole mounted remotely operable load interrupter switches	505
	27.6 kV, 13.8 kV pole mounted manually operable load interrupter switches	946
	27.6 kV, 13.8 kV, 4.16 kV pad mounted switchgear	742
	13.8 kV auto transfer switches	113
	Underground primary cable (in duct)	3,770 km
	Underground primary cable (direct buried)	1,481 km
	27.6 kV, 13.8 kV, 4.16 kV polemounted transformers	30,709
	27.6 kV, 13.8 kV, 4.16 kV padmounted transformers	5,609
	27.6 kV, 13.8 kV, 4.16 kV submersible transformers	8,289
	27.6 kV, 13.8 kV, 4.16 kV vault transformers	12,409
Civil	Cable chambers	10,071
	13.8 kV network transformer vaults	1,084

2.2 Asset Replacement Costs

As an indicator only of the overall significance of each asset class to THESL, an estimate of the total replacement cost of the major assets has been made based on the data provided. The following Table 2-2 summarizes the input data.

Table 2-2 Total Replacement Value of Asset Classes[1]

Asset Class	Cost/Unit to Replace	Units	Population	Replacement Cost (million $)
U/G Feeder Cable - Direct Buried	$ 500[2]	m	300000	150.00
U/G Dist Cable - Direct Buried	$ 280[2]	m	1188000	332.64
U/G Feeder Cable - in Duct	$ 150[3]	m	754000	113.00
U/G Dist Cable - in Duct	$ 150[3]	m	3016000	452.00
Poles	$ 5,780[4]	each	159000	919.02
O/H Transformers	$ 4,266	each	30709	131.00
U/G Transformers	$ 12,000	each	8289	99.47
Padmount Transformers	$ 25,000	each	5609	140.23
Building Vault Transformers	$ 12,000	each	12409	148.91
Network Transformers/protectors	$ 85,000	each	2055	174.7
O/H Switches - Manual	$ 8,000	each	946	7.57
O/H Switches - Remote	$ 25,000	each	505	12.63
UG ATS Switches	$ 19,428	each	113	2.20
Padmount Switches	$ 26,035	each	742	19.32
Cable Chamber Roof Replacement	$ 12,000	each	10071	120.85
Vault Roof Replacement	$ 22,566	each	1084	24.46
Stations Transformers	$ 180,000	each	287	51.66
Stations Circuit Breakers	$ 30,000	each	1732	52.00
Stations Switchgear	$ 1,750,000	each	272	476.00
Stations Buildings	$ 5,000,000	each	16	80.00

NOTES
1 The replacement cost per unit data was obtained from THESL's "Electric System Distribution Asset Strategy 2006" Table A1-1
2 Direct buried cable is replaced with cable in concrete encased duct
3 Does not include replacing the duct structure
4 The figure for poles includes insulators, hardware and conductors.
5 It was assumed that 20% of the cable was feeder cable and 80% distribution cable
6 Replacement costs provided may be maximum values rather than average values

The asset classes listed in Table 2-2 are not intended to be an exhaustive list of the asset classes of THESL but a list of the most important for determining priorities. Total replacement costs calculated for the assets of Table 2-2 therefore does not represent the total replacement value of the assets of THESL.

2.3 Asset Prioritization Considering Reliability Impact

As a further indicator of the relative importance of the asset classes to THESL, consideration was given to the reliability impact that each asset class could have on the THESL system.

The priority of the assets included the asset condition assessment was investigated based on their expected contribution to the system reliability. In the analysis, reliability was considered on a per customer basis. This means that the reliability impact of the failure of an asset depends critically on how many customers the asset serves as well as on how often it fails. Reliability also depends on how long the customers are without power. This is not necessarily the repair time for the asset that failed, since power can often be restored by using alternate equipment. In this case it is the fault location and switching time that determines the duration of the customer outage. Some equipment, usually close to the customer, may not have an alternate and the repair time will then be the outage duration.

When industry average failure rates are used, the highest priority asset classes are:

- station transformers
- switchgear
- breakers
- primary feeder cables.

Single phase distribution cables are often direct buried and have higher failure rates than feeder cable which is more often in duct, but each failure affects few customers and the duration is short because of the open loop design of the system. Overhead switches rarely cause an outage directly but instead they fail when they are called upon to operate to isolate a separate failure and restore power. This extends the duration of the separate outage and affects reliability in that way. The failure of Individual distribution transformers affects too few customers for this to be a large contributor to reliability problems at the usual rates of transformer failure. Vaults and cable chambers fail at a low enough rate that they do not cause significant reliability problems.

On the basis of reliability impact the following asset classes top the list of asset classes that should be of prime concern to THESL:

- station transformers,
- station switchgear
- feeder cable

However the actual contributions of equipment to the SAIFI, SAIDI and CAIDI indices at THESL indicate that cables are actually the largest contributor. This is may be because the station equipment condition is carefully monitored and THESL failure rates for station equipment may be below the industry averages. The reliability considerations based on industry average failure rates indicate that THESL should continue to monitor station equipment carefully, even though it is not a major contributor to customer outages at the present time.

2.4 Asset Degradation and End-Of-Life Criteria

Assessing asset condition requires an understanding of the degradation or deterioration process of the equipment in the asset classes. The failure modes of the equipment in the selected asset classes and the consequence of failures is discussed in the following sections. This information was used in the development of the condition criteria for THESL's assets and hence in the development of the Health Indices for the equipment. Information is provided on the end-of-life for equipment in the following asset classes:

- Power Transformers
- Circuit Breakers
- Switchgear
- Buildings
- Poles – Wood, Concrete
- Network Transformers
- Network Protectors
- Switches – Remote and Manually Operated
- Padmounted Switchgear
- Auto Transfer Switches
- Primary Cable – PILC, XLPE, In-Duct, Direct Buried
- Distribution Transformers – Polemounted, Padmounted, Submersible, Vault
- Cable Chambers and Vaults

2.4.1 Power Transformers

While power transformers can be employed in either step-up or step-down mode, a majority of the applications in transmission and distribution stations involve step down of the transmission or sub-transmission voltage to distribution voltage levels. Power transformers vary in capacity and ratings over a broad range. There are two general classifications of power transformers: transmission station transformers and distribution station transformers. For Distribution stations, power transformer ratings typically range from 5 MVA to 30 MVA. For transformer stations, when step down from 230kV or 115kV to distribution voltage is required, their ratings may typically range from 30MVA to 125 MVA.

Power transformers employ many different design configurations, but they are typically made up of the following main components:

- Primary and secondary windings
- Laminated iron core,
- Internal insulating mediums,
- Main tank,
- Bushings,
- Cooling system, including radiators, fans and pumps (Optional),
- Off load tap changer (Optional)
- On load tap changer (Optional)
- Instrument transformers
- Control mechanism cabinets
- Instruments and gauges

The primary and secondary windings are installed on a laminated iron core and serve as the coils in which electromotive force is produced when alternating magnetic flux passing through the core links with the windings. The internal insulating mediums provide insulation for energized coils. Insulating oil serves as the insulating medium as well as serves as the coolant.

Due to its low cost, high dielectric strength, excellent heat-transfer characteristics, and ability to recover after dielectric overstress mineral oil is most widely used transformer insulating material. The transformer coil insulation is reinforced with different forms of solid insulation that include wood-based paperboard (pressboard), wrapped paper and insulating tapes. Because the dielectric strength of oil is approximately half that of the pressboard, the dielectric stress in the oil ends up being higher than that in the pressboard, and the design structure is usually limited by the stress in the oil. The insulation on the conductors of the winding may be enamel or wrapped paper which is either wood or nylon based. The use of insulation directly on the conductor actually inhibits the formation of potentially harmful streamers in the oil, thereby increasing the strength of the structure. Heavy paper wrapping is also usually used on the leads coming from the windings.

The main tank holds the active components of the transformer in an oil volume and maintains a sealed environment through the normal variations of temperature and pressure. Typically the main tank is designed to withstand a full vacuum for initial and subsequent oil fillings and is able to sustain a positive pressure. The main tank also supports the internal and external components of the transformers. Main tank designs can be classified into 2 types those being conservator type and sealed type. Conservator types have an externally mounted tank that usually holds 10% of the main tank's volume. As the transformer oil expands and contracts due to system loading and ambient changes, the corresponding oil volume change must be accommodated. This tank is used to provide a holding mechanism for the expansion and contraction of the main tank's oil over these temperature variations. The liquid seal also provides some protection against moisture ingress into the insulation systems. A sealed tank design incorporates a gas header on top of the oil volume using nitrogen or dry air. This gas header can be either in a positive pressure or vacuum mode depending on the system loading or ambient changes. The pressure and vacuum conditions of a sealed tank design are controlled by the use of a regulator that ensures the tank is within its design limits.

Bushings are used to facilitate the egress of conductors to connect ends of he coils to power supply system in an insulated, sealed (oil-tight and weather-tight) manner. A bushing is typically composed of an outer porcelain body mounted on metallic flange. The phase leads are either independent paper insulated, or are an integral part of the bushing. At the higher voltage levels, additional insulation is incorporated in the form of mineral oil and/or wound paper leads installed within the porcelain column.

The purpose of cooling system in a power transformer is to efficiently dissipate heat generated due to copper and iron losses and help maintain the windings and insulation temperature within acceptable range. The utilization of a number of cooling stages allows for an increase in load carrying capability. Loss of any stage or cooling element may result in a forced de-rating of the transformer. Transformer cooling system ratings are typically expressed as:

- Self-cooled (radiators) with designation as ONAN (oil natural, air natural).
- Forced cooling first stage (fans) with designation as ONAF (oil natural, air forced).
- Forced cooling second stage (fans and pumps) with designation as OFAF (oil forced, air forced).

Off load tap changer allows the transformer turns ratio to be altered over a small range to effect changes in output voltage as required. An off load tap changer typically allows for an adjustment of 5% above nominal and 5% below nominal voltage in 2 ½ % steps. An off load tap changer must only be operated with the transformer off potential. Under load tap-changers (ULTCs) allow for automatic voltage regulation in response to varying load conditions on line. ULTCs consist of moving mechanical parts, a drive motor, linkages and voltage regulation sensing equipment. Instrument transformers include CT’s and PTs for metering or control purposes. Power transformers are equipped with externally mounted control cabinets for voltage and current control relay, secondary control circuits, and in some cases the tap changer motor and position indicators.

Both from the view of financial and operational risk, power transformers are the most important asset employed on the distribution and transmission systems. A significant proportion of power transformers employed by North American utilities were installed in the 1950s, 1960s or early 1970s. So despite the fact that the number of transformer failures arising due to End of Life (EOL) has to date been relatively small there is awareness that a majority of the transformer population will soon be reaching the end of life and it may significantly impact transformer failure rates.

For a majority of transformers, EOL is expected to be spelled by the failure of insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in service in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are presence of oxygen, high temperature and moisture.

Transformer oil is made up of complex hydrocarbon compounds, containing anti-oxidation compounds. Despite the presence of oxidation inhibitors oxidation occurs slowly under normal operating conditions. The rate of oxidation is a function of internal operating temperature and age. The oxidation rate increases as the oil ages, reflecting both the depletion of the oxidation inhibitors and the catalytic effect of the oxidation products on the oxidation reactions. The products of oxidation of hydrocarbons are moisture, which causes further deterioration of insulation system and organic acids, which result in formation of solids in the form of sludge. Increasing acidity and water levels result in the oil being more aggressive with regard to the paper and hence accelerate the ageing of the paper insulation. Formation of sludge adversely impacts the cooling capability of the transformer and adversely impacts its dielectric strength. An indication of the condition of insulating oil can be obtained through measurements of its acidity, moisture content and breakdown strength.

The paper insulation consists of long cellulose chains. As the paper ages through oxidization, these chains are broken. The tensile strength and ductility of insulting paper are determined by the average length of the cellulose chains; therefore, as the paper oxidizes the tensile strength and ductility are significantly reduced and insulating paper becomes brittle. The average length of the cellulose chains can be determined by measurement of the degree of polymerization (DP). But this test can be performed only after de-tanking or the core and coil and therefore, is not a practical test. For a new transformer the DP value of the paper is normally greater than 1,000. As the paper ages this figure gradually decreases. When the DP value approaches below 250 the paper is in a very brittle and fragile condition. The lack of mechanical strength of paper insulation can result in failure if the transformer is subjected to mechanical shocks that may be experienced during normal operational situations.

In addition to the general oxidation of the paper, degradation and failure can also result from partial discharge which can be initiated if the level of moisture is allowed to develop in the paper or if there are other minor defects within active areas of the transformer.

The relative levels of carbon dioxide and carbon monoxide dissolved in oil can provide an indication of paper degradation. Detection and measurement of Furans in the oil provides a more direct measure of the paper degradation. Furans are a group of chemicals that are created as a bi-product of the oxidation process of the cellulose chains. The occurrence of partial discharge and other electrical and thermal faults in the transformer can be detected and monitored by measurement of hydrocarbon gases in the oil through Dissolved Gas Analysis (DGA).

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units at high risk of failure. It is the ideal means on which to base an ongoing management strategy for aging transformers, identifying units that warrant consideration for continued use, consideration of remedial measures to extend life or identification of transformers that should be considered for replacement within a defined time frame.

Other condition assessment techniques for power transformers include the use of online monitors, capable of monitoring specific parameters, e.g. dissolved gas monitors, continuous moisture measurement or temperature monitoring, winding continuity checks, DC insulation resistance measurements and no load loss measurements. Dielectric measurements that attempt to give an indication of the condition of the insulation system include dielectric loss, dielectric spectroscopy, polarization index, and recovery voltage measurements. Doble testing is a procedure that falls within this general group. Other techniques that are commonly applied to transformers include infrared surveys, partial discharge detection and location using ultrasonics and/or electromagnetic detection and frequency response analysis.

Under load tap changers are prone to failure resulting from either mechanical or electrical degradation. Active maintenance is required for tap changers in order to manage these issues. It is normal practice to maintain tap changers either at a fixed time interval or after a number of operations. During operation wear of contacts and build up of oil degradation products, resulting from arcing activity during make and break of contacts, are the primary degradation processes. Maintenance, cleaning and replacement of contacts and any defective components in the mechanism, and changing or reprocessing of oil are the primary maintenance activities that deal with these issues. Oil analysis from tap changers is considered less useful than oil analysis for transformers due to the generation of gases and general degradation of the oil during arcing under normal ULTC operation.

The health indicator parameters for power transformers include:

- Condition of the bushings,
- Condition of transformer tank,
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results and
- Transformer age and winding temperature profiles

The anticipated life of transformers is often quoted as being 40 to 50 years. Many transformers in service are now approaching this age but failure rates remain low and there is little evidence that many are at, or near, EOL. There are a number of contributory factors to the long life of transformers. In the 1950s and 1960s transformers were designed and manufactured conservatively such that the thermal and electrical stresses, even at high load, were relatively low compared to modern designs. In addition, the loading of many of these transformers has been relatively light during their working life.

Consequences of power transformer failure include customer interruptions over significantly long durations. Catastrophic failure of transformers may also result in injury or death, fire and damage to property. There are also environmental risks due to oil spills during tank failures. These risks are more pronounced where transformers are located near water bodies or contain PCBs.

2.4.2 Circuit Breakers

The oil circuit breakers (OCB) represent the oldest type of breaker design, that have been in use for over 70 years. Two types of designs exist among OCBs: bulk oil breakers (in which oil serves as the insulating and arc quenching medium) and minimum oil breakers (in which oil provides the arc quenching function only). Generally, 4 to 8 fully rated interruptions represent an OCB's useful service time between major maintenance. This duty cycle can result in excessive contact erosion, carbonisation of oil, and the need for maintenance.

Vacuum breakers consist of fixed and moving butt type contacts in small evacuated chambers (i.e., bottles). A bellows attached to the moving contact permits the required short stroke to occur with no vacuum losses. Arc interruption occurs at current zero after withdrawal of the moving contact. Utilities typically install vacuum breakers indoors in metalclad switchgear. Current medium voltage vacuum breakers require low mechanical drive energy, have high endurance, can interrupt fully rated short circuits up to 100 times, and operate reliably over 30,000 or more switching operations. Vacuum breakers also are safe and protective of the environment.

Air magnetic breakers use the magnetic effect of the current undergoing interruption to draw an arc into an arc chute for cooling, splitting and extinction. Sometimes, an auxiliary puffer or air blast piston may help interrupt low-level currents. These designs are commonly used in metalclad switchgear applications. The air magnetic breakers have short duty cycles, require frequent maintenance and approach their end-of-life at much faster rates than either SF6 or vacuum breakers. They also have limited transient recovery voltage capabilities and can experience restrike when switching capacitive currents.

SF6 Circuit breakers were first developed in the late 1960s and based on air blast technology. SF6 breakers interrupt currents by opening a blast valve and allowing high pressure SF6 to flow through a nozzle along the arc drawn between fixed and moving contacts. This process rapidly deionizes, cools and interrupts the arc. After interruption, low-pressure gas is compressed for re-use in the next operation.

The circuit breakers have many moving parts that are subject to wear and stress. They frequently "make" and "break" high currents and experience the arcing accompanying these operations. All circuit breakers undergo some contact degradation every time they open to interrupt an arc. Also, arcing produces heat and decomposition products that degrade surrounding insulation materials, nozzles, and interrupter chambers. The mechanical energy needed for the high contact velocities of these assets adds mechanical deterioration to their degradation processes.

The rate and severity of degradation depends on many factors, including insulating and conducting materials, operating environments, and a breaker's specific duties. The International Council on Large Electric Systems' (CIGRE) have identified the following factors that lead to end-of-life for this asset class:

- Decreasing reliability, availability and maintainability
- High maintenance and operating costs
- Changes in operating conditions, rendering the existing asset obsolete;
- Maintenance overhaul requirements; and
- Circuit breaker age.

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;

Corrosion and moisture commonly cause degradation of internal insulation, breaker performance mechanisms, and major components like bushings, structural components, and oil seals. Corrosion presents problems for almost all circuit breakers, irrespective of their location or housing material. Rates of corrosion degradation, however, vary depending on exposure to environmental elements. Underside tank corrosion causes problem in many types of breakers, particularly those with steel tanks. Another widespread problem involves corrosion of operating mechanism linkages that result in eventual link seizures. Corrosion also causes damage to metal flanges, bushing hardware and support insulators.

Moisture causes degradation of the insulating system. Outdoor circuit breakers experience moisture ingress through defective seals, gaskets, pressure relief and venting devices. Moisture in the interrupter tank can lead to general degradation of internal components. Also, sometimes free water collects in tank bottoms, creating potential catastrophic failure conditions.

For circuit breakers, mechanical degradation presents greater end-of-life concerns than electrical degradation. Generally, operating mechanisms, bearings, linkages, and drive rods represent components that experience most mechanical degradation problems. Oil leakage also occurs. Contacts, nozzles, and highly stressed components can also experience electrical-related degradation and deterioration. Other defects that arise with aging include:

- Loose primary and grounding connections;
- Oil contamination and/or leakage; and
- Deterioration of concrete foundation affecting stability of breakers.

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 SF6 or vacuum designs, especially when the OCB undergoes frequent switching operations. Generally, 4 to 8 interruptions with contact erosion and oil carbonization will lead to the need maintenance, including oil filtration. Oil breakers can also experience restrike when switching low load or line charging currents with high recovery voltage values. Sometimes this can lead to catastrophic breaker failures.

SF6 circuit breakers rarely fail from internal degradation or insulation breakdowns. When such failures do occur, they typically result from design or manufacture deficiencies, and they happen early in the breaker's life. There is insufficient experience with failures from long-term SF6 chamber degradation. SF6 insulation systems are sensitive to enhanced stress caused by metal particles or other protrusions on live parts. Metallic particles generated by moving metal parts in the tank can accumulate and cause internal flashovers. Particle initiated failures do not appear age-related, since the problem has occurred on relatively new breakers. Low temperatures have caused operational problems and failures of SF6 breakers. Most international testing standards for these breakers specify minimum temperatures of -30° C, but many Canadian users require operation at -40° C or below. At low temperatures, early double pressure designs experience gas leaks as well as mechanism and ancillary system problems, including failures. Single pressure designs also may have gas leaks, with gas seals and valves presenting weak points. SF6 loss and the ingress of moisture and air compromise breaker performance. Generally, earlier models have more problems than later ones, since modern equipment has improved seal and valve designs.

SF6 is extremely stable. Even at high arcing temperatures limited SF6 breakdown occurs. Also, with use of a suitable desiccant most breakdown products recombine to form SF6. Consequently, SF6 breakers can operate under fault conditions much longer than OCBs or ABCBs before needing maintenance. Manufacturers generally state that these breakers can perform 20 to 50 operations at full rated fault levels before requiring maintenance.

Recently, concerns have arisen about the greenhouse properties of SF6. It is one of the gases specifically mentioned in the Kyoto Agreement. Canada has not issued regulations for SF6, but has made a commitment to reduce the country's overall greenhouse gas emissions.

The diagnostic tests to assess the condition of circuit breakers include:

- Visual inspections
- Travel time tests
- Contact resistance measurements
- Bushing - Doble Test
- Stored energy tests (Air/Hydraulic/Spring Recharge Time)
- Insulating medium tests

As indicated above, the useful life of circuit breakers can vary significantly depending on the duty cycle and typically lies within a broad range of 25 to 50 years.

Consequences of circuit breaker failure may be significant as they can directly lead to catastrophic failure of the protected equipment, leading to customer interruptions, health and safety consequences and adverse environmental impacts.

2.4.3 Switchgear

The metalclad switchgear is typically compartmentalized, with separate cells for the following functions:

- Bus-bar Compartment
- Switching Compartment

- Cable Compartment
- Control Compartment

The bus-bar compartment may be open across the entire length of gear, or it may be segmented into sections, as many as one per feeder. The bus-bars connect adjacent cells. Depending on the voltage and current level, the bus-bars can be bare or insulated and made of copper or aluminum. The switching compartments house the switching devices, i.e. breakers, disconnect switches etc. Design of breakers allows them to be fully engaged (connected); withdrawn to a test position, but still contained in the closed cell; or fully withdrawn from the compartment, usually for the purposes of inspection and maintenance. When in the engaged position, the breaker connects to the sub-bus, and the outgoing/incoming feeders, through tulip type contacts while the breaker controls connect through a separate contact block. Entry and exit for exterior power connections is usually by means of cables, but occasionally this may be carried using bus duct through the cable compartment. Current transformers, as well as the cable terminations are installed in the cable compartment. Normally, the required local control, protective relaying and metering devices are all placed within the compartment or on the doors of the compartment.

All compartments are isolated from each other by metal partitions to prevent inadvertent contact with live parts, particularly during maintenance. In the breaker compartment, a moveable shutter shields the main contacts when the breaker is withdrawn, and is retracted when the breaker is being racked in to allow breaker connection to the main contacts. Final racking in of the breaker can only be done from outside the switchgear to ensure personnel safety. Also for safety reasons, the breaker door can only be opened after the breaker is tripped.

A majority of the utilities are specifying metalclad switchgear to conform to arc-proof design standards - EEMAC Standard G14.1. Several classes of arc proof gear exist under this Standard. Under Type A arc-proofing, personnel are safe only in front of the gear. Under the Type B designation, personnel are safe all around the gear, front, back and sides. These arc-proof definitions conform in broad generality to the comparable IEC Publication 298. However, the EEMAC Standard goes further in defining a Type C gear, in which the arc resistance extends all around the gear and limits the extent of the arc allowed under fault conditions to prevent penetration of the arc between compartments within a cell, or between cells. The only exception is that an arc within a bus compartment may be allowed to break into its associated cell. Some standards go further, and define a C+ rating which prevents this exception and specifies that the arc must remain in the cell portion of the bus in which it started.

Any switchgear arc will cause an explosive rise in pressure, and initiate the release of gases and metallic particles. Arc-proof gear requires the provision of pressure relief vents to ensure release of such gases. Explosion products must be conducted upwards, away from the gear, and more importantly, away from any personnel that may be in the area. The minimum number of such vents must be at least one per separate internal compartment.

While the switchgear degradation is a function of a number of different factors, such as condition of mechanical mechanisms and interlocks, degradation of solid insulation and General degradation/corrosion, in most cases end-of-life is related to non-conditional issues. The important issues tend to be capability, obsolescence or specific/generic defects.

If the fault level on the system increases to exceed the rated interrupting value of the switchgear, the switchgear must be upgraded to meet the new requirements or the system reconfigured to reduce the fault levels. For much of the old vintage switchgear currently in use the original manufacturers no longer exist. It is therefore becoming increasingly difficult to obtain spare or replacement parts. In some cases alternative sources of replacement parts can be located, however, difficulties and failures have occurred where these have not met the original manufacturer's specifications.

As mentioned in earlier sections, some specific problems have given rise to decisions to replace particular types of equipment. In some cases these relate to condition of internal insulation or even susceptibility to general deterioration or corrosion. Discharge related problems with polymeric insulation have in few cases lead to decisions to phase out relatively new vacuum or SF6 equipment.
Failure of cable terminations is a significant contributor towards the overall switchgear failures. Discharge testing using non-intrusive, electro-magnetic and/or ultrasonic detectors provides a convenient way of detecting potential failures. However, periodic measurements of intermittent source of discharge activity are not always able to provide a complete guarantee against future problems.

The switchgear health and condition is indicated by the following parameters:

- Equipment age
- Presence of hotspots (indicated by thermal scan)
- Condition mechanical interlocks
- Condition of controls and relays
- Condition of bus insulation (indicated by megger tests)

The life expectancy for medium voltage distribution switchgear is 35 to 50 years. Failure consequences are serious and include customer interruptions over extended length of time, loss of revenue and employee safety.

2.4.4 Buildings

The asset grouped under buildings at distribution utilities includes housing facilities for substations, warehouses, service centres, offices and other general purpose buildings. While these structures must conform to utility's functional needs they also must conform to local building codes and relevant workplace health and safety regulations.

While many of the comments below apply to all buildings, the write up focuses on buildings housing the electrical substations, since they must meet the most stringent needs. The substation buildings, in addition to the buildings also contain the following subsystems:

Footings and Foundations, providing supporting base for substation equipment. Foundation materials usually consist of reinforced concrete. Since they have load (e.g., static, dynamic and possibly seismic) requirements based on the equipment supported, footings and foundations require proper engineering. In addition, they must conform to elevation and height constraints of particular stations. To ensure stability over time, designs for footings and foundations also must consider environmental issues such as local climate and soil conditions.

Grounds and Landscaping, to provide a pleasant environment for workers and the substation's neighbours. Landscaping also aids in controlling soil erosion, maintaining overall site cleanliness, and facilitating a safe and efficient workplace.

Surface Stone, required in outdoor substation yards to provide safety coordination for step and touch potentials during ground faults

Spill Response and Containment, required to contain spilled materials during equipment failures and minimize environmental harm

Sumps and Sump Pumps, employed wherever the potential exists for water build-up. For example, sump pumps can help keep basement facilities dry or clear water build-up in spill containment systems. Sump pumps are particularly critical in low water table areas.
Lifting Equipment, installed in buildings to facilitate maintenance activities. Lifting equipment ranges from small hoists that assist in managing spare parts' inventories to overhead cranes. In some cases, lifting equipment in substations plays an important role in fast restoration of power following equipment failures.

Buildings at substations house electrical equipment and serve as a base for administrative and service work. The health and condition of buildings is significantly impacted by environmental conditions, particularly rain, wind and snow storms. Because of the presence of electrical equipment, the potential for water ingress presents particular concerns for these assets. Thus, buildings must be weatherproof. Regular preventative maintenance, with occasional major refurbishment of roofs, windows and doors, helps ensure the long-term viability and integrity of buildings. Generally, for well-maintained buildings, operational issues dictate the asset's longevity.

Roof maintenance is the biggest maintenance activity associated with substation buildings. Generally, roof water proofing systems have a shorter life than buildings. Utilities typically replace roofs on a 15 – 20-year cycle. In most substations, feeder cables exist the substation through the basement. These, if not properly sealed can become a source of flooding.

Building inspections usually occur as part of routine visual inspections at 1 – 3 month intervals. Most utilities have inspection checklists to help identify defects and provide overall condition evaluations. Inspection reports also help set priorities for repair programs. Inspections, therefore, help ensure that minor problems receive prompt and effective correction to keep buildings fit for their stated purpose. Spill containment and other civil works also represent important station subsystems. Made primarily from concrete, these facilities may crack, corrode, and shift.

The following factors are commonly considered in establishing the health of this asset:

- Building age
- Structural condition of loading members
- Condition of floors, walls and ceilings
- Protection against weather elements – condition of roof and windows
- Environmental concerns, e.g. presence of asbestos, mold etc.
- Functional requirements

The life expectancy of buildings is largely dependent on frequency and content of preventative maintenance and may vary from 40 years to 100 years. End of life is reached when the existing buildings are no longer fit for functional requirements or when maintenance and repair costs exceed the annualized cost of a new building. Since in a majority of cases, building failure does not mean structural collapse but means failure of the existing building to provide required functions economically, consequence of asset failure is financial loss. A major leak or flooding may also result in damage to other assets in the building and may impact power supply reliability.

2.4.5 Poles (Wood and Concrete)

Wood species commonly used on distribution systems are predominately Red Pine, Jack Pine and Western Red Cedar (WRC), either butt treated or full length treated. Smaller numbers of Larch, Fir, White Pine and Southern Yellow Pine have also been used. Preservative treatments applied prior to 1980, range from none on some WRC poles, to butt treated and full length Creosote or Pentachlorophenol (PCP) in oil. The present day treatment, regardless of species, is CCA-Peg (Chromated Copper Arsenate, in a Polyethylene Glycol solution). Other treatments such as Copper Naphthenate and Ammoniacal Copper Arsenate have also been used, but these are relatively uncommon.

Distribution line design dictates usage of the poles varying in height and strength, depending upon the number and size of conductors, the average length of adjacent spans, maximum loadings, line angles, appropriate loading factors and the mass of installed equipment. Poles are categorized into classes (1 to 7), which reflect the relative strength of the pole. Stronger poles (lower numbered classes) are used for supporting equipment and handling stresses associated with corner structures and directional changes in the line. The height of a pole is determined by a number of factors, such as the number of conductors it must support, equipment-mounting requirements, clearances below the conductors for roads and the presence of coaxial cable or other telecommunications facilities.

Although wood pole condition assessment is driven by the condition of the wood pole itself, replacement of the ancillary components, of foundations, cross-arms, guys, anchors and insulators may also be required. The poles, foundations and cross-arms support the required insulation and phase conductors. The guys and anchors maintain the mechanical integrity of the structure and the insulators electrically insulate the conductor from ground potential. These wood pole system components are described below.

The condition of the concrete poles is assessed by taking into consideration reduction in strength due to spalling or mechanical damage caused by vehicular collisions.

The guys, anchors and span-guy poles maintain the mechanical integrity of the pole, when the pole is required to withstand additional stress due to unbalanced line tension. Various guying components include guy hook for direct pole attachment, epoxy rod or porcelain “johnny ball” insulator, 7 strand 5/16” or 3/8” diameter, zinc coated, steel guy wire, and any variety of anchors, depending upon soil conditions. While the Power Installed Screw Anchor (PISA) is predominant, screw anchor, expansion anchor, log (slug) anchor, steel plate anchor, rock (solid hard) anchor and the shale/limestone anchor are also used.

As wood is a natural material the degradation processes are somewhat different to those which affect other physical assets on electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot.

To prevent attack and decay of wood poles they are treated with preservatives prior to being installed. The preservatives have two functions, firstly to keep out moisture that is necessary to support the attacking fungus and secondly as a biocide to kill off the fungus spores. Over the period of wood pole use in the electricity industry, the nature of the preservatives used has changed, as the chemicals previously used have become unacceptable from an environmental viewpoint. Nevertheless, effective and acceptable preservatives are available and poles well treated prior to installation have a long life (typically in excess of 50 years) prior to decay resulting in significant damage.

The processes of decay require the presence of the fungus spores plus water and oxygen in order to develop. For this reason the area of the pole most susceptible to degradation is at and around the ground line or at the top of pole. Although it is possible in some circumstances for decay to occur in other locations it is normal to concentrate inspection and assessment of poles in these areas. In addition to the natural degradation processes, external damage to the pole by wildlife can also be a significant problem. This can vary from attack by termites, small mammals or woodpeckers.

Concrete poles age in the same manner as any other concrete structure. Any moisture ingress inside the concrete pores would result in freezing during the winter and damage to concrete surface. Road salt spray can further accelerate the degradation process and lead to concrete spalling. Typical concrete mixes employ a washed-gravel aggregate and have extremely high resistance to downward compressive stresses (about 3,000 lb/sq in); however, any appreciable stretching or bending (tension) will break the microscopic rigid lattice resulting in cracking and separation of the concrete. The spun concrete process used in manufacture of poles prevents moisture entrapment inside the pores.   Spun, pre-stressed concrete is particularly resistant to corrosion problems common in a water-and-soil environment.

As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species the mechanical strength of a new wood pole can vary greatly. Typically the first standard deviation has a width of ±15% for poles nominally in the same class. However in some test programs the minimum measured strength has been as low as 50% of the average.

Assessment techniques start with simple visual inspection of poles. This is often accompanied by basic physical tests, such as prodding tests and hammer tests to detect evidence of internal decay. Over the past 20 years, electricity companies have sought more objective and accurate means of determining condition and estimating remaining life. This has led to the development of a wide range of condition assessment and diagnostic tools and techniques for wood poles. These include techniques that are designed to apply the traditional probing or hammer tests in a more controlled, repeatable and objective manner. Devices are available that measure the resistance of a pin fired into the pole to determine the severity of external rot and instrumented hammers which record and analyze the vibration caused by a hammer blow and identify patterns which indicate the presence of decay. Direct assessment of condition by using a decay resistance drill or an auger to extract a sample through the pole, are also widely used. Indirect techniques, ultrasonics, X-rays, electrical resistance measurement have also been widely used.

Condition assessment of concrete poles can, similarly, be carried out through visual inspections and taking into account the extent of surface deterioration of the pole. There are many factors considered by utilities when establishing condition of poles. These include types of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the safety and security obligations.

The following criteria are used in establishing health and condition of this asset:

- Pole strength (through lab testing on selected samples)
- Existence of cracks for both wood and concrete poles
- Wood pecker or insect caused damage for wood poles
- Wood rot or concrete spalling
- Damage due to fire or mechanical damage
- Condition of guy wires
- Pole plumb ness

The life expectancy of wood poles or concrete poles ranges from 40 to 80 years, with 60 years being the mean. Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for significant number of customers.

2.4.6 Network Transformers

Since the individual transformers have no overload protection and are required to stay in service during secondary short circuits, the transformers are designed to withstand heavy short circuit current. Since in a majority of the applications transformers are installed in below grade vaults, the transformer is designed for partially submersible operation with additional protection against corrosion. While network transformers are available in dry-type (cast coil and epoxy impregnation) designs, a vast majority of the network transformers employ mineral oil for insulation and cooling. Therefore, condition assessment criteria and end of life criteria for network transformers is similar to distribution pad-mounted transformers.

For a majority of transformers, EOL is expected to be spelled by the failure of insulation system and more specifically the failure of pressboard and paper insulation, which is described in detail in Section 4.1. However, when employed in location with frequent flooding, transformer tank corrosion also leads to end of life for a significant number of network transformers.

For condition assessment while the frequency and extent of testing is not as rigorous as for power transformers, it is certainly more rigorous than pad mounted or pole mounted distribution transformers. Transformer oil is tested routinely for dielectric strength and moisture content but very rarely it is necessary to carry out gas in oil analysis or Furan measurement.

Network transformer condition is ranked by weighing in the following factors:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of transformer disconnect
- Transfer operating age and winding temperature profile

Network transformers often operate significantly below their nameplate rating and therefore, the anticipated life of transformers is often as high as 40 to 60 years. In-service age and loading levels are good indicators of transformer expired life. Presence of oil leaks, tank corrosion, condition of cable potheads and primary disconnects also included while assessing overall transformer condition.

Single element failures in the network system do not lead to any customer interruptions. Transformer failures that are not properly isolated by protective devices could lead to an eventful failure and collateral damage/failure. Once more than one element is taken out of service, customer interruptions will likely occur. Depending upon the extent of the collateral damage, the damaged equipment may be irreparable leading to long restoration times. Eventful failure may also result in public or staff injury, fire and damage to property. There are also environmental risks due to oil spill as a result of tank failures.

2.4.7 Network Protectors

The relays are, thus, a critical component of the protector and an improper operation of the relays can lead to breaker failure. Traditional relays used to be of electromechanical design type and employed induction discs. They used to be somewhat cumbersome and delicate, requiring frequent maintenance schedules for overhaul and recalibration. Solid-state network protector relays were developed in the early 1990’s and they are reported to have increased reliability due to the use of accurate, high reliability, military-grade components, and an increased life expectancy. Solid-state relays meet specifications with respect to vibration, salt spray, fungus and shock. Solid-state relays should require no recalibration.

The breaker design in network protectors employs mechanical linkages, rollers, springs and cams for operation which require periodic maintenance. All network protectors are equipped with special load-side fuses, mounted either internally or external to the network protector housing. The fuses are intended to allow normal load current and overloads while providing backup protection in the event that the protector fails to open on reverse fault current (due to faults internal to the protector or near transformer LV terminals). Every time arcing occurs in open air within the network protector housing, whether due to operation of the air breaker or because of fuse blowing (except silver sand), a certain amount of metal vapour is liberated and dispersed over insulating parts. Fuses evidently liberate more vapour than breaker operation. Over time, this buildup reduces the dielectric strength of insulating barriers. Eventually this may result in a breakdown, unless care is taken to clean the network protector internally, particularly after fuse operations. THESL typically replaces protectors with new or refurbished protectors if the backup fuses have been found to have operated.

Various parameters that impact the health and condition and eventually lead to end of life of a network include condition of mechanical moving parts, condition of inter phase barriers, number of protector operations (counter reading), accumulation of dirt or debris in protector housing, corrosion of protector housing, condition of fuses, condition of arc chutes and time period elapsed since last major overhaul of the protector.

The health of network protector is established by taking into account the following factors:

- Number of operations since last overhaul
- Operating age of protector
- Condition of operating mechanism
- Condition of fuses
- Condition of arc chutes
- Condition of protector relays
- Condition of gaskets and seals for submersible units

The life expectancy of network protectors can vary significantly as a function of the preventative maintenance and number of short circuit interruptions and can vary from 30 years to 50 years. Generally speaking, each trip and close of the primary feeder breaker results in a corresponding trip and close of the protector. However, during these operations, the protector is called upon to interrupt only the transformer magnetizing current. Only during a fault on the medium voltage feeder, the protector is required to interrupt short circuit current and such interruptions on underground fed feeders are rare.

A network protector failure may lead to catastrophic transformer failure or a vault fire and may result in wide spread outages to commercial customers.

2.4.8 Overhead Line Switches

Most distribution line switches are rated 600 A continuous rating. Switches when used in conjunction with cutout fuses provide short circuit interruption rating. Disconnect switches are sometimes provided with padlocks to allow staff to obtain work permit clearance with switch handle locked in open position.

In general, line switches consist of mechanically movable copper blades supported on insulators and mounted on metal bases. Their operating or control mechanism can be either a simple hook stick or a manual gang. Since they do not typically need to interrupt short circuit currents, disconnect switches are relatively simple in design compared to circuit breakers.

Generally, THESL uses air break switches in its system. Air break switches isolate equipment or sections of line. Air serves as the insulating medium between contacts when these switches are in the open position. Air break switches must have the capability of providing visual confirmation of the open/close position.

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod,
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation,
- Loose connections

- Non functioning padlocks,
- Insulators damage,
- Missing ground connections,
- Missing nameplates for proper identification

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions in which the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. When lubrication dries out the switch operating mechanism may seize making the disconnect switch inoperable. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

The condition assessment of overhead switches involve visual inspections which would reveal the extent of corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective test to locate hot spots.

The following parameters are considered in establishing the asset health:

- Condition of switch blades (contacts)
- Operating arm and switch mounting
- Condition of arcing horns or arc suppressors
- Condition of operating handle padlocks
- Condition of operating mechanism
- Operating age of disconnect switch

The average life expectancy of overhead switches is approximately 40 years. Consequences of overhead line switch failure may include customer interruption and health and safety consequences for operators.

2.4.9 Padmounted Switchgear

The first generation of pad mounted switchgear was first introduced in early 1970's and many of these units are still in good operating condition. The life expectancy of pad-mounted switchgear is impacted by a number of factors that include frequency of switching operations, load dropped, presence or absence of corrosive environmental and absence of existence of dampness at the installation site. On an average, the pad mounted switchgear, when maintained regularly can be expected to provide a service life of 30 to 35 years.

In the absence of specifically identified problems, the common industry practice for distribution switchgear is running it to end of life, just short of failure. To extend the life of these assets and to minimize in-service failures, a number of intervention strategies are employed on a regular basis: e.g. inspection with thermographic analysis and cleaning with CO_2 for air insulated pad-mounted switchgear. If problems or defects are identified during inspection, often the affected component can be replaced or repaired without a total replacement of the switchgear.

Failures of switchgear are most often not directly related to the age of the equipment, but are associated instead with outside influences. For example, padmounted switchgear is most likely to fail due to rodents, dirt/contamination, vehicle accidents, rusting of the case, and broken insulators caused by misalignment during switching. All of these causes are largely preventable with good design and maintenance practices. Failures caused by fuse malfunctions can result in a catastrophic switchgear failure.

There are other defects that are important and require intervention, but do not result into a failure and can be rectified by field action. For example, graffiti on padmounted switchgear is often considered an eyesore and may even conceal important safety and operating signage. Re-painting the outside of the case and replacing the signage can usually be done with no disruption of power. In areas with repeating problems, anti-graffiti paint may be an effective solution.
Rusting of a padmounted switchgear enclosure can lead to perforation and a public safety hazard. Touch-up and re-painting may delay the rusting process, but eventually a planned replacement of the equipment will be required.
Accumulation of dirt and pollution can often be removed by cleaning, and on-line cleaning using dry ice is one of the modern technologies used successfully.

The following factors are taken into account in developing the asset Health Index:

- Tank corrosion
- Condition of doors, door latches, locks and operating handle
- Condition of arc suppressors and interrupters
- Condition of grounding
- Condition of mounting base
- Condition of inter-phase barriers
- Presence of hot spots (Thermo vision scan)

Average life of pad mounted disconnect switches is approximately 40 years. Consequences of switchgear failure include customer interruptions, health and safety as well as environmental consequences.

2.4.10 Auto Transfer Switches

Transfer switches are designed to operate in several different configurations and controls can be generally configured to suit different operating scenarios. Open transition transfer switches are the simplest kind. They are mechanically interlocked to ensure that the power from one source is disconnected before the connection is made to the other source. The closed transition transfer switches eliminate momentary power interruption when both sources are present and synchronized, by transferring the loads with an overlapping contact arrangement. The soft load closed transition switch extends the overlap time to multiple seconds, for a smoother transition of load to the standby source.

The transfer switches are generally electrically operated and mechanically held and have auxiliary contacts for control circuits. Main contacts are commonly made of silver alloy to resist welding and sticking during load transfers. They are mounted either in ventilated or submersible enclosures depending on the installation location. Just like circuit breakers, the heavy duty switches are often equipped with arc chutes to extinguish switching arcs.

THESL employs 800A, 1000A,1600A, and 2500A rated transfer switches in mounted in below grade vaults inside submersible enclosures. The health degradations the transfer switch is subjected to include:

- contact wear,
- wear and tear of the mechanical operating mechanism,
- degradation of insulator supports and inter-phase barriers,
- corrosion of the switch tank,
- failure of the tanks seals allowing penetration of the moisture.

Since the primary purpose of transfer switches is to ensure high reliability for critical loads, it is imperative that any interruptions due to the failure of the switch itself be avoided. This is why the transfer switches should generally be maintained more frequently than other equipment.

The average life of transfer switch varies depending upon the number of actual operations and may vary from 25 to 30 years. Consequences of switchgear failure include customer interruptions and employee safety.

2.4.11 Primary Cables

The use of insulated cables on distribution feeders has virtually become a standard in most North American jurisdictions for urban residential areas where it is either impossible or extremely difficult to build overhead lines due to aesthetic, legal, environmental or safety reasons. The initial capital cost of a distribution underground cable circuit is approximately three times the cost of an overhead line of equivalent capacity and voltage.

The underground medium voltage feeders are commonly installed in loop or primary selective configurations to provide the level of reliability required. This allows the power supply to be restored thorough an automated or manual switching action, following a cable fault. The fault location and repairs are made after supply has been restored from the back-up supply. THESL's distribution's underground cables asset class consists of extruded XLPE insulated cable, PILC cable, and a small percentage of EPR cable. Underground cables in the suburban subdivisions are installed in direct buried configurations, except for road and railway crossings. Cables in the high density commercial areas are generally installed in ducts.

Distribution underground cables are one of the more challenging assets on electricity systems from a condition assessment and asset management viewpoint. Underground cables are relatively expensive asset. However, it is very difficult and therefore very expensive to obtain meaningful condition information for buried cables. Underground cable systems unlike overhead lines, do not suffer from weather induced faults and have better reliability records. Faults on underground cables are usually caused by insulation failure within a localized area and when failures do occur they can be repaired at much lower cost than replacement of the entire cable. Thus, the standard approach to cable system management has been based on reliability rather than the balance between and repair and replacement costs. As long as the reliability is within acceptable levels, it is virtually always cheaper to repair than replace cables.

Many utilities with high proportions of relatively old underground cables have concerns about reliability. Condition assessment programs enable utilities to prioritize the cable replacement programs based on available budgets.

PILC Cables

Generally, corrosion of metal sheath and degradation of the oil impregnated paper insulation cause degradation of the PILC cables. Instant failures may be caused through accidentally dig-ins, but these are generally repairable. Sheath corrosion may vary as a function of the original cable design, possibly sheath damage during installation, presence of corrosive soils in direct buried configurations or presence of corrosive flood water in ducts and the existence of corrosion due to stray dc current. Aging of paper insulation is a function of operating temperature and is dependent on cable loading during its life span as well as thermal conductivity of soils in which cables are installed. Surveys indicate that dielectric deterioration of oil impregnated paper insulation does not present significant end-of-life issues unless cables are subject to prolonged periods above their maximum allowable temperatures. Isolated sites of corrosion resulting in moisture penetration and isolated sites of dielectric deterioration resulting in insulation breakdown can both result in localized failures. However, if either of these conditions becomes widespread frequent cable failures will occur and the cable can be deemed at its effective end-of-life.

Condition information relating to either of these degradation processes is difficult to obtain. Generally, the only opportunity to obtain useful condition information is at the time of a failure and repair. Thus, examination and analysis of faulted sections can be an important condition assessment process. However, it is important to distinguish between condition related and non-condition related cable failures. External or third party damage is a major cause of failures, either immediately or at some time following the damage. If failure frequency is used as a measure of end-of-life, it is important to exclude these failures during the analysis.

Degree of sheath corrosion can be determined through microscopic examination of failed samples. Internal processes in paper insulation that lead to dielectric degradation involve localized discharge activity where impregnation is poor or has deteriorated, or where voids or discontinuities occur in cable fabrication. Thus, detecting, measuring and identifying the location of discharges in cables represent additional ways to assess condition. Discharge mapping using very low frequency (VLF) power supplies has been used over the past 10 to 15 years to assess cable condition. For short cable lengths (i.e., up to about 3 km), the technique not only can detect discharges, but also can locate them. In such cases, it is sometimes possible to identify and target replacement for individual sections of cables particularly at risk. While conventional cable discharge mapping involves an off-line test, permanent monitoring systems to measure discharge activity on line during normal operation are under development and available in prototype forms.

PILC cables have been known to provide long service life between 50 and 70 years.

Extruded Cross Linked Polyethylene (XLPE) Cables

Over the past 30 years XLPE insulated cables, due to their lower costs and easier splicing have all but replaced paper-insulated cables in new installations. The existing population of XLPE cables is still relatively young in terms of normal cable lifetimes. Therefore, failures that have occurred can be classified as early life failures. In the early days of polymeric insulated cables, their reliability was questionable. Many of the problems were associated with joints and accessories or defects introduced during manufacturing. Over the past 30 years many of these problems have been addressed, and modern XLPE cables and accessories are generally considered very reliable if manufactured and installed through competent workmanship.

Polymeric insulation is very sensitive to discharge activity. Thus, cable, joints and accessories must be discharge free when installed. Water penetration into the insulation/conductor barrier, existence of impurities within the semicon layer and presence of high dielectric stress are the principal causes of insulation treeing and the most significant degradation processes for earlier generation of polymeric cables. The rate of water tree growth depends on the quality of the polymeric insulation and the manufacturing process. In addition to manufacturing improvements, development of tree retardant XLPE cables and designs with metal foil barriers and water migration controls have further reduced the rate of deterioration from treeing.

Examining recovered failed cable samples to detect and quantify treeing serves as an effective means to assess the general condition and estimate the future life of XLPE cables. Alternatively, accelerated electrical testing of recovered cables can also be used to determine condition.

Most utilities are beginning to determine the condition of their cables through lab testing and in-situ testing. In the absence of testing, the only other indicators of cable heath are:

- Number of failures per unit length of installation
- Age of Cables.

At this time, the realistic life expectancy of XLPE cables is difficult to ascertain. There is concern that these cables will have a shorter lifetime than the earlier paper insulated cables, but experience is still limited. The life expectancy of TRXLPE cables is considered in excess of 40 years.

The major consequences of cable failure are adverse impacts on reliability.

2.4.12 Distribution Transformers

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers may, sometimes, need to be removed from service as a result of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transfer operating age and winding temperature profile

The consequences of distribution transformer failure are mostly reliability impacts and relatively minor. This is why most utilities run their distribution transformers for residential services to failure. However for larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts may be high; transformers may be replaced as the reach near the end of life, without actual failure. The average transformer life is expected to be approximately 40 years.

2.4.13 Cable Chambers and Vaults

Underground cable chambers come in different styles, shapes and sizes according to the location and application. For this analysis we identified only the broad categories depending on their use and type of construction. Precast cable chambers are normally installed only outside the traveled portion of the road although some end up under the road surface after road widening. Cast-in-place cable chambers are used under the traveled portion of the road because of their strength and also because they are cheaper to rebuild if they should fail. Customer cable chambers are on customer property and are usually in a benign environment. Although they supply a specific customer, system cables loop through these chambers so other customers could also be affected by any problems. Sidewalk vaults are most often located in or adjacent to pedestrian walkways.

These assets must withstand the heaviest structural loadings that they might be subjected to. For example, when located in streets, manholes must withstand heavy loads associated with traffic in the street. When located in driving lanes, manhole chimney and collar rings must match street grading. Since manholes and vaults often experience flooding, they sometimes include drainage sumps and sump pumps. However, environmental regulations may prohibit in some jurisdictions the pumping of manholes or vaults into sewer systems, without testing of water for environmentally hazardous contaminants.

Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have a stronger effect. Therefore, a condition-based asset management program based on periodic field inspections to identify problems and rate the condition of the structure is used by many utilities. Tracking the results of these inspections will show the rate of deterioration and provide advance notice of impending work to correct any problems. Some underground chambers may only need cleaning or repairs on frames and covers or vault doors and grates, but the others may require major rebuilding of the walls and/or roof.

Manhole degradation commonly includes corrosion of reinforcing steel, spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. Manhole systems also may experience a number of deficiencies or defects. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies in a manhole system. Similarly, manhole systems with lights that do not function properly constitute defective systems. Deteriorating ductwork associated with manholes also requires evaluation in assessing the overall condition of a manhole system. In addition to the above, for equipment vaults, condition of ventilation grates and padlocks need to be considered in assessing overall health.

Condition of underground chambers is ranked by taking into account the following factors:

- Condition of Floors, walls and roof
- Existence of asbestos tapes
- Condition of cable racks
- Existence of flooding
- Condition of drain and sump pump etc
- Manhole dimensions and available working space
- IR scan of splices

Like other civil structures, EOL for underground chambers is based on economic comparison of capital vs repair costs. In some cases end-of-life for an underground structure may be spelled when the size of the chamber is commensurate with the changed use of the facility. Average life of underground chambers is of the order of 60 to 80 years.

2.5 The Health Index Method

Health indexing quantifies equipment condition based on numerous condition criteria that are related to the long-term degradation factors that cumulatively lead to an asset's end-of-life. Health indexing differs from maintenance testing, which emphasizes finding defects and deficiencies that need correction or remediation to keep the asset operating during some time period.

When using the Health Index method it is important to understand the differences between defect management and reactive maintenance versus long-term asset degradation and asset condition assessment. Defects are usually well defined and associated with failed or defective components in the ancillary systems that affect operation and reliability of the asset well before its end-of-life. These defects do not normally affect the life of the asset itself, if detected early and corrected. Defects are routinely identified during inspection and dealt with by corrective maintenance activities to ensure continued operation of the asset.

Long-term degradation is generally less well defined and it is not easily determined by routine inspections. The purpose of asset condition assessment is to detect and quantify long-term degradation and to provide a means of quantifying remaining asset life. This includes identifying assets that are at or near end-of-life and assets that are at high risk of generalized failure that will require major capital expenditures to either refurbish or replace the assets.

A good understanding of the asset degradation and failure processes is vital if condition assessment procedures are to be effectively applied. It is important to identify the critical modes of degradation, the nature and consequences of asset failure, and, if possible, the time remaining until the asset is degraded to the point of failure. Unless there is a reasonable understanding of the degradation and failure processes, it is impossible to establish sensible assessment criteria or to define appropriate end-of-life criteria.

A composite Health Index is a very useful tool for representing the overall health of a complex asset. Transmission and distribution assets are seldom characterized by a single subsystem with a single mode of degradation and failure. Rather, most assets are made up of multiple subsystems, and each subsystem may be characterized by multiple modes of degradation and failure. Depending on the nature of the asset, there may be one dominant mode of failure, or there may be several independent failure modes. In some cases, an asset may be considered to have reached its end-of-life only when several subsystems have reached a state of deterioration that precludes continued service. The composite Health Index combines all of these condition factors using a multi-criteria assessment approach into a single indicator of the health of the asset.

For a typical asset class, a wide range of diagnostic tests and visual inspections may be undertaken, either as part of the ongoing maintenance program or as special-purpose Asset Condition Assessment (ACA) surveys. In some cases, a poor condition rating value will represent a failure of a subsystem, which can be repaired through replacement of that subsystem, with no resultant impact on the serviceability of the overall asset. However, it should be recognized that generalized deterioration of many or all of the subsystems that make up an asset can also be a valid indication of the overall health of the asset. A composite Health Index captures generalized deterioration of asset subsystems, as well as fatal deterioration of a dominant subsystem.

In developing a composite Health Index for an asset, it is very important to understand the functionality of the asset, and the manner in which the various subsystems work together to perform the key asset functions. With a clear understanding of asset functionality, condition ratings of different asset components and subsystems can be combined to create a composite "score" for the asset, and the continuum of asset scores can be subdivided into ranges of scores that represent varying degrees of asset health.

The critical objectives in the formulation of a composite Health Index are:

The index should be indicative of the suitability of the asset for continued service and representative of the overall asset health
The index should contain objective and verifiable measures of asset condition, as opposed to subjective observations
The index should be understandable and readily interpreted

Development of a condition-based Health Index requires an assessment of the relative degree of importance of the different condition factors in determining the health of the asset. Each condition factor must be assessed as falling into categories as shown in Table 2-3 below.

Table 2-3 Relative Degree of Importance of Condition Criteria

No impact	Indicator reflects defects or deterioration measures that have no impact on overall asset health. E.g. Silica gel in Transformers
Contributing Criteria	Indicator reflects defects or deterioration measures that range from low to high in importance, but typically in combination with other measures as part of a formulation of generalized deterioration. E.g. Contacts in Circuit Breakers.
Combinatorial Criteria	Indicator reflects a measure which does not represent asset condition in isolation, but is a critical component in a complex logical and/or mathematical formulation of asset health. E.g. Oil Quality Test in Transformers.
Dominant Criteria	Indicator reflects the health of dominant subsystem that makes up the asset, and end-of-life based on this single factor can represent end-of-life for the entire asset. E.g. DGA Test in Transformers or remaining strength in Wood poles.

By using a multi-criteria analysis approach, the various factors can be combined into an idealized condition- based Health Index. This involves grouping together the various factors, crafting the mathematical and/or logical formulations, and establishing the importance weightings of all the factors to allow combining them into a single Health Index.

Next a quantified scoring system can be developed to appropriately represent the asset health consistent with this philosophical approach. The steps are as follows:

1. "Deterioration" assessments or scores are converted to health scores in a defined range from "perfect health" to "end-of-life".
2. Importance weighting is assigned to each factor in a range from "modest importance" to "very high importance".

3. General deterioration index is formulated by calculating the maximum possible score by summing the multiples of steps 1 and 2 for each factor.
4. The general deterioration index is normalized to a maximum score of 100 based on having a defined acceptable/minimum number of condition criteria available.
5. Normalize the dominant factors to a maximum score of 100.
6. Calculation of the overall Health Index as the lesser of step 4 or 5, where 100% is excellent health and 0% is “poor” health.

Finally the continuum of asset health scores is correlated into discrete categories of asset health from “Very Poor” to “Very Good”. This conversion into discrete categories for a condition index requires fine-tuning of the health scoring system, since it is necessary that the relative degree of severity of the scores due to “dominant” factors and those due to generalized degradation match up at the boundaries between each category. This may require iteration of the individual steps to ensure that the resulting index is rational and coherent, and reasonably reflects field condition.

The next section explains in detail a typical Health Index formulation through the example of Station Transformers.

2.5.1 Station Transformer Health Index Example

The Health Index formulation developed for Transformers is explained in the text and tables below.

First Condition Criteria are developed for the asset class such as bushing condition or oil leaks. For purposes of formulating the Health Index, a particular piece of equipment is assessed and assigned a numeric value for each of the condition criteria. Numeric values of 1 to 5 were used in this study to have similar meanings to those used in THESL’s inspection forms. This assigned value for an asset was based on reviews of inspection records and diagnostic test reports extracted from THESL’s databases. For the Health Index method the THESL values were translated to factors from 0 to 4 as shown in Table 2-4 below.

Table 2-4 Condition Rating Factors and their Meaning

THESL Condition Rating	Factors	Interpretation
1	4	Component is in “As new” condition
2	3	Some minor problems or evidence of aging
3	2	Many minor problems or a major problem that requires attention – THESL category 3 equipment “Repaired during maintenance were mapped into this category
4	1	Many problems and the potential for major failure
5	0	Completely failed or is damaged/degraded beyond repair.

The components and tests shown in Table 2-5 below are weighted based on their importance in determining the transformer’s end-of-life. For example, those that relate to primary functions of the transformer or asset receive higher weights than those that relate to more ancillary features and functions.

The individual factors are multiplied by the assigned weights to compute weighted scores for each component and test. The weighted scores are totaled for each transformer. Because of the importance of the DGA test, if any of the tests scored a “5”, then the Health Index was divided by 2.

Totaled scores are used in calculating final Health Indices for each transformer. For each component, the Health Index calculation involves dividing its total condition score by its maximum condition score, then multiplying by 100. This step normalizes scores by producing a number from 0-100 for each transformer. For example, a transformer in perfect condition would have a Health Index of 100 while a completely degraded transformer would have a Health Index of 0.

Table 2-5 below shows the component/test condition criteria, weightings, condition ratings plus the total possible maximum score for each member of this asset class.

Table 2-5 Station Transformer Health Index Formulation

#	Station Transformers Condition Criteria	Weight	Condition Rating	Factors	Maximum Score
1	Bushing Condition	1	1,2,3,4,5	4,3,2,1,0	4
2	Oil Leaks	1	1,2,3,4,5	4,3,2,1,0	4
3	Main Tank/Corrosion/Paint	1	1,2,3,4,5	4,3,2,1,0	4
4	Transformer Gaskets	1	1,2,3,4,5	4,3,2,1,0	4
5	Barriers	1	1,2,3,4,5	4,3,2,1,0	4
6	Grounding	1	1,2,3,4,5	4,3,2,1,0	4
7	Foundation/Supporting Steel	1	1,2,3,4,5	4,3,2,1,0	4
8	Secondary Connections/Primary Terminations/IR Scan	2	1,2,3,4,5	4,3,2,1,0	8
9	Overall Power Transformer	2	1,2,3,4,5	4,3,2,1,0	8
10	DGA Oil Analysis*	4	1,2,3,4,5	4,3,2,1,0	16
11	Age	4	1,2,3,4,5	4,3,2,1,0	16
12	Oil Quality Test	3	1,2,3,4,5	4,3,2,1,0	12

Max Score= 88, HI = 100*Score/Max.
*In the case of a condition rating of 5, overall Health Index is divided by 2

This Health Index formulation is based upon a combination of industry best practice formulation as well as the availability of data at THESL for the purpose of this study. THESL may want to consider adding few criteria into their inspection and testing program for a true best practice Health Index formulation. These are criteria such as:

Furan Oil Test (Would be substituted for the age criteria, however only recommended for large and important transformers, also as a second tier test on suspect transformers)
Doble Winding Test (THESL is already performing this test but results need to be analyzed)

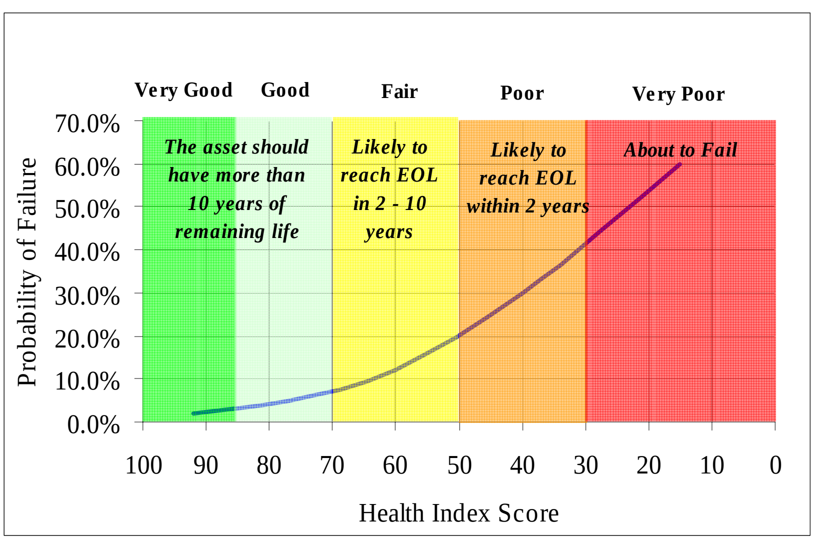
After performing all of the steps described above, the Health Index scale shown in Table 2-6 is used to determine the overall condition of the station transformer asset class.

Table 2-6 Health Index Scale for Station Transformers

Health Index	Condition	Description	Expected Lifetime	Requirements
85 – 100	Very Good	Some aging or minor deterioration of a limited number of components	More than 15 years	Normal maintenance
70 - 85	Good	Significant deterioration of some components	More than 10 years	Normal maintenance
50 - 70	Fair	Widespread significant deterioration or serious deterioration of specific components	From 3 – 10 years	Increase diagnostic testing, possible remedial work or replacement needed depending on criticality
30 - 50	Poor	Widespread serious deterioration	Less than 3 years	Start planning process to replace or rebuild considering risk and consequences of failure
0 - 30	Very Poor	Extensive serious deterioration	At End-of-Life	At end-of-life, immediately assess risk; replace or rebuild based on assessment

This assessment of when this asset is expected to reach end-of-life (EOL) along with probabilities of failure can also be illustrated in Figure 2-1 below. This is based on an engineering judgment with the backing of some failure statistics from other utilities and once more data becomes available this curve can be assessed more accurately and similarly developed for other asset groups.

Figure 2-1 Estimating Probability of Failure from the Health Index



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3 ANALYSIS OF ASSETS

The asset condition was analyzed primarily on the basis of Health Indexes. Where the data was insufficient, either in quantity or quality, to provide an accurate Health Index, then the condition assessment was estimated based on available information such as equipment age, or maintenance history.

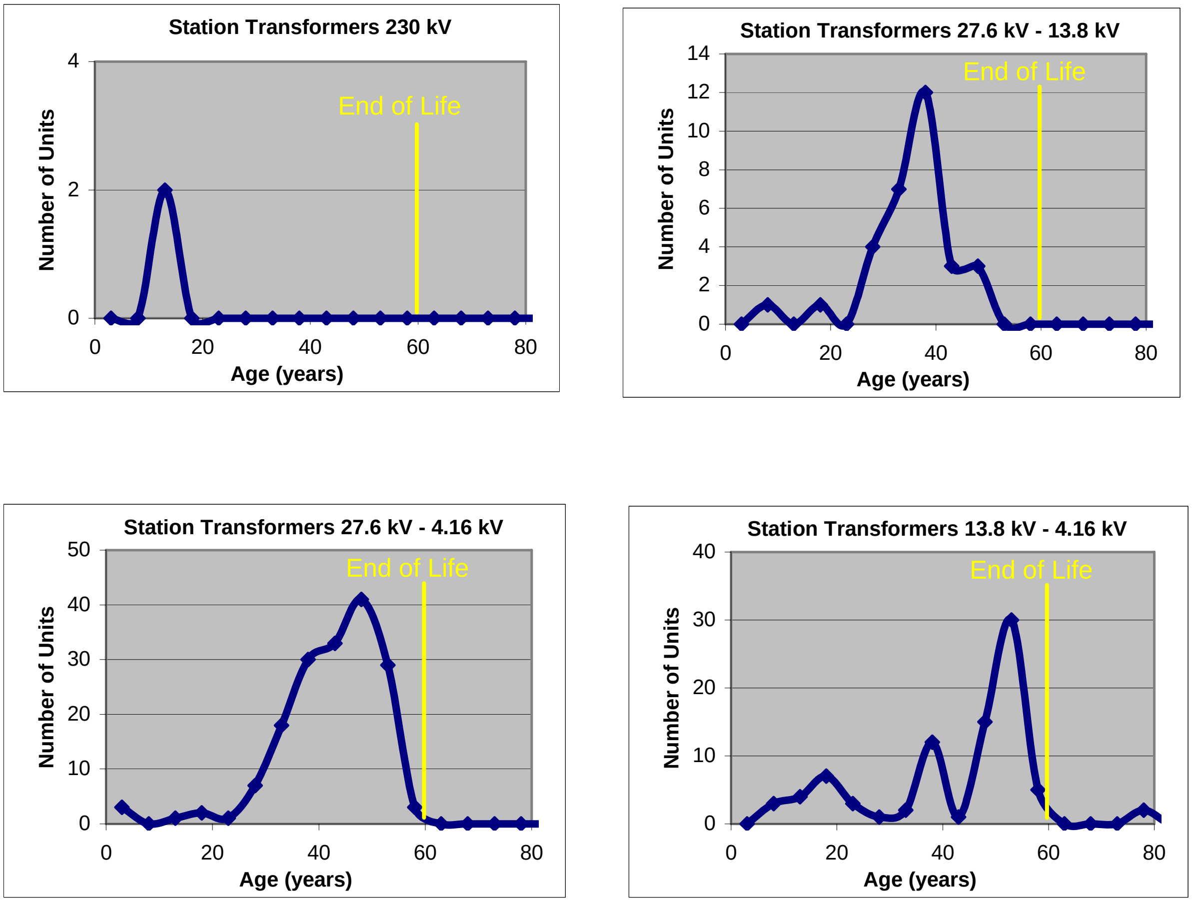
The end-of-life points (yellow line) marked on the age distribution figures in this section represent the typical age at which a component should be removed from the system and replaced for no other reason than it has reached the defined end of life. It does not represent the average age at which components are removed, which can be significantly less due to a number of other factors. It also does not indicate that a particular component of this age should be removed, if it is in good condition. Some of THESL's previous work will agree with the end-of-life on the age distribution figures while others, based upon average replacement age, will have lower end-of-life figures.

The total number of assets in the Health Index results or in the age distributions do not always match the total number of assets in service because of limitations in the available data. In these cases the conclusion at the end of each section on the total number of assets that will require replacement has been scaled to the total number in service.

3.1 Station Transformers

There are a total of 287 power transformers in active service on the THESL system, 2 at 230-27.6 kV, 34 at 27.6-13.8 kV, 166 at 27.6-4.16 kV and 85 at 13.8-4.16 kV. Each of these transformers supplies energy to a large number of customers and their continued operation is critical to meeting service requirements. For this reason they have always been a key asset for condition assessment and planned replacement. Historically they have been very reliable and have remained in service for up to 60 years. The present age distributions of these power transformers are shown in the Figure 3-1.

Figure 3-1 Age Distribution of Station Transformers



The expected lifetime of a power transformer is very dependent on how heavily it is loaded and for how long. It also depends on the design of the transformer, the quality of manufacture and its operating environment, particularly the number and severity of through faults. The yellow line indicating end of life in Figure 3-1 has historically been the typical average in the industry but it is not accurate for individual units. For these reasons age alone is not a good indicator of power transformer condition.

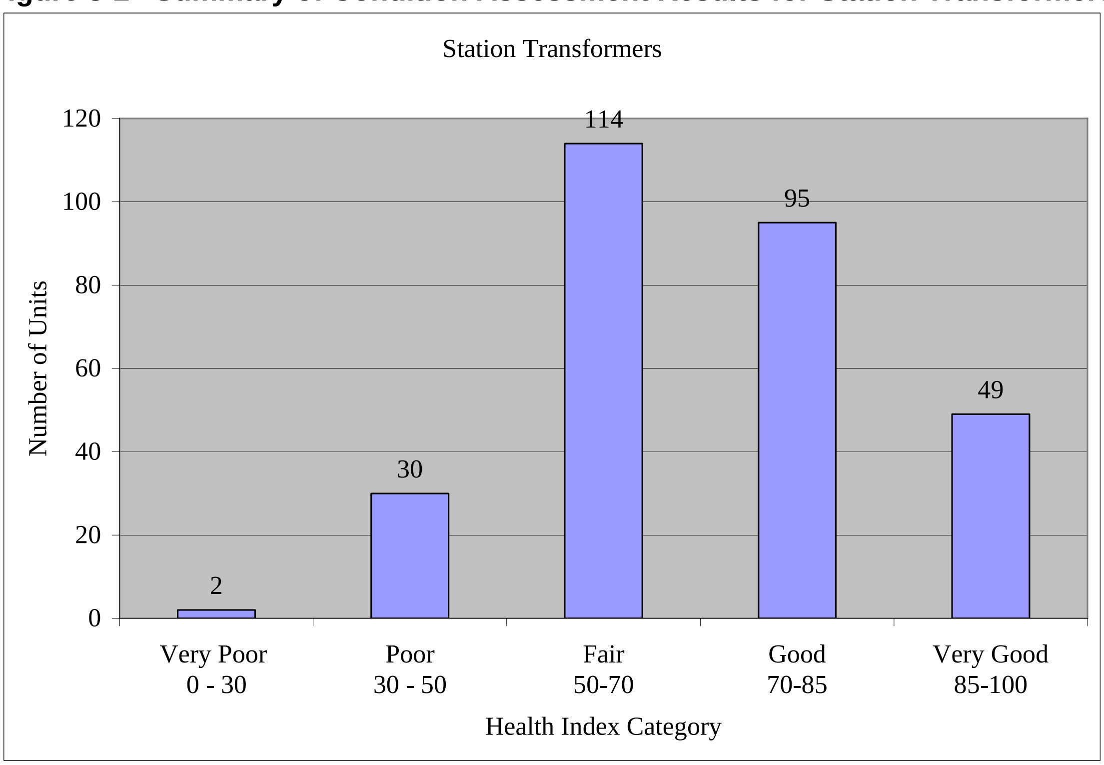
Health Indexes have been computed for all of the THESL power transformers based on the results of condition assessment tests and the results are presented in Table 3-1 and Figure 3-2.

Table 3-1 Summary of Condition Rating Results for Station Transformers

Condition Ratings: Station Transformers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Bushing Condition	1	9	0	0	0	10
Oil Leaks	0	9	0	0	0	9
Main Tank/Corrosion/Paint	0	8	0	0	0	8
Overall Condition/Other	217	36	15	7	0	275
DGA Analysis	187	62	23	2	16	290
Oil Quality Test	128	44	32	0	86	290
Age	29	91	168	2	0	290

The number of units in the "Very Poor" Health Index category indicates the number that should be replaced in the next year. The units in the "Poor" category are expected to require replacement in the following two years, and those in the "Fair" category in sometime in years 4 to 10.

Figure 3-2 Summary of Condition Assessment Results for Station Transformers

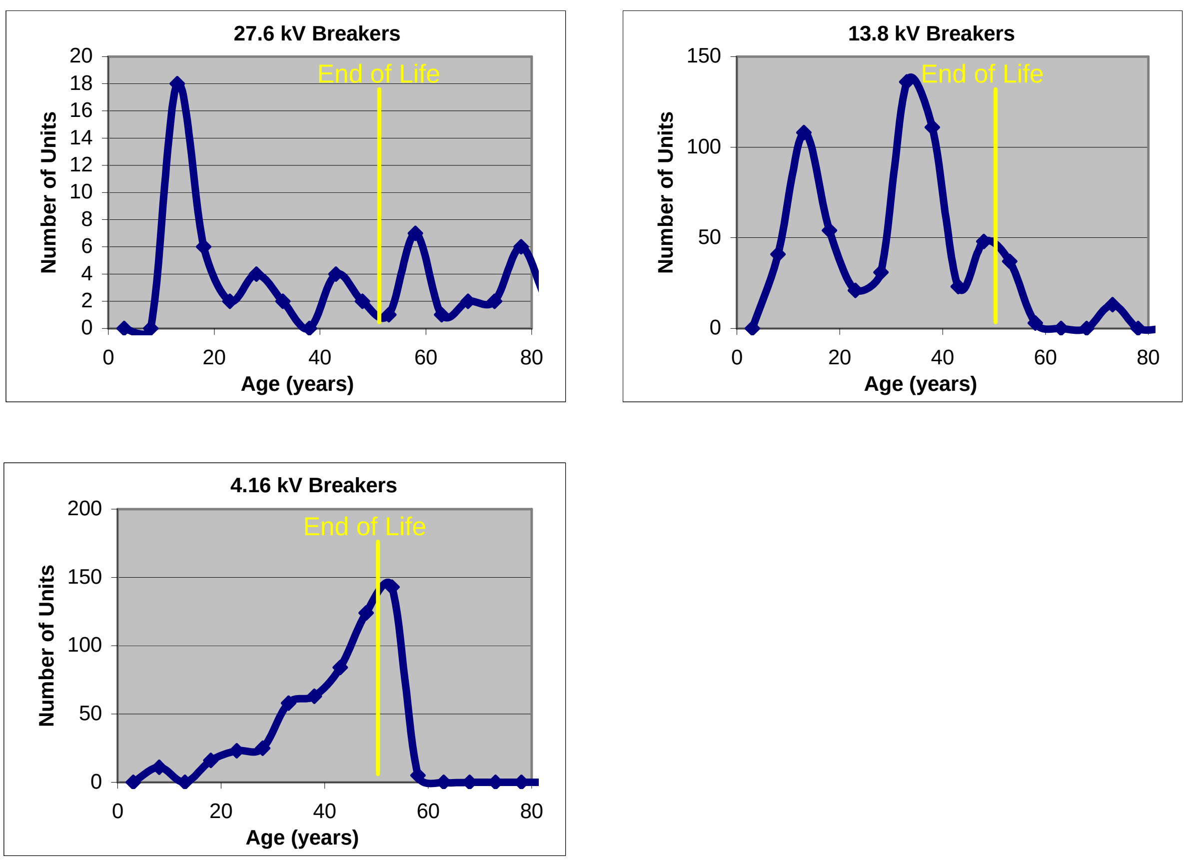


3.2 Circuit Breakers

The circuit breakers are automated switching devices that can make, 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. There are 120 27.6 kV breakers, 743 at 13.8 kV and 869 at 4.16 kV. Circuit breakers are required to operate infrequently, however, when an electrical fault occurs, breakers must operate reliably and with adequate speed to minimize damage. Circuit breakers designs have evolved over the years and many different types are currently in use. Commonly used circuit breaker types include oil circuit breakers, vacuum breakers, magnetic air circuit breakers and SF6 circuit breakers.

The present age distributions of the circuit breakers at THESL are shown in the Figure 3-3.

Figure 3-3 Age Distribution of Circuit Breakers



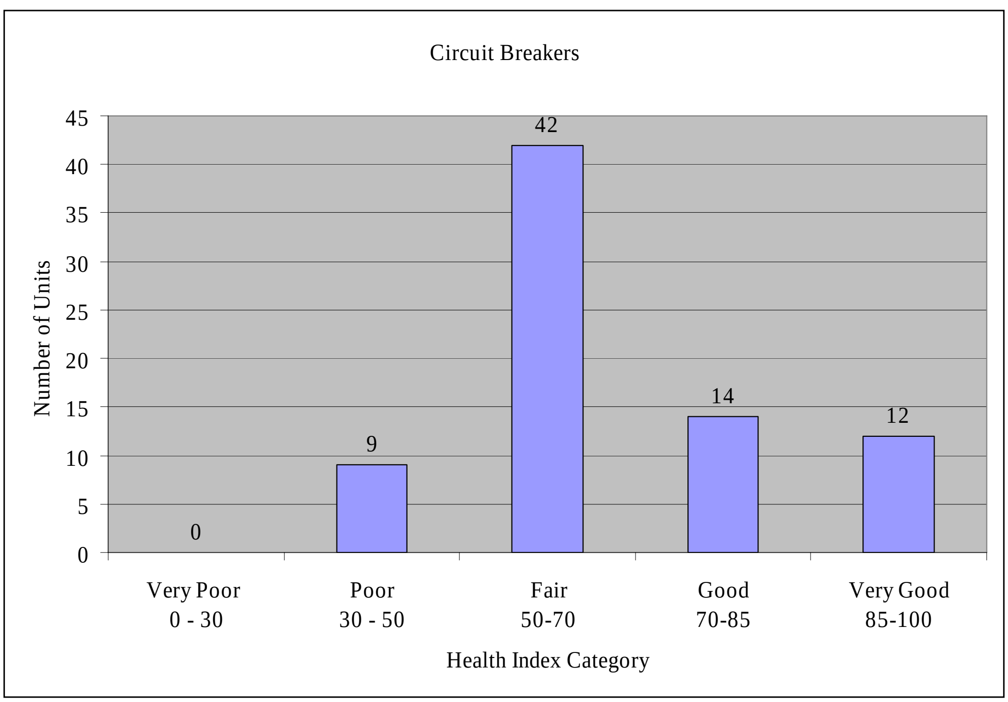
Circuit breakers are a very maintainable component. All of the parts that wear out with use, such as contacts, bearings, springs, can be replaced. The yellow end-of-life lines on Figure 3-3 are typical for the industry but they cannot be applied to individual units. The amount of maintenance circuit breakers require depends on how often they are called upon to interrupt faults and how severe the faults are, but their end of life is more often brought on by changes in the system that make their interrupting capability inadequate or by the unavailability of replacement parts. Age is not a good condition indicator for circuit breakers and cannot be used to estimate the number that will need to be replaced in the next ten years.

A Health Index has been defined for circuit breakers but the available data was not sufficient to create a Health Index that was representative of the population at this point in time. Only 10.8% of the units had sufficient data to calculate the Health Index and this was not random over the different types of breakers.

Table 3-2 Summary of Condition Rating Results for Circuit Breakers

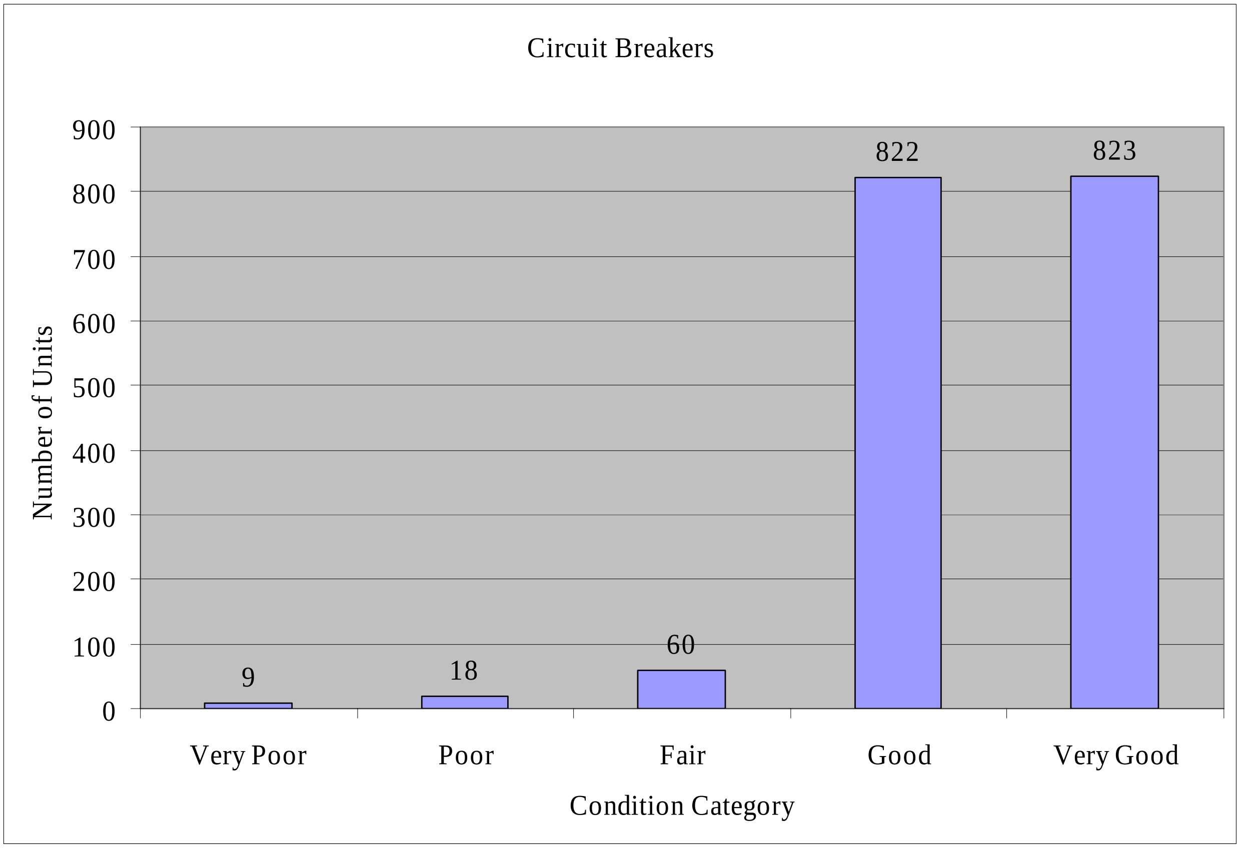
Condition Ratings: Circuit Breakers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Contact Resistance	41	26	9	1	0	77
Overall Condition	22	55	0	0	0	77
Age	15	2	16	14	30	77

Figure 3-4 Summary of Health Index Results for Circuit Breakers



Since age is not a preferred indicator of remaining life for circuit breakers, and the data for the Health Index was insufficient, an estimate must be based on historical trends. In interviews with staff the main issue seemed to be that the older breakers were obsolete, had few sources for replacement parts and in some cases were deteriorating faster than the rate of replacement. Taking this into account it is recommended that THESL plan on replacing 5% of the breakers over the next ten years. This replacement rate reflects 9 breakers in very poor condition, 18 in poor condition and 60 in fair condition, as shown in Figure 3-5.

Figure 3-5 Summary of Condition Assessment Results for Circuit Breakers

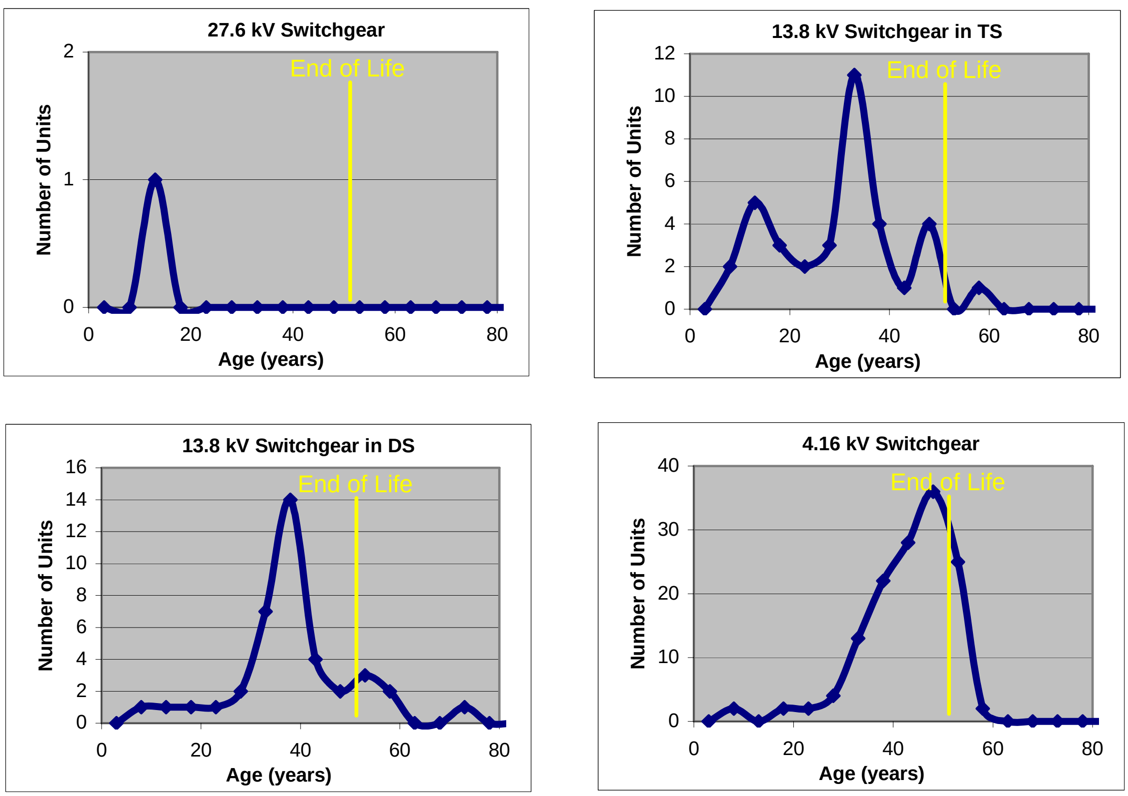


3.3 Switchgear

This asset covers the metal clad switchgear commonly employed at substations. Metalclad switchgear typically consists of an assembly of retractable/racked switching, metering and protection and control devices that are totally enclosed in a metal envelope. The switchgear comes in standard MV operating voltage ratings and includes busbar, circuit breakers, disconnect switches, fuses, protection and auxiliary relays, instrument transformers, metering devices etc. The gear is modular i.e. each breaker is enclosed in its own metal envelope (cell). The gear is also compartmentalized with separate compartments for breakers, control, incoming/outgoing cables or bus duct, and busbars associated with each cell.

The present age distribution of switchgear is shown in Figure 3-6.

Figure 3-6 Age Distribution of Switchgear



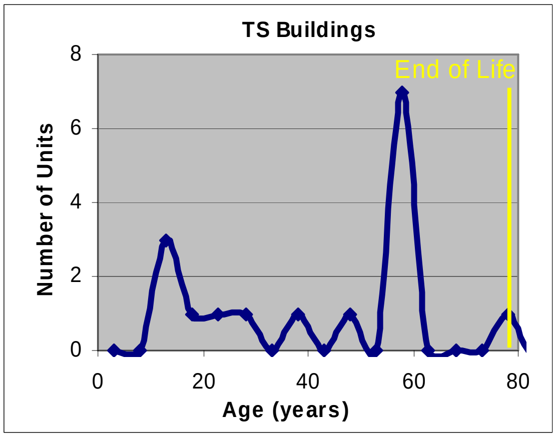
Although a Health Index for switchgear has been formulated, there was insufficient existing data available for the input condition monitoring parameters. A Health Index will be computed for switchgear when the data becomes available.

Switchgear, like circuit breakers, are very maintainable. The age alone is a poor indication of end of life. The annual maintenance expenditure that produces the lowest long term cost for switchgear is quite high because the capital replacement cost is very high. The best long term strategy is therefore to maintain these assets rather than replace them. The amount of required replacement in therefore estimated to be very low, at 1% (3 of the total 272 units) over the next ten years.

3.4 Buildings

Buildings at major terminal stations house the switchgear, relays and controls. This asset includes foundations, walls, roof, doors and windows, plumbing and wiring, and grounds.

Figure 3-7 Age Distribution for TS Buildings



Buildings are another very maintainable asset. The capital cost of replacement is high enough that the lowest long term cost is achieved even with quite high levels of annual maintenance. Age alone is a very poor indicator of end of life.

Although a Health Index for buildings has been formulated there is no available data for the input condition monitoring parameters. The data collected in the past has been oriented towards identifying maintenance requirements rather than towards predicting end-of-life.

Although there is one building that is approaching 80 years old, there are no indications that it will need to be replaced in the next ten years.

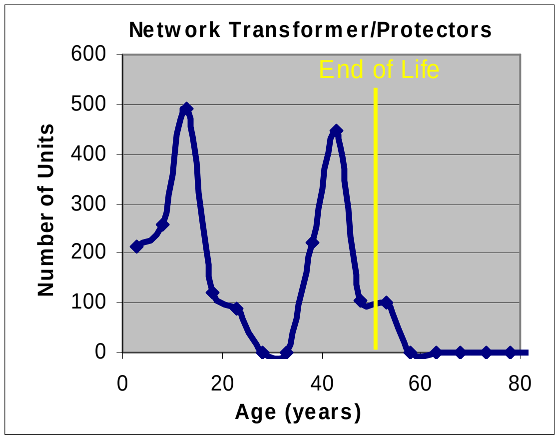
3.5 Network Transformer/Protector Units

Network transformers are special purpose distribution transformers, designed and constructed for successful operation in a parallel mode with a large number of transformers of similar characteristic. THESL employs network transformers in two distinct applications, the first type supplying grid network with low voltage of 208Y/120 V and the second supplying spot network with low voltage of 416Y/240 V and 600Y/347 V. The grid network transformers come in standard ratings of 500kVA, 750 kVA and 1000 kVA. The spot network transformers can range in nameplate rating from 500 kVA to 1500 kVA. The primary winding of the transformers is connected in Delta configuration while the secondary is in grounded star configuration. The network transformers are provided with a primary disconnect, which has no current interrupting rating and is used merely as in isolating device after the transformer has been de-energized both from primary and secondary source. The secondary bushings are mounted on the side wall of the transformer in a throat, suitable for mounting of the network protector.

Network protectors are special purpose low voltage air circuit breakers, designed for successful parallel operation of network transformers. Network protectors are fully self contained units, equipped with protective relays and instrument transformers to allow automatic closing and opening of the protector. The relays conduct a line test before initiating close command and allow closing of the breaker only if the associated transformer has the correct voltage condition in relation to the grid to permit flow of power from the transformer to the grid. If the conditions are not right, protector closing is blocked. The protector is also equipped with a reverse current relay that trips if the power flow reverses from its normal direction, i.e. if the power flows from grid into the transformer.

The present age distribution of network transformer/protector units is shown in Figure 3-8.

Figure 3-8 Age Distribution of Network Transformer Protectors

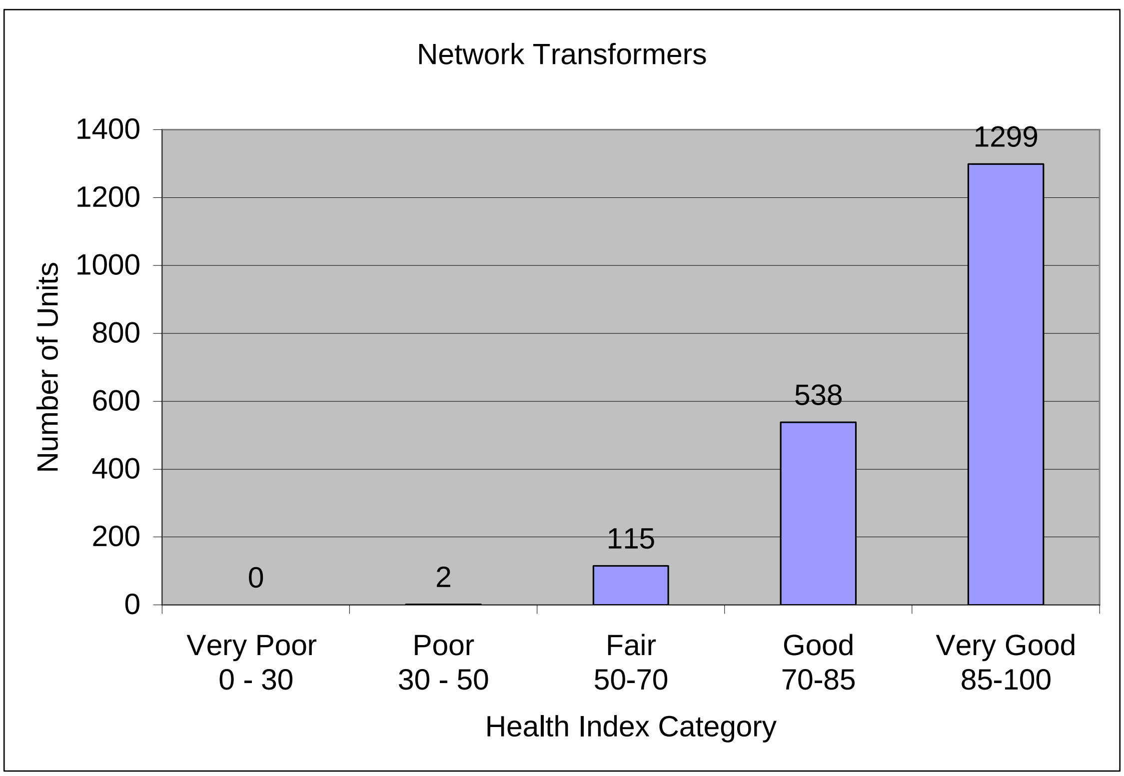


Health Indexes have been computed for the network transformer/protector units as described in Table 3-3 and Figure 3-9.

Table 3-3 Summary of Condition Rating Results for Network Transformers

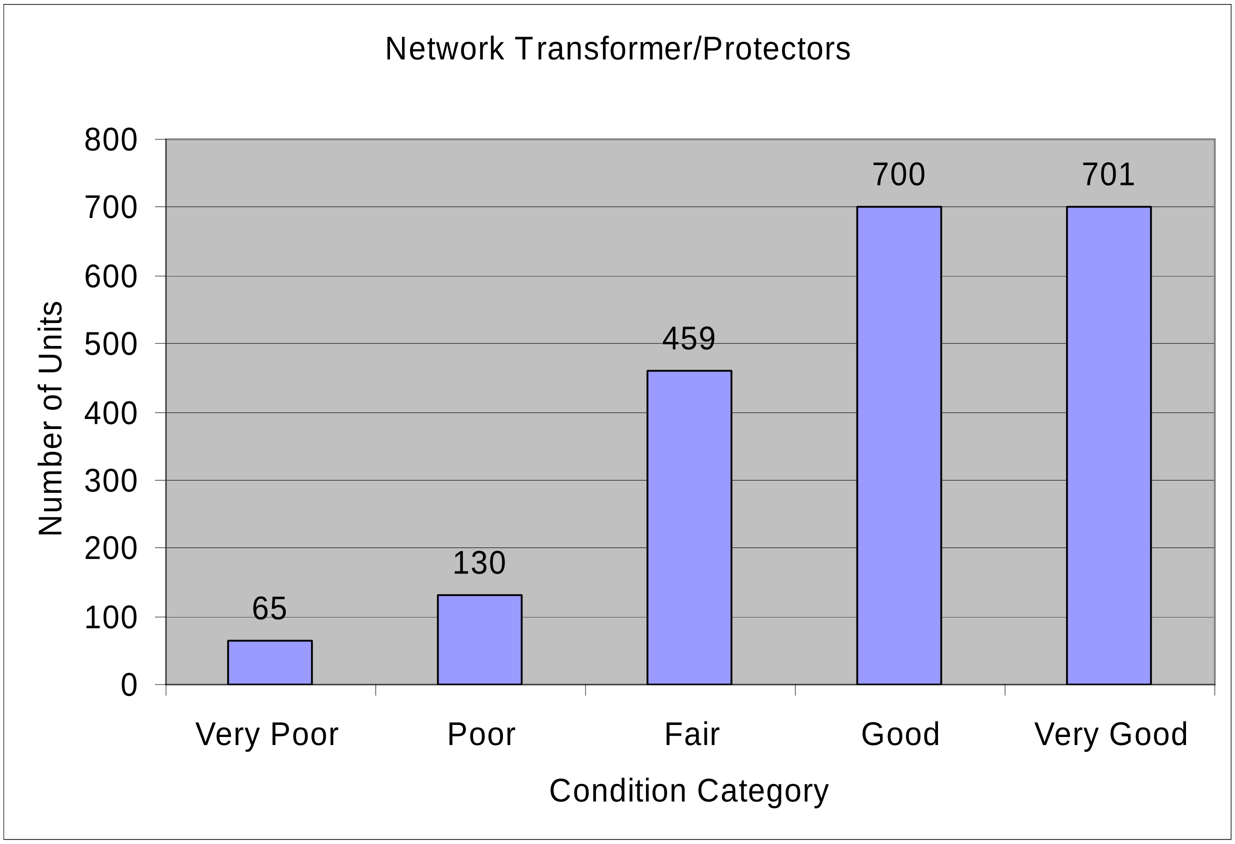
Condition Ratings: Network Transformers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Bushing/Insulator Condition	1545	24	0	10	0	1579
Oil Leaks	1267	143	0	43	0	1453
Corrosion/Paint	1381	309	1	20	0	1711
Transformer Lid Gaskets	1478	134	367	29	0	2008
Dirt/Debris/Contamination	185	1	6	0	0	192
Pothead Termination	1945	40	2	11	0	1998
Overall Condition/Other	91	3	0	0	0	94
Switch Unit	1793	45	126	2	0	1966
Age	791	436	377	201	212	2017

Figure 3-9 Summary of Health Index Results for Network Transformers



The Health Index calculates that only 117 of the 1952 units assessed by the Health Index will need to be replaced over the next ten years, or 6% of the total population. An estimate based strictly on age, from Figure 3-5, indicates that 654 units will need to be replaced; or 32% of the total 2,055 units in service. Historically THESL has replaced about 60 units per year. Unexpected failures have been experienced with some designs and locations. Due to a concern that the Health Index formulation may need adjustment, it is recommended that the estimate based on age and historical trends be used. This indicates that 65 units are in very poor condition, 130 are in poor condition and 459 are in fair condition. The condition assessment is shown in Figure 3-10.

Figure 3-10 Summary of Condition Assessment for Network Transformer/Protectors

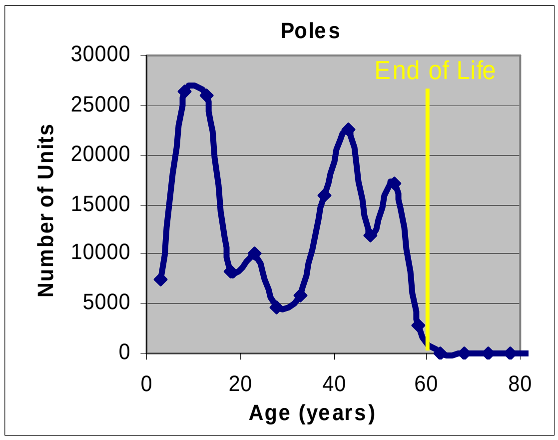


3.6 Poles

Wood poles are the most common form of support for medium voltage overhead feeders as well as LV lines. While a vast majority of the poles at THESL are wood poles, a significant number of concrete poles are also in use.

The present age distribution of wood poles is shown in Figure 3-11.

