Ontario Energy Board (Board Staff) INTERROGATORY #38

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **ExhibitC1/Tab2/Schedule 1**

a) Please provide a table that presents OM&A per customer, OM&A per km of line and OM&A per regular employee and OM&A per total employees, from 2010 to 2019.
b) In addition, please provide a table that presents OM&A as a percentage of total costs (i.e., OM&A plus Capital) from 2010 to 2019. Please use the capital costs used to derive Hydro One's TFP growth trend in Board Staff IR #60.

Response

a) See the table below.

OM&A $ per:	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Customer	445	444	441	482	455	438	469	467	455	449
KM of line	4,613	4,643	4,634	5,126	4,868	4,726	5,110	5,142	5,057	5,025
Regular Employees	102,722	102,099	101,467	111,383	107,648	106,311	116,450	118,762	118,668	120,000
Total Employees	74,891	76,680	76,436	74,418	70,692	68,666	74,396	75,024	73,926	73,511

b) See the table below.

In $M	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OM&A	550.9	554.4	553.4	610.6	581.3	564.3	610.2	614.0	603.9	600.0
Capital	712.6	736.4	705.9	726.2	738.9	822.6	847.4	880.7	903.8	930.4
Total	1,263.5	1,290.8	1,259.3	1,336.8	1,320.2	1,386.9	1,457.6	1,494.7	1,507.7	1,530.4
OM&A % of Total	43.6%	43.0%	43.9%	45.7%	44.0%	40.7%	41.9%	41.1%	40.1%	39.2%

Ontario Energy Board (Board Staff) INTERROGATORY #39

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 2/p. 34

Line Clearing and Brush Control appear to be the primary components of the increase in Vegetation Management expenses over the 2015 – 2019 time frame. In particular there is a spike in spending forecast in 2016.

What are the reasons that this significant increase in spending is planned to take place in 2016 rather 2015, (the first year of Hydro One's plan)?

Response

The significant increase is scheduled for 2016 to allow adequate time to plan and resource a program that is above the current spending levels and resource capacity.

Ontario Energy Board (Board Staff) INTERROGATORY #40

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 2 & Technical Conference #2 TR pp. 110-112

In the Second Technical Conference, while responding to questions on the Vegetation Management cycle, Hydro One indicated that it was not able to provide a definitive reason for the backlog in vegetation management.

a) Please provide the reasons for the backlog in vegetation management leading up to the test year.

b) In its EB-2009-0096 distribution rate proceeding, Hydro One proposed a 7 year cycle for the two test years, 2010 and 2011. Did Hydro One not accomplish the proposed 7 year cycle at that time? If not, why not? Please provide Hydro One's reasoning for choosing an 8 year cycle as optimal for vegetation management on its system. What is the cycle currently in place?

c) Please provide the most recent vegetation management study conducted by Hydro One and summarize the findings used to inform the decision to move to the intended 8 year cycle.

d) Is Hydro One able to provide comparisons of vegetation management accomplishments in $/km of cleared line with other distributors? Which distributor is showing the best practice and for what reasons? Which of those practices have been/are being adopted by Hydro One?

e) Aside from use of more feller bunchers, what other productivity improvements/cost efficiency measures is Hydro One planning in vegetation management?

f) Please provide the OM&A cost per km for vegetation management each year from 2010 to the 2019 forecast year, broken down by the 'line clearing' and 'brush control' categories. Please explain any trends that emerge.

Response

a) As documented in the benchmarking study in Proceeding EB-2009-0096 Exhibit A, Tab 15, Schedule 2 Attachment 1, Hydro One's average cycle length was 10 years.

Over the last 5 years, Hydro One has been strategically striving to reach a more optimum vegetation management cycle by tackling the rights-of-way beyond an 8 year cycle. However the level of funding has not been sufficient to address the increase in workload and unit costs associated with these backlogged rights-of-way.

b) With the Board's Decision with Reasons in Proceeding EB-2009-0096 to reduce overall OM&A spending envelope by $40 million in each of the test years, Hydro One made a business decision to discontinue plans for a 7 year clearing cycle. Although the vegetation management spending was increased, this increase was not sufficient to keep pace with the increase in workload required to meet the cycle targets.