Figure 3-11 Age Distribution of Wood Poles

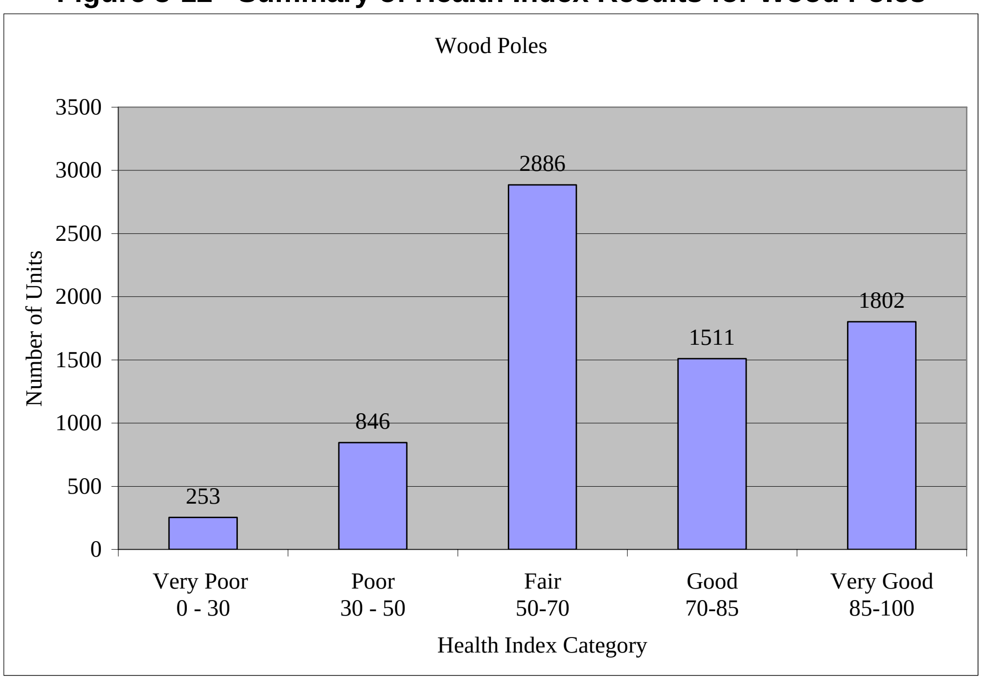


Health indexes have been computed for the wood poles as described in Table 3-4 and Figure 3-12.

Table 3-4 Summary of Condition Rating Results for Wood Poles

Condition Ratings: Wood Poles						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Overall Condition	2888	0	4800	250	233	8171
Remaining Strength	4579	1315	1159	139	106	7298
Cross Arm Condition	8063	116	11	0	2	8192
Damages (Moderate, Extensive):						
Cracks	-	-	3031	-	70	3101
Wood Pecker/ Carpenter Ant Damage	-	-	43	-	58	101
Surface Rot At/Below/Above Ground Level	-	-	553	-	40	593
Pole Top Feathering	-	-	2342	-	109	2451
Mechanical Fire Damage	-	-	13	-	2	15
Wood Loss	-	-	111	-	5	116
Other Criteria (Loose Shell, Soft Wood etc)	-	-	0	-	0	0

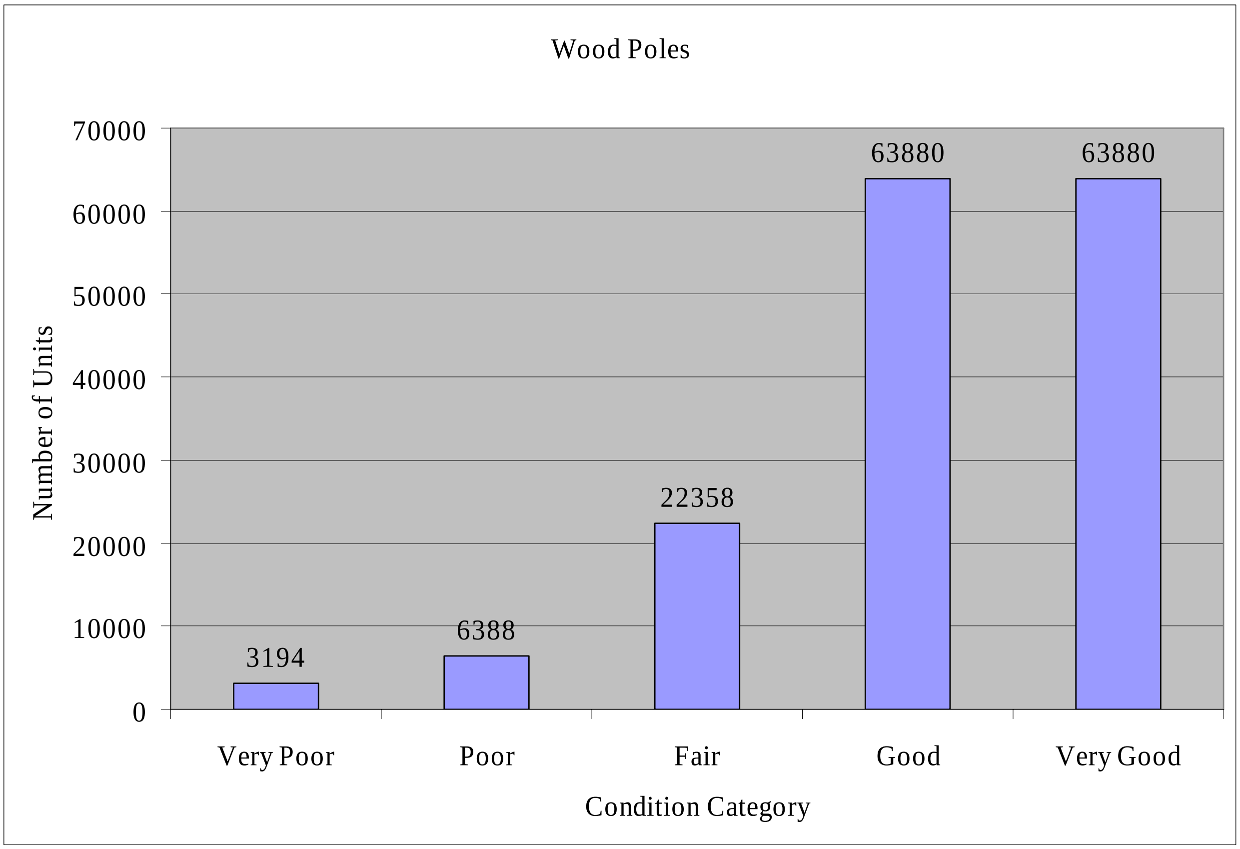
Figure 3-12 Summary of Health Index Results for Wood Poles



Input data for the wood pole Health Index was only available from one geographic area (Etobicoke). There are indications from maintenance records on the number of pole replacements that this area is not representative of the other areas of the service territory. Therefore, at the present time and until more data is available, the Health Index results must be interpreted carefully.

The best estimate of the number of poles that will need to be replaced has therefore been based on the age distribution. This indicates that 32,000 poles will need to be replaced in the next 10 years. The age based condition estimate is shown in Figure 3-13.

Figure 3-13 Summary of Asset Condition for Wood Poles



3.7 Remote Operated Overhead Switches

This asset class consists of overhead line load break, three-phase gang operated switches, that are capable of being operated from the control centre. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements. They consist of the switch itself, a motorized operator, voltage and current sensors and communication equipment.

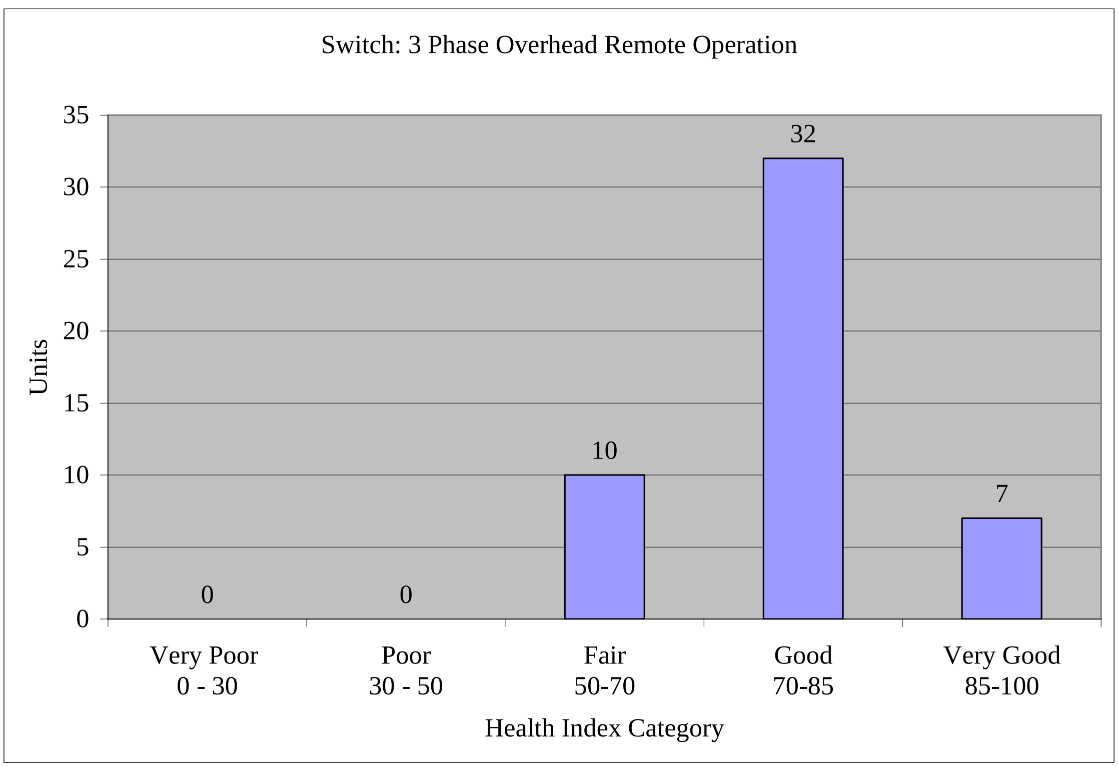
There was no age distribution data available for the remotely operated overhead switches.

Health indexes have been computed for the remotely operated overhead switches as described in Table 3-5 and Figure 3-14.

Table 3-5 Summary of Condition Rating Results for Remote Operated Overhead Switches

Condition Ratings: Remote Operated Overhead Switches						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Blade/Arm/Mounting	9	41	0	1	0	51
Connections/Terminations	9	39	0	1	0	49
Arc Suppressors/Interrupters	9	39	0	1	1	50
Grounding/Shunt Contact	8	42	0	1	0	51
Lock/Handles	7	43	0	0	0	50
Switch Insulator	9	36	1	4	0	50
Mechanism	4	20	0	0	0	24
Operations	3	19	0	0	0	22
Remote Open/Close Operation	143	15	1	7	0	166

Figure 3-14 Summary of Condition Assessment Results for Remote Operated Overhead Switches



The Health Index could only be computed for 49 of the 505 remotely operated overhead switches because of lack of data. It indicates that no remotely operated overhead switches will need replacement in the next three years and 103 in the seven years after that, if the Health Index results are extrapolated to the entire population.

3.8 Manual Operated Overhead Switches

This asset class consists of overhead line load break, three-phase gang operated switches, manually operated. The primary function of switches is to allow isolation of line sections or equipment for maintenance, safety or other operating requirements.

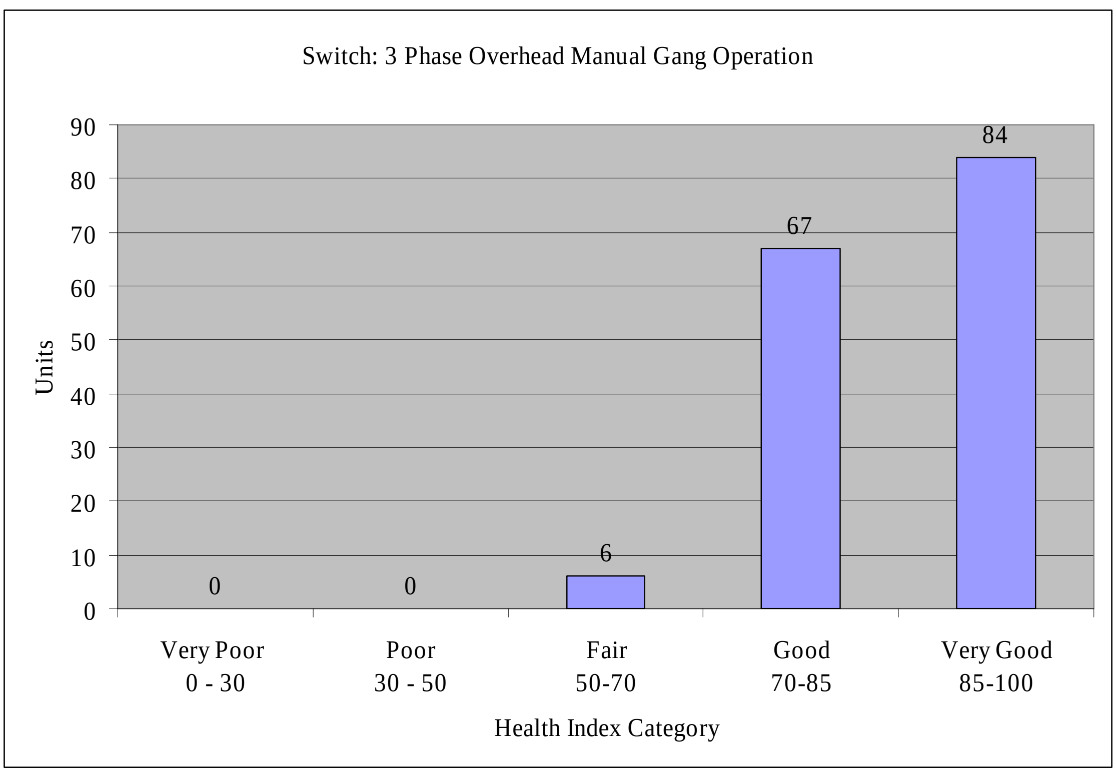
There was no age distribution data available for the manually operated overhead switches.

Health indexes have been computed for the manually operated overhead switches as described in Table 3-6 and Figure 3-15.

Table 3-6 Summary of Condition Rating Results for Manual Operated Overhead Switches

Condition Ratings: Manual Operated Overhead Switches						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Blade/Arm/Mounting	86	70	1	3	0	160
Connections/Terminations	81	66	1	4	0	152
Arc Suppressors/Interrupters	82	66	2	2	1	153
Grounding/Shunt Contact	86	68	2	1	0	157
Lock/Handles	67	67	1	22	0	157
Switch Insulator	85	64	1	3	1	154
Mechanism	3	3	0	0	0	6
Operations	2	5	0	0	0	7

Figure 3-15 Summary of Condition Assessment Results for Manual Operated Overhead Switches



The Health Index could only be computed for 157 of the 946 manually operated overhead switches because of limitations in the available data. It indicates that no manually operated overhead switches will need replacement in the next three years and 36 in the seven years after that, if the Health Index results are extrapolated to the entire population.

3.9 Pad Mounted Switches

This asset class consists of pad-mounted and above grade switchgear. A majority of the pad mounted switchgear currently in use employs air-insulated gang-operated load-break switches. The pad-mounted switchgear is very infrequently used for switching and often used to drop loads way below its rating. Therefore, switchgear aging and eventual end of life is often established by mechanical failures, e.g. rusting of the enclosures, ingress of moisture and dirt into the switchgear causing corrosion of operating mechanism or degradation of insulated barriers.

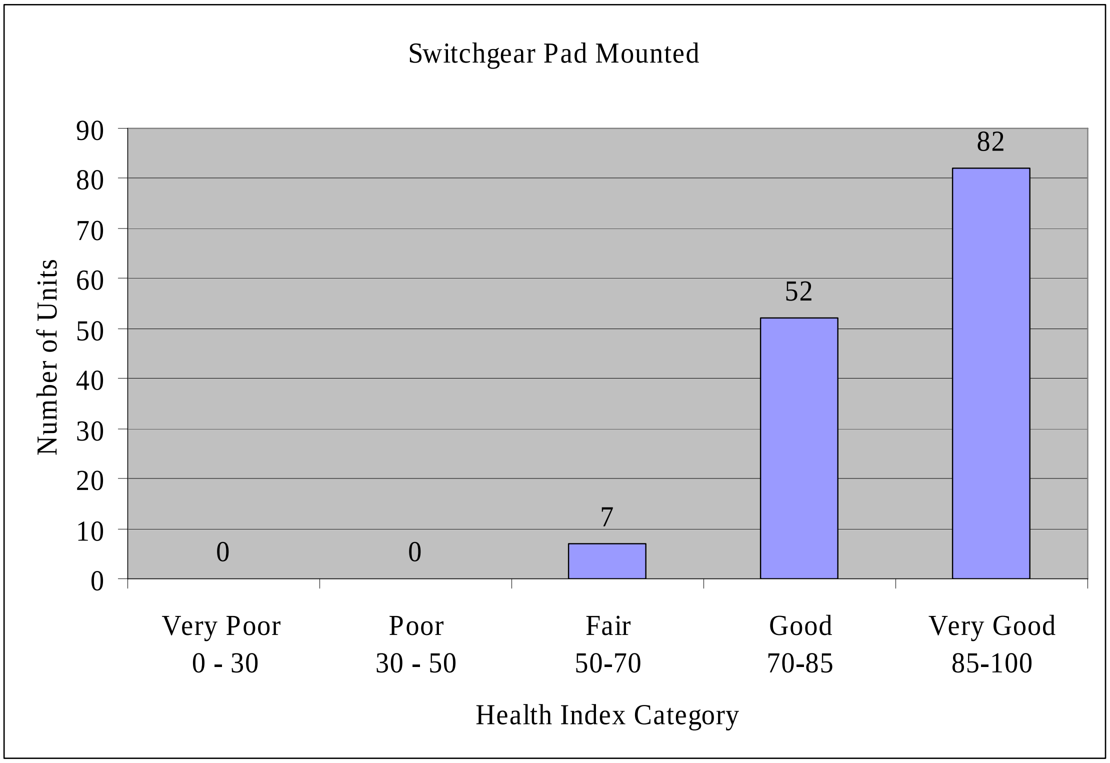
There was no age distribution data available for the pad mounted switches.

Health indexes have been computed for the pad mounted switches as described in Table 3-7 and Figure 3-16.

Table 3-7 Summary of Condition Rating Results for Pad Mounted Switchgear

Condition Ratings: Pad Mounted Switchgear						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Latches/Handles/Locks/Door	166	97	10	5	0	278
Grounding/Bonding	171	103	0	24	0	275
Corrosion/Paint	146	84	24	25	0	279
Concrete Base	0	0	0	0	0	0
Barriers	162	77	4	4	0	247
Arc Suppressors/Interrupters	70	65	0	0	1	136
Hot Spot in IR Scan	176	35	0	0	0	211
Age	33	47	3	0	0	83

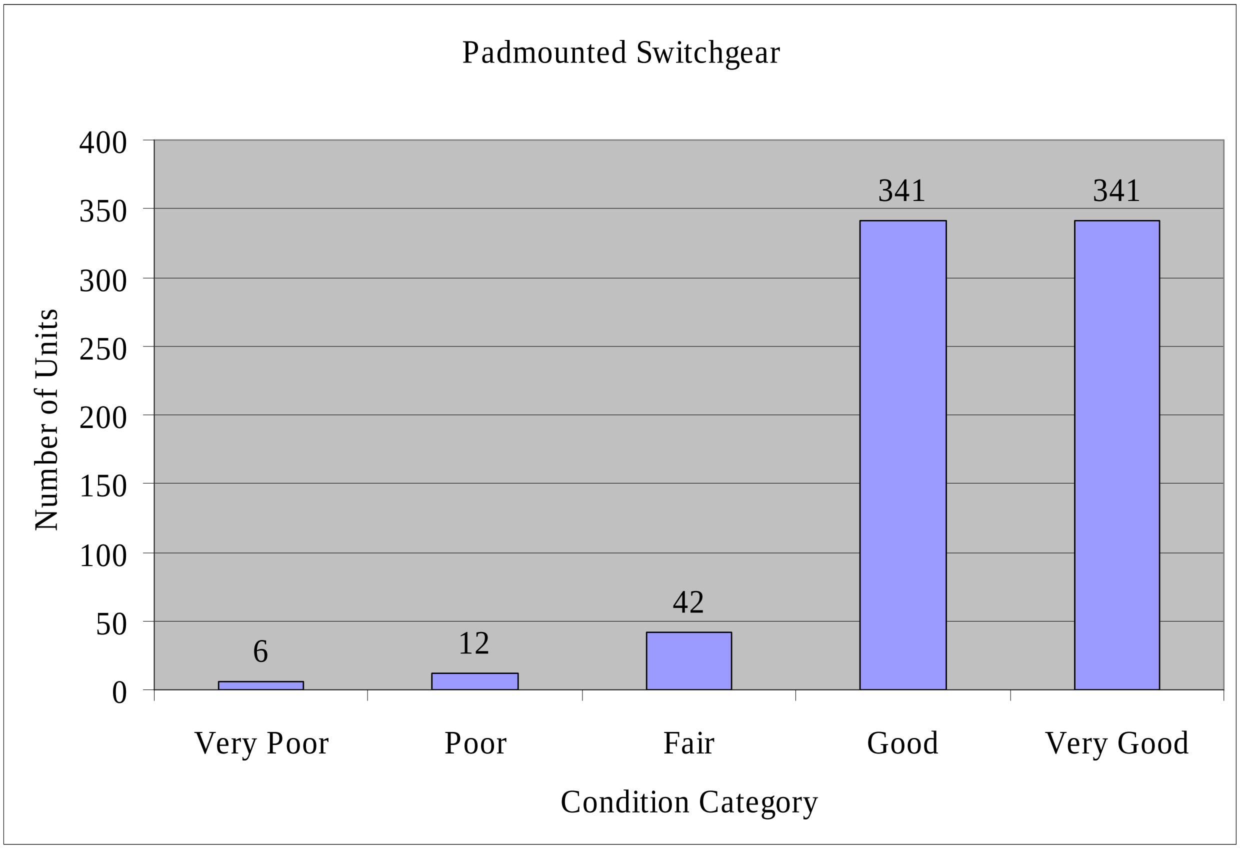
Figure 3-16   Summary of Health Index Results for Pad Mounted Switchgear



The Health Index results show that there are no pad mounted switches that should need replacement in the next three years and only 5% (37 units) in years 4 to 10. However, the field audit of condition determined that the average condition of pad mounted switches was worse than indicated by the Health Index. In interviews with maintenance staff concerns about pad mounted switches were noted. Padmounted switchgear populations are generally over 25 years old and have been experiencing a notable increase in electrical flashovers, particularly when installed near roadways. CO_2 washing has been used on these units, but there seems to be little correlation between failures and maintenance. Operators indicate that that PMH gear is responsible for 2 or 3 failures per year, but in a total population of 742 units this is not a high failure rate.

Given the mixed results, the Health Index formulation is being reviewed and it is recommended that THESL plan on replacing 6 units each year.   This would indicate 6 units in very poor condition, 12 units in poor condition, and 42 units in fair condition as shown in Figure 3-17.

Figure 3-17 Summary of Asset Condition for Padmounted Switchgear



3.10 Automatic Transfer Switches

THESL employs auto transfer switches on the low voltage system for automatic transfer of power from preferred to standby source, when power from the preferred source is lost, either during a planned shutdown or during a forced interruption. When power comes back on the preferred feeder, the transfer switch switches back to the normal position.

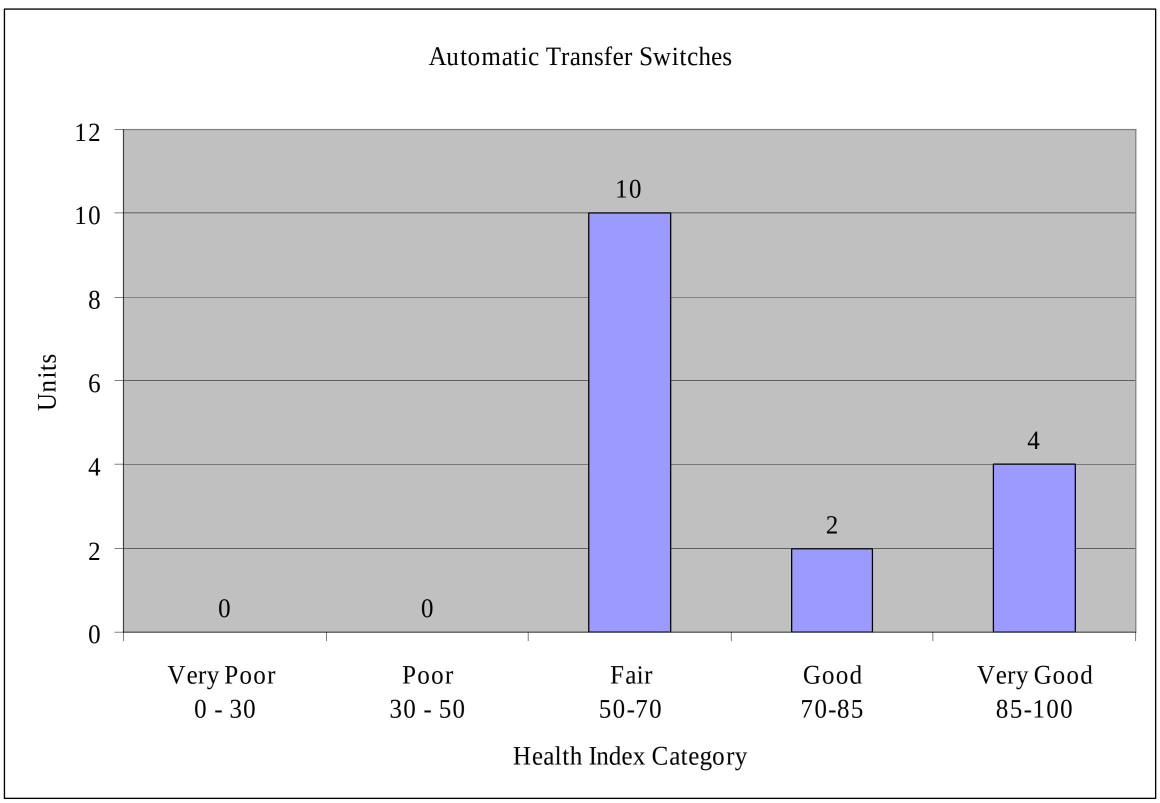
There was no age distribution data available for the automatic transfer switches.

Health indexes have been computed for the automatic transfer switches as described in Table 3-8 and Figure 3-18.

Table 3-8 Summary of Condition Rating Results for Automatic Transfer Switches

Condition Ratings: Automatic Transfer Switches						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Phase Barriers	87	0	0	0	0	87
Gasket	79	2	1	0	0	82
Overall/Other Condition	0	1	0	8	0	9
Years Since Overhaul	0	0	0	0	0	0
Age	0	5	4	0	0	9

Figure 3-18 Summary of Condition Assessment Results for Automatic Transfer Switches



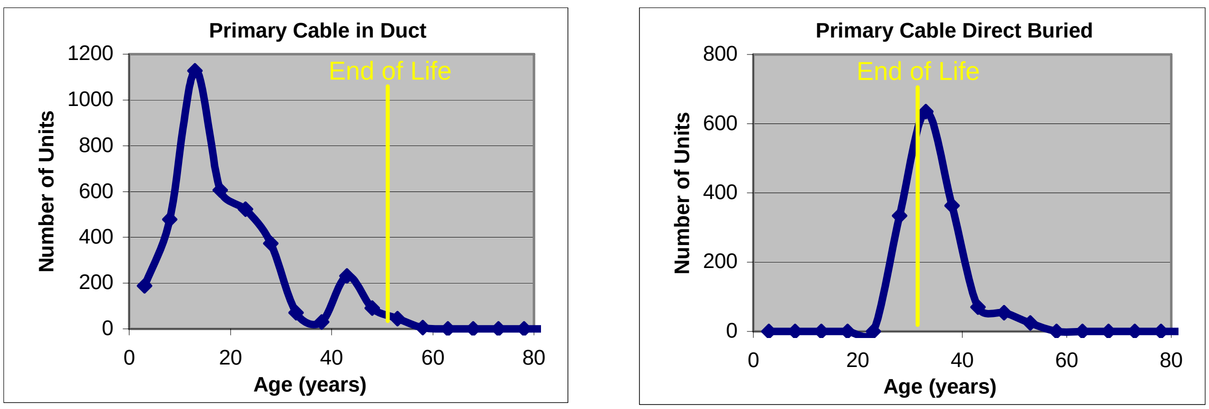
The Health Index indicates that none of the automatic transfer switches will need replacement in the next three years but that 62% will require replacement in the following seven years. This represents 71 switches when extrapolated to the entire population of 113 switches.

3.11 Underground Primary Cable

Distribution System Underground Cables consist of underground cables, splices/joints, elbows, potheads and terminators at voltage levels 27.6 kV, 25 kV, 13.8 kV and 4.16 kV. It includes direct buried and installed-in-duct feeder cables, underground cable sections running from stations to overhead lines and from overhead lines to customer service connections and switches.

The age distribution of the primary cable is shown in Figure 3-15, broken down into cable in duct and direct buried.

Figure 3-19   Age Distribution of Primary Cable



Health indexes have been computed for the primary cable as described in Tables 3-9 to 3-11 and Figures 3-16 to 3-18.

Table 3-9   Summary of Condition Rating Results for Direct Buried XLPE Underground Cables

Condition Ratings: Underground Cables						
	Number of Cables Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Age	4	0	4	14	49	71
Number of Failure in last 5 years	0	529	234	40	33	836

Note: the numbers in this table are the number of circuits.

Table 3-10 Summary of Condition Rating Results for Direct Buried XLPE Underground Cables

Health Index	Health Index Results Classification	Number of circuit km
70 - 100	Good	615
50 - 70	Fair	598
0 - 50	Poor	372
	Total	**1585**

Table 3-11 Summary of Condition Rating Results for PILC Cable in Duct

Health Index	Health Index Results Classification	Number of circuit km
70 - 100	Good	861
50 - 70	Fair	307
0 - 50	Poor	75
	Total	**1243**

The numbers in Tables 3-10 and 3-11 and Figures 3-20 to 3-22 are in circuit km because the cable failure data was most consistent on that basis.

Figure 3-20 Summary of Condition Assessment Results for All Underground Cables

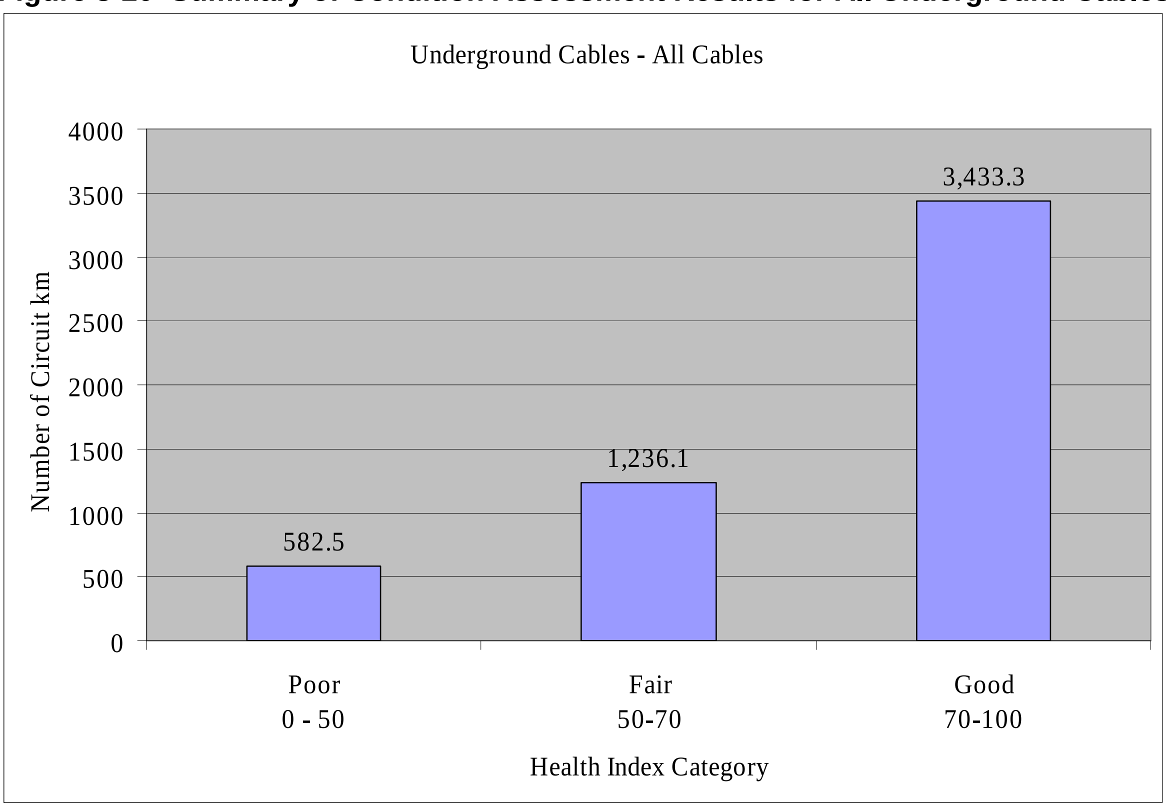


Figure 3-21 Summary of Condition Assessment Results for XLPE Direct Buried Underground Cables

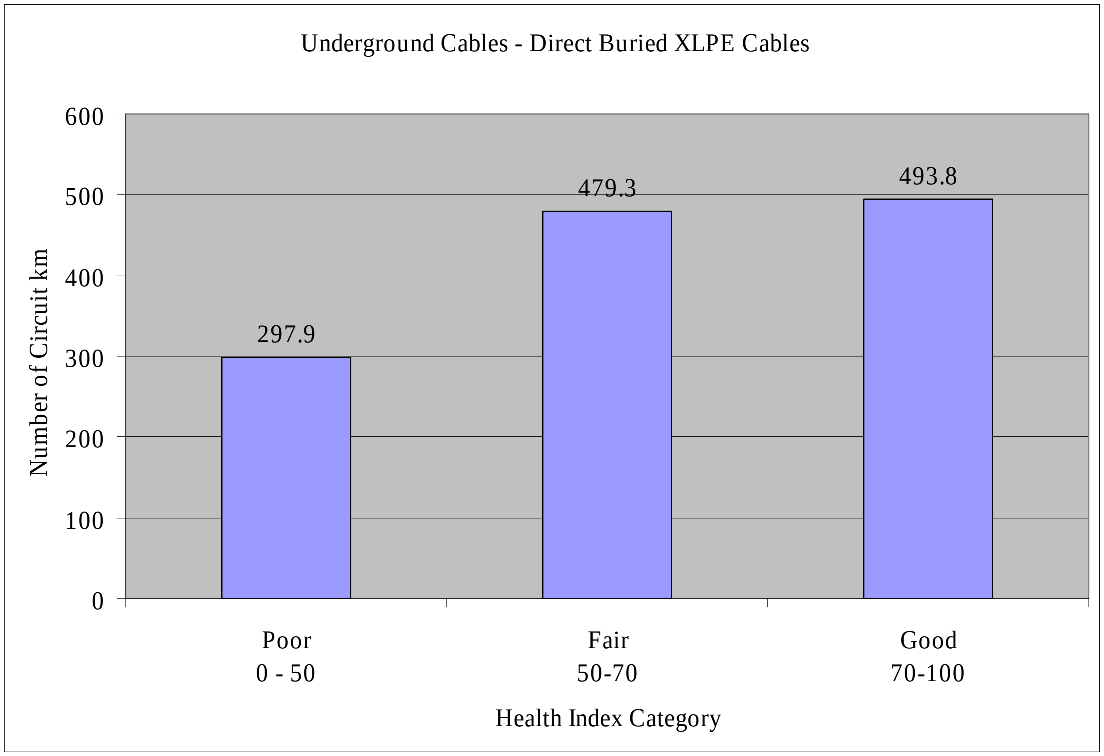
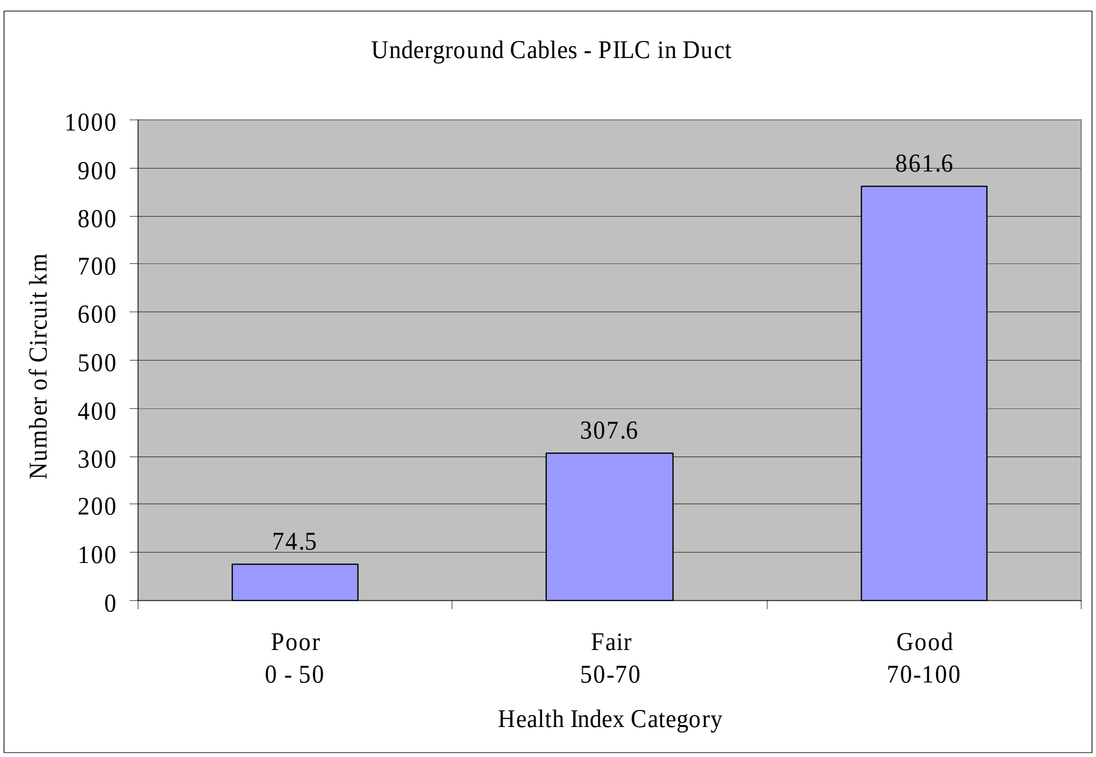


Figure 3-22 Summary of Condition Assessment Results for PILC Cables in Duct



The Health Index results indicate that 298 circuit km of XLPE direct buried cable should be replaced in the next three years, and 74 km of PILC in duct. In years 4 to 10, 479km of XLPE direct buried and 308 km of PILC in duct can be expected to require replacement.

In addition to the 1271 circuit km of direct buried XLPE and 1243 km of PILC in duct, there are also 2,497 circuit km of XLPE installed induct. This cable has had no failures so it is all classes in good condition.

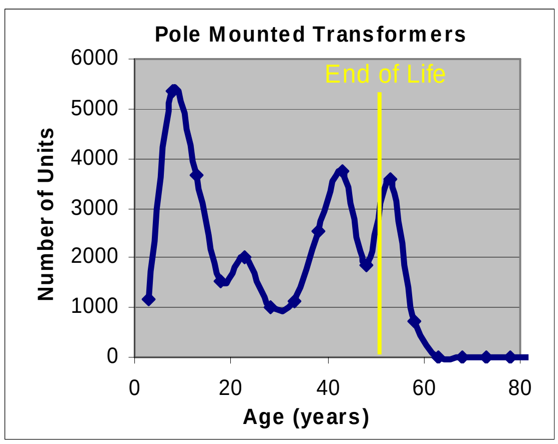
The conclusion that there are significant cable replacement requirements has been further substantiated through interviews with staff and analysis of customer outage data. The data shows that primary cable is the cause of 14% of the customer interruptions, over half of the total due to defective equipment. The customer outages caused by primary cable is steadily rising.

3.12 Pole Mounted Transformers

Pole mounted transformers are used to step down power from primary voltage to utilization voltage. These transformers are liquid filled, with mineral insulating oil in a sealed tank construction. The cylindrical tank is mounted on a wood or concrete pole that supports the overhead conductors.

The age distribution for pole mounted transformers is shown in Figure 3-23.

Figure 3-23 Age Distribution of Pole Mounted Transformers



Although a Health Index for pole mounted transformers has been formulated, there was no existing data available for the input condition monitoring parameters. A Health Index cannot be computed until the data has been collected.

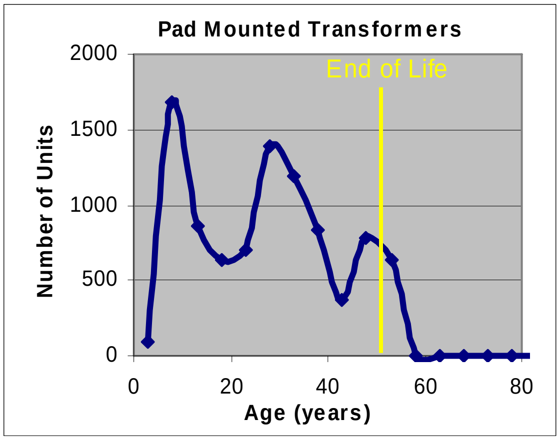
The age distribution in Figure 3-23 indicates that 35% of the total population, or 10,700 transformers will require replacement in the next ten years fairly evenly spread as 1,070 per year. This is a high rate of replacement, but it can be seen in Figure 3-23 that this is caused by an uneven distribution of ages in the population. The replacement rate in the following 10 years should be less.

3.13 Pad Mounted Transformers

Pad mounted transformers are used to step down power from primary voltage to utilization voltage. These transformers are liquid filled, with mineral insulating oil in a sealed tank construction. The low profile tank is mounted on a concrete pad.

The age distribution for pad mounted transformers is shown in Figure 3-24.

Figure 3-24 Age Distribution of Pad Mounted Transformers

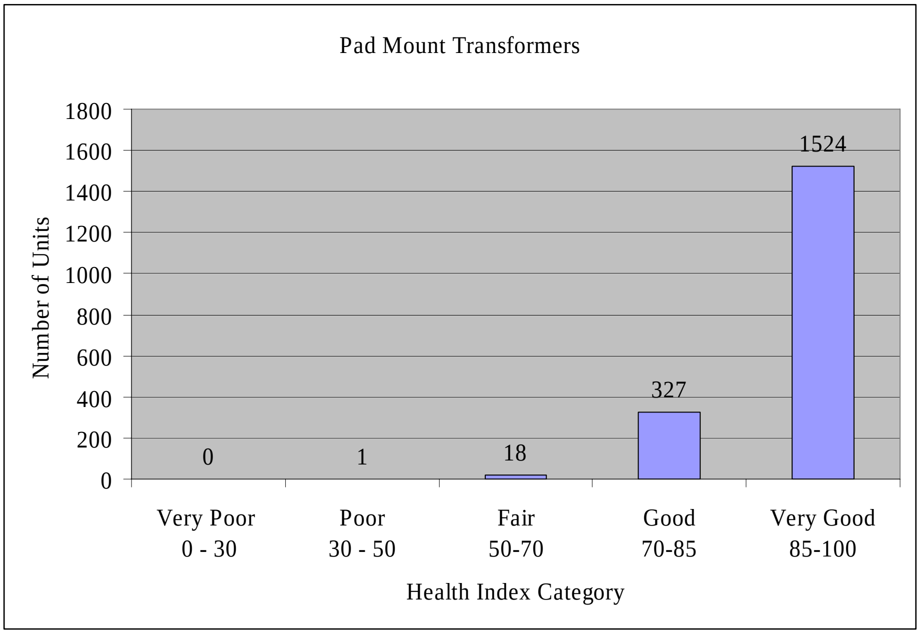


Health Indexes have been computed for the padmounted transformers as described in Table 3-12 and Figure 3-25.

Table 3-12 Summary of Condition Rating Results for Pad Mounted Transformers

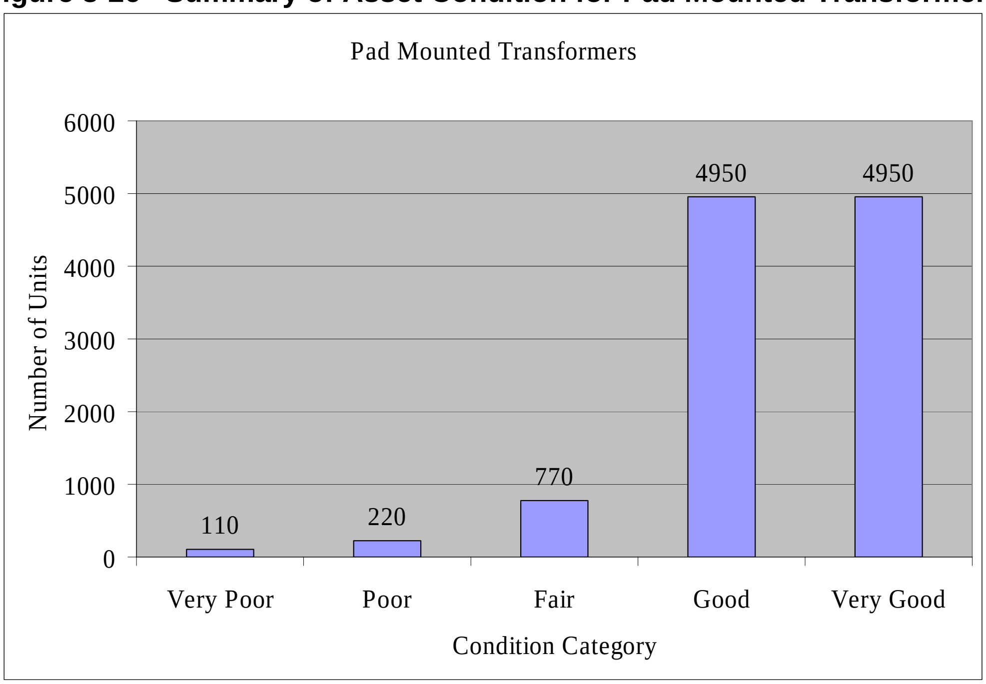
Condition Ratings: Pad Mounted Transformers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Bushing/Insulator Condition	1838	49	0	2	0	1889
Oil Leaks	1163	54	0	14	0	1231
Corrosion/Paint	1457	399	7	99	0	1962
Transformer Lid Gaskets	1608	92	4	9	0	1713
Barriers	825	4	0	2	0	831
Grounding	1897	51	0	1	0	1949
Concrete Base	0	0	0	0	0	0
Secondary Connections	233	1716	0	2	0	1951
Latches/Handles/Locks/Door	1601	92	224	23	1	1941
Age	1773	482	505	128	7	2895

Figure 3-25   Summary of Health Index Results for Pad Mounted Transformers



The Health Index results indicate that no pad mounted transformers will require replacement in the next year, 0.05% in the following two years and 0.96% in years 4 to 10. This rate of replacement is lower than past experience would indicate to be a prudent planning level. The Health Index formulation is therefore under review. At the present time the best available estimate for remaining life of pad mounted transformers is based on age. This indicates that 1100 pad mounted transformers will need to be replaced in the next 10 years, or 20% of the total population. Figure 3-26 illustrates the condition assessment based on age.

Figure 3-26   Summary of Asset Condition for Pad Mounted Transformers

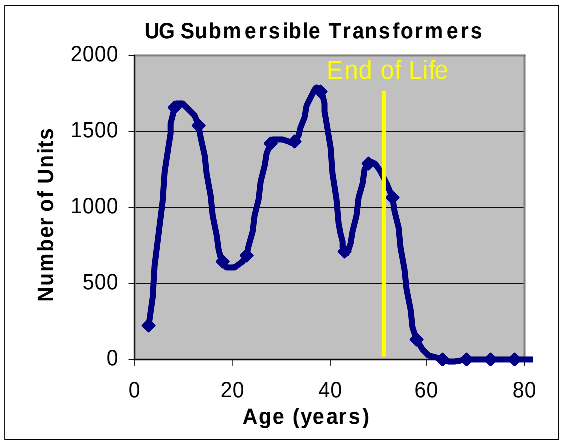


3.14 Submersible Transformers

Submersible transformers are used to step down power from primary voltage to utilization voltage. These transformers are liquid filled, with mineral insulating oil in a sealed tank construction. The tank is installed in an underground concrete vault which has a steel, ventilated lid at ground level.

The age distribution for submersible transformers is shown in Figure 3-27.

Figure 3-27 Age Distribution of Submersible Transformers

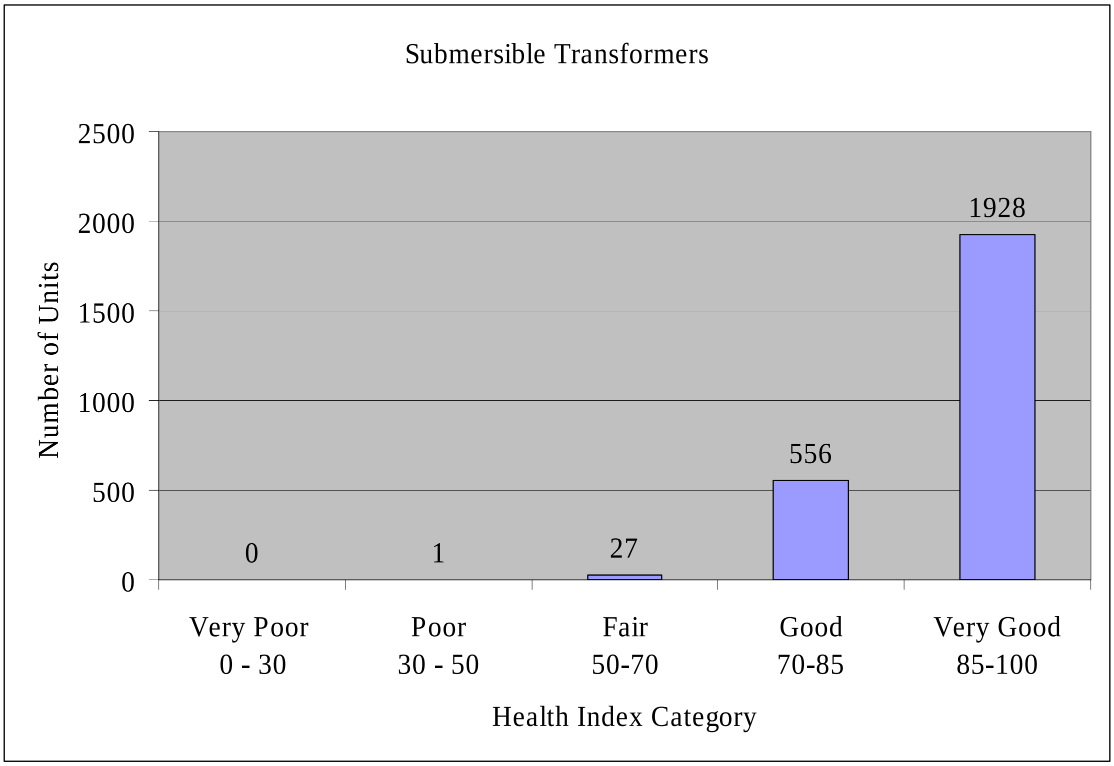


Health indexes have been computed for submersible transformers as described in Table 3-13 and Figure 3-28.

Table 3-13 Summary of Condition Rating Results for Submersible Transformers

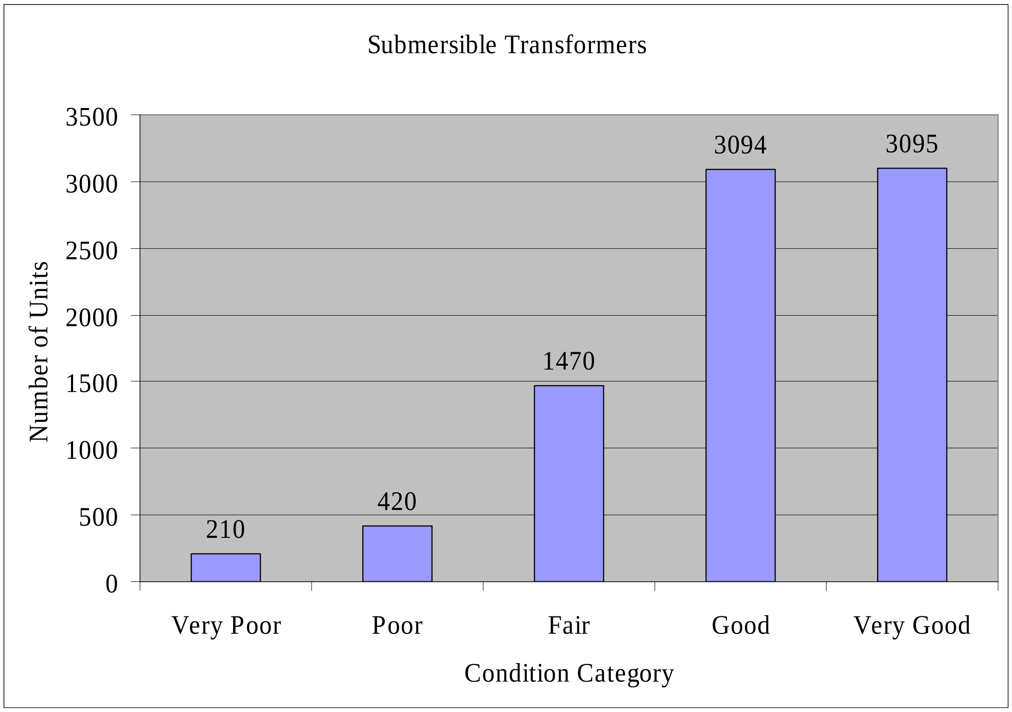
Condition Ratings: Submersible Transformers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Bushing/Insulator Condition	2574	30	0	2	0	2606
Oil Leaks	1600	97	1	24	0	1722
Corrosion/Paint	1705	410	2	33	0	2150
Transformer Lid Gaskets	2234	248	69	15	1	2567
Barriers	0	0	0	0	0	0
Grounding	2605	20	0	0	0	2625
Secondary Connections/Primary Terminations	263	2350	0	9	0	2622
Age	2510	1981	1219	110	5	5825

Figure 3-28 Summary of Health Index Results for Submersible Transformers



The Health Index results indicate that no submersible transformers will require replacement in the next year, 0.04% in the following two years and 1% in years 4 to 10. This rate of replacement is lower than past experience would indicate to be a prudent planning level. The field audit found that the average condition was worse than that computed by the Health Index. The Health Index formulation is therefore under review. At the present time the best available estimate for remaining life of submersible transformers is based on age. This indicates that 2100 submersible transformers will need to be replaced in the next 10 years, or 25% of the total population. Figure 3-29 illustrates the condition assessment based on age.

Figure 3-29 Summary of Asset Condition Assessment for Submersible Transformers

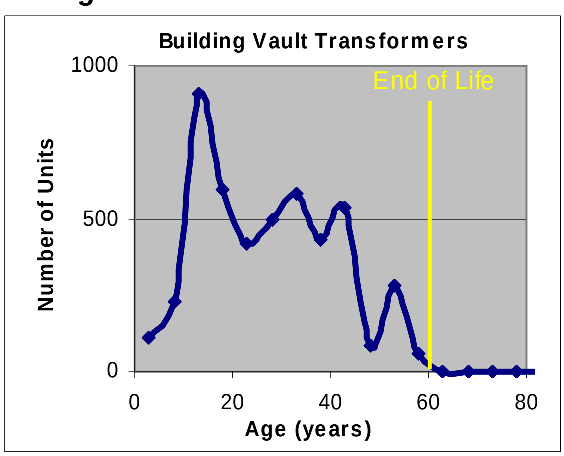


3.15 Vault Transformers

Building vault transformers are used to step down power from primary voltage to utilization voltage. These transformers are liquid filled, with mineral insulating oil in a sealed tank construction. The tank is installed in a concrete room in a building.

The age distribution for vault transformers is shown in Figure 3-30.

Figure 3-30 Age Distribution of Vault Transformers

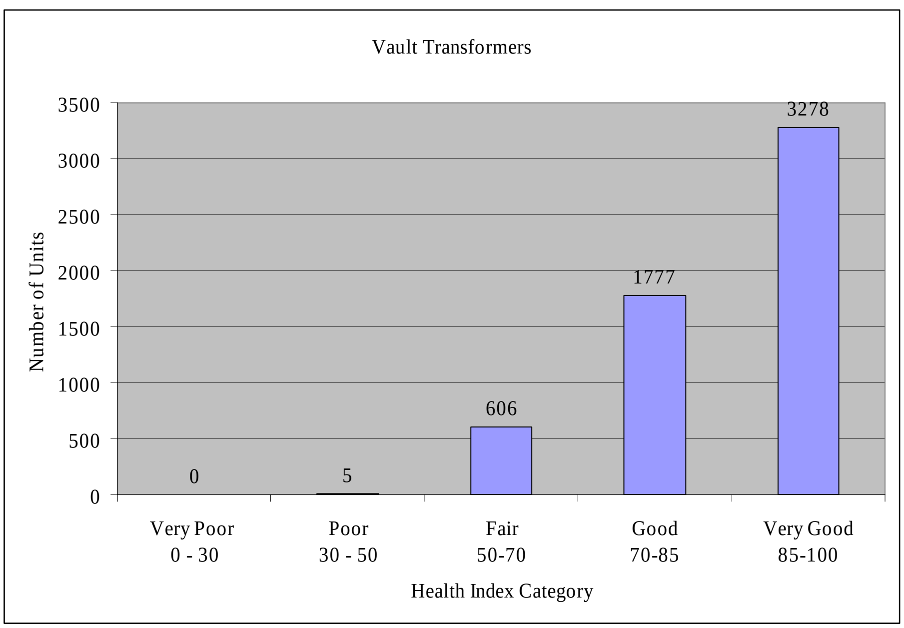


Health indexes have been computed for vault transformers as described in Table 3-14 and Figure 3-31.

Table 3-14 Summary of Condition Rating Results for Vault Transformers

Condition Ratings: Vault Transformers						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Bushing/Insulator Condition	4245	1745	0	12	0	6002
Oil Leaks	2974	939	3	11	1	3928
Corrosion/Paint	3097	1182	9	13	0	4301
Transformer Lid Gaskets	4103	1676	6	2	0	5787
Barriers	2657	1000	4	3	0	3664
Grounding	4322	1660	4	0	0	5986
Secondary Connections/Primary Terminations	4302	1680	0	9	1	5992
Age	2726	2048	2296	507	141	7718

Figure 3-31 Summary of Condition Assessment Results for Vault Transformers



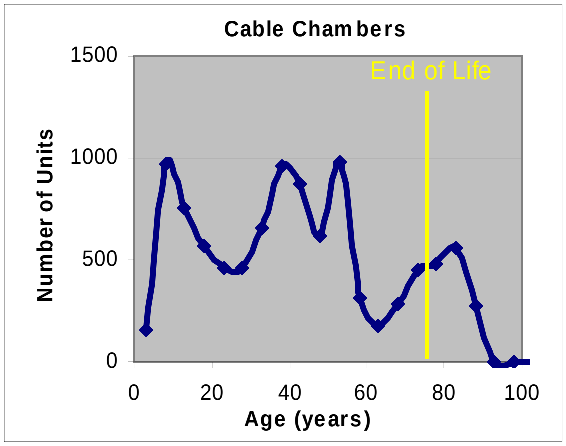
The Health Index results indicate that no vault transformers will require replacement in the next year, 0.09% in the following two years and 10% in years 4 to 10. This indicates that in the entire population of 12,409 units, 11 vault transformers will need to be replaced in years 2 and 3, and 1330 in years 4 to 10.

3.16 Cable Chambers

Cable Chambers or manholes facilitate cable pulling into underground ducts and provide access to splices and facilities that require periodic inspections or maintenance.

The age distribution for cable chambers is shown in Figure 3-32.

Figure 3-32 Age Distribution of Cable Chambers



Although a Health Index for cable chambers has been formulated, there was no existing data available for the input condition monitoring parameters. A Health Index cannot be computed until the data has been collected.

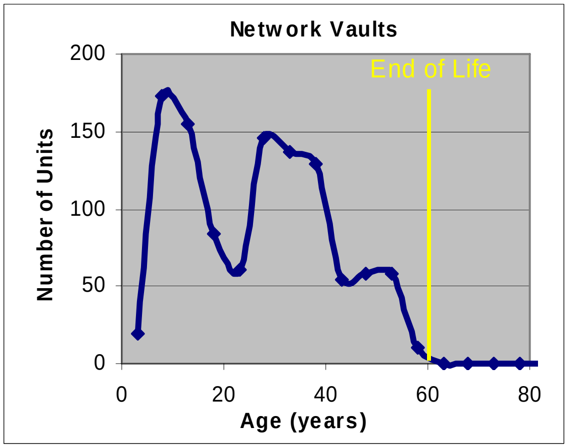
The age distribution in Figure 3-32 indicates that 35% of the total population will require replacement in the next ten years. However, cable chambers are expensive to replace and they can be maintained almost indefinitely, which often includes replacement of the roof or cover. This combination results in the lowest long term cost being achieved by repair rather than by replacement. Age is therefore not a good basis on which to estimate the number that need to be replaced. Past experience and engineering judgment have estimated the actual replacements to be 1% over the next ten years.

3.17 Network Vaults

Below ground equipment vaults are concrete structures that permit installation of transformers, switchgear or other equipment. Vaults used for transformer installation are often equipped with ventilation grates to provide natural or forced cooling.

The age distribution for network vaults is shown in Figure 3-33.

Figure 3-33   Age Distribution of Network Vaults



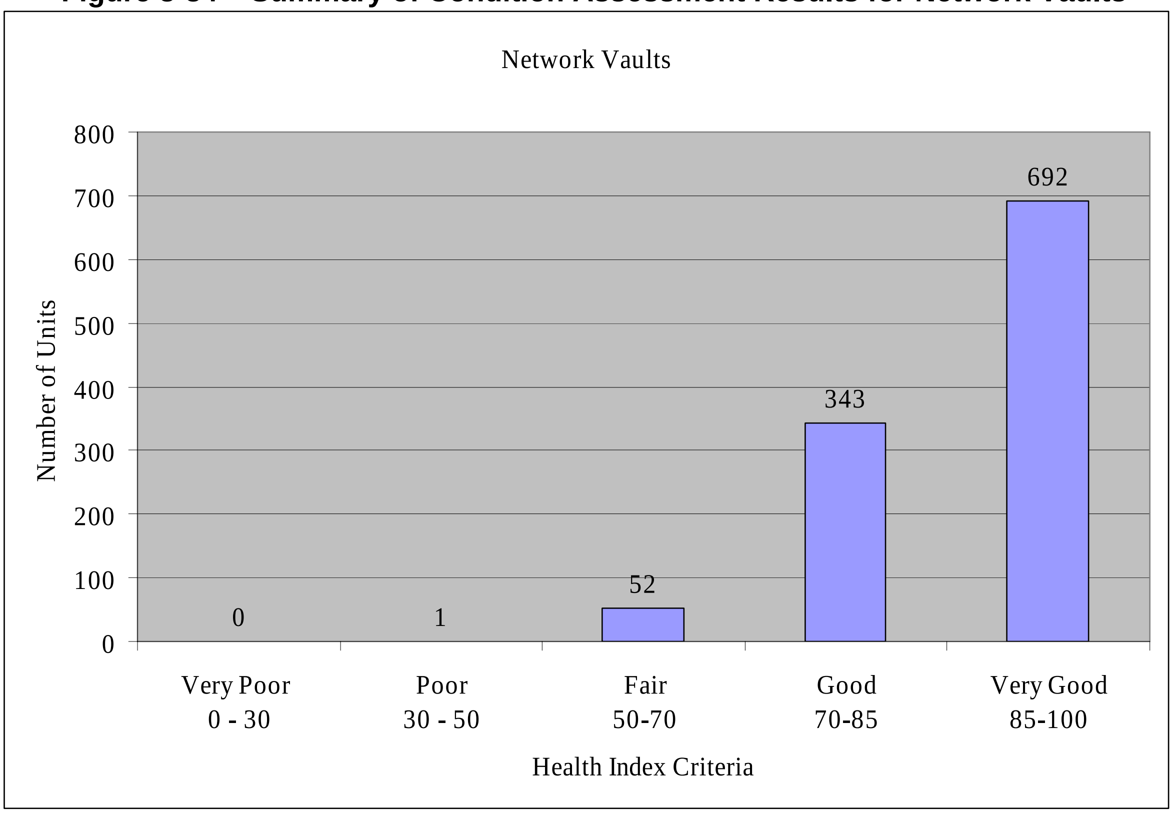
Health Indexes have been computed for network vaults as described in Table 3-15 and Figure 3-34

The Health Index results indicate that there are no network vaults that require replacement next year, 1 in years 2 to 3 and 52 in years 7 to 10. The field audit found vaults to be in slightly worse condition than the Health Index analysis. However, network vaults are quite maintainable and replacement is expensive. It may be possible to extend the life of these vaults by doing major maintenance such as roof replacement. This option could be a lower long term cost than replacement on the schedule indicated by the Health Index.

Table 3-15 Summary of Condition Rating Results for Network Vaults

Condition Ratings: Network Vaults						
	Number of Units Receiving the following ratings					Total Number of Units Assessed
Condition Criteria	1 As new	2	3	4	5 Near failure	Total
Floor/Roof/Walls/Slabs	838	174	3	73	1	1089
Vents/Grills/Ventilation	1046	20	6	16	0	1088
Ducts/Cables	1015	29	0	42	1	1087
Locks/Hinges/Entry/Door/Ladder	863	27	211	74	1	1089
Flooding	649	32	34	46	0	761
Drain/Sump Pump	863	27	111	85	0	1086
Dirt Debris/Contamination	63	10	999	4	0	1076
Grounding	1069	7	1	8	0	1085
Fuses	696	21	0	6	0	723

Figure 3-34 Summary of Condition Assessment Results for Network Vaults



3.18 Summary of Asset Condition

Table 3-16 presents a summary of the information on asset condition.

Table 3-16 Summary of Asset Condition

Asset Group	Asset Condition					Total Population	EOL within 10 years
	Very Good	Good	Fair	Poor	Very Poor		Units (%)
Station Transformers	49	92	114	30	2	287	146 (50%)
Circuit Breakers	823	822	60	18	9	1732	87 (5%)
Switchgear Assemblies	135	134	2	1	0	272	3 (1%)
Buildings	0	0	0	0	0	16	0 (0%)
Network Trans./Protectors	701	700	459	130	65	2,055	654 (32%)
Pole Mounted Transformers	10,000	10,000	7490	2140	1070	30,709	10,700 (35%)
Submersible Transformers	3095	3094	1470	420	210	8,289	2,100 (25%)
Vault Transformers	7178	3900	1330	11	0	12,409	1,341 (11%)
Pad Mounted Transformers	4950	4950	770	220	110	5,609	1,100 (20%)
Wood Poles	63,880	63,880	22,358	6388	3194	159,700	31,940 (20%)
Overhead Switches – Remote Operated	72	330	103	0	0	505	103 (20%)
Overhead Switches – Manual	506	404	36	0	0	946	36 (4%)
Pad Mounted Switchgear	341	341	42	12	6	742	60 (8%)
Automatic Transfer Switches	28	14	71	0	0	113	71 (63%)
Underground Cable – XLPE in Ducts	N/A	2497	0%	0%	N/A	2,497	0 km (0%)
Underground Cable – PILC in Ducts	N/A	862	308	74	N/A	1,243	382 km (31%)
Underground Cable – XLPE Direct Buried	N/A	494	479	298	N/A	1,271	777 km (61%)
Network Vaults	498	497	52	1	0%	1,048	53 (5%)
Cable Chambers	4985	4985	71	20	10	10,071	101 (1%)

4 FIELD AUDIT OF THESL ASSET CONDITION

4.1 Objectives

The field assessment of equipment condition was designed to provide a third party visual verification of the asset condition categories determined by Health Indexes. The audit was designed to be completed in a short time frame (a few weeks) identifying only the average condition of each asset class. A comparison can then be made to the results of the Health Index development process. Some differences between the two estimates of equipment condition can be expected since they are based on different sets of condition parameters.

4.2 Method

The major assets at THESL were divided into the 25 asset classes listed in Table 2-1.

For each asset class, locations for field inspection were identified. All of the TS locations where THESL owns equipment were inspected (18 of a total 35 stations). All other equipment was sampled at a statistically significant number of locations.

The equipment condition was assessed into four condition grades. Grade 1 was defined as basically new condition, grade 2 was normal wear, grade 3 was clear signs of age or degradation but still serviceable, and grade 4 was maintenance or replacement required. Grade 4 combines the Health Index condition categories 4 and 5.

The number of sampled locations was chosen so that the condition grade of the mean of the sample could be determined with 90% confidence, that is the 90% confidence interval on the mean would be less than 0.5. This means that if the audit was repeated with a different sample of locations then it would result in the same mean grade condition nine times out of ten. A larger sample size would not result in a better estimate of condition since the mean would still be in the same condition grade. The detailed calculation of the statistically significant sample size is included in Appendix C. Basically the number of samples required increases when the standard deviation of the sampled data increases. In the worst case, with samples evenly distributed over the four condition grades, this results in a requirement for 25 samples, in order to have the 90% confidence interval less than 0.5. In some asset types the maximum required number of samples were inspected, but in others the standard deviation of the data was determined from the first 15 samples and found to be low enough that 15 samples were sufficient.

The field assessment was based on a visual inspection. The actual locations for inspection were chosen so that they were geographically distributed over the entire operating area in proportion to the size of the population in the local area. Wherever possible they were selected to cover the entire age range of the population in proportion to the population in each age range. Beyond these two conditions, locations were selected at random.

4.3 Results of the Field Audit

The following Figures show the results of the field audit for each of the 25 classes of equipment. Each figure shows the number of samples inspected and the distribution of condition grades obtained, including the mean and the 90% confidence interval on the mean. These results will be directly compared with the Health Indexes determined from asset condition data in Section 8 of this report.

Figure 4-1 Power Transformer Field Audit

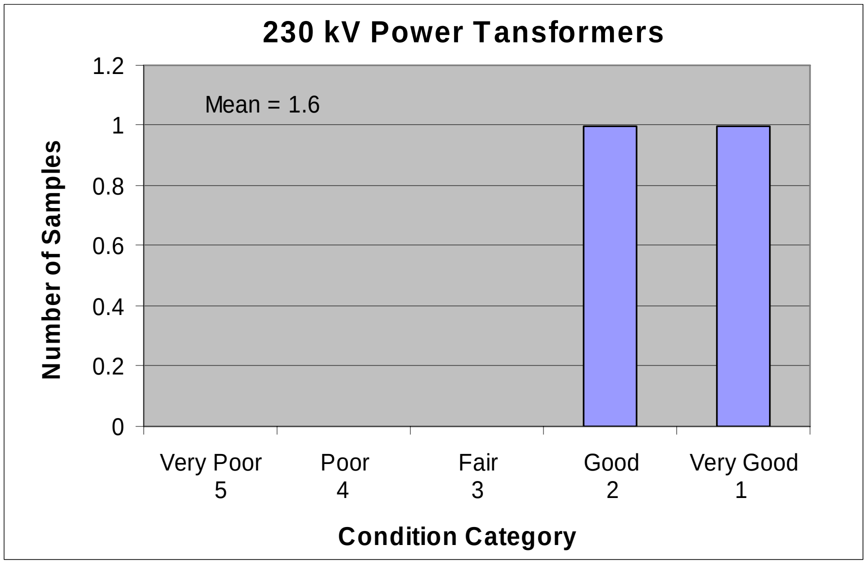


Figure 4-2 27.6 kV Breakers Field Audit

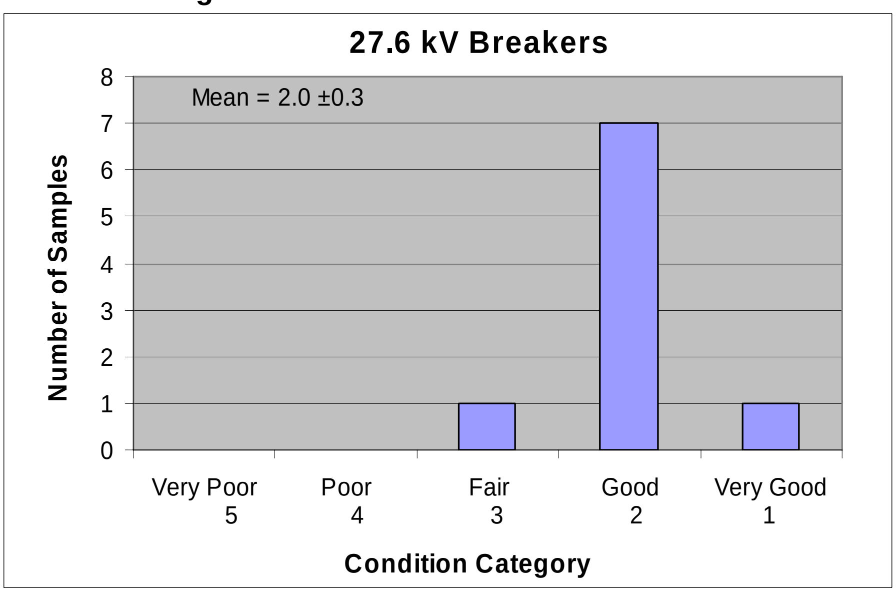


Figure 4-3 13.8 kV Breakers Field Audit

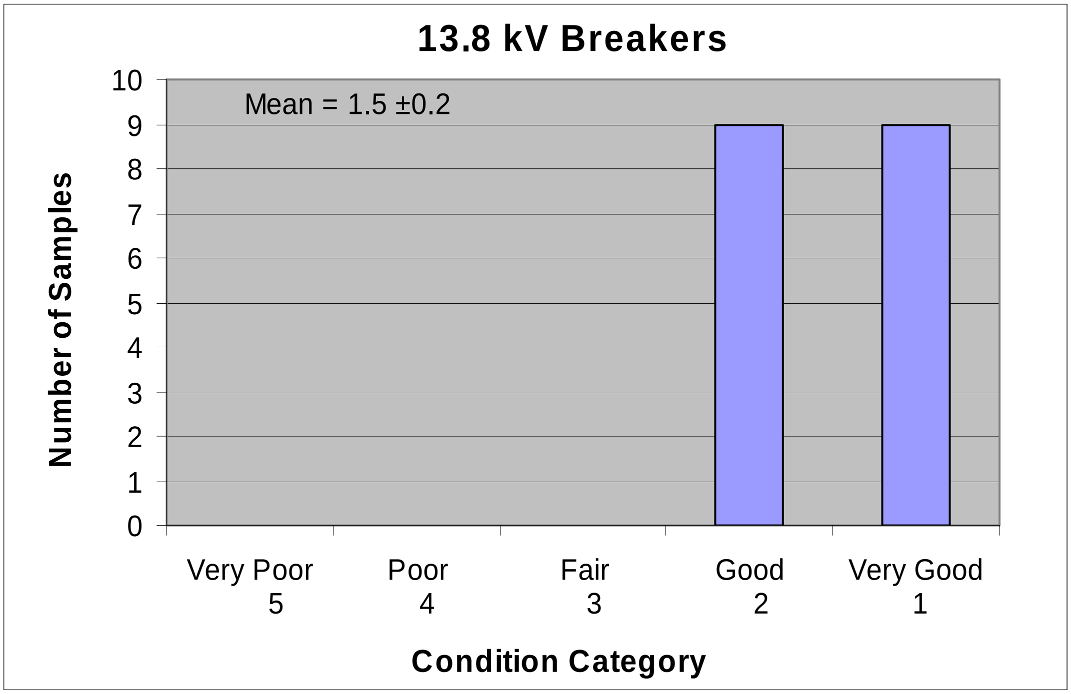


Figure 4-4 27.6 kV Switchgear Field Audit

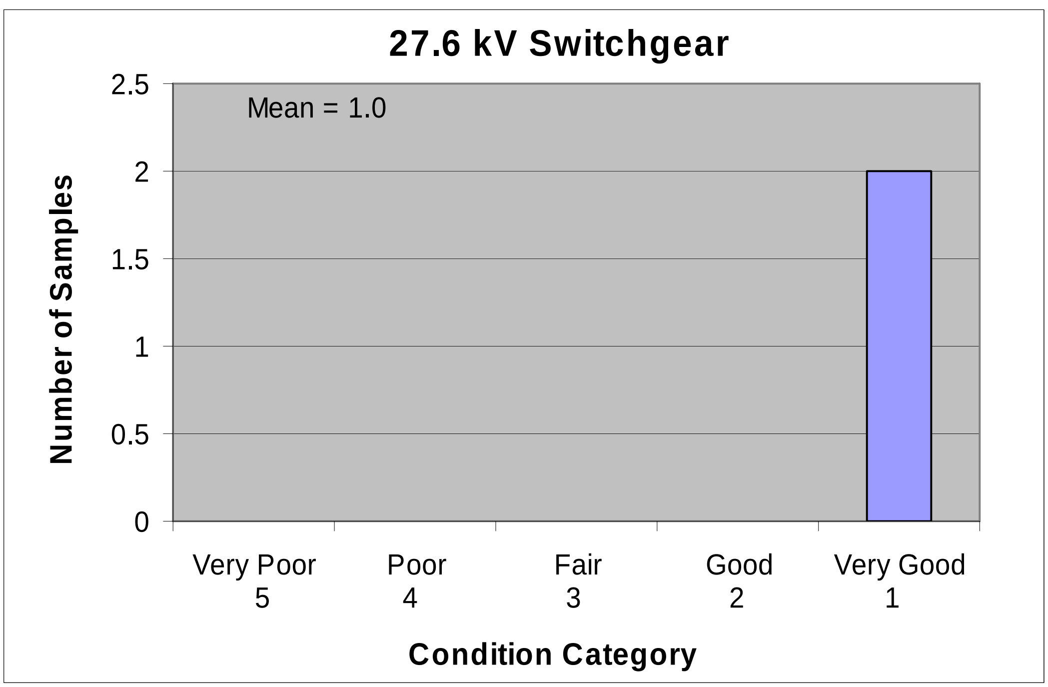


Figure 4-5   13.8 kV Switchgear Field Audit

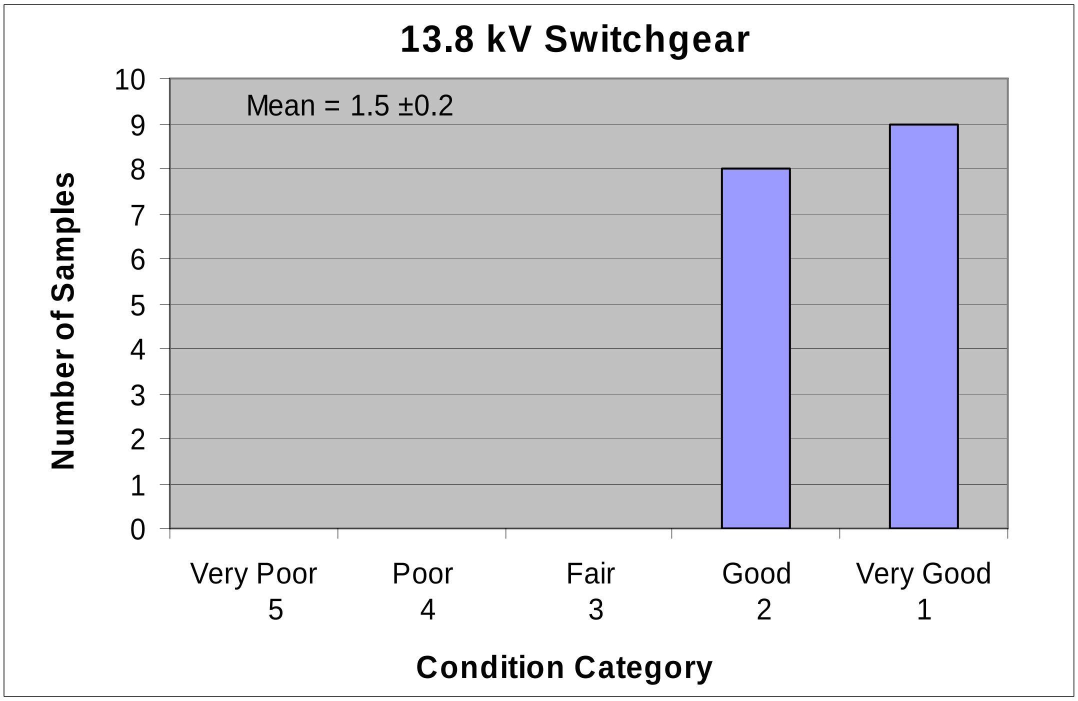


Figure 4-6   Example 13.8 kV Switchgear

Figure 4-7 Buildings Field Audit

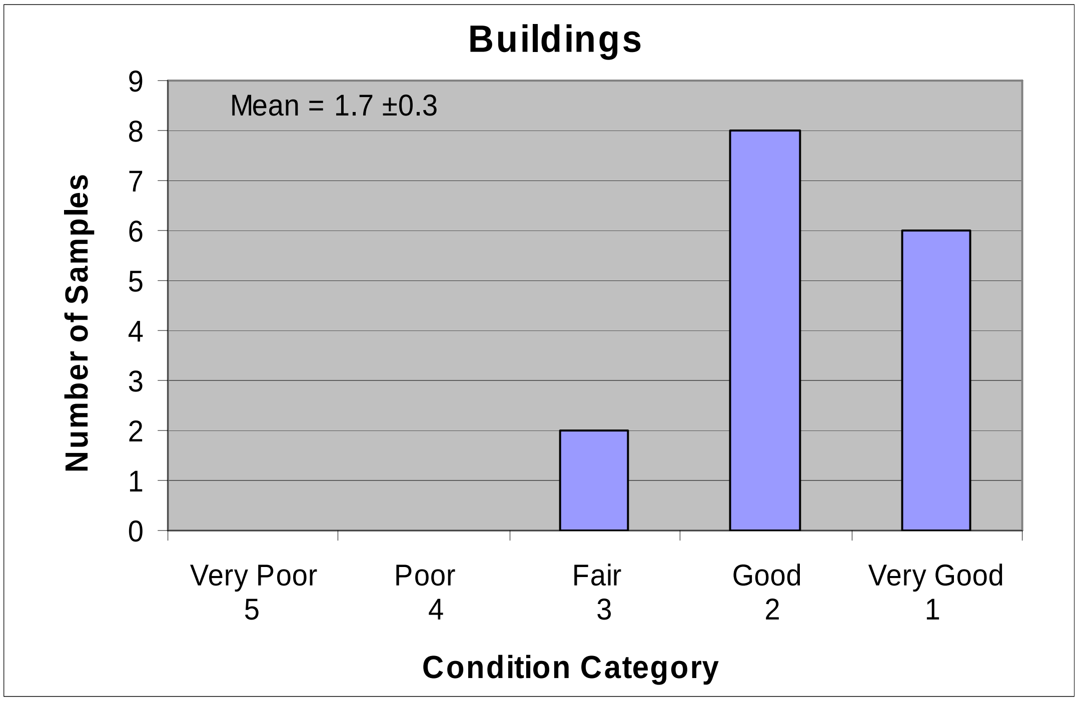


Figure 4-8 Example Building

Figure 4-9 27.6kV - 13.8kV Power transformer Field Audit

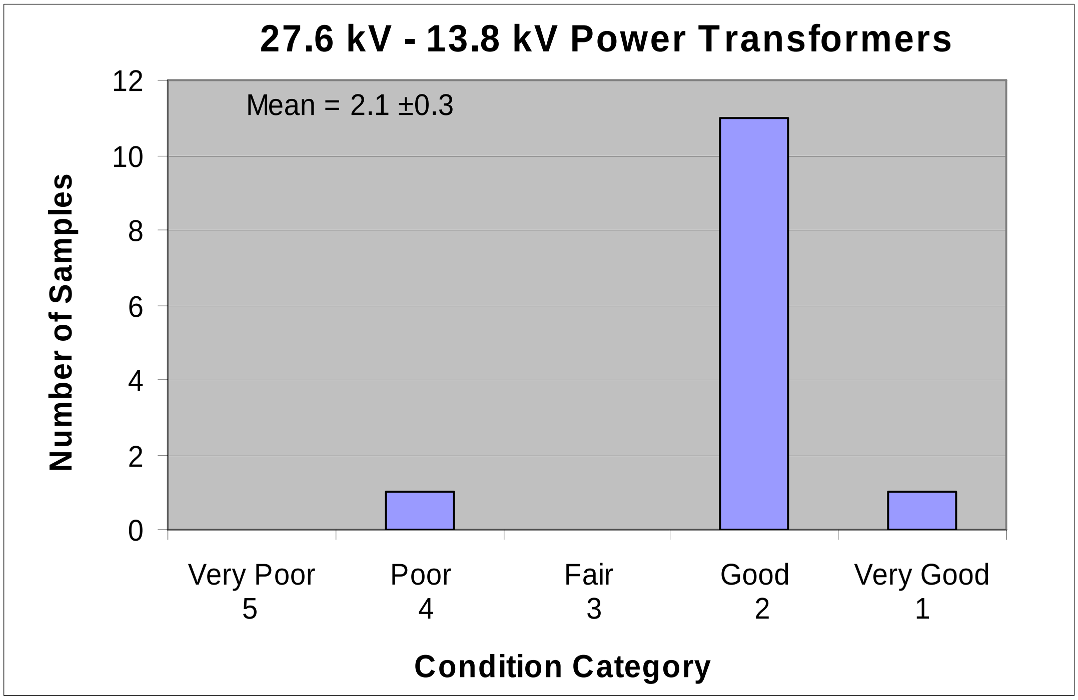


Figure 4-10 Example 27.6kV -13.8kV Power Transformer

Figure 4-11 27.6kV-4.16kV Power Transformer Field Audit

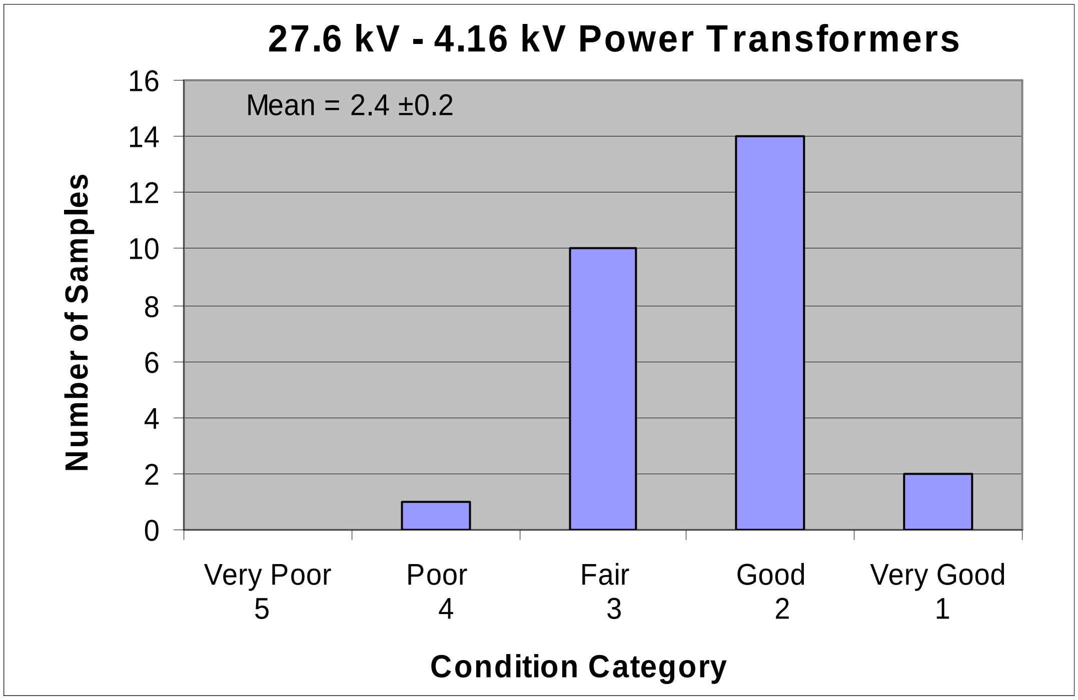


Figure 4-12 13.8kV-4.16kV Power Transformer Field Audit

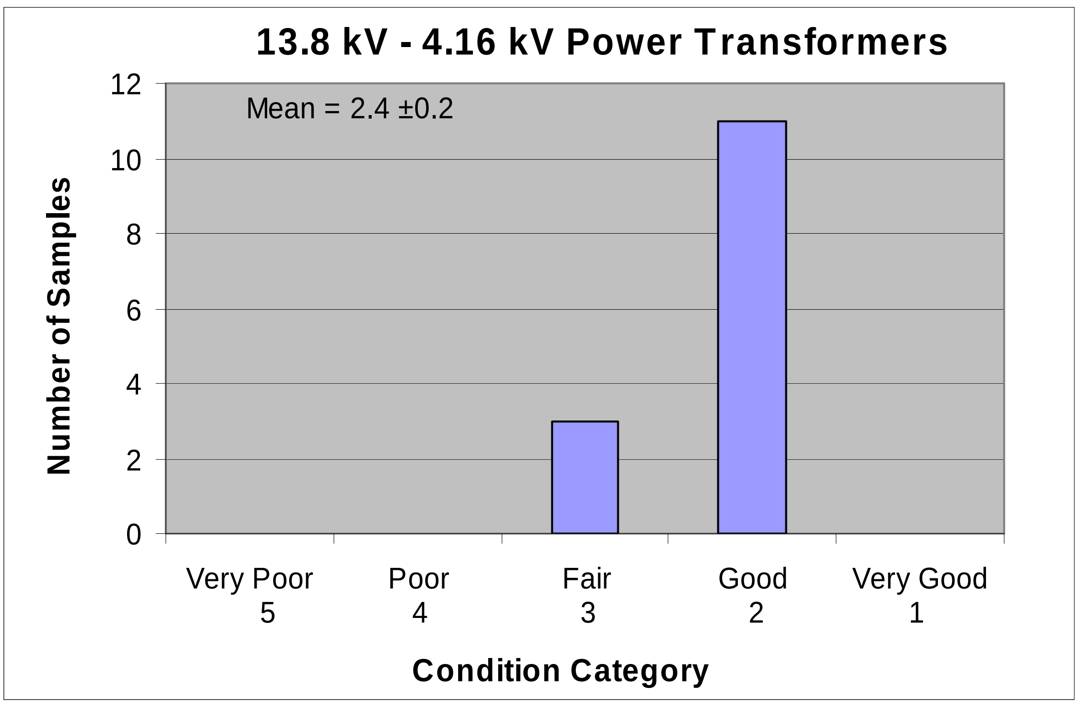


Figure 4-13 13.8 kV DS Switchgear Field Audit

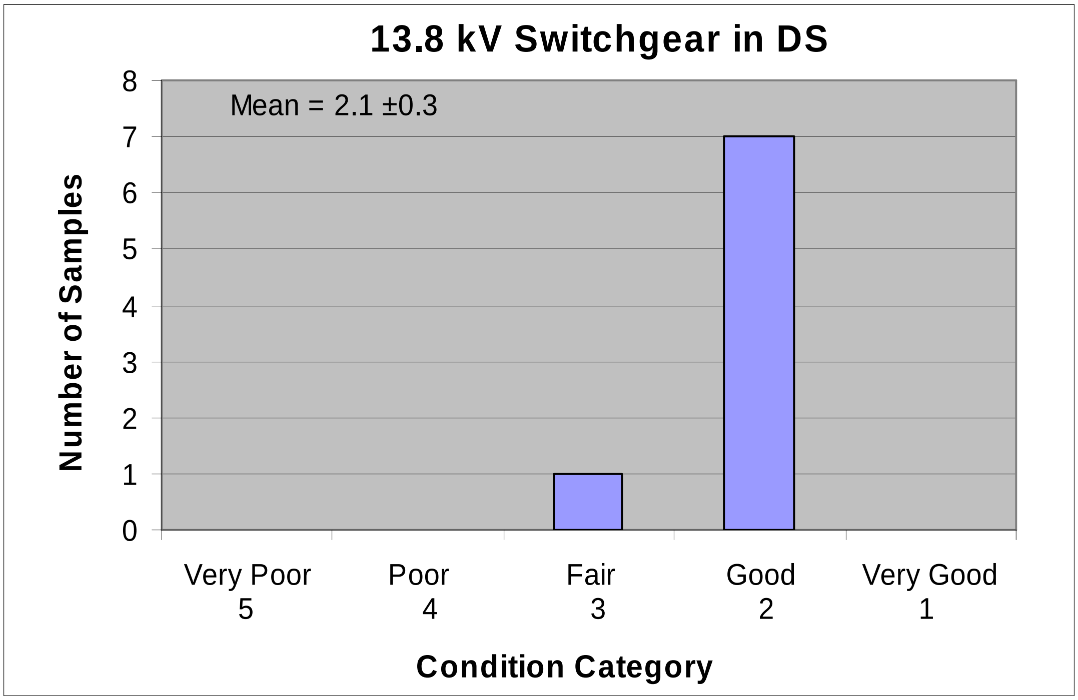


Figure 4-14 4.16 kV Switchgear Field Audit

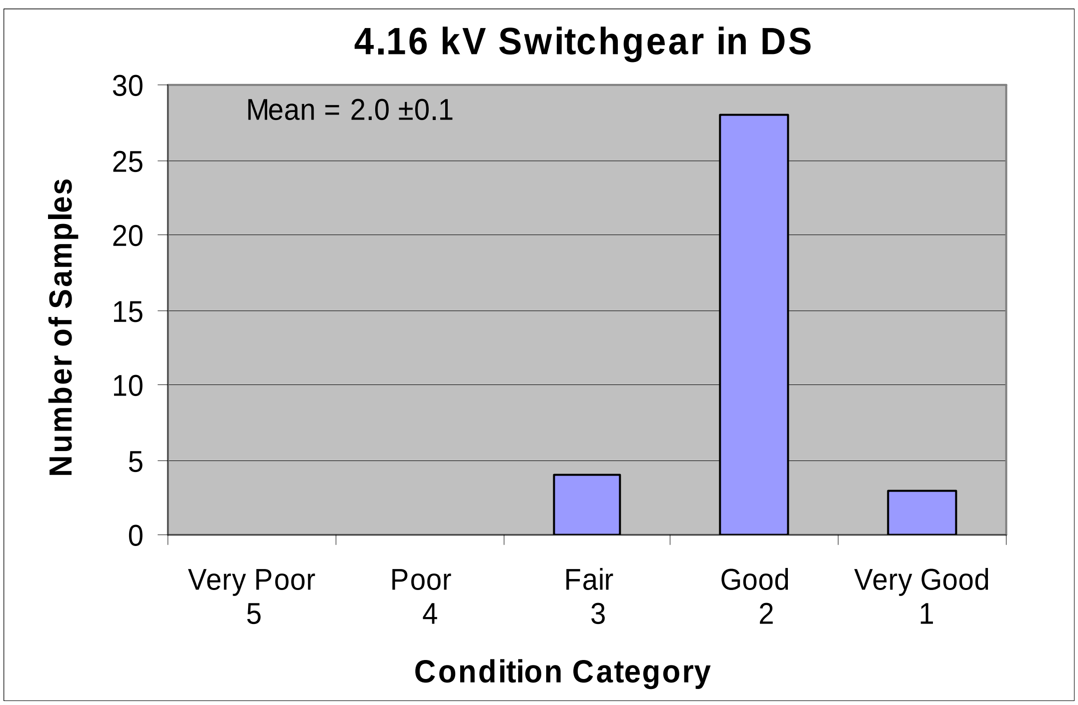


Figure 4-15 Transformer/Protector Units Field Audit

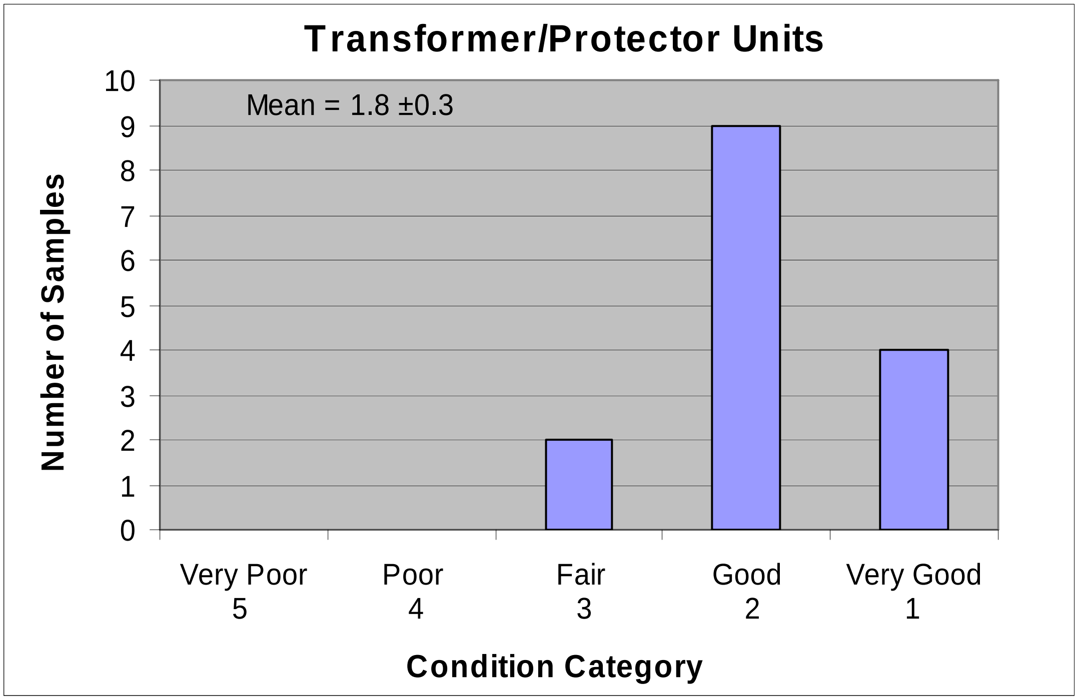


Figure 4-16 Example Transformer/Protector Units

Figure 4-17 Wood Pole Field Audit

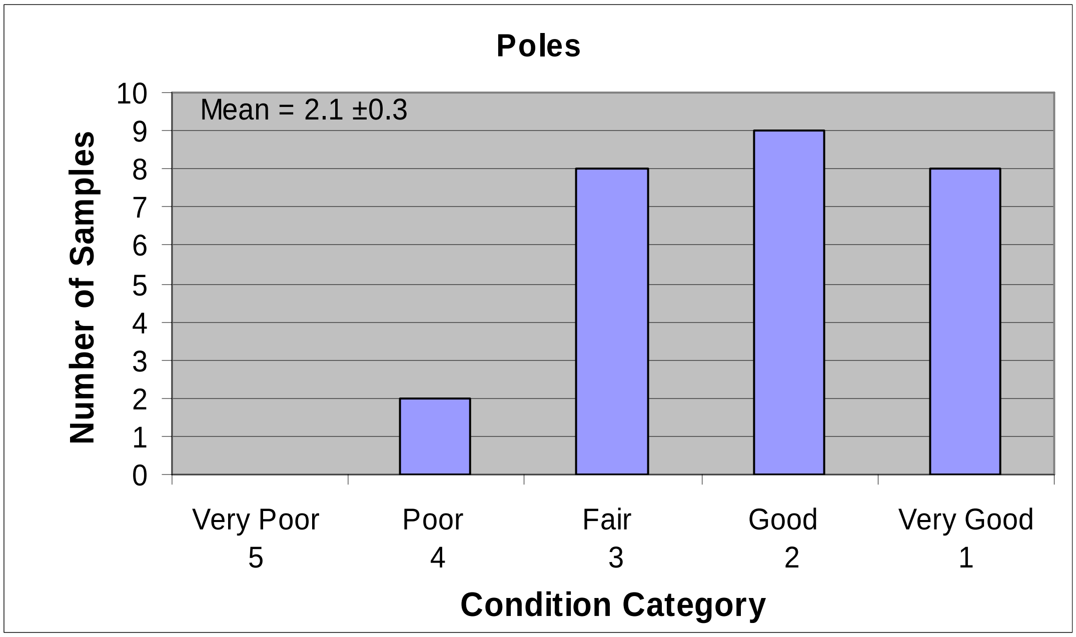


Figure 4-18 Example Wood Poles

Figure 4-19 Remotely Operated Overhead Switch Field Audit

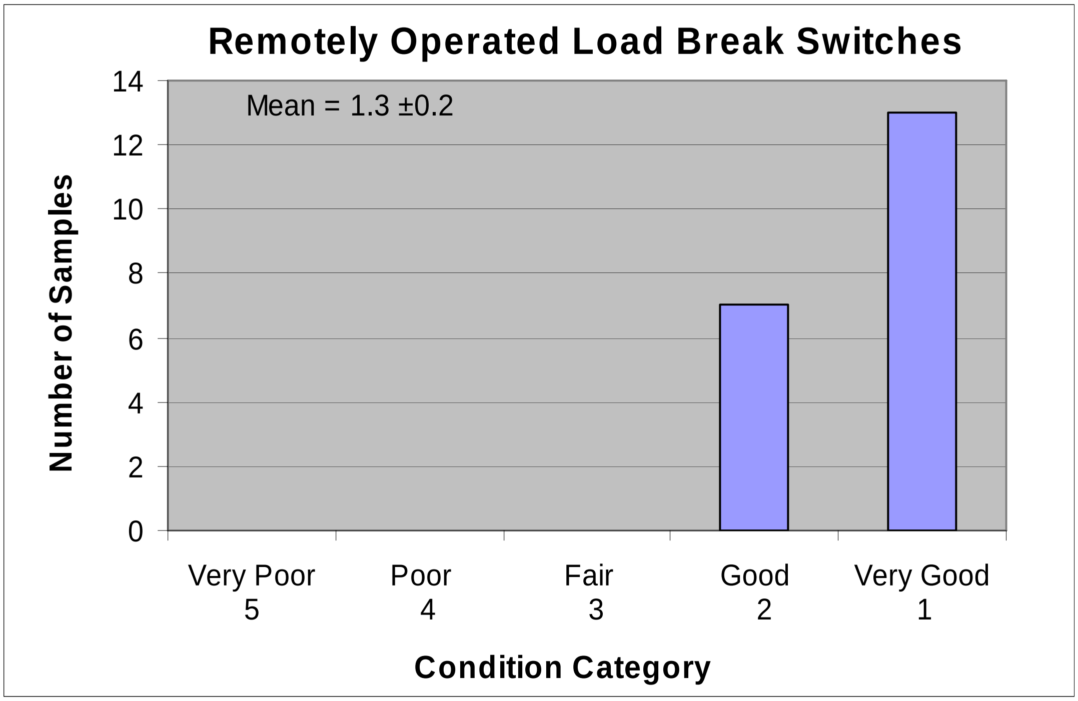


Figure 4-20 Example Remotely Operated Overhead Switch

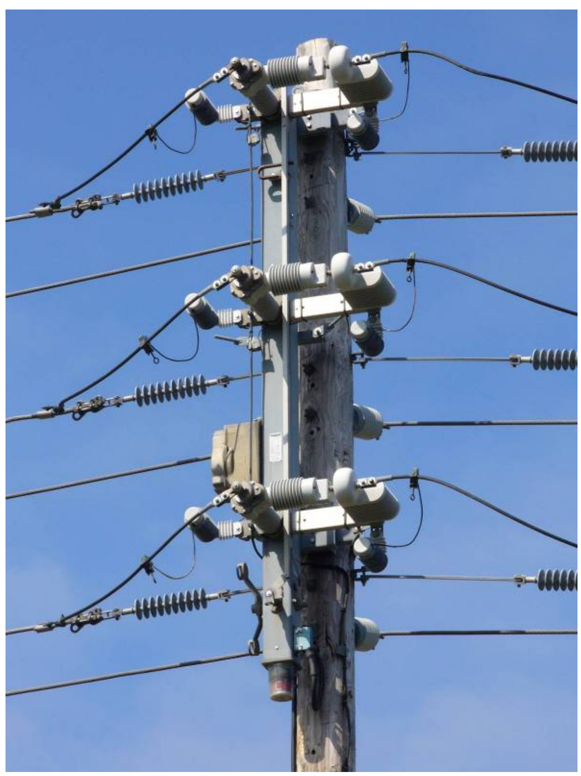


Figure 4-21 Manual Overhead Switch Field Audit

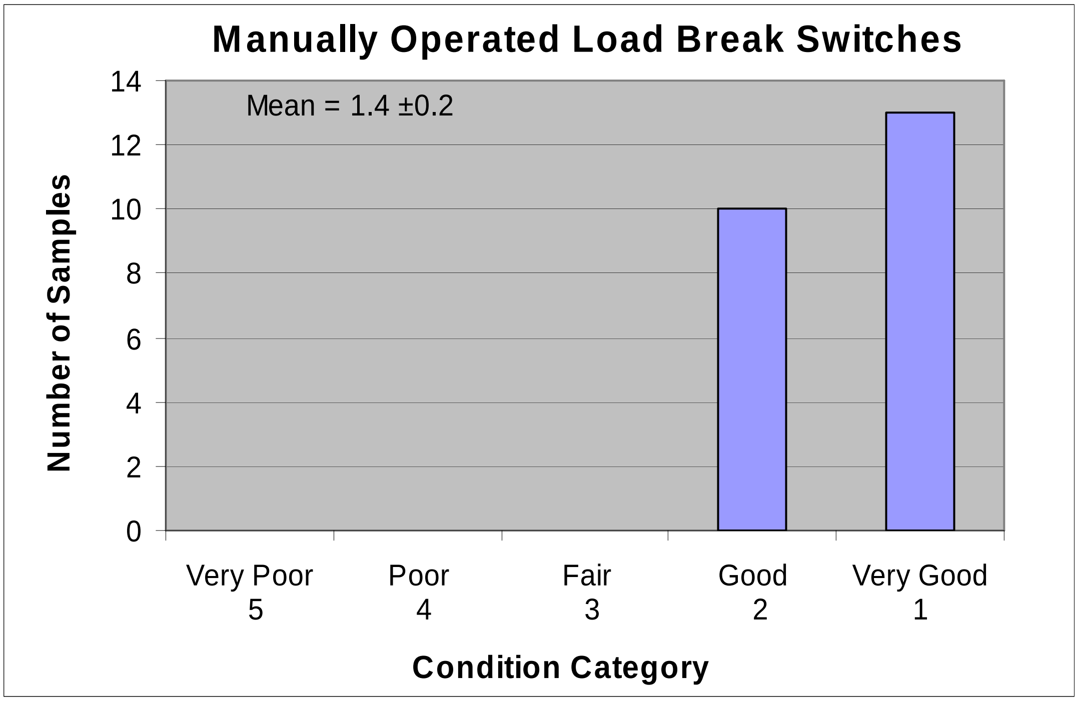


Figure 4-22 Example Manual Overhead Switch

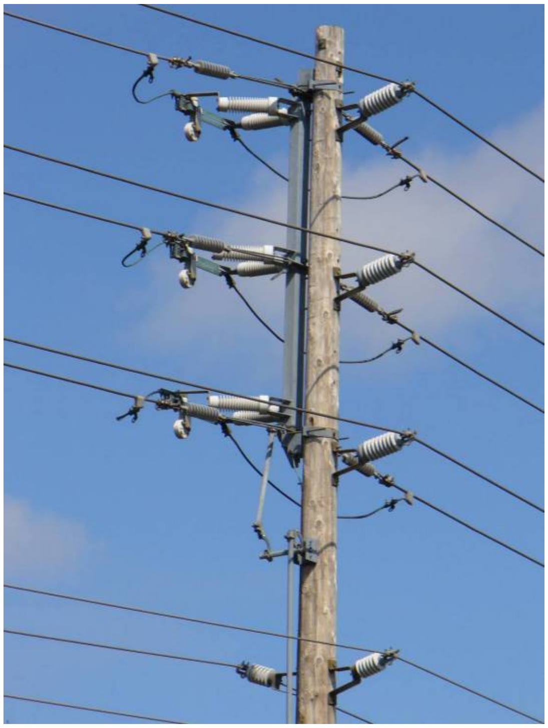


Figure 4-23 Pad Mounted Switch Field Audit

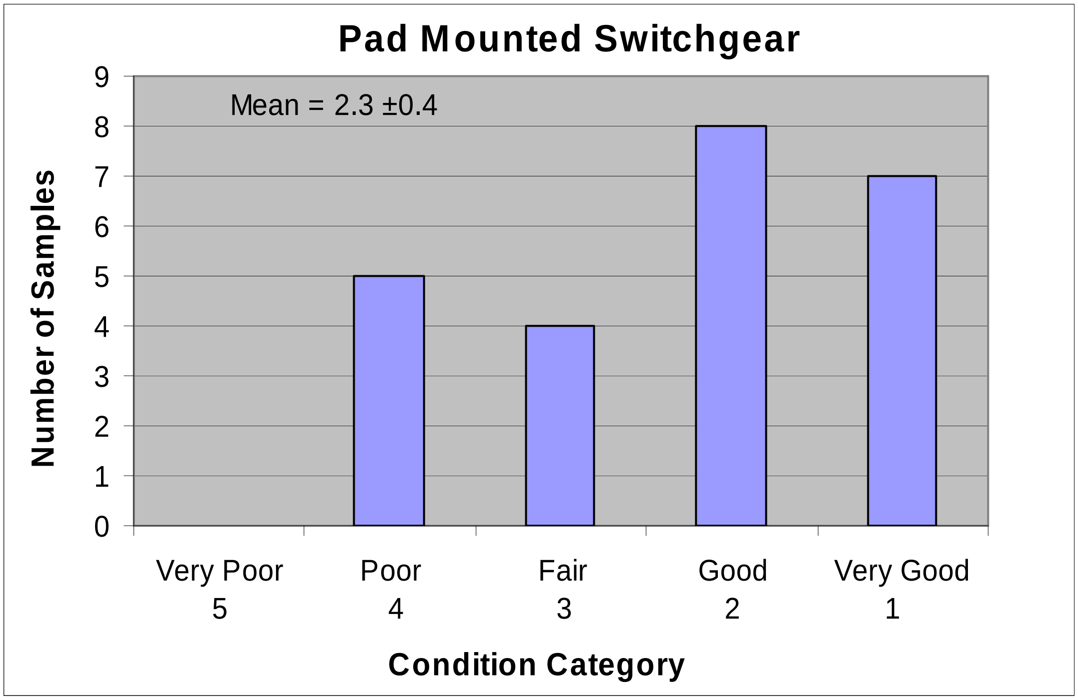


Figure 4-24 Example Pad Mounted Switch

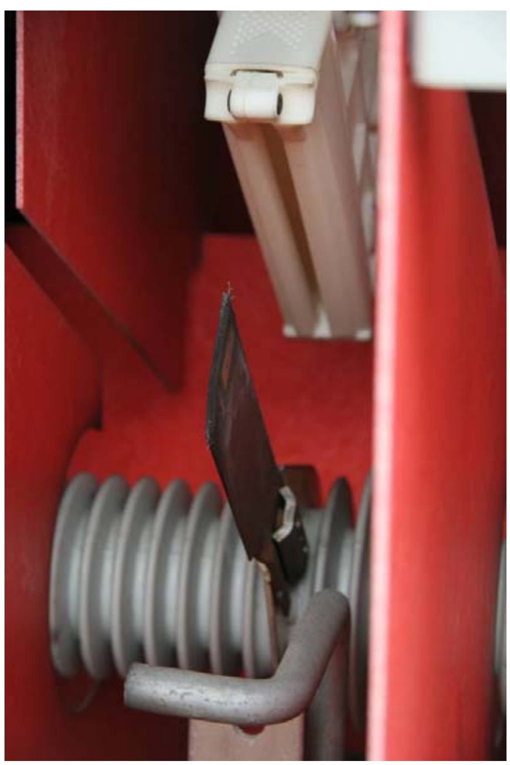


Figure 4-25 Auto Transfer Switch Field Audit

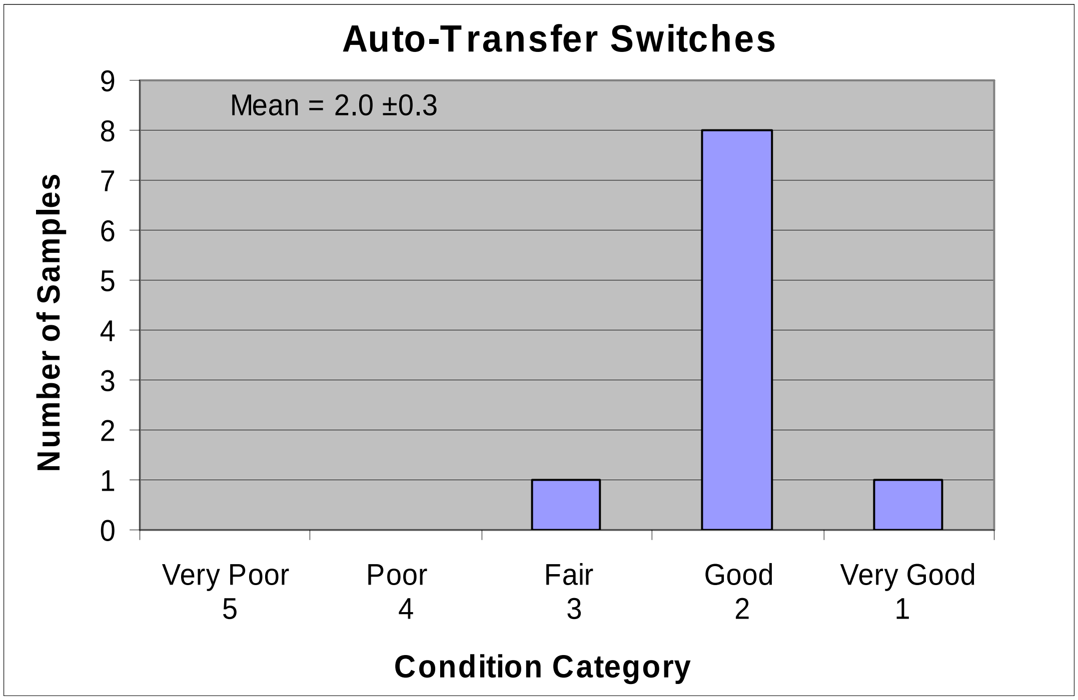


Figure 4-26 Example Auto Transfer Switch

Figure 4-27 Primary Cable Field Audit

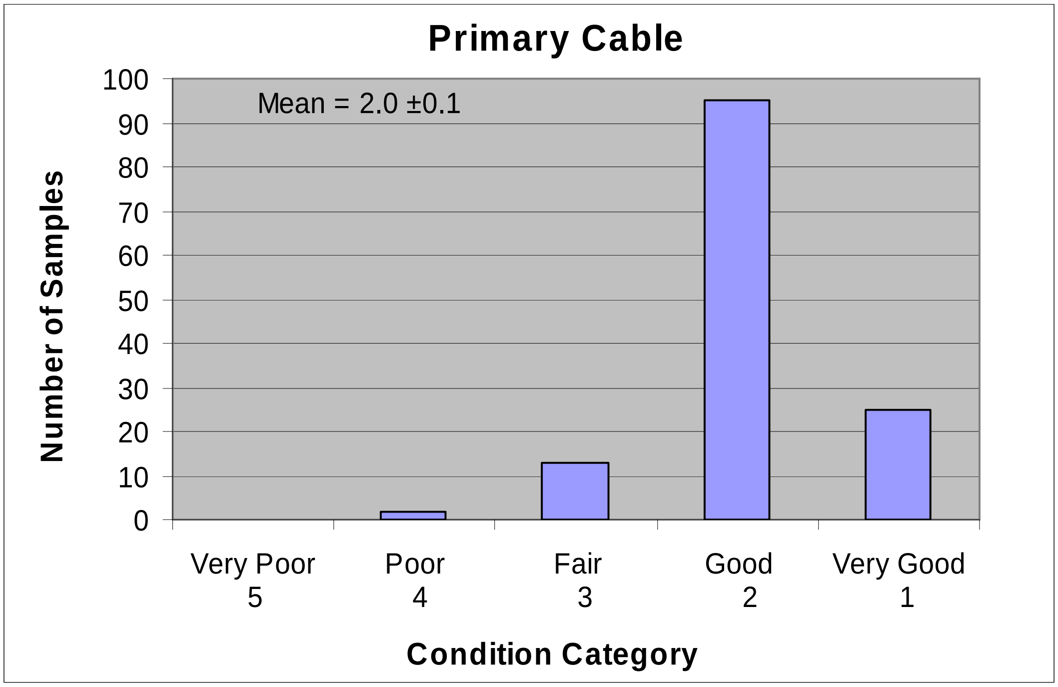


Figure 4-28 Example Primary Cable

Figure 4-29 Pole Mounted Transformer Field Audit

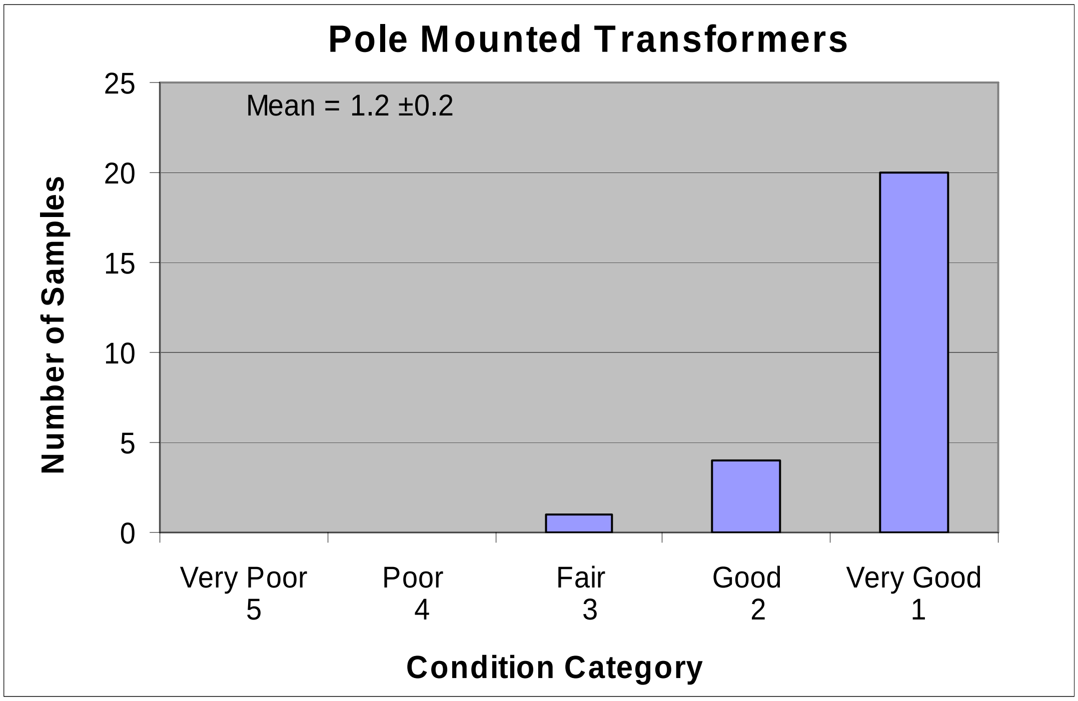


Figure 4-30 Example Pole Mounted Transformers

Figure 4-31 Pad Mounted Transformers Field Audit

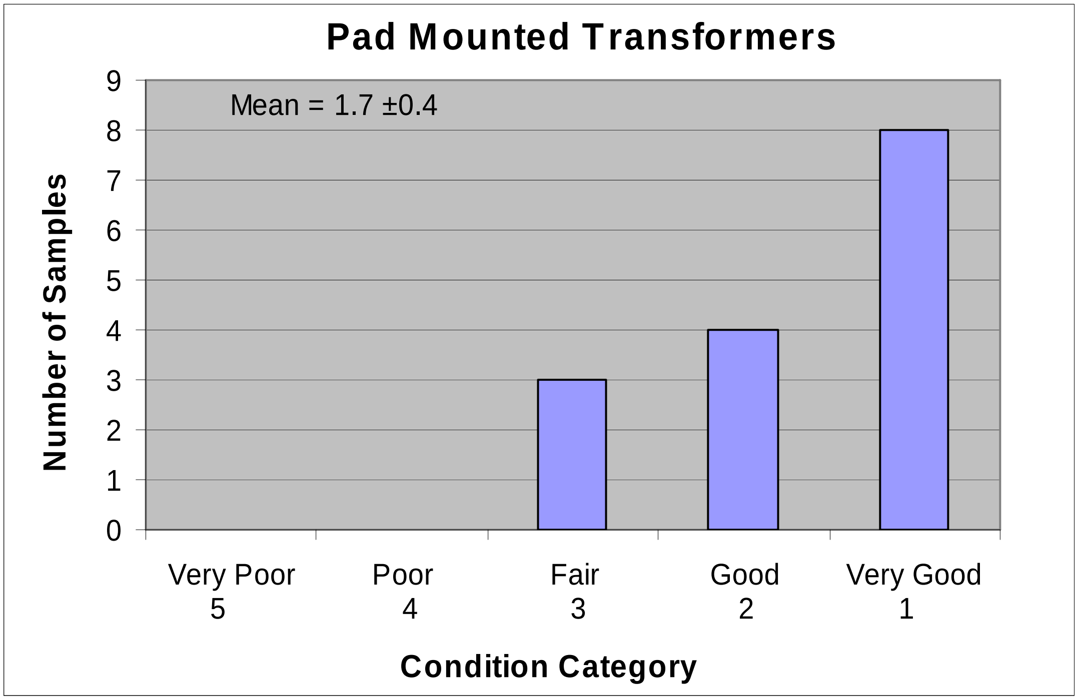


Figure 4-32 Example Pad Mounted Transformers

Figure 4-33 UG Submersible Transformer Field Audit

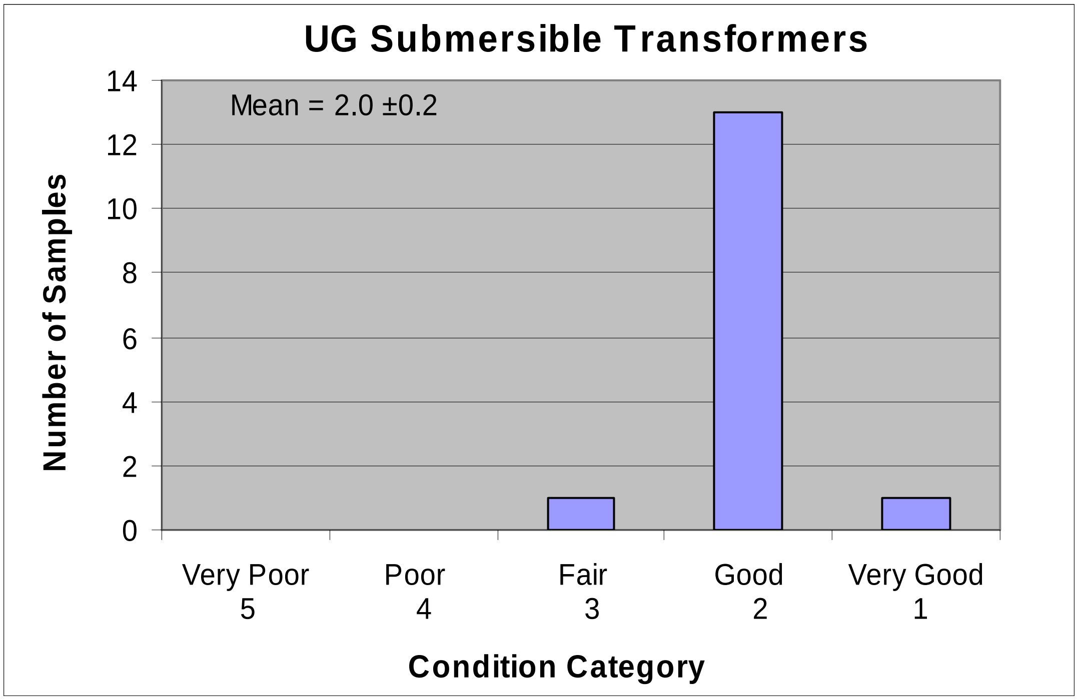


Figure 4-34 Example UG Submersible Transformer

Figure 4-35 Building Vault Transformer Field Audit

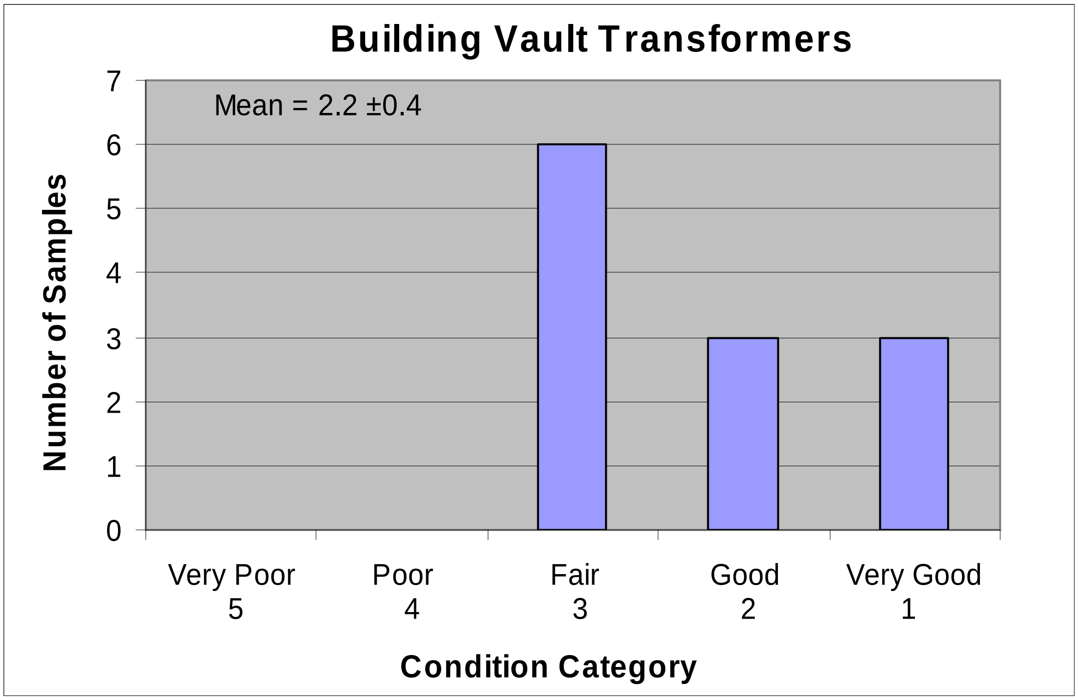


Figure 4-36 Example Building Vault Transformer

Figure 4-37 Cable Chamber Field Audit

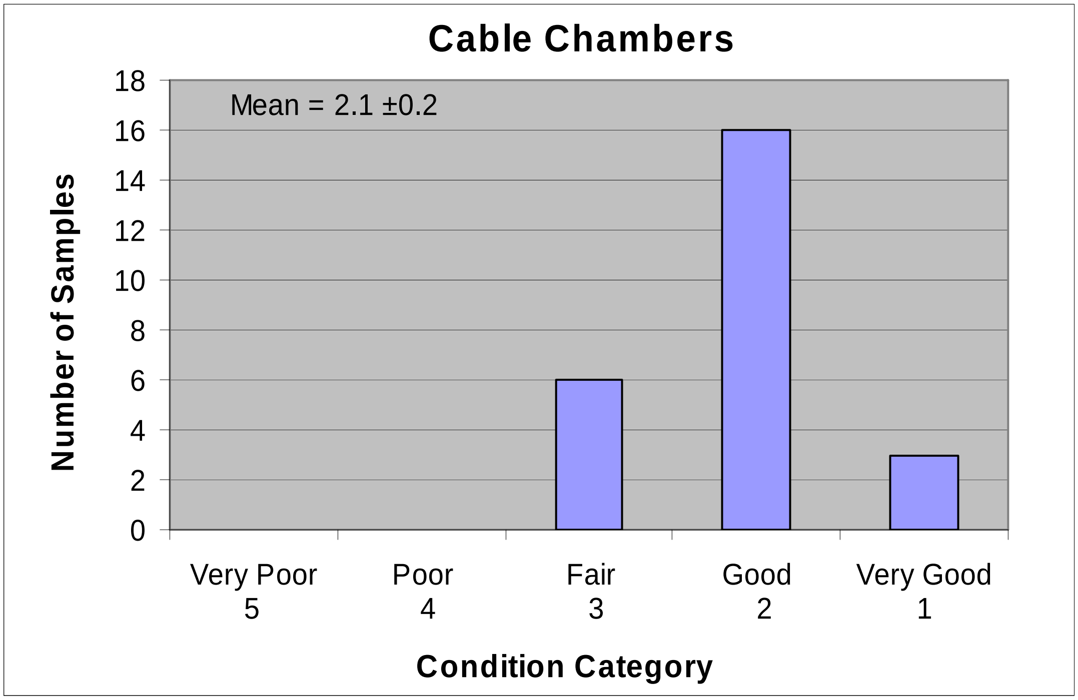


Figure 4-38 Example Cable Chambers

Figure 4-39 Network Vaults Field Audit

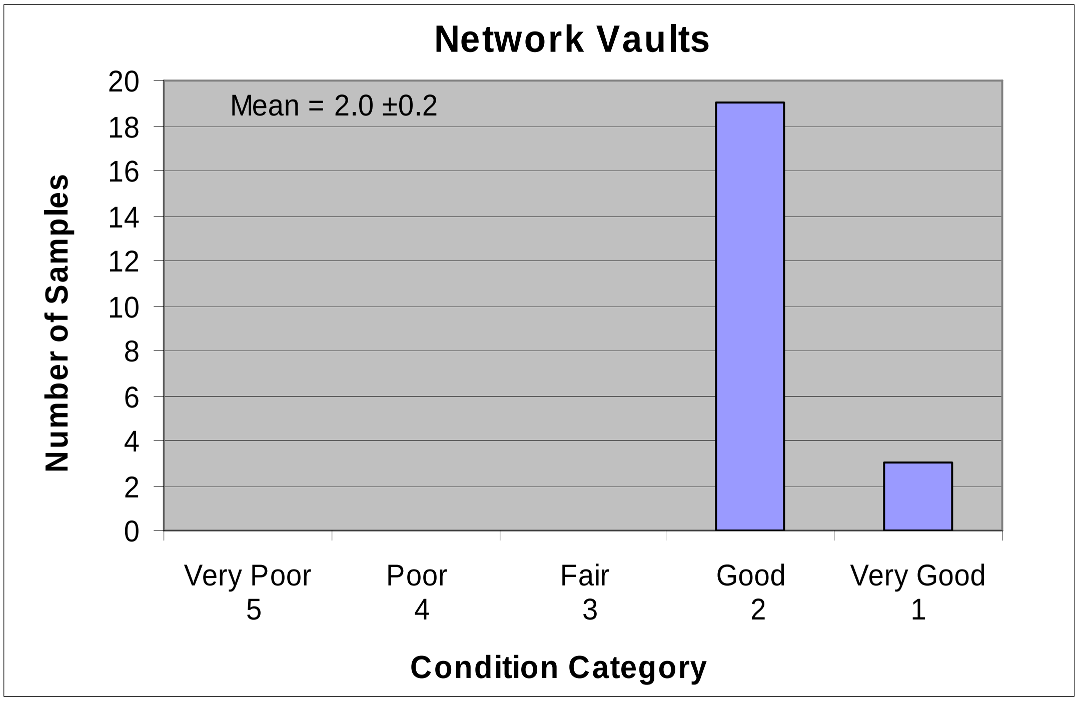


Figure 4-40 Example Network Vault

4.4 Interpretation and Significance of the Field Audit Results

The field audit results show that the major classes of THESL equipment are on average in good condition. This indicates that the past maintenance programs at THESL have been adequate. The equipment on average should reach its normally expected end of life.
Figure 4-41 below shows an example of old circuit breakers that have recently been rebuilt and can be expected to provide good service for many years to come.

Figure 4-41 Example of Old Equipment in Good Condition

The field audit found individual samples of equipment that are in need of replacement or repair. If no equipment were found to be in poor condition it would indicate that the equipment is being over maintained or replaced before its end of life. The field audit results indicate that this is not the case at THESL. Figure 4-42 shows examples of oil leaks from equipment. Repairing these leaks is part of normal maintenance. The leaks do not indicate that the equipment is at the end of its useful life.

Figure 4-42 Examples of Oil Leaks

For power transformers load history and oil analysis are much better indicators of condition. For breakers contact resistance and opening time are better indicators. For underground primary cables, failure rate is a much better indicator. The audit can only detect gross discrepancies between the Health Index based on THESL existing condition assessment techniques and the condition of equipment in the field.

4.5 Comparison of Field Audit with Health Index Condition

Since the audit determined the average condition category of each asset class, the audit results can be compared with the average condition category as determined by the Health Indexes. This comparison is shown in Table 8-1 below and on the bar chart (Figure 8-1) on the next page. A low number on the condition category indicates better condition (1 is “very good”, 5 is “very poor”).

The difference between the two estimates of asset condition category is not always large enough to be larger then the uncertainty in the estimates, i.e. large enough to be a significant difference. The audit results are statistically accurate to ±0.3, but the underlying accuracy of the assessment technique, which was an external visual inspection, makes the practical accuracy range at least ±0.5. The accuracy of the Health Index based condition category cannot be precisely calculated but it should be better than the audit. A value of ±0.2 is reasonable. The difference can therefore be considered significant if it is larger than ±0.7.

The Health Index for the following assets was not included in the comparison because of problems in the underlying data, as discussed in section 5.3: wood poles, circuit breakers, buildings, switchgear assemblies, and pole mounted transformers.

The third column in Table 8-1 shows that the two estimates of asset condition are in agreement for most asset classes.

For the first three asset classes, with a positive and significant difference in asset condition category, it is recommended that a detailed investigation of the source of the difference be conducted.

Table 4-1 Comparison of Asset Condition Measured by Health Index and Field Audit

Asset	Health Index	Audit	Differenc e
Pad Mounted Switchgear	1.3	2.3	**1.0**
Network Vaults	1.4	2.2	**0.8**
Submersible Transformers	1.2	2.0	**0.8**
Overhead Switches - Remote Operated	2.1	1.3	**-0.8**
Underground Cable Direct Buried	2.7	2.0	-0.7
Vault Transformers	1.5	2.2	0.7
Pad Mounted Transformers	1.2	1.7	0.5
Network Transformers/protectors	1.4	1.8	0.4
Station Transformers	2.5	2.1	-0.4
Automatic Transfer Switches	2.4	2.0	-0.4
Underground Cable in Duct	2.3	2.0	-0.3
Overhead Switches – Manual	1.5	1.4	-0.1
Cable Chambers	2.1	2.1	0.0

When the condition category based on the Health Index indicates a poorer condition (a negative difference in column 3) then the likely cause is that some aspect of asset condition was captured by the Health Index and could not be evaluated by visual inspection in the audit. The more relevant and varied asset condition parameters of the heath index formulation create a much higher degree of confidence. In other words, **when the two estimates differ, the Health Index is more accurate**.

However, when the condition based on the Health Index is better than that based on the field audit (a positive difference in column 3) then there may be more reason to put some weight on the field audit results. In these cases the visual inspection found evidence of condition degradation. For these assets it is recommended that the formulation of the Health Index be reviewed to ensure that all significant condition criteria are included and weighted appropriately. For example it is possible that the electrical tracking in the pad mounted switchgear, found during the field audit, should be given more weight in the Health Index formulation.

5 CONCLUSIONS

1. Kinectrics Inc. was retained by THESL to conduct an asset condition assessment based on the Health Index methodology and a field audit of asset condition. Health Indices have been formulated for THESL's assets and evaluated using existing condition data provided by THESL. Kinectrics Inc. has provided a best estimate of asset condition based on the Health Index method or, where existing data was insufficient, an age and historical trend based method. The asset condition results have been compared to the results of field audits.

2. The Health Index method provides THESL with a tool for improved tracking of asset condition, and managing and budgeting for asset replacement and maintenance. The project has provided spreadsheets that implement the Health Index formulation.

3. Kinectrics has completed a review of the asset condition of THESL, the findings of which are detailed in the balance of this report. In the majority of cases, the condition of the assets was within the range expected for distribution assets that are well maintained. Subject to the clarifications provided in this report, in general, Kinectrics found that the records of assets provided by THESL accurately reflected the condition of the equipment in service.

4. There are indications that the condition of specific pockets of assets at THESL are deteriorating and require actions beyond routine maintenance. The indications include the increasing failure rates and poor Health Indices of some classes of asset. Direct buried underground cables are a major component that suffers from this deterioration.

5. Estimates have been made of the number of components in each asset class that will need to be replaced within the next year, in 2 to 3 years and in 4 to 10 years. Assets that require particularly significant replacement programs in the next ten years include:
    - direct buried underground cable (65%)
    - station transformers (50%)
    - pole mounted transformers (35%)
    - network transformer/protectors (32%)

6. The field audit of system condition generally found equipment to be in the same average condition as determined by the condition assessment. The exceptions included padmounted switchgear, network vaults and submersible transformers. The Health Index formulation for these assets is being reviewed in response to the audit results.

7. The Heath Index results generated in this project provide a methodology for THESL to proceed with use of the Health Index approach to asset management. For some assets the Health Indices are limited by the incompleteness of available data. This situation is expected to improve with time as more specific data is collected.

8. Age alone is not a true indicator of the condition of the assets. The condition of the asset can more accurately be represented by measurements or observations of degradation of the asset, summarized as Health Indices. Age is included as part of the Health Index as a proxy for missing data and to accommodate the transition to Health Indices.

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6 RECOMMENDATIONS

1. Asset condition data used in this study was collected by THESL primarily to guide maintenance decisions rather than to provide the input for Health Index calculations. Health Indices have now been formulated for all major asset classes and in the future data can be collected specifically designed to provide a more comprehensive indication of condition. Further data required for formulation of the Health Indices should be collected and recorded in a single, easily accessed data base.

2. A risk assessment should be conducted to prioritize the assets that require replacement.

3. The Health Index formulation for the asset classes for which the audit found a significantly poorer average condition need to be re-examined and possibly reformulated.

4. There is a need to look at some of the asset classes in considerable more granularity than was possible in this study. Considering circuit breakers for instance it would be reasonable to divide the 13.8 kV breaker asset class and look at the specifics of the air circuit breakers, oil circuit breakers, etc. It is very important to note that the asset classes used in this study do not represent a homogenous set of equipment. In addition to the variance in age there are variations in model, types, ratings, installations, environments, etc. All of these factors can potentially have impact on the condition of the individual assets, the ultimate Health Indices and the estimated replacement timing.

5. There is a need to further understand the particular failure mode of assets on the THESL system in order to assure that replacement programs are truly warranted and not a result of a repairable condition. Failure investigations are required to determine true mode of failure. This is necessary to determine if the failure could have been prevented by either maintenance or earlier replacement.

6. Further study is required to gain an improved understanding of the condition information of underground cables. For example, a cable database was constructed for this project. This data base should be completed to include age, length, cable type, and installation type.

7. Statistics should be gathered on the age at which assets were replaced in the past and why they were replaced at that age for the purpose of more comprehensively relating equipment condition to end of life.

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Toronto Hydro-Electric System Limited
Networks Asset Condition Assessment

Kinectrics Inc. Report No: K-418015-RA-0002-R03

July 16, 2010

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Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and Toronto Hydro-Electric System Limited

Toronto Hydro-Electric System Limited
Networks Asset Condition Assessment

Kinectrics Inc. Report No: K-418015-RA-0002-R03

July 16, 2010

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R00	December 24, 2009	First Draft	n/a
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R03	July 16, 2010	Final Draft	Shahrokh Zangeneh

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1 Executive Summary

1.1 Background and OEB Decision

The Ontario Energy Board (OEB) required Toronto Hydro-Electric System Limited (THESL) to provide a report reflecting its progress in its replacement and maintenance programs for its underground cable replacement and plant replacement program. Specifically, the requirement is that a *"Utility must be in a position to provide asset condition studies and other analyses that support its capital strategies and budgets."* The Board expects that the Applicant will undertake appropriate studies and analysis to address the questions concerning its asset management practices that have been raised during this proceeding, including options for *"increased diagnostic testing, rehabilitation versus replacement, and better identification of situations where replacement in its distribution network (both in the nature and location) of the assets is needed in whole or in part."*

1.2 Project Scope and Condition Assessment (ACA) Considerations

Asset Condition Assessment (ACA) utilizes a multi-criteria analysis to estimate the condition of assets. It is a challenging task that involves gathering and processing appropriate asset data to produce an indicator of asset condition or Health Index (HI). The HI is expressed in terms of a percentage (0% through 100%), where 100% represents "as new" condition. The lower the HI score, the worse the asset condition. Depending on the HI score, assets are typically grouped into five (5) condition categories:

- Very Poor
- Poor
- Fair
- Good
- Very Good

This categorization allows for a) the understanding of assets condition distribution for the asset population within each asset category, and b) a means to better predict how many assets will be expected to fail, and thus would have to be replaced, over the next several years.

It is worth noting that the objective of the ACA is to estimate condition of assets as it relates to their long-term degradation and remaining life, and not defect management that is dealt with as a part of regular maintenance practices. Furthermore, it is important to remember that factors other than asset condition also play a significant role in determining sustaining capital replacement needs and replace versus refurbish decisions. These factors include but are not limited to:

- Obsolescence
- Regulatory requirements

- Rating limitation due to system additions, such as new load customers and Distributed Generation
- Rating limitations due to the growth of the existing loads
- Operational considerations
- Integration with system expansion

THESL has enlisted the services of Kinectrics Inc. (Kinectrics) to perform an assessment of its network assets, namely:

- Network Vaults
- Network Protectors
- Network Transformers

The two main tasks are as follows:

1. Refinement of data collected
2. Derivation of Health Indices

The first task is described in Section 1.3. Details on the derivation of Health Indices for vaults, protectors, and transformers are found in Sections 2, 3, and 4 respectively. The results for all three assets are summarized in 1.4. Finally, conclusions and recommendations are found in Section 1.5.

1.3 Refinement of Data Collected and Health Index Formulation

In order to facilitate the asset condition assessment process, refinements were made to the type of data collected during regular inspections for each of the network assets. Previously, asset inspection resulted in the collection of *maintenance* information only. As per Kinectrics' recommendations, inspection forms were revised to include *life grade* information. Life grade gives information relating to an asset's remaining life. For parameters that can affect equipment replacement (i.e. parameters that are not refurbish-able), inspectors were required to make assessments with respect to remaining life. The life grade scoring system is as follows:

A = Brand New
B = Most of life remaining
C = Replace in next 10-20 years
D = Replace in 2 -10 years
E = Replace in 1-2 years

Maintenance scoring, in contrast, will grade a parameter from 1 through 5. A score of 1 represents excellent condition, whereas a score of 5 indicates that immediate maintenance is required. The following table gives examples of parameters where life grade assessments were required:

Table 1-1 Example of Parameters where Life Grade is Assessed

Asset	Parameter
Network Vault	Roof Slab
Network Vault	Walls
Network Transformer	Corrosion
Network Transformer	Transformer Lid
Network Transformer	Oil Leak – Switch
Network Protector	Overall Condition

The newly collected life grade information was then used to develop improved Health Index formulas for each of the network assets. These formulas are shown in detail in each asset's respective section.

1.4 Health Index Results Summary

Table 1-1 summarizes total number of units assessed in each asset category and the Health Index distribution for each asset.

Table 1-2: Health Index Distribution for Network Assets

Network Asset	Total Units with Data	Sample Size (Units with Sufficient Data for HI)	% Sample Size	Health Index Results				
				Very Poor (< 30%)	Poor (30 - 50%)	Fair (50 - 70%)	Good (70 - 85%)	Very Good (> 85%)
Vaults	881	861	97.7%	2.1%	7.1%	34.1%	41.1%	15.6%
Transformers	1567	1425	90.9%	0.0%	0.0%	0.7%	37.2%	62.1%
Protectors	2600	2322	89.3%	0.0%	0.0%	0.9%	27.2%	71.9%

A vast majority of the network assets are in good or very good condition. Less than 1% of transformers and protectors are in fair or poor condition, and less than 9% of vaults were found to be in poor or very poor condition.

1.5 Conclusions and Recommendations

1. The Health Index results show that about 9% of the vaults are in poor or very poor condition, while the transformers and protectors are, in general, in good shape. It is

recommended that more maintenance work be done on vaults, especially on structure part.

2. In 2006, Kinectrics issued an Asset Condition Assessment report that made the following recommendation: *Asset Condition data used in this study was collected by THESL primarily to guide maintenance decisions rather than to provide the input for Health Index calculations. Health Indices have now been formulated for all major asset classes and in the future data can be collected specifically designed to provide a more comprehensive indication of condition. Further data required for formulation of the Health Indices should be collected and recorded in a single, easily accessible data base.*

   Modification of network assets inspection forms to include life grade assessments was a significant step in gathering the appropriate data for Health Indexing. Re-formulating network health indices to include this information is a further improvement to the asset condition assessment processes.

3. Gathering additional information that will improve the Health Index formulation results is recommended for all network assets. These include:

   a. Vaults
      - Age: This is a useful parameter in assessing the overall condition of a vault.

      - Friability of Asbestos: The extent of the friability of asbestos gives a better indication of vault environment than only knowing whether asbestos is present or not.

   b. Protectors
      - Age: The age of a Network Protector is useful indicator of the overall reliability of the protector.

   c. Transformers
      - Insulation Information: These include oil quality, oil DGA, and winding Doble results. Transformer degradation is closely linked to insulation condition so obtaining and incorporating data related to insulation will increase the degree of confidence in the Health Index results.

      - Loading: The life of the transformer's internal insulation is related to temperature-rise and duration. Overloading of Network Transformers can cause temperature rise that deteriorates the internal insulation, thus shortening life. The loading information used in this assessment was in terms of percent yearly loading. While valuable in determining which transformers were lightly loaded and therefore more subject to moisture, it is recommended that overloading information (e.g. contingency loading events) be obtained to facilitate assessments on insulation aging.

4. Sufficient condition data were available for a very high percentage of assets. The percentage of units with sufficient data for Health Indexing was 97.6%, 90.9%, and 89.3%, and for vaults, protectors, and transformers respectively. It is recommended

that THESL continue to gather condition data for each asset through periodic inspections. The records should then be consolidated into a single, easily accessible database to facilitate future assessments.

5. For the remaining Asset Categories at THESL, a similar process in gathering condition data that are related to long term degradation (as was done for Network assets) should be implemented. Health Indices based on revised formulations should then be determined for these remaining asset groups. It is then recommended that risk assessments be conducted so as to provide a basis for capital replacement plans for these assets. To generate an overall picture of the total life cycle costs of assets, risk assessments should consider not only the Health Index results obtained; other factors such as capital costs, probability of failure, and costs of maintenance failure, must be considered.

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2 Network Vaults

2.1 Network Vaults

Network Vaults permit installation of transformers and protectors. They are typically constructed out of reinforced concrete in combination with structural steel. Vaults used for transformer installation are often equipped with ventilation grates to provide natural or forced cooling.

2.2 Degradation Mechanism

Vaults should be capable of bearing the loads that are applied on them. As such, mechanical strength is a basic end of life parameter for a vault. Although age is loosely related to the condition of underground civil structures, it is not a linear relationship. Other factors such as mechanical loading, exposure to corrosive salts, etc. have a stronger effect.

Degradation commonly includes corrosion of rebars, structural steel (I beams, channels, etc.), spalling of concrete, and rusting of covers or rings. Acidic salts (i.e. sulfates or chlorides) affect corrosion rates. In roadways, defects exist when covers are not level with street surfaces. Conditions that lead to flooding, clogged sumps, and non-functioning sump-pumps also represent major deficiencies. Similarly, units with lights that do not function properly constitute defective systems.

2.3 Health Index Methodology

The Health Index quantifies asset condition and is based on numerous parameters that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. Theses parameters, referred to as *Condition Parameters,* are the characteristics that are used to derive the Health Index. In formulating a Health Index, Condition Parameters are ranked in terms of their contribution to equipment degradation through the assignment of weights (*Weight of Condition Parameter WCP*). The *Condition Parameter Score (CPS)* is a numerical evaluation of an asset with respect to a Condition Parameter. Note that a Condition Parameter may be a composite of multiple Sub-Condition Parameters (*Sub-Condition Parameter Factor CPF*). For example, the Condition Parameter "Insulation Condition" may be a composite of Sub-Condition Parameters "Oil Quality/Condition", "DGA results", or "Winding Doble results". Each of the Sub-Condition Parameters is assigned a weight (*Weight of Sub-Condition Parameter Factor WCPF*) and a resultant, weighted average CPS is calculated.

While weights are assigned based on the priority level of Condition Parameters, scores represent the evaluation of an asset against Condition Parameters. Scores for Condition Parameters are determined based on *Condition Criteria*, which is the scale that is used to determine an asset's score for a particular parameter.

The Health Index formulation used for Network Vaults is shown below:

$$HI = \frac{\sum_{m=1}^{4} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

Equation 2-1

where

$$\mathrm{CPS} = \frac{\sum_{\mathrm{n}=1} \beta_{\mathrm{n}} (\mathrm{CPF}_{\mathrm{n}} \times \mathrm{WCPF}_{\mathrm{n}})}{\sum_{\mathrm{n}=1} \beta_{\mathrm{n}} (\mathrm{CPF}_{\mathrm{n.max}} \times \mathrm{WCPF}_{\mathrm{n}})} \times 4$$

Equation 2-2

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
$CPS_{.max}$ = Maximum Condition Parameter Score
WCP = Weight of Condition Parameter
SDF = Structure De-rating Factor
CPF = Sub-condition Parameter Factor
$CPF_{.max}$ = Maximum Sub-condition Parameter Factor Score
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
($\alpha_m = 1$ when data available, $\alpha_m = 0$ when data unavailable)
β_n = Data availability coefficient for sub-condition parameter n
($\beta_n = 1$ when data available, $\beta_n = 0$ when data unavailable)

2.3.1 Condition and Sub-Condition Parameters

Tables depicting condition parameter scores and weights are shown below.

Table 2-1 Condition Weights and Maximum CPS

m	Network Vaults Condition Parameter	Weight of Condition Parameter (WCP_m)	Reference Table for Condition Parameter Score (CPS)	Health Index (HI)	
				HI Calculated per HI Formula	Maximum HI Score
1	Ventilation & Drainage	2	Table 2-2	Equation 2-1	100%
2	Supporting Plant	1	Table 2-3		
3	Access & Work Environment	1	Table 2-4		
4	Overall	2	Table 2-5		
	Structure de-rating multiplying factor (DRF)		Table 2-9	Multiply DRF to Calculated HI **Effective HI = HI x DRF**	

Sub-Condition parameters are as follows. The “Reference Table for Condition Parameter (CPF)” indicates the table where the Condition Criteria Scale is presented.

Table 2-2 Ventilation & Drainage (m=1) Weights, CPF, and CPS Calculation

n	Ventilation & Drainage	Weight of Sub-Condition Parameter Factor ($WCPF_n$)	Reference Table for Condition Parameter Factor (CPF_n)	Condition Parameter Score (CPS_1)	
				CPS_1 Calculated per CPS Formula	Maximum Score ($CPS_{1.max}$)
1	Vents/ Grills/ Ventilation	3	Table 2-7	Equation 2-2	4
2	Drain	2	Table 2-7		
3	Sump Pump	2	Table 2-7		
4	Flooding	2	Table 2-7		
5	Dirt/Debris/Contamination	1	Table 2-7		

Table 2-3 Supporting Plant (m=2) Weights, CPF, and CPS Calculation

n	Supporting Plant	Weight of Sub-Condition Parameter Factor ($WCPF_n$)	Reference Table for Condition Parameter Factor (CPF_n)	Condition Parameter Score (CPS_2)	
				CPS_2 Calculated per CPS Formula	Maximum Score ($CPS_{2.max}$)
1	Grounding	2	Table 2-7	Equation 2-2	4
2	Ducts	1	Table 2-7		

Table 2-4 Access & Work Environment (m=3) Weights, CPF, and CPS Calculation

n	Access & Work Environment	Weight of Sub-Condition Parameter Factor ($WCPF_n$)	Reference Table for Condition Parameter Factor (CPF_n)	Condition Parameter Score (CPS_3)	
				CPS_3 Calculated per CPS Formula	Maximum Score ($CPS_{3.max}$)
1	Entry	1	Table 2-7	Equation 2-2	4
2	Ladder	1	Table 2-7		
3	Door	1	Table 2-7		
4	Locks	1	Table 2-7		
5	Hinges	1	Table 2-7		
6	Clearance to Operate	2	Table 2-7		
7	Asbestos Present?	2	Table 2-6		

Table 2-5 Overall (m=4) Weights, CPF, and CPS Calculation

n	Supporting Plant	Weight of Sub-Condition Parameter Factor ($WCPF_n$)	Reference Table for Condition Parameter Factor (CPF_n)	Condition Parameter Score (CPS_4)	
				CPS_4 Calculated per CPS Formula	Maximum Score ($CPS_{4.max}$)
1	Overall Condition	1	Table 2-7	Equation 2-2	4

2.3.2 Condition Criteria

Three types of Condition Criteria score systems are adopted in determining the rating of a condition parameter:

- Y/N score system
  The score in this system tells whether there exists an unwanted defect on an asset unit, or part of the unit. It is an objective inspection on specific check items.

- Maintenance Inspection Score System
  The score in this system reflects the working condition an asset component or the entire unit. It rates whether the equipment is, at best, in excellent working condition or, at worst, in need of emergency repair. It is a subjective evaluation based on practical engineering operation and maintenance experience.

- Life Grade Score System
  The score in this system reflects the extent of physical degradation of an asset component or the entire unit. It indicates whether the equipment is, at best, new and has all its remaining life, or at worst, requires replacement or major refurbishment in the next year. It is a subjective evaluation based on practical engineering operation and maintenance experience.

Details for the score systems described above are shown on the following tables:

Table 2-6 Yes/No Condition Scores and Interpretations

Y/N Score System			
THESL Inspection Results		Health Index Formulation Translation of THESL Inspection Results	
THESL Inspection Rating	Interpretation	Sub-Condition Parameter Score (CPF)	Maximum Score CPF_{max}
1	No	4	4
2	Yes	0	

Table 2-7 Maintenance Scores and Interpretations

Maintenance Inspection Score System			
THESL Inspection Results		Health Index Formulation Translation of THESL Inspection Results	
THESL Inspection Rating	Interpretation	Sub-Condition Parameter Score (CPF)	Maximum Score CPF_{max}
1	Excellent Working condition	4	4
2	Minor Wear - Working as Required	3	
3	Major Wear/Failed - Repaired During Inspection	2	
4	Major Wear/Failed - Scheduled Corrective Repair Required	1	
5	Failed - Emergency Repair Required	0	

Table 2-8 Life Grade Scores and Interpretations

Life Grade Score System			
THESL Inspection Results		Health Index Formulation Translation of THESL Inspection Results	
THESL Inspection Rating	Interpretation	Sub-Condition Parameter Score (CPF)	Maximum Score CPF_{max}
A	Brand New	4	4
B	Most of life remaining	3	
C	Replace in next 10-20 years	2	
D	Replace in 2 -10 years	1	
E	Replace in 1-2 years	0	

The following pictures show examples of the maintenance and life grade scores of utility structures. The scores are in terms of the THESL Inspection Ratings (i.e. scores as per inspection forms)

Figure 2-1 A Wall with Life Grade Score "A"

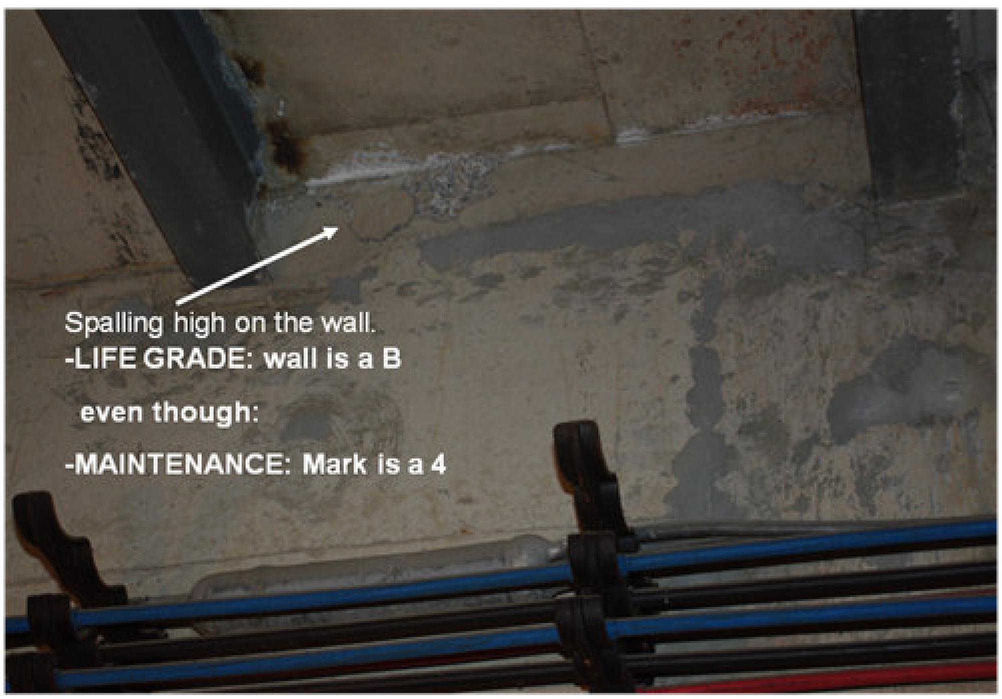

Figure 2-2 A Wall with Life Grade Score "B" and Maintenance Score "4"

Figure 2-3 A Wall with Life Grade Score “C”

Figure 2-4 A Wall with Life Grade Score “D”

Figure 2-5 A Wall with Life Grade Score "E"

Figure 2-6 A Beam (Roof) with Life Grade Score "B"

Figure 2-7 A Beam (Roof) with Life Grade Score "C"

Figure 2-8 A Bottom Slab (Floor) with Life Grade Score "D"

2.3.3 Structure De-Rating Factor

It is THESL's practice that Network Vaults be considered for replacement or major refurbishment should any one of its structural elements (roof, walls, or floor) be found in poor or very poor condition. As such, a de-rating system for Structural elements is applied to the Health Index calculation. In this system, a de-rating factor (DRF) is multiplied with the calculated Health Index to obtain an Effective Health Index Score.

$$\text{Effective HI} = HI\ x\ DRF$$

Equation 2-3

The score system for the Structure De-Rating Factor is given by the following tables:

Table 2-9 Structure De-Rating Factor

Condition Parameter Factors of De-Rating Elements CPF_{DRF}	CPF_{DRF} Lookup Table	Structure De-Rating Factor (DRF)	Highest Possible Effective Health Index Category
4	Table 2-10	1	Very Good
3		0.85	Good
2		0.7	Fair
1		0.5	Poor
0		0.3	Very Poor

Table 2-10 Structure Elements

De-Rating Element Number	Structure	Condition Parameter Factors of De-Rating Elements CPF_{DRF}	Reference Table for Condition Parameter Factor $CPF_{De\text{-}RatingElementNumber}$
1	Roof / Slabs (Life Grade)	$CPF_{DRF} = \min(CPF_1, CPF_2, CPF_3)$	Table 2-8
2	Walls (Life Grade)		Table 2-8
3	Floor		Table 2-7

In general, de-rating works such that:

- The de-rating Condition Parameter Factor (CPF_{DRF}) is the *minimum* CPF for any of the 3 structure elements (i.e. roof, walls, or floor).
- The Effective Health Index is limited by lowest (worst) structural element rating. For example, consider a vault that is found to have good floors and walls, but poor roof. The de-rating system will limit the Effective Health Index to the "poor" category.

2.4 Health Index Results

The Health Indices a total of 861 Network Vaults were calculated. The Health Index distribution is shown following figures. Over 9% of the vaults were found to be in poor or very poor condition.

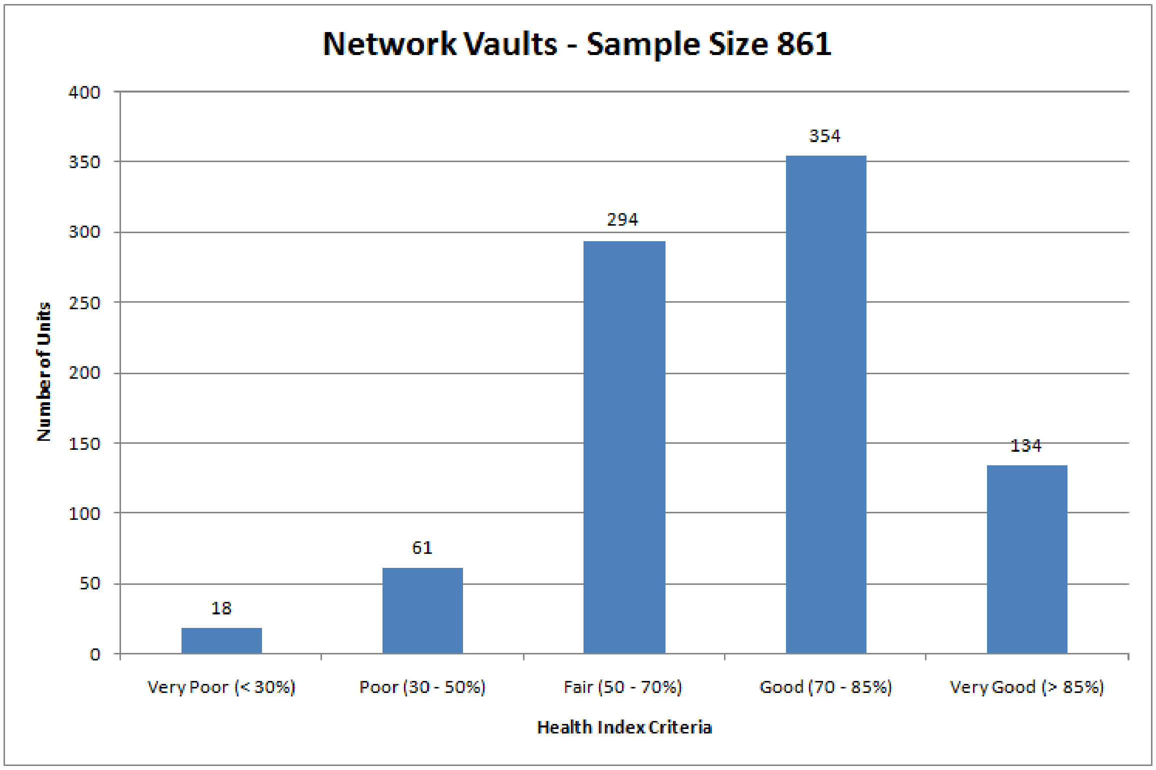

Figure 2-9 Network Vaults Health Index Distribution by Units

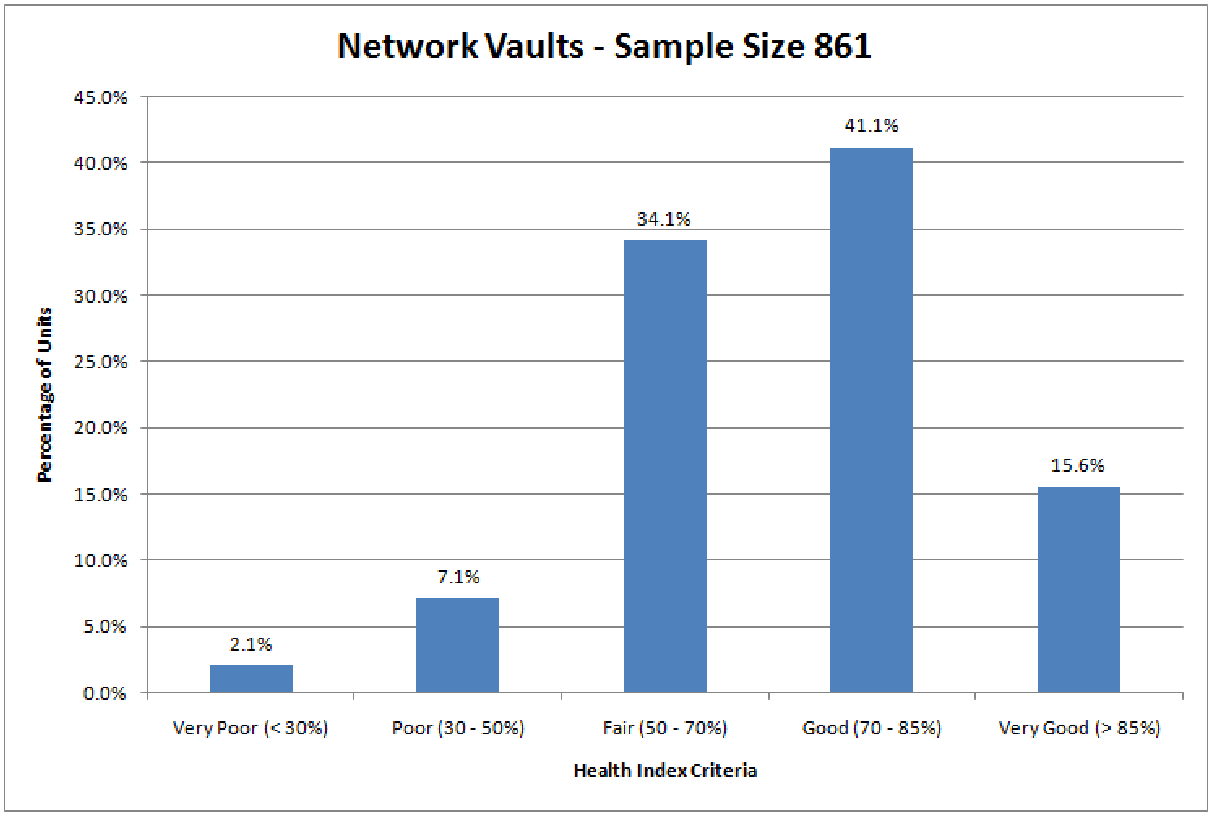

Figure 2-10 Network Vaults Health Index Distribution by Percentage

2.5 Data Availability

Network Vault information was provided in the "NetworkTransformer_Inspected 2009.xls" spreadsheet. There were 881 unique vault Equipment IDs in the data set. Where there were multiple assessments (i.e. assessments performed on different dates) for an asset, the data from the most recent assessments was used. Of the 881 vaults, 861, or 97.7% of the vaults had sufficient data for a Health Index assessment. Assets for which less than 60% of condition data were available were excluded from the calculation.

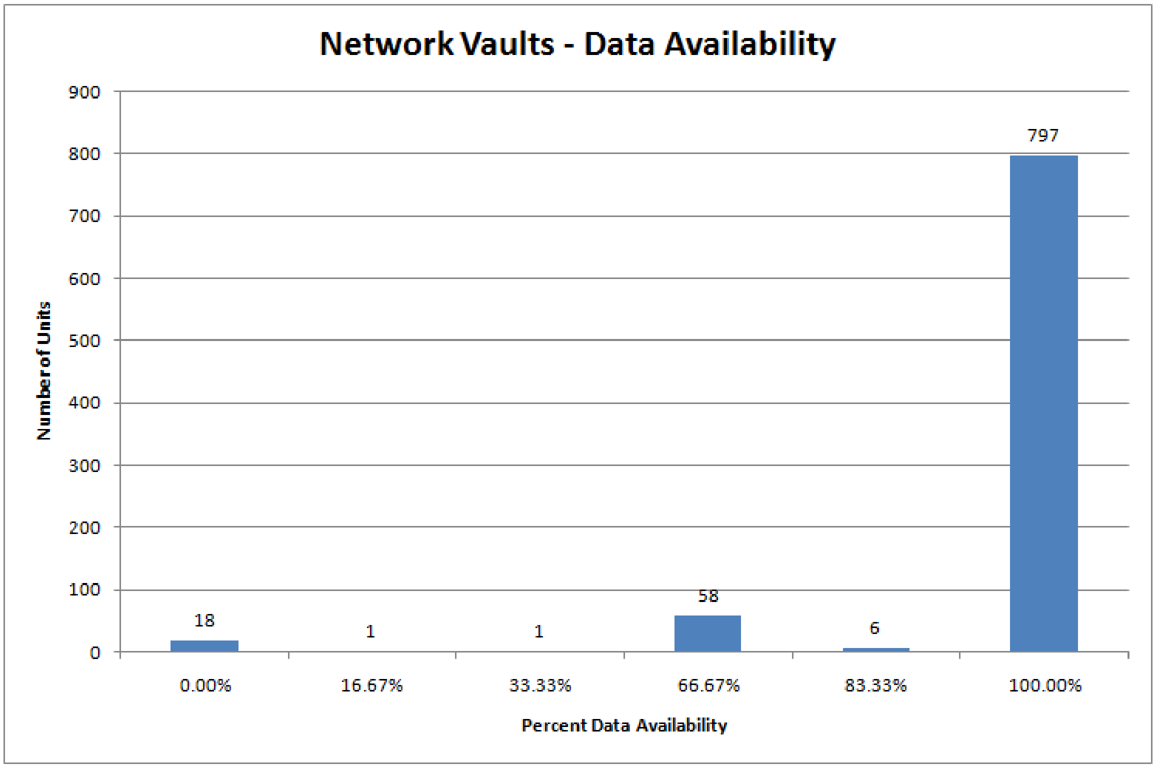

Figure 2-11 Network Vaults Data Availability Distribution

3 Network Transformers

3.1 Network Transformers

Network Transformers are special purpose distribution transformers, designed and constructed for successful operation in a parallel mode with a large number of transformers with similar characteristic. The primary winding of the transformers is connected in Delta configuration while the secondary is in grounded star configuration. The Network Transformers are provided with a primary disconnect, which has no current interrupting rating and is used merely as in isolating device after the transformer has been de-energized both from primary and secondary source. The secondary bushings are mounted on the side wall of the transformer in a throat, suitable for mounting of the Network Protector.

3.2 Degradation Mechanism

Since in a majority of the applications transformers are installed in below grade vaults, the transformer is designed for partially submersible operation with additional protection against corrosion. While Network Transformers are available in dry-type (cast coil and epoxy impregnation) designs, a vast majority of the Network Transformers employ mineral oil for insulation and cooling. The Network Transformer has a similar degradation mechanism to other distribution transformers.

For a majority of transformers, end of life is expected to be spelled by the failure of insulation system and more specifically the failure of pressboard and paper insulation. However, when employed in location with frequent flooding, transformer tank corrosion also leads to end of life for a significant number of Network Transformers.

3.3 Health Index Methodology

The Health Index formulation used for Network Transformers is shown below:

$$HI = \frac{\sum_{m=1}^{5} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{5} \alpha_m (CPS_{m.max} \times WCP_m)}$$

Equation 3-1

where

$$CPS = \frac{\sum_{n=1} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1} \beta_n (CPF_{n.max} \times WCPF_n)} \times 4$$

Equation 3-2

m = Condition parameter m
n = Sub-condition Parameter n

CPS	= Condition Parameter Score
$CPS_{.max}$	= Maximum Condition Parameter Score
WCP	= Weight of Condition Parameter
CPF	= Sub-condition Parameter Factor
$CPF_{.max}$	= Maximum Sub-condition Parameter Factor Score
WCPF	= Weight of Sub-condition Parameter Factor
α_m	= Data availability coefficient for condition parameter m (α_m = 1 when data available, α_m = 0 when data unavailable)
β_n	= Data availability coefficient for sub-condition parameter n (β_n = 1 when data available, β_n = 0 when data unavailable)

Tables depicting condition parameter scores and weights are shown below.

Table 3-1 Condition Weights and Maximum CPS

m	Network Transformer Condition Parameter	Weight of Condition Parameter (WCP_m)	Reference Table for Condition Parameter Score (CPS)	Health Index (HI)	
				HI Calculated per HI Formula	Maximum HI Score
1	Insulation	1	Table 3-2	Equation 3-1	100%
2	Cooling	2	Table 3-3		
3	Sealing & Connection	3	Table 3-4		
4	Reliability	3	Table 3-5		
5	Other Condition	1	Table 3-6		

Sub-Condition parameters are as follows. The "Reference Table for Condition Parameter (CPF)" indicates the table where the Condition Criteria Scale is presented.

Table 3-2 Insulation (m=1) Weights and Maximum CPF

n	Insulation	Weight of Sub-Condition Parameter Factor ($WCPF_n$)	Reference Table for Condition Parameter Factor (CPF_n)	Condition Parameter Score (CPS_1)	
				CPS Calculated per CPS Formula	Maximum Score ($CPS_{1.max}$)
1	Bushings	1	Table 3-7	Equation 3-2	4

Table 3-3 Cooling (m=2) Weights and Maximum CPF

n	Cooling	Weight of Sub-Condition Parameter Factor ($WCPF_n$)	Reference Table for Condition Parameter Factor (CPF_n)	Condition Parameter Score (CPS_2)	
				CPS Calculated per CPS Formula	Maximum Score ($CPS_{2.max}$)
1	Transformer Oil Temp (degree C)*	1	Table 3-9	Equation 3-2	4

Table 3-4 Sealing & Connection (m=3) Weights and Maximum CPF

n	Sealing & Connection	Weight of Sub-Condition Parameter Factor ($WCPF_n$)	Reference Table for Condition Parameter Factor (CPF_n)	Condition Parameter Score (CPS_3)	
				CPS Calculated per CPS Formula	Maximum Score ($CPS_{3.max}$)
1	Oil Leak (Life Grade)	2	Table 3-8	Equation 3-2	4
2	Oil Level - Transformer	1	Table 3-7		
3	Oil Level - Switch	1	Table 3-7		
4	Grounding	1	Table 3-7		
5	Pothead/Termination	1	Table 3-7		
6	Transformer Lid/Gasket Fit (Life Grade)	2	Table 3-8		
7	Corrosion/Paint (Life Grade)*	1	Table 3-8		
8	Oil Leak - Switch (Life Grade)	2	Table 3-7		
	* Corrosion Condition Parameter Factor (CPF_7) needs to be De-Rated as per Corrosion De-Rating Factor (DFR) to obtain an Effective CPF_7		DFR Reference: Table 3-12	Multiply Corrosion Condition Parameter Factor (CPF_7) wit DFR **Effective $CPF_7 = CPF_7 x DFR$**	

Table 3-5 Reliability (m=4) Weights and Maximum CPF

n	Reliability	Weight of Sub-Condition Parameter Factor ($WCPF_n$)	Reference Table for Condition Parameter Factor (CPF_n)	Condition Parameter Score (CPS_4)	
				CPS Calculated per CPS Formula	Maximum Score ($CPS_{4.max}$)
1	Loading	4	Table 3-10	Equation 3-2	4
2	AGE	3	Table 3-11		

Table 3-6 Other Condition (m=5) Weights and Maximum CPF

n	Other Condition	Weight of Sub-Condition Parameter Factor ($WCPF_n$)	Reference Table for Condition Parameter Factor (CPF_n)	Condition Parameter Score (CPS_5)	
				CPS Calculated per CPS Formula	Maximum Score ($CPS_{5.max}$)
1	Dirt/Debris/Contamination	1	Table 3-7	Equation 3-2	4
2	Switch Unit	3	Table 3-7		

3.3.1 Condition Criteria

The types of Condition Criteria score systems adopted in determining the rating of a condition parameter for this asset is as follows:

- Maintenance Inspection Score System
  The score in this system reflects the working condition an asset component or the entire unit. It rates whether the equipment is, at best, in excellent working condition or, at worst, in need of emergency repair. It is a subjective evaluation based on practical engineering operation and maintenance experience.

- Life Grade Score System
  The score in this system reflects the extent of physical degradation of an asset component or the entire unit. It indicates whether the equipment is, at best, new and has all its remaining life, or at worst, requires replacement or major refurbishment in the next year. It is a subjective evaluation based on practical engineering operation and maintenance experience.

- Oil Temperature Score System
  The score in this system reflects the performance of cooling system. It is based on practical measurement.

- Loading Score System
  The score in this system reflects the impact of loading on transformer life. It is based on practical measurement.

- Age Score System
  Age refers to the number of years that the transformer has been in service.

Details for the score systems described above are shown on the following tables:

Table 3-7 Maintenance Scores and Interpretations

Maintenance Inspection Score System			
THESL Inspection Results		Health Index Formulation Translation of THESL Inspection Results	
THESL Inspection Rating	Interpretation	Sub-Condition Parameter Score (CPF)	Maximum Score CPF_{max}
1	Excellent Working condition	4	4
2	Minor Wear - Working as Required	3	
3	Major Wear/Failed - Repaired During Inspection	2	
4	Major Wear/Failed - Scheduled Corrective Repair Required	1	
5	Failed - Emergency Repair Required	0	

Table 3-8 Life Grade Scores and Interpretations

Life Grade Score System			
THESL Inspection Results		Health Index Formulation Translation of THESL Inspection Results	
THESL Inspection Rating	Interpretation	Sub-Condition Parameter Score (CPF)	Maximum Score CPF_{max}
A	Brand New	4	4
B	Most of life remaining	3	
C	Replace in next 10-20 years	2	
D	Replace in 2 -10 years	1	
E	Replace in 1-2 years	0	

Table 3-9 Oil Temperature Scores and Interpretation

Oil Temperature Score System		
Transformer Top Oil Temperature (max)	Sub-Condition Parameter Score (CPF)	Maximum Score CPF_{max}
0-55	4	4
55-80	3	
80-95	2	
95-105	1	
>105	0	

Table 3-10 Loading Scores and Interpretation

Loading Score System		
Average Percent Loading (%)*	**Sub-Condition Parameter Score (CPF)**	**Maximum Score CPF_{max}**
0-60	4	4
60-80	3	
80-100	2	
100-120	1	
>120	0	

*Loading Data available from 2003 - 2007

Table 3-11 Age Scores and Interpretation

Age Score System		
Age	**Sub-Condition Parameter Score (CPF)**	**Maximum Score CPF_{max}**
0	4	4
20	3	
40	2	
60	1	
70	0	

The following pictures show examples of the life grade scores of utility structures. The scores are in terms of the THESL Inspection Ratings (i.e. scores as per inspection forms)

Figure 3-1 A Transformer with Life Grade Score “A”

Figure 3-2 A Transformer with Life Grade Score “B”

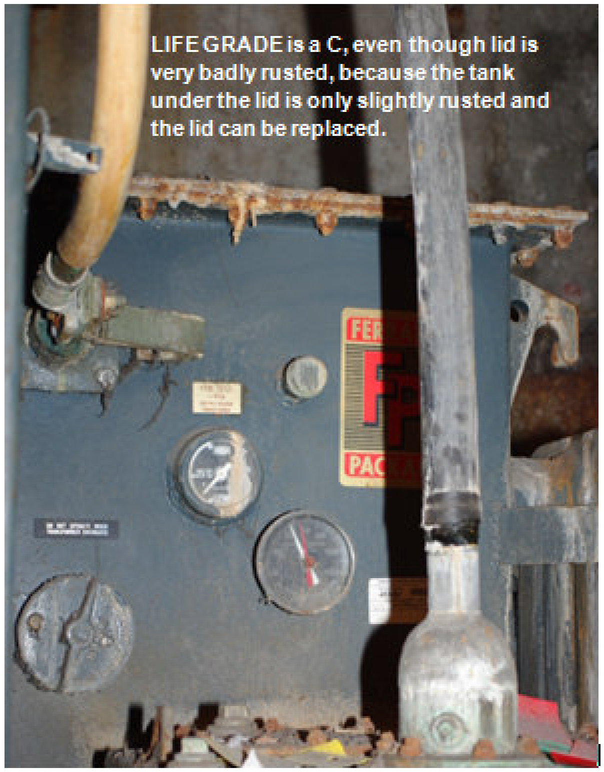

Figure 3-3 A Transformer with Life Grade Score "C"

Figure 3-4 A Transformer with Life Grade Score "D"

Figure 3-5 A Transformer with Life Grade Score "E"

3.3.2 Corrosion De-Rating Factor

A Corrosion De-Rating Factor based on Loading is used to adjust the Condition Parameter Factor for Corrosion. This de-rating factor is based on THESL's expert opinion that lightly loaded transformers do not dry out their vaults and are thus subject to moisture and increased corrosion. The de-rating factor is multiplied with the Corrosion Condition Factor (CPF). The score system is given on the following table:

Table 3-12 Corrosion De-Rating Factor

Corrosion - De-Rating	
Average Percent Loading (%)*	**Corrosion De-Rating Factor (DRF)**
0-25	0.2
25-30	0.4
30-40	0.6
40-50	0.8
>50	1

*Loading Data available from 2003 - 2007

3.4 Health Index Results

The Health Index distribution for Network Transformers is shown in the following figures. No the assets were found to be in poor or very poor condition.

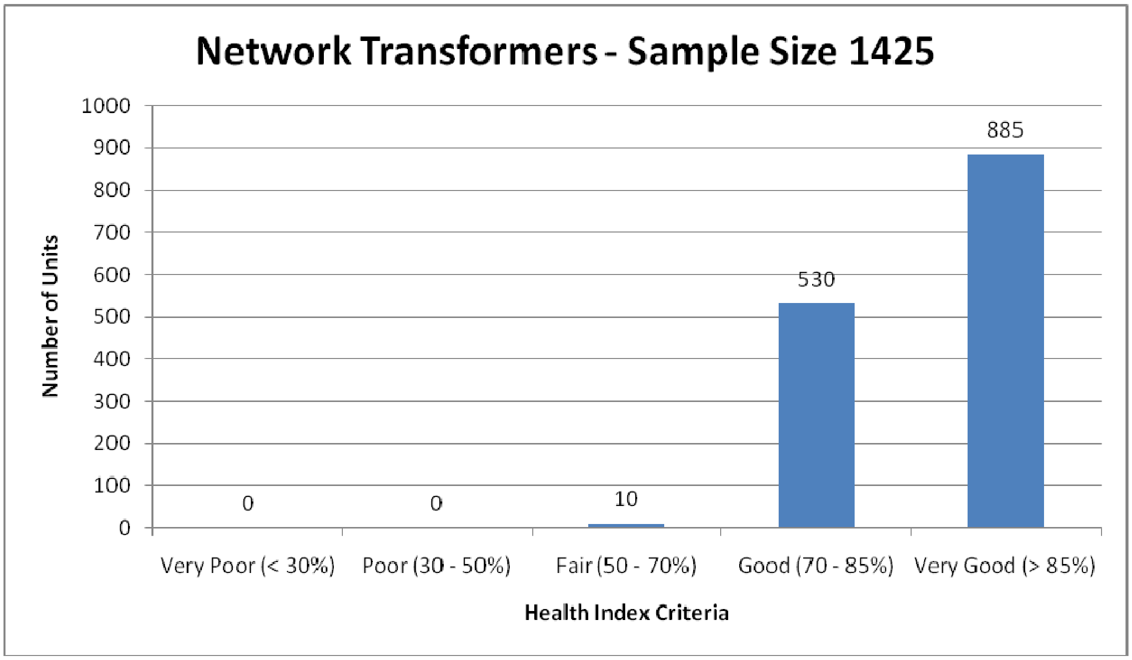

Figure 3-6 Network Transformers Health Index Distribution by Units

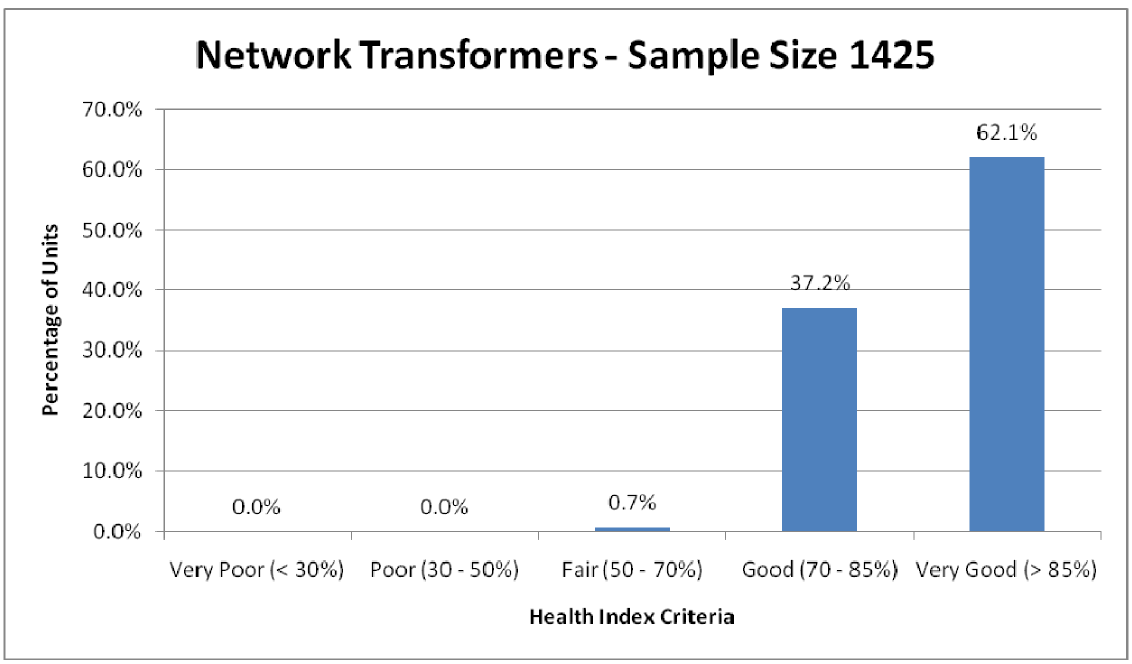

Figure 3-7 Network Transformers Health Index Distribution by Percentage

3.5 Data Availability

Network Transformer information was provided in the "NetworkTransformer_Inspected 2009.xls" spreadsheet. There were 1567 unique transformer Equipment IDs in the data set. Where there were multiple assessments (i.e. assessments performed on different dates) for an asset, the data from the most recent assessments was used. Of the 1567 transformers, 1425, or 90.9% of the transformers had sufficient data for a Health Index assessment. Assets for which less than 60% of condition data were available were excluded from the calculation.

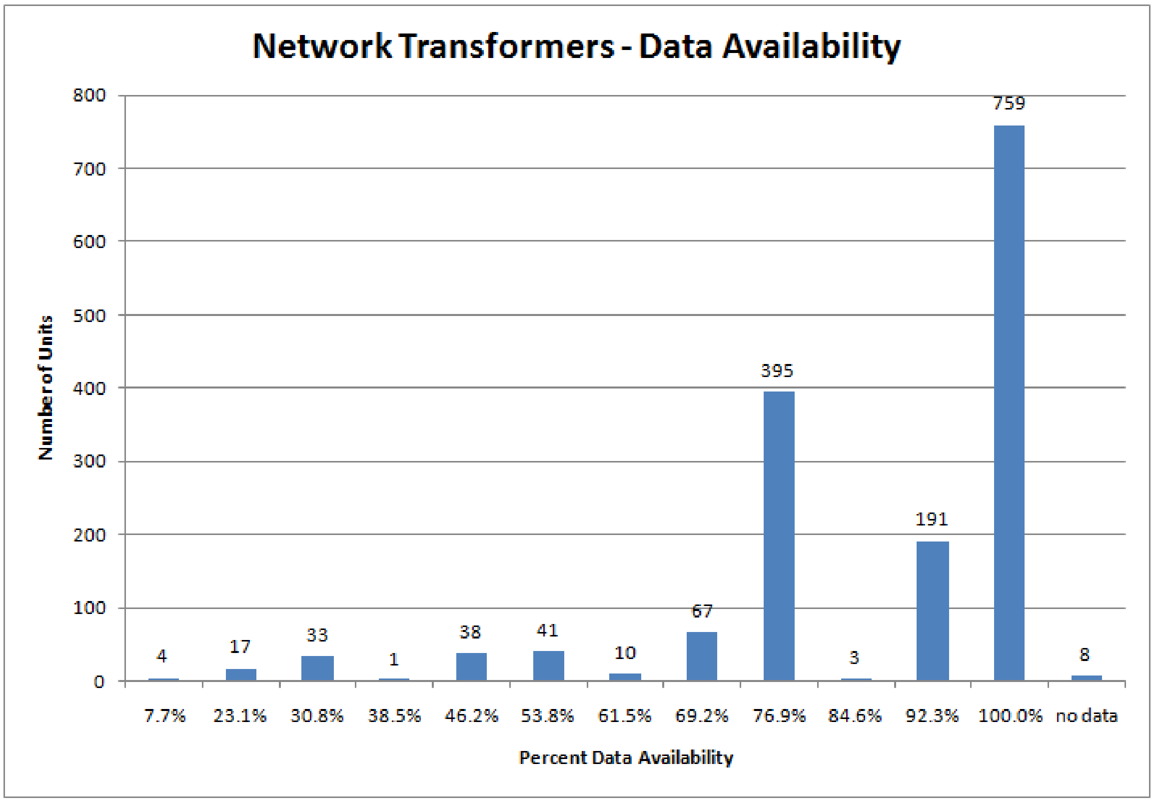

Figure 3-8 Network Transformers Data Availability Distribuiton

4 Network Protectors

4.1 Network Protectors

Network Protectors are special purpose low voltage air circuit breakers, designed for successful parallel operation of Network Transformers. Network protectors are fully self contained units, equipped with protective relays and instrument transformers to allow automatic closing and opening of the protector. The relays conduct a line test before initiating close command and allow closing of the breaker only if the associated transformer has the correct voltage condition in relation to the grid to permit flow of power from the transformer to the grid. If the conditions are not right, protector closing is blocked. The protector is also equipped with a reverse current relay that trips if the power flow reverses from its normal direction, i.e. if the power flows from grid into the transformer.

4.2 Degradation Mechanism

The breaker design in Network Protectors employs mechanical linkages, rollers, springs and cams for operation which require periodic maintenance. All Network Protectors are equipped with special load-side fuses, mounted either internally or external to the Network Protector housing. The fuses are intended to allow normal load current and overloads while providing backup protection in the event that the protector fails to open on reverse fault current (due to faults internal to the protector or near transformer low voltage terminals). Every time arcing occurs in open air within the Network Protector housing, whether due to operation of the air breaker or because of fuse blowing (except silver sand), a certain amount of metal vapour is liberated and dispersed over insulating parts. Fuses evidently liberate more vapour than breaker operation. Over time, this buildup reduces the dielectric strength of insulating barriers. Eventually this may result in a breakdown, unless care is taken to clean the Network Protector internally, particularly after fuse operations.

4.3 Health Index Methodology

The Health Index formulation used for Network Protectors is shown below:

$$HI = \frac{\sum_{m=1}^{2} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{5} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

Equation 4-1

where

$$\mathrm{CPS} = \frac{\sum_{n=1} \beta_n (\mathrm{CPF}_n \times \mathrm{WCPF}_n)}{\sum_{n=1} \beta_n (\mathrm{CPF}_{n.\max} \times \mathrm{WCPF}_n)} \times 4$$

Equation 4-2

m = Condition parameter m
n = Sub-condition Parameter n

CPS = Condition Parameter Score
$CPS_{.max}$ = Maximum Condition Parameter Score
WCP = Weight of Condition Parameter
CPF = Sub-condition Parameter Factor
$CPF_{.max}$ = Maximum Sub-condition Parameter Factor Score
WCPF = Weight of Sub-condition Parameter Factor

α_m = Data availability coefficient for condition parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)
β_n = Data availability coefficient for sub-condition parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

Tables depicting condition parameter scores and weights are shown below.

Table 4-1 Condition Weights and Maximum CPS

m	Network Protectors Condition Parameter	Weight of Condition Parameter (WCP_m)	Reference Table for Condition Parameter Score (CPS)	Health Index (HI)	
				HI Calculated per HI Formula	Maximum HI Score
1	Device & Connection	3	Table 4-2	Equation 4-1	100%
2	Reliability	2	Table 4-3		

Sub-Condition parameters are as follows:

Table 4-2 Device & Connection (m=1) Weights and Maximum CPF

n	Device & Connection	Weight of Sub-Condition Parameter Factor ($WCPF_n$)	Reference Table for Condition Parameter Factor (CPF_n)	Condition Parameter Score (CPS_1)	
				CPS Calculated per CPS Formula	Maximum Score ($CPS_{1.max}$)
1	Fuses	3	Table 4-5	Equation 4-2	4
2	Phase Barriers	1	Table 4-5		
3	Gasket, Seals, Surface Condition, etc.	1	Table 4-5		
4	Links	1	Table 4-5		
5	Dirt/Debris/Contamination	2	Table 4-5		

Table 4-3 Reliability (m=2) Weights and Maximum CPF

n	Reliability	Weight of Sub-Condition Parameter Factor ($WCPF_n$)	Reference Table for Condition Parameter Factor (CPF_n)	Condition Parameter Score (CPS_2)	
				CPS Calculated per CPS Formula	Maximum Score ($CPS_{2.max}$)
1	Counter Reading*	1	Table 4-4	Equation 4-2	4
2	Overall Condition (Life Grade)	2	Table 4-6		

4.3.1 Condition Criteria

Three types of Condition Criteria score systems are adopted in determining the rating of a condition parameter:

- Operating frequency score system
  The score in this system reflects the aging of the asset due to its operation. It is based on protector counter data.

- Maintenance Inspection Score System
  The score in this system reflects the working condition an asset component or the entire unit. It rates whether the equipment is, at best, in excellent working condition or, at worst, in need of emergency repair. It is a subjective evaluation based on practical engineering operation and maintenance experience.

- Life Grade Score System
  The score in this system reflects the extent of physical degradation of an asset component or the entire unit. It indicates whether the equipment is, at best, new and has all its remaining life, or at worst, requires replacement or major refurbishment in the next year. It is a subjective evaluation based on practical engineering operation and maintenance experience.

Details for the score systems described above are shown on the following tables:

Table 4-4 Operation Frequency Scores and Interpretations

Operation Frequency		
Operation	Sub-Condition Parameter Score (CPF)	Maximum Score CPF_{max}
0-1000	4	4
1000-2000	3	
2000-3000	2	
3000-4000	1	
>5000	0	

Table 4-5 Maintenance Scores and Interpretations

Maintenance Inspection Score System			
THESL Inspection Results		Health Index Formulation Translation of THESL Inspection Results	
THESL Inspection Rating	Interpretation	Sub-Condition Parameter Score (CPF)	Maximum Score CPF_{max}
1	Excellent Working condition	4	4
2	Minor Wear - Working as Required	3	
3	Major Wear/Failed - Repaired During Inspection	2	
4	Major Wear/Failed - Scheduled Corrective Repair Required	1	
5	Failed - Emergency Repair Required	0	

Table 4-6 Life Grade Scores and Interpretations

Life Grade Score System			
THESL Inspection Results		Health Index Formulation Translation of THESL Inspection Results	
THESL Inspection Rating	Interpretation	Sub-Condition Parameter Score (CPF)	Maximum Score CPF_{max}
A	Brand New	4	4
B	Most of life remaining	3	
C	Replace in next 10-20 years	2	
D	Replace in 2 -10 years	1	
E	Replace in 1-2 years	0	

The following pictures show examples of the life grade scores of utility structures. The scores are in terms of the THESL Inspection Ratings (i.e. scores as per inspection forms)

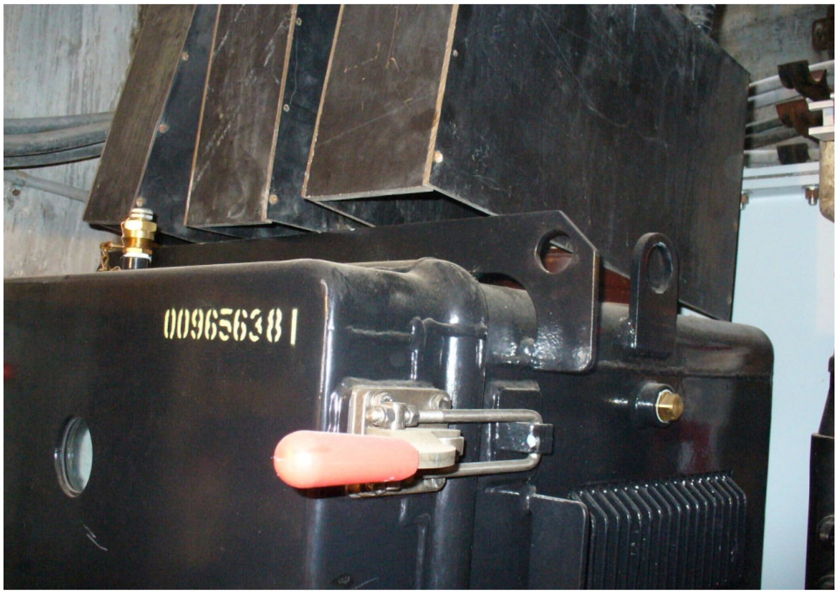

Figure 4-1 A Network Protector with Life Grade Score "A"

Figure 4-2 A Network Protector with Life Grade Score "B"

Figure 4-3 A Network Protector with Life Grade Score "C"

4.4 Health Index Results

The Health Index distribution for Network Protectors is shown in the following figures. No assets were found to be in poor or very poor condition.

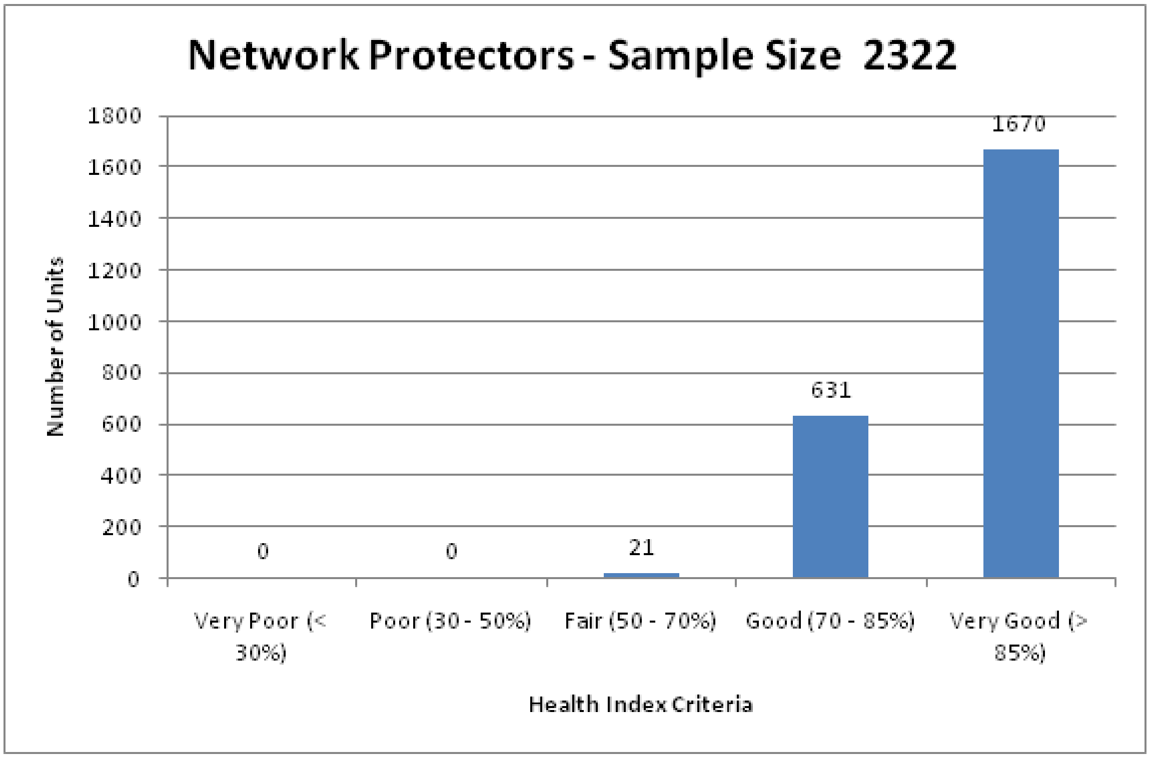

Figure 4-4 Network Protectors Health Index Distribution by Units

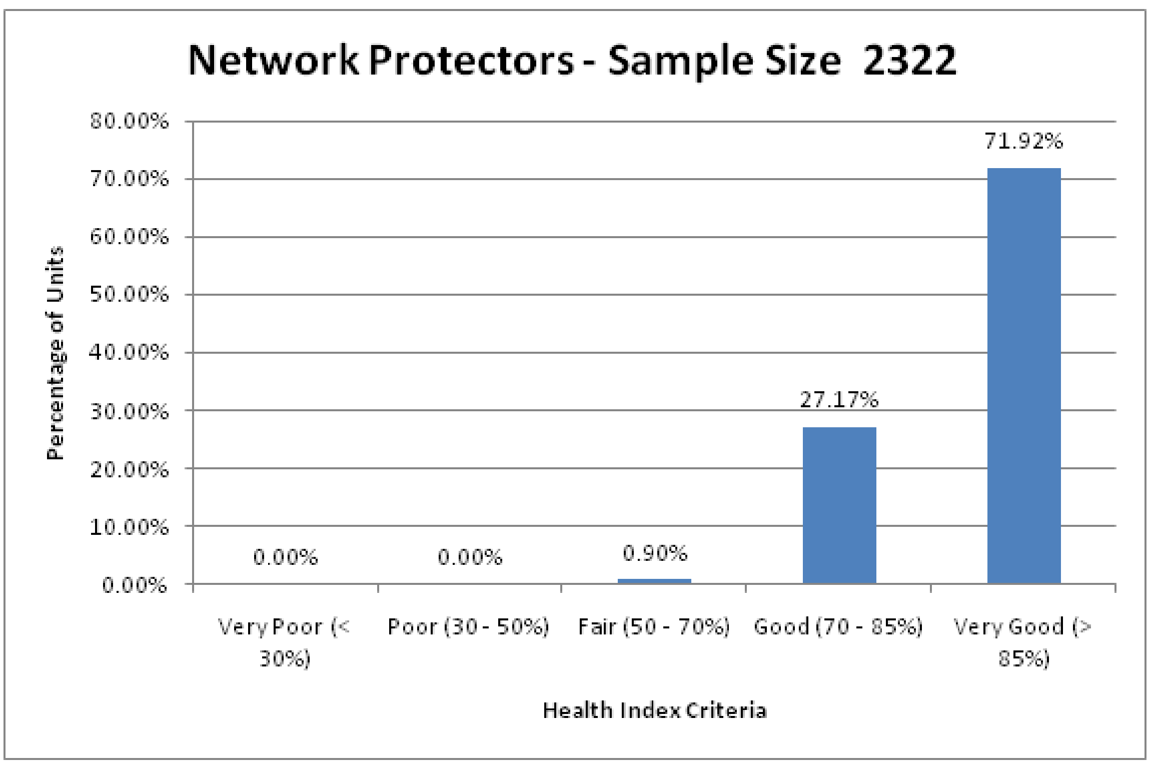

Figure 4-5 Network Protectors Health Index Distribution by Percentage

4.5 Data Availability

Network Protectors information was provided in the “NetworkTransformer_Inspected 2009.xls” spreadsheet. There were 2600 unique protector Equipment IDs in the data set. Where there were multiple assessments (i.e. assessments performed on different dates) for an asset, the data from the most recent assessments was used. Of the 2600 protector, 2322, or 89.3% of the protectors had sufficient data for a Health Index assessment. Assets for which less than 60% of condition data were available were excluded from the calculation.