However, under the direction from the benchmarking study (EB-2009-0096 Exhibit A, Tab 15, Schedule 2 Attachment 1) and the Board's Decision with Reasons in Proceeding EB-2009-0096 it is clear that continuing to reduce the vegetation management cycle was an important objective.

Hydro One's current clearing cycle is averaging 9.5 years. Hydro One has chosen an 8-year target as it is a reasonable goal that can be resourced; as well as it will provide benefits to life-cycle cost and improve reliability. This cycle period is also mindful of the impacts to customer bills as it will limit the rate impact when compared to moving towards an even shorter cycle.

c) The benchmarking study in Proceeding EB-2009-0096 Exhibit A, Tab 15, Schedule 2, Attachment 1 is Hydro One's most recent comprehensive review and benchmarking of the vegetation management program. In Section 1.0 Executive Summary of this study, the authors state "*Hydro One has the longest average reported cycle length in the study at 10 years as most participants operate on a 3 to 5 year cycle. The length of the cycle is on the fringe of acceptable UVM practice and leads to inefficiencies as a result of excessive vegetation growth between successive maintenance*".

Hydro One selected an 8-year cycle because it represented a shift in a positive direction to reduce the vegetation management cycle in a manner that would demonstrate value in reduced lifecycle costs, was operationally feasible from a resourcing perspective, and limited the rate impact over the short term compared to shorter cycle scenarios.

d) The benchmarking study in Proceeding EB-2009-0096 Exhibit A, Tab 15, Schedule 2, Attachment 1, Section 4.1 provides a detailed overview of Hydro One's relative position to comparable utilities in both labour hours and dollars per unit for line clearing and brush control.

Hydro One's vegetation management program already contains the elements of a best practice vegetation management program in the area of operations with the utilization of a diverse operational toolbox that includes manual, motor-manual, mechanical and chemical right-of-way treatments that are selected and used to ensure work is executed cost effectively.

However, Hydro One is integrating best practices from other utilities in the areas of: cycle length, program administration and overall program costs. Most comparable utilities manage their vegetation on a 3-5 year cycle and use external resources for work execution. In addition some utilities use a hazard tree program to reduce tree fall in outages. With those lessons in mind Hydro One has adopted the following best practices:

- Continue to increase vegetation management funding to reduce cycle length and realize the benefits of a better managed right-of-way as outlined in Exhibit C1, Tab 2, Schedule 2 page 36.
- Implement a staffing strategy for peak workloads by leveraging the work execution strategy as outlined in Exhibit A, Tab 17, Schedule 6 page 4
- Pilot a mid-cycle hazard tree program as outlined in Exhibit C1, Tab 2, Schedule 2 page 42.

e) Please refer to Exhibit A, Tab 17, Schedule 6, Section 3.0 (specifically: Increased Work Bundling, Work Program Releases, Work Prioritization, Staffing Strategy, and Improved Methods) for information on Hydro One's planned improvements in productivity and cost efficiency measures that would be applicable to Vegetation Management.

f) Please refer to Slide 9 of Exhibit PD1 from the executive presentation on May 12, 2014 for the unit cost data for the vegetation management program.

Line Clearing Trends –The unit cost increases through 2014 reflect the increased tree densities and work complexities resulting from clearing overgrown rights-of-way that are beyond an 8 year clearing cycle. As Hydro One reduces this backlog, the right-of-way conditions at the next time of clearing will be less complicated and require less time to complete. The unit cost reduction seen from 2015 to 2019 is reflective of the benefits of completing a large portion of the annual program on an 8 year cycle.

Brush Control Trends – The unit cost increases through 2013 reflect the increase due to: an increase in work density, an increase in qualified labour required to clear brush away from the limits of approach, and an increase in herbicide use to control heavier brush densities. The unit cost reduction seen from 2013 to 2019 is reflective of the benefits of addressing the backlogged vegetation conditions and leveraging the productivity and cost improvements.

Ontario Energy Board (Board Staff) INTERROGATORY #41

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 2 & Technical Conference #2 TR p. 115

In the Second Technical Conference, Hydro One indicated that increased Station Maintenance would not result in a reduction of trouble calls or demand work due to the demographic profile of the systems.

a) Please provide the evidence on which this statement is based and also provide an estimate of when the demographic profile of the system will change at current spending levels.
b) Can Hydro One provide an estimate of the spending level that would provide reduced costs on trouble calls and demand work within the 2015 to 2019 time frame?