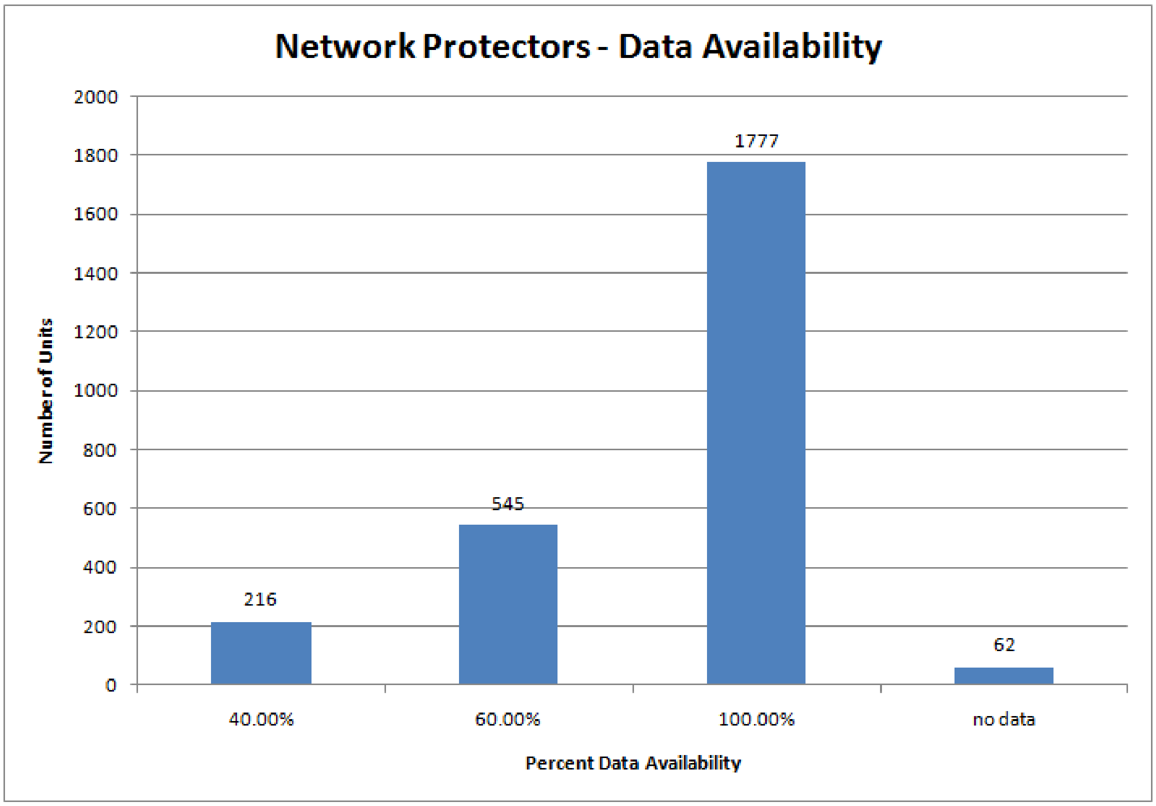

Figure 4-6 Network Protectors Data Availability Distribution

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TABLE OF CONTENTS % change in sample size

General Improvements/changes:

1) Uses latest inspection data upto 14th March 2014

2) Inspections data older than 1 inspection cycle is used in HI calculation incase where the latest inspection data within the inspectior cycle is not available (as opposed to BI tool, which only uses the inspection records that fall within the last inspection cycle)

3) Even if inspection history is available, BI does not extract data in some cases

SGEAR

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	189	31	172
Very Poor	0	12	0
Poor	27	91	25
Fair	33	83	46
Good	13	23	11
Very Good	22	39	25
Total population	284	279	279
Sample size (%)	33%	89%	38%

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	-5	0	-5
Sample size (%)	5%	51%	55%

Improvements/changes:

1) Uses correct "IR Hotspot" condition value: BI tool looked for condition parameter ('IR_HOTSPOT'), Correct condition is 'HOTSPOTDET'

2) Uses correct "Dirty" condition value: BI tool takes condition value with same condition parameter name from RELAY inspection (Insp Type: BI) where its not available from SGEAR inspection (Insp Type: SN)

Proposed Changes to Formula

1)

Reasons for Changes Between Manual Calc and BI

1) Uses correct "IR Hotspot" condition value: BI tool looked for condition parameter ('IR_HOTSPOT'), Correct condition is 'HOTSPOTDET'

2) Uses correct "Dirty" condition value: BI tool takes condition value with same condition parameter name from RELAY inspection (Insp Type: BI) where its not available from SGEAR inspection (Insp Type: SN)

Comments

1)

SWPAD

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	394	24	9
Very Poor	0	0	0
Poor	3	3	1
Fair	55	56	17
Good	140	281	72
Very Good	201	438	37
Total population	793	802	136
Sample size (%)	50%	97%	93%

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	-657	666	9
Sample size (%)	43%	4%	47%

Improvements/changes:
1) Includes assets under both SWPAD and SWPADAIR EGI: BI tool only includes assets under SWPAD EGI
2)
3)

Proposed Changes to Formula
1)

Reasons for Changes Between Manual Calc and BI
1) Increase in Total Population

Comments
1) Assets with SWPAD EGI being migrated to SWPADAIR or SWPADSF6 (depending on type) in Ellipse, but query was not updated in BI tool. As a result, BI tool queries a smaller total population

SWOHGANG

	SWOHGANG (manual)	**SWOHGANG (remote)**	**SWOHGANG (manual + remote)**	**SWOHGANG (manual + remote)**	**SWOHGANG (manual)**	**SWOHGANG (remote)**	**SWOHGANG (manual + remote)**
	2012 Kinetrics report	2012 Kinetrics report	2012 Kinetrics report	Manual Calc 2013	BI Tool	BI Tool	BI Tool
Insufficient for HI	1005	127	1132	743	471	350	821
Very Poor	0	0	0	0	0	0	0
Poor	0	0	0	0	0	0	0
Fair	3	9	12	11	1	5	6
Good	36	86	122	233	27	151	178
Very Good	25	41	66	121	18	84	102
Total population	1069	263	1332	1108	517	590	1107
Sample size (%)	**6%**	**52%**	**15%**	**33%**	**9%**	**41%**	**26%**

GOBACK

	BI Tool vs Kinetrics delta	**Man calc vs BI Tool delta**	**Man calc vs Kinetrics delta**
Total population	-225	1	-224
Sample size (%)	11%	7%	18%

Improvements/changes:
1) SWOHGANG are all manual switches, but some of these switches were classified as remote. All of the switches classified as manual in the manual calc tool
2)
3)

Proposed Changes to Formula
1)

Reasons for Changes Between Manual Calc and BI
1) Switches classified as manual have different HI formula than the ones classified as remote.

Comments
1) Out of 743 that have insufficient data to calculate HI, 548 have inspection records with 58% data availability (very close to being sampled with 60% rule)

SWOHGNGMOTOR

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI		2	
Very Poor		0	
Poor		0	
Fair		2	
Good		10	
Very Good		1	
Total population		15	
Sample size (%)		87%	

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	0	15	15
Sample size (%)	0%	87%	87%

Improvements/changes:
1) No Changes

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1)
2)
3)

SWSCADAMATE

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	290	136	210
Very Poor	0	1	1
Poor	0	0	0
Fair	8	9	10
Good	272	453	395
Very Good	167	327	308
Total population	737	926	924
Sample size (%)	61%	85%	77%

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	187	2	189
Sample size (%)	17%	8%	25%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)

Reasons for Changes Between Manual Calc and BI
1)

Comments
1) Revision 1 Scadamates are no longer being inspected/maintained. Total population of 926 includes these R1 Scadamates. There is currently a program to replace R1 Scadamate switches
2) There are currently 256 R1 Scadamates in service. THESL's plan is to replace ~60-70 units per year over the course of the next four years
3) Use of handheld devices for inspections vs paper records is likely for improvement in sample size

CBOIL-KSO

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	45	37	47
Very Poor	0	0	0
Poor	4	1	1
Fair	10	18	6
Good	5	3	5
Very Good	0	0	0
Total population	64	59	59
Sample size (%)	30%	37%	20%

GOBACK

BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
-5	0	-5
-9%	17%	8%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1) Use of handheld devices for inspections vs paper records is likely for improvement in sample size
2)
3)

CBSF6

	2012 Kinetics report	Manual Calc 2013	BI Tool
Insufficient for HI	176	136	136
Very Poor	0	0	0
Poor	0	0	0
Fair	1	5	4
Good	28	30	31
Very Good	35	30	30
Total population	240	201	201
Sample size (%)	27%	32%	32%

GOBACK

	BI Tool vs Kinetics delta	Man calc vs BI Tool delta	Man calc vs Kinetics delta
Total population	-39	0	-39
Sample size (%)	6%	0%	6%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1) Use of handheld devices for inspections vs paper records is likely for improvement in sample size
2)
3)

CBOIL

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	238	175	177
Very Poor	2	1	2
Poor	12	16	14
Fair	134	130	125
Good	12	10	14
Very Good	0	0	0
Total population	398	332	332
Sample size (%)	40%	47%	47%

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	-66	0	-66
Sample size (%)	6%	1%	7%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1) Drop in total population supports trend that oil circuit breakers are being replaced with vacuum circuit breakers. Large drop in total population likely due to data cleansing and validation o
2) Use of handheld devices for inspections vs paper records is likely for improvement in sample size
3)

CBAIRBLAST

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	163	110	113
Very Poor	0	0	1
Poor	5	7	12
Fair	108	158	150
Good	10	5	4
Very Good	6	10	10
Total population	292	290	290
Sample size (%)	44%	62%	61%

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	-2	0	-2
Sample size (%)	17%	1%	18%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1) Use of handheld devices for inspections vs paper records is likely for improvement in sample size
2)
3)

CBAIRMAG

	2012 Kinetrics report	Manual Calc 2013	BI Tool		BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Insufficient for HI	343	161	173	GOBACK			
Very Poor	0	1	0				
Poor	9	22	21				
Fair	163	346	315				
Good	101	88	111				
Very Good	14	9	7				
Total population	630	627	627		-3	0	-3
Sample size (%)	46%	74%	72%		27%	2%	29%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1) Use of handheld devices for inspections vs paper records is likely for improvement in sample size
2)
3)

CBVACUUM

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	190	197	197
Very Poor	0	0	0
Poor	1	1	1
Fair	21	15	12
Good	33	49	72
Very Good	301	413	392
Total population	546	675	674
Sample size (%)	65%	71%	71%

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	128	1	129
Sample size (%)	6%	0%	6%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1) Increase in total population supports trend that vacuum circuit breakers are replacing oil circuit breakers. Large increase in total population likely due to data cleansing and validation of cir
2) Use of handheld devices for inspections vs paper records is likely for improvement in sample size
3)

TRST

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	31	26	99
Very Poor	0	3	2
Poor	16	33	20
Fair	97	120	87
Good	90	56	51
Very Good	42	30	41
Total population	276	268	300
Sample size (%)	89%	90%	67%

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	24	-32	-8
Sample size (%)	-22%	23%	2%

Improvements/changes:

1) No Improvements/changes

2)

3)

Proposed Changes to Formula

1)

Reasons for Changes Between Manual Calc and BI

Comments

1) List of transformers generated manually rather than from BI tool (to remain consistent with what was done in previous ACA audit)

TXPAD

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	1597	1106	1116
Very Poor	0	0	1
Poor	0	1	13
Fair	27	611	688
Good	564	2634	2603
Very Good	4762	2808	2713
Total population	6950	7160	7134
Sample size (%)	77%	85%	84%

GOBACK

BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
184	26	210
7%	0%	8%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1) Use of handheld devices for inspections vs paper records is likely for improvement in sample size
2)
3)

TXVAULT

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	2358	1533	1518
Very Poor	7	0	29
Poor	43	26	82
Fair	2052	2700	2858
Good	3529	4577	4134
Very Good	5275	4198	4393
Total population	13263	13034	13014
Sample size (%)	82%	88%	88%

GOBACK

BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
-249	20	-229
6%	0%	6%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)

Reasons for Changes Between Manual Calc and BI
1)

Comments
1) Use of handheld devices for inspections vs paper records is likely for improvement in sample size

TXSUB

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	898	459	389
Very Poor	0	0	11
Poor	2	2	3
Fair	111	608	782
Good	1748	3177	3995
Very Good	6490	5308	4351
Total population	9249	9554	9531
Sample size (%)	90%	95%	96%

GOBACK

BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
282	23	305
6%	-1%	5%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1) Use of handheld devices for inspections vs paper records is likely for improvement in sample size
2)
3)

TXNETWORK

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	28	8	15
Very Poor	0	0	1
Poor	1	0	2
Fair	148	309	364
Good	637	781	805
Very Good	1066	794	640
Total population	1880	1892	1827
Sample size (%)	99%	100%	99%

GOBACK

BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
-53	65	12
1%	0%	1%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1)
2)
3)

VAULTNETWORK			
	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	4	5	3
Very Poor	12	18	0
Poor	62	93	0
Fair	330	765	90
Good	644	170	660
Very Good	9	11	275
Total population	1061	1062	1028
Sample size (%)	99.6%	100%	100%

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	-33	34	1
Sample size (%)	0%	0%	0%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1) Note that de-rating factor was applied to the manually calculated results
2)
3)

MS

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI		1	32
Very Poor		0	3
Poor		10	3
Fair		86	9
Good		52	88
Very Good		21	32
Total population	0	170	167
Sample size (%)	#DIV/0!	99%	81%

GOBACK

BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
167	3	170
#DIV/0!	19%	#DIV/0!

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1)
2)
3)

TS

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI		17	25
Very Poor		0	1
Poor		4	3
Fair		6	2
Good		2	3
Very Good		8	3
Total population	0	37	37
Sample size (%)	#DIV/0!	54%	32%

GOBACK

BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
37	0	37
#DIV/0!	22%	#DIV/0!

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1)
2)
3)

ATS

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	11	5	2
Very Poor	2	0	2
Poor	14	9	13
Fair	7	17	6
Good	21	16	14
Very Good	15	11	12
Total population	70	58	49
Sample size (%)	84%	91%	96%

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	-21	9	-12
Sample size (%)	12%	-5%	7%

Improvements/changes:
1) No Changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1)
2)
3)

CABLECHAMBER

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	8216	7085	7220
Very Poor	3	10	9
Poor	44	61	55
Fair	248	411	359
Good	1146	1915	1990
Very Good	1196	1420	1213
Total population	10853	10902	10846
Sample size (%)	24%	35%	33%

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	-7	56	49
Sample size (%)	9%	2%	11%

Improvements/changes:
1) No Improvements/changes
2)
3)

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1) poor sample size attributed to inspection cycle for cable chambers (10 years)
2) Use of handheld devices for inspections vs paper records is likely for improvement in sample size
3)

POLEWOOD

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI	81415	76849	80910
Very Poor	1100	1086	1116
Poor	3349	3546	2984
Fair	20095	20489	19670
Good	4179	3382	3378
Very Good	14942	17928	14970
Total population	125080	123280	123028
Sample size (%)	35%	38%	34%

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	-2052	252	-1800
Sample size (%)	-1%	3%	3%

Improvements/changes:
1) No Changes

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1) de-rating factor applied to this asset class worst of (pole-top feathering / cracks / insect damage / surface rot / wood loss / other unusual condition)
2)
3)

PROTECTOR

	2012 Kinetrics report	Manual Calc 2013	BI Tool
Insufficient for HI		40	
Very Poor		0	
Poor		0	
Fair		59	
Good		508	
Very Good		1008	
Total population		1615	
Sample size (%)		98%	

GOBACK

	BI Tool vs Kinetrics delta	Man calc vs BI Tool delta	Man calc vs Kinetrics delta
Total population	0	1615	1615
Sample size (%)	0%	98%	98%

Improvements/changes:
1) No Changes

Proposed Changes to Formula
1)
2)
3)

Reasons for Changes Between Manual Calc and BI
1)
2)
3)

Comments
1)
2)
3)

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INTERROGATORY 37:

Reference(s): **Exhibit 2B, Schedule D, App. A, Kinectrics Report and THESL EB-2012-0064, Tab 4, Schedule B14**

On page 14 of the first reference, it is stated that 87% of the Oil KSO breakers have a 2014 classification of fair or worse condition leaving only 13% in good condition, a decline from the 26% that were in good condition in 2012.

The second reference, which is THESL's evidence on these breakers from its previous IRM application, states on page 3, line 22 that there were 66 KSO breakers in 2012. On page 1 of this evidence, it is stated that 21 of these breakers were to be replaced in the 2012 to 2014 period.

a) Given the program to replace 21 of the breakers during 2012-2014, please provide an explanation for the increased percentage of "fair or worse" condition breakers and the decreased percentage of "good" condition breakers;
b) If the explanation is that THESL replaced less breakers than planned, please explain why this is the case, given the importance of these devices.

RESPONSE:

a) The KSO circuit breaker condition data collected in 2014 shows that 40% of the KSO circuit breakers which were in "good" condition in 2012 deteriorated to "fair" condition breakers. In addition, more KSO circuit breakers were tested in 2014 and a majority of the circuit breakers that were tested in 2014 were found to be "fair"

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condition breakers. For these two reasons, the percentage of “fair or worse” condition breakers increased and the percentage of “good” condition breakers decreased. In addition, Toronto Hydro has thus far only completed replacement of nine out of 21 circuit breakers planned replacement in for 2012-2014. This has resulted in 18% more “fair” breakers than would have otherwise been expected had all planned replacements been completed.

b) Despite the importance of the work, Toronto Hydro was only able to complete nine out of the 21 KSO circuit breaker replacements in 2012-2014 due to the timing of the rate decision on the 2012-13 capital program and resource constraints in the work group qualified to complete this type of job.

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INTERROGATORY 38:

Reference(s): Exhibit 2BSection D, App. A, Kinectrics Report, p.20

In the above reference, it is stated that:

> Of the 21 asset groups audited, only 4 groups showed improvements in overall health. For the remaining 17 asset categories, an overall decline in condition was observed.

Where station assets are concerned, it is particularly noted that: "Because station assets are generally substantial and have relatively higher consequences of failure, this trend in declining health is a major cause for concern."

a) Please provide THESL's general view of the audit results including:
    i) Identification of any areas of the report with which THESL does not concur, and the reasons;
    ii) THESL's view as to the extent to which the report reasonably and accurately represents the expected results of the System Renewal expenditures over the historical spending period 2010 through 2014;

b) Please comment on the statement noted above that "… this trend in declining health is a major cause of concern".

RESPONSE:

a) Toronto Hydro's comments are as follows:

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i) The Kinetrics 2014 ACA audit is a comparison of 2012 ACA data to 2014 ACA data, and summarizes changes seen in various asset classes. Because the ACA data is based on Toronto Hydro inspection records from those two years, the utility concurs with the results found in the audit.

ii) In early 2012, Toronto Hydro's 2012-2014 cost-of-service application (EB-2011-0144) was rejected, which produced immediate impacts to the 2012 work program that also carried over into the 2013 work program, resulting in reduced capital expenditures. In these circumstances, the observed decline in asset health could be expected as assets continued to age and relatively few were replaced.

b) Toronto Hydro agrees with this statement. A large portion of station assets are approaching or past end of useful life, as described throughout the relevant sections of the application. As a consequence, overall station asset condition continues to decline. Toronto Hydro plans to address this issue by executing programs that deal with station assets in the Distribution System Plan.

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INTERROGATORY 39:

Reference(s): **Exhibit 2B, Section E.6 and**
THESL EB-2012-0064, Tab 4, Schedule A, App 1, Tab 1

THESL's DSP has expenditures in the asset categories of System Access, System Renewal, System Service and General Plant. Board staff seeks information that will indicate the degree to which programs authorized in THESL's previous application have been achieved, including the impacts completion of these programs have had on OM&A expenditures, in tabular form including:

a) The objectives which were to be completed in the years 2012 to 2013 (Phase 1) and 2014 (Phase 2, projected) for which capital funding was sought from the Board in EB-2012-0064 according to Reference 2;
b) The total dollars that were sought and approved by the Board, in order to achieve the objective;
c) the capital expenditure (for assets that were actually in-service) that have been spent for the achieved objective;
d) the extent to which the objective was achieved, on a % of dollars basis i.e. "b"/"c";
e) an explanation for the differences where a) the objectives were not achieved or b) where the expenditure, on either a $ per unit or total $expenditure, varied by 10% or more;
f) The OM&A expenditures for the year and how it has been affected by the capital expenditures of earlier years.

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An example of the information Board staff is seeking is provided below for category E6, System Renewal Investments (note that this example only mentions 3 segments of the E6 Assets. All segments for all categories are required):

	Asset	Objective for 2012-2014	Dollars requested	Dollars expended	Achieved	OM&A
E6.1	Underground Circuit Renewal					
	Explanation					
E6.2	PILC Piece-outs and Leakers					
	Explanation					
E6.13	Switchgear Renewal	• Replace 4 obsolete MS switchgear • Replace 4 TS switchgear	Per [Reference 2] Project Schedule B13.1 and 13.2 2012-$19.35m 2013-$18.76m 2014-$20.31m			
	Explanation					
Etc.						

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Please complete the above table and provide similar tables for each of the categories (i.e., System Renewal, System Access, System Service and General Plant) and segments of assets within these categories as shown above.

RESPONSE:

Toronto Hydro has not completed its tracking and analysis of the ICM work program as that program is still being executed. Currently, the following information is available:

- Appendix A provides in-service additions at the segment level for 2012 and 2013 (actuals) and 2014 (forecast). As illustrated in the appendix, Toronto Hydro expects the in-service additions associated with the completed ICM program (excluding Copeland TS) to vary by approximately 5% of the forecasted overall in-service additions.
- Appendix B provides CAPEX at the segment level for 2012 and 2013 (actuals) and 2014 (forecast). Toronto Hydro expects the CAPEX associated with the completed ICM program (excluding Copeland TS) to vary by approximately 5% of the forecasted overall CAPEX.
- Appendix C presents overall CAPEX (actuals) and in-service additions (actuals) for jobs that were listed in approved segments in Phase 1 of the ICM filing (i.e., 2012 and 2013 filed jobs) and that were completed in 2012 or 2013. It compares the sum of the original CAPEX estimates for these jobs versus (i) the sum of the actual CAPEX and (ii) the sum of actual in-service additions associated with the completed jobs. As illustrated, the overall actual spending associated with these jobs has varied by approximately 8% versus overall forecasted spending.

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Toronto Hydro is unable to provide an accurate and complete true-up in advance of 2014 year-end close out and a subsequent analysis and reconciliation of segment level spending in each year. There are a number of practical constraints to providing further detailed true-up data in advance of the completion of the 2014 portion of the ICM work program. These result primarily from changes in job timing and composition within ICM segments, coupled with the need to reconcile large amounts of field data.[1] Moreover, as explained in the response to interrogatory 2A-CCC-23, Toronto Hydro believes that providing early or partial true-up information would be inefficient and inconsistent with the OEB's Decision in EB-2012-0064.

There are generally two different types of segments within Toronto Hydro's ICM work program: those that are asset-based (e.g., switchgear), and those that are geographically-based (e.g., underground). For both of these types of work, as jobs move from high-level planning to detailed design and then to execution, their nature and timing may be adjusted. The following situations represent examples of these types of necessary and prudent adjustments.

- *Job scopes change*
    - A detailed field inspection for a geographically-based job, such as an overhead rebuild, may uncover the need for additional asset refurbishment work to be added to the scope of the job.
- *Jobs are advanced and deferred*
    - A field inspection for a geographically-based job such as an overhead rebuild may identify additional assets that require replacement (e.g., more

[1] Toronto Hydro notes that its proposed Enterprise Resource Planning (ERP) system will make improvements to planning capabilities over the current ERP system. For more on the ERP, please see the ERP Program in the DSP, Exhibit 2B Section 8.6.

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    poles and transformers), which necessitates additional design work and delays the start date of construction.
  - Feeder loading restrictions imposed due to unusually hot weather may prevent isolation of, or transfer of load to, feeders to allow execution of a job, which necessitates a delay of the job and substitution of another.
- *Jobs are added and deleted from the ICM term*
  - A feeder reconfiguration scheduled during the ICM period may need to be deferred past 2014 because an initially-proposed load transfer was no longer feasible, due to new customer connections resulting in insufficient transfer capacity to undertake the work.
  - A job may need to be added to the ICM program because a new customer could request a connection to the system that would require the expansion and upgrade of an existing transformer. External agencies may require relocation of Toronto Hydro plant to allow for execution of their own work, resulting in the addition of a job to the program and forcing the deferral of another or others.
  - Poor asset performance with a resultant impact on reliability in a given area may require the addition or advancement of a job to the work program, forcing the deferral of another or others.

Toronto Hydro is diligently tracking these changes to the ICM program and intends to provide the OEB and intervenors with a specific reconciliation of forecasts versus actual, including detailed explanations for variance, through the true-up process. However, due to ongoing reconciliation activities and the number of personnel working on the capital program as it moves from planning to detailed design to execution, the detailed information that the utility currently has is in the form of a large amount of field data that

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has not yet been reviewed, compiled, and summarized such that it can be effectively presented. Only once the full ICM program is complete, 2014 financial closeout has occurred and all field data is gathered, will Toronto Hydro be able to begin undertaking the compilation exercise, which it expects to present to the OEB in the second quarter of 2015.

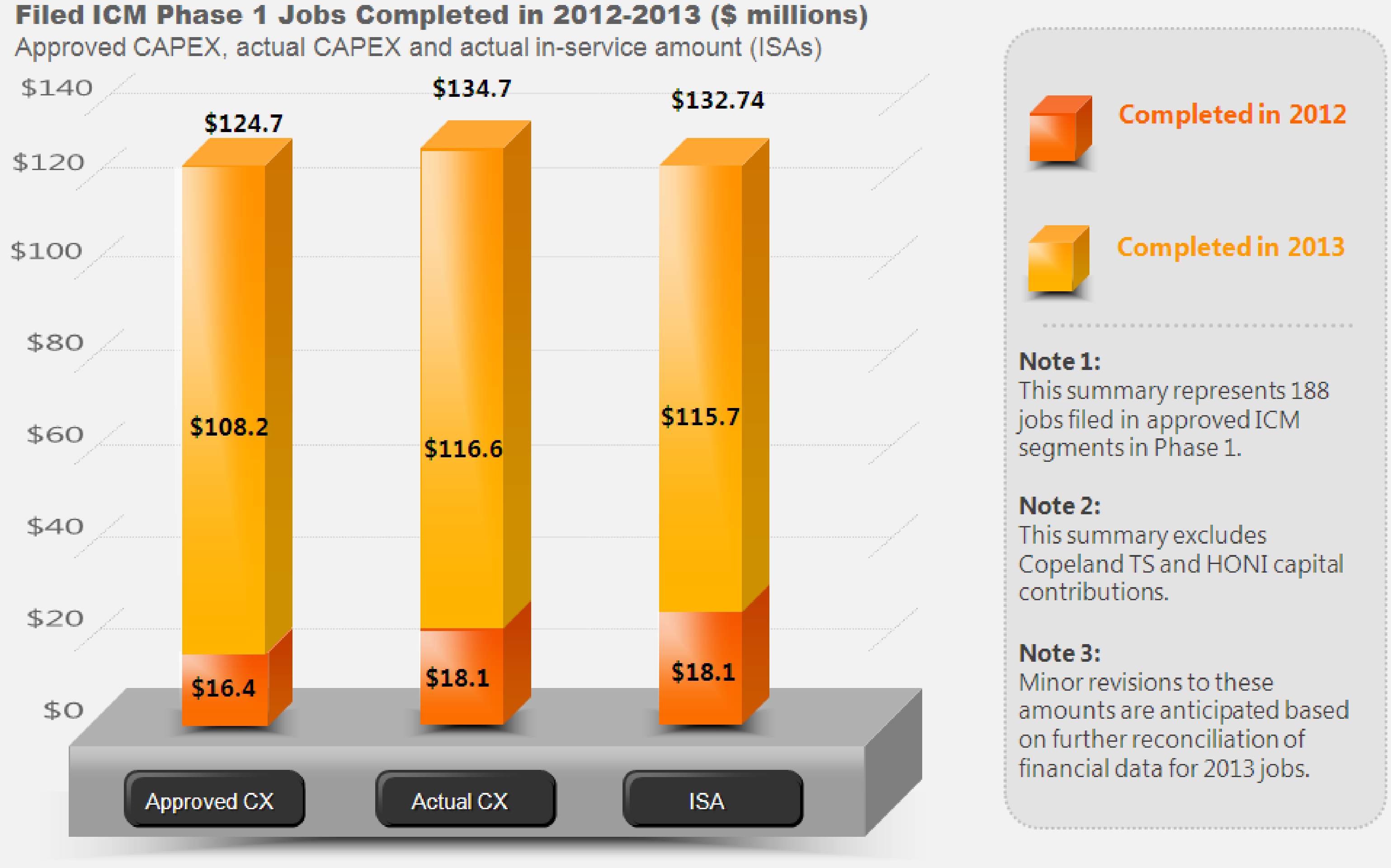
APPENDIX A: Capital Summary Table (ISAs)

		Phase 1: Approved			Phase 2: Approved	Phase 1 + 2: Approved		Phase 1 + 2: Actual/Forecast					Variance	
		In-Service Additions												
		A	B	C	D	E = C + D	F = A + B + E	G	H	I	J	K = G + H + J	L = J - E	M = K - F
Schedule Number	Segments	Total 2012 In-Service Additions	Total 2013 In-Service Additions	Total 2014 In-Service Additions	Total 2014 In-Service Additions	Total 2014 In-Service Additions	Total Approved In-Service Additions (2012-2014)	2012 In-Service Additions Actual (Annual)	2013 In-Service Additions Actual (Annual)	2014 In-Service Additions Actual (YTD June)	2014 In-Service Additions Forecast (Annual)	Total Forecast In-Service Additions (2012-2014)	Total 2014 In-Service Additions Approved vs Forecast	Total 2012-2014 In-Service Additions Approved vs Forecast
B1	Underground Infrastructure	12.74	51.88	23.07	36.70	59.77	124.39	9.35	62.17	10.07	76.54	148.06	16.78	23.67
B2	Paper Insulated Lead Covered Cable - Piece Outs and Leakers	0.04	3.34	2.12	1.42	3.54	6.92	0.11	0.15	0.38	6.17	6.44	2.63	(0.48)
B3	Handwell Replacement	6.05	17.73	6.52	7.22	13.74	37.53	5.41	16.61	2.34	10.89	32.92	(2.85)	(4.60)
B4	Overhead Infrastructure	4.02	39.06	21.87	14.78	36.65	79.73	1.03	33.47	12.86	49.82	84.32	13.17	4.59
B5	Box Construction	0.26	14.35	9.02	5.72	14.74	29.34	0.02	5.24	2.90	18.45	23.71	3.71	(5.64)
B6	Rear Lot Construction	7.25	27.02	11.52	5.00	16.52	50.79	3.49	27.23	8.35	16.70	47.42	0.18	(3.37)
B9	Network Vault & Roofs	1.26	13.00	7.34	0.90	8.24	22.50	-	12.33	2.05	2.29	14.62	(5.95)	(7.88)
B10	Fibertop Network Units	0.65	5.52	3.02	2.84	5.85	12.02	0.96	7.06	0.94	5.60	13.62	(0.25)	1.60
B11	Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)	-	1.99	1.28	0.10	1.38	3.36	-	1.51	0.29	0.30	1.81	(1.08)	(1.55)
B12	Stations Power Transformers	0.17	2.33	1.36	-	1.36	3.86	-	0.35	0.99	2.90	3.25	1.54	(0.60)
B13.1 & 13.2	Stations Switchgear - Municipal and Transformer Stations	0.77	9.16	5.37	1.41	6.78	16.71	-	-	3.21	3.61	3.61	(3.17)	(13.10)
B20	Metering	2.10	7.75	3.29	3.82	7.11	16.96	-	7.13	3.41	10.82	17.95	3.72	0.99
B21	Externally-Initiated Plant Relocations and Expansions	4.50	20.78	9.72	1.87	11.59	36.87	1.94	7.37	0.03	17.80	27.10	6.21	(9.77)
BXX	ICM Understatement of Capitalized Labour	3.69	4.63	-	-	-	8.32	-	-	-	-	-	-	(8.32)
Total ICM Projects (Excluding Copeland)		43.49	218.53	105.49	81.78	187.27	449.29	22.31	180.62	47.82	221.90	424.83	34.63	(24.46)
B17	Copeland Transformer Station	-	-	124.10	-	124.10	124.10	-	2.08	1.30	1.30	3.38	(122.80)	(120.72)
B18.2	Hydro One Capital Contributions	-	-	60.00	-	60.00	60.00	-	-	-	-	-	(60.00)	(60.00)
Total ICM Projects		**43.49**	**218.53**	**289.59**	**81.78**	**371.37**	**633.39**	**22.31**	**182.70**	**49.12**	**223.21**	**428.21**	**(148.16)**	**(205.18)**
B7	Polymer SMD-20 Switches	-	0.93	0.60	1.59	2.19	3.12	-	0.84	-	1.51	2.35	(0.68)	(0.77)
B8	SCADA-Mate R1 Switches	-	0.87	0.56	1.89	2.45	3.32	-	1.88	0.03	0.03	1.91	(2.43)	(1.42)
B14	Stations Circuit Breakers	0.34	0.76	0.22	1.05	1.27	2.36	0.22	0.90	0.19	0.50	1.62	(0.77)	(0.74)
B16	Downtown Station Load Transfers	0.30	1.68	0.84	-	0.84	2.82	-	0.03	1.33	1.33	1.36	0.49	(1.46)
B18.1	Hydro One Capital Contributions	-	1.48	-	2.64	2.64	4.12	5.48	2.61	-	1.76	9.85	(0.88)	5.73
C1	Operations Portfolio Capital	29.00	87.75	29.66	49.29	78.95	195.70	39.93	79.39	30.76	99.43	218.76	20.48	23.05
C2	Information Technology Capital	9.25	21.47	6.28	11.25	17.53	48.25	7.56	20.28	6.24	17.49	45.33	(0.04)	(2.92)
C3	Fleet Capital	0.29	0.76	1.75	2.00	3.75	4.80	0.80	0.44	1.83	3.72	4.96	(0.03)	0.16
C4	Buildings and Facilities Capital	3.76	2.90	3.35	5.00	8.35	15.00	1.40	6.16	0.04	7.21	14.77	(1.13)	(0.23)
Total Normal Capital Budget		**42.94**	**118.60**	**43.25**	**74.71**	**117.96**	**279.49**	**55.38**	**112.55**	**40.40**	**132.96**	**300.89**	**15.01**	**21.40**
Total		**86.43**	**337.12**	**332.84**	**156.49**	**489.33**	**912.88**	**77.69**	**295.25**	**89.53**	**356.17**	**729.10**	**(133.16)**	**(183.78)**

APPENDIX B: Capital Summary Table (CAPEX)

		Phase 1: Approved Capital Spending			Phase 2: Approved Capital Spending	Total Phase 1 + 2 Capex Approved		Phase 1 + Phase 2: Actual/Forecasted Capital Spending					Variance	
		CapEx			CapEx	CapEx	CapEx	CapEx						
		A	B	C	D	E = C + D	F = A + B + E	G	H	I	J	K = G + H + J	L = J - E	M = K - F
Schedule Number	Segments	2012 Approved Capex	2013 Approved Capex	2014 Approved Capex	Total 2014 Approved Capex	Total 2014 Approved Capex	Total Approved Capex (2012-2014)	2012 Capex (Actual)	2013 Capex (Actual)	2014 Capex Actual (YTD Jun)	2014 Capex IR Fcst as at Jul 2014 (Annual)	Total Fcst Capex (2012-2014)	Total 2014 Capex Approved vs Fcst	Total 2012-2014 Capex Approved vs Fcst
B1	Underground Infrastructure	28.75	58.94	-	77.86	77.86	165.56	36.90	55.97	41.69	107.08	199.95	29.22	34.39
B2	Paper Insulated Lead Covered Cable - Piece Outs and Leakers	0.08	5.42	-	3.55	3.55	9.05	0.14	1.98	2.33	5.96	8.08	2.42	(0.96)
B3	Handwell Replacement	13.65	16.65	-	18.06	18.06	48.36	12.39	11.87	3.96	15.52	39.77	(2.54)	(8.59)
B4	Overhead Infrastructure	9.07	55.88	-	26.01	26.01	90.96	11.59	40.42	28.23	64.12	116.13	38.10	25.16
B5	Box Construction	0.58	23.04	-	14.27	14.27	37.90	0.84	13.84	9.70	23.03	37.71	8.76	(0.18)
B6	Rear Lot Construction	16.36	29.43	-	12.51	12.51	58.29	15.98	23.20	7.35	26.42	65.60	13.91	7.31
B9	Network Vault & Roofs	2.84	18.76	-	2.25	2.25	23.85	2.81	10.58	1.17	1.18	14.58	(1.07)	(9.27)
B10	Fibertop Network Units	1.48	7.71	-	7.09	7.09	16.28	2.14	6.83	1.59	4.66	13.63	(2.43)	(2.65)
B11	Automatic Transfer Switches (ATS) & Reverse Power Breakers (RPB)	-	3.26	-	0.25	0.25	3.51	-	1.59	0.22	0.22	1.81	(0.03)	(1.70)
B12	Stations Power Transformers	0.38	3.48	-	-	-	3.86	0.02	1.54	0.87	2.66	4.21	2.66	0.36
B13.1 & 13.2	Stations Switchgear - Municipal and Transformer Stations	1.73	13.72	-	3.54	3.54	18.98	2.43	5.08	3.21	9.34	16.85	5.81	(2.13)
B20	Metering	4.74	8.40	-	9.54	9.54	22.68	5.69	4.72	4.91	12.56	22.97	3.02	0.29
B21	Externally-Initiated Plant Relocations and Expansions	10.16	24.84	-	4.55	4.55	39.55	9.20	18.57	3.87	6.46	34.23	1.91	(5.33)
BXX	ICM Understatement of Capitalized Labour	8.32	-	-	-	-	8.32	-	-	-	-	-	-	(8.32)
Total ICM Projects (Excluding Copeland)		**98.13**	**269.53**	**-**	**179.49**	**179.49**	**547.15**	**100.13**	**196.19**	**109.12**	**279.21**	**575.53**	**99.72**	**28.38**
B17	Copeland Transformer Station	8.50	81.00	34.60	-	34.60	124.10	4.07	26.72	20.57	54.51	85.29	19.91	(38.81)
B18.2	Hydro One Capital Contributions	-	23.00	37.00	-	37.00	60.00	-	18.60	8.85	21.20	39.80	(15.80)	(20.20)
Total ICM Projects		**106.63**	**373.53**	**71.60**	**179.49**	**251.09**	**731.25**	**104.19**	**241.51**	**138.54**	**354.92**	**700.63**	**103.83**	**(30.63)**
B7	Polymer SMD-20 Switches	-	1.53	-	3.97	3.97	5.50	-	0.84	0.71	1.85	2.69	(2.13)	(2.82)
B8	SCADA-Mate R1 Switches	-	1.43	-	4.73	4.73	6.16	-	1.90	0.45	1.79	3.69	(2.94)	(2.47)
B14	Stations Circuit Breakers	0.76	0.55	-	2.63	2.63	3.94	0.22	1.02	0.09	1.81	3.05	(0.82)	(0.89)
B16	Downtown Station Load Transfers	0.68	2.14	-	-	-	2.82	0.05	2.31	0.42	1.29	3.65	1.29	0.84
B18.1	Hydro One Capital Contributions	1.48	-	-	2.64	2.64	4.12	26.63	20.49	1.04	5.88	53.00	3.24	48.88
C1	Operations Portfolio Capital	64.78	81.63	-	103.78	103.78	250.19	66.67	93.24	41.61	98.24	258.15	(5.53)	7.96
C2	Information Technology Capital	22.00	15.00	-	15.00	15.00	52.00	23.20	17.12	5.99	16.24	56.57	1.24	4.57
C3	Fleet Capital	0.80	2.00	-	2.00	2.00	4.80	0.79	2.16	0.51	2.00	4.95	-	0.15
C4	Buildings and Facilities Capital	5.00	5.00	-	5.00	5.00	15.00	5.13	5.71	1.35	8.25	19.10	3.25	4.10
	Allowance for Funds Used During Construction	1.20	1.40	-	7.95	7.95	10.55	-	-	-	-	-	(7.95)	(10.55)
Total Normal Capital Budget		**96.70**	**110.68**	**-**	**147.70**	**147.70**	**355.08**	**122.70**	**144.80**	**52.15**	**137.35**	**404.85**	**(10.34)**	**49.77**
Total		**203.33**	**484.22**	**71.60**	**327.18**	**398.78**	**1,086.33**	**226.89**	**386.31**	**190.69**	**492.27**	**1,105.47**	**93.49**	**19.14**

APPENDIX C: Phase 1 ICM Jobs Completed in 2012-2013



Note 1:
This summary represents 188 jobs filed in approved ICM segments in Phase 1.

Note 2:
This summary excludes Copeland TS and HONI capital contributions.

Note 3:
Minor revisions to these amounts are anticipated based on further reconciliation of financial data for 2013 jobs.

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INTERROGATORY 40:

Reference(s): **Exhibit 2B, Section E, Schedule 6, p. 3 and**
Exhibit 2B, Section E, Schedule E6.6

Board staff's questions relate to THESL's programs to replace rear lot distribution with front lot underground distribution. In the first reference, it is stated that:

> This program replaces the existing end-of-life rear lot distribution service configuration with an underground front lot access system to eliminate challenges in performing maintenance activities and to mitigate the increased risk of long duration outages inherent in the existing plant design. The conversion eliminates operational constraints and reduces the safety and reliability risks associated with this obsolete connection configuration.

a) Please clarify if the "obsolete connection configuration" implies that not only rear lot placement, but also overhead distribution is obsolete;
b) At page 1 of the second reference, the photograph appears to show a box construction pole-top as a rear lot pole. Please state: (i) whether or not this indicates that there is overlap between the two programs and (ii) how many of the rear-lot conversions are also part of the box construction conversion program;
c) Table B of the second reference states under Failure Risk that "The majority of rear lot underground assets are direct buried", and on page 5 it is stated that most rear lot service is overhead. Please provide the proportion of rear lot distribution which is a) overhead, b) underground and direct buried, and c) underground but not direct buried and explain how this varies with locations within the city.

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RESPONSE:

a) The “obsolete connection configuration” refers to electricity distribution to residential customers from the rear of their residences, which is obsolete for the reasons discussed in section E6.6.3.1 Program Drivers. “Obsolete connection configuration” does not imply that the overhead distribution is obsolete.

b) The two programs are intended to be separate and distinct. However, there is a minor overlap in the years 2016 and 2017, where 18 poles with box construction are part of a rear lot conversion project. The funding to address these poles is in the rear lot conversion program budget and not in the box construction program budget. Refer to the response to Interrogatory 2B-OEBStaff-41 part b for more information.

c) The breakdown of the remaining rear lot distribution is presented in the table below.

Type	Percentage of Circuit Length
Overhead	53%
Underground Not Direct Buried	33%
Underground Direct Buried	14%

As can be seen from the table, the statement in Table B is in error and the statement on page 5 is correct. The majority of the rear lot remaining in the system is a combination of overhead, underground direct buried, and underground in duct. The map below illustrates the type of distribution supplying the customers for the remaining rear lot neighbourhoods and where they are located in THESL’s distribution system.

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INTERROGATORY 41:

Reference(s): Exhibit 2B, Section E6.7, p.21

The diagrams on this page indicate the assets which are to be removed when box construction feeders are replaced.

a) Please confirm that, for overhead switches, only 60 of the total population of 810 are at the end of life;

b) Please state whether or not box construction is only being replaced in situations where either a) voltage conversion or b) rear lot conversion is occurring;

c) Please identify the number and proportion of box construction poles being replaced if box construction conversion is in fact taking place outside of voltage conversion or rear lot conversion;

d) Please provide the justification for any replacement of box construction poles outside of the programs of voltage or rear lot conversion.

RESPONSE:

a) Toronto Hydro confirms that for overhead switches, 65 (not 60) of the population of 810, are past their useful life.

b) Box construction conversion is always associated with a voltage conversion program. Box construction conversion is not always part of a rear lot conversion, but in a few cases small portions of rear lot distribution utilize the obsolete box construction standard. Replacement of these rear lot box construction standard poles would fall within the Rear Lot program.

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c) Not applicable.

d) Not applicable.

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INTERROGATORY 42:

Reference(s): Exhibit 2B, Section E6.8, p.25

Table 8 of the above reference shows significantly different Total Project Costs for different installations of apparently the same switch being replaced under project types "ICM" or "CIR". Please provide:

a) An explanation of the differences; and
b) A detailed comparison of the costing for one of the projects shown in the table under ICM and one under CIR e.g., for ICM project number W14630 at $0.59m and for CIR E15497 at $0.87m.

RESPONSE:

a) The differences in costs are not due to differences between the ICM and CIR frameworks, but rather due to one or both of the following factors:
    1) The number of switches to be replaced is different between projects (the number of switches per project varies between 5 and 12)
    2) The amount of work per switch location differs based on the equipment connected to the switch and the configuration of the switch. The work per switch location can range from the replacement of only the SCADA-Mate R1 switch to the replacement of the switch, obsolete RTU, poor condition pole, and underground riser cable.

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b) A detailed comparison of the costing for the two projects W14630 and E15497 is provided in the table below. The projects are essentially for the same work with the exception that W14630 is replacing eight switches and E15497 is replacing 12 switches.

Labour and Material Heading	W14630	E15497
Design Costs	$31,165	$31,797
OH-Support Services	$4,519	$6,327
OH-Poles	$52,850	$85,945
OH-Conductor Stringing/Transfers	$8,140	$12,301
OH-Switch Install	$262,873	$394,485
OH-RTU/Communications	$158,456	$238,012
Variance from Q1v2 2105	-$3,896	-$2,767
Design, EAR & Apprentice cost allocation	$72,689.12	$103,240.51
Total	**$586,796**	**$869,341**

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INTERROGATORY 43:

Reference(s): Exhibit 2B, Section E6.10, p.3 and pp. 19-27

At the first reference, THESL discusses Network Unit Renewal and it is stated that "The overall pace at which Network Units were replaced was about 50 units per year. Toronto Hydro will continue with this pace throughout the 2015-2019 period."

Given that the pace of Network Unit replacement is stated to have been about 50 units per year in the historical period and that this pace is expected to be continued in the 2015-2019 period, Table C on page 3, which provides historical and future spending shows a wide range of costs, ranging from $0.93 million in 2014 and $3.95 million in 2015 to levels of over $10 million for each year in the 2016 to 2019 period.

At the second reference, Table 7 provides 2015 projects.

a) Please explain why, given that the pace will continue as before, the capital expenditures for the years 2015-2019 are so much higher than those for the years 2010-2012 and 2013-2014;
b) Please explain the variation in the costs of the replacement of the Network Unit renewals as shown in Table 7. Please include specific discussion of the following two projects shown in Table 7: Project X11508 for which the cost is $14,486 for one unit and X12338, for which the costs is $641,067 for what appears to be 2 units.

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RESPONSE:

a) The second referenced table contained incorrect information. The correct historical and future spending table can be found in Exhibit 2B, Section E.6.10.4, Table 4.

b) Please note that the preamble contained within the "2015 Project Details" subsection for each capital investment program within the Capital Expenditure Plan, except the Metering program, erroneously indicates that the 2015 amounts in the Project tables represent the total cost of projects with expenditures in 2015. In fact, the Project tables only present the spending planned for 2015. As the preamble correctly explains, "portions of the total project cost may be incurred before or after 2015". As the amounts listed for 2015 represent only the planned spending in 2015, they do not necessarily represent the total cost of each project shown in 2015.

With specific reference to Network Unit Renewal Program (Exhibit 2B, Section E6.10), the sentence on line 11 "Note that the table shows total costs for each program" is incorrect. Table 7 only shows the 2015 spending for each program. With respect to the Network Unit Renewal program, the high level total cost for project X11508 is $163,589; however, only $14,486 will be incurred in 2015. Therefore, only the amount incurred in 2015 of $14,486 is contained in Table 7.

The other reason for the observed variance is that each project has a unique scope that can include the replacement of additional assets such as secondary cabling. In the case of the cited project X12338, the network vault is also being rebuilt as a part of this project which results in the project costing $641,068. When this project was put together in 2010, replacement of the Fibertop Network Unit was the main driver;

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however, rebuild of the Network Vault was also necessary and this project encompasses the full scope of work for the location.

Since 2012, when Fibertop Network Units became a distinct work program, Network Vault rebuilds are scoped separately. As an example, Table 7 also includes project X14470, which is a Fibertop Network Unit replacement that is associated with a Network Vault Rebuild, but here the civil component is included in the Network Vault Rebuild program as project X14592. Although these projects are funded through separate programs they must be executed together.

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INTERROGATORY 44:

Reference(s): **Exhibit 2B, Section E6.11, page 9 and page 33 and Exhibit 2B, Section E6.17, p.20**

In the first two references, legacy equipment renewal (ATS & RPB) is discussed where the same assets being replaced in different projects seem to have widely varying costs.

In the third reference, it is stated that "Toronto Hydro also plans to install fire barrier systems in stations with two or more transformers that do not have a fire barrier system to mitigate the risk of transformers being affected by a catastrophic failure of any neighbouring transformers."

a) With respect to Figure 4 of the first reference, please explain how a single contingency incident of a fire in one transformer is prevented from affecting the other unit. Please state whether or not the design as shown in Figure 4 is in conformity with the statement quoted in the third reference and, if so, why;

b) With respect to the second reference, please explain the variation in the costs for projects X12953 and X14520, listed as 2015 replacements.

RESPONSE:

a) The third reference (Section E6.17, page 20) refers to stations equipment that supplies large portions of the city. Figure 4 (Section E6.11, page 9) is applicable only to transformer vaults that supply residential and commercial buildings.

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With respect to Figure 4, the incident of a fire in one transformer does not prevent it from affecting the other transformer unit since no fire barriers are installed. In general, when network/transformer vaults are retrofitted, no fire barriers are installed due to limited vault space. When new vaults are being built or old vaults are being rebuilt, two separate vault sections are installed, where practical, to prevent a fire in one transformer from affecting the other.

b) The costs of each of the two referenced jobs are detailed as follows:

- X12953 – The age and condition of the existing transformers requires both transformers to be replaced. Customer loading at this location requires two 500kVA network transformers to be installed.
- X14520 – The age and condition of the existing transformers requires both transformers to be replaced. Customer loading at this location is below 75kVA which requires the use of a different (lower kVA rating) size and type of transformer.

The use of different transformers and protection equipment to supply customers necessarily affects project costs. As noted in Exhibit 2B, Section E6.11.2, page 8, "each customer's solution will depend on various circumstances such as existing infrastructure type and size, system voltage requirements and customer loading".

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INTERROGATORY 45:

Reference(s): **Exhibit 2B, Section E6.12, p. 36, lines 10-11 and pp. 36-37**

In the first reference, work is shown as beginning on this program in 2016 and it is stated that in 2015, THESL plans to do preliminary engineering work necessary for projects to take place in subsequent years.

The second reference discusses the development of new equipment.

a) Please state why there are no costs reflected for 2015 in this program and whether or not the development and design costs for this program will be capitalized;
b) Please explain why new equipment have to be developed and describe any investigations of equipment used in analogous locations such as New York, Montreal, Chicago etc. where it is likely that similar vaults are used.

RESPONSE:

a) In 2015, development of the equipment is expected to consist largely of evolving design proposals between manufacturer and Toronto Hydro engineering staff. Purchase and billing for equipment are planned to take place beginning in 2016. Capitalization of development and design costs will occur in 2016.

b) Toronto Hydro uses the designs and experience of other utilities as a starting point in developing new equipment. Each utility has unique vault dimensions and operating environments, as well as unique operating and maintenance constraints and practices.

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As a result, each utility has unique design solutions that cannot be migrated intact to other utilities. In addition, the elevated operating voltage and new regulatory requirements on equipment (e.g., arc flash) mean that further development of these designs is required.

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INTERROGATORY 46:

Reference(s): **Exhibit 2B, Section E6.13, p. 15, lines 9-12 and pp.28-30 and p.38**

This section discusses a program to replace switchgear due to potential failure of breakers. There appears to be a distinction between occurrence of an arch-flash in a breaker and a subsequent explosion.

a) Please clarify the terms occurrence of an “arc-flash”, “switchgear failure” and “explosion” which are referred to at the above reference;
b) Please explain why an arc-flash would lead to a failure and a failure to an explosion;
c) Please state whether an explosion of a breaker is also classified as a failure;
d) Please state whether or not these breakers are manually operated, so that personnel are necessarily in the area;
e) For the current population of MS and TS breakers please indicate:
    i) the total number of breakers in TSs and in MSs and their nominal voltage rating;
    ii) the number of the TS and MS breakers that are “legacy” breakers;
    iii) the number of the legacy breakers are of non-arc resistant design;
    iv) Whether or not any of the other (non-legacy) breakers are of non-arc-resistant design, and if so, how many;
f) For the MS and TS breakers, for each of the most recent 5 years, please provide:
    i) the record of the number of operations for those breakers to be replaced in the 2015-2019 period; If normal and protection operations can be differentiated then please provide these numbers;

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ii) the average number of operations for the entire population of the different types of breakers;

iii) the record of failures of each of the type of switchgear in the entire population which is of non-arc-resistant design, including number of events and year;

iv) the record of explosions of breakers;

v) the number, age, type and Health Index of breakers that have been replaced;

vi) the capital expenditure for each replaced breaker; vii) the operation, maintenance and administration expenditure for the entire population.

g) Regarding Table 8 of the second reference:

  i) Please confirm that this table does not represent the complete record of failures in the years 2001-2008, or if not, please explain;

  ii) Please state whether or not the busbar fault at Jane MS shown in the table was accompanied by a breaker failure or explosion;

  iii) Please state whether or not Terauley TS the only case where the breaker exploded upon fault clearing;

  iv) Please indicate the ages and the recorded Health Indices of the switches when they failed;

  v) Please confirm that all of the breakers at the stations listed in table 8 have been replaced, which is the reason they do not appear in figure 11 and 12, or if not, please explain;

  vi) Please state whether or not all of the referenced breakers are remotely switchable and whether or not all the breakers in the MSs and TSs are remotely switchable;

  vii) Please state the procedures that have been put in place given these events and whether or not manual switching under load continued to be done in view of the failure possibility.

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h) Regarding Table 9 of the second reference:
   i) Please provide the references for the statement at page 30 lines 17-19 that THESL "received approval to replace four MS switchgear and four TS Switchgear, whereas the utility's original plan was to replace ten MS Switchgear and four TS switchgear";
   ii) Please clarify and detail what are the HONI payments associated with the switchgear replacement, as referred on page 30, lines 23-26. Please state whether or not the amount paid to Hydro One is for replacing the incoming breakers for Wiltshire (p50), Strachan (page 55), Duplex (page 56) and Windsor TSs;

i) Regarding Table 11 of the third reference:
   i) Please provide the details of the components of each cost;
   ii) Please state if the cost of the customer outage is considered in the Avoided Risk Cost and, if so, what value is used.

RESPONSE:

a) **Arc Flash**: Arc flash occurs due to an arcing fault between a phase bus bar and another phase bus bar, neutral or a ground. This can result in a rapid release of heat and energy, flash of light, strong shock and sound wave, and even a sudden spray of molten metal droplets or hot shrapnel flying in all directions.

   Switchgear failure: A Switchgear failure occurs when this equipment fails to clear faults downstream resulting in the loss of power to customers. It may or may not result in damage to the switchgear, any component breakers or other apparatus in the area.

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Explosion: A failure event that results in a rapid release of heat, energy and shock wave.

Please refer to Exhibit 2B, Section E6.13, page 20, lines18-21, pages 21-26 and page 27, lines1-6 for more details.

b) Please refer to Exhibit 2B, Section E6.13, page 20, lines18-21, pages 21-22 and page23, lines 1-5.

c) Yes, an explosion of a breaker is classified as a failure.

d) SCADA connected substations enable Toronto Hydro personnel to operate circuit breakers either remotely or manually. In case of substations which are not SCADA enabled, circuit breakers are operated manually, requiring the presence of Toronto Hydro personnel in the area.

e)

i) Legacy circuit breakers include oil breakers, air magnetic breakers and air blast breakers. Please refer to Exhibit 2B, Section E6.13, page 8, lines 4-12, page 9, lines 1-2 for details on legacy breakers.

Table 1: Number of breakers with their respective nominal voltage

Nominal Voltage Rating	Number of TS Breakers	Number of MS Breakers
600 VDC	0	13
4.16 kV	0	535
13.8 kV	605	215

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Nominal Voltage Rating	Number of TS Breakers	Number of MS Breakers
27.6 kV	54	0
Total:	659	763

ii)

Table 2: Number of legacy breakers

Type	Number of Legacy Breakers
MS	500
TS	215
Total:	715

iii) Table 3 shows a list of Toronto Hydro owned legacy circuit breakers that are installed in non-arc resistant switchgear. Non-arc/arc resistant design refers to a feature of the switchgear enclosure. Please refer to Exhibit 2B, Section E6.13 page 9, lines 3-7 for details on Switchgear enclosure type.

Table 3: Number of legacy breakers that are part of non-arc resistant Switchgear

Type	# of Legacy Breakers (Installed in Non-Arc Resistant Switchgear)
MS	500
TS	189
Total:	689

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iv)

Table 4: Number of non-legacy breakers that are part of non-arc resistant Switchgear

Type	Number of Non-Legacy Breakers (Installed in Non-Arc Resistant Switchgear)
MS	190
TS	156
Total:	346

f)

i) Breaker operations are not tracked by Toronto Hydro. A physical operation counter mechanism is present on some (but not all) circuit breakers. However, this data must be manually collected from the field and is not a reliable indicator of the information requested in this question. Counter readings show all breaker operations that have occurred since installation and therefore it is not possible to distinguish between normal and protection operations. In many substations, circuit breaker counters track only three digits and many of the readings have "rolled over" at least once. Lastly, breaker counters are occasionally reset during maintenance and/or repair work.

ii) This data is not tracked by Toronto Hydro and is therefore unavailable.

iii) All failed switchgear mentioned in the table below was of non-arc resistant design:

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Table 5: All recorded Switchgear failures from 2008 to 2013

Year	Type	Number of Failure Events
2008	Metal-Clad	2
	Brick-Structure	0
2009	Metal-Clad	0
	Brick-Structure	0
2010	Metal-Clad	1
	Brick-Structure	0
2011	Metal-Clad	2
	Brick-Structure	0
2012	Metal-Clad	1
	Brick-Structure	0
2013	Metal-Clad	2
	Brick-Structure	1

Note: These were the only recorded failure incidents from 2008 to 2013

iv)

Table 6: All recorded circuit breaker explosion from 2008 to 2013

Year	Station Name	Breaker ID
2008	Jane MS	F1 CB
2011	High Level MS	B18H CB
2012	George & Duke MS	A220GD CB
2013	Bridgeman TS	A52B CB
2013	Ashley MS	T1 CB

Note: These were the only recorded circuit breaker explosions from 2008 to 2013

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v)

Table 7: List of breakers replaced from 2009-2013

Year	Station Name - Bus ID	Type of Breakers Replaced	Age of Breakers Replaced	Number of Breakers Replaced	Health Index
2009	Underwriters' Crouse MS - T1SG	Oil	50	3	Not Available (1)
2009	George & Duke MS - A5-6GD	Air Blast	54	15	Not Available (1)
2010	Terauley TS - A7-8A	Air Magnetic	40	17	Not Available (1)
2010	Carlaw TS - A1-2E	Air Blast	42	12	Not Available (1)
2011	Glengrove TS - A5-6GL	Air Magnetic	53	11	Not Available (1)
2011	Wiltshire TS - A1-2W	Air Blast	57	16	Not Available (1)
2012	Strachan TS - A3-4T	Air Blast	56	12	Not Available (1)
2012	Jane MS - T1-T2SG	Air Magnetic	44	5	Not Available

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Year	Station Name - Bus ID	Type of Breakers Replaced	Age of Breakers Replaced	Number of Breakers Replaced	Health Index
					(1)

(1) Toronto Hydro does not keep records of historical health index. Therefore, this data is not available.

vi) Toronto Hydro does not generally replace individual breaker. Rather, the entire switchgear is replaced as is described throughout the program narrative. Replacement costs for completed switchgear replacement projects are provided in the table below.

Table 8: Capital expenditure of replaced switchgear

Year	Station Name - Bus ID	Cost of Switchgear Replacement (1)
2009	Underwriters' Crouse MS - T1SG	$0.85M
2009	George & Duke MS - A5-6GD	$7.17M
2010	Terauley TS - A7-8A	$9.69M
2010	Carlaw TS - A1-2E	$7.12M
2011	Glengrove TS - A5-6GL	$6.01M
2011	Wiltshire TS - A1-2W	$6.77M
2012	Strachan TS - A3-4T	$4.05M
2012	Jane MS - T1-T2SG	$3.93M

(1) Since Toronto Hydro does not replace one breaker at a time, the cost associated with breaker replacement includes the cost of the entire switchgear as a single entity. This includes equipment such a disconnect switches, circuit breakers, instrumentation equipment, enclosure, and/or protection/control devices.

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vii) Table 14 below shows the breaker OM&A cost for the entire metal-clad switchgear population from 2009 to 2013. Note that the detailed analysis required to allocate these costs to individual segments was only performed back to 2011, and therefore data for 2009 and 2010 is not available.

Table 9: OM&A cost of entire breaker population from 2009 to 2013

Year	2009	2010	2011	2012	2013
Cost	Not available	Not available	$1.2M	$0.9M	$1.4M

g)

i) Confirmed. This table does not represent all the switchgear failures in the years 2001-2008.

ii) The busbar fault at Jane MS was accompanied by a breaker failure and internal fire, resulting in smoke and burn marks in the Switchgear cabinets.

iii) No, it is not.

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iv)

Table 10: Age and HI of failed switchgear

Year	Station Name	Failure Type	Switchgear Age	Health Index
2001	Brimley Seminole MS	Switchgear Failure – Arcing Fault	41	Not Available (1)
2005	Walney MS	Switchgear Failure – Arcing Fault	41	Not Available (1)
2007	Glengrove TS	Switchgear Failure – Arcing Fault	49	Not Available (1)
2007	Terauley TS	Switchgear Failure – Arcing Fault	41	Not Available (1)
2008	Jane MS	Switchgear Failure – Bus Fault	40	Not Available (1)

(1) Toronto Hydro does not keep records of historical health index. Therefore, this data is not available.

v) Confirmed.

vi) Not all of the referenced breakers in the switchgear which are planned for replacement are remotely switchable. Not all of the breakers in the MS and TS

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switchgear are remotely switchable. Only Switchgear that are SCADA connected can be remotely operated.

vii) It is impossible to eliminate the possibility of failure. The purpose of this program is to mitigate unnecessary risk. Manual switching under load is occasionally required to operate the distribution system, as some breakers do not have the ability to be remotely operated. When manual breaker operation is required, Toronto Hydro crews follow the Electrical Utility Safety Rules for Ontario and the Toronto Hydro Supplementary Rules.

h)

i) Pages 36-38 of the Board's "Partial Decisions and Order" for EB-2012-0064 contain the Board Findings for B13.1 Municipal Stations Switchgear and B13.2 Transformer Stations Switchgear. Overall, $0.77M of funding was approved for 2012 and $11.24M of funding was approved for 2013. The Board Findings indicate "The Board accepts the need to proceed with the 4 TS in the IRM period." Toronto Hydro's interpretation is that this is in reference to the following Board statement on page 37 of the same decision: "Board staff argued that it would be reasonable that Toronto Hydro assign a high priority to 4 of the 12 municipal stations and that accordingly, Toronto Hydro's requested $14.24 million should be reduced to $11.24 million." The approved amounts also closely correspond to the forecasted (at the time) in service amounts for all 2012-13 TS switchgear replacement jobs and the four 2012-13 MS switchgear replacement jobs.

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ii) In 2014, $10.66M is currently planned to be contributed to HONI out of the $24.6M budget. The cost breakdown is shown below:

Table 11: Actual and planned HONI payments in 2014

Station Name (Bus ID)	Actual Amount	Planned Amount
Carlaw TS A6-7E	$0.34M	$0.35M
Wiltshire TS A3-4W	$2.14M	$4.57M
Duplex TS A5-6DX	TBD	$2.00M
Strachan TS A7-8T	$1.57M	$3.67M
Windsor TS A5-6WR	$0.075M	$0.070M
Total:	**$4.13M**	**$10.66M**

The amount and schedule of HONI payments are contingent on execution of a Connection Cost Recovery Agreement (CCRA) with HONI. Until this agreement is executed for a given project, costs are estimated based on the best information available to Toronto Hydro at the time. In general, the planned (estimated) costs are based on historical spending for comparable projects. As shown in Table 16, amount to be paid to HONI for replacing incoming breakers includes Wiltshire TS, Strachan TS, Duplex TS and Windsor TS.

i)

i) The components shown in Table 11 are the Net Cost for performing the project in either 2020 or in the first year of activities. Each cost, therefore, contains the same components, but in their respective years. The Net Cost shown in Table 11 is comprised of any sacrificed economic life and any incurred excess risk. The cumulative sacrificed life and excess risk of the assets involved becomes part of

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the net cost along with the project cost. The benefits of the program stem from the savings achieved by performing multiple asset replacements together as opposed to replacing these assets individually. The sum of these values produces the Net Cost for a particular year for that project. Please refer to Section D3.3.1 for more details on the components that produce the avoided risk cost in Table 11.

ii) Customer Interruption Costs ("CIC") is considered in the Avoided Risk Cost calculation. $30 per kVA is used as the Event Cost to represent the CIC value due to the initial period of the outage, and $15 per kVA-hour to represent the CIC value due to the increasing duration of customer outage, as detailed further in Section D3.1.2.1 (i).

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INTERROGATORY 47:

Reference(s): Exhibit 2B, Section E6.14

a) Please state the assumptions on which the Avoided Risk Cost estimate of $2.66 million is based (page 11, Table 1: Summary of Benefits);

b) Please state whether or not there is a primary program to install oil containment around transformers which do not have them, or whether this is only done secondary to the program of power transformer renewals. Please explain Toronto Hydro's risk assessment and vulnerabilities in this regard;

c) At page 17 "Asset Failure Impacts," Toronto Hydro describes the impact of subsequent failures after a first transformer failure. Please describe Toronto Hydro's design policy on ability of the system to maintain supply following a first contingency;

d) At page 23, in discussing the replacement of several transformers it is mentioned that Redcliff transformer, which is 42 years old, and has a health index score of 75, is being replaced because of an overhead bus structure. In other cases it appears that the driving force of the replacement is simply the age rather than the actual condition of the transformer e.g. Centennial has a relatively high health index and is just at theoretical end-of-life:

   i) In deciding to replace a "healthy" and pre-end of life transformer, please explain the process;

   ii) Please explain whether the individual risks involved with that particular transformer is determined;

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iii) It appears that the health index is overridden by the age of transformer, rather than being a screen for examining whether a transformer should be replaced. Please comment on this statement;

e) Referring to Table 8, page 31, it appears that the Total Project Cost for station transformers replacement in the current CIR proceeding has increased significantly over that for the ICM application. Please provide:
   i) a detailed explanation; and
   ii) a breakdown of the cost of a comparable ICM and CIR project.

RESPONSE:

a) Avoided Risk Cost is calculated using the various costs and benefits associated with executing the project in 2015 as opposed to 2020. The assets to be replaced under the power transformer program are all beyond their economic end-of-life. Prolonging the replacement of these assets presents an excess risk to Toronto Hydro due to asset failure. For more information regarding the Avoided Risk Cost, please refer to Section D3.3.1.

The major assumptions considered for the Power Transformer Renewal program Avoided Risk Cost calculation are:

- Condition of assets, captured from Asset Condition Assessment (ACA) as provided in Table 5, E6.14.4.
- Mean (typical) useful life of 45 years for Power Transformers.
- Direct Costs of asset replacement include both capital material costs and labour costs associated with each asset to be replaced. Detailed project cost is provided in Table 8, E6.14.7.

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- Outage duration of each transformer is determined based on system configuration and whether load transferring could be performed remotely or manually.
- Customer Interruption Costs, which consist of event cost ($30/kVa) and duration cost ($15/kVa per hour) as detailed further in Section D3.1.2.1 (i).

b) The installation of oil containments requires major civil and electrical work that necessitates de-energization of the existing in-service transformers, disconnecting all cables from these transformers and relocating these transformers temporarily out of their existing physical locations. This work is necessary to build the civil structure foundation and the dike around these transformers that will drain into the oil containment holding structure to be constructed nearby. There are also many additional electrical risks generated from the required work that can cause damage to the old transformers. For example, when moving the transformers out of their existing physical locations, the transformers' core and coil may move from their proper internal position, introducing additional electrical failure risks. The cost of this work is very high relatively compared to the cost of transformer replacement. For example, the cost of building a new oil containment is approximately $160K when the old transformers are replaced, but this cost could be increased significantly when no transformer is being replaced but oil containment work is required. This is due to the additional cost of moving the existing transformers, disconnecting and reconnecting the cables from the old transformers, cost of switching out the station and load transfer to ensure customers continue to receive service, cost of upgrading the reconnections of cables to comply with new standards (new way of cable terminations, new connector accessories, etc.). All these additional costs add up to make installation of oil containment on existing transformers not an effective investment. For these reasons, Toronto Hydro does not have a primary program for

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oil containment installation, but the utility has a secondary program when the transformers are replaced, then an oil containment system will be installed. There was no formal risk assessment done in the past on power transformer oil containment and related issues. However, Toronto Hydro considers the risk of major oil spillage from power transformers is very low since Toronto Hydro maintenance staff inspects these transformers at appropriate frequency and take corrective actions as required.

c) Toronto Hydro's design policy is N-1 to maintain supply following first contingency of failure of one piece of equipment. For power transformers in Toronto Hydro Municipal Stations, when a power transformer failure occurs, the customers will most likely experience a short interruption, to allow for isolation of the fault, and to allow load transfers to other feeders or stations, to restore customers' service. Under first contingency, all customers should have service, but additional transformer outages (planned or unplanned) may result in an extended outage until the equipment can be placed back in service. This also limits any further outages for maintenance which may have been planned.

d)

i) Except Flemingdon TR1 and Redcliff TR2 which are proposed for replacement for technical considerations (Refer to explanation on page 6, line 11 to 15 of Exhibit 2B, Section E6.14) all the power transformers submitted in this CIR have been in-service beyond the typical useful life of 45 years. As the power transformer ages beyond its typical useful life, its Health Index will continue to deteriorate increasing the failure risk. For example, if the next DGA oil test of a transformer shows there is a thermal fault within the transformer windings, then

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its Health Index will drop significantly from good health index to poor or very poor health index, leaving Toronto Hydro insufficient time to request funding for the capital replacement program. As shown in the Asset Condition Assessment (Exhibit 2B, Section D, Appendix A, page 13), the overall trend of Station Power Transformer Health Indices declined between 2012 and 2014.

Toronto Hydro has paced the power transformer replacement program at a reasonable rate of four to five transformers per year to avoid the sudden ”bow wave” of significant investment required in the future, when an increasingly large number of transformers would reach the failure point within a short time frame. Additionally, this approach aims to optimally utilize construction resources by spreading the work evenly across several years.

Toronto Hydro considers the following factors when determining transformer replacements:

- Current and future asset class demographics (population condition and age)
- Individual asset health index scores, age relative to useful life and FIM results
- Long term need for the station (i.e., voltage conversion plans)
- Coordination with other work needed at the station (switchgear replacements, other transformer replacements, etc.)
- Impact of failure (how many customers would be impacted, how many supporting stations are in the area, etc.)
- Location specific benefits of implementing a modern and standard installation (e.g., elimination of overhead bus structures, installation of oil containment, etc.)

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- Overall program effectiveness, sustainability and efficiency (resource availability to complete the necessary work, "smoothing" of cost/rate impacts, etc.)

ii) The individual risks for the Redcliff TR2 and Centennial TR1 have been determined by FIM using various parameters and assumptions as described in the response to part a) above.

iii) No single input necessarily "overrides" another in a general context. Toronto Hydro uses a diverse set of relevant asset attributes to determine appropriate asset intervention timing. Asset health condition and asset age are both important factors, as are the other considerations listed in part i) of this response. The relative weighting of these factors is considered on a case-by-case basis. A decision to replace a transformer is made holistically given the set of specific circumstances relevant to each individual station.

e)

i) The projects labelled as "ICM" type in Table 8 on page 31 are jobs that began during IRM/ICM period and are planned to be completed in 2015. Partial work on these three ICM projects has been completed, and the remaining costs forecasted to complete the work in 2015 is shown in the table. The total individual project cost is consistent whether the project is ICM- or CIR-type.

The first two ICM projects have been submitted under application EB-2012-0064, Tab 4, Schedule B12, Table 1, page 1, as extracted below:

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Job Title	Project Year	Cost Estimate ($M)
S13155 High Level MS replace TR1	2013	0.47
S13168 Blaketon MS replace TR1	2013	0.54

The third ICM project submitted in the application EB-2012-0064, Tab 9, Schedule C1, Table 12, as extracted below:

Job Title	Cost Estimate ($M)
S13463 Jane MS Install Oil Containment	0.14

Note that S13463 to install oil containment at Jane MS was undertaken in conjunction with a recently completed transformer replacement project at the same station.

ii) As clarification is provided in 47 e) i), the cost of individual project is consistent regardless of whether the project is a carryover job (ICM) or a new job for 2015 (CIR). Below is a breakdown cost of a typical power transformer replacement for the 5/6.7 MVA TR1 transformer at Blaketon MS. Costs can vary depending on transformer size and physical station configuration/layout.

Work Description	Estimate cost ($K)
Materials	330
Equipment	16
Civil	31
Electrical	5
Labour	88
Total	470

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INTERROGATORY 48:

Reference(s): Exhibit 2B, Section E6.15, p. 23

Referring to Table 9 of the above reference, it appears that the Total Project Cost for the replacement of a KSO Oil Circuit Breaker in the CIR Project Type is more than double that of the ICM Project Type.

Please provide:

a) a detailed explanation of this cost differential;
b) the number of replacements and the unit cost of replacements; and
c) a detailed breakdown of the cost of a comparable ICM and CIR project.

RESPONSE:

a) The "ICM" type projects as shown in Table 9 were all started in 2014, and therefore the amount shown in the table represents only the portion of the cost expected to be incurred in 2015. This generally represents the installation portion of the job, as the design and purchase of the circuit breakers is expected to be completed in 2014. The cost of the "CIR" type projects includes the full cost of the project.

b) For the "ICM" project type (i.e., carryover from the ICM period), five units are planned for 2015 (Project Number 21656 will involve installation of two units in 2015, all other projects address a single unit). For the "CIR" type (i.e., "new" jobs for 2015), four units are planned for 2015. The total typical unit cost is the same regardless of whether it is an "ICM" type or a "CIR" type. Since the previous ICM

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application was filed, Toronto Hydro has revised the scope for projects within the Station Circuit Breaker renewal program to include modernization of the feeder protection. The cost impact of this work is an additional $0.09M per project. The total cost for a typical unit, including feeder protection upgrades, is $0.30M.

c) The cost breakdown of a typical circuit breaker replacement project (ICM or CIR) is provided below. For the "ICM" type project, the majority of the 2015 cost is carry-over labour for installation.

Material Cost	Labour Cost	Equipment Cost	Total Cost
$0.11M	$0.18M	$0.01M	$0.30M

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INTERROGATORY 49:

Reference(s): **Exhibit 2B, Section E6.16, p. 7, lines 7-13 and p. 10**

At the first reference, it is implied that the SCADA RTU plays a significant role in avoidance of a fire due to protection failure, by clearing the fault through use of the RTU.

At the second reference, THESL states that many of its municipal substations in Scarborough are not connected to the SCADA system and concludes that as a result it is unable to provide acceptable service to customers. With respect to the first reference:

a) Please clarify why protection, or backup protection would not clear the faults;
b) Please state how the SCADA RTU would assist in the event of an un-cleared fault;
c) Please provide the timeline in which the relay and the RTU might reasonably be expected to assist in clearing a fault.

With respect to the discussion in the second reference regarding expanding the SCADA systems to Scarborough Municipal Stations,

d) Please provide evidence of a significant difference in response times in Scarborough and elsewhere in the city;
e) Since none of the stations in Exhibit 2B, sections E16.3 or E16.5 are in Scarborough please confirm that none of the circuit breakers which will be monitored and controlled by the new RTUs require breaker upgrades which are a part of the Switchgear Renewal Program (Exhibit 2B, section E6.13) or Circuit Breaker Renewal Program (Exhibit 2B, section 6.15);
f) Please identify the specific stations and the matching breakers where the new RTUs are to be implemented.

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RESPONSE:

a) If operating properly, feeder protection or backup protection will trip the breaker and isolate the fault.

b) In the event of an un-cleared fault, the SCADA RTU can provide supplementary information to the controller to help determine the location of the fault. The SCADA RTU primarily adds value by accelerating the restoration process once the fault has been cleared.

c) When a fault occurs, the protective relays trip the circuit breaker almost immediately to isolate the fault. When connected to a SCADA RTU, the control room will have immediate indication that a fault has occurred, the feeder where the fault occurred, as well as an accurate representation of the current system state. This greatly assists with power restoration efforts. Please refer to Exhibit 2B, Section E6.16, page 8 for more details on RTU operation.

d) Table 1 and 2 shows a randomly selected set of historical downstream cable faults. As evidenced by this data, substations with SCADA connection had a much lower response time in comparison to substations with non-SCADA status.

Table 1: Non-SCADA substation with fault clearing response times

Non-SCADA Substations			
Station Name	Fault Description	Restoration Time (Hours)	Area
Galloway Dearhamwoods MS	Downstream cable fault	3.73	Scarborough

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Non-SCADA Substations			
Station Name	Fault Description	Restoration Time (Hours)	Area
Lawrence Mccowan MS	Downstream cable fault	4.58	Scarborough
Brimley Seminole MS	Downstream cable fault	4.33	Scarborough
Pemberton MS	Downstream cable fault	2.66	North York

Table 2: SCADA connected substation with fault clearing response times

SCADA Connected Substations			
Station Name	Fault Description	Restoration Time (Hours)	Area
Leslie MS	Downstream cable fault	0.52	North York
High Level MS	Downstream cable fault	0.63	Toronto
Constellation MS	Downstream cable fault	0.67	Etobicoke
Renforth MS	Downstream cable fault	0.71	Etobicoke

e) The references provided in the question (Exhibit 2B, Sections E16.3 and E16.5) are unclear. Toronto Hydro infers that the intent of this question is to confirm that there are no plans to proactively upgrade or replace the switchgear and/or circuit breakers at MS locations where SCADA RTU connectivity is planned to be added under this program. Toronto Hydro can confirm this. None of the circuit breakers which are discussed in Exhibit 2B, Section E6.16 (Station Control & Monitoring Program) as part of the RTU upgrades or SCADA expansion in Scarborough Municipal Stations are included in Exhibit 2B, Section E6.13 (Circuit Breaker Renewal Program) or Exhibit 2B, Section E6.15 (Switchgear Renewal Program) for breaker upgrades.

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f) See Table 3 below:

Table 3: New RTUS and Respective Breaker Type

Year	Project Type	Station	Breaker Type
2015	RTU Replacement	Blaketon MS	Air Magnetic
2015	RTU Replacement	Walney MS	Air Magnetic
2016	RTU Replacement	Albion MS	Air Magnetic
2016	RTU Replacement	Centre Drive MS	Vacuum
2016	RTU Replacement	Palmwood MS	Air Magnetic
2016	RTU Replacement	Annabelle MS	Air Magnetic
2016	RTU Replacement	Royalcrest MS	Vacuum
2016	New RTU Installation	Ellesmere Kennedy T1 MS	Air Magnetic
2016	New RTU Installation	Ellesmere Kennedy T2 MS	Air Magnetic
2016	RTU Replacement	Esplanade TS	SF6/Vacuum
2017	RTU Replacement	Fieldway MS	Air Magnetic
2017	RTU Replacement	Humberline MS	Air Magnetic
2017	RTU Replacement	Gunton MS	Air Magnetic
2017	RTU Replacement	Constellation MS	Air Magnetic/Vacuum
2017	RTU Replacement	Redcliff MS	Air Magnetic
2017	New RTU Installation	Lawrence Mccowan MS	Air Magnetic
2017	New RTU Installation	Progress Markham MS	Air Magnetic
2017	RTU Replacement	Main TS	Air Magnetic/Vacuum
2018	RTU Replacement	Dalegrove MS	Vacuum
2018	RTU Replacement	Burnhamthorpe MS	Air Magnetic
2018	RTU Replacement	Hunting Ridge MS	Air Magnetic
2018	RTU Replacement	Centennial MS	Vacuum
2018	RTU Replacement	Westmore MS	Air Magnetic
2018	New RTU Installation	Brimley Shaddock T1 MS	Air Magnetic
2018	New RTU Installation	Brimley Shaddock T2 MS	Air Magnetic
2018	RTU Replacement	Cecil TS	Air Magnetic/SF6/Vacuum

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Year	Project Type	Station	Breaker Type
2018	RTU Replacement	Duplex TS	Air Magnetic
2019	RTU Replacement	Marmac MS	Air Magnetic
2019	RTU Replacement	Meteor MS	Air Magnetic
2019	RTU Replacement	Dunsany MS	Vacuum
2019	RTU Replacement	York MS	Oil/ Air Magnetic
2019	RTU Replacement	Windsor MS	Air Magnetic
2019	New RTU Installation	Kennedy Eglington MS	Oil
2019	RTU Replacement	Charles TS	Air Magnetic/Vacuum
2019	RTU Replacement	George & Duke TS	Air Magnetic/Vacuum

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INTERROGATORY 50:

Reference(s): **Exhibit 2B, Section E6.17, p.7**

According to the above reference, 8 of the 20 breakers that use compressors to operate are not at the end of their life but require new compressors.

a) Please state whether or not THESL will be making use of the 12 compressors (for spares) that are no longer required to maintain the 8 compressors that are still required;
b) Please indicate the additional situations where the station service transformer and the associated secondary distribution panel are located in the basement (Exhibit 2B section E6.17, page 18, lines 10-13.);
c) At page 22, at line 10, THESL advises that there are no spare 125MVA 230-27.6kV transformers. Please indicate how many of these transformers exist in the THESL system or will be added in the next five years, and what arrangements there are to find a replacement if required on an emergency basis;
d) Please state whether or not there are any arrangements with other utilities to share spares.

RESPONSE:

As a general point of clarification, the question posed erroneously states “8 of the 20 breakers that use compressors to operate are not at the end of their life but require new compressors.” There are significantly more than 20 breakers that rely on the 20 **air compressors** referenced in the narrative. In this context, air compressors serve an entire

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switchgear lineup which consists of multiple individual circuit breakers. The terms "switchgear" and "breakers" are **not** synonymous.

a) The 12 compressors that will be retired (compressors that are no longer required) will be used as spare parts for the remaining compressors, provided they are compatible with the remaining ones, since Toronto Hydro has different sizes of compressors depending on the number of circuit breakers that the existing compressors are required to operate.

b) There are three more stations whose station service transformers and/or the associated secondary distribution panel are located in the basement, but these stations have no readily available space above ground. The relocation of this equipment is being postponed until above grade space in the station is made available in the future.

c) Currently Toronto Hydro has two 125MVA, 230-27.6kV transformers in its distribution system. Two additional transformers of a similar voltage rating may be added as part of the Station Expansion program. At this point, no final decisions have been made regarding transformer specifications. Toronto Hydro does not currently have any formal arrangements in place to secure a replacement transformer on an emergency basis, but options do exist and such an approach is being explored.

d) Refer to response to part c).

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INTERROGATORY 51:

Reference(s): **Exhibit 2B, SectionE6.20, p. 3**

Future Reactive Capital budgeting is shown as exceeding $30m per year. Failures which require the use of Reactive Capital would likely include older and end-of-life equipment which is the subject of another capital expenditure category e.g. a breaker might fail which is already the subject of a program for renewal at a later year. Therefore it might be expected that use of the budget for reactive capital would result in the reduction of planned expenditures in other categories.

a) Please state to what extent THESL has been able to determine whether or not for historical years the use of the budget for reactive capital resulted in reductions of planned expenditures in other categories;
b) Please state to what extent and how this is reflected in the budget for reactive capital.

RESPONSE:

a) In a typical year, expenditures in the Reactive Capital Program result in little reduction to planned expenditures in other categories in that year. For example, in 2013, the Reactive Capital Program only impacted approximately $0.6 million of total (i.e., $231.1 million) System Renewal work. The reason for this is that the Reactive Capital Program addresses unplanned and typically dispersed asset failures across all of Toronto Hydro's electrical and civil assets. The probability that a like-for-like replacement of a failed or failing asset addresses an exact asset that is identified in a planned program is low. Furthermore, even when assets that are

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replaced by the Reactive Capital Program are part of a planned project, the replacement may not address the planned project's need. For example, a 4kV circuit breaker that failed may be replaced under the Reactive Capital portfolio, but the equipment may be decommissioned shortly after due to a voltage conversion project.

b) The potential for Reactive Capital to reduce the need for planned expenditures in other categories is not considered when budgeting Reactive Capital expenditures. This is because when the need arises for Reactive Capital expenditures on a particular asset, it would take precedence over future planned work. Please see Toronto Hydro's response to 2B-AMPCO-12 for more information on how Toronto Hydro projected the Reactive Capital budget over the application period.

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INTERROGATORY 52:

Reference(s): **Exhibit 2B, Section E6.21**

This section discusses planned expenditures for worst performing feeders.

Please state whether or not expenditures to correct Worst Performing Feeders is over and above other programs of replacement and renewal e.g., where a breaker or cable is replaced, would it appear in any other program as well.

RESPONSE:

The Worst Performing Feeders ("WPF") program is designed to execute short-term mitigation work by strengthening feeders in order to provide interim reliability relief until longer term renewal projects can be designed and constructed. If a renewal project has been issued for a portion of a feeder that is experiencing failures, no asset replacements would be issued through the WPF program for that portion of the feeder. Assets are replaced through the WPF program if those assets are not in a renewal project that has already been issued. As such, assets being replaced through the WPF program would not appear in any other project included in this filing.

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INTERROGATORY 53:

Reference(s): Exhibit 2B, Section E6.22

THESL states that it is planning to replace 117km of optical fibre because it is shared with Cogeco Data Services.

Please state whether or not THESL has considered instead negotiating with Cogeco to ensure there is no geographic duplication of alternate function communications, so that dependability can be obtained without duplicating a fibre network that exists. If not, please explain why not.

RESPONSE:

Toronto Hydro has considered the option of negotiating with Cogeco. However, Cogeco Data Services' (CDS) network is built to their specifications and adequately meets their needs. Toronto Hydro is essentially using strands inside of Cogeco's fiber-optic cable bundles shared with hundreds of other customers.

Since the network meets all of Cogeco's needs, there is no reason for them to change their core infrastructure based on one customer's demands. In this regard, Toronto Hydro would have to incur the costs of relocating its Service Provider's (Cogeco) infrastructure, rather than its own, an endeavour that will cost more than running Toronto Hydro-owned fiber. This is primarily due to all of the associated overhead costs including Cogeco labour, equipment, markups, etc. In addition, Toronto Hydro will still maintain complete

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dependence on the Service Provider. As a result, Toronto Hydro finds it prudent to replace the optical fiber that is shared with Cogeco with Toronto Hydro-owned fiber.

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INTERROGATORY 54:

Reference(s): **Exhibit 2B, Section E7 and**
Ontario Energy Board Filing Requirements for Electricity Transmission and Distribution Applications Chapter 5 Consolidated Distribution System Plan Filing Requirements March 28, 2013, p.ii.

A number of the program descriptions in the first reference which are described as "service" category appear to be programs of "renewal", rather than service, and vice versa or alternatively appear to duplicate what is provided for under the category of system renewal.

The definitions provided in the second reference are:

> System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of the distributor's distribution system to provide customers with electricity services.

> System service investments are modifications to a distributor's distribution system to ensure the distribution system continues to meet distributor operational objectives while addressing anticipated future customer electricity service requirements

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The Renewal Project for the Network Reconfiguration in exhibit 2B, section 6.12 describes plans to reconfigure the "functionally obsolete network system into enhanced mini-grids".

a) At Exhibit 2B section E6.12, page 1, lines 8-11 THESL describes "plans to upgrade the secondary grid by splitting large grids into more robust spot vaults and enhanced mini-grids, each with fewer primary feeders."
   i) Please state how is this different from the Option (II) in Section E7.1 page 3, lines 11-12 described as: "Enabling feeders to be segmented into smaller sections gives system controllers greater ability to transfer loads and minimize the number of customers impacted during power outages…';
   ii) Please provide a detailed breakdown of the Total Annual Spend estimates for 2015-2019 for both E6.12 (Table 5 page 36) and for E7.1 (Table 5 page 22);
   iii) Please explain how Section 6.12 and section 7.1 programs differ;

b) Board staff notes that the replacement of existing switches with autonomously operating SCADA switchers has a character of both replacement and enhancement and has been categorized as service rather than renewal. Please indicate the proportion which is ascribed to service and to renewal.

RESPONSE:

a)
   i) The Network Circuit Reconfiguration program is dealing with assets within the secondary network system in the downtown core, whereas the Contingency Enhancement program is dealing with looped distribution assets in the horseshoe

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– these sets of assets and configurations behave in fundamentally different ways during contingency events. No secondary network customers experience service interruptions during any first contingency conditions, and often only limited numbers of secondary network customers experience service interruptions during second contingency conditions. Multiple contingency conditions, however, often require the entire network grid to be dropped in order to avoid critical equipment overloads, resulting in the loss of all customer loads. Customers connected to looped distribution systems in the horseshoe will always experience service interruptions during any contingency conditions.

The Network Circuit Reconfiguration program, further detailed in Section E6.12 of Toronto Hydro's Distribution System Plan, maximizes customer reliability by splitting existing large network grids into robust spot vaults and mini-grids, thereby allowing the connected customers to ride through multiple contingency failures with only a small percentage of customers interrupted. This program is driven by the need to prevent the secondary network system from becoming functionally obsolete due to the mix of radial and network loads that exist today, as opposed to the pure network loads that the system was designed for. The execution of this program will provide the necessary flexibility for this system to adapt to this new standard.

The Contingency Enhancement program, further detailed in Section E7.1 of the Distribution System Plan, maximises customer reliability by minimizing the impact of individual feeder failures. Unlike the Network Circuit Reconfiguration program, in which existing secondary network grids will be reconfigured, the Contingency Enhancement program involves targeted upgrades to undersized

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feeder trunk egress cable and undersized looped conductors along horseshoe distribution feeders. Increased contingency capability in this case means improved ability to isolate failed portions of horseshoe distribution feeders, as well as improved ability to transfer customer loads to alternate feeders. This program is ultimately driven by the need to enhance reliability on the associated horseshoe distribution feeders.

Strategically, the Network Circuit Reconfiguration program serves to eliminate the *functional obsolescence* risk of the secondary network system through the re-configuration of the network grids – customer reliability will also be maximized across the interconnected grid system as a whole, and this has been noted as a secondary driver to this particular program. On the other hand, Contingency Enhancement's focus is strictly on maximizing the *reliability* for each individual looped distribution feeder, and this is reflected as the trigger driver for this program. Based on the above *primary drivers*, Network Circuit Reconfiguration has been positioned within the System Renewal investment category, and Contingency Enhancement has been positioned within the System Service investment category.

ii) Spending for 2016 in Table 5 of E6.12 was projected based on three proposed network reconfiguration projects at Carlaw East, Carlaw West and Cecil North networks, as well as four proposed projects to replace equipment at locations CTS, DHC, ECE and PCS with 600Y/347V network equipment. Spending for 2017 to 2019 is proposed to remain at a level similar to proposed 2016 spending in order to sustain a consistent ongoing effort to address network circuit reconfiguration issues.

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The breakdown of total 2015 spending on program E7.1 Contingency Enhancement is detailed in Table 8 of section E7.1.6. Spending for 2016 to 2019 in Table 5 of E7.1.4 involves similar projects to those in 2015, but the particular projects and spending each year varies to most efficiently and cost effectively coordinate with planned asset renewal projects in other programs.

iii) Please see response i) for details on the differences.

b) The Contingency Enhancement program is focused on improving and enhancing reliability on horseshoe distribution feeders through targeted upgrades of undersized trunk egress cables and looped conductors along with the installation of additional SCADA-enabled tie and sectionalizing points, such that overall restoration and isolation times can be reduced when an outage takes place. In some instances, new SCADA-enabled switches will be installed at given locations, whereas in other cases, existing switches may be strategically replaced with SCADA-enabled switches where a need exists to improve restoration and isolation capability. It is critical to note that the driver to replace these switches remains aligned to the trigger driver of the program; to enhance reliability, which is a driver applicable to the System Service investment category.

The replacement of these switches is not driven by drivers applicable to System Renewal investments, including failure risk (of the switch) or functional obsolescence. Section 5.1.1 of Chapter 5 – Consolidated Distribution System Plan Filing Requirements states that “a project or activity involving two or more ‘drivers’ associated with different categories should be placed in the category corresponding to the ‘trigger’ driver”. Therefore, all portions of the capital investments associated in

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the Contingency Enhancement program are associated to the System Service investment category.

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INTERROGATORY 55:

Reference(s): **Exhibit 2B, Section E7.2**

At page 32 the title of the Project is "E7.2.7.2 W15493 Overhead Design Enhancement on Fairbanks TS"

At page 35 the title of the subsequent project is "E7.2.9.2 W15495 Overhead Design Enhancement on Finch TS and Jane MS":

a) Please discuss and explain the numbering of the projects since they are not consecutive and sections appear to be missing e.g. E7.2.3 through E7.2.9.1. If any corrections or additions are necessary, please provide them;
b) At page 35, the title of the project refers to Finch TS and Jane MS, but the Objective refers to Fairbanks TS. Please correct or clarify.

RESPONSE:

a) The numbering of the projects in this section contains errors. There are three projects in total, with the following sectional numbers:
    1) E7.2.7.1 X14211 35M10 Fuse Coordination
    2) E7.2.7.2 W15493 Overhead Design Enhancement on Fairbanks TS
    3) E7.2.7.3 W15495 Overhead Design Enhancement on Finch TS and Jane MS

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b) The objective of this project contains an error. The correct objective is “The objective of this project is to convert portions of the trunk feeder on Finch TS and Jane MS into fused laterals”.

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INTERROGATORY 56:

Reference(s): Exhibit 2B, Section E7.3

Table 6 at page 27 shows that almost $20m has been spent between 2010 and 2014 on the Feeder Automation program.

a) Please state the date up to which the above referenced spending was current and the extent of any additional spending since that date;
b) Please provide a breakdown of the annual Capex (spent and in-service) in Table 6, including that portion which was/is for the downtown URD and for the Horseshoe area;
c) Please explain what was done and achieved in the years up to and including 2014 in the downtown and Horseshoe areas;
d) Referring to the trend of outage duration in Figure 15 for URD service, please provide any available evidence that the program of Feeder Automation will result in reduced "average minutes out" for customers;
e) Please state whether or not THESL has undertaken a demonstration project in the Horseshoe or downtown area for the proposed feeder automation which showed that improvements will likely result when the automation is applied in the URD downtown area. Please provide the evidence used to demonstrate the value of the program of $11m in the first year;
f) During 2015 THESL proposes a program of deployment in the Downtown URD system (E7.3.4 p28, line 13-21). Please state whether or not this has been preceded by a test program in the horseshoe area.

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RESPONSE:

a) The spending referenced in Table 6 was current as of July 2014 for the annual total forecast of each year. There has not been any additional spend planned since that date.

b) The only fully automated area that is in service is the pilot project area that was commissioned in 2010. All other spending has been for the installation of SCADA-Mate switches with automation hardware and software. Because the Feeder Automation program was denied funding in the 2012 ICM filing in 2013, many of the projects were not commissioned for automation and are not online as a fully automated system. The spending following the ICM decision in the spring of 2013 was to install the SCADA-Mate switches already purchased and to fulfil contracts that could not be cancelled. The switches installed are feeder automation ready and are currently in-service as remotely operable switches until they are commissioned to be part of an automated system. All spending up to 2014 was for the horseshoe area.

c) The following information supplements the map included in Exhibit 2B, Section E7.3.2, page 7, Figure 1.

1) Horseshoe Area
   - 2010: The feeder automation pilot project (zone 1) was constructed and went online in 2010, involving ten feeders.
   - 2011: Due to the promising operation of the 2010 pilot project, Toronto Hydro decided to expand the automation network with 12 new feeders (zone 2), installing switches on one feeder in 2011. Two more phases were planned

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for 2012: zone 3a consisting of ten new feeders and zone 3b consisting of 13 new feeders.

- 2012: Construction of zone 2 continued and the construction of zone 3a and zone 3b began. Planning for three new phases was included for 2013: zone 4a consisting of nine feeders, zone 4b consisting of eight feeders, and zone 4c consisting of 14 feeders; Planning for zone 5b for 2014, consisting of 14 feeders, also took place in 2012.
- 2013: The feeder automation program was denied funding and all remaining work that could not be stopped due to equipment purchased or contractual obligations continued. Installation of equipment in zones 2, 3a and was completed, with the commissioning of automation deferred to 2015. Installation of equipment on nine feeders in zone 4a and zone 4b was also completed, with the exception of commissioning of automation. Installation of three feeders in zone 3b with the majority of the remaining 11 feeders was completed. The remaining work on the 11 feeders was continued into 2014. All other work was stopped and deferred to 2015.
- 2014: The remaining work on the 11 feeders for zone 3b is to be completed in 2014.

2) URD:
   - The URD system is scheduled to begin its pilot phase in 2016 and continue expansion in 2018 if the pilot is successful. No feeder automation work was done in the URD system from 2010 through to 2014.

d) Since no test installation of the URD automation equipment has been conducted, firm reliability savings can not been demonstrated. Logically, based on system historical

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performance and the proposed function of the URD automation scheme, Toronto Hydro expects that a decrease in average outage duration can be realized.

Of the complete history of underground cable faults on URD feeders from 2000-2013, 57% of the faults occurred on the main loop of the URD feeder. The outages on the main loop of these feeders had an average outage duration of 141 minutes. Since any outage on the main loop could be restored remotely solely by using the proposed SCADA-enabled 600A switch and the (already) remote operable station breaker, outage times could be significantly decreased to as little as 30 minutes based on practical experience on overhead feeders with SCADA switching available on the feeder trunks. System operators would also be able to identify these outages as main loop outages based on the readings from the SCADA switches.

Of the remaining 53% of cable faults which are not on the main loop, system operators would also be able to determine the location of the fault from the SCADA FCIs, perform any 600A switching remotely and be able to dispatch crews to the correct locations for manual restoration (for 200A switching or for isolation at transformer feed-throughs). This would result in substantial restoration time savings since crews would not need to locate faults before restoring the outage. As discussed in Exhibit 2B, Section 7.3, fault locating is often the most time-consuming process in URD restoration due to the complex configuration combined with the existing unreliable FCIs.

For these historic non-main loop faults, it took an average of 122 minutes for the first step of the restoration to occur (i.e., when switching would have begun). Most of this time can be attributed to fault location before beginning to switch (since a crew

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arriving on site should only take 30-40 minutes). It can be reasonably estimated that there should be significant restoration time savings if fault locating can be done remotely in a matter of minutes based on information available via SCADA (switches and FCIs).

e) Toronto Hydro has not undertaken any demonstration projects in the Horseshoe area for URD automation. URD equipment/feeders are only located in the old Toronto 13.8 KV distribution area. The first installation of commissioned URD automation equipment is planned for 2016 as outlined in the Exhibit 2B, Section 7.3 (following the test switch installation in 2014/2015); Toronto Hydro expects for this installation to be tested in 2018. Exhibit 2B, Section 7.3 does not state that the program will produce a value of $11 M in the first year.

Any analysis of the value of this program in Exhibit 2B, Section 7.3 is limited to the first year (as with all programs) and there are no URD automation projects currently scheduled for 2015. The cost of the test switch installation would be borne reactively since a low gas switch candidate would be used for this test change out (since it would not make sense to replace a failed switch with a now obsolete switch style). A low gas switch on the defective equipment list has already been identified for this installation.

f) The 2014/2015 installation is limited to the installation of a new 600A switch to test the physical switch itself, as opposed to the automation scheme which Toronto Hydro expects to be tested in the 2016 full feeder installation on A310CE. Neither of these has, nor will be, preceded by a test in the Horseshoe area since the URD system configuration only exists in the old Toronto 13.8 kV distribution area.

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INTERROGATORY 57:

Reference(s): Exhibit 2B, Section E7.9

At page 17, line 5 through 18, the design of the THESL system is described as N-1 design.

At page 22, in lines 2-3 it is stated that "For planning purposes, Toronto Hydro considers a bus ... to be overloaded when it reaches 95% of the rated capacity."

a) Please clarify whether or not the entire distribution system is based on this design principle;
b) Regarding the N-1 principle:
   i) Please clarify if the "N-1" design accounts for a single outage, whether it be for maintenance or due to an equipment failure;
   ii) Please state whether or not this would imply that if a single transformer is out of service, and a fault occurs in the remaining supply configuration, then the customer load would be without power;
   iii) Please state whether or not this would also mean that there would be no interruption of power if, with all elements in service, a first element goes out of service through equipment failure;
   iv) Please state whether or not the N-1 design includes taking into account the possible availability of manually doing switching interconnections between transformer stations;

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c) At page 18, line 8, point (5) indicates "An adjustment factor of 70% is applied to the load requested by customers to reflect past experience of load being overstated at the application phase:
   i) Please state whether or not this past experience has been verified by any study comparing requested loading with actual loading;
   ii) Please describe how the 70% adjustment factor is applied;
   iii) Please state whether or not there are any percentage allowances introduced by THESL in the design process for equipment ratings;

d) At page 22, lines 10-11 it is stated that "As shown in the load forecast, within ten years, six of the buses supplied from Windsor TS, Copeland TS and Esplanade TS are forecasted to require capacity relief." Given THESL's statement quoted above that for planning purposes, it considers a bus to be overloaded when it reaches 95% of the rated capacity, please clarify how this conclusion is reached given that only one bus (Windsor, 2014) is shown at 95% loading, and none exceed the 95% level;

e) Please state whether or not similar capacity problems are also occurring elsewhere in Toronto, such as North York;

f) At page 2 THESL is proposing a new THESL owned transformer station in the Manby TS area:
   i) Please indicate why THESL would want this to be a THESL station, rather than a Transmitter owned TS;
   ii) Please state what is THESL's inventory of transformers of this size and how many spare transformers of this size/rating are available to THESL;
   iii) Please state THESL's strategy on spare transformers;

g) At page 29, lines 11-13, THESL is proposing to expand Copeland TS including the addition of three power transformers:

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  i) Please state whether or not Copeland TS (Phase 2) will involve the same rating of transformers as the proposed new Manby TS and as any other THESL TSs;
  ii) Please explain the rationale and economics for having a backup third transformer on potential and how this is consistent with the N-1 design philosophy;
  iii) Please state whether or not this design philosophy is applicable and intended in other transformer stations;

h) In general please provide an explanation for the apparent decision to extend ownership of the major (115 or 230kV high side) power transformers. Please include in the discussion:
  i) The current inventory including sizes and voltages of the power transformers owned by THESL and Hydro One;
  ii) Discussion of the maintenance of these transformers and the economics of THESL doing this versus Hydro One doing it;
  iii) Discussion of any spares or maintenance arrangements with Hydro One or other utilities which would reduce the common cost of ownership, maintenance and operation of major power transformers.

RESPONSE:

a) N-1 design principles are applied across the entire distribution system in circumstances where the risk of losing a single element outweighs the cost of redundancy. The statement “For planning purposes, Toronto Hydro considers a bus to be overloaded when it reaches 95% of the rated capacity,” specifically applies to station equipment in the former Toronto area.

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b)

i) Yes, a system designed based on N-1 principles will allow any single element to be taken out of service (on a planned or unplanned basis) without requiring an extended outage.

ii) If a single transformer was out of service, the system would be operating in a contingency state. An outage to the remaining transformer would result in an outage until such time that one of the two transformers could be placed back in service.

iii) With all elements in service, a fault or equipment failure of a single element may still result in a brief outage (depending on system configuration), however N-1 ensures that an alternate supply is readily available to restore power prior to any repairs or equipment replacements.

iv) At the feeder level, availability of ties between feeders from other stations would be considered for meeting N-1 design criteria. At the station level, inter-station ties would generally not be taken into account, unless the inter-station tie was sufficiently sized to carry the entire station load and station peak loading was kept to below 50% of design capacity (assuming a tie between two stations). These conditions are not true for any stations in Toronto Hydro service territory.

c)

i) Yes, this assumption was established as a result of an analysis comparing the amount of load requested by a set of customers to the amount of load that had actually materialized 1, 2, 3, 4 and 5 years after the in service date.

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ii) The amount of load requested by a customer is multiplied by 0.7, and the product is the total amount of load added to the forecast for that specific customer.

iii) Toronto Hydro is unable to answer this question as the meaning of the term "percentage allowances" in this context is unclear.

d) The table referenced by page 22, lines 10-11 shows 6 individual busses exceeding 95% of their rated capacity: A3-4CL (Copeland), A1-2GD (Esplanade), A3-4GD (Esplanade), A17-18WR (Windsor), A3-4WR (Windsor) and A5-6WR (Windsor). The forecasted peak load for these busses is highlighted red when 95% capacity is exceeded.

e) At this time, there are no major capacity issues which require intervention outside of the general areas referenced in this narrative (the former City of Toronto and southern Etobicoke/York).

f)

i) Regardless of the ultimate ownership arrangement of a new transformer station, Toronto Hydro would expect to be responsible for contributing a significant portion of the capital cost (either directly or through a capital contribution to the transmitter). The proposed new station would primarily, if not exclusively, serve the purpose of supplying existing and future Toronto Hydro customers. Building and owning a new transformer station provides Toronto Hydro with the ability to implement a solution that best serves its customers needs while maintaining responsibility, accountability and control over construction costs and schedule.

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Such an approach would not be expected to result in a material increase to the total project cost and would guarantee that Toronto Hydro has operational control of and responsibility for the upstream equipment that is critical to the supply of Toronto Hydro customers (such as feeder circuit breakers and transformers).

ii) The technical specifications of the transformers that would be employed at a new TS have not been established at this point; however, Toronto Hydro does not currently own any spare transformers which are likely to be usable as spares for a new transformer station as proposed here.

iii) Toronto Hydro employs a probabilistic model to determine how many spare power transformers of each type should be available to optimize the balance between system risk and ownership cost. In most cases, spare transformers are acquired by recovering used transformers from municipal stations which have been decommissioned due to load conversions. In the case of transformer types with very small system populations (i.e., the two 230/27.6 kV transformers installed at Cavanaugh TS), Toronto Hydro is exploring various options for sharing agreements with other North American utilities. This is seen as a viable option because the transformers at Cavanaugh TS are of a standard, widely used design (i.e., oil-filled).

g)

i) Copeland TS supplies a 13.8 kV distribution area, whereas the proposed new TS in the Manby area will supply a 27.6 kV distribution area, and thus they will require transformers with different design ratings. From a voltage and capacity perspective, Copeland TS will employ transformers which are similar to other

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power transformers at transformer stations in the 13.8 kV former Toronto area. That said, Copeland TS transformers will be of a gas-insulated design (versus oil-insulated) and therefore will not be interchangeable with any other transformers in Toronto Hydro's distribution system.

ii) Copeland TS is designed to accommodate five gas-insulated transformers (two installed as part of phase 1 to supply the first two busses, provisions for two additional transformers to supply two additional busses, and provisions for a fifth on-potential spare transformer). With four transformers, the station meets N-1 criteria. However, gas-insulated transformers have a unique physical size, footprint, form factor and HV/LV termination requirements and thus are not interchangeable with conventional oil-insulated transformers). They are also not widely used throughout or manufactured within North America and require significant lead times to manufacture. With two transformers installed per set of two busses, in the event of a single transformer failure, supply to up to 72 MVA of load will be under first contingency for an unacceptably long time (approximately 15 months based on lead times for Copeland TS phase 1). During this time, if the remaining transformer is removed from service (due to maintenance, a fault, a catastrophic failure, etc) Toronto Hydro will be unable to supply this load until the transformer can be placed back in service. If the second transformer is damaged such that it is not usable, this would result in an extremely long and costly outage.

iii) This design philosophy would be considered for any station with specialized equipment (i.e., not easily replaceable) performing a critical function. All other transformers at stations in Toronto Hydro service territory are oil-insulated and

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thus replacement units would ostensibly be easier to procure on an emergency basis.

h) Please refer to the response to part (f). With respect to the specific points raised in this part of the question:

- Toronto Hydro does not currently have any spare transformers that would be suitable for use at the proposed new TS. Toronto Hydro does not have any details regarding HONI's spare transformer inventory. That said, the station would in all likelihood be built with a standard transformer configuration such that spares could be expected to be available from other North American utilities. Alternatively, Toronto Hydro may determine through a cost of ownership analysis that it is prudent for the utility to purchase its own spare unit.
- Toronto Hydro is already responsible for maintenance of two 230 kV power transformers at Cavanaugh TS and 200+ municipal station transformers. Toronto Hydro sees no reason why the cost of maintenance would differ in a material manner whether HONI or Toronto Hydro completed the work.
- Toronto Hydro does not currently have any spares arrangements with HONI or other utilities. Provided it was proven to be feasible and prudent, Toronto Hydro would certainly explore all opportunities to reduce the common cost of ownership through such agreements.

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INTERROGATORY 58:

Reference(s): Exhibit 2B, Section E8.1

a) Table 1 on page 9 lists vehicle Assets to be replaced. Please provide the 2014 inventory for each Asset Class;

b) Table 4 at page 16 provides the 2013 Vehicle Replacement Criteria. Please clarify if Age and Km criteria must both be met, or if just one of the criteria must be met;

c) Please provide a copy of the reference at the bottom of page 16, titled "Toronto Hydro Life Cycle Cost Analysis & Peer Fleet Comparison, - Final report 23 May 2013;

d) Please explain the processes for acquisition and disposal of vehicles i.e., tendering, trading RFPs etc.

RESPONSE:

a) The 2014 Inventory for each Asset Class is provided in the table below:

Vehicle Description	Number (In-Service) as of October 20, 2014
Car	23
Cube Van	57
Double Bucket up to 50’	8
Double Bucket 51’ to 64’	35
Double Bucket 65’+	2
Full Size Van - Cargo	53
Line Truck	6

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Vehicle Description	Number (In-Service) as of October 20, 2014
Crane Truck	20
Cable Truck	6
Derrick Truck	16
Dump Truck	9
Minivan-Cargo	75
Minivan-Passenger	18
Pickup	99
Single Bucket-Van Mounted	7
Single Bucket Truck	81
Small Digger Truck	1
SUV	31
Forklift	29
Trailer	54
Sweeper	4
Backhoe	2
Miscellaneous Equipment	14

b) Please see Exhibit 2B, Section 8.1.4.1 for a full discussion on how both criteria are used to determine fleet replacements.

c) A copy of *Toronto Hydro Life Cycle Cost Analysis & Peer Fleet Comparison (Element 2) Final Report* prepared May 23, 2013 is provided as Appendix A to this Schedule.

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d) Acquisition Process:

1) Vehicles are acquired per Toronto Hydro's Procurement Policy (please see Exhibit 4A, Tab 3, Schedule 2).

Disposal Process:

1) Vehicles that have been replaced are tagged for disposal.
2) Vehicles to be disposed of are prepared for transport. Minor repairs may be made to increase the resale value of the vehicle.
3) Toronto Hydro contacts one of its disposal vendors to transport the vehicles to the disposal site. Toronto Hydro currently disposes of the vast majority of its vehicles via public auction.
4) Sale proceeds are sent from the vendor to Toronto Hydro.

Toronto Hydro Fleet Life Cycle Cost Analysis & Peer Fleet Comparison (Element 2)

- Final Report -

Prepared by Richmond Sustainability Initiatives

May 23, 2013

TORONTO HYDRO

Executive Summary

Introduction

Toronto Hydro is interested in refining its fleet capital replacement program to account for vehicle historical and operational performance, and more specifically, optimizing replacement cycles by applying Life Cycle Analysis (LCA). This exploration is commensurate with recent developments that have impacted the level of - and approval process for - fleet funding. It is expected that financial tools such as Life Cycle Analysis (LCA) will influence how new business models are presented and ultimately supported in the organization.

In early 2013, Toronto Hydro met with Richmond Sustainability Initiatives (RSI) to discuss the current context around fleet management, data mining, and opportunities for improvement. At this meeting, various opportunities to provide fleet consulting services to address Toronto Hydro's needs were discussed, with primary focus on data compilation and the development of an LCA for the fleet.

In support of this process, it was agreed that RSI was to deliver four key elements:

- **Element 1:** Fleet Data Review & Data Compilation
- **Element 2:** Life Cycle Analysis & Peer Fleet Comparison
- **Element 3:** Draft Report & Presentation
- **Element 4:** Final Report

The final report provided herein summarizes the approach and project results. Element 1 – *Fleet Data Review & Data Compilation* – is provided as separate cover. This latter worksheet is a compiled inventory of the historical operating data used in this analysis and provides a comprehensive baseline of fleet and vehicle performance.

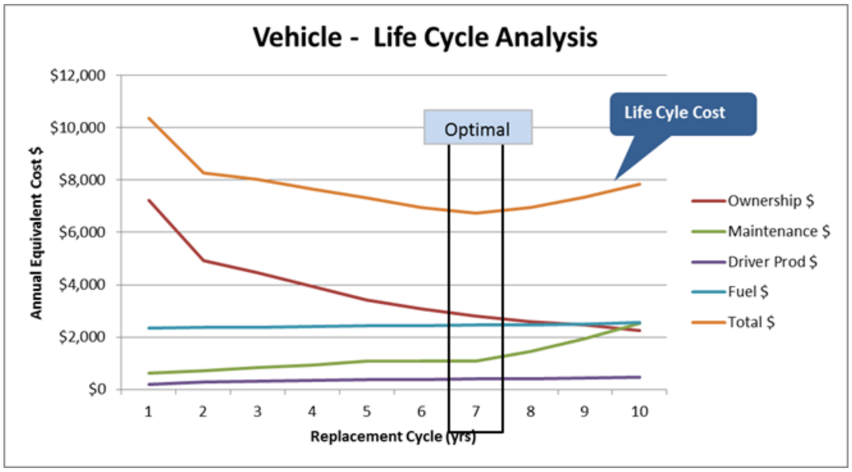
Methodology and Approach

Life cycle analysis (LCA) is a structured approach to determine the best time to replace vehicles and equipment in terms of age, mileage or other pertinent factors. LCA provides the empirical justification for replacement polices and facilitates the analysis and communication of future replacement costs.

Figure 1 illustrates the concept of life cycle costing. As a vehicle's age at retirement increases, ownership costs decrease and operating costs increase. The ideal time to replace vehicles is therefore when the rise in operating costs begins to outweigh the decline in ownership costs.

The LCA completed for Toronto Hydro was based on data provided from 2008 to 2012 (Appendix 1).

Figure 1: Vehicle Life Cycle Analysis



Vehicle Replacement Criteria

LCA Results and Replacement Recommendations

LCA provides the empirical justification for replacement polices and facilitates the analysis and communication of future replacement costs. However, as some vehicles that are in poor or unsafe condition may require replacement before the criteria is met, and conversely, some vehicles that exceed the criteria may be in good condition and may not warrant replacement, the recommended replacement criteria should be used as a guide only.

The life cycle analysis completed in this report optimizes vehicle life cycle cost based on vehicle age. Vehicle age is the best replacement criteria for Toronto Hydro given the geographic footprint of the operating territory. However, it is recommended that Toronto Hydro review the condition of high mileage vehicles at standard thresholds of 20,000 km/yr for light duty vehicles and 15,000 km/yr for medium and heavy duty vehicles for potential early replacement.

The recommended vehicle replacement criteria based on the analysis completed is summarized in **Table 1**. This criteria is based on a series of analyses performed by RSI using increasingly refined datasets provided by Toronto Hydro, and in consultation with fleet management.

Table 1: Vehicle Replacement Criteria

Vehicle Replacement Criteria		
Report Section	**Vehicle Type**	**Age**
6.1	Car	6 yrs.
6.2	Pickup	9 yrs.
6.3	SUV	6 yrs.
6.4	Passenger Mini-van	6 yrs.
6.5	Cargo Mini-van	7 yrs.
6.6	Passenger Full Size Van	9 yrs.

Vehicle Replacement Criteria		
Report Section	Vehicle Type	Age
6.7	Cargo Full Size Van	9 yrs.
6.8	Cube Van	12 yrs.
6.9	Line Truck	13 yrs.
6.10	Cable Truck	16 yrs.
6.11	Single Bucket Truck	14 yrs.
6.12	Single Bucket Van Mount	8 yrs.
6.13	Double Bucket up to 50’	14 yrs.
6.14	Double Bucket 51’-64’	14 yrs.
6.15	Double Bucket 65’+	14 yrs.
6.16	Small Digger Truck	13 yrs.
6.17	Large Digger Truck	14 yrs.
6.18	Small Crane Truck	14 yrs.
6.19	Large Crane Truck	16 yrs.
6.20	Small Dump Truck	14 yrs.

Peer Benchmark Comparison Results

An additional component to the report included the research and comparison of the Toronto Hydro fleet to salient peer fleets from RSI’s Canadian database, which include a municipal electrical utility, a gas distribution utility, a large municipal fleet, a national telecom fleet, and a regional electrical utility.[1] The Toronto Hydro fleet is younger than the peer comparison fleets applied in the analysis to date. The results to date are summarized below (Table 2).

Qualitative research was also conducted to identify and provide comparison to other fleets having similar operating characteristics. This review showed that age and/or mileage criterion, while typically employed as vehicle replacement criteria in most fleets reviewed, was not always based on comprehensive analysis (as would be expected in order to achieve optimized fleet performance).

[1] The regional electrical utility is from outside of RSI’s database.

Table 2: Peer Fleet Vehicle Replacement Criteria

Report Section	Vehicle Type	Toronto Hydro Proposed	Fleet "A" Mid-size Urban MEU	Fleet "B" Gas Utility	Fleet "C" Large Urban Municipality	Fleet "D" National Telecom	Fleet "E" Large, Commonwealth Country Regional Electrical Utility**
6.1	Car	6 yrs.	-	5 yrs.	5-7 yrs.	7 yrs. or 180K km	150K km
6.2	Pickup	9 yrs.	7 yrs.	5 yrs.	5-7 yrs.	7-8 yrs. or 180-225K km	140K km
6.3	SUV	6 yrs.	10 yrs.	5 yrs.	5-7 yrs.	9 yrs. or 225K km	-
6.4	Passenger Mini-van	6 yrs.	7 yrs.	5 yrs.	5-7 yrs.	-	150K km
6.5	Cargo Mini-van	7 yrs.	7 yrs.	5 yrs.	5-7 yrs.	8 yrs. or 180K km	140K km
6.6	Passenger Full Size Van	9 yrs.	7 yrs.	5 yrs.	5-7 yrs.	-	140K km
6.7	Cargo Full Size Van	9 yrs.	7 yrs.	5 yrs.	10-12 yrs.	7 yrs. or 225K km	140K km & condition
6.8	Cube Van	12 yrs.	7 yrs.	10 yrs.	10-12 yrs.	10 yrs. or 180K km.	10 yrs. or 200K km
6.9	Line Truck	13 yrs.	10+ yrs.	10 yrs.	10-12 yrs.	12-17 yrs. unlimited km*	10 yrs. or 200K km
6.10	Cable Truck	16 yrs.	-	-	-	12-17 yrs. unlimited km*	20 yrs.
6.11	Single Bucket Truck	14 yrs.	10+ yrs.	-	-	12-17 yrs. unlimited km*	10 yrs. or 200K km
6.12	Single Bucket Van Mount	8 yrs.	-	-	-	10 yrs. or 225K km	10 yrs. or 200K km
6.13	Double Bucket up to 50’	14 yrs.	10+ yrs.	-	-	-	10 yrs. or 200K km

Report Section	Vehicle Type	Toronto Hydro Proposed	Fleet "A" Mid-size Urban MEU	Fleet "B" Gas Utility	Fleet "C" Large Urban Municipality	Fleet "D" National Telecom	Fleet "E" Large, Commonwealth Country Regional Electrical Utility**
6.14	Double Bucket 51'-64'	14 yrs.	10+ yrs.	-	-	-	-
6.15	Double Bucket 65'+	14 yrs.	-	-	-	-	-
6.16	Small Digger Truck	13 yrs.	10+ yrs.	10+ yrs.	-	12-17 yrs. unlimited km*	10 yrs.
6.17	Large Digger Truck	14 yrs.	10+ yrs.	10+ yrs.	-	12-17 yrs. unlimited km*	10 yrs.
6.18	Small Crane Truck	14 yrs.	10+ yrs.	10+ yrs.	10-12 yrs.	12-17 yrs. unlimited km*	10 yrs.
6.19	Large Crane Truck	16 yrs.	10+ yrs.	10+ yrs.	10-12 yrs.	12-17 yrs. unlimited km*	10 yrs.
6.20	Small Dump Truck	14 yrs.	10+ yrs.	10+ yes	10-12 yrs.	12-17 yrs. unlimited km*	10 yrs. or 300K km

* Categorized as a "construction truck" by the fleet.

** Vehicle types/categories aligned with North American standard categories. The original vehicle definitions provided for this fleet were interpreted and aligned with the specified categories. Vehicle condition is considered in the replacement decision.

Recommendations

Due diligence by fleet management is best achieved when fleet replacement criteria are created based on quantitative *and* qualitative evaluation, in tandem with a mechanism for ongoing evaluation and review of performance, as follows:

(1) *Quantitative Evaluation*: Use historical data to determine the LCA for each vehicle type and with that information, prepare a list of vehicle replacements meeting the LCA thresholds; and,
(2) *Qualitative Evaluation*: Assess each unit meeting the replacement criteria threshold(s) (i.e. be this age, kms or both) on a case-by-case basis with a view of extending the life cycle of

specific units (wherever deemed practical and not excessively risky to do so). Adopt a formal mechanism to periodically review and assess vehicle operational performance.

In keeping, we recommend that Toronto Hydro adopt the age-prioritized vehicle replacement recommendations identified through the Life Cycle Analysis performed on the vehicle fleet. These recommendations are the result of the review, compilation, and analysis of over four years of highly specific vehicle operating data and reflect a state-of-the-art technical evaluation of fleet performance.

A review of peer fleet data show recommendations to fall within the "norm" of typically adopted vehicle replacement criteria in North America, however we suggest that the approach taken by Toronto Hydro is more highly informed given that it is based on actual vehicle performance accrued over an unusually robust period of time.

Lastly, we would recommend that Toronto Hydro also adopt a recurring mechanism for qualitative evaluation of vehicle performance on a case-by-case basis so as to continually monitor and refine fleet performance over time.

Table of Contents

1 Introduction

In early 2013, Toronto Hydro met with Richmond Sustainability Initiatives (RSI) to discuss the current context around its vehicle fleet and associated data management. At this meeting, various opportunities to provide fleet consulting services to address Toronto Hydro's needs were discussed, with primary focus on data review and the development of a Life Cycle Analysis (LCA) for the fleet. The intent of the project was to assist Toronto Hydro in refining its fleet capital replacement program by accounting more specifically for operating performance exhibited to date and using this data to inform business planning going forward.

This activity dovetails recent developments that have impacted the level of and approval process for fleet funding. It is expected that financial tools such as LCA will influence how new business models are presented and ultimately supported in the organization.

In support of this process, it was agreed that RSI was to deliver four key elements, including a Fleet Review (Element 1), an LCA and Peer Fleet Comparison (Element 2), and a Draft Report/presentation and Final Report (Elements 3 and 4, respectively).

The report provided herein summarizes the approach and results to date pertaining to Element 2, or the *Life Cycle Analysis and Peer Fleet Comparison*.

Element 1 – *Fleet Data Review & Data Compilation* – has been completed as a supporting activity and will be summarized in the Final Report.

2 Project Objective and Deliverables

2.1 Project Objectives

Toronto Hydro is interested in refining its fleet capital replacement program to account for vehicle historical and operational performance, and more specifically, optimize vehicle replacement cycles by applying Life Cycle Analysis (LCA). LCA is a structured approach to determine the best point in time to replace vehicles and equipment (in terms of age, mileage or other pertinent factors). LCA provides the empirical justification for replacement polices and ultimately helps facilitate the analysis of, justification for, and communication regarding future replacement needs and costs.

The project objectives were thus to gain a comprehensive understanding of the current metrics and operating performance of the Toronto Hydro fleet over the last few years, and to develop an LCA based on discrete vehicle performance over this time period. In addition and where possible, key performance indicators from other utility and peer fleets were to be identified in order to enable Toronto Hydro to evaluate and compare its performance.

2.2 Deliverables

In support of this process, it was agreed that RSI was to deliver four key elements, as described in Table 2.

Table 2: Toronto Hydro Fleet Project Deliverables

Element	Supporting Activities	Delivery Date / Status
1. Fleet Data Review & Data	Cleanse and compile Toronto Hydro fleet operating data for recent years to describe and summarize fleet asset, operating and assets management profiles structured by salient vehicle classes (i.e. aerial trucks, cable trucks, cars, digger trucks, dump trucks, line trucks, pick ups, cargo vans and cube vans). For each class, generate the following data fields: average capital cost, remarket value, maintenance cost as the vehicle ages (parts and labour), work order number (i.e. shop visits for reactive repairs) as the vehicle ages, km/yr., fuel consumption, engine hours, power take off hours, among other fields.	March 29, completed, to be summarized in Final Report
2. Life Cycle Analysis & Peer Fleet	Develop and complete an LCA for the nine Toronto Hydro vehicle categories described in Element 1.0. Design the LCA so as to provide further insight into inventory and utilization rates (whether these are currently predicated on LCA or otherwise). Develop vehicle retention recommendations based on LCA results and determine an overarching retention strategy that describes optimal replacement times for all types of vehicles in the Toronto Hydro fleet. Compare Toronto Hydro's fleet status in select performance indicators relative to peer fleets, including utility fleets where possible.	Draft report on LCA and Peer Benchmarks to be provided April 17 (herein)
3. Draft Report & Presentation	Prepare a Draft Report summarizing outcomes of the Fleet Review and LCA process, including assumptions made, data input to model, and draft recommended vehicle replacement criteria Deliver an in-person presentation highlighting process, findings, and initial recommendations.	April 29
4. Final Report	Based on the outcomes of the draft report and feedback, prepare a Final Report that highlights relevant indicators of interest (i.e. performance	By May 6

	indicators as in exception units, etc.), as well as final recommendations for consideration for capital replacement policy, business planning, and in fleet management.	

3 Project Approach

A life cycle analysis from the Toronto Hydro fleet was completed using RSI's Fleet Challenge proprietary life cycle analysis tool. Available Toronto Hydro historical data for 2008-2012 was used for the analysis, including the following (as listed in Appendix 1):

1. Ellipse Folder, which contains the fleet inventory by make, model and year (from 2009 onwards);
1. Financial Folder, which includes 2012 parts costs, excluding NAPA by Work Order Number;
2. 2012 NAPA Invoices, which includes 2012 parts costs by WO;
3. Man Productivity Reports, which includes 2012 labour costs by WO and Vehicle ID;
4. Utilization Data: Which includes Km travelled and hours used for the last three year;
5. Previously combined data sets, including parts and labour cost by vehicle for 2008 to 2011 by Vehicle ID;
6. Fuel, which lists transactional fuel data from 4Refuel, ARI, and in-house pumps for 2010 to 2012 by Vehicle ID;
5. Financial Folder, which includes historical purchase and remarket prices for each vehicle sold for 2010 to 2012;
6. Meter reading updates for odometer, engine hours and PTO for 2008-2012; and,
7. Recent purchases prices for the vehicle category.

Any data gaps (such as unavailable maintenance cost information) were filled based on RSI's database estimates and in dialogue with Toronto Hydro fleet management where salient. Assumptions and estimates made for each of the 20 vehicle types analyzed are highlighted in the respective subsection of Section 6.

In the analysis completed, the expected cash flows for owning and operating the vehicle were modeled. The approach involves forecasting a stream of costs over a study horizon (future period) for a particular type of vehicle and then determining the replacement cycle that results in the lowest total cost of ownership.

To complete the LCA, a discounted cash flow analysis was completed for each vehicle type. A net present value (NPV) was calculated for outgoing cash flows (such as vehicle purchase cost, maintenance cost, the impact of downtime on driver productivity cost, improved fuel efficiency of new vehicle compared to the old vehicle) and incoming cash flows (vehicle residual value) to calculate the total life cycle cost for various vehicle retention periods. The NPV amounts for cash flows were converted to Annual Equivalent Cost (AEC) in order to provide a dollar amount that is easy to relate to and compare the cost of life cycle alternative.

The recommended replacement criteria were then compared to peer fleet benchmarks to ensure alignment with industry standards. For this part of the project, the retention practices of the Toronto Hydro fleet was compared to four peer fleets including:

1. An urban Ontario mid-sized municipal electrical utility fleet,
2. A large gas utility fleet,

3. A large, urban municipal fleet,
4. A large telecom fleet, and,
5. A large, regional electrical utility fleet operating in a Commonwealth country.

4 Fleet Data Review and Compilation

4.1 Compilation

Toronto Hydro provided a number of folders and fleet datasets for the period 2008-2012 (Appendix 1). The fleet data required to complete the LCA was merged into one file to create a customized Fleet Review report.

Maintenance Costs

Table 3 below provides the maintenance costs used for the LCA analysis. Vehicles that were retired in the calendar year that incurred expenses were flagged as "Pending Disposal". Since fleets generally minimize maintenance costs on vehicles planned for retirement, any costs associated with "Pending Disposal" vehicles were excluded from the LCA analysis.

Table 3: Maintenance Costs used for the LCA Analysis

	2008	2009	2010	2011 [1]	2012
# Vehicles					
Active	599	619	616	693	570
Pending Disposal	47	58	54	52	2
Total	646	677	670	745	572
Part $					
Active	$1,086,008	$1,088,443	$942,583	$1,094,263	$987,215
Pending Disposal	$29,869	$51,608	$45,979	$0	$1,635
Total	$1,115,877	$1,140,050	$988,562	$1,094,263	$988,849
Labour $					
Active	$1,705,896	$1,680,144	$1,587,141	$1,907,987	$1,615,713
Pending Disposal	$65,462	$107,454	$114,766	$0	$6,719
Total	$1,771,358	$1,787,598	$1,701,906	$1,907,987	$1,622,433
Total $					
Active	$2,791,904	$2,768,587	$2,529,724	$3,002,251	$2,602,928
Pending Disposal	$95,331	$159,062	$160,745	$0	$8,354
Total	$2,887,235	$2,927,649	$2,690,468	$3,002,251	$2,611,282

[1] Active vehicles include 166 vehicles pending disposal that incurred parts and labour cost in 2011. Annual parts and labour cost was estimated by prorating costs incurred from date removed from service to year end in order to reflect the impact of these older vehicles in the life cycle cost analysis.

Note: For 2008 to 2011, maintenance costs were obtained from the files titled: "Previously combined data sets" which included transactional maintenance costs for each base vehicle.

For 2012, maintenance costs were mapped to the Dec 31, 2012 Ellipse Vehicle Listing from files; "Man Prod" for labour cost, "Parts 5100 Opex" for parts cost up to the transition to NAPA for parts management; "NAPA Parts" for parts cost post transition to NAPA.

Fuel

Fuel consumed for 2011 to 2012 was summarized and mapped to vehicles. In discussion with Toronto Hydro, it was agreed fuel data would not be consolidated for previous years due to the level of effort required to map this data.

Meter Readings

Odometer readings, engine hour readings and power take off (PTO) hour readings were provided for 2008 to 2012. The last meter reading of each calendar year was mapped to each vehicle. Since the readings were updated manually and subject to error or change if a meter was replaced on a vehicle, Toronto Hydro recommended that the readings be validated. A validation was completed by reviewing the monthly update trend for each vehicle and making manual adjustments as required to correct for obvious discrepancies.

GPS Information

GPS information for 2011-2012 was summarized and mapped to each vehicle. This includes distance travelled, total hours, driving hours, PTO hours, idling hours, direct usage hours and total usage hours.

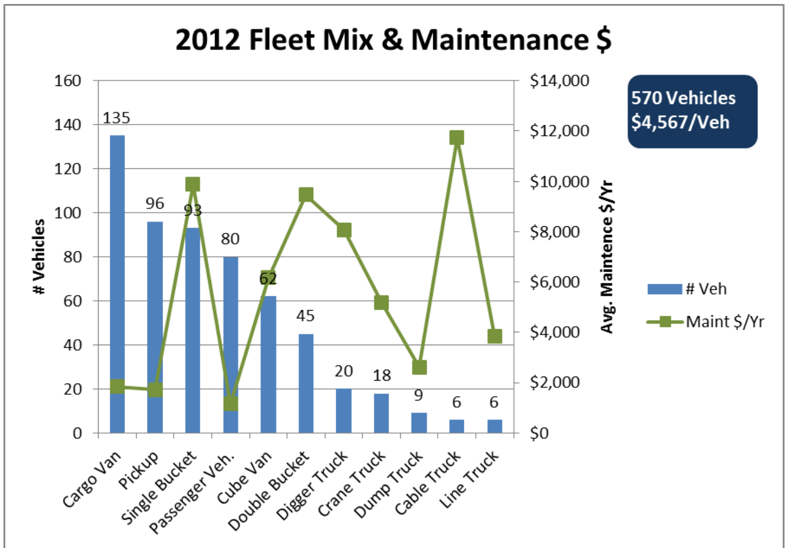
4.2 Fleet Review

Fleet Overview

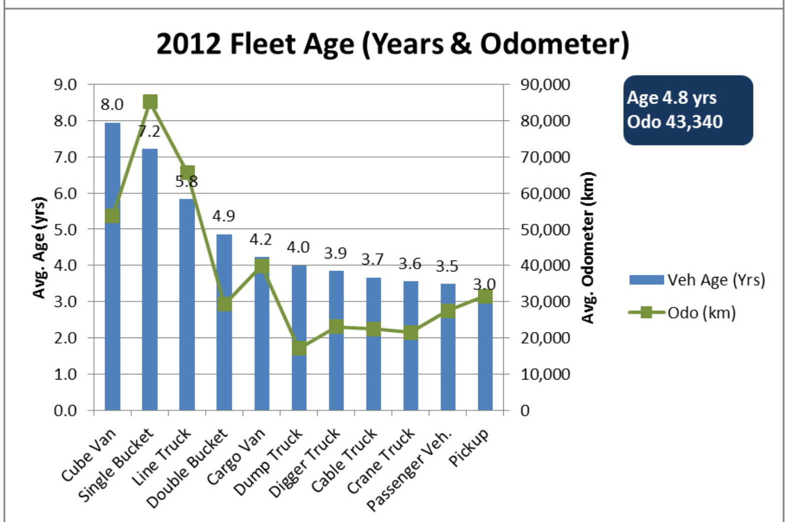
The charts at right provide a snap shot of the 2012 fleet.

The fleet mix is concentrated with top six vehicle types representing 90% of the fleet.

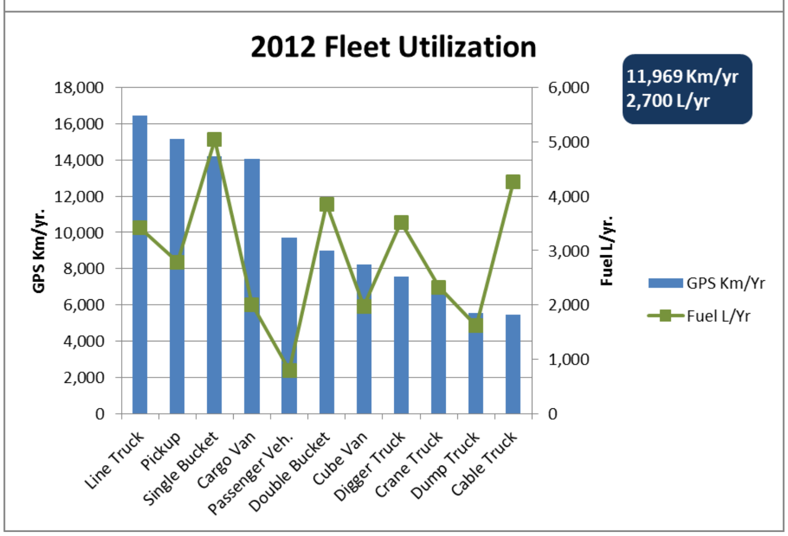
Bucket trucks, digger trucks and cable trucks stand out with the highest maintenance cost.



The fleet is young, with an average age of 4.8 years and average odometer of 43,340 km.



Fleet utilization is low. The average vehicle travelling 11,969 Km/yr., and fuel consumption data confirms the low utilization.



General Observations

One of the benefits of having five years of data is that it allows year over year comparisons to be made and trends identified (see the table below). Notable highlights to date are that:

- The number of vehicles has been trending down;
- Fleet average age also has been trending down and the impact of the large replacement program in 2011 stands out;
- The fleet is very young in terms of average age and average meter reading (cumulative engine hours and PTO hours); and,
- Maintenance costs have been decreasing which is a reflection of the younger and smaller fleet. This said, it is interesting to note that the number of work orders per vehicle has not been reduced with a younger fleet.

Fleet Data	2008	2009	2010	2011	2012	Trend
# Veh	646	677	670	745	572	
GPS Km	-	-	-	4,997,311	6,838,919	
LTD Km (life to date)[1]	1,772,185	5,932,856	6,051,719	6,138,614	4,761,027	
# Veh No Odo Updates[1]	439	54	40	83	6	
Fuel L	-	-	-	1,697,071	1,544,242	
GPS Driving Hrs	-	-	-	172,629	229,882	
GPS Idling Hrs	-	-	-	79,932	128,253	
GPS PTO Hrs	-	-	-	42,296	51,814	
GPS Total Usage Hrs	-	-	-	602,756	832,154	
Parts $	$1,115,877	$1,140,050	$988,562	$1,094,263	$988,849	
Labour $	$1,771,358	$1,787,598	$1,701,906	$1,907,987	$1,622,433	
Total $	$2,887,235	$2,927,649	$2,690,468	$3,002,251	$2,611,282	
# Work Orders	8,377	8,502	9,476	9,485	7,649	

KPI	2008	2009	2010	2011	2012	Trend
Avg Age (yrs)	7.3	7.0	6.8	6.1	4.8	
Avg Odo (km)	23,649[1]	60,787	61,556	52,969	43,414	
Avg Cum. Engine Hours	1648[1]	3,294	3,442	2,929	2,567	
Avg Cum. PTO Hours	670[1]	592	479	388	405	
GPS Km/Veh	-	-	-	6,708	11,956	
LTD Km/Veh	2,743	8,763	9,032	8,240	8,323	
GPS Driving Hrs/Veh	-	-	-	2,278	2,700	
GPS Idling Hrs/Veh	-	-	-	107	224	
GPS % Idling	-	-	-	13%	15%	
GPS PTO Hrs/Veh	-	-	-	57	91	
Fuel (L/veh)	-	-	-	2,278	2,700	
Fuel (L/100km)	-	-	-	34	23	
Parts ($/veh)	$1,727.36	$1,683.97	$1,475.47	$1,468.81	$1,728.76	
Labour ($/veh)	$2,742.04	$2,640.47	$2,540.16	$2,561.06	$2,836.42	
Parts ($/LTD Km)	$0.63	$0.19	$0.16	$0.18	$0.21	
Labour *$/LTD Km)	$1.00	$0.30	$0.28	$0.31	$0.34	
# WO/veh	13.0	12.6	14.1	12.7	13.4	
Reliability (LTD Km/#WO)	212	698	639	647	622	

[1] Few meter readings are available for 2008

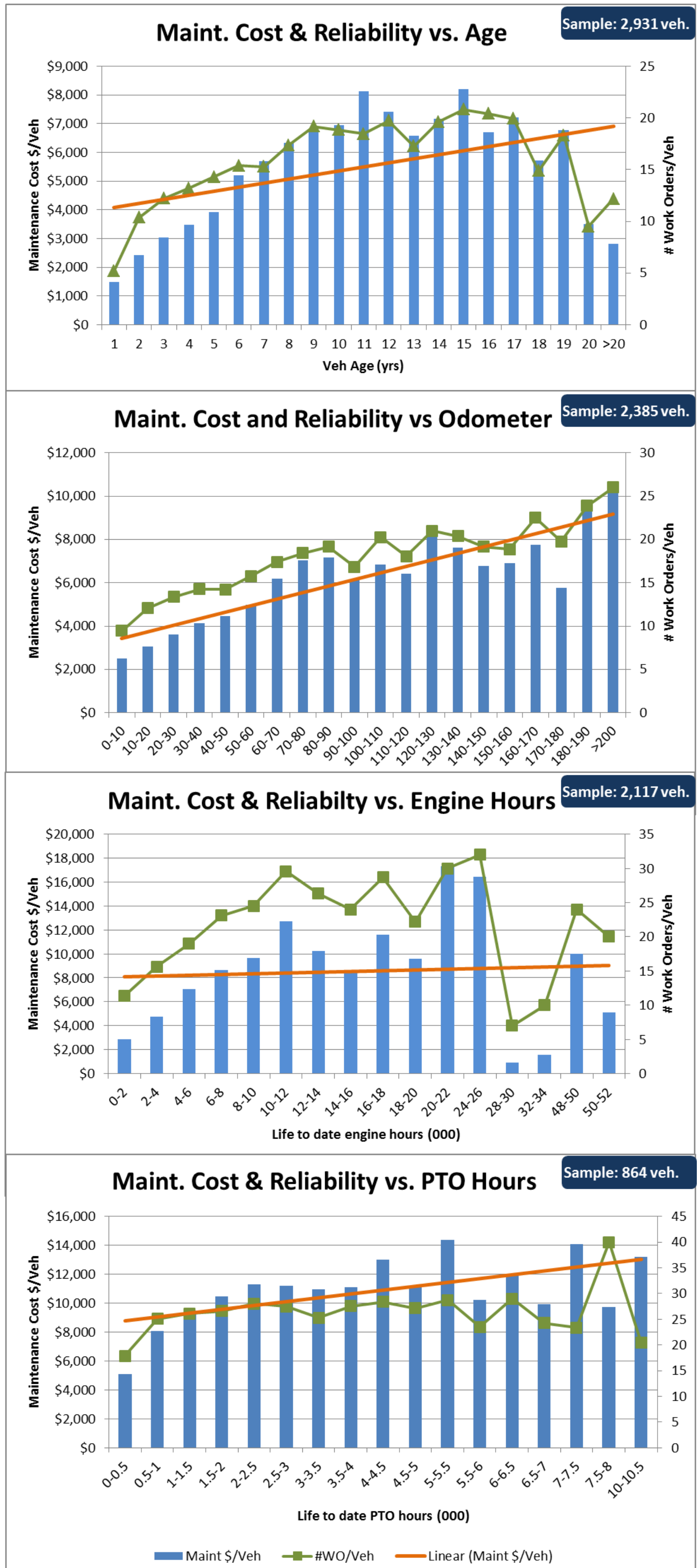
Maintenance Cost Correlation

A key element of completing a life cycle analysis is to predict maintenance cost as a vehicle ages. In this case, it was assumed that historical Toronto Hydro maintenance costs could be used to predict future maintenance cost. The availability of maintenance cost results for five years (2008-201) increased the sample size considerably as well as the confidence level in forecasting maintenance cost for the various life cycles analyzed.

The charts to the right illustrate a total fleet view of the correlation between annual maintenance cost per vehicle and vehicle reliability (based on # work orders per vehicle) with age, odometer, engine hours and PTO hours. The straight line (orange) shows the maintenance cost trend. Note that Section 6 includes pertinent correlations by individual vehicle type.

As would be expected, both cost and work orders generally increase with vehicle age, odometer reading and PTO hours. Anomalies for older vehicles could result from using a smaller sample in that bracket or fleet users shifting usage to newer vehicles.

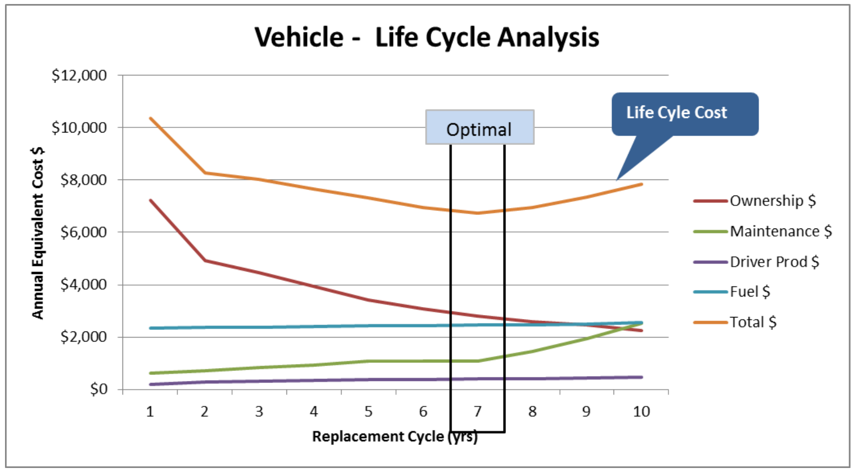
The charts indicate that age and odometer are the best predictors of maintenance cost and were thus used as the primary inputs to the LCA described in Section 6. The use of these factors aligns well with industry best practice vehicle replacement criteria.



5 Life Cycle Analysis Methodology and Assumptions

5.1 Methodology

Life cycle analysis (LCA) enables determining the best time to replace vehicles and equipment in terms of age, mileage or other pertinent factors. The graph to the right illustrates the concept of life cycle cost. As the age of a vehicle at retirement increases, ownership costs decline and operating costs increase. In this example, operating cost includes maintenance, driver productivity loss from reduced vehicle reliability and the impact of increased fuel consumption by delaying the purchase of a new vehicle. The sum of all of these costs represents the "Life Cycle Cost" curve. The ideal time to replace vehicles is before the rise in operating costs begins to outweigh the decline in ownership costs.



The "Life Cycle Cost" curve and the ideal replacement cycle will be different for various types of vehicles and possibly even individual vehicles of the same type. The variability could be caused by differences in the vehicle make, model year, equipment design, operating environment or even by how the operator uses the vehicle. Recommended replacement cycles for a class of vehicles is thus an approximation of the optimal time to replace *most* units within that class. Replacement cycles should be considered a guideline only, as some vehicles that are in poor condition or unsafe may require replacement before the criteria is met, and conversely, some vehicles that exceed the criteria may be in good condition and may not warrant replacement. The Fleet Manager will need to exercise judgment and fleet management principles in either advancing replacement or delaying replacement for individual vehicles case by case.

Life cycles for vehicles are determined by modeling the expected cash flows for owning and operating the vehicle. The approach involves forecasting a stream of costs over a study horizon (future period) for a particular type of vehicle and determine the replacement cycle that results in the lowest *total* cost of ownership.

In Toronto Hydro's case, a discounted cash flow analysis was completed for each vehicle class in order to complete the LCA. A Net Present Value (NPV) was calculated for outgoing cash flows (vehicle purchase cost, maintenance cost, the impact of downtime on driver productivity cost, improved fuel efficiency of new vehicle compared to the old vehicle) and incoming cash flows (vehicle residual value) to calculate the total life cycle cost for various vehicle retention periods.

The NPV amounts for cash flows were converted to Annual Equivalent Cost (AEC) in order to provide a dollar amount that is easy to relate and compare alternative life cycle costs to. AEC is the fixed annual payment that that would be required to pay back the cumulative capital and operating costs over the study period. The AEC can be viewed as an average annual cost that takes into account the time value of money for future cash flows.

5.2 Key LCA Parameters and Assumptions

Section 6 of this report provides the results of the LCA analysis for each vehicle class, assumptions made and recommendations. The key LCA parameters used for all vehicle classes are listed in **Table 5**.

Table 5: Key LCA Parameters and Assumptions

Parameter	Value	Description
Net Acquisition Cost:	Varies by vehicle class	Average vehicle acquisition cost provided by Toronto Hydro
Cost of Capital/Lease Rate	6.16%	Cost of funds for vehicle acquisition provided by Toronto Hydro
Discount Rate for NPV	1.75%	Rate used to discount cash flows provided by Toronto Hydro
HST Rate %	0%	HST was assumed to be zero as recommended by Toronto Hydro
Tech Prod Loss Hrs./Touch	2.5	Average loss in driver productivity each time a vehicle is serviced by a mechanic. Work orders were deemed to be equivalent to touches. Value used approved by Toronto Hydro.
Tech Labour Rate $/Hr.	$74	Loaded labour rate for drivers provided by Toronto Hydro.
CIF[1] on Maintenance	4.0%	Cost increase factor or inflation on parts and mechanic labour
CIF[1] on Driver Rate	3.0%	Cost increase factor or inflation on driver loaded labour rate approved by Toronto Hydro.
CIF[1] on Vehicle	2.0%	Cost increase factor or inflation on vehicle replacement prices approved by Toronto Hydro.
CIF[1] on Fuel	4.0%	Cost increase factor or inflation on fuel prices approved by Toronto Hydro.
Fuel Baseline Price	$1.30	Starting fuel price for cash flows provided by Fleet Challenge.
Annual Vehicle Efficiency Improvement	2.0%	Fuel efficiency improvement factor for new vehicles compared to the vehicles being replaced estimated by Fleet Challenge.
New Vehicle Baseline L/100Km	Varies by vehicle class	Fuel efficiency of the new vehicle in Year 1. Assumption made that fuel efficiency of the new vehicle is the same as the vehicle being retired.
Average Km/Yr.	Varies by vehicle class	Annual distance travelled. Assumption that the new vehicle will travel the same km/yr. as the old vehicle.
Cash Flow Horizon (yrs.)	Varies by vehicle class	The discounted cash flow study period. The period was adjusted based on vehicle class (up to 20 years)

5.3 Cash Flow Overview

Four cash flows as described below were discounted to a present value using the methodology, parameters and assumptions provided in Section 5.1 and 5.2 above.

Sample Cash Flow

Life Cycle (yrs)	**3**											
			Yr 1	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**Yr 6**	**Yr 7**	**Yr 8**	**Yr 9**	**Yr 10**
Veh Replacement Flag			1			1			1			1
Veh Age for Maint Cost			1	2	3	1	2	3	1	2	3	1
Purchase Price			$22,600			$23,983			$25,451			$27,009
End of Term Residual %			45%			45%			45%			45%
End of Term Residual $			$10,170			$10,792			$11,453			$12,154
Lease Cost incl HST			$4,983			$5,288			$5,612			$5,956
Cash Flows	**AEC**	**NPV**										
Ownership Cost	$4,452	$48,654	$4,983	$4,983	$4,983	$5,288	$5,288	$5,288	$5,612	$5,612	$5,612	$5,956
Maintenance Cost	$892	$9,743	$657	$897	$1,349	$739	$1,009	$1,517	$831	$1,135	$1,707	$935
Driver Productivity	$335	$3,660	$241	$378	$514	$264	$413	$562	$288	$451	$614	$315
Fuel Cost	$520	$5,686	$563	$585	$609	$597	$621	$645	$633	$658	$684	$670
Total	**$6,199**	**$67,743**	$6,445	$6,844	$7,455	$6,888	$7,331	$8,013	$7,364	$7,856	$8,617	$7,876

Ownership Cost

- The average original cost for recent purchases was amortized over the life cycle to a residual value based on the Toronto Hydro cost of capital.
- Each time a vehicle is replaced, the cost of replacement vehicle was increased based on a cost increase factor
- Residual values (remarket prices) provided by Toronto Hydro and supplemented by Fleet Challenge estimates) were calculated as a percent of replacement vehicle cost.

Maintenance Cost

- It was assumed that Toronto Hydro historical maintenance cost patterns could be used to forecast future maintenance costs given that new vehicle duty cycles are not expected to change. A cost increase factor was applied to account for the impact of inflation. For example, if historically, cars incur a cost for parts and labour at 5 years of age, it was assumed that a replacement vehicle would incur the same cost after inflation at the same age.
- The availability of 5 years of Toronto Hydro data was very useful in completing the analysis. However in some cases this historical information did not show increasing cost at higher vehicle age, odometer reading or hour meter readings. This is likely due to lower utilization of older vehicles or cost avoidance with the expectation that a vehicle would soon be replaced. In such cases, Fleet Challenge estimated maintenance costs subjectively. Any estimates made were informed by cost correlation with age, odometer reading, engine hours or PTO hours and Fleet Challenge experience with other fleets. Pertinent correlation charts where applicable are provided with the LCA analysis for each vehicle type.

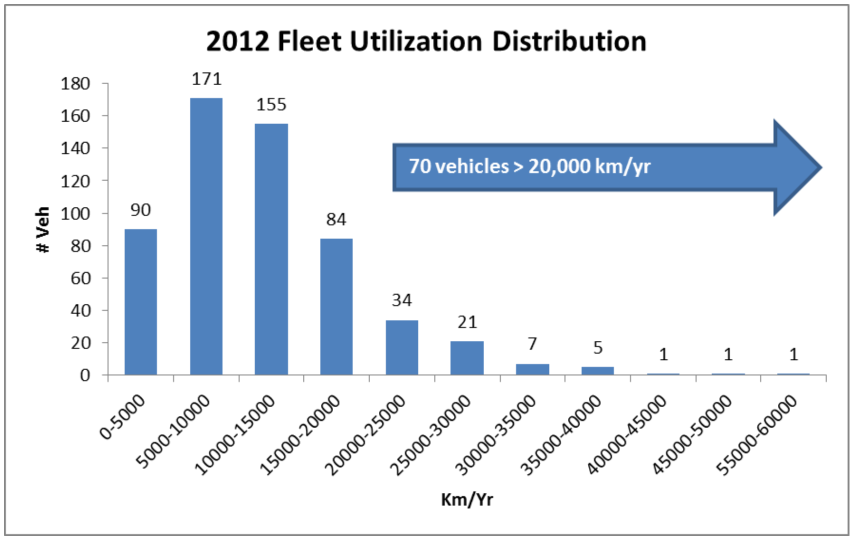
Driver Productivity

- Anytime a vehicle is serviced or "touched" by a mechanic, it presents an inconvenience to the driver and may impact productivity. It was assumed that Toronto Hydro historical number of work orders per year could be used to forecast the future number of work orders per year.
- The availability of 5 years of Toronto Hydro data was very useful in completing the analysis. However in some cases this historical information did not show an increasing number of work orders cost at higher vehicle age, odometer reading or hour meter readings. This is likely due to lower utilization of older vehicles or cost avoidance with the expectation that a vehicle would soon be replaced. In such cases, Fleet Challenge estimated the number of work orders subjectively based on Toronto Hydro trends and experience with other fleets.
- The cash flow applies the number of work orders times the loaded labour rate after inflation to obtain the impact of older less reliable vehicles on driver productivity.

Fuel Cost

- It was assumed that current duty cycles for new vehicles would be the same as current vehicles and therefore the fuel efficiency of the current vehicle would be the baseline to forecast the fuel consumption of the new vehicle.
- A further assumption was made that new vehicles will continue to improve efficiency in comparison to the vehicle being replaced by applying an annual fuel efficiency improvement factor.
- A cost increase factor was applied to fuel prices to account for inflation.

5.4 Vehicle Replacement Criteria



As noted in Section 4.2 and as detailed in the chart at right, the Toronto Hydro Fleet Utilization is low. The average distance travelled is approximately 12,000 km/yr. 88% of the fleet travels less than 20,000/yr. and only 70 vehicles or 12% of the fleet is above 20,000 km/yr.

The life cycle analysis completed in this report optimizes vehicle life cycle cost based on vehicle age. Vehicle age is the best replacement criteria for Toronto Hydro given the geographic footprint of the operating territory since most vehicles time out versus mileage out at retirement. It is recommended that Toronto Hydro review the condition of high mileage vehicles at standard thresholds of 20,000 km/yr. for light duty vehicles and 15,000 km/yr. for medium and heavy-duty vehicles for potential early replacement.

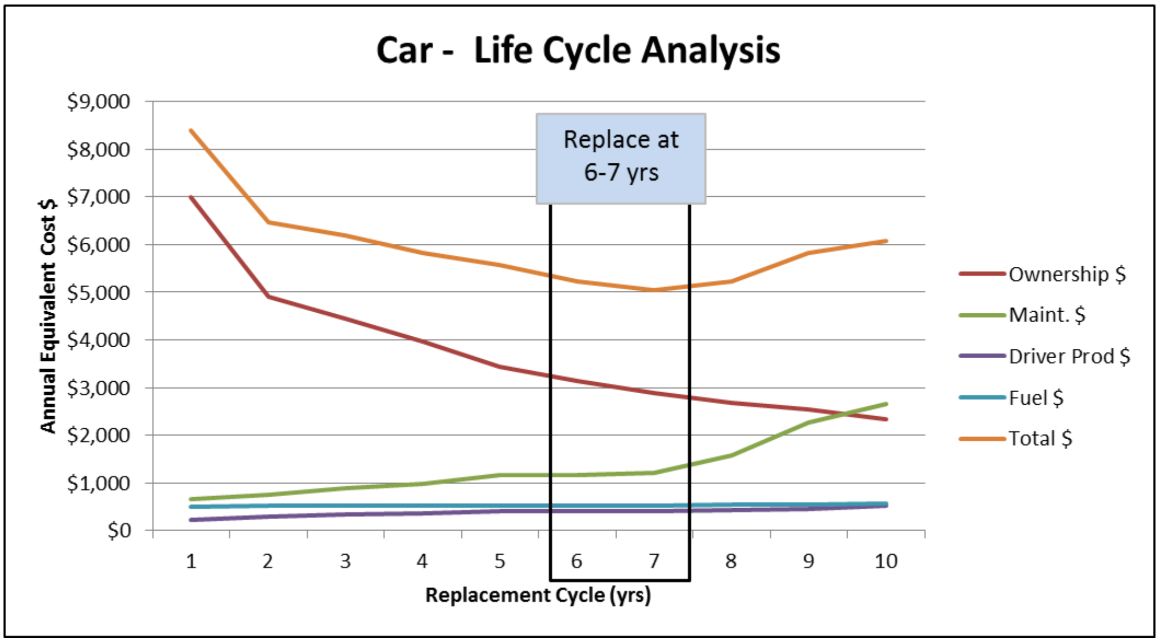
The recommended vehicle replacement age was multiplied these values for mileage thresholds. For example, if the recommended life cycle is 7 years for a light duty vehicle, the recommended replacement mileage is 7 x 20,000 = 140,000 km.

6 Life Cycle Analysis Results and Recommendations

6.1 Cars (Equipment Type 0A, 0B)

Car	2012 KPI
# Vehicles	27
Avg. Replacement Cost $	$22,600
Avg. Age (yrs)	3.5
GPS Mileage (Km/Yr)	8,661
GPS Total Usage (Hrs/Yr)	680
GPS PTO Usage (Hrs/Yr)	0
Fuel L/100Km	5.0

- Maintenance costs for cars, SUVs and passenger minivans were averaged to minimize data gaps (Appendix 2 provides details)
- The optimum life cycle is 7 years but the life cycle can be shortened to 6 years with minimal impact on cost.
- Recommendation: Replace at 6 years. Review condition of units at 120,000 km for possible early replacement.



Replacement Cycle	Annual Equivalent Cost: Ownership $	Maint. $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$7,000	$653	$230	$511	$8,394	$3,344	$90,296
2	$4,900	$756	$290	$516	$6,462	$1,412	$38,137
3	$4,452	$892	$335	$520	$6,199	$1,149	$31,034
4	$3,960	$988	$360	$525	$5,833	$783	$21,134
5	$3,451	$1,175	$409	$532	$5,566	$516	$13,945
6	$3,134	$1,163	$409	$533	$5,239	$189	$5,111
7	$2,890	$1,207	$417	$536	$5,050	Optimum	
8	$2,690	$1,570	$437	$542	$5,239	$189	$5,096
9	$2,547	$2,273	$460	$550	$5,830	$591	$15,969
10	$2,347	$2,659	$516	$560	$6,082	$843	$22,773

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for the Car LCA:

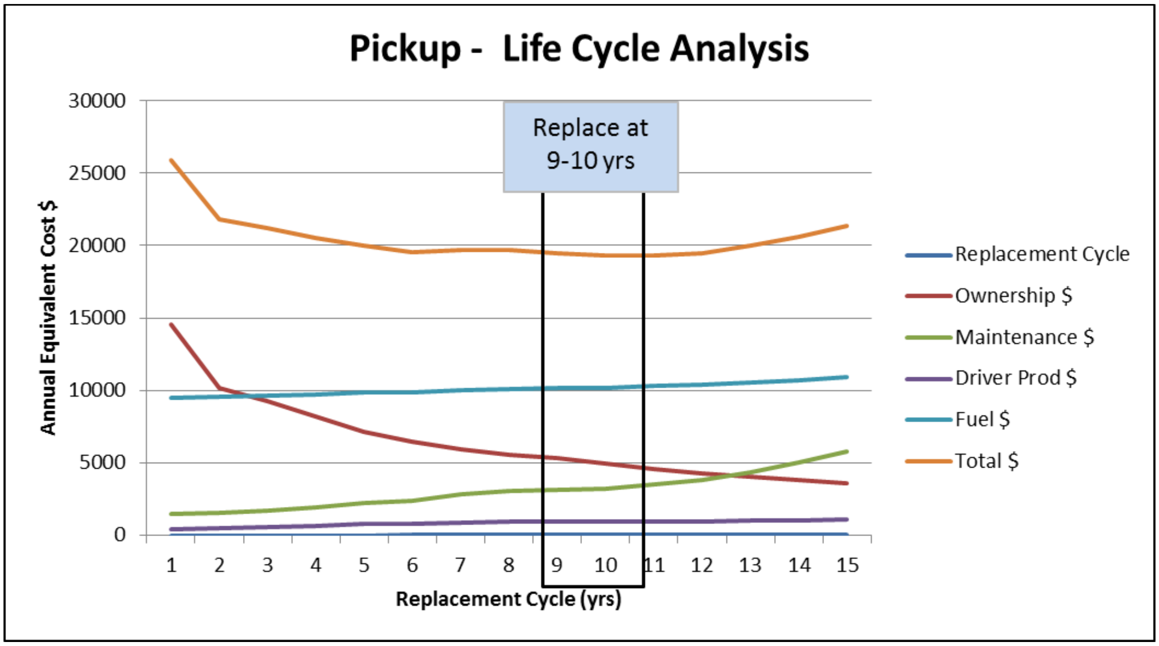
Maintenance costs for cars, SUVs and passenger minivans were averaged to provide cost data for as many vehicle ages as possible (Appendix 2 provides details prior to averaging).

Assumptions		Fleet Data[2]					Used for LCA			
Veh Type	Car	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	27	1	61	$657	3.3		1	657	3	70.0%
Net Acquisition Co	$22,600	2	50	$862	5.0		2	862	5	60.0%
Cost of Capital	6.16%	3	62	$1,247	6.5		3	1,247	7	45.0%
Discount Rate for N	1.75%	4	52	$1,440	6.7		4	1,440	7	35.0%
HST Rate %		5	32	$1,645	7.5	16.2%	5	1,645	8	30.0%
Tech Prod Loss Hr	2.5	6	26	$1,586	7.5		6	1,586	8	25.0%
Tech Labour Rate $	$74	7	23	$1,896	7.9	9.2%	7	1,896	8	20.0%
CIF[1] on Maintenan	4.0%	8	12	$4,736	9.4	9.0%	8	4,736	9	15.0%
CIF[1] on Driver Rate	3.0%	9	14	$7,429	8.1	8.9%	9	7,429	8	8.0%
CIF[1] on Vehicle	2.0%	10	5	$4,184	10.8	9.8%	10	4,184	11	6.0%
CIF[1] on Fuel	4.0%	11					11			
Fuel Baseline Pric	$1.30	12					12			
Annual Veh Eff Imp	2.0%	13					13			
New Veh Baseline	5.0	14					14			
Average Km/Yr	8,661	15					15			
Cash Flow Horizon	10	16					16			
[1] CIF (Cost Increase Factor)		17					17			
[2] Car, SUV & Pass. Minivan		18					18			
		19					19			
		20					20			
							RSI Estimate			

6.2 Pickup (Equipment Type 1A, 1B, 1C)

- The optimum life cycle is 10 years but the life cycle could be shortened to 9 years with minimal impact on cost.
- Recommendation: Replace at 9 years. Review condition of units at 180,000 km for possible early replacement.

Pickup	2012 KPI
# Vehicles	96
Avg. Replacement Cost $	$31,119
Avg. Age (yrs)	3.0
GPS Mileage (Km/Yr)	15,140
GPS Total Usage (Hrs/Yr)	1,733
GPS PTO Usage (Hrs/Yr)	0
Fuel L/100Km	18.4



Replacement Cycle	Annual Equivalent Cost						
	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$14,548	$1,476	$406	$9,471	$25,901	$6,610	$634,564
2	$10,190	$1,540	$522	$9,559	$21,812	$2,521	$241,979
3	$9,234	$1,725	$607	$9,662	$21,227	$1,936	$185,889
4	$8,213	$1,931	$679	$9,740	$20,563	$1,271	$122,060
5	$7,171	$2,228	$767	$9,858	$20,024	$733	$70,374
6	$6,501	$2,383	$784	$9,898	$19,566	$275	$26,428
7	$5,959	$2,854	$847	$10,020	$19,681	$390	$37,399
8	$5,548	$3,100	$915	$10,115	$19,677	$386	$37,031
9	$5,314	$3,118	$924	$10,143	$19,499	$208	$19,949
10	**$4,960**	**$3,191**	**$940**	**$10,200**	**$19,291**	**Optimum**	
11	$4,606	$3,486	$955	$10,287	$19,333	$42	$4,048
12	$4,300	$3,824	$961	$10,403	$19,488	$197	$18,872
13	$4,049	$4,370	$1,003	$10,548	$19,970	$679	$65,187
14	$3,804	$5,025	$1,056	$10,723	$20,607	$1,316	$126,316
15	$3,580	$5,766	$1,122	$10,927	$21,395	$2,104	$201,979

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Pickup LCA:

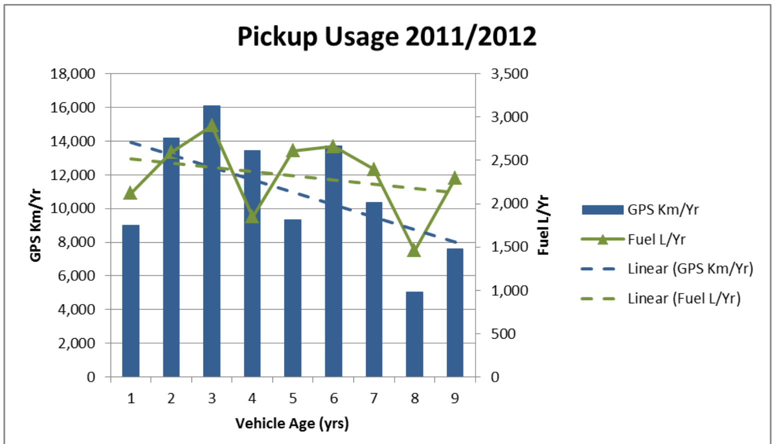
Assumptions		Fleet Data					Used for LCA			
Veh Type	Pickup	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	96	1	118	$934	3.7	10.6%	1	934	3.7	70.0%
Net Acquisition Cost:	$31,119	2	80	$1,021	6.0		2	1,021	6.0	60.0%
Cost of Capital	6.16%	3	44	$1,312	6.9		3	1,312	6.9	45.0%
Discount Rate for NPV	1.75%	4	31	$1,746	8.9		4	1,746	8.9	35.0%
HST Rate %		5	28	$1,978	9.5		5	1,978	9.5	30.0%
Tech Prod Loss Hrs/Touch	2.5	6	40	$2,663	10.6	20.9%	6	2,663	10.6	25.0%
Tech Labour Rate $/Hr	$74	7	20	$3,268	10.7	18.7%	7	3,268	10.7	20.0%
CIF[1] on Maintenance	4.0%	8	39	$3,122	12.7	9.3%	8	3,122	12.7	15.0%
CIF[1] on Driver Rate	3.0%	9	60	$3,664	12.2	10.6%	9	3,664	12.2	8.0%
CIF[1] on Vehicle	2.0%	10	47	$3,476	12.9	10.8%	10	3,476	12.9	6.0%
CIF[1] on Fuel	4.0%	11	36	$4,677	11.6	6.5%	11	4,677	11.6	6.0%
Fuel Baseline Price	$1.30	12	16	$4,746	9.9	7.9%	12	4,746	9.9	6.0%
Annual Veh Eff Improvement	2.0%	13	12	$4,351	12.4		13	6,000	12.4	5.0%
New Veh Baseline L/100Km	35.8	14	9	$3,610	12.8	10.7%	14	6,500	12.8	5.0%
Average Km/Yr	14,867	15	6	$4,449	12.2	4.2%	15	7,000	12.2	5.0%
Cash Flow Horizon (yrs)	15	16					16			
[1] CIF (Cost Increase Factor)		17					17			
		18					18			
		19					19			
		20					20			
							RSI Estimate			

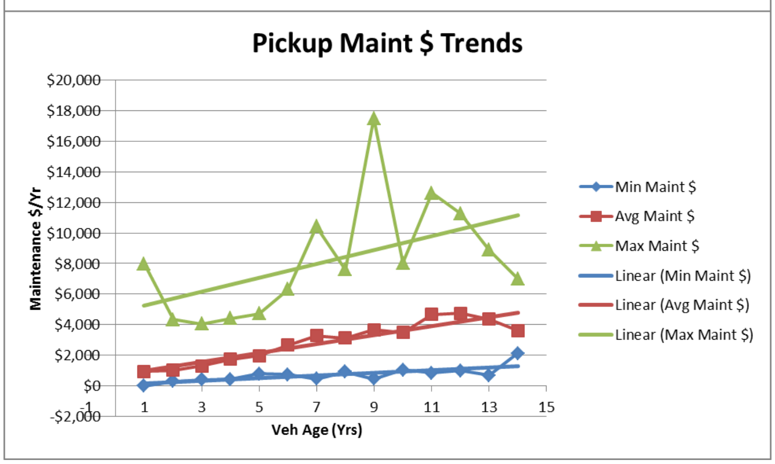
RSI Maintenance Cost Estimates

Assumptions were made for maintenance cost for years 13-15 since TH costs should be increasing more significantly at these vehicle ages.

The upper chart at right shows that vehicle utilization decreases as vehicles age which reflects a preference for using newer vehicles. Lower utilization results in lower than expected maintenance cost.

The lower chart at right shows minimum, average and maximum maintenance costs and linear trends. The maximum cost trend is indicative of maintenance cost for normalized utilization. Based on this trend, the RSI database and RSI experience with other fleets, the maintenance cost estimates made are reflective of realistic expected costs for normalized utilization.

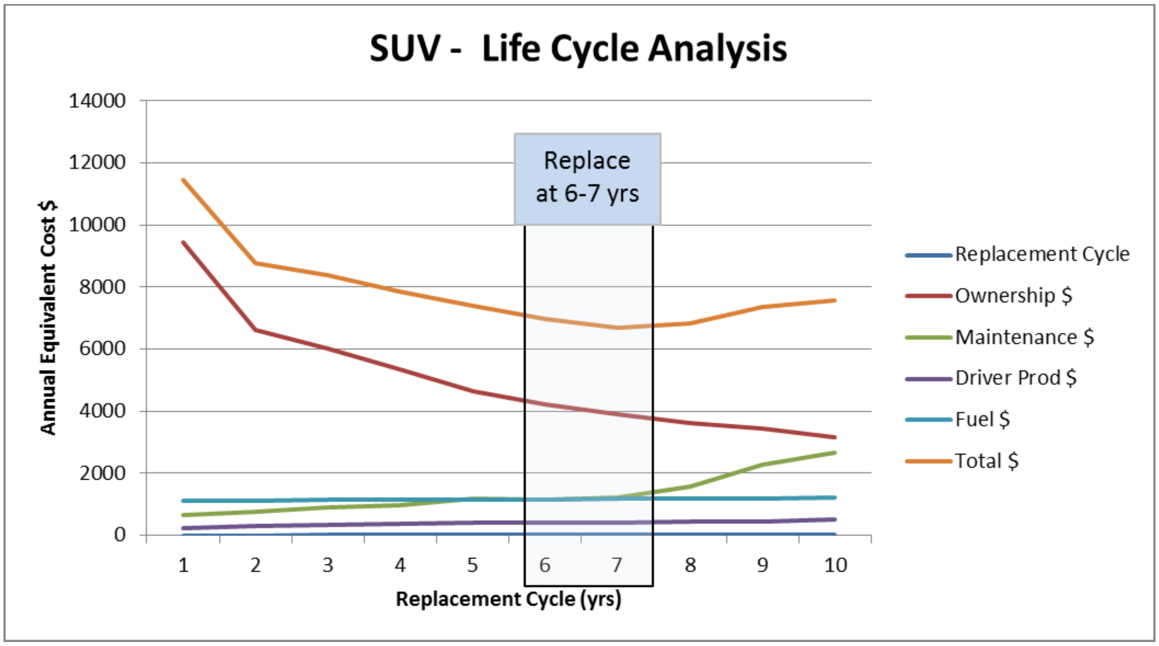




6.3 SUV (Equipment Type 1D)

- The optimum life cycle is 7 years but could be shortened to 6 years with minimal impact on cost.
- Recommendation: Replace at 6 years. Review condition of units at 120,000 km for possible early replacement.

SUV	2012 KPI
# Vehicles	34
Avg. Replacement Cost $	$30,504
Avg. Age (yrs)	2.7
GPS Mileage (Km/Yr)	10,835
GPS Total Usage (Hrs/Yr)	927
GPS PTO Usage (Hrs/Yr)	0
Fuel L/100Km	8.7



	Annual Equivalent Cost						
Replacement Cycle	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$9,449	$653	$230	$1,112	$11,444	$4,752	$161,569
2	$6,614	$756	$290	$1,124	$8,784	$2,092	$71,118
3	$6,010	$892	$335	$1,133	$8,369	$1,677	$57,015
4	$5,345	$988	$360	$1,142	$7,835	$1,143	$38,860
5	$4,657	$1,175	$409	$1,158	$7,399	$707	$24,049
6	$4,230	$1,163	$409	$1,160	$6,963	$271	$9,204
7	**$3,901**	**$1,207**	**$417**	**$1,168**	**$6,692**	**Optimum**	
8	$3,630	$1,570	$437	$1,180	$6,817	$125	$4,254
9	$3,438	$2,273	$460	$1,197	$7,368	$676	$22,986
10	$3,168	$2,659	$516	$1,219	$7,562	$870	$29,575

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for SUV LCA

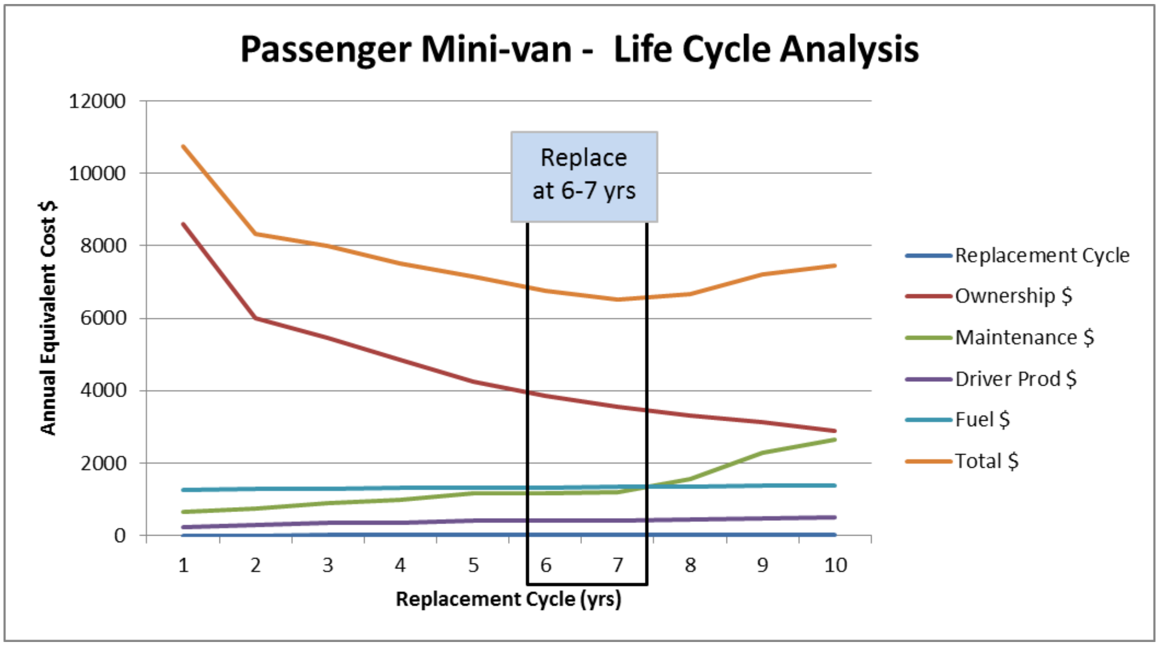
Maintenance costs for cars, SUVs and passenger minivans were averaged to provide cost data for as many vehicle ages as possible (Appendix 2 provides details prior to averaging).

Assumptions		Fleet Data[2]					Used for LCA			
Veh Type	SUV	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	34	1	61	$657	3.3		1	657	3	70.0%
Net Acquisition Cost:	$30,504	2	50	$862	5.0		2	862	5	60.0%
Cost of Capital	6.16%	3	62	$1,247	6.5		3	1,247	7	45.0%
Discount Rate for NPV	1.75%	4	52	$1,440	6.7		4	1,440	7	35.0%
HST Rate %		5	32	$1,645	7.5	16.2%	5	1,645	8	30.0%
Tech Prod Loss Hrs/Touch	2.5	6	26	$1,586	7.5		6	1,586	8	25.0%
Tech Labour Rate $/Hr	$74	7	23	$1,896	7.9	9.2%	7	1,896	8	20.0%
CIF[1] on Maintenance	4.0%	8	12	$4,736	9.4	9.0%	8	4,736	9	15.0%
CIF[1] on Driver Rate	3.0%	9	14	$7,429	8.1	8.9%	9	7,429	8	8.0%
CIF[1] on Vehicle	2.0%	10	5	$4,184	10.8	9.8%	10	4,184	11	6.0%
CIF[1] on Fuel	4.0%	11					11			
Fuel Baseline Price	$1.30	12					12			
Annual Veh Eff Improvement	2.0%	13					13			
New Veh Baseline L/100Km	8.7	14					14			
Average Km/Yr	10,835	15					15			
Cash Flow Horizon (yrs)	10	16					16			
[1] CIF (Cost Increase Factor)		17					17			
[2] Car, SUV & Pass. Minivan		18					18			
		19					19			
		20					20			
							RSI Estimate			

6.4 Passenger Mini-Van (Equipment Type 2A)

- The optimum life cycle is 7 years but could be shortened to 6 years with minimal impact on cost.
- The life cycle could be shortened or lengthened slightly with minimal impact to total cost.
- Recommendation: Replace at 6 years. Review condition of units at 120,000 km for possible early replacement.

Passenger Mini-van	2012 KPI
# Vehicles	18
Avg. Replacement Cost $	$27,740
Avg. Age (yrs)	5.0
GPS Mileage (Km/Yr)	9,363
GPS Total Usage (Hrs/Yr)	1,318
GPS PTO Usage (Hrs/Yr)	0
Fuel L/100Km	11.5



Replacement Cycle	Annual Equivalent Cost						
	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$8,593	$653	$230	$1,271	$10,746	$4,242	$76,347
2	$6,015	$756	$290	$1,283	$8,344	$1,840	$33,113
3	$5,465	$892	$335	$1,294	$7,985	$1,481	$26,656
4	$4,861	$988	$360	$1,304	$7,513	$1,008	$18,152
5	$4,235	$1,175	$409	$1,323	$7,142	$637	$11,473
6	$3,847	$1,163	$409	$1,325	$6,744	$240	$4,317
7	$3,547	$1,207	$417	$1,334	$6,504	Optimum	
8	$3,301	$1,570	$437	$1,347	$6,656	$151	$2,725
9	$3,127	$2,273	$460	$1,367	$7,227	$722	$12,998
10	$2,881	$2,659	$516	$1,392	$7,448	$944	$16,983

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Passenger Mini-van LCA

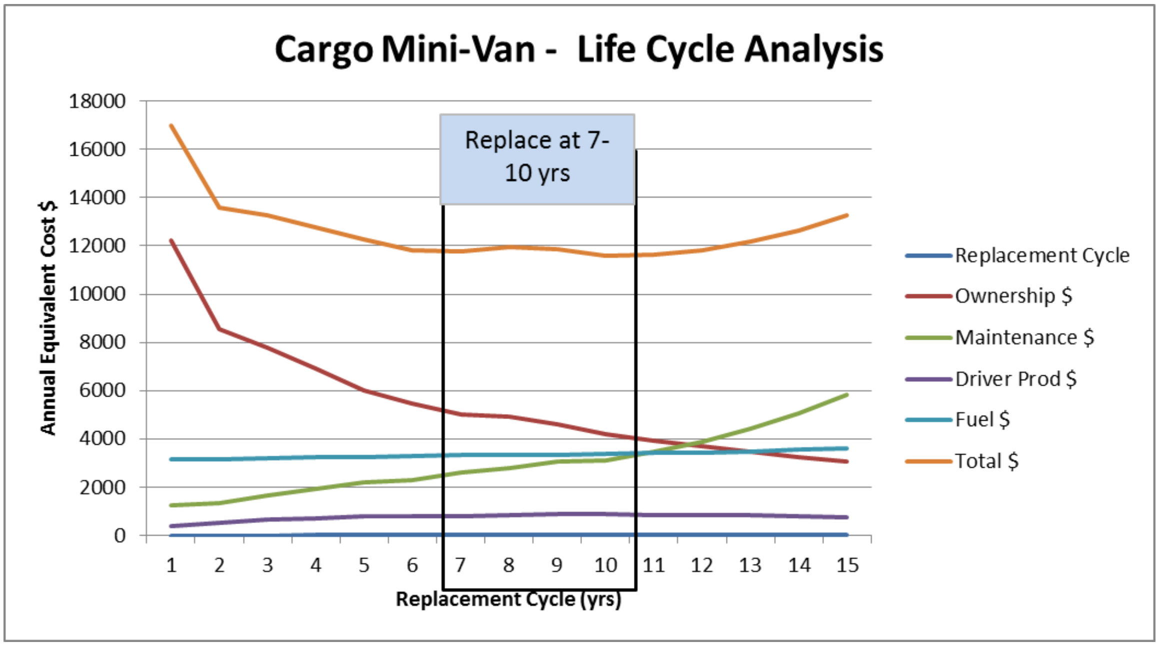
Maintenance costs for cars, SUVs and passenger minivans were averaged to provide cost data for as many vehicle ages as possible (Appendix 2 provides details prior to averaging).

Assumptions		Fleet Data[2]					Used for LCA			
Veh Type	Passenger Mini-van	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	18	1	61	$657	3.3		1	657	3.3	70.0%
Net Acquisition Cost:	$27,740	2	50	$862	5.0		2	862	5.0	60.0%
Cost of Capital	6.16%	3	62	$1,247	6.5		3	1,247	6.5	45.0%
Discount Rate for NPV	1.75%	4	52	$1,440	6.7		4	1,440	6.7	35.0%
HST Rate %		5	32	$1,645	7.5	16.2%	5	1,645	7.5	30.0%
Tech Prod Loss Hrs/Touch	2.5	6	26	$1,586	7.5		6	1,586	7.5	25.0%
Tech Labour Rate $/Hr	$74	7	23	$1,896	7.9	9.2%	7	1,896	7.9	20.0%
CIF[1] on Maintenance	4.0%	8	12	$4,736	9.4	9.0%	8	4,736	9.4	15.0%
CIF[1] on Driver Rate	3.0%	9	14	$7,429	8.1	8.9%	9	7,429	8.1	8.0%
CIF[1] on Vehicle	2.0%	10	5	$4,184	10.8	9.8%	10	4,184	10.8	6.0%
CIF[1] on Fuel	4.0%	11					11			
Fuel Baseline Price	$1.30	12					12			
Annual Veh Eff Improvement	2.0%	13					13			
New Veh Baseline L/100Km	11.5	14					14			
Average Km/Yr	9,363	15					15			
Cash Flow Horizon (yrs)	10	16					16			
[1] CIF (Cost Increase Factor)		17					17			
[2] Car, SUV & Pass. Minivan		18					18			
		19					19			
		20					20			
							RSI Estimate			

6.5 Cargo Mini-van (Equipment Type 2B)

- The optimum life cycle is 10 years but the life cycle could be shortened to 7 years with minimal impact on cost.
- Recommendation: Replace at 7 years. Review condition of units at 140,000 km for possible early replacement.

Cargo Mini-van	2012 KPI
# Vehicles	82
Avg. Replacement Cost $	$26,150
Avg. Age (yrs)	4.4
GPS Mileage (Km/Yr)	14,446
GPS Total Usage (Hrs/Yr)	1,345
GPS PTO Usage (Hrs/Yr)	0
Fuel L/100Km	12.2



Replacement Cycle	Annual Equivalent Cost						
	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$12,225	$1,253	$372	$3,136	$16,985	$5,417	$520,019
2	$8,563	$1,353	$517	$3,165	$13,599	$2,030	$194,919
3	$7,760	$1,652	$645	$3,199	$13,256	$1,687	$161,985
4	$6,902	$1,916	$716	$3,225	$12,759	$1,190	$114,228
5	$6,026	$2,196	$783	$3,264	$12,269	$701	$67,248
6	$5,463	$2,286	$793	$3,278	$11,820	$251	$24,102
7	$5,008	$2,611	$814	$3,318	$11,751	$182	$17,471
8	$4,906	$2,814	$862	$3,349	$11,931	$363	$34,835
9	$4,595	$3,053	$874	$3,359	$11,881	$313	$30,025
10	$4,202	$3,118	$871	$3,378	$11,569	Optimum	
11	$3,946	$3,461	$842	$3,406	$11,656	$87	$8,349
12	$3,684	$3,868	$840	$3,445	$11,836	$268	$25,711
13	$3,450	$4,403	$835	$3,493	$12,181	$613	$58,814
14	$3,239	$5,068	$794	$3,551	$12,651	$1,083	$103,952
15	$3,046	$5,827	$767	$3,618	$13,257	$1,689	$162,117

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions used for Cargo Mini-van LCA

Assumptions		Fleet Data					Used for LCA			
Veh Type	Cargo Mini-Van	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	96	1	51	$793	3.4	11.4%	1	793	3.4	70.0%
Net Acquisition Cost:	$26,150	2	47	$930	6.3		2	930	6.3	60.0%
Cost of Capital	6.16%	3	68	$1,402	8.0		3	1,402	8.0	45.0%
Discount Rate for NPV	1.75%	4	62	$1,883	9.2		4	1,883	9.2	35.0%
HST Rate %		5	55	$1,877	8.9		5	1,877	8.9	30.0%
Tech Prod Loss Hrs/Touch	2.5	6	48	$2,384	9.9	11.8%	6	2,384	9.9	25.0%
Tech Labour Rate $/Hr	$74	7	35	$2,614	8.6	7.1%	7	2,614	8.6	20.0%
CIF[1] on Maintenance	4.0%	8	29	$2,582	9.6	7.3%	8	2,582	9.6	7.3%
CIF[1] on Driver Rate	3.0%	9	23	$4,993	10.3	3.3%	9	4,993	10.3	3.3%
CIF[1] on Vehicle	2.0%	10	9	$3,085	9.7	4.5%	10	3,085	9.7	4.5%
CIF[1] on Fuel	4.0%	11	8	$1,510	5.1	2.3%	11	5,000	5.1	2.3%
Fuel Baseline Price	$1.30	12	2	$2,785	9.0	2.1%	12	5,500	9.0	2.1%
Annual Veh Eff Improvement	2.0%	13	4	$2,162	7.5		13	6,000	7.5	2.0%
New Veh Baseline L/100Km	12.2	14	2	$783	1.0		14	6,500	1.0	2.0%
Average Km/Yr	14,446	15					15	7,000		2.0%
Cash Flow Horizon (yrs)	15	16					16			
		17					17			
		18					18			
		19					19			
		20					20			

[1] CIF (Cost Increase Factor)

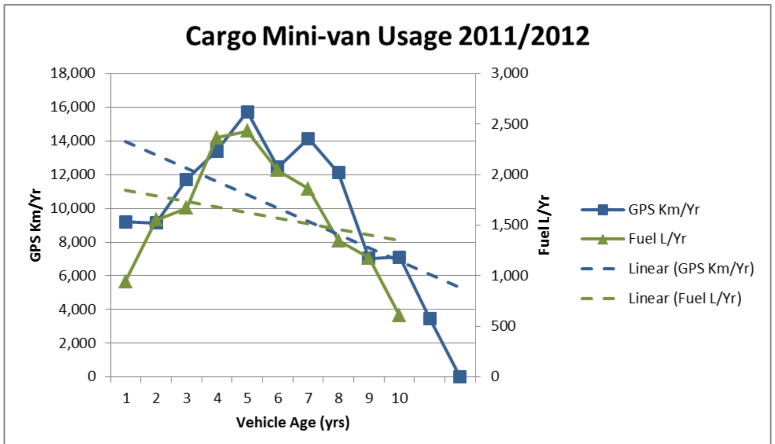
RSI Estimate

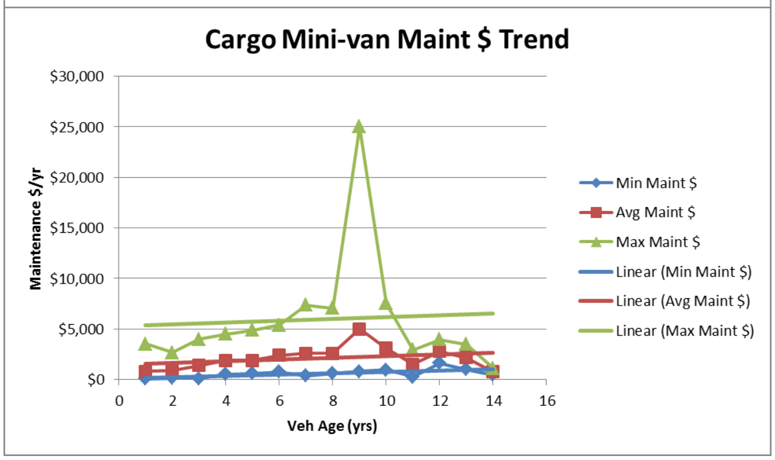
RSI Maintenance Cost Estimates

Assumptions were made for maintenance cost for years 11-15 since TH costs should be increasing instead of reducing at these vehicle ages.

The upper chart at right shows that vehicle utilization decreases as vehicles age which reflects a preference for using newer vehicles. Lower utilization results in the lower than expected maintenance cost.

The lower chart at right shows minimum, average and maximum maintenance costs and linear trends. The maximum cost trend is indicative of maintenance cost for normalized utilization. Based on this trend, the RSI database and RSI experience with other fleets, the maintenance cost estimates made are reflective of realistic expected costs for normalized utilization.

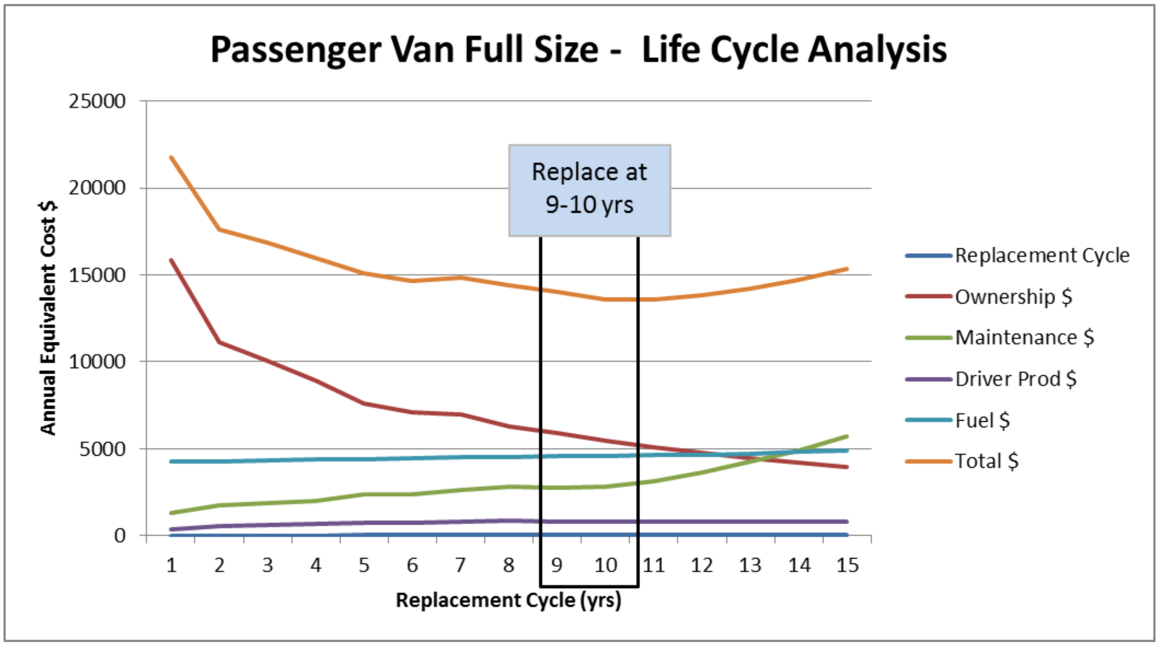




Passenger Full Size Van	2012 KPI
# Vehicles	1
Avg. Replacement Cost $	$33,875
Avg. Age (yrs)	2.0
GPS Mileage (Km/Yr)	6,304
GPS Total Usage (Hrs/Yr)	514
GPS PTO Usage (Hrs/Yr)	0
Fuel L/100Km	7.9

6.6 Passenger Full Size Van (Equipment Type 2C)

- The optimum life cycle is 10 years but the life cycle could be shortened to 9 years with minimal impact on cost
- Recommendation: Replace at 9 years. Review condition of units at 180,000 km for possible early replacement.



Replacement Cycle	Annual Equivalent Cost						
	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$15,837	$1,298	$370	$4,240	$21,745	$8,159	$8,159
2	$11,093	$1,730	$521	$4,280	$17,624	$4,038	$4,038
3	$10,052	$1,852	$617	$4,326	$16,847	$3,261	$3,261
4	$8,940	$2,007	$665	$4,360	$15,973	$2,387	$2,387
5	$7,575	$2,385	$741	$4,413	$15,116	$1,530	$1,530
6	$7,077	$2,385	$751	$4,431	$14,644	$1,058	$1,058
7	$6,954	$2,631	$784	$4,486	$14,855	$1,269	$1,269
8	$6,242	$2,811	$831	$4,528	$14,412	$826	$826
9	$5,902	$2,732	$814	$4,541	$13,990	$404	$404
10	$5,446	$2,792	$782	$4,567	$13,586	Optimum	
11	$5,068	$3,139	$786	$4,605	$13,598	$12	$12
12	$4,752	$3,631	$785	$4,657	$13,825	$239	$239
13	$4,470	$4,241	$795	$4,722	$14,228	$642	$642
14	$4,196	$4,908	$792	$4,800	$14,695	$1,109	$1,109
15	$3,945	$5,723	$765	$4,892	$15,326	$1,740	$1,740

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Passenger Van Full Size LCA

Since there is only one passenger van full size in service, maintenance history was not sufficient to complete the LCA. It was assumed that maintenance and work order data for full size cargo vans would be a good proxy for this class of vehicle. Section 6.7 provides justification for RSI maintenance cost estimates.

Assumptions		Fleet Data[2]					Used for LCA			
Veh Type	Passenger Van Full Size	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	1	1	45	$822	3.4		1	822	3.4	70.0%
Net Acquisition Cost:	$33,875	2	43	$1,408	6.4		2	1,408	6.4	60.0%
Cost of Capital	6.16%	3	27	$1,278	7.2		3	1,278	7.2	45.0%
Discount Rate for NPV	1.75%	4	31	$1,664	7.9		4	1,664	7.9	35.0%
HST Rate %		5	33	$2,310	9.1	33.1%	5	2,310	9.1	33.1%
Tech Prod Loss Hrs/Touch	2.5	6	37	$2,071	9.3		6	2,071	9.3	25.0%
Tech Labour Rate $/Hr	$74	7	49	$2,445	9.0	10.5%	7	2,445	9.0	10.5%
CIF[1] on Maintenance	4.0%	8	35	$2,395	9.5	10.1%	8	2,395	9.5	10.1%
CIF[1] on Driver Rate	3.0%	9	18	$1,825	6.9	4.7%	9	1,825	6.9	4.7%
CIF[1] on Vehicle	2.0%	10	12	$2,682	5.0	4.5%	10	2,682	5.0	4.5%
CIF[1] on Fuel	4.0%	11	5	$2,869	9.8		11	5,500	9.8	4.0%
Fuel Baseline Price	$1.30	12	6	$5,997	7.8	6.5%	12	6,000	7.8	3.0%
Annual Veh Eff Improvement	2.0%	13	2	$2,381	8.5	14.5%	13	6,500	8.5	2.0%
New Veh Baseline L/100Km	17.7	14	1	$1,719	6.0		14	7,000	6.0	2.0%
Average Km/Yr	13,462	15					15	7,500		2.0%
Cash Flow Horizon (yrs)	15	16					16			
		17					17			
		18					18			
		19					19			
		20					20			

[1] CIF (Cost Increase Factor)

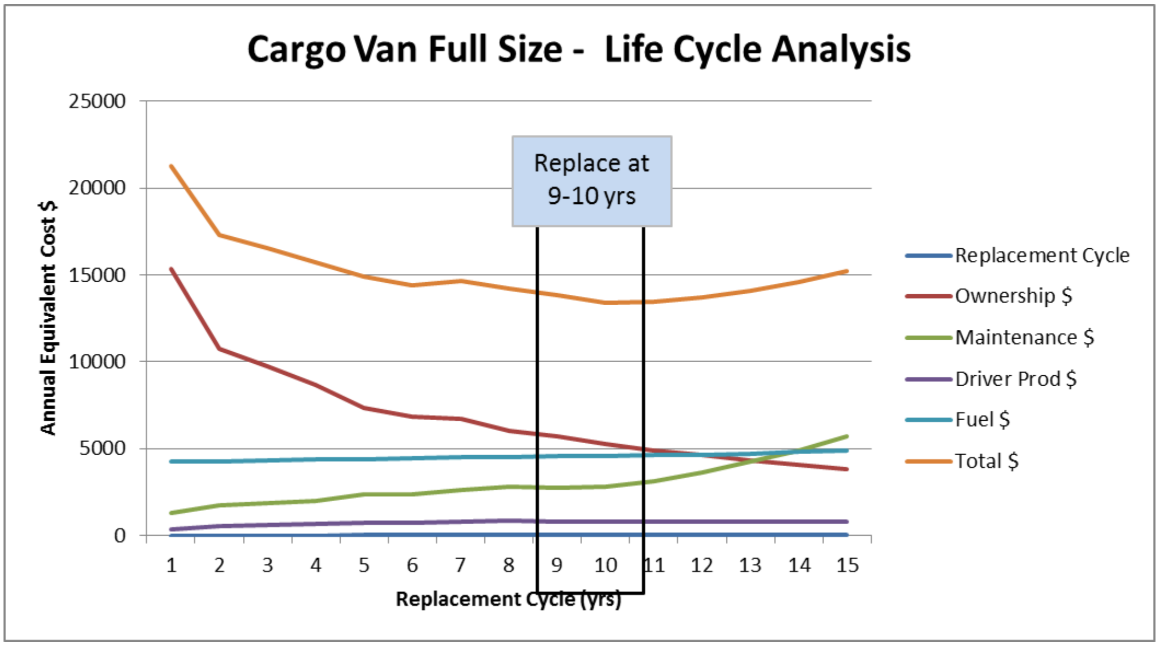
[2] Cargo van average

RSI Estimate

6.7 Cargo Van Full Size (Equipment Type 2D)

- The optimum life cycle is 10 years but the life cycle could be shortened to 9 years with minimal impact on cost.
- Recommendation: Replace at 9 years. Review condition of units at 180,000 km for possible early replacement.

Cargo Full Size Van	2012 KPI
# Vehicles	53
Avg. Replacement Cost $	$32,832
Avg. Age (yrs)	3.9
GPS Mileage (Km/Yr)	13,462
GPS Total Usage (Hrs/Yr)	1,550
GPS PTO Usage (Hrs/Yr)	0
Fuel L/100Km	17.7



Replacement Cycle	Annual Equivalent Cost: Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$15,349	$1,298	$370	$4,240	$21,257	$7,839	$415,453
2	$10,751	$1,730	$521	$4,280	$17,282	$3,864	$204,779
3	$9,743	$1,852	$617	$4,326	$16,537	$3,119	$165,309
4	$8,665	$2,007	$665	$4,360	$15,697	$2,279	$120,794
5	$7,342	$2,385	$741	$4,413	$14,882	$1,464	$77,597
6	$6,859	$2,385	$751	$4,431	$14,426	$1,008	$53,399
7	$6,740	$2,631	$784	$4,486	$14,641	$1,223	$64,807
8	$6,050	$2,811	$831	$4,528	$14,220	$802	$42,488
9	$5,721	$2,732	$814	$4,541	$13,808	$390	$20,669
10	$5,278	$2,792	$782	$4,567	$13,418	Optimum	
11	$4,912	$3,139	$786	$4,605	$13,442	$24	$1,248
12	$4,605	$3,631	$785	$4,657	$13,679	$260	$13,796
13	$4,332	$4,241	$795	$4,722	$14,090	$672	$35,602
14	$4,066	$4,908	$792	$4,800	$14,566	$1,148	$60,835
15	$3,824	$5,723	$765	$4,892	$15,204	$1,786	$94,653

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Cargo Van Full Size LCA

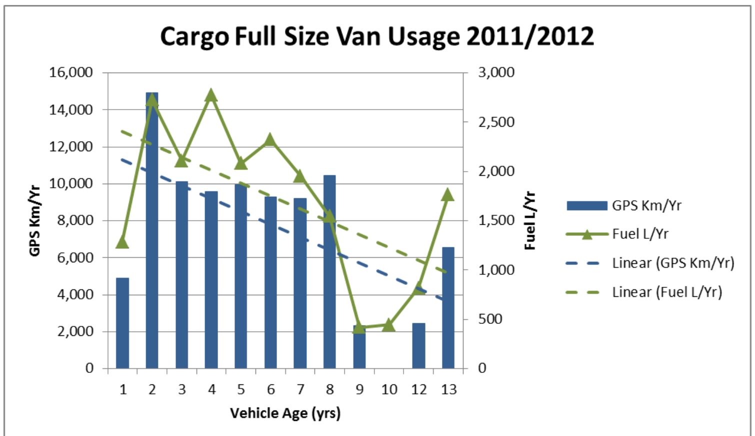
Assumptions		Fleet Data					Used for LCA			
Veh Type	Cargo Van Full Size	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	53	1	45	$822	3.4		1	822	3.4	70.0%
Net Acquisition Cost:	$32,832	2	43	$1,408	6.4		2	1,408	6.4	60.0%
Cost of Capital	6.16%	3	27	$1,278	7.2		3	1,278	7.2	45.0%
Discount Rate for NPV	1.75%	4	31	$1,664	7.9		4	1,664	7.9	35.0%
HST Rate %		5	33	$2,310	9.1	33.1%	5	2,310	9.1	33.1%
Tech Prod Loss Hrs/Touch	2.5	6	37	$2,071	9.3		6	2,071	9.3	25.0%
Tech Labour Rate $/Hr	$74	7	49	$2,445	9.0	10.5%	7	2,445	9.0	10.5%
CIF[1] on Maintenance	4.0%	8	35	$2,395	9.5	10.1%	8	2,395	9.5	10.1%
CIF[1] on Driver Rate	3.0%	9	18	$1,825	6.9	4.7%	9	1,825	6.9	4.7%
CIF[1] on Vehicle	2.0%	10	12	$2,682	5.0	4.5%	10	2,682	5.0	4.5%
CIF[1] on Fuel	4.0%	11	5	$2,869	9.8		11	5,500	9.8	4.0%
Fuel Baseline Price	$1.30	12	6	$5,997	7.8	6.5%	12	5,997	7.8	3.0%
Annual Veh Eff Improvement	2.0%	13	2	$2,381	8.5	14.5%	13	6,500	8.5	2.0%
New Veh Baseline L/100Km	17.7	14	1	$1,719	6.0		14	7,000	6.0	2.0%
Average Km/Yr	13,462	15					15	7,500		2.0%
Cash Flow Horizon (yrs)	15	16					16			
[1] CIF (Cost Increase Factor)		17					17			
		18					18			
		19					19			
		20					20			
							RSI Estimate			

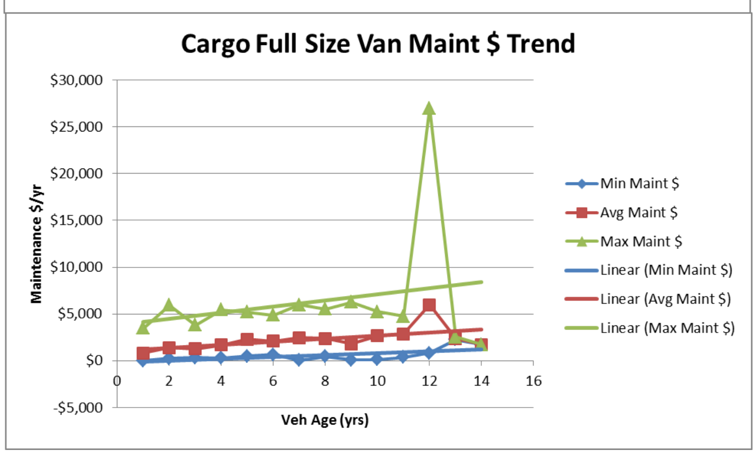
RSI Maintenance Cost Estimates

Assumptions were made for maintenance cost for years 11 and 13-15 since TH costs should be increasing at a faster rate with vehicle age.

The upper chart at right shows that vehicle utilization decreases as vehicles age which reflects a preference for using newer vehicles. Lower utilization results in the lower than expected maintenance cost.

The lower chart at right shows minimum, average and maximum maintenance costs and linear trends. The maximum cost trend is indicative of maintenance cost for normalized utilization. Based on this trend, the RSI database and RSI experience with other fleets, the maintenance cost estimates made are reflective of realistic expected costs for normalized utilization.

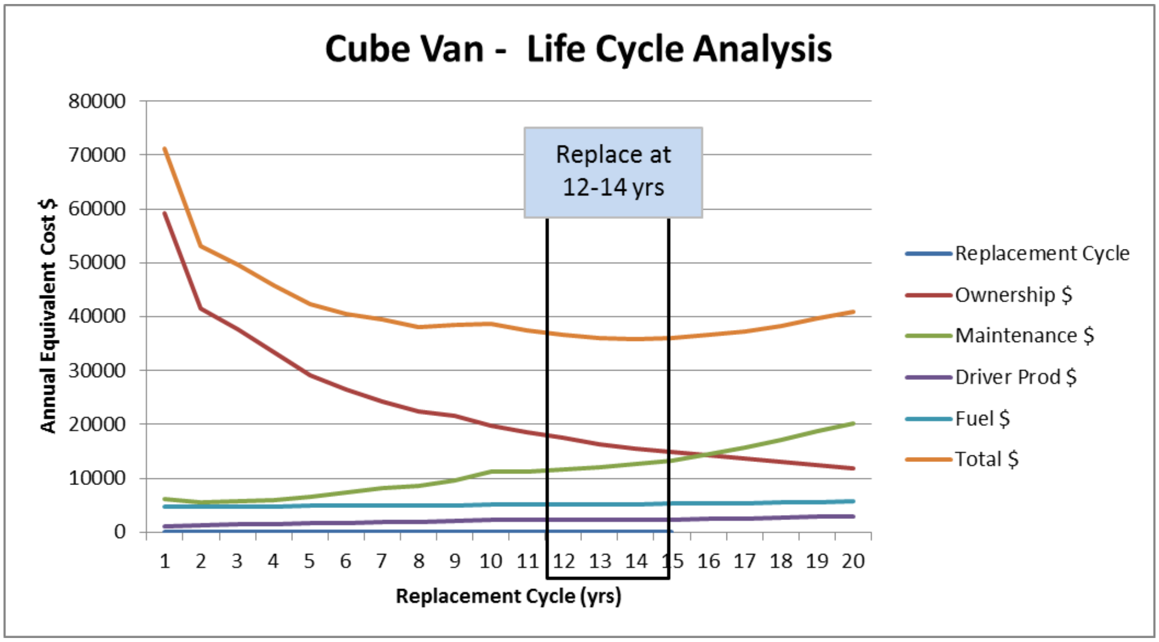




6.8 Cube Van (Equipment Type 2F)

Cube Van	2012 KPI
# Vehicles	62
Avg. Replacement Cost $	$94,515
Avg. Age (yrs)	8.0
GPS Mileage (Km/Yr)	8,216
GPS Total Usage (Hrs/Yr)	1,728
GPS PTO Usage (Hrs/Yr)	0
Fuel L/100Km	24.0

- The optimum life cycle is 14 years but the life cycle could be shortened to 12 years with minimal impact on cost.
- Recommendation: Replace at 12 years. Review condition of units at 180,000 km for possible early replacement.



Replacement Cycle	Annual Equivalent Cost Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$59,280	$6,114	$1,149	$4,703	$71,247	$35,358	$2,192,219
2	$41,495	$5,547	$1,254	$4,750	$53,047	$17,159	$1,063,827
3	$37,666	$5,812	$1,432	$4,793	$49,703	$13,815	$856,531
4	$33,399	$5,935	$1,559	$4,846	$45,740	$9,851	$610,785
5	$29,220	$6,556	$1,729	$4,895	$42,400	$6,512	$403,746
6	$26,438	$7,422	$1,804	$4,925	$40,590	$4,702	$291,493
7	$24,255	$8,292	$1,935	$4,980	$39,461	$3,573	$221,524
8	$22,440	$8,710	$1,961	$5,006	$38,117	$2,229	$138,169
9	$21,551	$9,740	$2,114	$5,063	$38,467	$2,579	$159,905
10	$19,876	$11,283	$2,289	$5,151	$38,599	$2,711	$168,075
11	$18,660	$11,348	$2,292	$5,156	$37,457	$1,569	$97,275
12	$17,565	$11,683	$2,276	$5,173	$36,697	$809	$50,131
13	$16,439	$12,086	$2,297	$5,201	$36,024	$135	$8,392
14	$15,630	$12,674	$2,345	$5,240	$35,888	Optimum	
15	$14,925	$13,391	$2,396	$5,291	$36,003	$115	$7,125
16	$14,356	$14,438	$2,466	$5,354	$36,614	$726	$44,982
17	$13,606	$15,742	$2,575	$5,428	$37,352	$1,463	$90,725
18	$12,998	$17,125	$2,694	$5,514	$38,331	$2,443	$151,454
19	$12,463	$18,695	$2,851	$5,612	$39,620	$3,732	$231,374
20	$11,946	$20,297	$3,030	$5,721	$40,994	$5,106	$316,584

Assumptions and Data Used for Cube Van LCA

Assumptions		Fleet Data					Used for LCA			
Veh Type	Cube Van	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	62	1	12	$2,740	7.7	3.2%	1	2,740	8	70.0%
Net Acquisition Cost:	$94,515	2	16	$2,237	9.1	2.0%	2	2,237	9	60.0%
Cost of Capital	6.16%	3	18	$2,882	12.3		3	2,882	12	45.0%
Discount Rate for NPV	1.75%	4	20	$2,770	12.5		4	2,770	12	35.0%
HST Rate %		5	19	$3,991	15.9		5	3,991	16	30.0%
Tech Prod Loss Hrs/Touch	2.5	6	16	$5,801	17.1		6	5,801	17	25.0%
Tech Labour Rate $/Hr	$74	7	48	$6,196	16.6		7	6,196	17	20.0%
CIF[1] on Maintenance	4.0%	8	43	$7,026	18.7	16.6%	8	7,026	19	16.6%
CIF[1] on Driver Rate	3.0%	9	38	$7,051	22.3		9	7,051	22	8.0%
CIF[1] on Vehicle	2.0%	10	36	$8,556	19.1		10	8,556	19	6.0%
CIF[1] on Fuel	4.0%	11	33	$8,278	16.8	5.2%	11	10,000	20	5.2%
Fuel Baseline Price	$1.30	12	5	$4,821	16.0		12	10,500	21	5.0%
Annual Veh Eff Improvement	2.0%	13	6	$3,781	13.5	7.0%	13	11,000	22	7.0%
New Veh Baseline L/100Km	24.0	14	5	$4,231	11.2	6.5%	14	11,500	23	6.5%
Average Km/Yr	8,216	15	4	$4,738	9.5	5.6%	15	12,000	24	5.6%
Cash Flow Horizon (yrs)	20	16	1	$3,155	16.0	3.2%	16	12,500	25	3.2%
		17	1	$4,657	9.0		17	13,000	26	5.0%
		18	1	$1,471	6.0	5.0%	18	13,500	27	5.0%
		19					19	14,000	28	4.0%
		20					20	14,500	29	3.0%
							RSI Estimate			

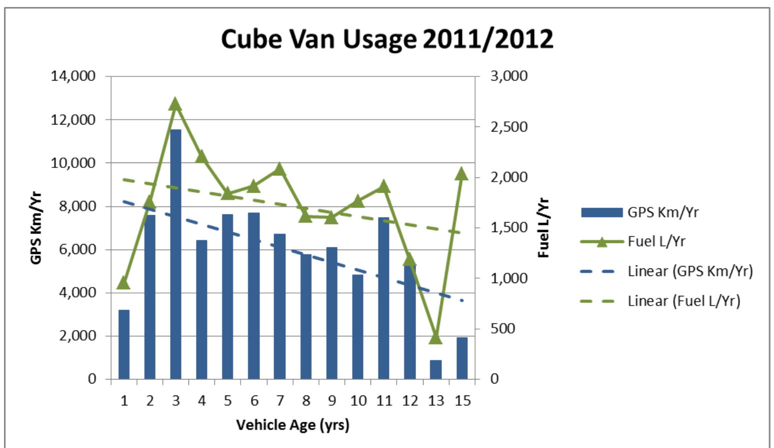
[1] CIF (Cost Increase Factor)

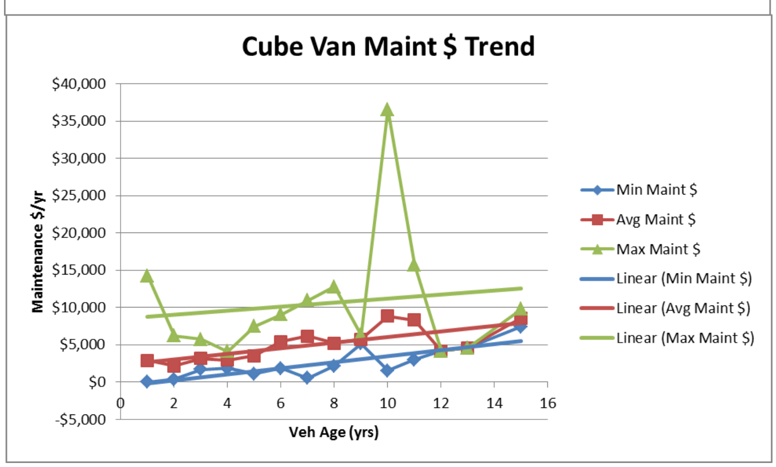
RSI Maintenance Cost Estimates

Assumptions were made for maintenance cost for years 11-20 since TH costs should be increasing at a faster rate with vehicle age and there were few vehicles over 12 years old in service.

The upper chart at right shows that vehicle utilization decreases as vehicles age which reflects a preference for using newer vehicles. Lower utilization results in the lower than expected maintenance cost.

The lower chart at right shows minimum, average and maximum maintenance costs and linear trends. The maximum cost trend is indicative of maintenance cost for normalized utilization. Based on this trend, the RSI database and RSI experience with other fleets, the maintenance cost estimates made are reflective of realistic expected costs for normalized utilization.

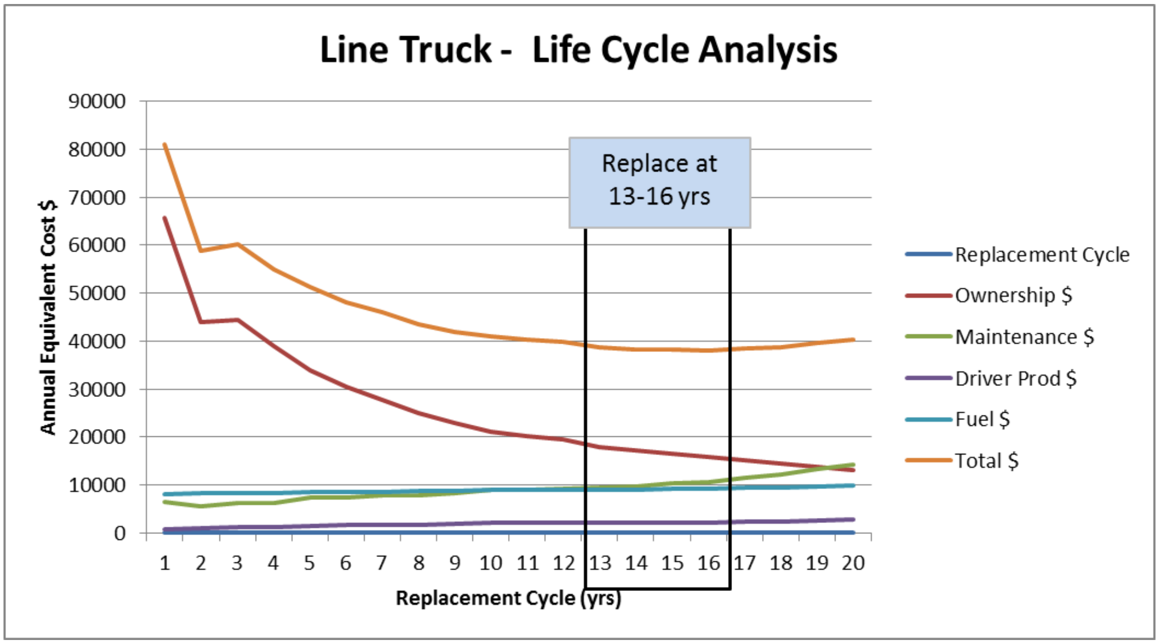




Line Truck	2012 KPI
# Vehicles	6
Avg. Replacement Cost $	$104,623
Avg. Age (yrs)	5.8
GPS Mileage (Km/Yr)	16,468
GPS Total Usage (Hrs/Yr)	1,385
GPS PTO Usage (Hrs/Yr)	0
Fuel L/100Km	20.8

6.9 Line Truck (Equipment Type 3A, 3B, 3E)

- The optimum life cycle is 16 years but the life cycle could be shortened to 13 years with minimal impact on cost.
- Recommendation: Replace at 13 years. Review condition of units at 195,000 km for possible early replacement.



Replacement Cycle	Annual Equivalent Cost						
	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$65,620	$6,497	$674	$8,169	$80,961	$42,915	$257,493
2	$43,930	$5,624	$1,014	$8,251	$58,819	$20,773	$124,639
3	$44,487	$6,181	$1,204	$8,326	$60,197	$22,152	$132,909
4	$38,980	$6,303	$1,335	$8,418	$55,036	$16,990	$101,942
5	$33,887	$7,343	$1,563	$8,504	$51,296	$13,250	$79,503
6	$30,504	$7,344	$1,629	$8,555	$48,032	$9,986	$59,919
7	$27,662	$7,936	$1,785	$8,651	$46,034	$7,988	$47,930
8	$25,110	$7,836	$1,785	$8,696	$43,426	$5,380	$32,282
9	$22,979	$8,290	$1,877	$8,795	$41,941	$3,895	$23,371
10	$21,051	$9,054	$2,061	$8,948	$41,114	$3,069	$18,411
11	$20,218	$9,071	$2,064	$8,957	$40,311	$2,265	$13,589
12	$19,597	$9,215	$2,084	$8,986	$39,881	$1,835	$11,010
13	$17,949	$9,523	$2,114	$9,035	$38,620	$574	$3,445
14	$17,310	$9,795	$2,152	$9,103	$38,361	$315	$1,887
15	$16,647	$10,288	$2,205	$9,192	$38,331	$286	$1,713
16	$15,790	$10,693	$2,263	$9,300	$38,046	Optimum	
17	$15,169	$11,473	$2,376	$9,429	$38,447	$401	$2,407
18	$14,463	$12,270	$2,498	$9,578	$38,809	$763	$4,576
19	$13,840	$13,321	$2,646	$9,748	$39,555	$1,509	$9,056
20	$13,223	$14,355	$2,844	$9,938	$40,360	$2,314	$13,884

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Line Truck LCA

Assumptions		Fleet Data					Used for LCA			
Veh Type	Line Truck	Veh Age	# Veh	Maint $/Yr[2]	# WO	Residual %	Veh Age	Maint $/Yr[3]	# WO/Yr[3]	Residual %
# Veh In Service	6	1	2	$2,911	4.5		1	2,911	4.5	70%
Net Acquisition Cost:	$104,623	2	3	$2,137	9.0	62.3%	2	2,137	9.0	62%
Cost of Capital	6.16%	3	2	$3,353	11.0		3	3,353	11.0	40%
Discount Rate for NPV	1.75%	4	4	$2,883	11.0		4	2,883	11.0	30%
HST Rate %		5	3	$5,054	16.3		5	5,054	16.3	25%
Tech Prod Loss Hrs/Touch	2.5	6	3	$3,894	16.0	62.3%	6	3,894	16.0	20%
Tech Labour Rate $/Hr	$74	7	3	$4,998	16.7		7	4,998	16.7	16%
CIF[1] on Maintenance	4.0%	8	3	$4,260	16.7		8	4,260	16.7	15%
CIF[1] on Driver Rate	3.0%	9				10.5%	9	5,000	17.0	14%
CIF[1] on Vehicle	2.0%	10				13.6%	10	5,500	18.0	13.6%
CIF[1] on Fuel	4.0%	11				9.2%	11	6,000	19.0	9.2%
Fuel Baseline Price	$1.30	12				3.4%	12	6,500	20.0	3.4%
Annual Veh Eff Improvement	2.0%	13	1	$3,026	12.0	9.9%	13	7,000	21.0	9.9%
New Veh Baseline L/100Km	20.8	14				6.4%	14	7,500	22.0	6.4%
Average Km/Yr	16,468	15				3.8%	15	8,000	23.0	3.8%
Cash Flow Horizon (yrs)	20	16				4.9%	16	8,500	24.0	4.9%
		17	2	$4,985	15.0	3.1%	17	9,000	25.0	3.1%
		18	2	$3,298	11.0	3.5%	18	9,500	26.0	3.5%
		19	2	$5,284	17.0		19	10,000	27.0	3.0%
		20					20	10,500	28.0	3.0%
							RSI Estimate			

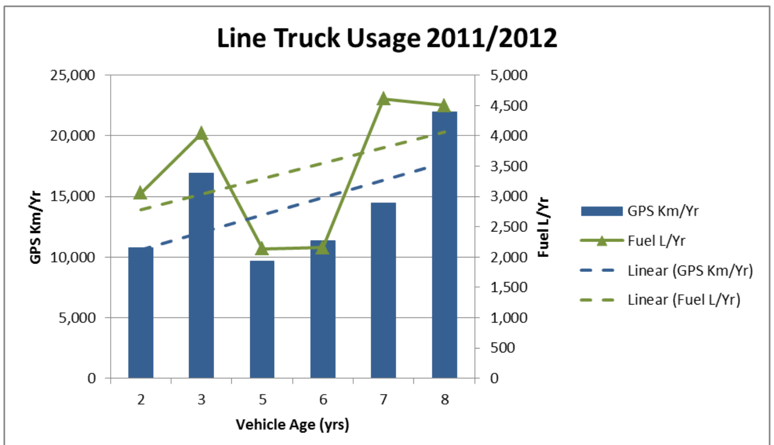
[1] CIF (Cost Increase Factor)

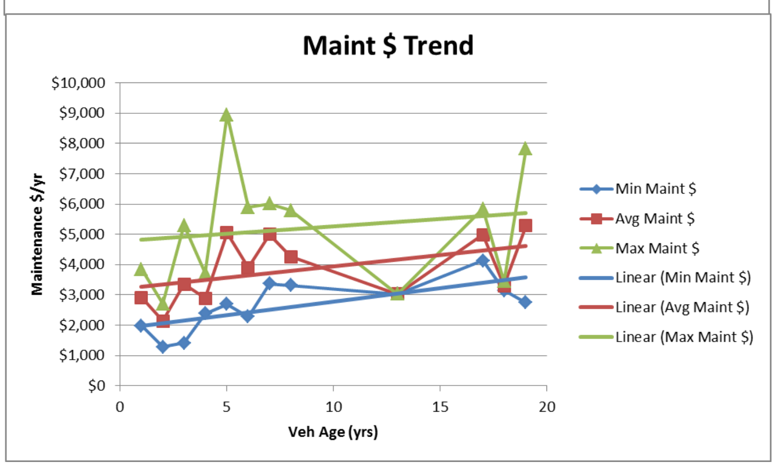
RSI Maintenance Cost Estimates

Assumptions were made for maintenance cost for years 9-20 since TH costs should be increasing at a faster rate with vehicle age, there few vehicles and to address data gaps.

The upper chart at right shows that vehicle utilization does not reduce as these vehicles age.

The lower chart at right shows minimum, average and maximum maintenance costs and linear trends. The maximum cost trend shows a modest upward trend. Based on this modest upward trend, the RSI database and RSI experience with other fleets, the maintenance cost estimates for a modest annual increase reflect realistic expected costs.

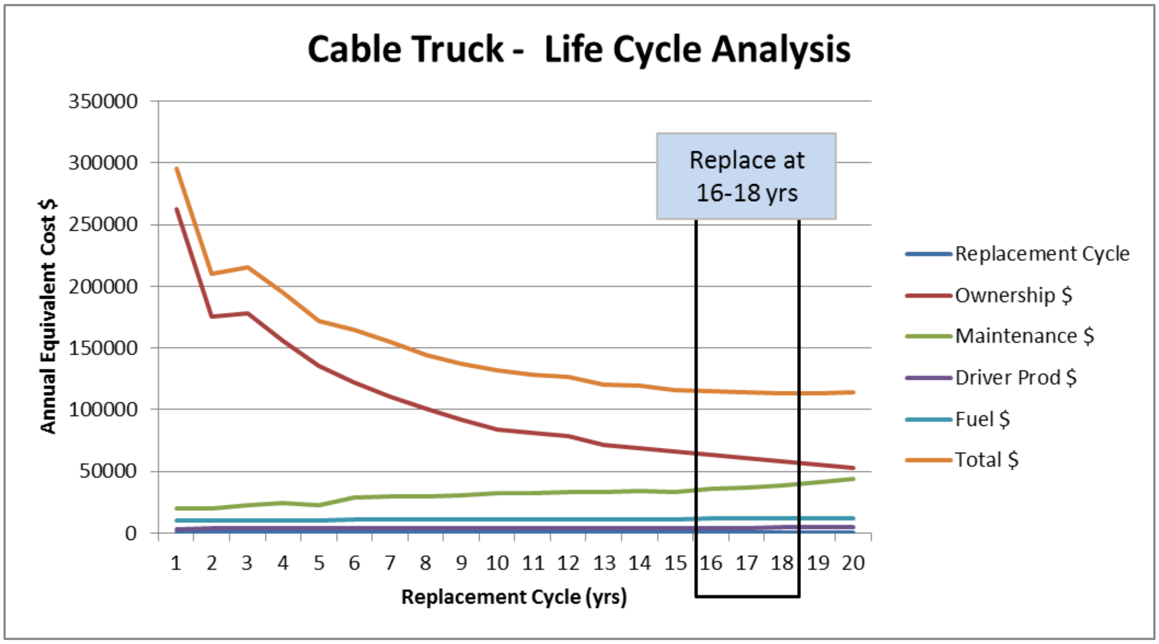




6.10 Cable Truck (Equipment Type 4B)

Cable Truck	2012 KPI
# Vehicles	6
Avg. Replacement Cost $	$418,577
Avg. Age (yrs)	3.7
GPS Mileage (Km/Yr)	5,475
GPS Total Usage (Hrs/Yr)	1,421
GPS PTO Usage (Hrs/Yr)	486
Fuel L/100Km	77.9

- The optimal life cycle is 18 years but the life cycle could be shortened to 16 years with minimal impact on cost.
- Recommendation: Replace at 16 years. Review condition of units at 240,000 km for possible early replacement.



Replacement Cycle	Annual Equivalent Cost Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$262,534	$19,876	$3,267	$10,172	$295,849	$182,734	$1,096,404
2	$175,755	$20,303	$3,840	$10,274	$210,171	$97,056	$582,337
3	$177,984	$22,897	$3,958	$10,367	$215,205	$102,090	$612,539
4	$155,952	$24,804	$3,934	$10,482	$195,172	$82,056	$492,339
5	$135,577	$22,313	$3,819	$10,588	$172,296	$59,181	$355,087
6	$122,041	$28,506	$4,062	$10,653	$165,262	$52,146	$312,879
7	$110,672	$29,892	$4,070	$10,772	$155,406	$42,291	$253,744
8	$100,459	$29,379	$4,031	$10,827	$144,696	$31,581	$189,486
9	$91,934	$30,289	$4,049	$10,951	$137,223	$24,107	$144,644
10	$84,221	$32,598	$4,103	$11,142	$132,065	$18,949	$113,696
11	$80,890	$32,617	$4,109	$11,153	$128,770	$15,655	$93,927
12	$78,403	$32,890	$4,132	$11,189	$126,613	$13,498	$80,988
13	$71,809	$33,426	$4,170	$11,249	$120,654	$7,539	$45,233
14	$69,254	$34,309	$4,225	$11,335	$119,123	$6,008	$36,046
15	$66,601	$33,357	$4,204	$11,445	$115,606	$2,491	$14,947
16	$63,171	$35,694	$4,306	$11,580	$114,751	$1,636	$9,813
17	$60,690	$37,188	$4,391	$11,741	$114,010	$894	$5,366
18	**$57,862**	**$38,864**	**$4,462**	**$11,926**	**$113,115**	**Optimum**	
19	$55,372	$41,225	$4,533	$12,138	$113,268	$153	$917
20	$52,904	$43,827	$4,677	$12,375	$113,783	$667	$4,004

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Cable Truck LCA

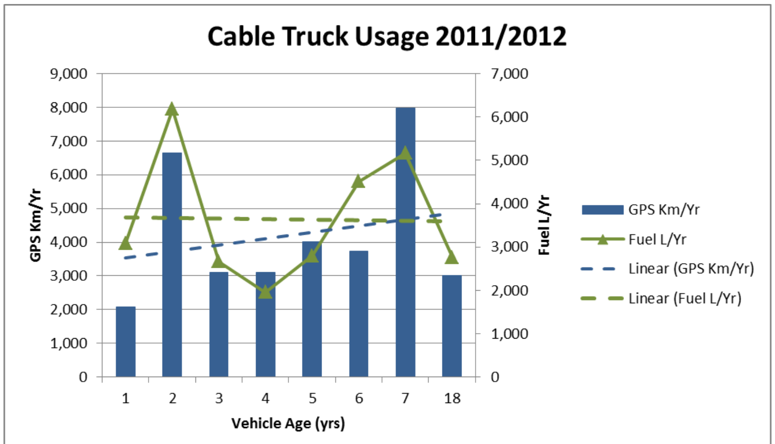
Assumptions		Fleet Data					Used for LCA			
Veh Type	Cable Truck	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	6	1	5	$8,906	21.8		1	8,906	22	70%
Net Acquisition Cost:	$418,577	2	5	$9,284	29.4	62.3%	2	9,284	29	62%
Cost of Capital	6.16%	3	4	$12,978	28.3		3	12,978	28	40%
Discount Rate for NPV	1.75%	4	2	$13,109	25.5		4	13,109	26	30%
HST Rate %		5	2	$5,769	22.5		5	5,769	23	25%
Tech Prod Loss Hrs/Touch	2.5	6	1	$28,644	36.0	62.3%	6	28,644	36	20%
Tech Labour Rate $/Hr	$74	7	1	$14,443	26.0		7	14,443	26	16%
CIF[1] on Maintenance	4.0%	8					8	16,000	27	15%
CIF[1] on Driver Rate	3.0%	9				10.5%	9	17,000	28	14%
CIF[1] on Vehicle	2.0%	10				13.6%	10	18,000	29	13.6%
CIF[1] on Fuel	4.0%	11				9.2%	11	19,000	30	9.2%
Fuel Baseline Price	$1.30	12				3.4%	12	20,000	31	3.4%
Annual Veh Eff Improvement	2.0%	13				9.9%	13	21,000	32	9.9%
New Veh Baseline L/100Km	77.9	14				6.4%	14	22,000	33	6.4%
Average Km/Yr	5,475	15	3	$12,613	26.3	3.8%	15	23,000	34	3.8%
Cash Flow Horizon (yrs)	20	16	1	$14,737	31.0	4.9%	16	24,000	35	4.9%
[1] CIF (Cost Increase Factor)		17	3	$9,014	24.7	3.1%	17	25,000	36	3.1%
		18	2	$18,783	25.0	3.5%	18	26,000	37	3.5%
		19					19	27,000	38	3.0%
		20					20	28,000	39	3.0%
							RSI Estimate			

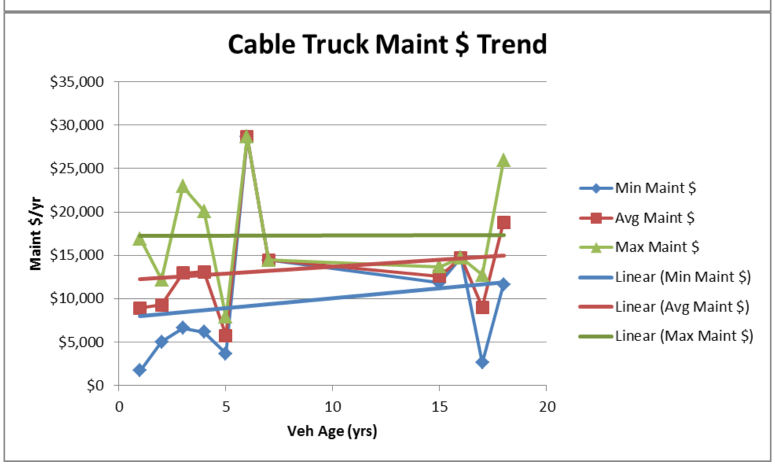
RSI Maintenance Cost Estimates

Assumptions were made for maintenance cost for years 8-20 to address data gaps and the lower than expected maintenance cost in years 15-18.

The upper chart at right shows that vehicle utilization does not reduce as these vehicles age.

The lower chart at right shows minimum, average and maximum maintenance costs and linear trends. The maximum cost trend shows a modest upward trend. Based on this modest upward trend, the RSI database and RSI experience with other fleets, the maintenance cost estimates for a modest annual increase reflect realistic expected costs. Note that these are complex production vehicles that require hydraulic system maintenance and repairs.

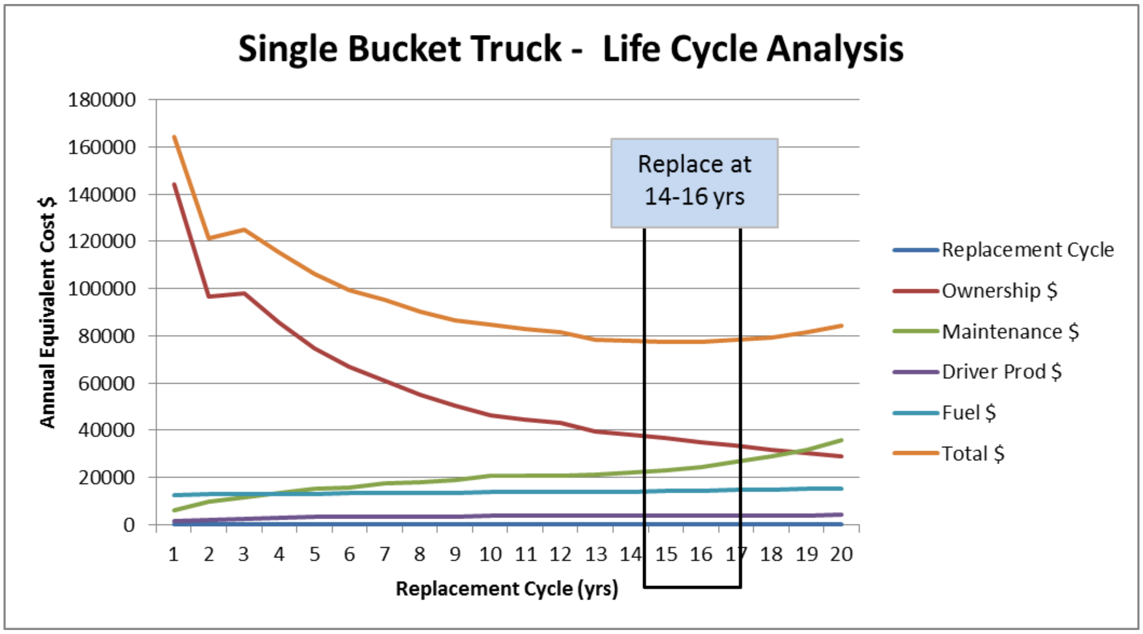




6.11 Single Bucket Truck (Equipment Type 5A,5B,5J)

Single Bucket Truck	2012 KPI
# Vehicles	86
Avg. Replacement Cost $	$230,076
Avg. Age (yrs)	7.6
GPS Mileage (Km/Yr)	14,867
GPS Total Usage (Hrs/Yr)	1,802
GPS PTO Usage (Hrs/Yr)	318

- A 16 year life minimizes life cycle cost but the life cycle could be shortened to 14 years with minimal cost impact.
- Recommendation: Replace at 14 years. Review condition of units at 210,000 km for possible early replacement.



Replacement Cycle	Annual Equivalent Cost Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$144,305	$6,091	$1,401	$12,694	$164,491	$87,001	$7,482,078
2	$96,606	$9,608	$2,186	$12,821	$121,220	$43,730	$3,760,799
3	$97,831	$11,657	$2,657	$12,937	$125,082	$47,592	$4,092,920
4	$85,721	$13,565	$3,013	$13,080	$115,379	$37,889	$3,258,462
5	$74,522	$15,063	$3,264	$13,213	$106,062	$28,572	$2,457,173
6	$67,081	$15,859	$3,278	$13,294	$99,512	$22,022	$1,893,911
7	$60,832	$17,592	$3,471	$13,442	$95,338	$17,848	$1,534,905
8	$55,218	$18,015	$3,457	$13,512	$90,201	$12,711	$1,093,138
9	$50,533	$18,873	$3,497	$13,666	$86,569	$9,078	$780,733
10	$46,293	$20,720	$3,718	$13,904	$84,635	$7,145	$614,484
11	$44,462	$20,711	$3,709	$13,918	$82,800	$5,309	$456,601
12	$43,095	$20,938	$3,702	$13,963	$81,697	$4,207	$361,823
13	$39,471	$21,258	$3,706	$14,038	$78,473	$982	$84,490
14	$38,066	$21,978	$3,723	$14,145	$77,911	$421	$36,170
15	$36,608	$23,022	$3,734	$14,282	$77,646	$156	$13,416
16	**$34,723**	**$24,572**	**$3,745**	**$14,451**	**$77,490**	**Optimum**	
17	$33,359	$26,568	$3,780	$14,651	$78,357	$867	$74,567
18	$31,805	$28,980	$3,826	$14,883	$79,494	$2,003	$172,293
19	$30,436	$31,924	$3,922	$15,147	$81,429	$3,939	$338,770
20	$29,079	$35,641	$4,112	$15,442	$84,275	$6,784	$583,457

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Single Bucket Truck LCA

Assumptions		Fleet Data					Used for LCA			
Veh Type	Single Bucket Truck	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	86	1	20	$2,729	9.4		1	2,729	9	70%
Net Acquisition Cost:	$230,076	2	37	$5,847	19.8	62.3%	2	5,847	20	62%
Cost of Capital	6.16%	3	37	$7,371	25.1		3	7,371	25	40%
Discount Rate for NPV	1.75%	4	38	$8,171	25.9		4	8,171	26	30%
HST Rate %		5	40	$9,292	28.3		5	9,292	28	25%
Tech Prod Loss Hrs/Touch	2.5	6	47	$10,965	27.6	62.3%	6	10,965	28	20%
Tech Labour Rate $/Hr	$74	7	49	$11,428	26.6		7	11,428	27	16%
CIF[1] on Maintenance	4.0%	8	53	$12,529	27.6		8	12,529	28	15%
CIF[1] on Driver Rate	3.0%	9	46	$11,478	28.4	10.5%	9	11,478	28	14%
CIF[1] on Vehicle	2.0%	10	44	$11,362	28.0	13.6%	10	11,362	28	13.6%
CIF[1] on Fuel	4.0%	11	24	$11,786	27.2	9.2%	11	11,786	27	9.2%
Fuel Baseline Price	$1.30	12	16	$10,646	27.3	3.4%	12	14,000	28	3.4%
Annual Veh Eff Improvement	2.0%	13	7	$9,143	23.9	9.9%	13	16,000	29	9.9%
New Veh Baseline L/100Km	35.8	14	12	$8,992	21.8	6.4%	14	18,000	29	6.4%
Average Km/Yr	14,867	15	15	$9,638	22.0	3.8%	15	20,000	30	3.8%
Cash Flow Horizon (yrs)	20	16	5	$8,037	20.4	4.9%	16	22,000	30	4.9%
		17	3	$5,347	17.3	3.1%	17	24,000	31	3.1%
		18	2	$3,593	11.5	3.5%	18	26,000	31	3.5%
		19					19	28,000	32	3.0%
		20					20	30,000	32	3.0%

[1] CIF (Cost Increase Factor)

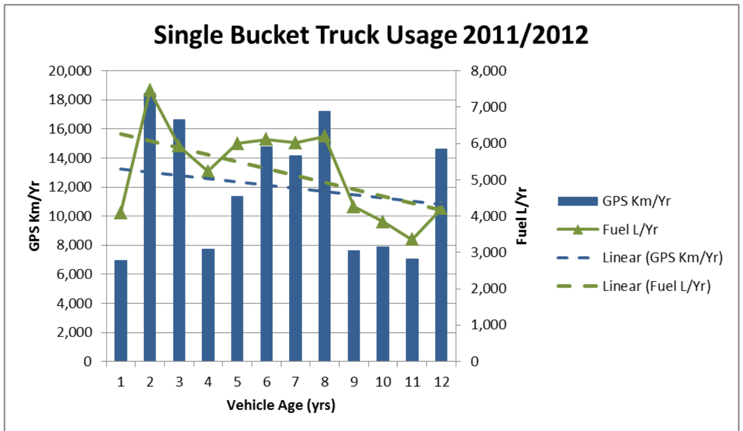
RSI Estimate

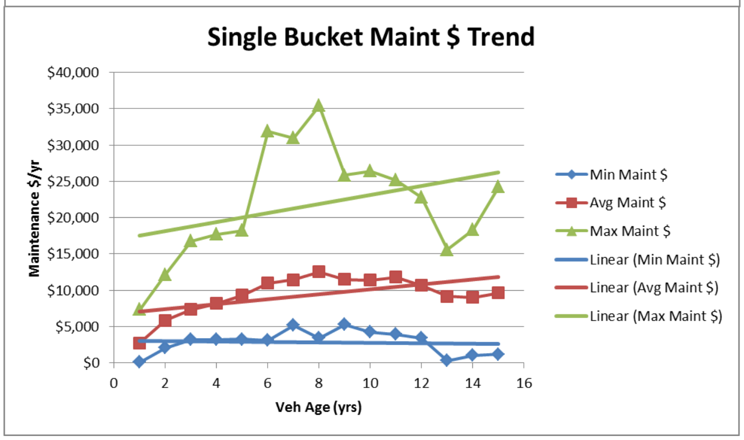
RSI Maintenance Cost Estimates

Assumptions were made for maintenance cost for years 12-20 since TH costs should be increasing at a faster rate with vehicle age.

The upper chart at right shows that vehicle utilization decreases as vehicles age which reflects a preference for using newer vehicles. Lower utilization results in the lower than expected maintenance cost.

The lower chart at right shows minimum, average and maximum maintenance costs and linear trends. The maximum cost trend is indicative of maintenance cost for normalized utilization. Based on this trend, the RSI database and RSI experience with other fleets, the maintenance cost estimates made are reflective of realistic expected costs for normalized utilization. Note that these are complex production vehicles that require high cost hydraulic system maintenance and repairs.

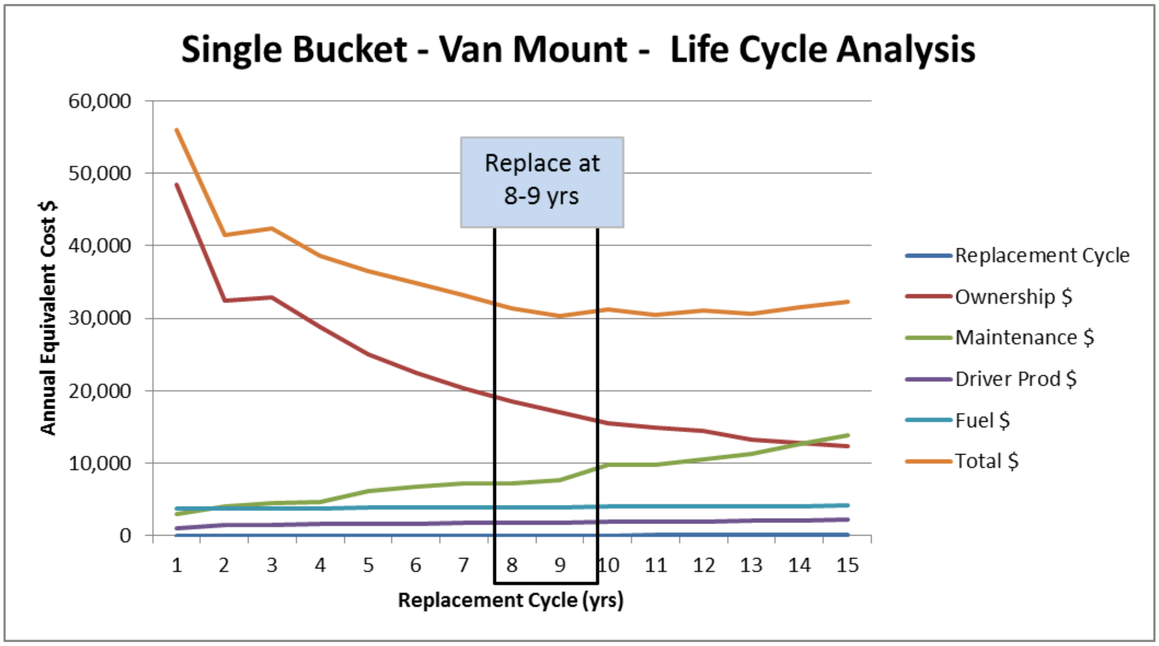




6.12 Single Bucket Truck Van Mount (Equipment Type 5D)

- A 9 year life minimizes life cycle cost but the life cycle could be lowered to 8 years with minimal cost impact.
- Vehicle frame integrity is critical on this type of vehicle to support torsion loads from the boom. This favours a shorter life cycle.
- Recommendation: Replace at 8 years. Review condition of units at 160,000 km for possible early replacement.

Single Bucket Van	2012 KPI
# Vehicles	7
Avg. Replacement Cost $	$77,212
Avg. Age (yrs)	3.1
GPS Mileage (Km/Yr)	6,013
GPS Total Usage (Hrs/Yr)	542
GPS PTO Usage (Hrs/Yr)	68
Fuel L/100Km	25.4



Replacement Cycle	Annual Equivalent Cost Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$48,428	$2,954	$1,019	$3,643	$56,044	$25,781	$180,468
2	$32,420	$4,019	$1,424	$3,679	$41,542	$11,279	$78,955
3	$32,831	$4,433	$1,446	$3,712	$42,423	$12,160	$85,118
4	$28,767	$4,571	$1,557	$3,754	$38,649	$8,386	$58,703
5	$25,009	$6,165	$1,560	$3,792	$36,526	$6,263	$43,838
6	$22,512	$6,808	$1,650	$3,815	$34,785	$4,522	$31,654
7	$20,415	$7,151	$1,720	$3,857	$33,144	$2,881	$20,167
8	$18,531	$7,205	$1,752	$3,877	$31,365	$1,102	$7,711
9	**$16,958**	**$7,666**	**$1,717**	**$3,922**	**$30,263**	**Optimum**	
10	$15,536	$9,770	$1,900	$3,990	$31,196	$933	$6,532
11	$14,921	$9,703	$1,862	$3,994	$30,480	$218	$1,523
12	$14,462	$10,590	$1,964	$4,007	$31,023	$760	$5,321
13	$13,246	$11,334	$2,023	$4,028	$30,631	$368	$2,579
14	$12,775	$12,646	$2,099	$4,059	$31,579	$1,316	$9,215
15	$12,285	$13,785	$2,176	$4,098	$32,345	$2,082	$14,573

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Single Bucket Truck Van Mount LCA

Assumptions		Fleet Data					Used for LCA			
Veh Type	Single Bucket - Van Mount	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	7	1	5	$1,324	6.8		1	1,324	7	70%
Net Acquisition Cost:	$77,212	2	6	$2,268	12.2	62.3%	2	2,268	12	62%
Cost of Capital	6.16%	3	2	$2,420	10.0		3	2,420	10	40%
Discount Rate for NPV	1.75%	4	2	$2,153	12.5		4	2,153	13	30%
HST Rate %		5	2	$5,467	10.5		5	5,467	11	25%
Tech Prod Loss Hrs/Touch	2.5	6	1	$5,377	15.0	62.3%	6	5,377	15	20%
Tech Labour Rate $/Hr	$74	7	1	$3,043	14.0		7	3,043	14	16%
CIF[1] on Maintenance	4.0%	8					8	5,000	15	15%
CIF[1] on Driver Rate	3.0%	9	1	$6,152	16	10.5%	9	6,152	16	14%
CIF[1] on Vehicle	2.0%	10	1	$4,139	9	13.6%	10	4,139	9	13.6%
CIF[1] on Fuel	4.0%	11	1	$10,180	21	9.2%	11	10,180	21	9.2%
Fuel Baseline Price	$1.30	12				3.4%	12	12,000	22	3.4%
Annual Veh Eff Improvement	2.0%	13				9.9%	13	13,000	23	9.9%
New Veh Baseline L/100Km	25.4	14	1	$95	1	6.4%	14	14,000	24	6.4%
Average Km/Yr	6,013	15				3.8%	15	15,000	25	3.8%
Cash Flow Horizon (yrs)	20	16				4.9%	16			4.9%
		17				3.1%	17			3.1%
		18				3.5%	18			3.5%
		19					19			3.0%
		20					20			3.0%
							Fleet Challenge Estimate			

[1] CIF (Cost Increase Factor)

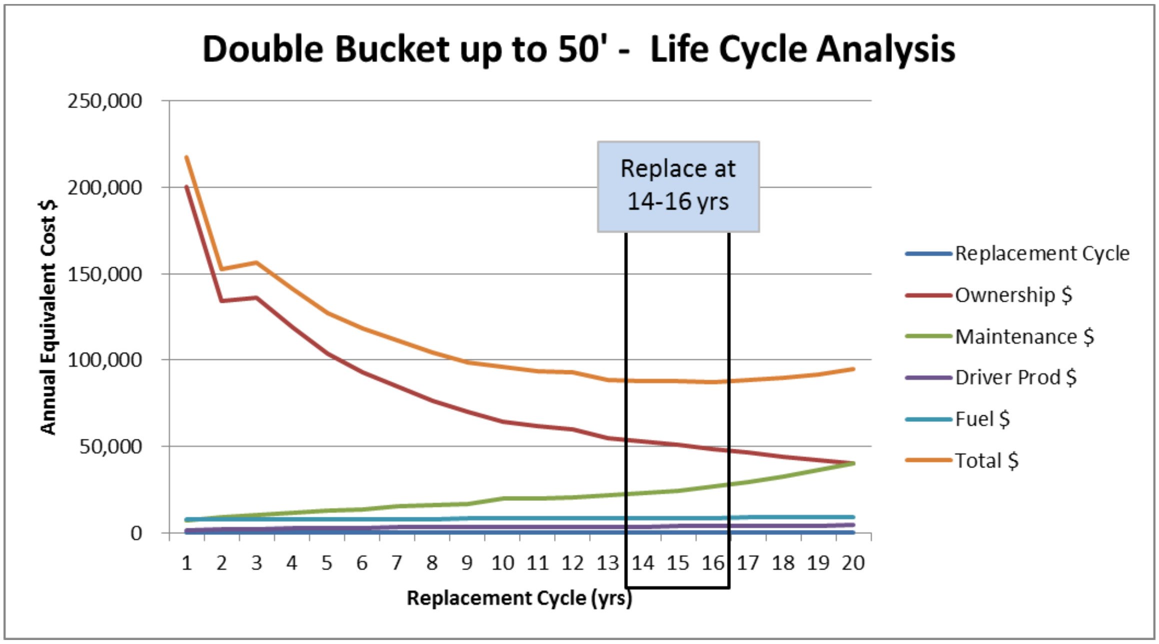
RSI Maintenance Cost Estimates

Assumptions were made for maintenance cost for years 11-15 to address data gaps and the low cost of one TH 14 year old vehicle. The estimates made are supported by the RSI database and RSI experience with other fleets.

6.13 Double Bucket up to 50' (Equipment Type 5E)

Double Bucket up to 50	2012 KPI
# Vehicles	8
Avg. Replacement Cost $	$319,510
Avg. Age (yrs)	8.0
GPS Mileage (Km/Yr)	7,750
GPS Total Usage (Hrs/Yr)	1,482
GPS PTO Usage (Hrs/Yr)	315
Fuel L/100km	41.6

- A 16 year life minimizes life cycle cost but the life cycle could be lowered to 14 years with minimal cost impact.
- Recommendation: Replace at 14 years. Review condition of units at 210,000 km for possible early replacement.



Replacement Cycle	Annual Equivalent Cost						
	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$200,399	$7,550	$1,538	$7,689	$217,176	$129,615	$1,036,918
2	$134,158	$8,991	$2,046	$7,766	$152,962	$65,400	$523,200
3	$135,859	$10,442	$2,399	$7,836	$156,536	$68,974	$551,795
4	$119,042	$11,738	$2,700	$7,923	$141,403	$53,842	$430,734
5	$103,489	$12,834	$2,964	$8,004	$127,290	$39,729	$317,831
6	$93,157	$13,931	$2,958	$8,053	$118,099	$30,537	$244,298
7	$84,478	$15,641	$3,142	$8,142	$111,405	$23,843	$190,744
8	$76,682	$16,124	$3,223	$8,185	$104,215	$16,653	$133,224
9	$70,176	$16,706	$3,299	$8,278	$98,459	$10,897	$87,177
10	$64,288	$19,751	$3,523	$8,422	$95,984	$8,423	$67,383
11	$61,745	$19,714	$3,554	$8,431	$93,445	$5,883	$47,067
12	$59,847	$20,734	$3,655	$8,458	$92,693	$5,132	$41,053
13	$54,814	$21,639	$3,654	$8,503	$88,610	$1,049	$8,389
14	$52,863	$22,853	$3,713	$8,568	$87,996	$435	$3,478
15	$50,838	$24,466	$3,789	$8,651	$87,744	$183	$1,462
16	$48,220	$26,735	$3,853	$8,754	$87,562	Optimum	
17	$46,326	$29,441	$3,956	$8,875	$88,597	$1,036	$8,286
18	$44,168	$32,533	$4,081	$9,015	$89,797	$2,235	$17,884
19	$42,267	$36,174	$4,255	$9,175	$91,871	$4,309	$34,475
20	$40,383	$40,347	$4,496	$9,354	$94,579	$7,018	$56,141

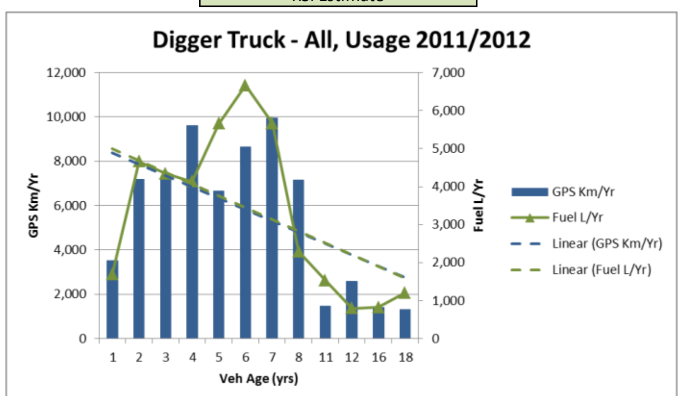
[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

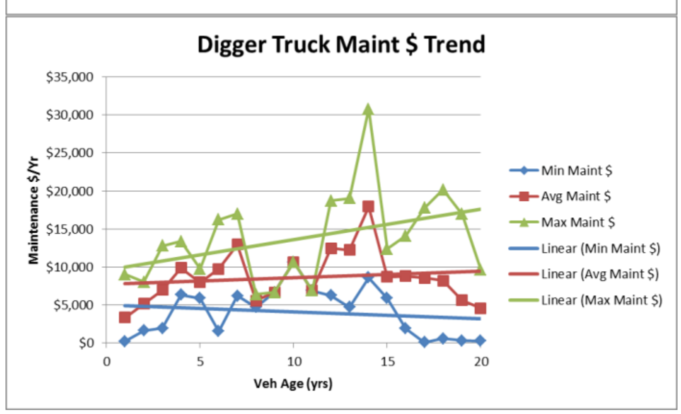
Assumptions and Data Used for Double Bucket up to 50' LCA

Maintenance costs for all double bucket trucks (up to 65+ feet) were averaged to provide cost data for as many vehicle ages as possible (Appendix 2 provides details prior to averaging).

Assumptions		Fleet Data[2]					Used for LCA			
Veh Type	Double Bucket up to 50'	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	8	1	30	$3,383	10.3		1	3,383	10	70%
Net Acquisition Cost:	$319,510	2	37	$4,660	17.0	62.3%	2	4,660	17	62%
Cost of Capital	6.16%	3	30	$6,199	21.5		3	6,199	22	40%
Discount Rate for NPV	1.75%	4	26	$6,671	23.0		4	6,671	23	30%
HST Rate %		5	13	$7,610	26.6		5	7,610	27	25%
Tech Prod Loss Hrs/Touch	2.5	6	19	$10,274	24.0	62.3%	6	10,274	24	20%
Tech Labour Rate $/Hr	$74	7	6	$11,191	25.2		7	11,191	25	16%
CIF[1] on Maintenance	4.0%	8	6	$11,551	31.2		8	11,551	31	15%
CIF[1] on Driver Rate	3.0%	9	6	$8,885	27.3	10.5%	9	8,885	27	14%
CIF[1] on Vehicle	2.0%	10	6	$16,035	27.3	13.6%	10	16,035	27	13.6%
CIF[1] on Fuel	4.0%	11	1	$17,463	32.0	9.2%	11	17,463	32	9.2%
Fuel Baseline Price	$1.30	12	1	$15,373	41.0	3.4%	12	18,000	41	3.4%
Annual Veh Eff Improvement	2.0%	13	4	$11,324	28.5	9.9%	13	20,000	32	9.9%
New Veh Baseline L/100Km	41.6	14	6	$8,430	22.3	6.4%	14	22,000	33	6.4%
Average Km/Yr	7,750	15	6	$8,973	18.2	3.8%	15	24,000	34	3.8%
Cash Flow Horizon (yrs)	20	16	3	$4,150	10.3	4.9%	16	26,000	35	4.9%
[1] CIF (Cost Increase Factor)		17	6	$8,781	19.0	3.1%	17	28,000	36	3.1%
[2] All double bucket trucks up to 65+ ft		18	3	$4,644	14.3	3.5%	18	30,000	37	3.5%
		19	5	$8,909	20.8		19	32,000	38	3.0%
		20	6	$4,331	10.0		20	34,000	39	3.0%
							RSI Estimate			

RSI Maintenance Cost Estimates





Assumptions were made for maintenance cost for years 12-20 since TH costs should be increasing at a faster rate with vehicle age and there were few vehicles over 11 years old in service.

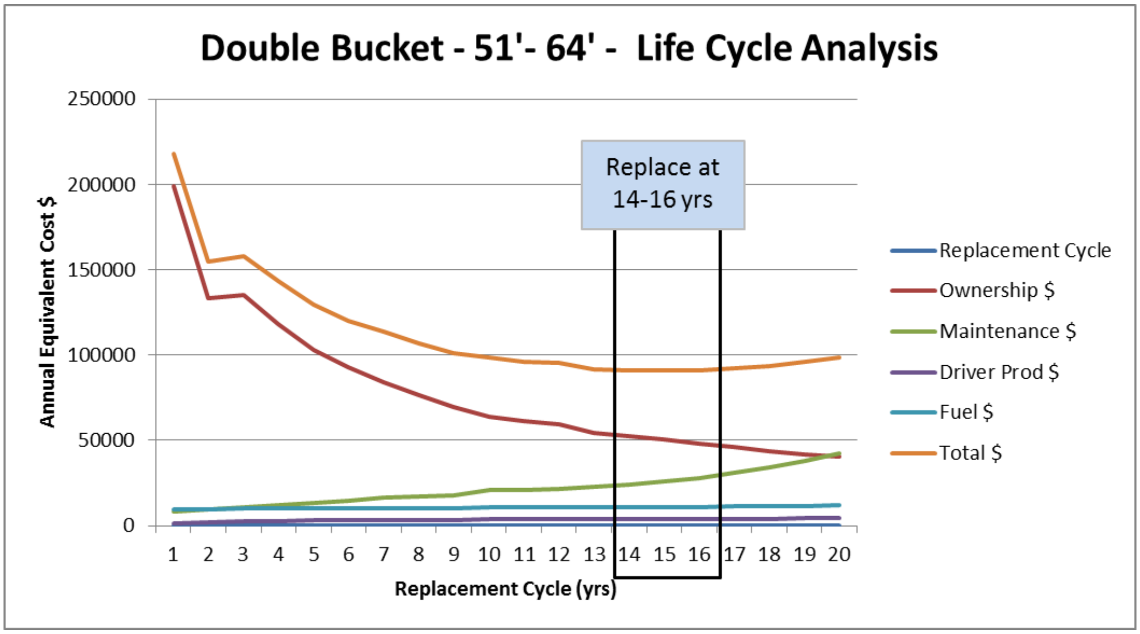
The upper chart at right shows that vehicle utilization decreases as vehicles age which reflects a preference for using newer vehicles. Lower utilization results in the lower than expected maintenance cost.

The lower chart at right shows minimum, average and maximum maintenance costs and linear trends. The maximum cost trend is indicative of maintenance cost for normalized utilization. Based on this trend, the RSI database and RSI experience with other fleets, the maintenance cost estimates made are reflective of realistic expected costs for normalized utilization. Note that these are complex production vehicles that require high cost hydraulic system maintenance and repairs.

6.14 Double Bucket 51'-64' (Equipment Type 5F)

- A 16 year life minimizes life cycle cost but the life cycle could be lowered to 14 years with minimal cost impact.
- Recommendation: Replace at 14 years. Review condition of units at 210,000 km for possible early replacement.

Double Bucket 51-64	2012 KPI
# Vehicles	35
Avg. Replacement Cost $	$317,787
Avg. Age (yrs)	4.1
GPS Mileage (Km/Yr)	9,404
GPS Total Usage (Hrs/Yr)	1,565
GPS PTO Usage (Hrs/Yr)	305
Fuel L/100km	43.1



Replacement Cycle	Annual Equivalent Cost						
	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$199,318	$7,927	$1,538	$9,667	$218,451	$127,561	$4,464,639
2	$133,435	$9,441	$2,046	$9,763	$154,685	$63,795	$2,232,839
3	$135,127	$10,964	$2,399	$9,852	$158,341	$67,451	$2,360,794
4	$118,400	$12,325	$2,700	$9,961	$143,386	$52,497	$1,837,378
5	$102,931	$13,475	$2,964	$10,062	$129,432	$38,543	$1,349,002
6	$92,655	$14,628	$2,958	$10,123	$120,364	$29,474	$1,031,605
7	$84,023	$16,423	$3,142	$10,237	$113,825	$22,936	$802,749
8	$76,269	$16,930	$3,223	$10,290	$106,712	$15,823	$553,792
9	$69,797	$17,542	$3,299	$10,407	$101,044	$10,155	$355,426
10	$63,941	$20,739	$3,523	$10,588	$98,791	$7,902	$276,566
11	$61,413	$20,700	$3,554	$10,599	$96,266	$5,376	$188,172
12	$59,524	$21,771	$3,655	$10,633	$95,582	$4,693	$164,246
13	$54,518	$22,721	$3,654	$10,690	$91,583	$694	$24,290
14	$52,578	$23,996	$3,713	$10,771	$91,057	$168	$5,875
15	$50,564	$25,689	$3,789	$10,876	$90,918	$29	$1,012
16	$47,960	$28,072	$3,853	$11,005	$90,889	Optimum	
17	$46,076	$30,913	$3,956	$11,157	$92,102	$1,212	$42,433
18	$43,930	$34,159	$4,081	$11,334	$93,504	$2,615	$91,509
19	$42,039	$37,983	$4,255	$11,535	$95,811	$4,922	$172,262
20	$40,165	$42,364	$4,496	$11,760	$98,784	$7,895	$276,320

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Double Bucket up to 51'-64' LCA

Maintenance costs for all double bucket trucks (up to 65+ feet) were averaged to provide cost data for as many vehicle ages as possible (Appendix 2 provides details prior to averaging). The average was increased 5% to account for the increased complexity and maintenance cost of the longer boom.

Section 6.13 provides additional rationale for RSI Maintenance Cost Estimates.

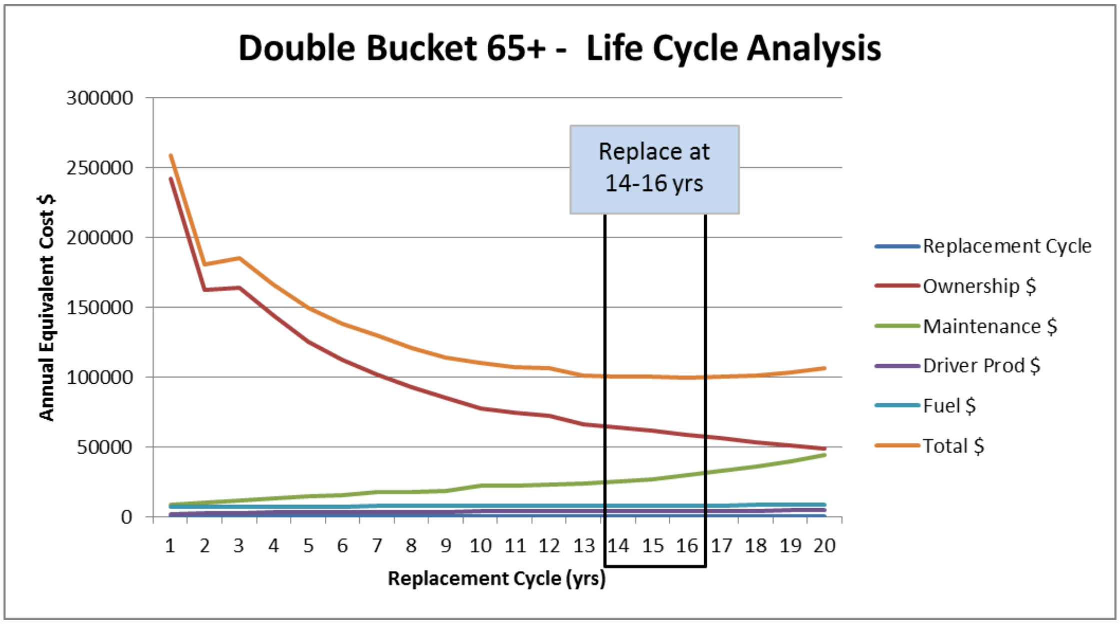
Assumptions		Fleet Data[2]					Used for LCA			
Veh Type	Double Bucket - 51'-64'	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr[3]	# WO/Yr	Residual %
# Veh In Service	35	1	30	$3,383	10.3		1	3,552	10	70%
Net Acquisition Cost:	$317,787	2	37	$4,660	17.0	62.3%	2	4,893	17	62%
Cost of Capital	6.16%	3	30	$6,199	21.5		3	6,509	22	40%
Discount Rate for NPV	1.75%	4	26	$6,671	23.0		4	7,005	23	30%
HST Rate %		5	13	$7,610	26.6		5	7,990	27	25%
Tech Prod Loss Hrs/Touch	2.5	6	19	$10,274	24.0	62.3%	6	10,788	24	20%
Tech Labour Rate $/Hr	$74	7	6	$11,191	25.2		7	11,751	25	16%
CIF[1] on Maintenance	4.0%	8	6	$11,551	31.2		8	12,128	31	15%
CIF[1] on Driver Rate	3.0%	9	6	$8,885	27.3	10.5%	9	9,329	27	14%
CIF[1] on Vehicle	2.0%	10	6	$16,035	27.3	13.6%	10	16,837	27	13.6%
CIF[1] on Fuel	4.0%	11	1	$17,463	32.0	9.2%	11	18,336	32	9.2%
Fuel Baseline Price	$1.30	12	1	$15,373	41.0	3.4%	12	18,900	41	3.4%
Annual Veh Eff Improvement	2.0%	13	4	$11,324	28.5	9.9%	13	21,000	32	9.9%
New Veh Baseline L/100Km	43.1	14	6	$8,430	22.3	6.4%	14	23,100	33	6.4%
Average Km/Yr	9,404	15	6	$8,973	18.2	3.8%	15	25,200	34	3.8%
Cash Flow Horizon (yrs)	20	16	3	$4,150	10.3	4.9%	16	27,300	35	4.9%
[1] CIF (Cost Increase Factor)		17	6	$8,781	19.0	3.1%	17	29,400	36	3.1%
[2] All double bucket trucks up to 65+ ft		18	3	$4,644	14.3	3.5%	18	31,500	37	3.5%
[3] Increased 5% over double bucket average		19	5	$8,909	20.8		19	33,600	38	3.0%
		20	6	$4,331	10.0		20	35,700	39	3.0%

RSI Estimate

6.15 Double Bucket 65'+ (Equipment Type 5G)

- A 16 year life minimizes life cycle cost but the life cycle could be lowered to 14 years with minimal cost impact.
- Recommendation: Replace at 14 years. Review condition of units at 210,000 km for possible early replacement.

Double Bucket 65+	2012 KPI
# Vehicles	2
Avg. Replacement Cost $	$386,011
Avg. Age (yrs)	6.0
GPS Mileage (Km/Yr)	7,274
GPS Total Usage (Hrs/Yr)	1,005
GPS PTO Usage (Hrs/Yr)	272
Fuel L/100km	39.3



	Annual Equivalent Cost						
Replacement Cycle	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$242,109	$8,305	$1,538	$6,818	$258,770	$159,490	$318,981
2	$162,081	$9,890	$2,046	$6,886	$180,904	$81,624	$163,248
3	$164,136	$11,486	$2,399	$6,948	$184,969	$85,690	$171,380
4	$143,819	$12,912	$2,700	$7,026	$166,456	$67,177	$134,353
5	$125,029	$14,117	$2,964	$7,097	$149,207	$49,927	$99,854
6	$112,546	$15,324	$2,958	$7,140	$137,969	$38,689	$77,378
7	$102,061	$17,206	$3,142	$7,220	$129,629	$30,350	$60,699
8	$92,643	$17,737	$3,223	$7,257	$120,860	$21,580	$43,161
9	$84,782	$18,377	$3,299	$7,340	$113,797	$14,518	$29,036
10	$77,669	$21,726	$3,523	$7,468	$110,386	$11,106	$22,213
11	$74,597	$21,686	$3,554	$7,475	$107,312	$8,033	$16,066
12	$72,303	$22,807	$3,655	$7,499	$106,264	$6,985	$13,970
13	$66,222	$23,803	$3,654	$7,540	$101,219	$1,940	$3,880
14	$63,866	$25,138	$3,713	$7,597	$100,313	$1,034	$2,068
15	$61,419	$26,912	$3,789	$7,671	$99,792	$512	$1,025
16	$58,256	$29,409	$3,853	$7,762	$99,279	Optimum	
17	$55,968	$32,385	$3,956	$7,869	$100,178	$898	$1,797
18	$53,361	$35,786	$4,081	$7,994	$101,222	$1,942	$3,884
19	$51,064	$39,792	$4,255	$8,135	$103,246	$3,966	$7,933
20	$48,788	$44,381	$4,496	$8,294	$105,959	$6,679	$13,359

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Double Bucket up to 64'+ LCA

Maintenance costs for all double bucket trucks (up to 65+ feet) were averaged to provide cost data for as many vehicle ages as possible (Appendix 2 provides details prior to averaging). The average was increased 10% to account for the increased complexity and maintenance cost of the longer boom.

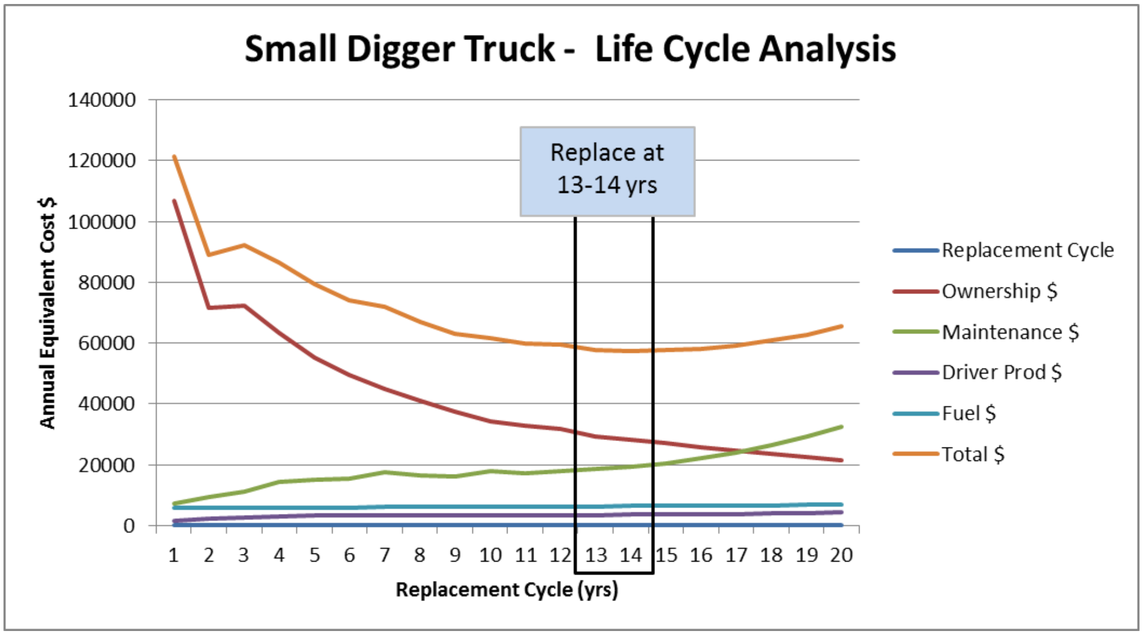
Section 6.13 provides additional rationale for RSI Maintenance Cost Estimates.

Assumptions		Fleet Data[2]					Used for LCA			
Veh Type	Double Bucket 65+	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr[3]	# WO/Yr	Residual %
# Veh In Service	2	1	30	$3,383	10.3		1	3,721	10	70%
Net Acquisition Cost:	$386,011	2	37	$4,660	17.0	62.3%	2	5,126	17	62%
Cost of Capital	6.16%	3	30	$6,199	21.5		3	6,819	22	40%
Discount Rate for NPV	1.75%	4	26	$6,671	23.0		4	7,338	23	30%
HST Rate %		5	13	$7,610	26.6		5	8,371	27	25%
Tech Prod Loss Hrs/Touch	2.5	6	19	$10,274	24.0	62.3%	6	11,302	24	20%
Tech Labour Rate $/Hr	$74	7	6	$11,191	25.2		7	12,310	25	16%
CIF[1] on Maintenance	4.0%	8	6	$11,551	31.2		8	12,706	31	15%
CIF[1] on Driver Rate	3.0%	9	6	$8,885	27.3	10.5%	9	9,773	27	14%
CIF[1] on Vehicle	2.0%	10	6	$16,035	27.3	13.6%	10	17,638	27	13.6%
CIF[1] on Fuel	4.0%	11	1	$17,463	32.0	9.2%	11	19,209	32	9.2%
Fuel Baseline Price	$1.30	12	1	$15,373	41.0	3.4%	12	19,800	41	3.4%
Annual Veh Eff Improvement	2.0%	13	4	$11,324	28.5	9.9%	13	22,000	32	9.9%
New Veh Baseline L/100Km	39.3	14	6	$8,430	22.3	6.4%	14	24,200	33	6.4%
Average Km/Yr	7,274	15	6	$8,973	18.2	3.8%	15	26,400	34	3.8%
Cash Flow Horizon (yrs)	20	16	3	$4,150	10.3	4.9%	16	28,600	35	4.9%
[1] CIF (Cost Increase Factor)		17	6	$8,781	19.0	3.1%	17	30,800	36	3.1%
[2] All double bucket trucks up to 65+ ft		18	3	$4,644	14.3	3.5%	18	33,000	37	3.5%
[3] Increased 10% over double bucket average		19	5	$8,909	20.8		19	35,200	38	3.0%
		20	6	$4,331	10.0		20	37,400	39	3.0%
							RSI Estimate			

6.16 Small Digger (Equipment Type 6A,6B)

- A 14 year life minimizes life cycle cost but the life cycle could be lowered to 13 years with minimal cost impact.
- Recommendation: Replace at 13 years. Review condition of units at 195,000 km for possible early replacement.

Small Digger Truck	2012 KPI
# Vehicles	10
Avg. Replacement Cost $	$170,361
Avg. Age (yrs)	4.9
GPS Mileage (Km/Yr)	5,960
GPS Total Usage (Hrs/Yr)	948
GPS PTO Usage (Hrs/Yr)	197
Fuel L/100Km	48.4



Replacement Cycle	Annual Equivalent Cost Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$106,852	$7,432	$1,452	$5,726	$121,461	$64,019	$640,191
2	$71,532	$9,513	$2,284	$5,783	$89,112	$31,670	$316,704
3	$72,439	$11,320	$2,571	$5,835	$92,165	$34,724	$347,239
4	$63,472	$14,263	$3,002	$5,900	$86,637	$29,196	$291,960
5	$55,180	$14,996	$3,228	$5,960	$79,364	$21,923	$219,228
6	$49,671	$15,383	$3,221	$5,996	$74,271	$16,829	$168,293
7	$45,043	$17,453	$3,409	$6,063	$71,968	$14,526	$145,261
8	$40,887	$16,620	$3,346	$6,094	$66,947	$9,505	$95,054
9	$37,417	$16,137	$3,299	$6,164	$63,018	$5,576	$55,763
10	$34,278	$17,791	$3,428	$6,271	$61,769	$4,328	$43,275
11	$32,922	$17,293	$3,443	$6,278	$59,936	$2,495	$24,948
12	$31,910	$17,983	$3,482	$6,298	$59,673	$2,231	$22,312
13	$29,226	$18,814	$3,472	$6,332	$57,845	$403	$4,034
14	**$28,186**	**$19,318**	**$3,557**	**$6,380**	**$57,441**	**Optimum**	
15	$27,107	$20,526	$3,660	$6,442	$57,734	$293	$2,925
16	$25,711	$22,261	$3,757	$6,518	$58,246	$805	$8,050
17	$24,701	$24,025	$3,861	$6,608	$59,195	$1,754	$17,538
18	$23,550	$26,492	$4,027	$6,713	$60,782	$3,340	$33,404
19	$22,537	$29,263	$4,210	$6,832	$62,842	$5,401	$54,007
20	$21,532	$32,625	$4,498	$6,965	$65,621	$8,179	$81,792

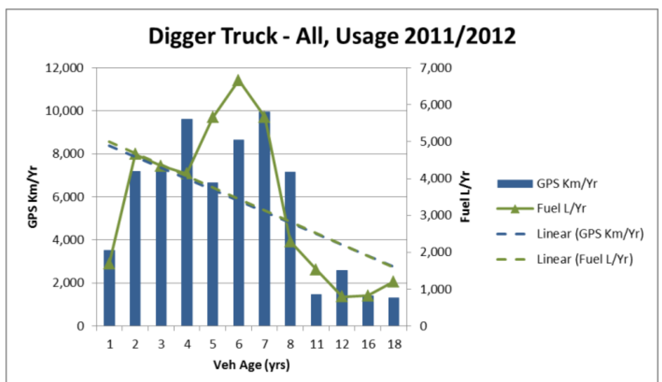
[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

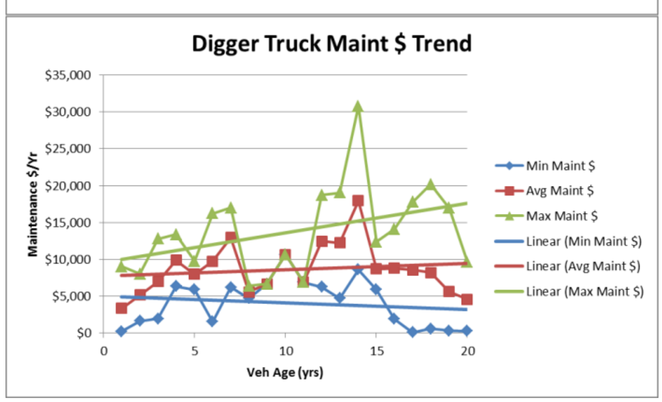
Assumptions and Data Used for Small Digger LCA

Maintenance costs for small and large digger trucks were averaged to provide cost data for as many vehicle ages as possible (Appendix 2 provides details prior to averaging).

Assumptions		Fleet Data					Used for LCA			
Veh Type	Small Digger Truck	Veh Age	# Veh	Maint $/Yr[2]	# WO	Residual %	Veh Age	Maint $/Yr[3]	# WO/Yr[3]	Residual %
# Veh In Service	10	1	16	$3,330	9.7		1	3,330	10	70%
Net Acquisition Cost:	$170,361	2	11	$5,174	20.7	62.3%	2	5,174	21	62%
Cost of Capital	6.16%	3	11	$6,965	21.6		3	6,965	22	40%
Discount Rate for NPV	1.75%	4	8	$9,859	27.8		4	9,859	28	30%
HST Rate %		5	5	$7,964	27.4		5	7,964	27	25%
Tech Prod Loss Hrs/Touch	2.5	6	5	$9,759	25.8	62.3%	6	9,759	26	20%
Tech Labour Rate $/Hr	$74	7	3	$12,939	27.0		7	12,939	27	16%
CIF[1] on Maintenance	4.0%	8	2	$5,546	23.0		8	5,546	23	15%
CIF[1] on Driver Rate	3.0%	9	1	$6,658	22.0	10.5%	9	6,658	22	14%
CIF[1] on Vehicle	2.0%	10	1	$10,663	23.0	13.6%	10	10,663	23	13.6%
CIF[1] on Fuel	4.0%	11	1	$6,870	25.0	9.2%	11	6,870	25	9.2%
Fuel Baseline Price	$1.30	12	2	$12,475	27.0	3.4%	12	12,475	27	3.4%
Annual Veh Eff Improvement	2.0%	13	4	$12,230	21.8	9.9%	13	12,230	22	9.9%
New Veh Baseline L/100Km	48.4	14	4	$17,952	38.3	6.4%	14	17,952	38	6.4%
Average Km/Yr	4,960	15	4	$8,699	24.8	3.8%	15	20,000	39	3.8%
Cash Flow Horizon (yrs)	20	16	8	$8,808	27.3	4.9%	16	22,000	40	4.9%
[1] CIF (Cost Increase Factor)		17	6	$8,572	24.8	3.1%	17	24,000	41	3.1%
[2] Small and large digger truck average		18	5	$8,216	15.6	3.5%	18	26,000	42	3.5%
		19	4	$5,620	16.0		19	26,000	43	3.0%
		20	4	$4,551	12.8		20	28,000	44	3.0%
							RSI Estimate			

RSI Maintenance Cost Assumptions





Assumptions were made for maintenance cost for years 15-20 since TH costs should be increasing at a faster rate with vehicle age.

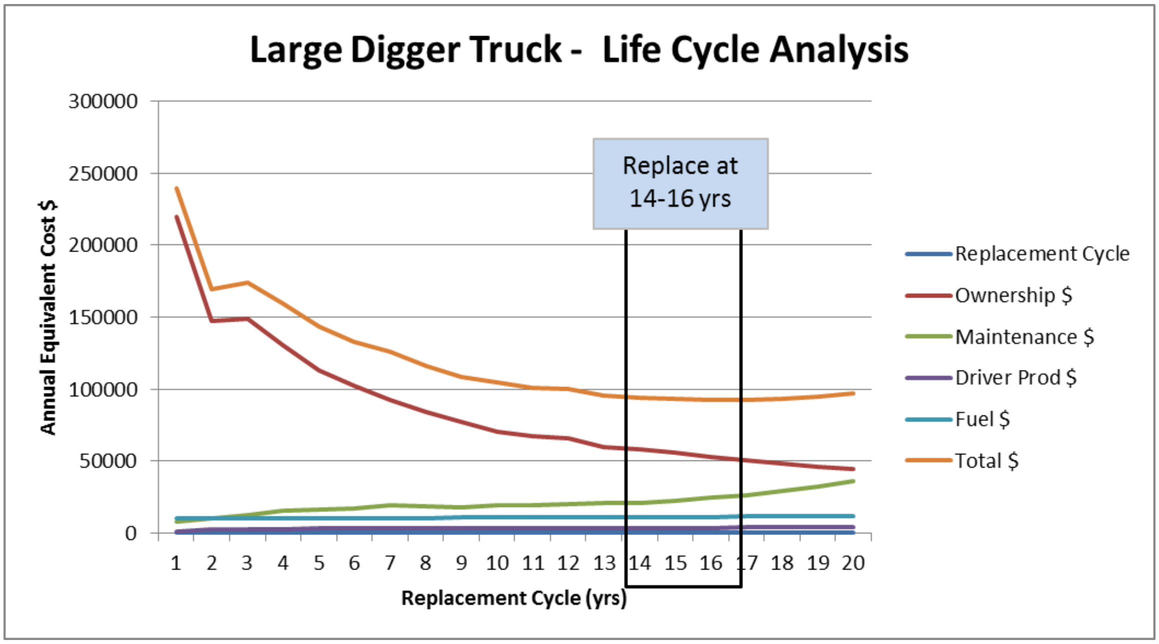
The upper chart at right shows that vehicle utilization decreases as vehicles age which reflects a preference for using newer vehicles. Lower utilization results in the lower than expected maintenance cost.

The lower chart at right shows minimum, average and maximum maintenance costs and linear trends. The maximum cost trend is indicative of maintenance cost for normalized utilization. Based on this trend, the RSI database and RSI experience with other fleets, the maintenance cost estimates made are reflective of realistic expected costs for normalized utilization. Note that these are complex production vehicles that require high cost hydraulic system maintenance and repairs.

6.17 Large Digger (Equipment Type 6C, 9C)

- A 16 year life minimizes life cycle cost but the life cycle could be lowered to 14 years with minimal cost impact.
- Recommendation: Replace at 14 years. Review condition of units at 210,000 km for possible early replacement.

Large Digger Truck	2012 KPI
# Vehicles	10
Avg. Replacement Cost $	$352,926
Avg. Age (yrs)	2.8
GPS Mileage (Km/Yr)	9,205
GPS Total Usage (Hrs/Yr)	1,392
GPS PTO Usage (Hrs/Yr)	292
Fuel L/100Km	45.2



Replacement Cycle	Annual Equivalent Cost						
	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$219,668	$8,175	$1,452	$9,923	$239,218	$146,821	$1,468,207
2	$147,058	$10,464	$2,284	$10,022	$169,828	$77,431	$774,313
3	$148,923	$12,452	$2,571	$10,113	$174,058	$81,661	$816,614
4	$130,488	$15,689	$3,002	$10,225	$159,405	$67,008	$670,079
5	$113,440	$16,496	$3,228	$10,329	$143,493	$51,096	$510,964
6	$102,114	$16,922	$3,221	$10,392	$132,649	$40,252	$402,516
7	$92,601	$19,198	$3,409	$10,508	$125,716	$33,319	$333,188
8	$84,056	$18,281	$3,346	$10,563	$116,246	$23,849	$238,489
9	$76,923	$17,751	$3,299	$10,683	$108,657	$16,260	$162,596
10	$70,470	$19,570	$3,428	$10,869	$104,337	$11,940	$119,405
11	$67,683	$19,022	$3,443	$10,880	$101,028	$8,631	$86,311
12	$65,601	$19,781	$3,482	$10,915	$99,779	$7,382	$73,823
13	$60,084	$20,696	$3,472	$10,974	$95,226	$2,829	$28,292
14	$57,946	$21,250	$3,557	$11,057	$93,810	$1,413	$14,132
15	$55,726	$22,579	$3,660	$11,165	$93,129	$732	$7,320
16	**$52,856**	**$24,487**	**$3,757**	**$11,297**	**$92,397**	**Optimum**	
17	$50,780	$26,427	$3,861	$11,453	$92,522	$125	$1,252
18	$48,415	$29,141	$4,027	$11,634	$93,217	$820	$8,202
19	$46,331	$32,190	$4,210	$11,841	$94,572	$2,175	$21,748
20	$44,265	$35,888	$4,498	$12,072	$96,723	$4,326	$43,264

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Large Digger LCA

Maintenance costs for small and large digger trucks were averaged to provide cost data for as many vehicle ages as possible (Appendix 2 provides details prior to averaging). The average was increased 10% to account for the increased complexity and maintenance cost of the large digger.

Section 6.16 provides additional rationale for RSI Maintenance Cost Estimates.

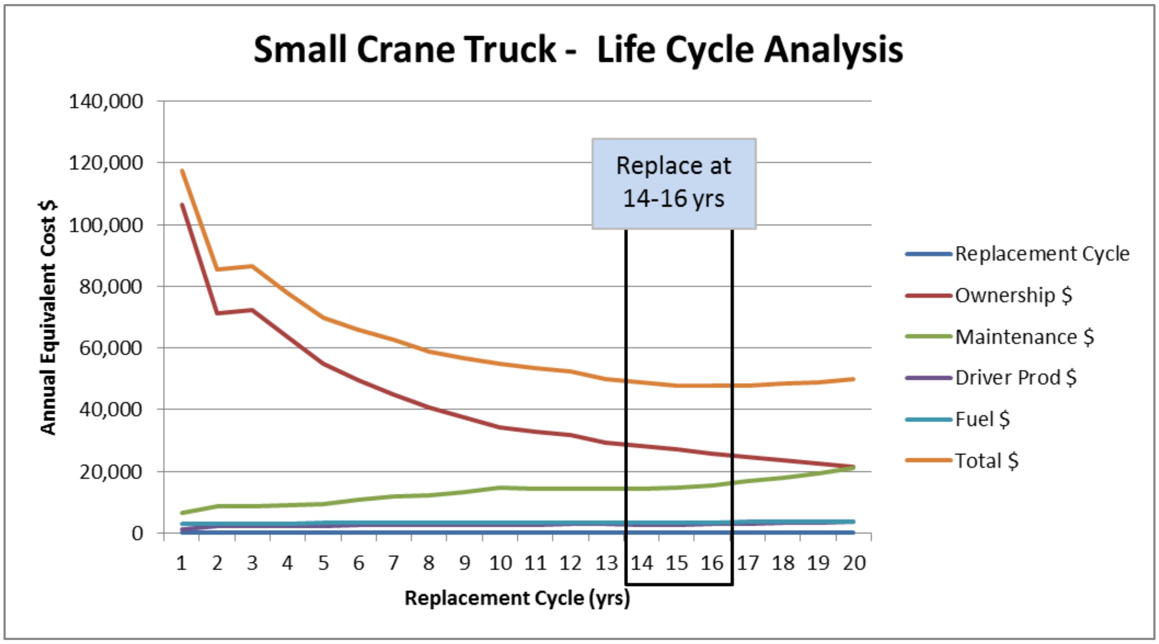
Assumptions		Fleet Data					Used for LCA			
Veh Type	Large Digger Truck	Veh Age	# Veh	Maint $/Yr[2]	# WO	Residual %	Veh Age	Maint $/Yr[3]	# WO/Yr[3]	Residual %
# Veh In Service	10	1	16	$3,330	9.7		1	3,663	10	70%
Net Acquisition Cost:	$350,232	2	11	$5,174	20.7	62.3%	2	5,692	21	62%
Cost of Capital	6.16%	3	11	$6,965	21.6		3	7,662	22	40%
Discount Rate for NPV	1.75%	4	8	$9,859	27.8		4	10,845	28	30%
HST Rate %		5	5	$7,964	27.4		5	8,761	27	25%
Tech Prod Loss Hrs/Touch	2.5	6	5	$9,759	25.8	62.3%	6	10,735	26	20%
Tech Labour Rate $/Hr	$74	7	3	$12,939	27.0		7	14,233	27	16%
CIF[1] on Maintenance	4.0%	8	2	$5,546	23.0		8	6,100	23	15%
CIF[1] on Driver Rate	3.0%	9	1	$6,658	22.0	10.5%	9	7,324	22	14%
CIF[1] on Vehicle	2.0%	10	1	$10,663	23.0	13.6%	10	11,730	23	13.6%
CIF[1] on Fuel	4.0%	11	1	$6,870	25.0	9.2%	11	7,557	25	9.2%
Fuel Baseline Price	$1.30	12	2	$12,475	27.0	3.4%	12	13,722	27	3.4%
Annual Veh Eff Improvement	2.0%	13	4	$12,230	21.8	9.9%	13	13,453	22	9.9%
New Veh Baseline L/100Km	45.2	14	4	$17,952	38.3	6.4%	14	19,747	38	6.4%
Average Km/Yr	9,205	15	4	$8,699	24.8	3.8%	15	22,000	39	3.8%
Cash Flow Horizon (yrs)	20	16	8	$8,808	27.3	4.9%	16	24,200	40	4.9%
		17	6	$8,572	24.8	3.1%	17	26,400	41	3.1%
		18	5	$8,216	15.6	3.5%	18	28,600	42	3.5%
		19	4	$5,620	16.0		19	28,600	43	3.0%
		20	4	$4,551	12.8		20	30,800	44	3.0%
								RSI Estimate		

[1] CIF (Cost Increase Factor)
[2] Small and large digger truck average
[3] Increased 10% for Large Digger Truck

6.18 Small Crane (Equipment Type 9A)

- A 16 year life minimizes life cycle cost but the life cycle could be lowered to 14 years with minimal cost impact.
- Recommendation: Replace at 14 years. Review condition of units at 210,000 km for possible early replacement.

Small Crane Truck	2012 KPI
# Vehicles	8
Avg. Replacement Cost $	$170,000
Avg. Age (yrs)	3.9
GPS Mileage (Km/Yr)	4,458
GPS Total Usage (Hrs/Yr)	658
GPS PTO Usage (Hrs/Yr)	28
Fuel L/100km	28.9



Replacement Cycle	Annual Equivalent Cost						
	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$106,625	$6,510	$1,333	$3,073	$117,541	$69,882	$559,053
2	$71,381	$8,683	$2,272	$3,103	$85,439	$37,780	$302,237
3	$72,286	$8,702	$2,371	$3,132	$86,490	$38,830	$310,643
4	$63,338	$8,887	$2,449	$3,166	$77,840	$30,180	$241,442
5	$55,063	$9,258	$2,459	$3,198	$69,978	$22,318	$178,546
6	$49,566	$10,749	$2,543	$3,218	$66,075	$18,416	$147,325
7	$44,948	$11,860	$2,634	$3,254	$62,696	$15,036	$120,288
8	$40,800	$12,218	$2,664	$3,271	$58,953	$11,293	$90,345
9	$37,338	$13,347	$2,718	$3,308	$56,711	$9,051	$72,412
10	$34,205	$14,578	$2,813	$3,366	$54,962	$7,303	$58,422
11	$32,853	$14,520	$2,811	$3,369	$53,552	$5,893	$47,142
12	$31,842	$14,412	$2,832	$3,380	$52,466	$4,807	$38,454
13	$29,164	$14,390	$2,826	$3,398	$49,778	$2,119	$16,949
14	$28,126	$14,487	$2,769	$3,424	$48,806	$1,146	$9,171
15	$27,049	$14,708	$2,759	$3,457	$47,973	$313	$2,504
16	**$25,656**	**$15,600**	**$2,905**	**$3,498**	**$47,660**	**Optimum**	
17	$24,648	$16,719	$3,053	$3,547	$47,967	$307	$2,457
18	$23,500	$18,034	$3,214	$3,603	$48,350	$690	$5,523
19	$22,489	$19,382	$3,350	$3,666	$48,888	$1,228	$9,825
20	$21,486	$21,058	$3,603	$3,738	$49,885	$2,225	$17,803

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

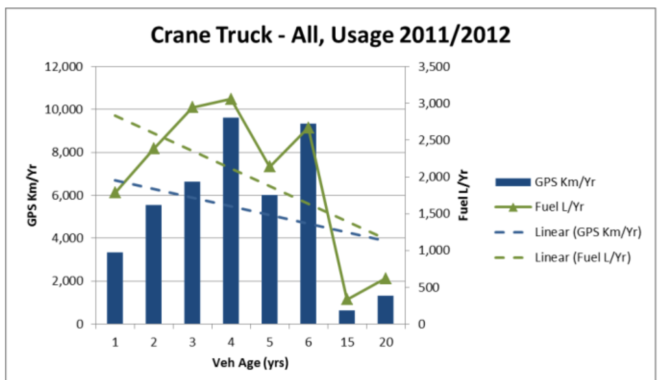
Assumptions and Data Used for Small Crane LCA

Maintenance costs for small and large crane trucks were averaged to provide cost data for as many vehicle ages as possible (Appendix 2 provides details prior to averaging).

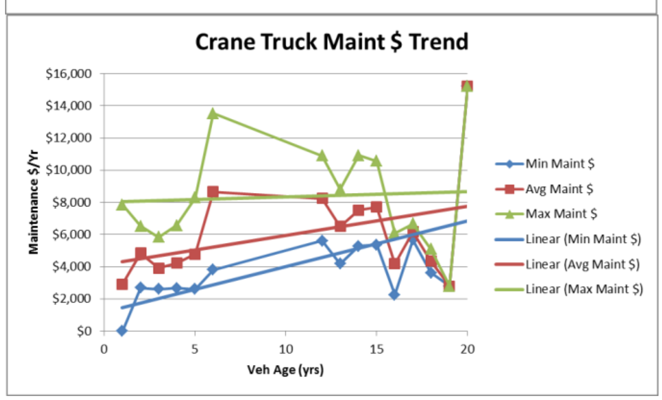
Assumptions		Fleet Data[2]					Used for LCA			
Veh Type	Small Crane Truck	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	8	1	19	$2,917	8.9		1	2,917	9	70%
Net Acquisition Cost:	$170,000	2	17	$4,843	21.4	62.3%	2	4,843	21	62%
Cost of Capital	6.16%	3	14	$3,919	17.4		3	3,919	17	40%
Discount Rate for NPV	1.75%	4	8	$4,217	17.6		4	4,217	18	30%
HST Rate %		5	3	$4,778	16.7		5	4,778	17	25%
Tech Prod Loss Hrs/Touch	2.5	6	2	$8,669	21.0	62.3%	6	8,669	21	20%
Tech Labour Rate $/Hr	$74	7					7	8,669	21	16%
CIF[1] on Maintenance	4.0%	8					8	8,669	21	15%
CIF[1] on Driver Rate	3.0%	9				10.5%	9	8,669	21	14%
CIF[1] on Vehicle	2.0%	10				13.6%	10	8,669	21	13.6%
CIF[1] on Fuel	4.0%	11				9.2%	11	8,669	21	9.2%
Fuel Baseline Price	$1.30	12	2	$8,255	22.0	3.4%	12	8,255	24	3.4%
Annual Veh Eff Improvement	2.0%	13	2	$6,497	22.0	9.9%	13	9,000	21	9.9%
New Veh Baseline L/100Km	28.9	14	4	$7,515	31.8	6.4%	14	10,000	14	6.4%
Average Km/Yr	4,458	15	5	$7,696	28.8	3.8%	15	11,000	20	3.8%
Cash Flow Horizon (yrs)	20	16	2	$4,178	19.5	4.9%	16	12,000	35	4.9%
[1] CIF (Cost Increase Factor)		17	2	$6,172	24.0	3.1%	17	13,000	36	3.1%
[2] Small and Large Crane Truck		18	2	$4,358	20.5	3.5%	18	14,000	37	3.5%
		19	1	$2,793	14.0		19	15,000	38	3.0%
		20	1	$15,213	20.0		20	15,213	39	3.0%
								RSI Estimate		

RSI Maintenance Cost Estimates

Assumptions were made for maintenance cost for years 7-11 to address data gaps and years 13-19 since TH costs should be increasing at a faster rate with vehicle age.



The upper chart at right shows that vehicle utilization decreases as vehicles age which reflects a preference for using newer vehicles. Lower utilization results in the lower than expected maintenance cost.

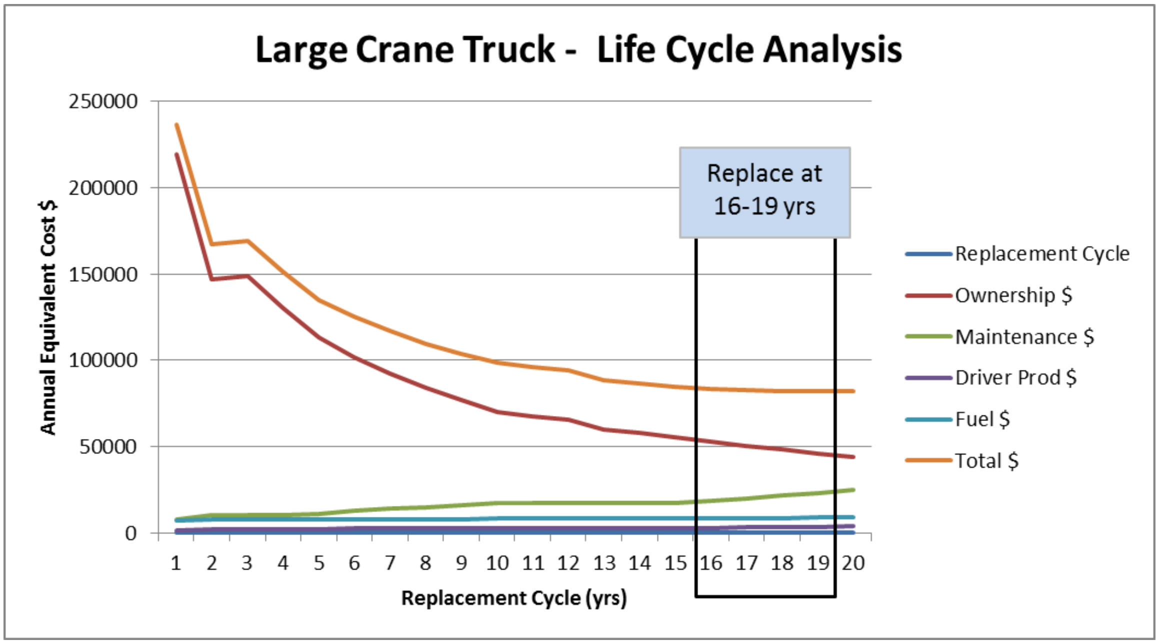


The lower chart at right shows minimum, average and maximum maintenance costs and linear trends. The maximum cost trend is indicative of maintenance cost for normalized utilization. Based on this trend, the RSI database and RSI experience with other fleets, the maintenance cost estimates made are reflective of realistic expected costs for normalized utilization. Note that these are complex production vehicles that require high cost hydraulic system maintenance and repairs.

6.19 Large Crane (Equipment Type 9B)

- A 19 year life cycle minimizes cost but the life cycle could be shortened to 16 years with minimal impact on cost.
- Recommendation: replace at 16 years. Review condition of units at 240,000 km for possible early replacement.

Large Crane Truck	2012 KPI
# Vehicles	10
Avg. Replacement Cost $	$350,000
Avg. Age (yrs)	3.3
GPS Mileage (Km/Yr)	8,918
GPS Total Usage (Hrs/Yr)	933
GPS PTO Usage (Hrs/Yr)	104
Fuel L/100km	35.4



Replacement Cycle	Annual Equivalent Cost						
	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$219,522	$7,813	$1,333	$7,529	$236,197	$154,099	$1,540,992
2	$146,961	$10,419	$2,272	$7,605	$167,257	$85,159	$851,589
3	$148,824	$10,442	$2,371	$7,673	$169,310	$87,212	$872,124
4	$130,402	$10,664	$2,449	$7,759	$151,273	$69,175	$691,754
5	$113,365	$11,109	$2,459	$7,837	$134,770	$52,672	$526,723
6	$102,047	$12,898	$2,543	$7,885	$125,373	$43,275	$432,754
7	$92,540	$14,232	$2,634	$7,973	$117,379	$35,281	$352,810
8	$84,000	$14,662	$2,664	$8,014	$109,340	$27,242	$272,423
9	$76,872	$16,016	$2,718	$8,106	$103,713	$21,615	$216,148
10	$70,423	$17,494	$2,813	$8,247	$98,977	$16,879	$168,791
11	$67,638	$17,423	$2,811	$8,255	$96,128	$14,030	$140,298
12	$65,558	$17,295	$2,817	$8,282	$93,951	$11,853	$118,531
13	$60,044	$17,268	$2,822	$8,327	$88,461	$6,363	$63,632
14	$57,907	$17,384	$2,904	$8,390	$86,585	$4,487	$44,871
15	$55,689	$17,649	$2,963	$8,471	$84,773	$2,675	$26,749
16	$52,821	$18,720	$3,109	$8,572	$83,223	$1,125	$11,248
17	$50,747	$20,062	$3,257	$8,690	$82,757	$659	$6,589
18	$48,383	$21,640	$3,418	$8,828	$82,269	$171	$1,707
19	$46,300	$23,259	$3,555	$8,984	$82,098	Optimum	
20	$44,236	$25,269	$3,807	$9,160	$82,472	$375	$3,745

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Large Crane LCA

Maintenance costs for small and large crane trucks were averaged to provide cost data for as many vehicle ages as possible (Appendix 2 provides details prior to averaging). The average was increased 20% to account for the increased complexity and maintenance cost of the large crane.

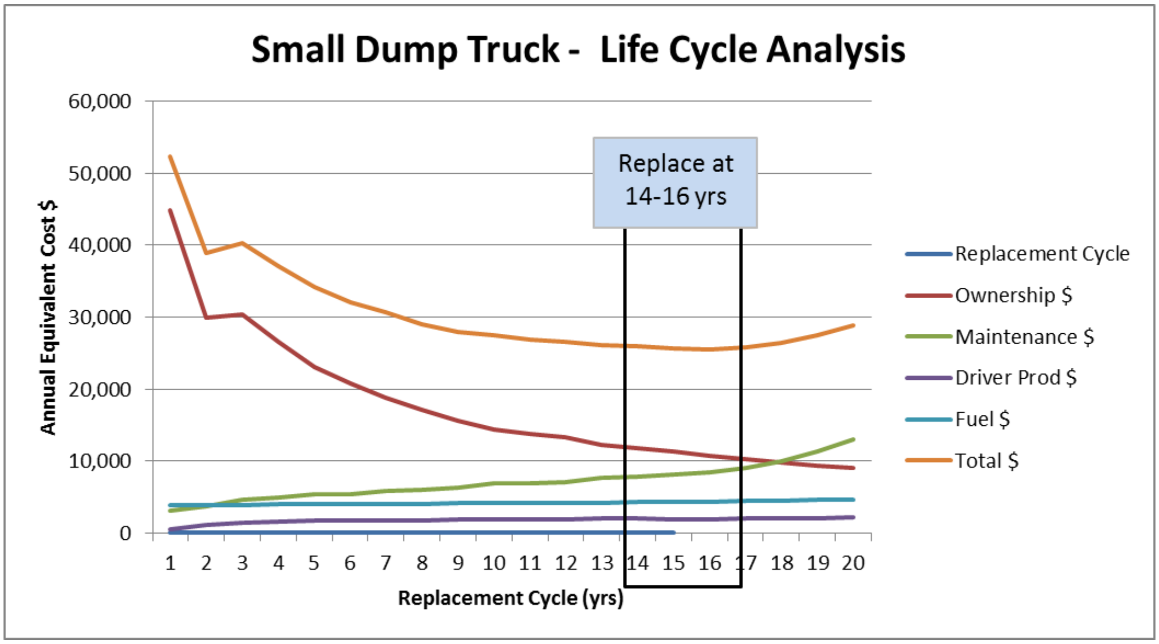
Section 6.18 provides additional rationale for RSI Maintenance Cost Estimates.

Assumptions		Fleet Data					Used for LCA			
Veh Type	Large Crane Truck	Veh Age	# Veh	Maint $/Yr[2]	# WO	Residual %	Veh Age	Maint $/Yr[3]	# WO/Yr[3]	Residual %
# Veh In Service	10	1	19	$2,917	8.9		1	3,500	9	70%
Net Acquisition Cost:	$350,000	2	17	$4,843	21.4	62.3%	2	5,811	21	62%
Cost of Capital	6.16%	3	14	$3,919	17.4		3	4,703	17	40%
Discount Rate for NPV	1.75%	4	8	$4,217	17.6		4	5,060	18	30%
HST Rate %		5	3	$4,778	16.7		5	5,733	17	25%
Tech Prod Loss Hrs/Touch	2.5	6	2	$8,669	21.0	62.3%	6	10,402	21	20%
Tech Labour Rate $/Hr	$74	7					7	10,402	21	16%
CIF[1] on Maintenance	4.0%	8					8	10,402	21	15%
CIF[1] on Driver Rate	3.0%	9				10.5%	9	10,402	21	14%
CIF[1] on Vehicle	2.0%	10				13.6%	10	10,402	21	13.6%
CIF[1] on Fuel	4.0%	11				9.2%	11	10,402	21	9.2%
Fuel Baseline Price	$1.30	12	2	$8,255	22.0	3.4%	12	9,906	22	3.4%
Annual Veh Eff Improvement	2.0%	13	2	$6,497	22.0	9.9%	13	10,800	22	9.9%
New Veh Baseline L/100Km	35.4	14	4	$7,515	31.8	6.4%	14	12,000	32	6.4%
Average Km/Yr	8,918	15	5	$7,696	28.8	3.8%	15	13,200	29	3.8%
Cash Flow Horizon (yrs)	20	16	2	$4,178	19.5	4.9%	16	14,400	35	4.9%
[1] CIF (Cost Increase Factor)		17	2	$6,172	24.0	3.1%	17	15,600	36	3.1%
[2] Small and Large Crane Truck average		18	2	$4,358	20.5	3.5%	18	16,800	37	3.5%
[3] Increased 20% for Large Crane Truck		19	1	$2,793	14.0		19	18,000	38	3.0%
		20	1	$15,213	20.0		20	18,255	39	3.0%
							RSI Estimate			

6.20 Small Dump Truck (Equipment Type LA)

Small Dump Truck	2012 KPI
# Vehicles	9
Avg. Replacement Cost $	$71,660
Avg. Age (yrs)	4.0
GPS Mileage (Km/Yr)	5,559
GPS Total Usage (Hrs/Yr)	799
GPS PTO Usage (Hrs/Yr)	45
Fuel L/100Km	29.0

- Life cycle costs are minimized at 16 years but the life cycle could be lowered to 14 years with minimal cost impact.
- Recommendation: Replace at 14 years. Review condition of units at 210,000 km for possible early replacement.



Replacement Cycle	Annual Equivalent Cost						
	Ownership $	Maintenance $	Driver Prod $	Fuel $	Total $	Savings $/Veh[1]	Savings $/All Veh[1]
1	$44,864	$3,184	$450	$3,845	$52,342	$26,807	$241,260
2	$30,005	$3,795	$1,170	$3,883	$38,854	$13,319	$119,871
3	$30,400	$4,572	$1,443	$3,918	$40,333	$14,799	$133,188
4	$26,632	$4,982	$1,585	$3,962	$37,160	$11,626	$104,630
5	$23,145	$5,340	$1,690	$4,002	$34,176	$8,642	$77,774
6	$20,828	$5,449	$1,717	$4,027	$32,021	$6,486	$58,378
7	$18,883	$5,889	$1,817	$4,072	$30,660	$5,125	$46,128
8	$17,133	$6,004	$1,820	$4,093	$29,050	$3,515	$31,639
9	$15,674	$6,293	$1,828	$4,139	$27,935	$2,400	$21,599
10	$14,353	$6,950	$1,946	$4,211	$27,461	$1,926	$17,338
11	$13,784	$6,947	$1,937	$4,216	$26,883	$1,349	$12,137
12	$13,359	$7,007	$1,943	$4,229	$26,539	$1,004	$9,040
13	$12,227	$7,679	$1,988	$4,252	$26,146	$611	$5,499
14	$11,790	$7,829	$1,992	$4,284	$25,896	$361	$3,250
15	$11,336	$8,073	$1,972	$4,326	$25,707	$172	$1,552
16	**$10,748**	**$8,439**	**$1,971**	**$4,377**	**$25,535**	**Optimum**	
17	$10,324	$9,121	$1,989	$4,438	$25,871	$336	$3,024
18	$9,839	$10,045	$2,005	$4,508	$26,397	$862	$7,761
19	$9,413	$11,381	$2,041	$4,588	$27,423	$1,888	$16,991
20	$8,991	$13,094	$2,167	$4,677	$28,929	$3,395	$30,551

[1] Annual savings with Optimum life cycle vs. alternative replacement cycle

Assumptions and Data Used for Small Dump Truck LCA

Assumptions		Fleet Data					Used for LCA			
Veh Type	Small Dump Truck	Veh Age	# Veh	Maint $/Yr	# WO	Residual %	Veh Age	Maint $/Yr	# WO/Yr	Residual %
# Veh In Service	9	1	9	$1,426	3.0		1	1,426	3	70%
Net Acquisition Cost:	$71,660	2	9	$1,969	12.6	62.3%	2	1,969	13	62%
Cost of Capital	6.06%	3	9	$2,863	13.9		3	2,863	14	40%
Discount Rate for NPV	1.75%	4	9	$2,623	12.7		4	2,623	13	30%
HST Rate %		5					5	3,000	14	25%
Tech Prod Loss Hrs/Touch	2.5	6				62.3%	6	3,250	15	20%
Tech Labour Rate $/Hr	$74	7					7	3,500	14	16%
CIF[1] on Maintenance	4.0%	8					8	3,750	15	15%
CIF[1] on Driver Rate	3.0%	9				10.5%	9	4,000	14	14%
CIF[1] on Vehicle	2.0%	10				13.6%	10	4,250	15	13.6%
CIF[1] on Fuel	4.0%	11				9.2%	11	4,500	14	9.2%
Fuel Baseline Price	$1.30	12				3.4%	12	4,750	15	3.4%
Annual Veh Eff Improvement	2.0%	13	1	$9,672	21.0	9.9%	13	9,672	21	9.9%
New Veh Baseline L/100Km	29.0	14	4	$4,890	14.8	6.4%	14	4,890	15	6.4%
Average Km/Yr	5,559	15	3	$5,344	12.7	3.8%	15	5,344	13	3.8%
Cash Flow Horizon (yrs)	20	16	1	$2,660	12.0	4.9%	16	6,000	14	4.9%
		17	1	$5,647	17.0	3.1%	17	8,000	15	3.1%
		18	2	$4,138	13.0	3.5%	18	10,000	16	3.5%
		19	1	$3,090	10.0		19	12,000	17	3.0%
		20					20	14,000	18	3.0%
							RSI Estimate			

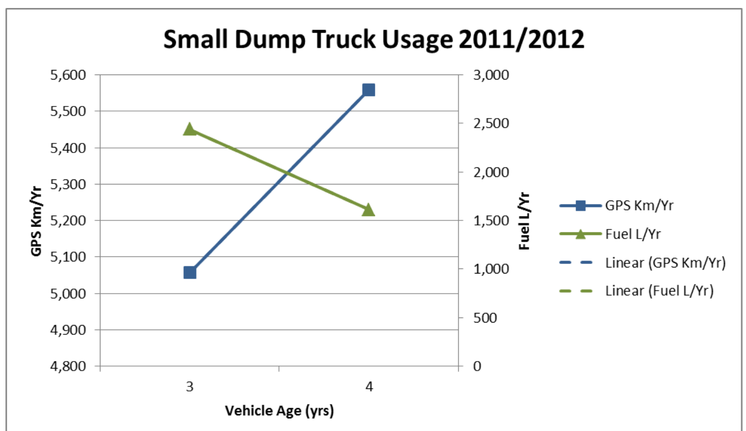
[1] CIF (Cost Increase Factor)

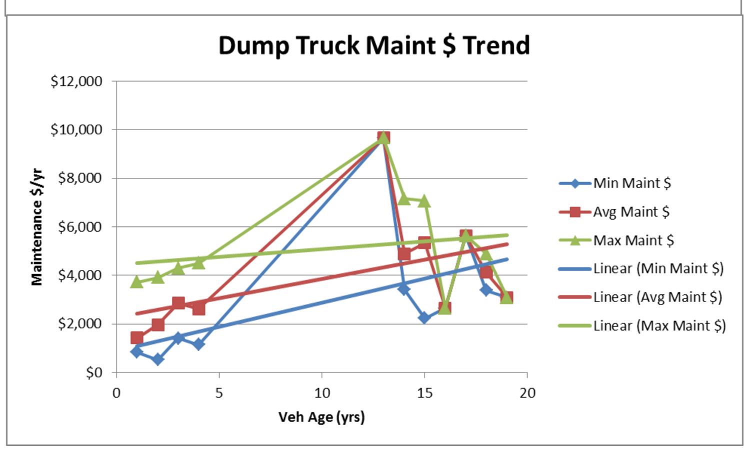
RSI Maintenance Cost Estimates

Assumptions were made for maintenance cost for years 5-12 to address data gaps and years 16-20 since TH costs should be increasing at a faster rate with vehicle age.

The upper chart at right shows that current dump trucks are young so it is not possible to assess utilization levels as they age.

The lower chart at right shows minimum, average and maximum maintenance costs and linear trends. The maximum cost trend is indicative of maintenance cost for normalized utilization. Based on this modest upward trend, the RSI database and RSI experience with other fleets, the maintenance cost estimates for a modest annual increase reflect realistic expected costs.





7 Report Summary

In early 2013, Toronto Hydro met with Richmond Sustainability Initiatives (RSI) to discuss the current context around fleet management, data mining, and opportunities for improvement. At this meeting, various opportunities to provide fleet consulting services to address Toronto Hydro's needs were discussed, with primary focus on data compilation and the development of an LCA for the fleet. Financial tools such as Life Cycle Analysis (LCA) will influence how new business models are presented and ultimately supported in the organization and are an important resource when it comes to optimizing fleet management budgets.

An LCA was completed for Toronto Hydro based on data provided from 2008 to 2012. LCA provides the empirical justification for replacement polices and facilitates the analysis and communication of future replacement costs. The recommended vehicle replacement criteria based on the analysis completed is summarized in Table 1 (see Executive Summary).

This information was compared and contrasted with peer fleets available within RSI's database and found to be within the "norm" of standard replacement criteria. Qualitative research also identified that age and/or km criteria were typically barometers for vehicle replacement adopted by most fleets, however the degree of rigour supporting these parameters is unknown. The best approach to sound fleet management utilizes both quantitative analysis and qualitative evaluation so as to inform decision-making "by the numbers" (i.e. as identified through historical operating performance) as well as accommodating for unanticipated wear or usage of vehicles (i.e. as would be identified through case-by-case vehicle evaluation).

As such, we recommend that Toronto Hydro adopt the age-prioritized vehicle replacement criteria identified through the LCA performed on the fleet. The LCA is based on a significant database of Toronto Hydro's fleet operating performance and as a result provides a robust projection of expected vehicle performance -- and optimal lifespan. We also recommend that Toronto Hydro adopt a formal and recurring mechanism for routine qualitative evaluation of vehicle condition and performance.

8 Peer Fleet Comparison

8.1 RSI Database, Vehicle Replacement Criteria for Comparison

RSI maintains a database of approximately 50,000 Canadian fleet vehicles through its Fleet Challenge program. The database is comprised primarily of municipal fleets (both urban and regional) but also contains private sector fleets, provincial and federal government fleets and a small number of electrical, gas and telecom utilities. Tracked information includes historical data for over 100 operating cost, emissions and service level Key Performance Indicators (KPI) for fleets that have participated in the Fleet Review process.

A key element of Fleet Review includes evaluation of the subject fleet's capital replacement strategy, if available and/or in place. Typically, the data shows that most fleet managers do not have a formal fleet replacement strategy that is based on historical data or thorough life cycle analysis evaluation. Rather, replacement decisions are made using a "seat of pants" approach – which depends heavily on a fleet manager's instinctive knowledge and past personal observations around the vehicle/age relationship, as opposed to statistical analysis.

With this caveat in mind, we have compiled replacement statistics for five peer fleets operating in closely related conditions to Toronto Hydro (Table 7): a municipal electrical utility, a gas distribution utility, a large municipal fleet, a national telecom fleet, and a Commonwealth country based large electrical utility.[2] Except for the latter, all examples operate within the southern Ontario region under similar climactic conditions to those experienced by the Toronto Hydro fleet.

The fleets we have selected for peer comparison share the following operational characteristics:

- All are 'mixed' fleets in that each is comprised of vehicles belonging to all, or most vehicle categories (i.e., cars, pickups, vans as well as light, medium and heavy trucks with mounted equipment including cranes, aerial devices/ladders and digger/derricks),
- All (with one sub-fleet exception) return to "home" base each night,
- All fleets directly serve their customers or constituents,
- The utility fleets operate in a competitive, deregulated marketplace with government oversight (i.e., a regulator),
- All fleets operate primarily in highly populated urban environments,
- All fleets operate primarily during daytime business hours,
- Maintenance and repairs are primarily carried out in-house,
- All the peer fleets selectively outsource specific work to speciality shops (such as paint & body work, springs and radiators)
- Drivers and fleet maintenance technicians are unionized.

[2] Participants in the Fleet Review process are promised data-anonymity. For this reason the peer fleet data is provided anonymously (i.e., Fleet A, B, etc.).

Peer Fleet Profiles[3]

1) Fleet "A"

- Description: Municipal electrical utility
- Location: Southern Ontario
- Area of Operation: Urban
- Fleet Size: mid-size <200 on-road licensed power units
- Vehicle types: Mixed – all categories
- Average Utilization: ~12,000 km per year
- Average age: 8.2 years

2) Fleet "B"

- Description: Gas distribution utility
- Location: Southern Ontario
- Area of Operation: Urban
- Fleet Size: Mid-size ~650 on-road licensed power units
- Vehicle types: Mixed – all categories
- Average Utilization: ~21,500 km per year
- Average age: 3.9 years

3) Fleet "C"

- Description: Large municipal fleet
- Location: Eastern Ontario
- Area of Operation: Urban
- Fleet Size: Mid-size >1300 on-road licensed power units
- Vehicle types: Mixed – all categories
- Average Utilization: ~22,000 km per year
- Average age: 5.5 years

4) Fleet "D"

- Description: National telecom fleet
- Location: Canada
- Area of Operation: Urban and rural
- Fleet Size: mid-size ~12,000 on-road licensed power units
- Vehicle types: Mixed – all categories
- Average Utilization: ~21,000 km per year (but varies between several sub-fleets)
- Average age: 6.9 years (2009)

5) Fleet "E" Large, Commonwealth country-based regional electrical utility

[3] Statistics presented in this table were current are as of the time of each clients most recent Fleet Review.

- Description: Large regional electrical utility
- Area of Operation: Urban and rural
- Fleet Size: Mid-size <900 on-road licensed power units
- Vehicle types: Mixed – all categories
- Value of Fleet: <$30m

Table 7: Peer Fleet Comparison

Report Section	Vehicle Type	Toronto Hydro Proposed	Fleet "A" Mid-size Urban MEU	Fleet "B" Gas Utility	Fleet "C" Large Urban Municipality	Fleet "D" National Telecom	Fleet "E" Large, Commonwealth Country Regional Electrical Utility**
6.1	Car	6 yrs.	-	5 yrs.	5-7 yrs.	7 yrs. or 180K km	150K km
6.2	Pickup	9 yrs.	7 yrs.	5 yrs.	5-7 yrs.	7-8 yrs. or 180-225K km	140K km
6.3	SUV	6 yrs.	10 yrs.	5 yrs.	5-7 yrs.	9 yrs. or 225K km	-
6.4	Passenger Mini-van	6 yrs.	7 yrs.	5 yrs.	5-7 yrs.	-	150K km
6.5	Cargo Mini-van	7 yrs.	7 yrs.	5 yrs.	5-7 yrs.	8 yrs. or 180K km	140K km
6.6	Passenger Full Size Van	9 yrs.	7 yrs.	5 yrs.	5-7 yrs.	-	140K km
6.7	Cargo Full Size Van	9 yrs.	7 yrs.	5 yrs.	10-12 yrs.	7 yrs. or 225K km	140K km & condition
6.8	Cube Van	12 yrs.	7 yrs.	10 yrs.	10-12 yrs.	10 yrs. or 180K km.	10 yrs. or 200K km
6.9	Line Truck	13 yrs.	10+ yrs.	10 yrs.	10-12 yrs.	12-17 yrs. unlimited km*	10 yrs. or 200K km
6.10	Cable Truck	16 yrs.	-	-	-	12-17 yrs. unlimited km*	20 yrs.
6.11	Single Bucket Truck	14 yrs.	10+ yrs.	-	-	12-17 yrs. unlimited km*	10 yrs. or 200K km
6.12	Single Bucket	8 yrs.					

Report Section	Vehicle Type	Toronto Hydro Proposed	Fleet "A" Mid-size Urban MEU	Fleet "B" Gas Utility	Fleet "C" Large Urban Municipality	Fleet "D" National Telecom	Fleet "E" Large, Commonwealth Country Regional Electrical Utility**
	Van Mount		-	-	-	10 yrs. or 225K km	10 yrs. or 200K km
6.13	Double Bucket up to 50’	14 yrs.	10+ yrs.	-	-	-	10 yrs. or 200K km
6.14	Double Bucket 51’-64’	14 yrs.	10+ yrs.	-	-	-	-
6.15	Double Bucket 65’+	14 yrs.	-	-	-	-	-
6.16	Small Digger Truck	13 yrs.	10+ yrs.	10+ yrs.	-	12-17 yrs. unlimited km*	10 yrs.
6.17	Large Digger Truck	14 yrs.	10+ yrs.	10+ yrs.	-	12-17 yrs. unlimited km*	10 yrs.
6.18	Small Crane Truck	14 yrs.	10+ yrs.	10+ yrs.	10-12 yrs.	12-17 yrs. unlimited km*	10 yrs.
6.19	Large Crane Truck	16 yrs.	10+ yrs.	10+ yrs.	10-12 yrs.	12-17 yrs. unlimited km*	10 yrs.
6.20	Small Dump Truck	14 yrs.	10+ yrs.	10+ yes	10-12 yrs.	12-17 yrs. unlimited km*	10 yrs. or 300K km

* Categorized as a “construction truck” by the fleet.

** Vehicle types/categories aligned with North American standard categories. The original vehicle definitions provided for this fleet were interpreted and aligned with the specified categories. Vehicle condition is considered in the replacement decision.

8.2 Literature Review, Vehicle Replacement Criteria for Comparison

In addition to compiling fleet profile and replacement data from the RSI database, a literature review was performed to identify examples of vehicle replacement criteria from other peer fleet and/or utility fleets. Salient examples and available supporting data are presented below.

Utility Fleet: Aurora Energy (Tasmania)

Located in Tasmania, Aurora Energy is a fully integrated energy and network business, with complementary activities in telecommunications and energy-related technologies. Employing 1,100 people, the company generates, distributes and sells electricity as well as natural gas.

The book value of the company's fleet assets is estimated at $30.3 million (2010)[4], as follows (Table 8):

Table 8: Aurora Energy Fleet Asset Profile

Fleet Asset Category	Number of Units	Average Capital Value per Unit
Light passenger vehicles	133	$30K
Light commercial vehicles	391	$41K
Heavy vehicles	30	$90K
Mobile Elevated Work Platform units	69	$285K
Borer units	8	$560K
Trailers, plant, etc.	227	$25K
Total	858 units	

In 2011, Aurora published its *Strategic Fleet Asset Management Plan* (2011 – 2016) based on the principles of financial, social and environmental impacts. The strategy focuses on the implementation of a dedicated fleet system to enable comprehensive analysis, which is in turn predicated on considering the fixed and variable cost components occurring over the life cycle of a fleet asset. The total maintenance and capital expenditure expected annually is approximately $11.1 million.

The Plan incorporates several elements of interest to Toronto Hydro's exploration of LCA for its fleet. These include prioritizing the ongoing analysis of maintenance, repair and fuel costs, the implementation of a Fleet Asset Replacement Guideline, and periodic reviews relating to replacement timing and optimal replacement strategies. Specifically, the vehicle replacement criteria adopted by the fleet are to range by either mileage *or* age (Table 9).

[4] Although they state the book value at $30M, RSI calculates the replacement value to be $52M (# units x avg replacement cost).

Table 9: Aurora Energy Vehicle Replacement Criteria

Asset Service Life Class	Age Based Criteria	Km Based Criteria	Replacement Decision Guide
Passenger – small	n/a	150,000	Km subject to asset condition
Passenger – medium	n/a	150,000	Km subject to asset condition
Passenger - large	n/a	150,000	Km subject to asset condition
Executive special vehicle	2	n/a	Not used
Station wagon – medium	n/a	150,000	Km subject to asset condition
Station wagon - large	n/a	150,000	Km subject to asset condition
Station wagon – 4WD small	n/a	140,000	Km subject to asset condition
Executive special vehicle	3 or 4	n/a	
2WD light commercial utility	n/a	140,000	Km subject to asset condition
Van	n/a	140,000	Km subject to asset condition
4WD light commercial utility – 1 tonne	n/a	140,000	Km subject to asset condition
Bus	n/a	140,000	Km subject to asset condition
Hard tops – 4WD LWB	n/a	140,000	Km subject to asset condition
Truck – 4WD LWB	n/a	140,000	Km subject to asset condition
Truck – 4WD GVM 5000 g	10	200,000	Age/km subject to asset condition
Truck – Flat Gray GVM up to 8000 kg	10	200,000	Age/km subject to asset condition
Truck – Tipper GVM up to 15,000 kg	10	200,000	Age/km subject to asset condition
Truck – with mounted Pole Hole Borer Erector GVM up to 22,500 kg	10	200,000	Age/km subject to asset condition
Truck – Flat Tray for crane, GVM up to 15,000 kg	10	300,000	Age/km subject to asset condition
Truck – 5 yard tipper, GVM up to 15,000 kg	10	300,000	Age/km subject to asset condition
Truck – with Winch, GVM up to 15,000 kg	10	300,000	Age/km subject to asset condition
Truck – Flat Tray 4WD for Crane/Winch, GVM up to 15,000 kg	10	300,000	Age/km subject to asset condition
Truck – 5 yard tipper 4WD, GVM up to 15,000	10	300,000	Age/km subject to asset condition

Asset Service Life Class	Age Based Criteria	Km Based Criteria	Replacement Decision Guide
kg			
Truck – 4x2 for MEWP, GVM up to 8,500 kg	10	300,000	Age/km subject to asset condition
Truck – 4x4 for MEWP, GVM up to 15,000 kg	10	n/a	Age subject to asset condition
Truck – 6x4 for MEWP, GVM 22,500 kg	10	n/a	Age subject to asset condition
Mobile Elevating Work platform (MEWP), 10.5 m, fitted with purpose built tray	10	n/a	Age subject to asset condition
MEWP up to 14 m, fitted with purpose built tray	10	n/a	Age subject to asset condition
MEWP up to 19 m, fitted with purpose built tray	10	n/a	Age subject to asset condition
Crane – truck mounted	10	n/a	Age subject to asset condition
Pole Hole Borer Erector, truck mounted	10	n/a	Age subject to asset condition
Compressor – truck mounted	10	n/a	Age subject to asset condition
Rewind frame – winch truck mounted (hydraulically operated)	20	n/a	Age subject to asset condition
Special vehicles/Other plant	15	n/a	Subject to asset condition
Trailer – light, box trailers	15	n/a	Subject to asset condition
Trailer – heavy multi pole trailers, cable recover trailers	15	n/a	Subject to asset condition
Construction equipment – plant, forklift trucks	15	n/a	Subject to asset condition

Our observations on the Aurora Energy plan are that, although it is a comprehensive guiding document, we are not able to ascertain where the availability or uptime of the vehicles relative to their age is accounted for. This is an important metric as the Fleet Department, as a service provider, must ensure that the fleet is sufficiently "young" to provide an acceptable rate of "uptime" to their internal clients. If that rate is not being achieved, then additional capital should be immediately spent to bring the fleet to an average age that will provide an acceptable rate of uptime. This is especially critical in the electrical utilities where customer satisfaction rates are closely tied to vehicles being available (i.e. in order to get technicians quickly and reliably out to job sites whenever there is a system outage and customers are without power). Once the fleet is providing an acceptable level of uptime, then a good rule of thumb is to replace vehicles at the rate of depreciation.

Moreover, without further information on how the replacement criteria in Table 9 were derived, we surmise that the bulk of these values are based on general guidelines or intuitive principles as opposed to historical operating data. In general, both quantitative and qualitative approaches to optimizing vehicle replacement criteria are important to consider, for example through the following steps:

(1) Using historical data to determine the LCA for each vehicle type and with that information, prepare a list of vehicle replacements meeting the LCA thresholds (as determined for Toronto Hydro through this report); and,
(2) Qualitatively assess each unit meeting the replacement criteria threshold(s) (i.e. be this age, kms or both) on a case-by-case basis with a view of extending the life cycle of specific units wherever deemed practical and not excessively risky to do so. This assessment would be facilitated through adopting a formal mechanism to periodically review and assess vehicle operational performance.

State Fleet: Budget and Control Board (U.S.)[5]

The Budget and Control Board of the State of North Carolina of requires that the State achieve the maximum return on investment in its motor vehicle fleet. The following are disposal criteria currently recommended for the various classes and sizes of state vehicles (Tables 10 and 11).

These criteria are established as minimums only, as the Board indicates that state agencies may continue to operate vehicles past these minimums so long as the vehicle is determined to be safe and cost effective to operate.

Table 10: Guidelines for Passenger-Carrying Vehicles

Vehicle Class	Minimum Mileage (in km)
Compact Sedans	160,000
Intermediate Sedans	176,000
Full Size Sedans	200,000
All Station Wagons	200,000
Mini Vans	200,000
Full Size Vans	240,000
Intermediate Utility Vehicles	200,000
Full Size Utility Vehicles	240,000
14 Passenger Mini Bus	280,000
Handicap Bus	320,000

Table 11: Guidelines for Non Passenger-Carrying Vehicles

Vehicle Class	Minimum Mileage (in km)
Full Size Police Sedans	200,000
All Other Police Sedans	176,000
Compact Trucks	200,000
Trucks < 10,500 GVW	240,000
Trucks > 10,500 GVW	280,000

[5] http://www.ogs.state.sc.us/statefleet/SFM-replace-criteria.phtm

Mini Cargo Van	200,000
Full Size Cargo Van	240,000
Bus (Other than School)	320,000
Truck Tractor, Diesel	480,000
Scooter, 3-Wheel	19,200

The mileage thresholds stated by the Budget and Control Board of the State of North Carolina are marginally higher than those set by Aurora Energy when it comes to passenger vehicles. This may be due to geography - Aurora, being in Tasmania, and having a smaller footprint- may have vehicles travelling less distance. This logic may similarly apply to Toronto Hydro as well given Toronto's operational footprint is much smaller that the State of North Carolina and as such vehicles would travel much less distance.

Utility Fleet: Baltimore Gas & Electric (U.S.)[6]

An affiliate of Constellation Energy in Maryland, Baltimore Gas & Electric (BGE) provides electric and gas service across a 3,840 square kilometre territory surrounding the Baltimore metropolitan area. BGE Fleet Services manages a fleet of more than 1,500 vehicles, 400 pieces of equipment, and has a central shop where all major repairs and maintenance takes place.

The fleet replacement cycle is documented as being "based on economic life, the evaluation of units, user input and a review of maintenance records". Although it is acknowledged that budgetary and business cycles can constrain replacement activity, BGE Fleet Services still adheres to an annual replacement plan that is cognizant and conscious of current budgets. Moreover, the department has developed standardized specifications for each vehicle and equipment type. Any departures from standard offerings is evaluated through a specified user-needs review.

It is the opinion of RSI that, while stating that fleet management will place its focus on "*economic life, the evaluation of units, user input and a review of maintenance records*" is commendable; this approach to vehicle replacement is vague and open to continual re-interpretation. A better approach would set replacement policies that specify the limits of the economic life cycles (i.e., years, kilometres or both) for each and every vehicle category in the fleet– as defined by careful Life Cycle Analysis of actual historical operating data.

Once these thresholds have been established, it becomes a relatively simple and effective exercise to determine a long-term (five years or more) capital plan that stabilizes go-forward spending and prevents cost spikes.

[6] http://www.utilityfleetprofessional.com/utility-equipment/item/176-proven-practices.html

As with all approaches to vehicle replacement, RSI believes that focus must also be placed on qualitative assessment of all units meeting the replacement thresholds. This step will ensure maximum value is received from all fleet vehicles prior to their replacement.

Utility Fleet: Progress Energy (U.S.)[7]

Progress Energy generates and supplies electricity and natural gas to more than three million customers over an 80,000 square kilometre territory (North Carolina, South Carolina, and Florida). Its fleet of nearly 4,000 vehicles and equipment is maintained in 26 regional garages.

The Progress Energy fleet includes over 2,500 light-, medium- and heavy-duty vehicles from a variety of manufacturers. Also in the operation are more than 1,300 pieces of equipment including trailers and off-road excavating equipment.

Current replacement cycles for the Progress Energy fleet are five years -- or 200,000 kms -- for light-duty vehicles, seven to eight years for medium-duty models and 11 years for heavy-duty units. Service buckets are typically replaced after four to five years and trailers after operating over 20 years.

RSI supports the dual parameter replacement criteria approach employed by Progress Energy fleet management. Age and mileage criteria makes sense for light duty vehicles since at higher odometer readings, maintenance cost generally increases faster than ownership cost declines. Age only criteria has merit for medium and heavy duty vehicles where it takes significantly longer for increasing maintenance cost as the vehicle ages to offset reductions in ownership cost. This said, we would expect that the mileage driven over 7,8 and 11 year life cycles would be well within the capability of medium and heavy duty vehicles.

Finally, as with all approaches to vehicle replacement, consideration must also be given to qualitative assessment of all units meeting the replacement thresholds in order to ensure maximum value is received from all fleet vehicles prior to their replacement.

Municipal Fleet: City of Independence (U.S.)[8]

The City of Independence in Missouri has a total fleet of 895 vehicles managed through its Central Garage which services a population of over 110,000 people. The City also oversees for the Power & Light Department fleet, numbering at 206 vehicles. This latter fleet operates on an annual budget of $2.2M which includes all maintenance, repair, overhead, and refuelling.

The Power & Light Fleet Department uses a Fleet Controller software system to track data and

[7] http://www.utilityfleetprofessional.com/utility-equipment/item/176-proven-practices.html

[8]http://www.ci.independence.mo.us/UserDocs/MgmtAnalyst/Fleet%20Maintenance%20Report%20Final%20%28WEB%29.pdf

performance indicators, as well as to provide notification when an asset is approaching its useful life. Each year the Department conducts a 12-year projection in order to identify when each piece of equipment will be due for replacement.

A 2013 audit of the City's Central Garage and associated fleets found that "a lack of funding and strategic planning for vehicle replacement has contributed to a fleet that has been in service on average nearly four years longer than that of peer cities", concluding that these units have negatively impacted maintenance, repair and downtime costs. Lack of funding has also contributed to a highly diverse fleet which prevents parts standardization and mechanic specialization – and their associated costs impacts.

This same audit indicated that according to the U.S. Government Fleet *2012 Industry Profile Survey*, 65% of governmental fleets have a formal replacement program primarily made up by either vehicle mileage and age. Average time-in-service for the Central Garage is 11 years, compared to cities of similar sizes with in time service periods of seven years. The average from various peer cities reviewed is excerpted below (Table 12).

RSI supports the notions of timely vehicle replacement and standardization - assuming replacement cycles have been determined for the subject fleet based on economic life cycle analysis using actual historical data.

We note that the published fleet size of Independence, Missouri appears to be disproportionately large.[9] If the fleet size is correct as stated, we assume that this may be due to the advanced age of the fleet and the need for retention of many spare vehicles to backfill for poor reliability of the current vehicles and the resultant breakdowns. In such cases, fleet sizes can grow exponentially as numerous spare vehicles of all categories deemed necessary to support aging and no-longer-reliable primary vehicles. With these spare vehicles also comes stranded fixed and operating costs that quickly over-inflate operating budgets.

Table 12: Average Vehicle and Equipment Time In-Service (Months/Yrs.)

City[10]	Pop.	LDV, <8,500	LDV, 8,501-10,000	MDV 10,001 – 19,500	HDV > 19,501	Heavy Equipt	Police	Fire Apparatus
All	132,555	78 mths, 6.5 yrs.	79 mths, 6.6 yrs.	79 mths, 6.6 yrs.	82 mths, 6.8 yrs.	100 mths, 8.3 yrs.	45 mths, 2.8 yrs.	108 mths, 9 yrs.

[9] The population of Independence is 120,000 people with a fleet of 895 vehicles vs. the City of Toronto at 2.6 Million, fleet of 3,900.
[10] Drawn from Savannah, Peoria, Surprise, Bellevue, Columbia, Olathe, Cedar Rapids, Concord, Coral Springs, Elk Grove, Fort Collins, McAllen

Appendix 1 Toronto Hydro Data Sets Provided

1. Ellipse Folder, which contains the fleet inventory by make, model and year from 2008 onwards. This includes vehicle class.

2. Financial Folder, which includes 2012 parts costs, excluding NAPA by Work Order Number (WO).

3. 2012 NAPA Invoices, which includes 2012 parts costs by WO.

4. Man Productivity Reports, which includes 2012 labour costs by WO and Veh ID.

5. Utilization Data: As Geotab telematics are installed on all vehicles, Km travelled and hours used are available for the last three years.

6. Previously combined data sets, including parts and labour cost by vehicle for 2008 to 2011 by Veh ID (note that each year is provided in separate files).

7. Fuel, which lists transactional fuel data from 4Refuel, ARI, and in-house pumps for 2010 to 2012 by Veh ID (note that this data is listed in separate files).

8. Financial Folder, which includes historical purchase and remarket prices for each vehicle sold for 2010 to 2012.

9. Meter reading updates for odometer, engine hours and PTO for 2008-2012.

10. Recent purchases prices for the vehicle category.

Appendix 2 Maintenance Cost Backup

To complete a Life Cycle Analysis, it is useful to have sufficient data to observe how maintenance cost varies as vehicles age. For some vehicle types as listed in this section, there were data gaps to necessitate averaging maintenance cost for similar vehicle types. For reference purposes, the original data and the average data are provided below.

Car, SUV and Passenger Minivan

	# Veh			Maint. $/Yr			# WO/Yr			All Passenger Vehicles		
Veh Age	Car	Minivan	SUV	Car	Minivan	SUV	Car	Minivan	SUV	Total # Veh	Maint. $/Yr	# WO/Yr
1	29	13	19	$630	$604	$733	2.9	2.5	4.4	61	$657	3.3
2	31	9	10	$839	$706	$1,073	5.0	4.4	5.4	50	$862	5.0
3	28	18	16	$1,199	$1,356	$1,209	6.8	6.0	6.8	62	$1,247	6.5
4	17	19	16	$1,391	$2,002	$823	6.7	7.9	5.1	52	$1,440	6.7
5	17	15		$1,475	$1,838		6.6	8.5		32	$1,645	7.5
6	17	7		$1,367	$1,689		6.6	7.1		24	$1,461	6.8
7	11	6		$1,548	$2,246		7.8	8.2		17	$1,795	7.9
8	10			$2,501			9.8			10	$2,501	9.8
9	8			$3,880			8.0			8	$3,880	8.0
10	4	1		$4,133	$4,385		10.8	11.0		5	$4,184	10.8

Double Bucket Trucks – up to 50', 61-64', 65+'

	# Veh			Maint. $/Yr			# WO/Yr			All Double Bucket Trucks		
Veh Age	up to 50'	51-64'	65+'	up to 50'	51-64'	65+'	up to 50'	51-64'	65+'	Total # Veh	Maint. $/Yr	# WO/Yr
1	3	27		$1,056	$3,641		5.7	10.8		30	$3,383	10.3
2	2	33	2	$6,629	$4,726	$1,613	21.0	17.6	3.0	37	$4,660	17.0
3		28	2		$6,319	$4,520		22.0	14.0	30	$6,199	21.5
4		24	2		$6,901	$3,917		23.5	17.0	26	$6,671	23.0
5		11	2		$7,474	$8,354		27.3	23.0	13	$7,610	26.6
6	6	11	2	$10,208	$10,859	$7,256	26.7	23.5	18.5	19	$10,274	24.0
7	6			$11,191			25.2			6	$11,191	25.2
8	6			$11,551			31.2			6	$11,551	31.2
9	6			$8,885			27.3			6	$8,885	27.3
10	6			$16,035			27.3			6	$16,035	27.3
11	1			$17,463			32.0			1	$17,463	32.0
12	1			$15,373			41.0			1	$15,373	41.0
13	3	1		$10,477	$13,865		27.3	32.0		4	$11,324	28.5
14	4	2		$8,720	$7,850		22.3	22.5		6	$8,430	22.3
15	5	1		$10,112	$3,278		19.0	14.0		6	$8,973	18.2
16	3			$4,150			10.3			3	$4,150	10.3
17	3	2	1	$5,648	$12,656	$10,426	16.3	20.5	24.0	6	$8,781	19.0
18		2	1		$6,397	$1,139		18.0	7.0	3	$4,644	14.3
19		3	2		$4,504	$15,518		15.7	28.5	5	$8,909	20.8
20		3	2		$2,278	$6,323		7.0	14.5	5	$3,896	10.0

Small and Large Digger Trucks

	# Veh		Maint. $/Yr		# WO/Yr		All Digger Trucks		
Veh Age	Small Digger	Large Digger	Small Digger	Large Digger	Small Digger	Large Digger	Total # Veh	Maint. $/Yr	# WO/Yr
1	5	11	$3,379	$3,307	11.4	8.9	16	$3,330	9.7
2	3	8	$3,077	$5,961	9.0	25.1	11	$5,174	20.7
3	4	7	$6,379	$7,301	18.8	23.3	11	$6,965	21.6
4	5	3	$9,637	$10,229	25.2	32.0	8	$9,859	27.8
5	5		$7,964		27.4		5	$7,964	27.4
6	5		$9,759		25.8		5	$9,759	25.8
7	3		$12,939		27.0		3	$12,939	27.0
8	2		$5,546		23.0		2	$5,546	23.0
9	1		$6,658		22.0		1	$6,658	22.0
10	1		$10,663		23.0		1	$10,663	23.0
11	1		$6,870		25.0		1	$6,870	25.0
12	2		$12,475		27.0		2	$12,475	27.0
13	2	2	$16,839	$7,620	26.5	17.0	4	$12,230	21.8
14	1	3	$21,115	$16,897	55.0	32.7	4	$17,952	38.3
15		4		$8,699		24.8	4	$8,699	24.8
16	2	4	$5,324	$10,300	15.5	36.8	6	$8,641	29.7
17	3	3	$7,185	$9,959	20.7	29.0	6	$8,572	24.8
18	4		$8,670		15.0		4	$8,670	15.0
19	2	1	$8,613	$3,176	22.5	13.0	3	$6,800	19.3
20	2	1	$274	$8,028	2.0	22.0	3	$2,859	8.7

Small and Large Crane Trucks

	# Veh		Maint. $/Yr		# WO/Yr		All Crane Trucks		
Veh Age	Small Crane	Large Crane	Small Crane	Large Crane	Small Crane	Large Crane	Total # Veh	Maint. $/Yr	# WO/Yr
1	9	10	$2,995	$2,847	8.8	9.0	19	$2,917	8.9
2	8	9	$4,444	$5,197	18.9	23.6	17	$4,843	21.4
3	8	6	$3,716	$4,190	16.5	18.5	14	$3,919	17.4
4	4	4	$3,408	$5,025	16.5	18.8	8	$4,217	17.6
5	2	1	$5,448	$3,436	16.0	18.0	3	$4,778	16.7
6	1	1	$13,532	$3,805	28.0	14.0	2	$8,669	21.0
12	1	1	$5,618	$10,891	20.0	24.0	2	$8,255	22.0
13	1	1	$8,814	$4,181	27.0	17.0	2	$6,497	22.0
14	1	3	$5,291	$8,256	19.0	36.0	4	$7,515	31.8
15		4		$7,866		30.8	4	$7,866	30.8
16		2		$4,178		19.5	2	$4,178	19.5
17		2		$6,172		24.0	2	$6,172	24.0
18		2		$4,358		20.5	2	$4,358	20.5
19		1		$2,793		14.0	1	$2,793	14.0

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 59:

Reference(s): Exhibit 2B, Section E8.2

a) Please describe how Asbestos Containing Materials have been secured in each of THESL's properties and what is being done to remove the hazard. Please state whether or not THESL can confirm that the asbestos containing material is properly secured and not a threat to employee and public health and safety;

b) At page 11, line 23, it is stated that "The exits have failed to open during fire drills and …" Please provide further discussion as to why this happened and what has been done to address the problem;

c) Please state whether building management is conducted in house or contracted out;

d) Please describe the management structure responsible for the maintenance of building facilities, and the processes, principles, targets and measures according to which they are operated;

e) At page 13, in regard to building automation system and fire and security monitoring systems, it is stated that "many of the breakers, relays and switches are very difficult to source and maintain.":

   i) Please clarify why only Original Equipment Manufacturer components should be used, if other CSA or ESA approved equipment is available;

   ii) Please state what is meant by "very difficult to source". Please discuss factors such as price and delivery period.

f) It is stated at page 14, Civil Work, that storm water management at 14 Carlton is a problem, including causing flooding of the foyer. Please state how long this problem has existed and what is believed to be causing it;

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g) At page 24, lines 5-9, the application states that the System Response Units will be dispersed to sites throughout the city:

i) Please state whether or not these sites are the property of THESL or whether they still to be acquired or rented and how many sites are involved;

ii) Please describe the sites, their price of acquisition or rental, their size, any facilities improvement and implementation costs, and their expected annual operating costs;

iii) Please confirm that all of the costs mentioned in b. above have been taken into account in Table 10 on page 25;

iv) Please state whether the Building facilities have any form of Asset Management applied, or if this is intended to be included in the Asset Management Plan that THESL is currently running, or if neither, why not.

RESPONSE:

a) Toronto Hydro follows all legal requirements of Ontario Regulation 278/05 (Designated Substance – Asbestos on Construction Projects and in Buildings and Repair Operations) made under the *Occupational Health and Safety Act*, R.S.O. 1990, c. O.1. Toronto Hydro also follows Policy 1810-006 – Asbestos Management. Toronto Hydro confirms that the asbestos-containing material is properly secured so as to mitigate potential risks to employee and public health and safety.

b) The Emergency exit doors are only used for evacuations. Many of them are approaching 20 years old and are rusted beyond repair which makes them difficult to open and close. These failures were observed during the 2013 annual fire drill. All

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the doors are now inspected monthly to ensure they operate properly. Repairs are made as required to ensure operation until such time as the doors are replaced.

c) Building Management at Toronto Hydro uses both internal and external services. The external portion is contracted out to a Facility Management Operations company.

d) The management structure in the Facilities program at Toronto Hydro consists of supervisors who manage work orders in the work centers and the stations. The processes include the use of a central maintenance management system ("CMMS"), a 24-hour call centre and an asset database. The work orders are divided into three categories: preventative maintenance, corrective work orders and tenant requests. Since implementing the CMMS in January 2014, there have been over 16,000 work orders. Toronto Hydro's targets include being above 95% for preventative maintenance tasks, above 80% for corrective and tenant request work orders and 100% for all legislated maintenance tasks. Work orders that are older than 30 days are reviewed weekly and progress against these targets scores are reviewed monthly.

e) Exhibit 2B, Section E8.2, page 13 discusses electrical systems as a whole. The statement about the breakers, relays and switches was referring to the panel boards at 14 Carlton St. As stated on page 29, lines 12-15 (Exhibit 2B, Section E8.2) the equipment is past its useful life. There are no replacement parts aside from used parts available at companies that specialize in refurbishing old equipment. These parts may not be available when needed.

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f) Exhibit 2B, Section E8.2, page 30 includes a description of the cause of the flooding. The two events in 2013 were the first major occurrences where the water moved into the main lobby. All other events prior to 2013 were observed in the vestibule only.

g) The sites to which the System Response Units will be relocated are already owned or leased by Toronto Hydro. Accordingly, no incremental acquisition or rental costs are expected. Any incremental operating costs resulting from this change are expected to be minor in nature and immaterial relative to the avoided operational costs detailed in Table 10 of Exhibit 2B, Section E8.3.

The table below summarizes the facilities that will house the System Response Units and the associated $4.7 million in one-time capital expenditures needed to prepare those cites to receive and house the System Response Units. These costs are not included in Table 10 of Exhibit 2B, Section E8.3 as that table summarizes benefits only.

Location	One-time Capital Investment
Eglinton	$ 1.8
Pandora	$ 0.8
Cavanagh	$ 0.7
Wiltshire	$ 0.7
Enterprise	$ 0.7

The Asset Management Plans for buildings are distinct from, but consistent with, Toronto Hydro's standard Asset Management Plan.

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INTERROGATORY 60:

Reference(s): Exhibit 3, Tab 1, Schedule 1, pp. 1-2

Table 1 at page 1 of the above reference shows total load, revenues and customers for the period 2009 to 2019.

Board staff notes that in the period from the 2014 Bridge year to the 2019 Test year Total Normalized Gwh decreases by roughly 2%, while Total Customers increases by roughly 8%.

On page 2 of the second reference, it is stated that:

> Since 2007, there has been a significant decrease in total energy consumption. Essentially flat growth over the 2004-2006 period has been replaced by declining loads over the 2007-2013 period. While it is difficult to precisely attribute this decline to any particular event, Toronto Hydro believes that the effect of conservation activities – both program driven and naturally occurring - continue to have a significant impact on the overall load change. Furthermore, in late 2008 and 2009, economic conditions also contributed to the load decline.

Please state whether the forecast decline in load in the 2014 to 2019 period, in spite of an anticipated increase in the number of customers, is entirely the effect of conservation activities, or whether other factors are also involved and, if so, what they are and how significant they are relative to the conservation effects.

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RESPONSE:

The forecast reduction in total kWh between 2014 and 2019 is largely attributed to conservation activities. Excluding the forecast CDM loads, the forecast for total kWh shows a small annual increase of approximately 0.4%. This forecast reflects the expected continued trend to lower use per customer than in prior periods, even before accounting for the effects of CDM activities.

The table below shows the total kWh load forecast exclusive ("Gross") and inclusive ("Net") of CDM loads.

Year	Forecast GWh (Gross of CDM)	% Change	Forecast GWh (Net of CDM)	% Change
2014	26,581.9		25,018.5	
2015	26,717.3	0.5%	24,993.3	-0.1%
2016	26,905.6	0.7%	25,027.4	0.1%
2017	26,942.0	0.1%	24,841.6	-0.7%
2018	27,049.3	0.4%	24,696.9	-0.6%
2019	27,154.9	0.4%	24,611.4	-0.3%

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INTERROGATORY 61:

Reference(s): **Exhibit 3, Tab 1, Schedule 1, pp. 9-10**

Table 3 at page 9 of the above reference shows regression variables by rate class. While other classes with the exception of those for Street lighting and Unmetered Load show multiple regression variables, the Competitive Sector Multi-unit Residential class shows only one which is normalized average use per customer.

Page 10 of the above reference explains the use of normalized average use per customer as follows:

> The load forecast for Competitive Sector Multi-unit Residential ("CSMUR") was determined using the NAC as the most suitable model for this relatively new rate class. Historically, CSMUR customers were part of Residential rate class, however, as directed by the Ontario Energy Board in EB-2010-0142, Toronto Hydro established a separate rate class with rates implemented as of June 1, 2013.

a) Please state why NAC was determined as the most suitable model for the CSMUR class;
b) Please state whether there have been any changes to the regression variables for the other rate classes relative to those presented in the EB-2010-0142 application and, if so, why such changes were made.

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RESPONSE:

a) The CSMUR class is a new class with consumption data being collected as of its implementation date – June 1, 2013. With the limited historical load data available, Toronto Hydro determined that using the normalized average use per customer would be the most suitable forecast approach for this class. As more historical data for the CSMUR class becomes available, Toronto Hydro anticipates also developing multivariate models for this class.

b) Toronto Hydro confirms that there have been changes to the regression variables used for the other rate classes relative to the last rebasing application (EB-2010-0142), specifically for the GS < 50 kW, GS 50-999 kW, GS 1,000-4,999 kW and Large Use rate classes. The table below lists the regression models used in this application (EB-2014-0116) and the 2011 rebasing application (EB-2010-0142).

Toronto Hydro assesses the appropriateness of all model variables each time it goes through its forecasting exercises. The regression variables are tested for their statistical significance, along with other explanatory variables in the regression models for each customer class independently. Based on the results of the statistical estimation (variables significance in the models and (adjusted) R Squared) “the best-fitted” variables are chosen for those customer classes. As a result, some of the variables become more statistically significant, while the others less.

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1 **Regression Variables by Rate Class (2015 CIR and 2011 COS)**

GS<50 kW		GS 50-999 kW		GS 1,000-4,999 kW		Large Use	
2015 CIR EB2014-0116	2011 COS EB-2010-0142	2015 CIR EB2014-0116	2011 COS EB-2010-0142	2015 CIR EB2014-0116	2011 COS EB-2010-0142	2015 CIR EB2014-0116	2011 COS EB-2010-0142
Toronto Unemployment Rate	**Toronto City Population**	**Toronto Unemployment Rate**	HDD10 per day	**Toronto Unemployment Rate**	**Linear Trend (January 2007)**	**Number of LU customers**	**Linear Trend (January 2007)**
Dew Point Temp.	**Business Days Percent.**	HDD10 per day	CDD per day	HDD10 per day	HDD10 per day	**Time Trend**	HDD10 per day
Time Trend	Linear Trend (July 2002)	CDD per day	Dew Point Temp.	CDD per day	CDD per day	HDD10 per day	CDD per day
HDD10 per day	HDD10 per day	Dew Point Temp.	Business Days Percent.	Dew Point Temp.	Dew Point Temp.	CDD per day	Dew Point Temp.
CDD per day	CDD per day	Business Days Percentage	Number of GS 50-1000 kW customers	Business Days Percent.	Business Days Percent.	Dew Point Temp	Business Days Percent.
Number of GS<50 kW customers	Number of GS<50 kW customers	Number of GS 50-1000 kW customers	Blackout dummy	Number of GS 1,000-4,999 kW customers	Number of GS 1,000-4,999 kW customers	Business Days Percent.	Blackout dummy
Blackout dummy	Blackout dummy	Blackout dummy	Intercept term	Blackout dummy	Blackout dummy	Blackout dummy	Intercept term
Intercept term	Intercept term	Intercept term		Intercept term	Intercept term	Intercept term	

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INTERROGATORY 62:

Reference(s): Exhibit 3, Tab 2, Schedule 1, p. 6

The above reference discusses gains from sale of utility properties in the context of revenue offsets. In its discussion, THESL notes that gains on the sales of such properties were recorded as revenue offsets in the 2011 to 2014 period.

THESL, however, states that in 2015 it expects to sell idle properties at 5800 Yonge and 28 Underwriters and given the relatively large value of these properties, these gains are not recorded as part of revenue offsets, but are proposed to be treated as regulatory liabilities to be refunded to customers over a multi-year period.

a) Please state whether THESL would have any reasons other than the potential size of these gains for its proposed treatment and, if so, what they would be. If not, please explain why THESL believes the size of the gain should be a criteria in determining its treatment and what criteria the Board should use in determining whether a gain should be treated as a revenue offset, or a regulatory liability;
b) In the event the Board was to determine that the 2015 gains were to be treated as revenue offsets, please describe any concerns THESL would have with such treatment.

RESPONSE:

a) As noted in Exhibit 8, Tab 1, Schedule 1, page 17, Toronto Hydro has proposed clearance of the 2015 Gains on Sale (as well as the proposed Tax Refund) through a

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rate rider in place for 36 months, to assist in smoothing bill impacts for customers. Providing for full clearance through a single 2015 Revenue Offset for this sizable amount is problematic under THESL's proposed 2015-19 framework since it would effectively set into base rates an equivalent full amount in each year (which would be inappropriate since the offset only occurs once). It would also eliminate the desired bill impact smoothing.

b) As noted above, if the Board were to determine that the gains were to be treated as a revenue offset, Toronto Hydro would be concerned that a custom clearance term could not be accommodated under its proposed custom PCI formula, and as a result, the gains could only be cleared over the full five-year rate term (by including one-fifth of the total amount as a revenue offset in 2015). This would nullify the positive impacts a three-year clearance would have on rate smoothing.

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INTERROGATORY 63:

Reference(s): **Exhibit 4A, Tab 1, Schedule 1, page 2 and 4, Table 1**

In the first reference, THESL states that:

> While Toronto Hydro submits that the manner of presentation of its 2015 OM&A activities is consistent with the OEB guidance, the utility notes that its work in developing a meaningful program/Segment OM&A presentation involved a significant amount of assumptions and complex analytic work, given that Toronto Hydro internal OM&A tracking procedures do not fully lend themselves to the approach contemplated by the OEB.
>
> At Toronto Hydro, OM&A plans are generally presented on an operating department or "Responsibility Centre" (RC) basis, whereby each RC is tied to the operational management of broad, but discrete functional areas such as customer care, finance, regulatory, safety, IT, HR or legal. That is, on the basis of the areas of discrete responsibility and type of departmental expenditures, rather than the (often cross-functional) activities or programs that the utility at large undertakes.

In Table 1 of the second reference, THESL lists Historical, Bridge and Test Year OM&A expenditures by program. Board staff observes that:

(1) a number of the categories in this table are the same or similar to those presented in THESL's EB-2011-0144 application (e.g. Fleet and Equipment Services, Control Centre);

(2) In addition to being the same or similar a number of the categories do not appear to represent a program/outcome type of approach (e.g Legal Services, Rates and Regulatory Affairs);

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(3) Costs such as Legal Services and those of other departments might seem to be the types of costs which under a program/outcomes based approach would be allocated to the various projects rather than continuing to appear separately. Such an allocation would be reflective of the Board's focus on outcomes rather than inputs discussed in the "Operating Expenses" section of the Filing Requirements.

a) Please comment on Board staff's observations;
b) Please elaborate on the nature of the "significant amount of assumptions and complex analytic work" referenced above. Please state what the key assumptions were;
c) Please state whether or not THESL will be further evolving its approach to OM&A in the future to fully align it with the approach contemplated by the Board. If yes, please state what approximate percentage of this process was completed for the current filing and when full completion would be anticipated. If not, please explain, why not.

RESPONSE:

a) While a number of its programs comprising the 2015 Test Year budget are the same or similar to those presented in previous applications, Toronto Hydro does not agree that these programs do not represent activity areas driven by distinct higher-level outcomes, relevant to the utility and/or its customers. In Toronto Hydro's view, individual OEB proceedings are not "outcomes" for customers. For example, the relevant outcome for the Regulatory OM&A Program is that the utility effectively and efficiently addresses numerous OEB regulatory requirements including the ability to meet reporting obligations, participate in consultations and respond to information requests from the OEB. Please also see Toronto Hydro's response to interrogatory 4A-CCC-30 for additional discussion of the Program/Segment taxonomy.

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Moreover, Toronto Hydro submits that allocating the costs of such activities as Regulatory Affairs or Legal Services to specific programs and projects as suggested would be impractical, since there is a base-level of activity related to meeting the OEB's ongoing requirements and participating in regulatory activities that is independent of specific proceedings. Furthermore, it is not always clear which specific proceeding or project (and to what degree) is a driver and/or a beneficiary of such utility-wide activities as regulatory research and training. Finally, Toronto Hydro believes that direct assignment of legal, regulatory or finance costs to a specific program area could have a detrimental effect on the transparency of spending in these areas.

b) The assumptions and analytic work referenced in the Interrogatory refer to the steps Toronto Hydro took to delineate certain expenditures tracked internally in departmental budgets to specific programs and segments (in particular with regard to the four Operation Support Programs), as well as calculations required to allocate certain historical departmental-level expenditures to the programs that drove such expenditures (for example, historical IT expenditures that were previously tracked as a part of the Control Centre or Customer Care budgets). Key assumptions varied case-by-case, but generally involved determining which portion of a particular department or staff member's time was spent on activities comprising their respective mandates, or which portions of specific project expenditures could be allocated to one program or another. For greater clarity, Toronto Hydro submits that the assumptions made to comply with the OEB-mandated program/segment breakdown had no effect on the utility's aggregate OM&A spend, as presented in the application.

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c) As discussed above, Toronto Hydro believes that its approach to program/segment presentation complies with the OEB's guidance on this issue provided to date. Accordingly, at this point the utility does not anticipate further activities to develop this approach. That said, Toronto Hydro continues to observe that its management remains responsible for the activities of the utility and must retain the ability to organize and evolve financial and operational reporting in a manner that allows it to best meet this responsibility.

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INTERROGATORY 64:

Reference(s): Exhibit 4A, Tab 1, Schedule 1, p.5 and p.10

In the first reference, THESL states that:

> In particular, the utility approached its 2015 proposed OM&A expenditures from the perspective of savings it has achieved over the 3GIRM period together with resource requirements for 2015 and forward. Further, Toronto Hydro viewed 2016-2019 as years where its funding request would be consistent with the IRM framework – i.e., less than inflation and determined on the basis of a Price Cap Index-based formulaic adjustment.

In the second reference, THESL states that: "Absent a sufficient level of funding in the test/rebasing year, an IRM plan for the successive four years would not be sustainable":

a) Please further discuss what THESL means by the second reference and how it would define a sufficient level of funding;
b) Please confirm that THESL's 2015 Test year OM&A expenditures are intended to be representative of its OM&A expenditures anticipated in the 2015 to 2019 period, or if not please explain;
c) If THESL's 2015 OM&A expenditures are intended to be representative of its OM&A expenditures in the 2015 to 2019 period:
    i) Please state whether or not THESL has a 2015 specific OM&A forecast and if so what it is;
    ii) Please state which other numbers in the application are based on the 2015 to 2019 period rather than 2015 alone.

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RESPONSE:

a) Toronto Hydro has determined the OM&A level for 2015 based on operational assessments with considerations for its service obligations and compliance requirements. The utility believes the level of OM&A funding requested in the rate application is sufficient to meet its obligations and requirements.

In the second reference, Toronto Hydro means that since the OM&A funding levels for the years 2016-2019 are a function of the rebasing year (2015), any changes to the base year OM&A budget would consequently impact the utility's ability to meet its plans, obligations and requirements over the remaining plan period.

b) Toronto Hydro's 2015 Test year OM&A expenditures are the amounts required to fund necessary OM&A activities to be executed during the test year. Beyond 2015, and consistent with the principles of incentive regulation, Toronto Hydro expects to manage operations within the OM&A levels determined on the basis of a Price Cap Index-based formulaic adjustment to the 2015 base rates.

c)

i) See the response to part b above. The presented OM&A amounts for the 2015 Test year represent the forecast for that year.

ii) Forecasted 2015 Test Year financial amounts presented in the application reflect the utility's plans for 2015 alone. Forecasted capital spending was developed and is presented on an annual basis for each year 2015-2019. Please also see response to interrogatory 4A-OEB-68, as well as interrogatory 4A-CCC-29.

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INTERROGATORY 65:

Reference(s): **Exhibit 4A, Tab 1, Schedule 1, page 6**

THESL states that:

> For example, Toronto Hydro believes that staffing levels beyond the operating costs proposed in this application are optimal based on the utility's assessment of its operating requirements, its retirement projections for the next five to 15 years, and the significant lead time for training certified and skilled trades (four to six years). However, the utility has moderated its funding request in light of other considerations, such as rate impacts.
>
> Informed by the considerations described above, Toronto Hydro developed the OM&A plan on the basis of both a top-down and bottom-up approach as described in Exhibit 1C, Tab 3, Schedule 2. In general, Toronto Hydro's objective was to put forward a plan that largely maintained functional requirements such as safe and reliable grid operations and system performance, service levels and legal, regulatory and statutory compliance in an efficient manner.

a) Please state by how much THESL has moderated its funding request in light of other considerations, such as rate impacts;
b) Please state how THESL determined that the level of funding requested in the application is optimal and what impacts on customers it would anticipate that the moderated funding request would have and when these impacts would be felt. Please include an explanation as to what THESL means by its reference to its plan "largely"

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

maintaining functional requirements and if this statement means that some functional requirements would not be maintained, please state what such requirements would be.

RESPONSE:

a) In light of considerations such as rate impacts, Toronto Hydro has moderated its funding request for 2015 OM&A by between $5 million and $10 million in the test year, and its capital requests by over $300 million 2015 through 2019. Please see Exhibit 4A, Tab 1, Schedule 1, page 9 and Exhibit 2B, Section 00 (DSP Executive Summary), pp. 12-18 for further details.

b) Toronto Hydro does not believe that the levels of funding requested in this application are optimal from the perspective of utility operations; however, the utility assesses that given the information known today regarding the next five years, all other things being equal, the levels requested are just sufficient to serve its customers effectively and efficiently, and ensure a safe and reliable source of electricity for the City of Toronto (including maintaining functional requirements). In order to achieve this plan, Toronto Hydro will be required to – and is committed to – find additional productivity savings and seek continuous improvement in its operations, which is encouraged by its proposed custom Price Cap Index.

The impact that these funding requests may have on customers is two-fold. First, Toronto Hydro's plan leads to lower rate impacts during the next five years than an un-moderated or unconstrained proposal at the expenditure levels referenced in (a) above. Second, Toronto Hydro's proposed plan means that capital refurbishment and replacement of retiring employees will move at a slower pace than if the utility

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

invested more during the next five years. Toronto Hydro believes that its proposed plan balances operational needs with other considerations, such as rate impacts.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 66:

Reference(s): Exhibit 4A, Tab 1, Schedule 1, page 8

THESL states that it is putting forward in this application a 2015 rebasing plan containing a number of new or materially-expanded OM&A activities that it expects will be sustained over the period of the plan that are largely driven by functional requirements, examples of which include: (1) Disaster Preparedness Program, (2) Increased Billing, Remittance and Meter Data Management expenditures, and (3) Increased Preventative and Predictive Maintenance expenditures.

Please state the extent to which THESL's customer engagement efforts influenced the above referenced new or materially expanded OM&A activities and, if the customer engagement efforts were a significant impacting factor, how the input received was used to determine the expenditures. If the customer engagement activities were not a significant impacting factor, please explain why not.

RESPONSE:

As discussed in Exhibit 4A, Tab 2, Schedule 4, the key elements of the Disaster Preparedness Program align with the recommendations of the Independent Review Panel Report, "The Response of Toronto Hydro-Electric System Limited to the December 2013 Ice Storm". Among other sources, the Panel's recommendations were based on the results of extensive consultation activities with Toronto Hydro's customers and key stakeholders conducted by Davies Consulting.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

Toronto Hydro's customer engagement efforts as summarized in Exhibit 1B, Tab 2, Schedule 7 were not a significant factor driving the proposed Billing, Remittance and Meter Data Management expenditure proposals, as these programs relate to non-discretionary drivers, such as meter-reading infrastructure maintenance and upgrades, and the significant increase of Canada Post rates.

Almost half of the proposed increase for Preventative and Predictive Maintenance is for vegetation management in order to improve reliability and harden Toronto Hydro's system against major storm events, with other incremental increases driven by planned ramp-up of maintenance cycles to facilitate optimal intervention times. Toronto Hydro believes that these drivers align with the findings of the above-noted Independent Review Panel Report, as well as identified customer preferences summarized in the Innovative Research Group Report (Exhibit 1B, Tab 2, Schedule 7, Appendix B).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 67:

Reference(s): **Exhibit 4A, Tab 1, Schedule 1, page 9**

THESL states that an example of an area where it did not put forward the full possible sustained and reasonable OM&A request is its proposed staffing plan and that it constrained its compensation costs by approximately $3 million by employing contingent resources rather than full-time employees to deliver a variety of administrative and support functions.

a) Please state whether the referenced $3 million savings is per annum, or over the 2015-2019 period;
b) Please state whether THESL believes the approach it has undertaken will result in short-term cost savings at the expense of longer-term cost increases and if so when costs would start to be higher and, if not, why not.

RESPONSE:

a) The referenced savings are per annum.

b) This approach is expected to limit longer-term cost increases to customers while providing the utility with a flexible workforce to meet its capital work program commitments.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 68:

Reference(s): Exhibit 4A, Tab 1, Schedule 1, pages 9-10

On page 9 of the above reference, it is stated that:

> In building its five-year OM&A plan, while Toronto Hydro endeavoured to consider foundational expenditure requirements, including potential emerging requirements (e.g., extreme weather preparedness) that can be reasonably anticipated, it did not engage in a detailed five-year financial planning exercise.

On page 10 of the above reference, it is stated that:

> As discussed above, Toronto Hydro engaged in a detailed financial planning exercise, based on functional requirements, informed by the four pillars, and designed to provide the utility sufficient funding levels for the next five years.

a) Please clarify whether THESL did or did not engage in a detailed financial planning exercise in preparing the current application;
b) Please provide THESL's definition of a detailed financial planning exercise;
c) If THESL did not engage in a detailed financial planning exercise in preparing the current application, please explain what it did do and why in its view this would be considered adequate for the approvals requested.

RESPONSE:

a) As explained in the reference for this interrogatory, Toronto Hydro engaged in a detailed financial planning exercise in determining the current OM&A needs that

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

would be sustained over the CIR period. It did not engage in detailed financial planning for 2016-2019 OM&A.

b) Toronto Hydro identifies a detailed planning exercise as an iterative process of working with the departmental management and the Executive Team to propose and assess funding needs at the departmental level, as well as consider the overall amount in light of a variety of considerations such as rate impacts.

c) Please see responses above, response to interrogatory 4A-OEB-65, as well as response to interrogatory 4A-CCC-29.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 69:

Reference(s): **Exhibit 4A, Tab 1, Schedule 1, p.10 and**
Exhibit 1B, Tab 1, Schedule 3, p.17

The first reference states that:

> ..a corollary of Toronto Hydro's OM&A proposal - and a consideration in how it engaged in financial planning - is its proposal regarding the Z-Factor (Exhibit 1B, Tab 2, Schedule 3). While Toronto Hydro has endeavoured to consider foundational expenditure requirements, including potential emerging requirements as can be known today, for any regulated utility that operates in a dynamic environment such as Toronto Hydro, there will inevitably be material events over a five year time horizon that are outside the known, anticipated and quantifiable scope of requirements… By proposing the Z-Factor approach to be used if and when determined to be appropriate, Toronto Hydro attempts to balance the considerations of customer impacts with the necessity of maintaining safe and efficient system operation under a variety of potential conditions.

The second reference states that:

> One of the incremental challenges inherent in a five-year rates plan is the need to contend with prudent, material unexpected costs. As part of this application, and as explained in further detail throughout this application, Toronto Hydro has proposed restrained/constrained OM&A and capital funding requests. The funding that Toronto Hydro seeks in this application is expected to enable the utility to carry out the work that it has detailed in these programs. That funding, by definition, is not sufficient to address the prudent costs of material events that

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

are outside the control of the utility and which have not been forecasted. Accordingly, Toronto Hydro proposes to incorporate within its rate framework the availability of Z-factor relief, which Toronto Hydro understands is available to CIR filers as part of the RRFE framework.

In the above references THESL appears to be establishing a linkage between its stated approach in this application of constraining OM&A and capital funding requests and the availability of Z-factor relief.

a) Please state whether or not THESL would view its Z-factor proposals as expanding the range of events for which a Z-factor would be applicable and why or why not this would be the case;
b) Please state whether or not THESL would anticipate that any of the constrained OM&A and capital funding programs that it is not seeking relief for in the present application might ultimately need to be recovered through a Z-factor application and, if so, please state which programs and under what circumstances;
c) Given the constrained OM&A and capital funding programs in the current application, please state whether or not THESL would anticipate that catch-up would be a significant factor in the 2020-2024 period if the present application is approved as filed.

RESPONSE:

a) Toronto Hydro believes that its Z-factor approach is consistent with the current Z-factor criteria, and as indicated in the referenced evidence, Toronto Hydro proposes that the "standard Z-factor criteria" be applicable. However it acknowledges that applications have not been brought for all of the specific example events it lists in

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

Exhibit 1B, Tab 2, Schedule 3 (pages 17-18). In addition, the OEB may find that for any given category of material, unexpected expense, an approach other than the standard Z-factor may be appropriate, particularly for events that materially affect all or a majority of distributors.

b) In Exhibit 1B, Tab 2, Schedule 3 (pages 17-18), Toronto Hydro has listed the specific events which it believes could qualify for Z-factor treatment, or substantially equivalent treatment. The utility does not presently anticipate seeking Z-factor relief for the OM&A and capital programs that Toronto Hydro is not seeking funding for as part of this application.

Whether the utility will ultimately need to seek Z-factor relief for some of that work during the plan term depends on the extent to which such work becomes non-discretionary, and whether the utility's circumstances satisfy the Z-factor criteria in relation to that work. Toronto Hydro has no specific plans to seek Z-factor relief at this time.

c) Toronto Hydro's plan is to manage its business within the funding levels sought in this application over the 2015-2019 period. Whether or not catch-up during the next five years after that is required will be the product of many factors that are unknowable today.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 70:

Reference(s): Exhibit 4A, Tab 3, Schedule 1, pp. 6-7, Table 3

The referenced table lists THESL's non-affiliate purchased products or services over $1 million procured without a competitive process.

One such purchase is from DDP Technologies which provided THESL with "Inspection services for Pad Tx, Sub Tx, network vaults and building vaults along with "Find it – Fix it" repairs for each program." THESL states that the reason for the sole sourcing was "The need to commence the program on an urgent basis prevented the use of a competitive bid process. Informal quotes were obtained from five suppliers and the program was granted to the lowest qualified provider."

A second purchase was from Panasonic Canada for "Three years supply of Panasonic tough books and tough pads consistent with existing technology used by field staff." The justification provided is that "Negotiations with Panasonic coupled with market benchmarking indicated it was cheaper to deal direct with manufacturer instead of issuing RFP to resellers."

a) With respect to the DDP Technologies contract, please explain how THESL determines that a program is sufficiently urgent to depart from a competitive bidding process and whether THESL would anticipate similar departures for other programs and why or why not this would be the case;
b) With respect to the Panasonic Canada contract, please state why THESL used negotiations with Panasonic coupled with market benchmarking instead of going

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

directly to an RFP and whether this is an approach that might be used to award other contracts. If this is the case, please explain what the criteria would be for adopting this approach. If this is not the case, please explain why this approach was used in awarding the Panasonic contract.

RESPONSE:

a) Toronto Hydro considers the work of a given program to be sufficiently urgent to justify departures from competitive bidding in the short term if failing to do the work would present unacceptable risks to safety, reliability, or compliance with statutory, code, or other external requirements, or if a postponement of the work would introduce a substantial risk of significant cost escalation, for example due to having to complete work that could have been done on a planned basis under emergency, reactive conditions.

Depending on the complexity of the goods or services that Toronto Hydro needs to purchase, it can take anywhere between one to six months to conduct a competitive bid process. If a functional requirement must be met before the competitive bid process can be completed, the utility may engage a vendor on a short-term basis to perform the work or supply the goods. Based on this rationale, DDP Technologies was engaged to conduct maintenance work and perform repairs on certain assets while Toronto Hydro completed a competitive bid process for a long term vendor. Toronto Hydro would consider similar departures for other programs, on a case by case basis, as necessary to satisfy short term functional requirements.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

b) Toronto Hydro negotiated with Panasonic instead of doing a formal RFP because Panasonic informed Toronto Hydro that its manufacturer pricing was significantly lower than pricing offered through resellers, and that it would not participate in an RFP against its resellers. Toronto Hydro assessed the competitiveness of Panasonic's direct price by obtaining quotes from four different resellers; this exercise confirmed that the lowest reseller quote was 18.4% higher than the direct pricing offered by Panasonic. In these circumstances, Toronto Hydro did not undertake an RFP among resellers because it would have led to significantly higher costs than purchasing directly from Panasonic. The approach of purchasing directly from a manufacturer may be utilized in other circumstances where manufacturers either do not sell their goods through a distributor/reseller model or do so at significant cost mark-up, as evidenced by a market assessment.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 71:

Reference(s): **Exhibit 4A, Tab 4, Schedule 5, App. 2-K**

With respect to the first reference:

a) Please confirm that the amounts shown in Appendix 2-K are totals before capitalization to fixed assets;

b) Please provide a benefits table that shows cash benefit costs separate from OPEBs before capitalization that balances to the numbers in Appendix 2-K;

c) Please show how much of the total benefit costs in Appendix 2-K have been capitalized in fixed assets and how much has been recorded in OM&A.

RESPONSE:

a) Confirmed.

b) Please see the table below.

$Millions	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Benefits net of OPEBs	$40.8	$ 35.0	$ 40.6	$ 40.3	$ 39.4
OPEBs	$ 16.7	$ 20.4	$ 17.4	$ 16.3	$ 16.5
Total Benefits (including OPEB)	**$ 57.5**	**$ 55.4**	**$ 57.9**	**$ 56.7**	**$ 55.9**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

c) Please see the table below.

$Millions	2011 Actual	2012 Actual	2013 Actual	2014 Bridge	2015 Test
Total Capitalized Benefits	$23.3	$19.9	$22.3	$21.3	$20.9
Total OM&A Benefits	$34.2	$35.5	$35.6	$35.4	$34.9
Total Benefits	**$57.5**	**$55.4**	**$57.9**	**$56.7**	**$55.9**

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 72:

Reference(s): **Exhibit 4A, Tab 4, Schedule 7, Towers Watson actuarial report**

The above reference provides calculations in accordance with US GAAP. THESL has applied for rates under IFRS.

Please provide an analysis that compares the 2014 and 2015 projections under US GAAP with IFRS. In the event, there are any differences arising from this analysis, please state whether or not THESL would consider it necessary to update its application to reflect them. If not, please explain why not.

RESPONSE:

OPEB projections for 2014 are provided under US GAAP and those for 2015 are provided under IFRS, consistent with Toronto Hydro's transition to IFRS on January 1, 2015. Please refer to Appendix A to this response for a copy of the IFRS actuarial report as at December 31, 2013. This report includes IFRS projections for 2015 that were included in the Application.

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January 16, 2014

Mr. Daniel Paquin
Toronto Hydro Corporation
14 Carlton Street
Toronto, ON
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Dear Dan:

POST-EMPLOYMENT BENEFITS FOR EMPLOYEES OF TORONTO HYDRO
2013 YEAR-END DISCLOSURES AND ESTIMATED 2014 AND 2015 BENEFIT EXPENSE UNDER INTERNATIONAL ACCOUNTING STANDARDS

As requested, this letter and appendices have been prepared for Toronto Hydro Corporation ("the Company", or "Toronto Hydro") and present the Company's liabilities and costs in respect of the following post-retirement and post-employment benefits plans ("the Plans"):

- Extended health benefits for retirees and members on total and permanent long-term disability;
- Dental benefits for retirees and members on total and permanent long-term disability;
- Life insurance benefits for retirees;
- Vested and non-vested accumulating sick leave benefits;
- OMERS top up pension; and
- Executive retirement allowances.

This letter and appendices have been prepared for the Company, for the following purposes:

- Determining the final calculation of the 2013 benefit expense under International Financial Reporting Standards (IFRS) in accordance with International Accounting Standards Section 19 revised in 2011;
- Providing the required information for year-end disclosure purposes as of December 31, 2013 under IAS 19 rev. 2011; and
- Determining an estimate of 2014 and 2015 benefit expense under IAS 19 rev. 2011.

The information contained in this letter and appendices is presented in thousands of Canadian dollars, and is in respect of the benefits mentioned above only.

The 2013 benefit expense was determine based on the 2013 benefit expense provided in our letter dated January 15, 2013, with updates for immediate recognition of (gains)/losses related to the retirement allowance and the accumulating sick leave benefits plans. The 2013 year-end disclosure obligations and extrapolations for 2014 and 2015 are based on the results of the January 1, 2012 actuarial valuation.

In 2013, the Company chose to include an obligation in respect of two executive retirement allowances (one of which is considered an incentive plan under IFRS, and the other considered a post-employment benefit under IFRS) granted to one key employee. As directed by the company, the impact of this change was recognized as part of the service cost in expense as at June 30, 2013 in the financial accounting for the Plans under IFRS for the Toronto Hydro Corporation division. Please refer to our email dated July 18, 2013 for additional information.

The balance of this letter sets out comments and notes to our calculations. Appendix A provides details of the relevant accounting results. Please refer to the January 1, 2012 actuarial valuation report prepared by Towers Watson for the summaries of the plan provisions, the membership data and the actuarial basis used in the valuation.

ACTUARIAL ASSUMPTIONS AND METHODS

- The measurement date used for Fiscal 2013 year-end financial reporting is December 31, 2013.
- The 2013 benefit expense is based on a discount rate of 4.25% per annum and the defined benefit obligation ("DBO") at December 31, 2013 is based on a discount rate of 4.75% per annum, as instructed by the Company. The discount rates are based on long-term high-quality Canadian corporate bond yields at December 31, 2012 and December 31, 2013 respectively.
- Other than those noted in this letter, the actuarial methods and assumptions used for the determination of the 2013 net periodic benefit cost and the December 31, 2013 obligation are consistent with those used for the 2012 disclosures.
- The obligation as of December 31, 2013 and the 2014 and 2015 expense estimates are based on extrapolations from the January 1, 2012 valuation results for the medical, dental, life insurance, accumulating sick leave and OMERS benefits plans, and the June 30, 2013 valuation results for the retirement allowance benefit plans, assuming that there are no experience gains or losses other than from actual benefit payments being different from expected, and reflecting changes in the assumptions during the extrapolation period such as changes in the discount rate.

ACCOUNTING METHODS

- The information presented assumes that the transition date (between IAS 19 rev. 2008 and IAS 19 rev. 2011) is January 1, 2013.
- Under IAS 19 rev. 2011, we understand that Toronto Hydro has determined that both the non-vested accumulating sick leave benefits plan and the vested accumulating sick leave benefits plan should be included for post-employment benefits reporting. As such, these benefits are included in the financial information under IAS 19 rev. 2011 presented in this letter.
- As directed by the Company, as of January 1, 2013, upon transition from IAS 19 rev. 2008 to IAS 19 rev. 2011, all unrecognized gains and losses were fully recognized in other comprehensive income. As such there were no further unrecognized actuarial gains and losses reflected in the defined benefit liability at January 1, 2013 under IAS 19 rev. 2011.
- On an ongoing basis, actuarial gains and losses for all benefit plans other than the accumulating sick leave benefits plans and the one executive retirement allowance considered to be an incentive plan will be immediately recognized in other comprehensive income. Actuarial gains and losses for the accumulating sick leave benefits plans and the one executive retirement allowance considered to be an incentive plan will be recognized immediately in expense.
- On an ongoing basis, the impact of plan changes will be immediately recognized in benefit expense.

SUMMARY OF FINANCIAL RESULTS

Disclosure Results Summary

The summary of Fiscal 2013 benefit expense, the defined benefit liability and the DBO as at December 31, 2013, under IAS 19 rev. 2011 are as follows (in $ 000s):

	Fiscal 2013 Net Periodic Benefit Costs	*Defined Benefit Asset/(Liability) at December 31, 2013*	*DBO at December 31, 2013*
Electric System Limited	$ 15,028	$ (229,962)	$ 229,962
Toronto Hydro Corporation	408	(2,193)	2,193
Energy Service Incorporated	270	(2,815)	2,815
LDC Unregulated	96	(1,041)	1,041
Consolidated	15,802	(236,011)	236,011

- Actual benefit payments for 2013 of $10,936,000 are based on information provided by the Company on January 9, 2013. We have projected 2014 and 2015 benefit payments based on the valuation assumptions.

OTHER COMMENTS

- The Company transitioned to IFRS rev. 2011 from IFRS rev. 2008 for financial reporting beginning in Fiscal 2013. Please refer to our letter dated January 15, 2013 for additional details.

- We understand that the post-employment benefits plans are not pre-funded, and therefore our accounting results do not consider any expected investment income on plan assets.

- As directed by the Company, the full defined benefit liability has been classified as a non-current liability

- A draft report on Canadian Pensioners Mortality has been published by the Canadian Institute of Actuaries. We understand that the Company will assess the appropriateness of the new mortality tables when the report is released.

- Other than those described in this letter and appendices, the Company's management has confirmed that there have been no significant events, changes to the plan provisions or changes to plan membership since January 1, 2012 for the all benefit plans other than the retirement allowance, and since June 30, 2013 for the retirement allowance, that would materially affect the results of our valuations.

* * * * *

ACTUARIAL CERTIFICATION

The consulting actuaries are members of the Canadian Institute of Actuaries and Society of Actuaries and other professional actuarial organizations and meets their "General Qualification Standard for Statements of Actuarial Opinions" relating to pension and other post-employment benefit plans.

In preparing the results presented in this letter (including attached exhibits), we have relied upon information provided to us regarding plan provisions, actual benefit payments, historical plan costs and plan participants. We have reviewed this information for overall reasonableness and consistency, but have neither audited nor independently verified this information. The accuracy of the results presented in this letter is dependent upon the accuracy and completeness of the underlying information.

The figures provided in this letter reflect, to the best of our knowledge, all of the Company's substantive commitments and obligations, as described herein. Furthermore, to the best of our knowledge, there are no other subsequent events, the occurrence of which is probable and the effects of which are reasonably estimable, which have not been reflected in the figures provided as of the date of our letter.

The calculations for the 2013, 2014 and 2015 accounting schedules have been made in accordance with Section 19 (IAS 19 rev. 2011) of the International Accounting Standards, with which we are familiar.

The actuarial assumptions, methods (including guidance on attribution methods) and the accounting policies and methods employed in the development of the pension cost have been selected by the Toronto Hydro management as representing their best estimates of future contingent events.

The expense and obligation levels will change in the future as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions, accounting rules, legislature, and the government health care programs, or as a result of future experience gains or losses. None of these changes has been anticipated at this time, but will be revealed in future accounting valuations.

The results shown in this letter have been developed based on actuarial assumptions that are considered to be reasonable and within the "best-estimate range" as described by the Actuarial Standards of Practice. Other actuarial assumptions could also be considered to be reasonable and within the best-estimate range. Thus, reasonable results differing from those presented in this report could have been developed by selecting different points within the best-estimate ranges for various assumptions.

* * * * *

The information contained in this report was prepared for Toronto Hydro, for its internal use and for the preparation of its period financial disclosures, and its auditors, for the preparation of its periodic financial disclosures. It is neither intended nor necessarily suitable for other purposes. Further distribution to, or use by, other parties of all or part of this report is expressly prohibited with Towers Watson's prior written consent.

We are pleased to provide you with this year-end disclosure report. Please contact us if you need any additional information.

Towers Watson

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Enclosures

cc: Olga Baliakina, Mitchell Coviensky — Towers Watson

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2013 Year-End Disclosure Information ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			**January 01, 2013**		
Defined Benefit Asset/(Liability) at Beginning of Period	(244,084)	(2,020)	(2,909)	(1,068)	(250,081)
Reconciliation of Defined Benefit Obligation			**2013**		
Defined Benefit Obligation at Beginning of Period	244,084	2,020	2,909	1,068	250,081
Employer Service Cost at Beginning of Period	5,355	321	118	49	5,843
Interest Cost	10,383	92	128	47	10,650
Net Actuarial (Gain) or Loss					
Sick Leave Plan	*(710)*	-	*24*	-	*(686)*
Retirement Allowance Plan #1	-	*(5)*	-	-	*(5)*
Other	*(18,384)*	*(157)*	*(304)*	*(91)*	*(18,936)*
Total Net Actuarial (Gain) or Loss	*(19,094)*	*(162)*	*(280)*	*(91)*	*(19,627)*
Benefits Paid Directly by the Employer	(10,766)	(78)	(60)	(32)	(10,936)
Defined Benefit Obligation at Current Period End	229,962	2,193	2,815	1,041	236,011
Change in Plan Assets			**2013**		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	10,766	78	60	32	10,936
Benefits Paid	(10,766)	(78)	(60)	(32)	(10,936)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			**2013**		
Employer Service Cost at Beginning of Period	5,355	321	118	49	5,843
Interest Cost	10,383	92	128	47	10,650
Actuarial (Gain)/Loss Recognized in Expense	(710)	(5)	24	-	(691)
Total Benefit Expense/(Income)	15,028	408	270	96	15,802
Reconciliation of Balance Sheet			**2013**		
Defined Benefit Asset/(Liability) at Prior Period End	(244,084)	(2,020)	(2,909)	(1,068)	(250,081)
Total Benefit (Expense)/Income for Period	(15,028)	(408)	(270)	(96)	(15,802)
Benefits Paid Directly by the Employer	10,766	78	60	32	10,936
Gain/(Loss) Recognized via OCI	18,384	157	304	91	18,936
Defined Benefit Asset/(Liability) at Current Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Change in Accumulated Other Comprehensive Income			**2013**		
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Prior Period End	-	-	-	-	-
(Gain) or Loss recognized upon transition to IFRS rev. 2011	36,315	637	656	217	37,825
Actuarial (Gain) or Loss Recognized via OCI for Period	(18,384)	(157)	(304)	(91)	(18,936)
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Current Period End	17,931	480	352	126	18,889
Statement of Financial Position at End of Period			**December 31, 2013**		
Defined Benefit Asset/(Liability) at Current Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Breakdown of Defined Benefit Obligation: Current and Non-Current			**December 31, 2013**		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Defined Benefit Asset/(Liability) at Current Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Sensitivity to Changes in Medical and Dental Trend Rate Assumption					
Effect on total of service and interest cost for 2013					
1% point increase	2,300	11	41	16	2,368
1% point decrease	(2,010)	(11)	(37)	(14)	(2,072)
Effect on accrued benefit obligation at December 31, 2013					
1% point increase	28,986	202	459	157	29,804
1% point decrease	(25,426)	(182)	(403)	(139)	(26,150)
Key Assumptions					
Discount rate at Dec 31/13 (used for Dec 31/13 obligation)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate at Dec 31/12 (used for 2013 Benefit Costs)	4.25%	4.25%	4.25%	4.25%	4.25%
Assumed medical and dental cost trend rate at December 31, 2013					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	6.0%	6.0%	6.0%	6.0%	6.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Health care cost trend rate assumed for next year	7.5%	7.5%	7.5%	7.5%	7.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Expected Benefit Payments for Following Year	8,245	90	44	22	8,401

TOWERS WATSON

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2014 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2014		
Defined Benefit Asset/(Liability) at Beginning of Period	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Reconciliation of Defined Benefit Obligation			2014		
Defined Benefit Obligation at Beginning of Period	229,962	2,193	2,815	1,041	236,011
Employer Service Cost at Beginning of Period	4,931	198	109	44	5,282
Interest Cost	10,962	111	138	51	11,262
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(8,245)	(90)	(44)	(22)	(8,401)
Defined Benefit Obligation at Current Period End	237,610	2,412	3,018	1,114	244,154
Change in Plan Assets			2014		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	8,245	90	44	22	8,401
Benefits Paid	(8,245)	(90)	(44)	(22)	(8,401)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2014		
Employer Service Cost at Beginning of Period	4,931	198	109	44	5,282
Interest Cost	10,962	111	138	51	11,262
Total Benefit Expense/(Income)	15,893	309	247	95	16,544
Reconciliation of Balance Sheet			2014		
Defined Benefit Asset/(Liability) at Prior Period End	(229,962)	(2,193)	(2,815)	(1,041)	(236,011)
Total Benefit (Expense)/Income for Period	(15,893)	(309)	(247)	(95)	(16,544)
Benefits Paid Directly by the Employer	8,245	90	44	22	8,401
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Change in Accumulated Other Comprehensive Income			2014		
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Prior Period End	17,931	480	352	126	18,889
Actuarial (Gain) or Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Current Period End	17,931	480	352	126	18,889
Statement of Financial Position at End of Period			December 31, 2014		
Defined Benefit Asset/(Liability) at Current Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2014		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Defined Benefit Asset/(Liability) at Current Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Key Assumptions					
Discount rate at Dec 31/14 (used for Dec 31/13 obligation)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate at Dec 31/13 (used for 2014 Benefit Costs)	4.75%	4.75%	4.75%	4.75%	4.75%
Assumed medical and dental cost trend rate at December 31, 2014					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	5.5%	5.5%	5.5%	5.5%	5.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Health care cost trend rate assumed for next year	7.0%	7.0%	7.0%	7.0%	7.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Expected Benefit Payments for Following Year	8,384	96	47	25	8,552

Post-Employment Benefits Plan - IFRS (rev. 2011) - 2015 Expense Estimate ($ 000's)

	Electric System Limited	Toronto Hydro Corporation	Energy Services Incorporated	LDC Unregulated	Consolidated
Statement of Financial Position at Beginning of Period			January 01, 2015		
Defined Benefit Asset/(Liability) at Beginning of Period	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Reconciliation of Defined Benefit Obligation			2015		
Defined Benefit Obligation at Beginning of Period	237,610	2,412	3,018	1,114	244,154
Employer Service Cost at Beginning of Period	5,128	206	113	46	5,493
Interest Cost	11,331	122	148	55	11,656
Net Actuarial (Gain) or Loss	-	-	-	-	-
Benefits Paid Directly by the Employer	(8,384)	(96)	(47)	(25)	(8,552)
Defined Benefit Obligation at Current Period End	245,685	2,644	3,232	1,190	252,751
Change in Plan Assets			2015		
Fair Value of Plan Assets at Prior Period End	-	-	-	-	-
Employer Contributions	8,384	96	47	25	8,552
Benefits Paid	(8,384)	(96)	(47)	(25)	(8,552)
Fair Value of Plan Assets at Current Period End	-	-	-	-	-
Total Benefit (Expense)/Income for Period			2015		
Employer Service Cost at Beginning of Period	5,128	206	113	46	5,493
Interest Cost	11,331	122	148	55	11,656
Total Benefit Expense/(Income)	16,459	328	261	101	17,149
Reconciliation of Balance Sheet			2015		
Defined Benefit Asset/(Liability) at Prior Period End	(237,610)	(2,412)	(3,018)	(1,114)	(244,154)
Total Benefit (Expense)/Income for Period	(16,459)	(328)	(261)	(101)	(17,149)
Benefits Paid Directly by the Employer	8,384	96	47	25	8,552
Gain/(Loss) Recognized via OCI	-	-	-	-	-
Defined Benefit Asset/(Liability) at Current Period End	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Change in Accumulated Other Comprehensive Income			2015		
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Prior Period End	17,931	480	352	126	18,889
Actuarial (Gain) or Loss Recognized via OCI for Period	-	-	-	-	-
Cumulative Actuarial (Gain) or Loss Recognized via OCI at Current Period End	17,931	480	352	126	18,889
Statement of Financial Position at End of Period			December 31, 2015		
Defined Benefit Asset/(Liability) at Current Period End	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Breakdown of Defined Benefit Obligation: Current and Non-Current			December 31, 2015		
Current Liabilities	-	-	-	-	-
Non-Current Asset/(Liability)	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Defined Benefit Asset/(Liability) at Current Period End	(245,685)	(2,644)	(3,232)	(1,190)	(252,751)
Key Assumptions					
Discount rate at Dec 31/15 (used for Dec 31/15 obligation)	4.75%	4.75%	4.75%	4.75%	4.75%
Discount rate at Dec 31/14 (used for 2015 Benefit Costs)	4.75%	4.75%	4.75%	4.75%	4.75%
Assumed medical and dental cost trend rate at December 31, 2015					
Dental care cost trend rate assumed for next year	4.0%	4.0%	4.0%	4.0%	4.0%
For pre July 2000 retirements:					
Health care cost trend rate assumed for next year	5.0%	5.0%	5.0%	5.0%	5.0%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2016	2016	2016	2016	2016
For other retirements:					
Health care cost trend rate assumed for next year	6.5%	6.5%	6.5%	6.5%	6.5%
Rate that the cost trend gradually declines to	5.0%	5.0%	5.0%	5.0%	5.0%
Year that the rate reaches the ultimate rate	2019	2019	2019	2019	2019
Expected Benefit Payments for Following Year	8,990	99	53	28	9,170

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 73:

Reference(s): Exhibit 4B, Tab 2, Schedule 2, p. 20 – Schedule 8 Test Year

THESL has disclosed proceeds of disposal in Schedule 8 of $14,347,679 for Class 1, and $899,095 for Class 17:

a) Please provide a description of each of the transactions, including how much profit is forecast on the disposals and the references in the application where the other parts of the transactions can be located;

b) Please provide similar Schedule 8 formats for each year 2016, 2017, 2018 and 2019 showing the capital additions based on the proposed capital plan and any forecast disposals of assets.

RESPONSE:

a) In its originally filed application, THESL disclosed proceeds of disposal in Schedule 8 of $14,347,679 and $899,095 for Class 1 and Class 17 respectively. THESL revised both amounts in its September update to $16,318,959 and $1,034,729 respectively. The proceeds disclosed for tax purposes do not reflect the net profit on the dispositions. Exhibit 2B, Section E8.3, provides details related to disposal of properties.

b) Copies of Schedule 8 for the years 2016-2019 are provided as Appendix A to this Schedule. There are no forecasted disposals for the years 2016-2019.

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited

Schedule 8 CCA - 2016 Test Year

Class	Class Description	UCC Test Year Opening Balance (note 1)	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 1,089,244,526	26,268,538		$ 1,115,513,064	$ 13,134,269	$ 1,102,378,795	4%	$ 44,095,152	$ 1,071,417,912
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 273,664,743			$ 273,664,743	$ -	$ 273,664,743	6%	$ 16,419,885	$ 257,244,858
8	General Office/Stores Equip	$ 25,270,742	6,896,260		$ 32,167,002	$ 3,448,130	$ 28,718,872	20%	$ 5,743,774	$ 26,423,228
10	Computer Hardware/ Vehicles	$ 12,668,867	3,303,283		$ 15,972,150	$ 1,651,642	$ 14,320,508	30%	$ 4,296,152	$ 11,675,997
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 11,840,863	84,887,414		$ 96,728,277	$ 42,443,707	$ 54,284,570	100%	$ 54,284,570	$ 42,443,707
13 1	Lease # 1	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 3	Lease # 3	$ 19,181			$ 19,181	$ -	$ 19,181	SL	$ 19,181	$ -
13 4	Lease # 4	$ 176,240			$ 176,240	$ -	$ 176,240	SL	$ 117,492	$ 58,748
13 5	Lease # 5	$ 271,314			$ 271,314	$ -	$ 271,314	SL	$ 77,518	$ 193,796
13 6	Lease # 6	$ 38,759			$ 38,759	$ -	$ 38,759	SL	$ 8,613	$ 30,146
13 7	Lease # 7	$ -	27,826		$ 27,826	$ -	$ 27,826	SL	$ 2,783	$ 25,043
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 15,155,582			$ 15,155,582	$ -	$ 15,155,582	8%	$ 1,212,447	$ 13,943,136
42	Fibre Optic Cable	$ 28,969			$ 28,969	$ -	$ 28,969	12%	$ 3,475	$ 25,494
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 24,702			$ 24,702	$ -	$ 24,702	45%	$ 11,116	$ 13,586
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 167,425	238,723		$ 406,148	$ 119,362	$ 286,786	30%	$ 86,036	$ 320,112
47	Distribution System - post February 2005	$ 1,834,221,266	371,995,434		$ 2,206,216,700	$ 185,997,717	$ 2,020,218,983	8%	$ 161,617,519	$ 2,044,599,181
50	Data Network Infrastructure Equipment - post Mar 2007	$ 21,602,654	24,612,799		$ 46,215,453	$ 12,306,400	$ 33,909,053	55%	$ 18,649,979	$ 27,565,474
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 405,809,399			$ 405,809,399	$ -	$ 405,809,399	0%	$ -	$ 405,809,399
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 3,690,205,231	$ 518,230,277	$ -	$ 4,208,435,508	$ 259,101,226	$ 3,949,334,282		$ 306,645,692	$ 3,901,789,816

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited

Schedule 8 CCA - 2017 Test Year

Class	Class Description	UCC Test Year Opening Balance (note 1)	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 1,071,417,912	18,025,435		$ 1,089,443,347	$ 9,012,718	$ 1,080,430,630	4%	$ 43,217,225	$ 1,046,226,122
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 257,244,858			$ 257,244,858	$ -	$ 257,244,858	6%	$ 15,434,692	$ 241,810,167
8	General Office/Stores Equip	$ 26,423,228	6,967,813		$ 33,391,041	$ 3,483,907	$ 29,907,134	20%	$ 5,981,427	$ 27,409,614
10	Computer Hardware/ Vehicles	$ 11,675,997	3,828,481		$ 15,504,478	$ 1,914,241	$ 13,590,238	30%	$ 4,077,070	$ 11,427,408
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 42,443,707	17,868,647		$ 60,312,354	$ 8,934,324	$ 51,378,031	100%	$ 51,378,031	$ 8,934,324
13 1	Lease # 1	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 4	Lease # 4	$ 58,748			$ 58,748	$ -	$ 58,748	SL	$ 58,748	$ -
13 5	Lease # 5	$ 193,796			$ 193,796	$ -	$ 193,796	SL	$ 77,518	$ 116,278
13 6	Lease # 6	$ 30,146			$ 30,146	$ -	$ 30,146	SL	$ 8,613	$ 21,533
13 7	Lease # 7	$ 25,043			$ 25,043	$ -	$ 25,043	SL	$ 5,565	$ 19,478
13 8	Lease # 8	$ -	6,143		$ 6,143	$ -	$ 6,143	SL	$ 614	$ 5,529
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 13,943,136			$ 13,943,136	$ -	$ 13,943,136	8%	$ 1,115,451	$ 12,827,685
42	Fibre Optic Cable	$ 25,494			$ 25,494	$ -	$ 25,494	12%	$ 3,059	$ 22,435
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 13,586			$ 13,586	$ -	$ 13,586	45%	$ 6,114	$ 7,472
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 320,112	217,129		$ 537,241	$ 108,565	$ 428,676	30%	$ 128,603	$ 408,638
47	Distribution System - post February 2005	$ 2,044,599,181	419,967,718		$ 2,464,566,899	$ 209,983,859	$ 2,254,583,040	8%	$ 180,366,643	$ 2,284,200,256
50	Data Network Infrastructure Equipment - post Mar 2007	$ 27,565,474	17,466,009		$ 45,031,483	$ 8,733,005	$ 36,298,478	55%	$ 19,964,163	$ 25,067,320
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 405,809,399			$ 405,809,399	$ -	$ 405,809,399	0%	$ -	$ 405,809,399
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 3,901,789,816	$ 484,347,375	$ -	$ 4,386,137,191	$ 242,170,616	$ 4,143,966,575		$ 321,823,535	$ 4,064,313,656

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited

Schedule 8 CCA - 2018 Test Year

Class	Class Description	UCC Test Year Opening Balance (note 1)	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 1,046,226,122	3,573,269		$ 1,049,799,391	$ 1,786,635	$ 1,048,012,756	4%	$ 41,920,511	$ 1,007,878,880
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 241,810,167			$ 241,810,167	$ -	$ 241,810,167	6%	$ 14,508,610	$ 227,301,557
8	General Office/Stores Equip	$ 27,409,614	2,441,756		$ 29,851,370	$ 1,220,878	$ 28,630,492	20%	$ 5,726,098	$ 24,125,271
10	Computer Hardware/ Vehicles	$ 11,427,408	3,737,496		$ 15,164,904	$ 1,868,748	$ 13,296,156	30%	$ 3,988,847	$ 11,176,057
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 8,934,324	17,897,950		$ 26,832,274	$ 8,948,975	$ 17,883,299	100%	$ 17,883,299	$ 8,948,975
13 1	Lease # 1	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 5	Lease # 5	$ 116,278			$ 116,278	$ -	$ 116,278	SL	$ 77,518	$ 38,760
13 6	Lease # 6	$ 21,533			$ 21,533	$ -	$ 21,533	SL	$ 8,613	$ 12,920
13 7	Lease # 7	$ 19,478			$ 19,478	$ -	$ 19,478	SL	$ 5,565	$ 13,913
13 8	Lease # 8	$ 5,529			$ 5,529	$ -	$ 5,529	SL	$ 1,229	$ 4,300
13 9	Lease # 9	$ -	6,302		$ 6,302	$ -	$ 6,302	SL	$ 630	$ 5,672
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 12,827,685			$ 12,827,685	$ -	$ 12,827,685	8%	$ 1,026,215	$ 11,801,470
42	Fibre Optic Cable	$ 22,435			$ 22,435	$ -	$ 22,435	12%	$ 2,692	$ 19,743
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 7,472			$ 7,472	$ -	$ 7,472	45%	$ 3,362	$ 4,110
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 408,638	178,627		$ 587,265	$ 89,314	$ 497,951	30%	$ 149,385	$ 437,879
47	Distribution System - post February 2005	$ 2,284,200,256	382,891,213		$ 2,667,091,469	$ 191,445,607	$ 2,475,645,862	8%	$ 198,051,669	$ 2,469,039,800
50	Data Network Infrastructure Equipment - post Mar 2007	$ 25,067,320	8,422,322		$ 33,489,642	$ 4,211,161	$ 29,278,481	55%	$ 16,103,164	$ 17,386,477
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 405,809,399			$ 405,809,399	$ -	$ 405,809,399	0%	$ -	$ 405,809,399
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 4,064,313,656	$ 419,148,935	$ -	$ 4,483,462,591	$ 209,571,317	$ 4,273,891,274		$ 299,457,408	$ 4,184,005,183

Ontario Energy Board

Income Tax/PILs Workform for 2015 Filers

Toronto Hydro-Electric System Limited

Schedule 8 CCA - 2019 Test Year

Class	Class Description	UCC Test Year Opening Balance (note 1)	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA	UCC End of Test Year
1	Distribution System - post 1987	$ 1,007,878,880	3,478,737		$ 1,011,357,617	$ 1,739,369	$ 1,009,618,248	4%	$ 40,384,730	$ 970,972,887
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	$ -			$ -	$ -	$ -	6%	$ -	$ -
2	Distribution System - pre 1988	$ 227,301,557			$ 227,301,557	$ -	$ 227,301,557	6%	$ 13,638,093	$ 213,663,464
8	General Office/Stores Equip	$ 24,125,271	2,468,923		$ 26,594,194	$ 1,234,462	$ 25,359,733	20%	$ 5,071,947	$ 21,522,248
10	Computer Hardware/ Vehicles	$ 11,176,057	3,898,175		$ 15,074,232	$ 1,949,088	$ 13,125,145	30%	$ 3,937,543	$ 11,136,689
10.1	Certain Automobiles	$ -			$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ 8,948,975	18,832,100		$ 27,781,075	$ 9,416,050	$ 18,365,025	100%	$ 18,365,025	$ 9,416,050
13 1	Lease # 1	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 2	Lease #2	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 3	Lease # 3	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 4	Lease # 4	$ -			$ -	$ -	$ -	SL	$ -	$ -
13 5	Lease # 5	$ 38,760			$ 38,760	$ -	$ 38,760	SL	$ 38,760	$ -
13 6	Lease # 6	$ 12,920			$ 12,920	$ -	$ 12,920	SL	$ 8,613	$ 4,307
13 7	Lease # 7	$ 13,913			$ 13,913	$ -	$ 13,913	SL	$ 5,565	$ 8,348
13 8	Lease # 8	$ 4,300			$ 4,300	$ -	$ 4,300	SL	$ 1,229	$ 3,071
13 9	Lease # 9	$ 5,672			$ 5,672	$ -	$ 5,672	SL	$ 1,260	$ 4,412
13 10	Lease # 10	$ -	6,003		$ 6,003	$ -	$ 6,003	SL	$ 600	$ 5,403
14	Franchise	$ -			$ -	$ -	$ -		$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ 11,801,470			$ 11,801,470	$ -	$ 11,801,470	8%	$ 944,118	$ 10,857,352
42	Fibre Optic Cable	$ 19,743			$ 19,743	$ -	$ 19,743	12%	$ 2,369	$ 17,373
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -			$ -	$ -	$ -	30%	$ -	$ -
43.2	Certain Clean Energy Generation Equipment	$ -			$ -	$ -	$ -	50%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ 4,110			$ 4,110	$ -	$ 4,110	45%	$ 1,849	$ 2,260
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ 437,879	186,185		$ 624,064	$ 93,093	$ 530,972	30%	$ 159,292	$ 464,773
47	Distribution System - post February 2005	$ 2,469,039,800	470,967,445		$ 2,940,007,245	$ 235,483,723	$ 2,704,523,522	8%	$ 216,361,882	$ 2,723,645,363
50	Data Network Infrastructure Equipment - post Mar 2007	$ 17,386,477	8,848,812		$ 26,235,289	$ 4,424,406	$ 21,810,883	55%	$ 11,995,986	$ 14,239,303
52	Computer Hardware and system software	$ -			$ -	$ -	$ -	100%	$ -	$ -
95	CWIP	$ 405,809,399			$ 405,809,399	$ -	$ 405,809,399	0%	$ -	$ 405,809,399
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
					$ -	$ -	$ -	0%	$ -	$ -
	TOTAL	$ 4,184,005,183	$ 508,686,380	$ -	$ 4,692,691,563	$ 254,340,189	$ 4,438,351,374		$ 310,918,861	$ 4,381,772,702

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 74:

Reference(s): **Exhibit 4B, Tab 2, Schedule 2, pp. 6, 13 and 21 – Cumulative Eligible Capital**

The above references show additions of $2,489,752 in 2013, $3,370,623 in 2014 and $84,096,612 in 2015 respectively:

a) Please provide explanations for these additions;
b) Please state whether or not THESL expects material additions in the years 2016-2019. If yes, please describe the expenditures and calculate the tax impacts for each of the years 2016-2019 using the PILs model formats.

RESPONSE:

a) The eligible capital expenditures additions of $2,489,752, $3,370,623 and $84,096,612 relate primarily to contributions payments made to Hydro One Networks Inc. for connections to increase electricity distribution system capacity.

b) Consistent with its proposed rate framework, Toronto Hydro has not included forecasted additions of eligible capital expenditures and the resulting tax impacts beyond the 2015 Test Year. For a discussion of its proposed rate framework, please refer to Exhibit 1B, Tab 2, Schedule 3.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 75:

Reference(s): **Exhibit 4B, Tab 2, Schedule 2, p.16 - 2014 Taxable Income and Exhibit 9, Tab 3, Schedule 1, p. 1**

In the second reference, THESL has shown an IFRS derecognition amount for 2014 of $25,782,326.

In the first reference, this amount does not appear as an addition in the 2014 taxable income calculations.

Please provide an explanation for this treatment.

RESPONSE:

IFRS derecognition of $25,782,326 for 2014 does not appear as an addition in the 2014 taxable income calculations because this amount is not included in net income for calculating PILs. The balance has been recorded in account 1575 which is used to record differences as a result of the transition from US GAAP to IFRS.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 76:

Reference(s): **Exhibit 4B, Tab 2, Schedule 2, p. 22 – Continuity of Reserves**

In the above reference, an addition of $8,521,000 is shown for Other Post-Employment Benefits:

a) Please state whether or not THESL expects a similar amount to be incurred in each of the years 2016-2019;

b) Please explain the causes of these increases.

RESPONSE:

a) Consistent with its proposed rate framework, THESL has not forecasted Other Post-Employment Benefits beyond the 2015 Test Year. For a discussion of its proposed rate framework, please refer to Exhibit 1B, Tab 2, Schedule 3.

b) The addition of $8,521,000 was determined by an actuarial report prepared by Towers Watson under IFRS for 2015. For the specific actuarial schedule please refer to the response to Interrogatory 4A-OEBStaff-72.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 77:

Reference(s): **Exhibit 4B, Tab 2, Schedule 2, pp. 24-25 - 2015 Taxable Income and**
Exhibit 4B, Tab 1, Schedule 2, p.3 and
Exhibit 4BTab 2, Schedule 2, p. 22

On page 24 of the first reference, a placeholder amount for derecognition of tangible assets of $33,932,393 is recorded as an addition to income. On page 25, OPEBs deductions of $446,000 and $6,519,410 are recorded.

In the second reference, a variance account is requested to record the difference between the placeholder amount and the actual de-recognition amounts during the period 2016-2019.

In the third reference, an amount of $8,521,000 is shown as the change in the OPEB reserve (liability):

a) Please state whether or not the tax impact on the variances will be calculated as part of the proposed variance account true-up. If yes, please state whether the tax impact would be included in the same variance account, or whether a separate variance account would be needed;
b) Please explain what the OPEBs deductions of $446,000 and $6,519,410 are for;
c) Please state where the difference between the deductions referenced in part b above and the $8,521,000 shown as the change in the OPEB reserve (liability) are recorded and provide an explanation.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

RESPONSE:

a) Once the proposed variance account is approved for clearance, a PILs gross up will be added to the balance. A separate variance account for PILs will not be required.

b) The OPEB deduction of $446,000 represents the amounts transferred from related parties. The OPEB deduction of $6,519,410 represents the capitalized portion of OPEB in the year. These amounts form part of the $8,521,000 shown as the change in the OPEB reserve (liability) referenced in part c).

c) The balance of $8,521,000 is represented by the difference between the opening and closing OPEB reserve for the 2015 test year. Please note that the OPEB reserve as presented, includes liabilities associated with Energy Services Incorporated and Toronto Hydro Corporation. The liability balance excludes LDC Unregulated. The OPEB costs associated with Toronto Hydro Corporation, Energy Services Incorporated and LDC Unregulated are accounted for in the income statements of the subsidiaries and are therefore not taken into account when calculating Toronto Hydro rates. The table below illustrates the movement of the balance:

Opening balance	$243,040,000
OM&A	9,939,590
Capital expenditures	6,519,410
Transfer from related parties	446,000
Benefits paid	(8,384,000)
Closing balance	$251,561,000

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 78:

Reference(s): Exhibit 4B, Tab 2, Schedule 2, p. 22

The recent Ontario government budget, which has received Royal Assent, changed the Ontario small business credit.

Please state whether or not THESL believes any changes to the calculation of PILs for 2015 are required as a result of the passage of the Ontario budget.

RESPONSE:

The 2014 Ontario budget eliminated the provincial small business deduction for a corporation with taxable capital greater than $15 million. This change applied to taxation years ending after May 1, 2014. The impact will be an increase of $62,680 in the PILs revenue requirement for 2015. THESL will exclude the Ontario small business deduction on finalization of its Rates for 2015.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 79:

Reference(s): **Exhibit 4B, Tab 2, Schedule 2, p. 22**

THESL has recovered OPEBs in rates since 2000 both on a cash basis and on an accrual accounting basis. It is Board staff's understanding that THESL has recovered OPEBs on a cash basis up to May 1, 2006 and on an accrual basis thereafter:

a) Please confirm that Board staff's understanding is correct, or if not, please correct and explain;

b) Please complete the table below in a live Excel worksheet to show how much has been recovered for the period 2000 to 2013 relative to the actual cash benefit payments and how much is anticipated to be recovered in the forecast periods of 2014 to 2019;

OPEBs	Actual			Forecast			Grand Total
	2000 to	2013	Total	2014 to	2019	Total	
Amounts included in rates							
OM&A							
Capital expenditures							
Sub-total							
Paid benefit amounts							
Net excess amount included in rates greater than amounts actually paid							

c) Please describe what has been done with the recoveries in excess of the cash benefit payments.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

RESPONSE:

a) Since 2000, Toronto Hydro has recovered OPEB in rates under the accrual accounting basis. There was never a change from the cash basis to the accrual basis of accounting.

b) Please refer to the live Excel worksheet (IR_4B_OEBStaff_79B_20141105.xlsx) attached to this response. Consistent with its proposed rate framework, Toronto Hydro has not forecasted its operating expenses beyond the 2015 Test Year. For a discussion of the proposed rate framework please refer to Exhibit 1B, Tab 2, Schedule 3.

c) Recoveries in excess of the cash benefits have been used to fulfil the cost of ongoing utility operations.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 80:

Reference(s): **Exhibit 4B, Tab 3, Schedule 1, App. A – 2013 Tax Return Schedule 13 Reserves**

In the above reference, a reduction of the POEB reserve (OPEBs) of $15,098,000 is recorded:

a) Please explain the causes of this reduction;
b) Please state whether or not this reduction was determined by an actuary and, if so, please provide the actuary's valuation;
c) Please provide a full explanation of the reduction identified as "termination accrual" on the same schedule including whether or not it is related to staff reductions.

RESPONSE:

a) The reduction of the consolidated Toronto Hydro POEB reserve of $15,098,000 is comprised of the following:

Service Cost	$5,226,000
Interest Cost	$10,792,000
Actuarial (gain) loss	($20,684,000)
Benefits Paid	($10,432,000)
Total	**($15,098,000)**

b) This reduction was determined by our actuary, Towers Watson under US GAAP for 2014. For the specific actuarial schedule please refer to Exhibit 4A, Tab 4, Schedule 7.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

c) The termination accrual balance on Schedule 13 represents the non deductible portion of the balance for tax purposes. The non deductible portion is the balance that was unpaid after 180 days from THESL's year-end. The balance accrued is primarily related to an approved workforce restructuring program implemented in 2012.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 81:

Reference(s): **Exhibit 5, Tab 1, Schedule 1, p. 4 and**
Exhibit 5, Tab 1, Schedule 3

At the first reference, Table 3 Long-Term Debt shows two outstanding debt issues with significantly smaller principal amounts than the remaining debt issues. These are a $15 million promissory note maturing January 1, 2022 with a rate of 3.32% and a $45 million promissory note due on demand with a rate of 6.16%.

The second reference, which is OEB Appendix 2-OB Debt Instruments shows the lender of both of these issues as being THC and that are both expected to remain outstanding in 2015:

a) Please explain why THESL issued these debt instruments given that the principal amounts are significantly smaller than its other outstanding issues;
b) Please state why the interest rate on the $45 million promissory note is 6.16% versus 3.32% on the $15 million promissory note when both are shown as issued on January 1, 2012.

RESPONSE:

a) These debt instruments were issued pursuant to THESL's internal cash and liquidity management policies. The primary purpose for the issuance of these debt instruments was to incrementally complement and mirror the parent company's external debt, which was issued to finance THESL.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

b) The $15 million promissory note was issued with a term of ten years and therefore the interest rate was determined using the benchmark Government of Canada ten-year bond yield at the time of issuance, plus a corporate spread. The $45 million promissory note does not have a maturity date and is payable on demand. The interest rate on the note was set based on prevailing market conditions and on the rate for a similar instrument that the parent company had outstanding at the time of issuance.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 82:

Reference(s): Exhibit 8, Tab 1, Schedule 1, pp. 14-16

On page 14 of the above reference, it is stated that:

> Toronto Hydro believes that recent OEB request for comments in EB-2014-0219 specifically recognizes the problems associated with year-end ratebase not being accounted for under the IRM framework. By letter dated June 20, 2014, the OEB has sought comments related to a mechanism to "Eliminate the effect of the half year rule on test year capital additions for the intervening years between rebasing applications (i.e., during the subsequent IR plan) by adjusting for the incremental revenue requirement (depreciation expense plus return on capital and associated taxes/PILs) of the test year capital additions." This is precisely the issue for which Toronto Hydro seeks relief.
>
> Toronto Hydro relies on its analysis previously provided to the OEB (attached as Appendix A). Toronto Hydro has made an adjustment to the calculations to reflect the fact that the initial calculation was based on year-end capital expenditures, rather than in-service amounts. This adjustment has reduced the calculated lost revenue amount. The full calculation, which appeared as Appendix A to the Manager's Summary in EB-2012-0064, is updated and reproduced in Table 4 below.

Board staff notes that the referenced Table 4 is entitled "Lost Revenue due to IRM Framework – 2012-14":

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

a) Please state whether the type of mechanism proposed by the Board in its June 20, 2014 letter would address THESL's concerns and why or why not this would be the case;

b) Please state the basis for THESL's conclusion that the Board's letter of June 20, 2014 envisages retroactive recoveries of the kind proposed by THESL;

c) Please state why THESL requested three years of prior period recovery rather than a greater or lesser period;

d) Please state whether or not THESL would see the granting of its requested Table 4 recovery as retroactive rate making by the Board. If THESL believes this to be the case, please state why it would be appropriate for the Board to approve it. If THESL does not believe this to be the case, please state why and provide any precedents THESL is aware of that would be supportive of its recovery request.

RESPONSE:

a) As the details of the mechanism described by the OEB in its June 20, 2014 have not been established, it is not possible for Toronto Hydro to assess whether its current concerns would be addressed by the proposed mechanism.

b) It is not Toronto Hydro position that OEB's' June 20, 2014 letter "envisages retroactive recoveries". As detailed in the lines 1-18 on page 14 of the referenced evidence, Toronto Hydro interpreted the OEB's decision in EB-2012-0064 as indicating that the relief currently sought is appropriate in the context of a rebasing application. The mechanism proposed by the OEB in its June 20, 2014 letter further indicates that the OEB is willing to consider a mechanism to address the half-year rule concerns that Toronto Hydro and other utilities have raised.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

c) Toronto Hydro ‘selected three years of prior period recovery (2012 – 2014) because these three years are relevant to the operation of the IRM mechanism, and the associated loss of revenues. Toronto Hydro did not select a lesser recovery period because such a period would not fully compensate the utility for the revenue that it lost during the 2012 – 2014 IRM period. Toronto Hydro did not select a greater recovery period because such a period would extend beyond the utility’s last rebasing application (EB-2010-0142).

d) Toronto Hydro seeks recovery of revenue requirement foregone due to the operation of the IRM mechanism, which the OEB acknowledges in its June 20, 2014 letter as the “effect of the half year rule on test year capital additions for the intervening years between rebasing applications”. Toronto Hydro reasonably believes that the OEB is able to grant the requested relief without engaging in retroactive ratemaking because the OEB did not rule on this issue in EB-2012-0064.[1]

[1] EB-2012-0064, Partial Decision and Order (April 2, 2013), at pages 9-10.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 83:

Reference(s): Exhibit 8, Tab 2, Schedule 1, page 2

Table 1 at the above reference shows new and updated specific service charges for the 2015 to 2019 period.

Please add a column to Table 1 which would show for the four new proposed charges the revenue that each is projected to generate annually and for the charges which are being increased the incremental revenue expected from each of these charges.

RESPONSE:

Please refer to Toronto Hydro's response to interrogatory 3-SIA-30 part (d).

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 84:

Reference(s): **Exhibit 8, Tab 3, Schedule 1, p. 13 and**
Exhibit 8, Tab 3, Schedule 2, p.22

The two references above are the loss factor pages of THESL's currently approved Tariff of Rates and Charges and its proposed Tariff of Rates and Charges for May 1, 2015 implementation.

Board staff notes that both these pages contain a "Billing Determinant" section which is unique to THESL:

a) Please state why THESL believes that this section is necessary to include on the Tariff of Rates and Charges;
b) In the event the Board was to determine that this section should be removed in order to conform THESL's tariff to those of other distributors, please state any concerns that THESL may have about doing so.

RESPONSE:

a) The Billing Determinants have been part of Toronto Hydro's OEB-approved Rate Schedules since 2002. Therefore, Toronto Hydro continued to include this section in its proposed 2015 Rate Schedule.

b) Toronto Hydro would not have any concerns if this section was removed to conform its tariff with those of other distributors.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 85:

Reference(s): **Exhibit 9, Tab 1, Schedule 1, page 1 Group 1 DVAs**

THESL states that it is still evaluating options to measure or estimate actual line losses. THESL indicates that it will also assess the impact on affected Group 1 DVAs as per the audit report [E9A-T1-S1-Appendix A]. Please state whether or not if THESL is not able to conclude on the line loss issue by the end of this proceeding, it would intend to continue to dispose of the Group 1 DVA balances as currently shown in the application.

RESPONSE:

Toronto Hydro anticipates that the information required to update (if necessary) the balances in the Group 1 RSVA accounts will be available prior to the conclusion of this proceeding. In the event this information is not available, Toronto Hydro proposes to clear the balances as proposed, and any updates can be booked to the accounts to be cleared in a future proceeding.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 86:

Reference(s): **Exhibit 9, Tab 1, Schedule 1, page 2 and**
Exhibit 9, Tab 1, Schedule 1, pages 20-22

The first reference shows an account 1508 – Impact For USGAAP Deferral Account balance of $38.8 million as of December 31, 2013.

The second reference states that in 2014 THESL expects differences between USGAAP and IFRS of $36.0 million. THESL has asked to continue to use this account or to create a new account to record the transition to IFRS:

a) Please provide the projected balance of the two transitions at December 31, 2014, specifically discussing whether it is $74.8 million, which represents the sum of $38.8 million plus $36.0 million, or $36 million. Please provide a complete explanation;
b) Please explain why THESL does not want disposition of the projected balance in account 1508 – Impact For USGAAP Deferral Account.

RESPONSE:

a) The amount of $36.0 million in account 1508 as at December 31, 2014 is a forecast of the IFRS actuarial loss on the OPEB liability based on the actuarial valuation as at December 31, 2013. The $36.0 million balance is the cumulative impact of the transition to US GAAP and then subsequent transition to IFRS. The balance of this account as at December 31, 2013 of $38.8 million related only to the transition to US GAAP.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

The $36.0 million represents the shortfall of the amount recovered (actual and forecast) in OM&A expenses up to that date compared to the OPEB liability of $237.6 million. Under IFRS rules, effective January 1, 2015 actuarial gains or losses may not be amortized into profit or loss (i.e., Recovered in OM&A expense), but must be recognized directly into Shareholder's equity via Accumulated Other Comprehensive Income. Under both Canadian and US GAAP, actuarial gains and losses were permitted to be amortized into OM&A expense and thus would be recovered in electricity rates over time. Accordingly, this "orphaned" expense could be considered as eligible for disposition over future periods as a transition adjustment.

b) Toronto Hydro has decided not to apply for disposition of the actuarial loss of $36.0 million in the current application. Being a stream of cash that outlays over a number of future years, the net present value of the OPEB is very sensitive to interest rates. Relative to historic values, interest rates now are very low and this has increased the value of the OPEB liability and hence the current balance of the actuarial loss. Toronto Hydro projects that interest rates are more likely to increase than decrease over the CIR period, which would reduce the actuarial loss. As such, Toronto Hydro believes that there is a reasonable probability that the current actuarial loss will be substantially reduced before the end of the application period without the necessity of funding from rate payers.

The underlying determinates of the value of the OPEB change over time and thus Toronto Hydro wishes to reserve the right to maintain an account and potentially to apply for disposition of a future actuarial loss as per the Accounting Procedures Handbook (December 2011), Article 470, page 13.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 87:

Reference(s): **Exhibit 9, Tab 1, Schedule 1, page 2 and pages 7-11- 5.4 1592 HST**

THESL has calculated capital savings in the account differently than the proxy method used in the illustrative example provided in the APH FAQ December 2010, Q4. The FAQ states “any alternative method to determine and record incremental ITCs must yield similar results so that there is no material difference between results from the alternative method and the amounts that would be derived from a transactional analysis”. Please explain how THESL’s method of calculating capital savings would result in no material difference in the amounts that would be derived from a transactional analysis.

The $1.2 million credit requested for disposition pertains to July 2010 to December 2010. Please explain why the amount does not include savings pertaining from January 1, 2011 to April 30, 2015 as per the Filing Requirements for Electricity Rate Applications for 2015 Rate Applications, section 2.12.2. Please update the evidence as necessary.

Per APH FAQ December 2010, Q5, the Board concluded that 50% of the confirmed balances recorded in 1592 HST would be returned to rate payers. Please explain if THESL has included the 50% in its calculation of the $1.2 million credit. If not, please explain why not.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

RESPONSE:

As indicated in Exhibit 9, Tab 1, Schedule 1, page 9, lines 3-4, Toronto Hydro's calculation of the HST Input Tax credit was essentially the same as the methodology as described in the December 2010 APH FAQ. Toronto Hydro believes that this methodology fairly represents the credits that would have been derived through a transactional analysis, which in Toronto Hydro's case would have been unreasonably complex.

Toronto Hydro's calculation only covers the period from July 2010 to December 2010 because Toronto Hydro filed and received OEB approval for 2011 rates on a cost of service basis. The 2011 basis for rates excluded PST amounts; therefore, Toronto Hydro does not require variance account treatment from January 1, 2011 to April 30, 2015..

The $1.2 million credit proposed by Toronto Hydro represents 100% of the estimated savings. In other words, Toronto Hydro did not reduce this amount further by 50%.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 88:

Reference(s): **Exhibit 9, Tab 1, Schedule 1, pages 12-13**

In the above reference, Account 1508 Named Properties are discussed. Table 5 presents capital gains related to the sale of property. Please provide the documents and analysis that support the calculations of the pre-tax and after-tax capital gains shown in Table 5.

Please explain why there is such a large difference between the forecasted net capital gains per EB-2007-0680 and the actual net capital gains incurred.

RESPONSE:

Forecasted gains on the properties as provided in EB-2007-0680 were the best estimates of gains made at the time (mid-2007). The actual gains reflect the market values of the properties at the time of actual sale.

With respect to the variance in the Goddard property, changes in market conditions and costs related to environmental remediation contributed to the lower gains on sale. With respect to the Wilson property, the variance is primarily due to changes in market conditions.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 89:

Reference(s): **Exhibit 9, Tab 1, Schedule 1, pages 14-16**

In the above reference, Account 1575 – IFRS USGAAP Transitional PP&E Amounts is discussed. THESL has recorded $25.8 million as a derecognition amount on the changeover date to IFRS.

Please state if this is a forecast amount or the actual amount that THESL will recognize in its 2014 audited financial statements and provide all necessary explanations. If it is a forecast amount, please state if there will be a true-up when the 2014 financial statements are finalized and provide all necessary explanations.

Please also provide a calculation that would remove the effects of derecognition from the 2015 revenue requirement including any variance account effects in the 2016 to 2019 period.

RESPONSE:

The derecognition amount recorded in Account 1575 – IFRS USGAAP Transitional PP&E is a forecast amount. Article 510 of the OEB Accounting Procedure Handbook ("APH") – Accounting for Transitional Issues states the following with respect to Account 1575:

> In general, the account will be cleared at the first rebasing under MIFRS. In individual cases, the Board may decide to clear only a portion of the

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

balance, and await actual results for the clearance of the remainder of the account.

A true-up of Account 1575 would be consistent with the proposed treatment for 2015-2019.

With respect to 2015 revenue requirement, if the 2015 derecognition amount ($33.9 million) was removed, revenue requirement would be reduced by $33.9 million (excluding any PILs impacts). In this hypothetical case, the proposed variance account would capture the full amount of actual derecognition expense in each year from 2015 to 2019.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 90:

Reference(s): Exhibit 9, Tab 1, Schedule S1, pages 14-16

THESL indicates that the derecognition of assets under MIFRS occurs when assets are disposed of or when they are no longer expected to offer future economic benefits [E4B-T1-S2-P1].

a) Please explain how similar assets were previously treated under USGAAP in historical and bridge years when the assets were disposed of or when they were no longer expected to provide future economic benefits;

b) Please state what portion of the $25.8 million derecognition loss relates to readily identifiable asset and what portion pertains to like assets.

RESPONSE:

a) Toronto Hydro's accounting policy under US GAAP is: "Property, plant and equipment are stated at cost and are removed from the accounts at the end of their estimated average useful lives, except in those instances were *specific identification* allows their removal at retirement or disposition." In current practice, assets that are specifically identifiable include rolling stock and properties.

b) The total derecognition loss of $25.7 million in Account 1575 pertains to like assets.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 91:

Reference(s): **Exhibit 9, Tab 1, Schedule 1, pages 26-30**

In the above reference, THESL's request for a variance account for externally driven capital is discussed.

Please explain why when a third party requests the relocation of THESL's assets, the third party does not pay for 100% of THESL's costs.

RESPONSE:

All third party relocation requests of Toronto Hydro assets, with the exception of a road or rail authority, require 100% payment of Toronto Hydro's relocation costs. A relocation request by a road or rail authority is subject to the apportionment of costs in accordance with existing legislation. Please see Section E5.3.2 of Exhibit 2B E5.3 for additional detail.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 92:

Reference(s): Exhibit 9, Tab 1, Schedule 1, page 28

In the above reference, THESL's request for a variance account for derecognition is discussed.

THESL used Account 1575 to record derecognition as at January 1, 2014, the changeover date to IFRS. The amount recorded is $25.7 million. THESL has requested an additional amount of $33.9 million to be included in depreciation and a variance account to record the difference between actual and forecast for each year 2016-2019:

a) Please provide the calculation of the $33.9 million and identify the capital projects that will give rise to the amount;
b) THESL plans to strand assets each year during its five-year capital plan. Assuming the $33 million per year does arise during the test period 2015-2019, this will total $165 million. Please state why this amount was not considered to be part of the total capital plan for the five-year period;
c) Please state whether or not THESL expects to receive any proceeds from the asset stranding process. If yes, please state how THESL would treat such proceeds for regulatory purposes.

RESPONSE:

To clarify, Toronto Hydro has requested a variance account to record the difference between actual and forecast for each year 2015-2019.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

a) The methodology used to forecast the $33.9 million derecognition for 2015 was two-fold:

1) Derecognition losses were forecasted on the basis of the capital investment programs outlined in the company's Distribution System Plan ("DSP"). The removal of distribution assets was projected based on the planned capital work outlined in the programs discussed in Exhibit 2B Section E. Specific asset details such as asset type, age and quantity were collected for each asset removal and a reasonable match was established to the asset forecasted net book values in order to calculate the amount to be derecognized. All capital programs contained in the DSP with a forecasted attainment date in 2015 contribute to the $33.9 million derecognition loss.
2) Where specific asset details regarding asset type, age and quantity was not known at the time of the forecast, the derecognition loss was estimated as a percentage of forecasted capex spend. The Reactive Capital and Externally-Initiated Plant Relocation & Expansion programs were calculated under this approach.

The $33.9 million derecognition loss can be broken down into the four DSP groupings:

System Service	System Renewal	System Access	General Plant	**Total DSP**
$0.8	$30.9	$1.6	$0.6	**$33.9**

b) As noted in Exhibit 9, Tab 1, Schedule 1, page 28, Toronto Hydro's 2015 Revenue Requirement includes $33.9 million of depreciation to include the forecasted

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

derecognition in 2015. Through the operation of the proposed custom PCI, rates for 2016-2019 will include forecasted derecognition amounts through the C factor calculation. The variance account is intended to capture any actual variances from these amounts included in rates over the 2015-2019 period.

c) Toronto Hydro does not expect to receive any proceeds from the assets forecasted in the $33.9 million derecogntion loss. Any material proceeds from the assets are budgeted as part of scrap sales in Revenue Offsets. Please refer to Exhibit 3, Tab 2, Schedule 1, pages 4-5 for the discussion on scrap sales.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 93:

Reference(s): Exhibit 9, Tab 1, Schedule 1, page 28

Account 1551 Smart Metering Entity Charge Variance Account is classified as a Group 1 account. Please explain why THESL has not requested the disposition of this account.

RESPONSE:

Toronto Hydro had anticipated that clearances of any balances in Account 1551 Smart Meter Entity Charge Variance Account would occur when the current rate expires, at the end of Oct 2018.

Toronto Hydro has re-read the OEB's March 28, 2013 letter to Licensed Electricity Operators, and the included Accounting and Reporting Requirements. Based on these requirements, Toronto Hydro will include the Dec 31, 2013 balance ($0.4M) plus carrying charges ($13K) to the DVA amounts requested for clearance. Carrying charges are calculated on the December 2013 principal balances until April 30, 2015.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 94:

Reference(s): **Exhibit 9, Tab 2, Schedule 4, App. 2-EA**

The difference in 2014 closing net book values between MIFRS and USGAAP is $19,079,572 as per Appendix 2-EA. This is different from the amount of $19,648,940 as can be calculated from Appendix 2-BA [E2A-T1-S2-Pages 5-6]. It is also noted that the opening net PP&E, net additions and closing net PP&E under USGAAP and MIFRS as shown in Appendix 2-EA do not agree to those shown in Appendix 2-BA.

a) Please explain how the figures in Appendix 2-EA were derived in relation to Appendix 2-BA;
b) For Appendix 2-BA, please explain why there is a difference between the 2014 opening gross cost under USGAAP and MIFRS for land rights;
c) Please explain why the 2014 MIFRS opening gross cost does not equal the 2013 USGAAP closing gross cost;
d) Please explain why land rights are excluded from Account 1575;
e) Though THESL is proposing to delay the true-up of its ICM, please explain why the asset transfer impact from ICM is excluded from Account 1575.

RESPONSE:

It is Toronto Hydro's understanding that based on the Chapter 2 filing requirements, Appendix 2-EA refers to the Account 1575 Deferral Account, which Toronto Hydro has filed in its application under Appendix 2-EC. The following responses are based on the assumption that the two appendices are synonymous.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

a) Appendix 2-BA excludes construction work in progress. The reconciliation is as follows:

	Closing Balance per 2-BA	Construction work in progress	Closing Balance per 2-EA (or 2-EC)
2014 USGAAP	$2,454,797,898	$508,563,952	$2,963,361,850
2014 MIFRS	$2,435,148,959	$509,133,320	$2,944,282,279
Difference	$19,648,939		$19,079,571

b) The difference between the 2014 opening gross cost for Land Rights under USGAAP and MIFRS is due to the difference in the accounting treatment of a land lease under these two accounting standards. Under USGAAP, THESL treated this land lease as a prepaid with an annual amortized amount of approximately $0.09 million into OM&A. Under MIFRS, this land lease qualifies as a capital asset. As such, the land lease is shown in PP&E and amortized over the remaining lease term. The amount amortized into depreciation expense is $0.09 million, the same amount that would have been expensed into OM&A under USGAAP.

c) The 2014 MIFRS opening gross cost does not equal the 2013 US GAAP closing gross cost due to the following transitional differences upon adoption of MIFRS on January 1, 2014:

2013 USGAAP Closing Gross Cost	Day 1 Difference related to Asset Retirement Obligation	Day 1 Difference related to Land Lease	2014 MIFRS Opening Gross Cost
$4,977,690,044	($859,059)	$7,191,090	$4,984,022,075

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

d) Land rights are excluded from Account 1575 because it is a balance sheet reclassification between prepaid and PP&E. Account 1575 is designed to defer the recognition of transitional differences in the profit and loss, including opening retained earnings.

e) The asset transfer impact from ICM is excluded from Account 1575 because the ICM transfer is a balance sheet reclassification between PP&E and regulatory assets. Account 1575 is designed to defer the recognition of transitional differences in the profit and loss.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 95:

Reference(s): Exhibit 9, Tab 2, Schedule 5, pp.3-7

It is noted that the savings data THESL receives from the OPA is annualized and this does not accurately reflect the actual initiation and implementation of CDM savings when compared to CDM estimates by customer class.

THESL also notes that it "has adjusted its claimed savings based on typical application rates and monthly savings realization from samples and averages":

a) Please provide further description of this approach. In particular, please state whether or not this approach differs from the "half-year" approach approved by the Board for estimating the actual impact of CDM programs in their first year of introduction;
b) Please discuss whether THESL's approach has been discussed with and endorsed by the OPA;
c) Please also state whether or not THESL's approach has been used by any other distributor when making an LRAMVA claim and, if so, state which distributor;
d) Please provide the LRAMVA amount without applying the adjustments that THESL has made and discuss the areas of the lost revenue amount for which the removal of these adjustments causes the largest variations;
e) Please provide further description of how THESL derived the incremental 2011 CDM program savings on 2011-2013 shown in E9/T2/T5/pg.5/Table 3 from the estimated savings for 2011 programs as shown in E9/T2/S5/pg. 4/Table 2;
f) With respect to E9/T2/S5/pg. 6/Table 4, please provide separate tables showing the initial year impact and the persistence in subsequent years for each of the 2011, 2012

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

and 2013 CDM programs, in other words, the breakdown of Table 4 by the CDM programs for each of the years 2011, 2012 and 2013;

g) THESL notes that it has provided the preliminary unaudited OPA results for 2013 CDM programs in E9/T2/S5/Appendix B. The final OPA Reports are typically released in the fall of the following year:

   i) If available, please provide a copy of the final OPA results for 2013 CDM for THESL.

   ii) If the final results would necessitate a material change in the LRAMVA balances for disposition, please update tables 4 and 5, and any tables requested in this interrogatory, to reflect any such updates.

RESPONSE:

a) Where available, Toronto Hydro used actual project completion dates to accumulate savings throughout the year of completion. For example, if a project was completed on January 1, the full 12 months of savings would be counted in that year. However, if the projected was completed on June 30, the monthly savings would start accumulating in July to the end of the year. This was further refined to account for project types which were assessed for their likely pattern of annual savings, so as not to allocate the same level of peak demand or consumption savings each month. For example, peak demand and consumption savings related to CDM projects involving cooling loads were considered 100% realized in the hottest months (July and August). However, the savings resulting from these projects were reduced accordingly in the shoulder and heating months. Where completion dates were not available, the savings were evenly distributed throughout the year. Toronto Hydro believes this is a

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more comprehensive analysis, and therefore, a more accurate depiction of the realization of savings.

b) This approach was not discussed with the OPA. Toronto Hydro is not aware that LRAMVA calculations are required to be reviewed by the OPA.

c) No, Toronto Hydro is not aware of any LDCs using the same approach of allocating the actual CDM savings when making an LRAMVA claim.

d) The Table below shows updated LRAMVA amounts without applying the adjustments to CDM savings. The removal of the adjustments results in an increase in the 2011-2013 LRAMVA by approximately $2.9 million.

Customer Class	2011 LRAMVA Amounts	2012 LRAMVA Amounts	2013 LRAMVA Amounts	2011, 2012, 2013 LRAMVA Amounts
Residential	$49,054	$889	$175,314	$223,257
Competitive Sector Multi-Unit Residential ("CSMUR")	$0	$0	$3,271	$3,271
General Service <50 kW	$312,033	$571,518	$1,186,699	$2,070,251
General Service 50 - 999 kW	$640,965	$1,258,778	$1,868,634	$3,768,377
General Service 1000 - 4,999 kW	$53,500	$4,985	$97,163	$155,648
Large Use	$35,361	-$51,222	$111,713	$95,853
Total	**$1,090,913**	**$1,784,949**	**$3,440,795**	**$6,316,656**

e) The 2011 forecasted incremental CDM (“A-B”) is the difference between the 2011 (“A”) and 2010 end of year (“B”) cumulative CDM estimates (see Figure 1 below for

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

more details). The 2011 estimated cumulative CDM savings (refer to Exhibit 9, Tab 2, Schedule 5, page 4, Table 2, column 4) consist of the estimated impacts related to 2011 CDM program activities plus the persistence of CDM programs from the prior years. Subsequently, the 2010 end of year cumulative CDM estimates represent the savings from persistence of programs implemented in years prior to 2011.

The latest Toronto Hydro OEB-approved load forecast was for 2011 (EB-2010-0142). As a result, the 2012 and 2013 forecasted CDM savings include only the impacts from persistence of 2011CDM programs. Please refer to the tables below for further details on 2011-2013 CDM forecast calculations, by class.

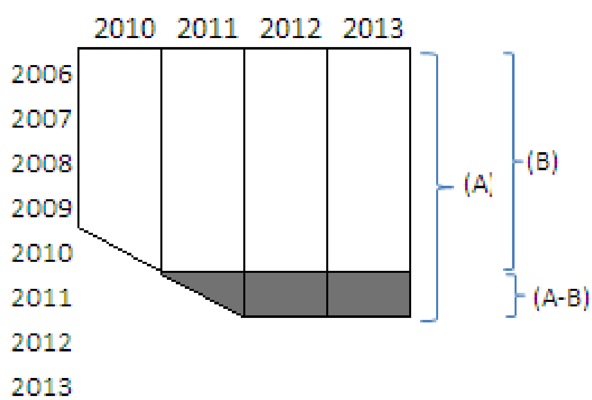

Figure 1: Calculation of incremental CDM Forecast

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2011 CDM Savings Forecast

Customer class	2011 estimated cumulative CDM Savings (A)	Estimated CDM Savings persistence (2010 and prior) (B)	2011 Incremental CDM Savings (A-B)	2011 Incremental CDM Savings	
	kWh	kWh	kWh	kWh (TLF adj)	kVA
Residential	181,121,318	164,439,472	16,681,846	16,077,338	
GS< 50kW	145,464,252	127,918,428	17,545,824	16,910,008	
GS 50-999 kW	0	0	0		0
GS 1000-4999 kW	152,041,157	133,560,920	18,480,237		40,863
Large Use	149,271,581	131,127,988	18,143,593		37,655

2012 CDM Savings Forecast

Customer class	2012 estimated cumulative CDM Savings	Estimated CDM Savings persistence (2010 and prior)	2012 estimated CDM Savings	2012 estimated CDM Savings	
	kWh	kWh	kWh	kWh (TLF adj)	kVA
Residential	195,698,546	164,940,079	30,758,467	29,643,858	
GS< 50kW	160,655,176	128,303,682	32,351,494	31,179,157	
GS 50-999 kW	0	0	0		0
GS 1000-4999 kW	168,037,220	133,962,829	34,074,391		75,086
Large Use	164,976,254	131,522,576	33,453,678		69,011

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2013 CDM Savings Forecast

Customer class	Estimated cumulative CDM Savings	Estimated CDM Savings persistence (2010 and prior)	2013 estimated CDM Savings	2013 estimated CDM Savings	
	kWh	kWh	kWh	kWh (TLF adj)	kVA
Residential (incl CSMUR)	195,113,899	164,439,472	30,674,427	29,562,863	
GS< 50kW	160,181,530	127,918,428	32,263,102	31,093,969	
GS 50-999 kW	0	0	0		0
GS 1000-4999 kW	167,542,212	133,560,920	33,981,292		74,891
Large Use	164,490,262	131,127,988	33,362,275		68,831

f) The following tables include 2011-2013 actual CDM savings by class broken down into three categories: the initial year impact, remaining realization in the following year, and persistence.

Residential – Actual 2011-2013 CDM Savings, MWh

<table>
<tr><th></th><th>2011</th><th colspan="2">2012</th><th colspan="2">2013</th></tr>
<tr><td>2011 CDM Programs</td><td>7,041</td><td>12,060</td><td>7,040</td><td colspan="2">18,867</td></tr>
<tr><td>2012 CDM Programs</td><td></td><td colspan="2">4,429</td><td>6,119</td><td>4,244</td></tr>
<tr><td>2013 CDM Programs</td><td></td><td colspan="2"></td><td colspan="2">4,828</td></tr>
<tr><td>Total</td><td>7,041</td><td colspan="2">23,529</td><td colspan="2">34,059</td></tr>
</table>

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CSMUR – Actual 2011-2013 CDM Savings, MWh

	2011	2012		2013	
2011 CDM Programs	N/A	N/A	N/A	233	
2012 CDM Programs		N/A		62	83
2013 CDM Programs				81	
Total				**459**	

GS<50 kW – Actual 2011-2013 CDM Savings, MWh

	2011	2012		2013	
2011 CDM Programs	11,311	19,375	11,329	30,717	
2012 CDM Programs		10,740		15,173	10,629
2013 CDM Programs				11,529	
Total	**11,311**	**41,444**		**68,048**	

GS 50-999 kW – Actual 2011-2013 CDM Savings, MVA

	2011	2012		2013	
2011 CDM Programs	61.75	54.12	61.75	115.87	
2012 CDM Programs		46.31		64.43	45.15
2013 CDM Programs				51.56	
Total	**61.75**	**162.18**		**277.01**	

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

GS 1000-4999 kW – Actual 2011-2013 CDM Savings, MVA

	2011	2012		2013	
2011 CDM Programs	30.00	26.43	30.00	56.43	
2012 CDM Programs		8.34		11.65	8.13
2013 CDM Programs				10.73	
Total	**30.00**	**64.78**		**86.94**	

Large Use – Actual 2011-2013 CDM Savings, MVA

	2011	2012		2013	
2011 CDM Programs	25.58	22.55	25.58	48.13	
2012 CDM Programs		3.75		5.23	3.65
2013 CDM Programs				17.80	
Total	**25.58**	**51.88**		**74.81**	

g)

i) A copy of the final OPA results for 2013 CDM for Toronto Hydro is provided as Appendix A to this Schedule.

ii) Toronto Hydro has recalculated the LRAMVA balances based on 2013 final verified OPA CDM results. The resulting LRAMVA amount is approximately $35,000 higher. As a result, Toronto Hydro believes that the LRAMVA balance change is immaterial and does not require any further updates.

Message from the Vice President:

The OPA is pleased to provide you with the enclosed Final 2013 Verified Results Report.

2013 Report highlights:

- We have achieved 86% of our cumulative energy savings target and 48% of our annual peak demand savings target to date (Scenario 2).

  By the end of 2013, 42 LDCs have exceeded 80% of their energy target and 19 LDCs have met or exceeded their 2011-14 energy target.
- In 2013, LDCs have achieved over 600 GWh in savings, representing an increase of 20% over the 2012 net incremental energy savings results.
- The BUSINESS PROGRAM continues to generate strong interest and participation amongst business customers with significant savings results. 71% of total energy savings in 2013 came from the BUSINESS PROGRAM and its momentum continues. Also, as the program matures, we are seeing more and more studies in the PROCESS AND SYSTEMS pipeline converting to completed projects.
- Within 4 cents per kWh, Conservation programs continue to be a valuable and cost effective resource for customers across the province.

2013 has been a year of significant operational advancements centered around creating a better customer and LDC experience:

- A number of operational changes were made in 2013 to enhance processes, such as payment of LDC invoices streamlined to an average of 20 days, enhanced reporting and iCon updates to improve users' experience.
- Proactive updates to measures incentivized through saveONenergy have allowed programs to stay ahead of changing market conditions. Specifically in 2013, LEDs became popular measures in both the Consumer and Business programs.
- Technical tools also played a significant role in 2013, which included an updated Measure and Assumptions List as well as new and improved engineering worksheets for RETROFIT which allow customers to more easily access programs by building strong business cases based on latest estimates of savings potential.
- The Conservation Fund introduced the LDC Fast Track stream to support LDCs with innovative program ideas. 2013 LDC pilots included Oshawa PUC Networks Inc.'s retro-commissioning program, Toronto Hydro-Electric System Limited multi-unit demand response, and Niagara-on-the-Lake Hydro Inc.'s electric vehicles load shifting program.
- Key market sectors were also engaged in 2013 through Capability Building programs targeted at Home Builders and HVAC Installers to build conservation knowledge with these partners. Energy Efficiency Services Programs (EESPs) also provided valuable support to a variety of sectors.

The format of this report was developed in collaboration with the Reporting Working Group and is designed to help LDCs populate their 2013 Annual Reports that will be submitted to the OEB by September 30th. Any additional 2013 program activity not captured here will be reported in your Final 2014 Verified Results Report.

Please continue to monitor saveONenergy E-blasts for any further updates and should you have any other questions or comments please contact LDC.Support@powerauthority.on.ca.

We appreciate your ongoing collaboration and cooperation throughout the reporting and evaluation process. We look forward to another successful year in 2014.

Sincerely,

Andrew Pride

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OPA-Contracted Province-Wide CDM Programs Final Verified 2013 Results

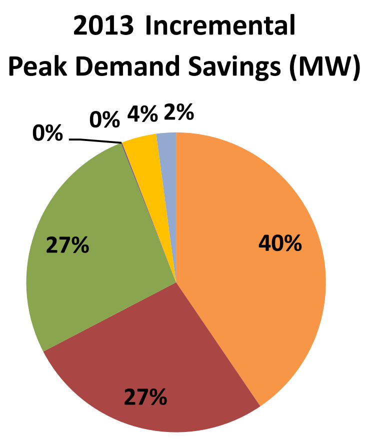
LDC: Toronto Hydro-Electric System Limited

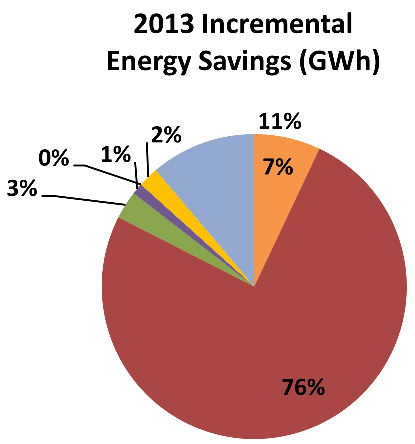
FINAL 2013 Progress to Targets	2013 Incremental	Program-to-Date Progress to Target (Scenario 1)	Scenario 1: % of Target Achieved	Scenario 2: % of Target Achieved
Net Annual Peak Demand Savings (MW)	93.6	85.4	**29.8%**	**52.7%**
Net Energy Savings (GWh)	135.5	1,301.5	**99.8%**	**99.8%**

Scenario 1 = Assumes that demand response resources have a persistence of 1 year

Scenario 2 = Assumes that demand response resources remain in the LDC service territory until 2014

Achievement by Sector

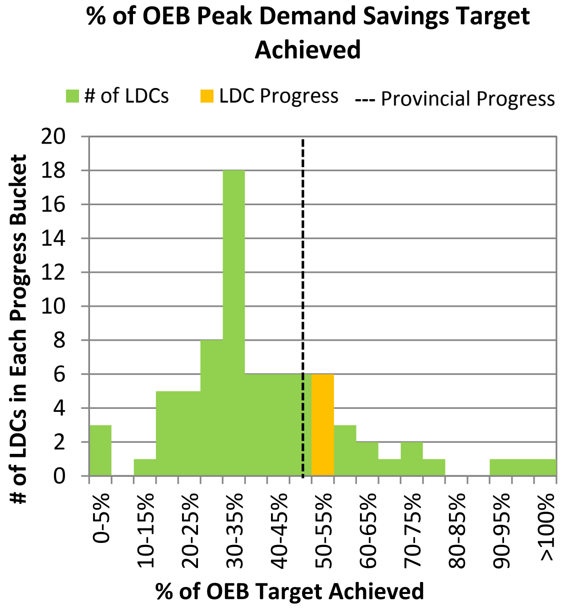




**Other includes adjustments to previous years' results and savings from pre-2011 initiatives*

Comparison: LDC Achievement vs. LDC Community Achievement (Progress to Target)

The following graphs assume that demand response resources remain in the LDC service territory until 2014 (aligns with Scenario 2)



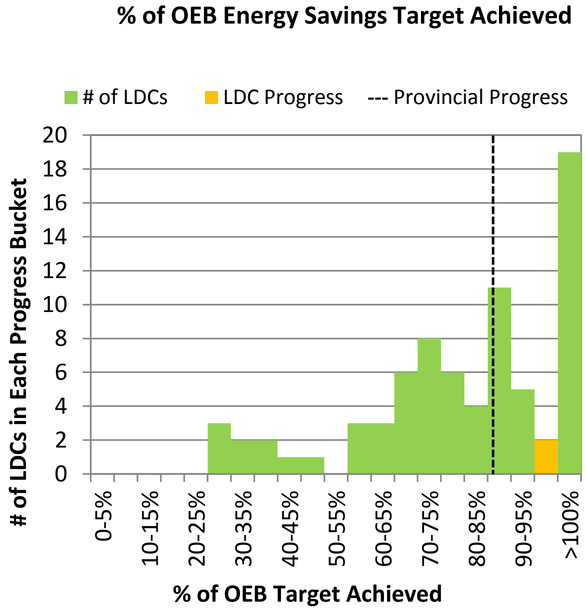


Table 1: Toronto Hydro-Electric System Limited Initiative and Program Level Net Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	6,088	2,802	1,541		349	161	100		2,343,820	1,091,609	656,268		579	13,933,867
Appliance Exchange	Appliances	549	580	397		52	83	82		57,879	143,607	146,668		178	920,442
HVAC Incentives	Equipment	16,744	13,393	14,327		5,674	2,821	3,015		10,493,166	4,781,806	5,189,758		11,510	66,697,599
Conservation Instant Coupon Booklet	Items	66,320	3,953	44,396		150	29	66		2,439,881	178,941	986,409		245	12,269,164
Bi-Annual Retailer Event	Items	121,855	135,773	120,911		215	189	151		3,760,986	3,427,499	2,198,663		556	29,723,766
Retailer Co-op	Items	13	0	0		0	0	0		230	0	0		0	919
Residential Demand Response	Devices	1,328	43,149	54,306		743	22,940	34,491		1,924	168,943	239,477		0	410,345
Residential Demand Response (IHD)	Devices	0	23,824	51,736		0	0	0		0	0	0		0	0
Residential New Construction	Homes	0	0	50		0	0	14		0	0	105,822		14	211,643
Consumer Program Total						**7,184**	**26,223**	**37,920**		**19,097,886**	**9,792,405**	**9,523,065**		**13,082**	**124,167,747**
Business Program															
Retrofit	Projects	636	1,268	1,713		7,527	15,973	15,424		43,007,032	80,294,445	90,527,082		38,362	591,225,618
Direct Install Lighting	Projects	3,971	3,519	2,366		4,903	2,502	2,092		12,683,558	9,383,020	6,898,480		7,404	85,037,910
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	0	11	3		0	151	74		0	269,821	407,340		225	1,624,142
Energy Audit	Audits	79	93	89		0	393	784		0	1,913,395	4,312,118		1,178	14,364,423
Small Commercial Demand Response	Devices	36	132	145		23	84	92		84	478	119		0	682
Small Commercial Demand Response (IHD)	Devices	0	0	89		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	26	28	44		1,915	4,413	6,678		75,010	64,142	98,839		0	237,991
Business Program Total						**14,369**	**23,516**	**25,144**		**55,765,683**	**91,925,302**	**102,243,979**		**47,169**	**692,490,765**
Industrial Program															
Process & System Upgrades	Projects	0	0	0		0	0	0		0	0	0		0	0
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	19	26		0	785	607		0	5,639,289	3,446,706		1,037	21,517,666
Retrofit	Projects	32	0	0		522	0	0		3,017,532	0	0		522	12,070,127
Demand Response 3	Facilities	17	20	28		10,024	10,274	24,336		588,385	247,610	564,746		0	1,400,741
Industrial Program Total						**10,545**	**11,059**	**24,943**		**3,605,917**	**5,886,899**	**4,011,451**		**1,559**	**34,988,535**
Home Assistance Program															
Home Assistance Program	Homes	0	626	2,398		0	98	122		0	790,242	1,620,650		215	5,534,388
Home Assistance Program Total						**0**	**98**	**122**		**0**	**790,242**	**1,620,650**		**215**	**5,534,388**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0		0	0	0		0	0	0		0	0
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0		0	0	0		0	0
High Performance New Construction	Projects	0	0	0		16	14	0		84,494	14,011	0		31	380,009
Toronto Comprehensive	Projects	577	0	0		15,805	0	0		86,964,886	0	0		15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	107	0	0		1,906	0	0		7,400,835	0	0		1,906	29,603,338
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**17,727**	**14**	**0**		**94,450,215**	**14,011**	**0**		**17,741**	**377,842,892**
Other															
Program Enabled Savings	Projects	1	5	2		0	0	3,513		0	0	2,915,337		3,513	5,830,674
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
Other Total						**0**	**0**	**3,513**		**0**	**0**	**2,915,337**		**3,513**	**5,830,674**
Adjustments to 2011 Verified Results							**178**	**401**			**3,791,694**	**215,912**		**571**	**16,007,321**
Adjustments to 2012 Verified Results								**1,588**				**14,922,926**		**1,546**	**44,622,782**
Energy Efficiency Total						**37,120**	**23,199**	**26,046**		**172,254,298**	**107,927,685**	**119,411,301**		**83,279**	**1,238,805,242**
Demand Response Total (Scenario 1)						**12,705**	**37,711**	**65,597**		**665,403**	**481,174**	**903,181**		**0**	**2,049,758**
Adjustments to Previous Years' Verified Results Total						**0**	**178**	**1,988**		**0**	**3,791,694**	**15,138,838**		**2,117**	**60,630,103**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**49,825**	**61,088**	**93,631**		**172,919,701**	**112,200,552**	**135,453,320**		**85,396**	**1,301,485,103**
													Full OEB Target:	**286,270**	**1,303,990,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**29.8%**	**99.8%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

*Includes adjustments after Final Reports were issued

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Table 2: Adjustments to Toronto Hydro-Electric System Limited Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program													
Appliance Retirement	Appliances	0	0			0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0			0	0		
HVAC Incentives	Equipment	-3,164	346			-863	70			-1,572,488	138,411		
Conservation Instant Coupon Booklet	Items	1,051	0			2	0			35,278	0		
Bi-Annual Retailer Event	Items	10,471	0			14	0			279,429	0		
Retailer Co-op	Items	0	0			0	0			0	0		
Residential Demand Response	Devices	0	0			0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0			0	0		
Residential New Construction	Homes	0	0			0	0			0	0		
Consumer Program Total						**-847**	**70**			**-1,257,781**	**138,411**		
Business Program													
Retrofit	Projects	54	100			905	1,067			4,543,720	7,586,120		
Direct Install Lighting	Projects	25	21			32	48			78,682	164,080		
Building Commissioning	Buildings	0	0			0	0			0	0		
New Construction	Buildings	0	0			0	0			0	0		
Energy Audit	Audits	19	17			98	88			478,349	427,996		
Small Commercial Demand Response	Devices	0	0			0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Business Program Total						**1,036**	**1,203**			**5,100,751**	**8,178,195**		
Industrial Program													
Process & System Upgrades	Projects	0	0			0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0			0	0		
Energy Manager	Projects	0	0			0	0			0	0		
Retrofit	Projects	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Industrial Program Total						**0**	**0**			**0**	**0**		
Home Assistance Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Home Assistance Program Total						**0**	**0**			**0**	**0**		
Aboriginal Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0			0	0		
Aboriginal Program Total						**0**	**0**			**0**	**0**		
Pre-2011 Programs completed in 2011													
Electricity Retrofit Incentive Program	Projects	0	0			0	0			0	0		
High Performance New Construction	Projects	0	0			0	0			0	0		
Toronto Comprehensive	Projects	0	0			0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0			0	0		
Pre-2011 Programs completed in 2011 Total						**0**	**0**			**0**	**0**		
Other													
Program Enabled Savings	Projects	1	4			390	315			164,800	6,606,320		
Time-of-Use Savings	Homes	0	0			0	0			0	0		
Other Total						**390**	**315**			**164,800**	**6,606,320**		
Adjustments to 2011 Verified Results						**579**				**4,007,770**			
Adjustments to 2012 Verified Results							**1,588**				**14,922,926**		
Total Adjustments to Previous Years' Verified Results						**579**	**1,588**			**4,007,770**	**14,922,926**		

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Table 3: Toronto Hydro-Electric System Limited Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	n/a		0.49	0.46	0.42		1.00	1.00	n/a		0.50	0.47	0.44	
Appliance Exchange	1.00	1.00	1.00		0.52	0.52	0.53		1.00	1.00	1.00		0.52	0.52	0.53	
HVAC Incentives	1.00	1.00	n/a		0.60	0.50	0.48		1.00	1.00	n/a		0.60	0.49	0.48	
Conservation Instant Coupon Booklet	1.00	1.00	1.00		1.14	1.00	1.11		1.00	1.00	1.00		1.11	1.05	1.13	
Bi-Annual Retailer Event	1.00	1.00	1.00		1.13	0.91	1.04		1.00	1.00	1.00		1.10	0.92	1.04	
Retailer Co-op	1.00	n/a	n/a		0.68	n/a	n/a		1.00	n/a	n/a		0.68	n/a	n/a	
Residential Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential New Construction	n/a	n/a	0.75		n/a	n/a	0.63		n/a	n/a	2.85		n/a	n/a	0.63	
Business Program																
Retrofit	0.98	0.92	0.91		0.69	0.72	0.71		1.02	0.98	0.97		0.72	0.74	0.72	
Direct Install Lighting	1.08	0.69	0.82		0.93	0.94	0.94		0.90	0.85	0.84		0.93	0.94	0.94	
Building Commissioning	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
New Construction	n/a	1.00	0.59		n/a	0.49	0.54		n/a	1.00	0.97		n/a	0.49	0.54	
Energy Audit	n/a	n/a	1.02		n/a	n/a	0.66		n/a	n/a	0.97		n/a	n/a	0.66	
Small Commercial Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Small Commercial Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Demand Response 3	0.76	n/a	n/a		n/a	n/a	n/a		1.00	n/a	n/a		n/a	n/a	n/a	
Industrial Program																
Process & System Upgrades	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Monitoring & Targeting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Energy Manager	n/a	1.13	0.90		n/a	0.90	0.90		n/a	1.13	0.90		n/a	0.90	0.90	
Retrofit																
Demand Response 3	0.84	n/a	n/a		n/a	n/a	n/a		1.00	n/a	n/a		n/a	n/a	n/a	
Home Assistance Program																
Home Assistance Program	n/a	0.41	0.84		n/a	1.00	1.00		n/a	1.00	0.87		n/a	1.00	1.00	
Aboriginal Program																
Home Assistance Program	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Direct Install Lighting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
High Performance New Construction	1.00	1.00	1.00		0.50	0.50	0.50		1.00	1.00	1.00		0.50	0.50	0.50	
Toronto Comprehensive	1.33	n/a	n/a		0.41	n/a	n/a		1.15	n/a	n/a		0.41	n/a	n/a	
Multifamily Energy Efficiency Rebates	0.99	n/a	n/a		0.69	n/a	n/a		0.99	n/a	n/a		0.69	n/a	n/a	
LDC Custom Programs	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Other																
Program Enabled Savings	n/a	n/a	1.00		n/a	n/a	1.00		n/a	n/a	1.00		n/a	n/a	1.00	
Time-of-Use Savings	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Summary Progress Towards CDM Targets

Results are attributed to target using current OPA reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year (Scenario 1). Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW) (Scenario 1)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	49.8	37.1	36.7	35.2
2012 - Verified†	0.2	61.1	23.1	22.7
2013 - Verified†	0.4	2.0	93.6	27.5
2014				
Verified Net Annual Peak Demand Savings Persisting in 2014:				**85.4**
Toronto Hydro-Electric System Limited 2014 Annual CDM Capacity Target:				**286.3**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**29.8%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	172.9	172.1	171.0	166.9	683.0
2012 - Verified†	3.8	112.2	110.8	109.4	336.3
2013 - Verified†	0.2	15.1	135.5	131.4	282.3
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**1,301.5**
Toronto Hydro-Electric System Limited 2011-2014 Annual CDM Energy Target:					**1,304.0**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**99.8%**

†Includes adjustments to previous Years' verified results

Table 6: Province-Wide Initiatives and Program Level Net Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014 Net Annual Peak Demand Savings (kW) 2014	2011-2014 Net Cumulative Energy Savings (kWh) 2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146	20,952		3,299	2,011	1,433		23,005,812	13,424,518	8,713,107		6,605	149,603,072
Appliance Exchange	Appliances	3,688	3,836	5,337		371	556	1,106		450,187	974,621	1,971,701		1,795	8,455,927
HVAC Incentives	Equipment	92,743	87,427	91,581		32,037	19,060	19,552		59,437,670	32,841,283	33,923,592		70,650	404,121,713
Conservation Instant Coupon Booklet	Items	567,678	30,891	346,896		1,344	230	517		21,211,537	1,398,202	7,707,573		2,091	104,455,900
Bi-Annual Retailer Event	Items	952,149	1,060,901	944,772		1,681	1,480	1,184		29,387,468	26,781,674	17,179,841		4,345	232,254,579
Retailer Co-op	Items	152	0	0		0	0	0		2,652	0	0		0	10,607
Residential Demand Response	Devices	19,550	98,388	171,733		10,947	49,038	93,076		24,870	359,408	390,303		0	774,582
Residential Demand Response (IHD)	Devices	0	49,689	133,657		0	0	0		0	0	0		0	0
Residential New Construction	Homes	26	19	86		0	2	18		743	17,152	163,690		20	381,811
Consumer Program Total						**49,681**	**72,377**	**116,886**		**133,520,941**	**75,796,859**	**70,049,807**		**85,506**	**900,058,189**
Business Program															
Retrofit	Projects	2,819	6,134	8,785		24,467	61,147	59,678		136,002,258	314,922,468	345,346,008		142,831	2,168,497,702
Direct Install Lighting	Projects	20,741	18,691	17,782		23,724	15,284	18,708		61,076,701	57,345,798	64,315,558		49,886	519,693,356
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	22	69	86		123	764	1,584		411,717	1,814,721	4,959,266		2,472	17,009,564
Energy Audit	Audits	198	345	319		0	1,450	2,811		0	7,049,351	15,455,795		4,261	52,059,644
Small Commercial Demand Response	Devices	132	294	1,211		84	187	773		157	1,068	373		0	1,597
Small Commercial Demand Response (IHD)	Devices	0	0	378		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	145	151	175		16,218	19,389	23,706		633,421	281,823	346,659		0	1,261,903
Business Program Total						**64,617**	**98,221**	**107,261**		**198,124,253**	**381,415,230**	**430,423,659**		**199,449**	**2,758,523,766**
Industrial Program															
Process & System Upgrades	Projects	0	0	3		0	0	294		0	0	2,603,764		294	5,207,528
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	42	205		0	1,086	3,558		0	7,372,108	21,994,263		3,194	54,888,570
Retrofit	Projects	433	0	0		4,615	0	0		28,866,840	0	0		4,613	115,462,282
Demand Response 3	Facilities	124	185	281		52,484	74,056	162,543		3,080,737	1,784,712	4,309,160		0	9,174,609
Industrial Program Total						**57,098**	**75,141**	**166,395**		**31,947,577**	**9,156,820**	**28,907,187**		**8,101**	**184,732,989**
Home Assistance Program															
Home Assistance Program	Homes	46	5,033	26,756		2	566	2,361		39,283	5,442,232	20,987,275		2,904	57,949,913
Home Assistance Program Total						**2**	**566**	**2,361**		**39,283**	**5,442,232**	**20,987,275**		**2,904**	**57,949,913**
Aboriginal Program															
Home Assistance Program	Homes	0	0	584		0	0	267		0	0	1,609,393		267	3,218,786
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**267**		**0**	**0**	**1,609,393**		**267**	**3,218,786**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,028	0	0		21,662	0	0		121,138,219	0	0		21,662	484,552,876
High Performance New Construction	Projects	179	69	4		5,098	3,251	772		26,185,591	11,901,944	3,522,240		9,121	147,492,677
Toronto Comprehensive	Projects	577	0	0		15,805	0	0		86,964,886	0	0		15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0	0		1,981	0	0		7,595,683	0	0		1,981	30,382,733
LDC Custom Programs	Projects	8	0	0		399	0	0		1,367,170	0	0		399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**	**772**		**243,251,550**	**11,901,944**	**3,522,240**		**48,967**	**1,015,756,510**
Other															
Program Enabled Savings	Projects	14	56	13		0	2,304	3,692		0	1,188,362	4,075,382		5,996	11,715,850
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
Other Total						**0**	**2,304**	**3,692**		**0**	**1,188,362**	**4,075,382**		**5,996**	**11,715,850**
Adjustments to 2011 Verified Results							**1,406**	**641**			**18,689,081**	**1,736,381**		**1,797**	**80,864,121**
Adjustments to 2012 Verified Results								**6,260**				**41,947,840**		**6,180**	**126,287,857**
Energy Efficiency Total						**136,610**	**109,191**	**117,536**		**603,144,419**	**482,474,435**	**554,528,447**		**351,190**	**4,920,743,312**
Demand Response Total (Scenario 1)						**79,733**	**142,670**	**280,099**		**3,739,185**	**2,427,011**	**5,046,495**		**0**	**11,212,691**
Adjustments to Previous Years' Verified Results Total						**0**	**1,406**	**6,901**		**0**	**18,689,081**	**43,684,221**		**7,976**	**207,151,978**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**	**404,536**		**606,883,604**	**503,590,526**	**603,259,163**		**359,166**	**5,139,107,980**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**27.0%**	**85.7%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

*Includes adjustments after Final Reports were issued

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Table 7: Adjustments to Province-Wide Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011*	2012*	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program													
Appliance Retirement	Appliances	0	0			0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0			0	0		
HVAC Incentives	Equipment	-18,844	2,206			-5,271	452			-9,709,500	907,735		
Conservation Instant Coupon Booklet	Items	8,216	0			16	0			275,655	0		
Bi-Annual Retailer Event	Items	81,817	0			108	0			2,183,391	0		
Retailer Co-op	Items	0	0			0	0			0	0		
Residential Demand Response	Devices	0	0			0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0			0	0		
Residential New Construction	Homes	19	0			1	0			13,767	0		
Consumer Program Total						**-5,146**	**452**			**-7,236,687**	**907,735**		
Business Program													
Retrofit	Projects	303	529			3,204	4,443			16,216,165	28,739,635		
Direct Install Lighting	Projects	444	197			501	204			1,250,388	736,541		
Building Commissioning	Buildings	0	0			0	0			0	0		
New Construction	Buildings	12	0			828	0			3,520,620	0		
Energy Audit	Audits	95	65			492	337			2,391,744	1,636,457		
Small Commercial Demand Response	Devices	0	0			0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Business Program Total						**5,025**	**4,984**			**23,378,917**	**31,112,632**		
Industrial Program													
Process & System Upgrades	Projects	0	0			0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0			0	0		
Energy Manager	Projects	0	3			0	68			0	719,235		
Retrofit	Projects	0	0			0	0			0	0		
Demand Response 3	Facilities	0	0			0	0			0	0		
Industrial Program Total						**0**	**68**			**0**	**719,235**		
Home Assistance Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Home Assistance Program Total						**0**	**0**			**0**	**0**		
Aboriginal Program													
Home Assistance Program	Homes	0	0			0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0			0	0		
Aboriginal Program Total						**0**	**0**			**0**	**0**		
Pre-2011 Programs completed in 2011													
Electricity Retrofit Incentive Program	Projects	12	0			138	0			545,536	0		
High Performance New Construction	Projects	34	0			1,407	0			2,065,200	0		
Toronto Comprehensive	Projects	0	0			0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0			0	0		
Pre-2011 Programs completed in 2011 Total						**1,545**	**0**			**2,610,736**	**0**		
Other													
Program Enabled Savings	Projects	14	40			624	824			1,673,712	9,927,473		
Time-of-Use Savings	Homes	0	0			0	0			0	0		
Other Total						**624**	**824**			**1,673,712**	**9,927,473**		
Adjustments to 2011 Verified Results						**2,047**				**20,426,678**			
Adjustments to 2012 Verified Results							**6,328**				**42,667,076**		
Adjustments to Previous Years' Verified Results Total						**2,047**	**6,328**			**20,426,678**	**42,667,076**		

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	1.00		0.51	0.46	0.42		1.00	1.00	1.00		0.46	0.47	0.44	
Appliance Exchange	1.00	1.00	1.00		0.51	0.52	0.53		1.00	1.00	1.00		0.52	0.52	0.53	
HVAC Incentives	1.00	1.00	1.00		0.60	0.50	0.48		1.00	1.00	1.00		0.50	0.49	0.48	
Conservation Instant Coupon Booklet	1.00	1.00	1.00		1.14	1.00	1.11		1.00	1.00	1.00		1.00	1.05	1.13	
Bi-Annual Retailer Event	1.00	1.00	1.00		1.12	0.91	1.04		1.00	1.00	1.00		0.91	0.92	1.04	
Retailer Co-op	1.00	n/a	n/a		0.68	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Residential New Construction	1.00	3.65	0.78		0.41	0.49	0.63		3.65	7.17	3.09		0.49	0.49	0.63	
Business Program																
Retrofit	1.06	0.93	0.92		0.72	0.75	0.73		0.93	1.05	1.01		0.75	0.76	0.73	
Direct Install Lighting	1.08	0.69	0.82		1.08	0.94	0.94		0.69	0.85	0.84		0.94	0.94	0.94	
Building Commissioning	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
New Construction	0.50	0.98	0.68		0.50	0.49	0.54		0.98	0.99	0.76		0.49	0.49	0.54	
Energy Audit	n/a	n/a	1.02		n/a	n/a	0.66		n/a	n/a	0.97		n/a	n/a	0.66	
Small Commercial Demand Response	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Small Commercial Demand Response (IHD)	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Demand Response 3	0.76	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Industrial Program																
Process & System Upgrades	n/a	n/a	0.85		n/a	n/a	0.94		n/a	n/a	0.87		n/a	n/a	0.93	
Monitoring & Targeting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Energy Manager	n/a	1.16	0.90		n/a	0.90	0.90		1.16	1.16	0.90		0.90	0.90	0.90	
Retrofit	1.11	n/a	n/a		0.72	n/a	n/a		0.91	n/a	n/a		0.75	n/a	n/a	
Demand Response 3	0.84	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Home Assistance Program																
Home Assistance Program	1.00	0.32	0.26		0.70	1.00	1.00		0.32	0.99	0.88		1.00	1.00	1.00	
Aboriginal Program																
Home Assistance Program	n/a	n/a	0.05		n/a	n/a	1.00		n/a	n/a	0.95		n/a	n/a	1.00	
Direct Install Lighting	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.80	n/a	n/a		0.54	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
High Performance New Construction	1.00	1.00	1.00		0.49	0.50	0.50		1.00	1.00	1.00		0.50	0.50	0.50	
Toronto Comprehensive	1.13	n/a	n/a		0.50	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Multifamily Energy Efficiency Rebates	0.93	n/a	n/a		0.78	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
LDC Custom Programs	1.00	n/a	n/a		1.00	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	
Other																
Program Enabled Savings	n/a	1.06	1.00		n/a	1.00	1.00		1.06	2.26	1.00		1.00	1.00	1.00	
Time-of-Use Savings	n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a		n/a	n/a	n/a	

Energy Manager, Aboriginal Program and Program Enabled Savings were not independently evaluated

Summary Provincial Progress Towards CDM Targets

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012†	1.4	253.3	109.8	108.2
2013†	0.6	7.0	404.5	122.0
2014				
Verified Net Annual Peak Demand Savings in 2014:				**359.2**
2014 Annual CDM Capacity Target:				**1,330**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**27.0%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393.1
2012†	18.7	503.6	498.4	492.6	1,513.3
2013†	1.7	44.4	603.3	583.4	1,232.8
2014					
Verified Net Cumulative Energy Savings 2011-2014:					**5,139.1**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**85.7%**

†Includes adjustments to previous Years' verified results

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and Projects	**Gross Savings = Activity * Per Unit Assumption** **Net Savings = Gross Savings * Net-to-Gross Ratio** **All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)**
Engineered and Custom Projects	**Gross Savings = Reported Savings * Realization Rate** **Net Savings = Gross Savings * Net-to-Gross Ratio** **All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)**
Demand Response	**Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio** **Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW** **All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)**
Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of 2008 & 2009 residential throughput; Home pickup stream directly attributed by postal code or customer selection.	Savings are considered to begin in the year the appliance is picked up.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year that the exchange event occurred.	
HVAC Incentives	Results directly attributed to LDC based on customer postal code.	Savings are considered to begin in the year that the installation occurred.	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the coupon was redeemed.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the event occurs.	
Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists.	Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement.	Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any “snapback” in energy consumption experienced after the event. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Initiative was not evaluated in 2011, reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
	Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2013)		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011 or 2012.	Savings are considered to begin in the year of the actual project completion date.	Peak demand and energy savings are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	
Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the audit date.	Peak demand and energy savings are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a peaksaver PLUS™ participant agreement.	Peak demand savings are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. Energy savings are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to persist for only 1 year, reflecting that savings will only occur if the resource is activated.
Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, no completed projects in 2011, 2012 or 2013.	Savings are considered to begin in the year in which the incentive project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
Energy Manager	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	Peak demand savings are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. Energy savings are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program			
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Aboriginal Program			
Aboriginal Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the measures were installed.	Peak demand and energy savings are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross), taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012 or 2013 assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported. A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012 or 2013, assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	Peak demand and energy savings are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). If energy savings are not available, an estimate is made based on the kWh to kW ratio in the provincial results from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation.		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation.		

Retrofit Sector (C&I vs. Industrial Mapping)

Building Type	Sector
Agribusiness - Cattle Farm	C&I
Agribusiness - Dairy Farm	C&I
Agribusiness - Greenhouse	C&I
Agribusiness - Other	C&I
Agribusiness - Other,Mixed-Use - Office/Retail	C&I
Agribusiness - Other,Office,Retail,Warehouse	C&I
Agribusiness - Other,Office,Warehouse	C&I
Agribusiness - Poultry	C&I
Agribusiness - Poultry,Hospitality - Motel	C&I
Agribusiness - Swine	C&I
Convenience Store	C&I
Education - College / Trade School	C&I
Education - College / Trade School,Multi-Residential - Condominium	C&I
Education - College / Trade School,Multi-Residential - Rental Apartment	C&I
Education - College / Trade School,Retail	C&I
Education - Primary School	C&I
Education - Primary School,Education - Secondary School	C&I
Education - Primary School,Multi-Residential - Rental Apartment	C&I
Education - Primary School,Not-for-Profit	C&I
Education - Secondary School	C&I
Education - University	C&I
Education - University,Office	C&I
Hospital/Healthcare - Clinic	C&I
Hospital/Healthcare - Clinic,Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Clinic,Industrial	C&I
Hospital/Healthcare - Clinic,Retail	C&I
Hospital/Healthcare - Long-term Care	C&I
Hospital/Healthcare - Long-term Care,Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail	C&I
Hospital/Healthcare - Medical Building,Mixed-Use - Office/Retail,Office	C&I
Hospitality - Hotel	C&I
Hospitality - Hotel,Restaurant - Dining	C&I
Hospitality - Motel	C&I
Industrial	Industrial
Mixed-Use - Office/Retail	C&I
Mixed-Use - Office/Retail,Industrial	Industrial
Mixed-Use - Office/Retail,Mixed-Use - Other	C&I
Mixed-Use - Office/Retail,Mixed-Use - Other,Not-for-Profit,Warehouse	C&I
Mixed-Use - Office/Retail,Mixed-Use - Residential/Retail	C&I
Mixed-Use - Office/Retail,Office,Restaurant - Dining,Restaurant - Quick Serve,Retail,Warehouse	C&I

Mixed-Use - Office/Retail,Office,Warehouse	C&I
Mixed-Use - Office/Retail,Retail	C&I
Mixed-Use - Office/Retail,Warehouse	C&I
Mixed-Use - Office/Retail,Warehouse,Industrial	Industrial
Mixed-Use - Other	C&I
Mixed-Use - Other,Industrial	Industrial
Mixed-Use - Other,Not-for-Profit,Office	C&I
Mixed-Use - Other,Office	C&I
Mixed-Use - Other,Other: Please specify	C&I
Mixed-Use - Other,Retail,Warehouse	C&I
Mixed-Use - Other,Warehouse	C&I
Mixed-Use - Residential/Retail	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Condominium	C&I
Mixed-Use - Residential/Retail,Multi-Residential - Rental Apartment	C&I
Mixed-Use - Residential/Retail,Retail	C&I
Multi-Residential - Condominium	C&I
Multi-Residential - Condominium,Multi-Residential - Rental Apartment	C&I
Multi-Residential - Condominium,Other: Please specify	C&I
Multi-Residential - Rental Apartment	C&I
Multi-Residential - Rental Apartment,Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Not-for-Profit	C&I
Multi-Residential - Rental Apartment,Warehouse	C&I
Multi-Residential - Social Housing Provider	C&I
Multi-Residential - Social Housing Provider,Industrial	C&I
Multi-Residential - Social Housing Provider,Not-for-Profit	C&I
Not-for-Profit	C&I
Not-for-Profit,Office	C&I
Not-for-Profit,Other: Please specify	C&I
Not-for-Profit,Warehouse	C&I
Office	C&I
Office,Industrial	Industrial
Office,Other: Please specify	C&I
Office,Other: Please specify,Warehouse	C&I
Office,Restaurant - Dining	C&I
Office,Restaurant - Dining,Industrial	Industrial
Office,Retail	C&I
Office,Retail,Industrial	C&I
Office,Retail,Warehouse	C&I
Office,Warehouse	C&I
Office,Warehouse,Industrial	Industrial
Other: Please specify	C&I
Other: Please specify,Industrial	Industrial
Other: Please specify,Retail	C&I
Other: Please specify,Warehouse	C&I
Restaurant - Dining	C&I
Restaurant - Dining,Retail	C&I

Restaurant - Quick Serve	C&I
Restaurant - Quick Serve,Retail	C&I
Retail	C&I
Retail,Industrial	Industrial
Retail,Warehouse	C&I
Warehouse	C&I
Warehouse,Industrial	Industrial

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%

Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%
Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity in a given year and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (e.g. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Table 11: Toronto Hydro-Electric System Limited Initiative and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	751	161	216		4,896,184	1,091,609	1,395,407	
Appliance Exchange**	Appliances	101	83	156		112,306	143,607	278,659	
HVAC Incentives	Equipment	9,421	5,659	6,221		17,547,359	9,728,761	10,883,754	
Conservation Instant Coupon Booklet	Items	133	30	59		2,213,090	169,687	875,665	
Bi-Annual Retailer Event	Items	192	208	146		3,442,548	3,739,819	2,104,149	
Retailer Co-op	Items	0	0	0		339	0	0	
Residential Demand Response	Devices	743	22,940	34,491		1,924	168,943	239,477	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	0	22		0	0	167,971	
Consumer Program Total		**11,342**	**29,080**	**41,312**		**28,213,749**	**15,042,427**	**15,945,082**	
Business Program									
Retrofit	Projects	10,942	22,291	22,012		59,789,306	108,932,749	127,698,424	
Direct Install Lighting	Projects	4,579	3,352	2,215		13,659,691	11,273,244	7,308,716	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	0	8	137		0	7,679	754,333	
Energy Audit	Audits	0	393	1,195		0	1,913,395	6,524,651	
Small Commercial Demand Response	Devices	23	84	92		84	478	119	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	1,915	4,413	6,678		75,010	64,142	98,839	
Business Program Total		**17,459**	**30,540**	**32,329**		**73,524,091**	**122,191,688**	**142,385,082**	
Industrial Program									
Process & System Upgrades	Projects	0	0	0		0	0	0	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	769	675		0	5,526,412	3,829,673	
Retrofit	Projects	719	0	0		3,974,681	0	0	
Demand Response 3	Facilities	10,024	10,274	24,336		588,385	247,610	564,746	
Industrial Program Total		**10,742**	**11,043**	**25,011**		**4,563,066**	**5,774,022**	**4,394,418**	
Home Assistance Program									
Home Assistance Program	Homes	0	239	122		0	788,226	1,620,650	
Home Assistance Program Total		**0**	**239**	**122**		**0**	**788,226**	**1,620,650**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	0		0	0	0	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**0**		**0**	**0**	**0**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0	
High Performance New Construction	Projects	33	29	0		168,988	28,022	0	
Toronto Comprehensive	Projects	33,467	0	0		174,070,574	0	0	
Multifamily Energy Efficiency Rebates	Projects	2,443	0	0		9,488,249	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**35,943**	**29**	**0**		**183,727,812**	**28,022**	**0**	
Other									
Program Enabled Savings	Projects	0	0	3,513		0	0	2,915,337	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
Other Total		**0**	**0**	**3,513**		**0**	**0**	**2,915,337**	
Adjustments to 2011 Verified Results		**0**	**17**	**401**		**0**	**4,645,167**	**216,431**	
Adjustments to 2012 Verified Results		**0**	**0**	**2,056**		**0**	**0**	**17,839,461**	
Energy Efficiency Total		**62,780**	**33,220**	**36,689**		**289,363,315**	**143,343,211**	**166,357,389**	
Demand Response Total		**12,705**	**37,711**	**65,597**		**665,403**	**481,174**	**903,181**	
Adjustments to Previous Years' Verified Results Total		**0**	**17**	**2,457**		**0**	**4,645,167**	**18,055,893**	
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**75,486**	**70,948**	**104,743**		**290,028,718**	**148,469,552**	**185,316,462**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 12: Adjustments to Toronto Hydro-Electric System Limited Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0		
HVAC Incentives	Equipment	-1,433	159			-2,629,958	282,613		
Conservation Instant Coupon Booklet	Items	2	0			32,760	0		
Bi-Annual Retailer Event	Items	15	0			303,774	0		
Retailer Co-op	Items	0	0			0	0		
Residential Demand Response	Devices	0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0		
Residential New Construction	Homes	0	0			0	0		
Consumer Program Total		**-1,417**	**159**			**-2,293,425**	**282,613**		
Business Program									
Retrofit	Projects	1,312	1,443			6,427,137	10,348,357		
Direct Install Lighting	Projects	35	51			84,737	174,175		
Building Commissioning	Buildings	0	0			0	0		
New Construction	Buildings	0	0			0	0		
Energy Audit	Audits	98	88			478,349	427,996		
Small Commercial Demand Response	Devices	0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Business Program Total		**1,445**	**1,582**			**6,990,222**	**10,950,528**		
Industrial Program									
Process & System Upgrades	Projects	0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0		
Energy Manager	Projects	0	0			0	0		
Retrofit	Projects	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Industrial Program Total		**0**	**0**			**0**	**0**		
Home Assistance Program									
Home Assistance Program	Homes	0	0			0	0		
Home Assistance Program Total		**0**	**0**			**0**	**0**		
Aboriginal Program									
Home Assistance Program	Homes	0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0		
Aboriginal Program Total									
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	0	0			0	0		
High Performance New Construction	Projects	0	0			0	0		
Toronto Comprehensive	Projects	0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0		
Pre-2011 Programs completed in 2011 Total		**0**	**0**			**0**	**0**		
Other									
Program Enabled Savings	Projects	390	315			164,800	6,606,320		
Time-of-Use Savings	Homes	0	0			0	0		
Other Total		**390**	**315**			**164,800**	**6,606,320**		
Adjustments to 2011 Verified Results		**418**				**4,861,598**			
Adjustments to 2012 Verified Results			**2,056**				**17,839,461**		
Total Adjustments to Previous Years' Verified Results		**418**	**2,056**			**4,861,598**	**17,839,461**		

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

Table 13: Province-Wide Initiatives and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	6,750	2,011	3,151		45,971,627	13,424,518	18,616,239	
Appliance Exchange**	Appliances	719	556	2,101		873,531	974,621	3,746,106	
HVAC Incentives	Equipment	53,209	38,346	40,418		99,413,430	66,929,213	71,225,037	
Conservation Instant Coupon Booklet	Items	1,184	231	464		19,192,453	1,325,898	6,842,244	
Bi-Annual Retailer Event	Items	1,504	1,622	1,142		26,899,265	29,222,072	16,441,329	
Retailer Co-op	Items	0	0	0		3,917	0	0	
Residential Demand Response	Devices	10,390	49,038	93,076		23,597	359,408	390,303	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	1	29		1,813	4,884	259,826	
Consumer Program Total		**73,757**	**91,805**	**140,380**		**192,379,633**	**112,240,615**	**117,521,084**	
Business Program									
Retrofit	Projects	34,201	78,965	82,896		184,070,265	387,817,248	478,410,896	
Direct Install Lighting	Projects	22,155	20,469	19,807		65,777,197	68,896,046	68,140,249	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	247	1,596	2,934		823,434	3,755,869	9,183,826	
Energy Audit	Audits	0	1,450	4,283		0	7,049,351	23,386,108	
Small Commercial Demand Response	Devices	55	187	773		131	1,068	373	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	21,390	19,389	23,706		633,421	281,823	346,659	
Business Program Total		**78,048**	**122,056**	**134,399**		**251,304,448**	**467,801,406**	**579,468,111**	
Industrial Program									
Process & System Upgrades	Projects	0	0	313		0	0	2,799,746	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	1,034	3,953		0	7,067,535	24,438,070	
Retrofit	Projects	6,372	0	0		38,412,408	0	0	
Demand Response 3	Facilities	176,180	74,056	162,543		4,243,958	1,784,712	4,309,160	
Industrial Program Total		**182,552**	**75,090**	**166,809**		**42,656,366**	**8,852,247**	**31,546,976**	
Home Assistance Program									
Home Assistance Program	Homes	4	1,777	2,361		56,119	5,524,230	20,987,275	
Home Assistance Program Total		**4**	**1,777**	**2,361**		**56,119**	**5,524,230**	**20,987,275**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	267		0	0	1,609,393	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**267**		**0**	**0**	**1,609,393**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	40,418	0	0		223,956,390	0	0	
High Performance New Construction	Projects	10,197	6,501	772		52,371,183	23,803,888	3,522,240	
Toronto Comprehensive	Projects	33,467	0	0		174,070,574	0	0	
Multifamily Energy Efficiency Rebates	Projects	2,553	0	0		9,774,792	0	0	
LDC Custom Programs	Projects	534	0	0		649,140	0	0	
Pre-2011 Programs completed in 2011 Total		**87,169**	**6,501**	**772**		**460,822,079**	**23,803,888**	**3,522,240**	
Other									
Program Enabled Savings	Projects	0	2,177	3,692		0	525,011	4,075,382	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
Other Total		**0**	**2,177**	**3,692**		**0**	**525,011**	**4,075,382**	
Adjustments to 2011 Verified Results			**13,266**	**645**			**48,705,294**	**1,744,645**	
Adjustments to 2012 Verified Results				**8,707**				**55,101,043**	
Energy Efficiency Total		**213,515**	**156,735**	**168,583**		**942,317,539**	**616,320,385**	**753,683,966**	
Demand Response Total		**208,015**	**142,670**	**280,099**		**4,901,107**	**2,427,011**	**5,046,495**	
Adjustments to Previous Years' Verified Results Total		**0**	**13,266**	**9,352**		**0**	**48,705,294**	**56,845,688**	
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**421,530**	**312,671**	**458,033**		**947,218,646**	**667,452,690**	**815,576,149**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above does not consider persistence of savings

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 14: Adjustments to Province-Wide Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0			0	0		
Appliance Exchange	Appliances	0	0			0	0		
HVAC Incentives	Equipment	-8,762	1,036			-16,245,279	1,854,833		
Conservation Instant Coupon Booklet	Items	15	0			255,975	0		
Bi-Annual Retailer Event	Items	117	0			2,373,616	0		
Retailer Co-op	Items	0	0			0	0		
Residential Demand Response	Devices	0	0			0	0		
Residential Demand Response (IHD)	Devices	0	0			0	0		
Residential New Construction	Homes	0	0			328,256	0		
Consumer Program Total		**-8,630**	**1,036**			**-13,287,430**	**1,854,833**		
Business Program									
Retrofit	Projects	4,504	6,218			22,046,931	40,101,273		
Direct Install Lighting	Projects	541	217			1,346,618	781,858		
Building Commissioning	Buildings	0	0			0	0		
New Construction	Buildings	3,243	0			11,323,593	0		
Energy Audit	Audits	492	337			2,391,744	1,636,457		
Small Commercial Demand Response	Devices	0	0			0	0		
Small Commercial Demand Response (IHD)	Devices	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Business Program Total		**8,780**	**6,771**			**37,108,886**	**42,519,588**		
Industrial Program									
Process & System Upgrades	Projects	0	0			0	0		
Monitoring & Targeting	Projects	0	0			0	0		
Energy Manager	Projects	0	75			0	799,151		
Retrofit	Projects	0	0			0	0		
Demand Response 3	Facilities	0	0			0	0		
Industrial Program Total		**0**	**75**			**0**	**799,151**		
Home Assistance Program									
Home Assistance Program	Homes	0	0			0	0		
Home Assistance Program Total		**0**	**0**			**0**	**0**		
Aboriginal Program									
Home Assistance Program	Homes	0	0			0	0		
Direct Install Lighting	Projects	0	0			0	0		
Aboriginal Program Total		**0**	**0**			**0**	**0**		
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	266	0			1,049,108	0		
High Performance New Construction	Projects	12,872	0			23,905,663	0		
Toronto Comprehensive	Projects	0	0			0	0		
Multifamily Energy Efficiency Rebates	Projects	0	0			0	0		
LDC Custom Programs	Projects	0	0			0	0		
Pre-2011 Programs completed in 2011 Total		**13,137**	**0**			**24,954,771**	**0**		
Other									
Program Enabled Savings	Projects	624	824			1,673,712	9,927,473		
Time-of-Use Savings	Homes	0	0			0	0		
Other Total		**624**	**824**			**1,673,712**	**9,927,473**		
Adjustments to 2011 Verified Results		**13,911**				**50,449,939**			
Adjustments to 2012 Verified Results			**8,707**				**55,101,043**		
Adjustments to Previous Years' Verified Results Total		**13,911**	**8,707**			**50,449,939**	**55,101,043**		

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

The IHD line item on the 2013 annual report has been left blank pending a results update from evaluations; results will be updated once sufficient information is made available.

Gross results are presented for informational purposes only and are not considered official 2013 Final Verified Results

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

INTERROGATORY 96:

Reference(s): Exhibit 9, Tab 2, Schedule 5, page 6

THESL notes that demand savings from the Demand Response ("DR") programs have been excluded from its LRAMVA request. THESL further notes that it believes that the peak demand savings from the DR program are not necessarily coincident with the customer's individual peak demand for the demand reduction occurrence:

a) Please further discuss the rationale for not including demand savings from the DR program with reference to any OPA advice or documentation which supports this position;
b) Please provide the lost revenue amount related to the demand savings from the DR programs.

RESPONSE:

a) Toronto Hydro excluded demand savings from the Demand Response programs in its LRAMVA claim as there is not enough supporting evidence to confirm that the savings from demand response programs were coincident with the customer's individual monthly peak demand charge. When examining the impact of a demand response event, Toronto Hydro noted that while a customer's peak demand would be reduced on an event day, this may simply shift their individual monthly peak demand to a similar day in the same month when an event was not called. In some cases, this would result in no decrease in monthly peak demand, while in other cases the monthly peak demand reduction would be negligible. As a result, Toronto Hydro felt that claiming any LRAMVA for these programs was not supportable.

RESPONSES TO ONTARIO ENERGY BOARD STAFF INTERROGATORIES

b) If Toronto Hydro was to include savings from Demand Response programs, the total 2011-2013 Lost Revenue amount related to the demand response savings would be $211,713.