Response

a) Primarily the capital replacement programs will result in a reduction of demand work, not the OM&A station maintenance programs. The maintenance programs ensure the continued operation of the distribution system which plays an important role in maintaining the level of reliability.

b) Hydro One's proposed station capital investments is forecast to maintain the level of substation caused interruptions over the 2015 to 2019 period, as outlined in Exhibit A, Tab 4, Schedule 4. If this level of spending was maintained or increased beyond the test years, then reductions in demand work could potentially be achieved.

Ontario Energy Board (Board Staff) INTERROGATORY #42

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: ExhibitC1/Tab2/Schedule 2/p. 16

On page 16 of this exhibit, under Service Disconnects and Reconnects, Hydro One has indicated that requests have been increasing over the past several years and that the proposed spending for the test years is based on a forecast of 13,300 disconnect and reconnect requests per year.

a) Why is the number of service disconnects and reconnects increasing?

b) What does the forecast of 13,300 per year represent? Please provide the number of service disconnects and reconnects from 2010 and forecast from 2015 to 2019.

c) Is the increase a concern for Hydro One?

Response

a) Disconnects and reconnects are driven by requests from customers to temporarily isolate their services. As these requests are driven by external demand, Hydro One Distribution cannot accurately attribute any specific causes as to why demand has increased in recent years. However some increases may be attributed to the increased emphasis on public safety when dealing with electrical equipment.

b) The forecast of 13,300 per year represents the number of customer requests forecast to be received by Hydro One Distribution for disconnection and reconnection of service. One unit represents both the disconnection of the customer's service and the corresponding reconnection of their service.

	Historic Years				**Bridge Year**	**Test Years**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Volume of Disconnects/ Reconnects	13,391	13,525	13,398	14,309	13,300	13,300	13,300	13,300	13,300	13,300

c) No, as responding to these customer requests is in everyone's best interest as anyone working without isolation may cause harm to themselves or members of the public.

Ontario Energy Board (Board Staff) INTERROGATORY #43

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 2/p. 16

On page 16 of this exhibit, under Customer Inquiries, Hydro One indicates that the proposed spending forecast is based on the historic volume of approximately 8,000 inquiries per year.

What does the forecast of 8,000 per year represent? Please provide the number of customer enquiries from 2010 and the forecast from 2015 to 2019. With investments and spending in the customer service area, is Hydro One expecting a decrease in customer enquiries over the course of this plan? If not, why not?

Response

The forecast of 8,000 per year represents the number of customer inquiries forecast to be received by Hydro One Distribution. A description of the type of inquiries covered can be found in Exhibit C1, Tab 2, Schedule 2, page 26. Below is a table of the historic and forecasted number of inquiries.

Year	# of Inquiries
2010	7913
2011	7033
2012	7347
2013	7202
2014	8000
2015	8000
2016	8000
2017	8000
2018	8000
2019	8000

The bulk of the inquiries in this program are related to customers seeking information on the location of Hydro One's distribution assets. The forecasted units reflect an increasing trend in customer inquiries for routing oversized vehicles through Hydro One's service territory. Spending on customer service should not have a material effect on the demand activities addressed by the Customer Inquiries program.

Ontario Energy Board (Board Staff) INTERROGATORY #44

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit C1/Tab 2/Schedule 2/p. 19 & Technical Conference #2 TR pp. 117 – 118**

In the evidence, Hydro One indicates that Line patrols are performed on one sixth of rural feeders each year and one third of urban feeders each year. In the technical conference, Hydro One indicated that it is following the Distribution System Code in terms of line patrol frequency and indicated that this was not an optimal frequency for Hydro One.

a) Please indicate the optimal line patrol frequency for the Hydro One Distribution system, the rationale for this position and quantify the efficiency gains/cost savings possible if this frequency were adopted.

b) What proportion of Hydro One's feeders is patrolled as a by-product of dispatch and other work? What is the incremental cost of meeting DSC requirements relative to the schedule of truck rolls, etc, that would otherwise take place?

c) Has Hydro One considered requesting an exemption from this requirement in the DSC?

Response

a) Hydro One continues to perform line patrols at the frequency outlined in the Distribution System Code. At this time, Hydro One has not completed any detailed analysis on the optimal line patrol frequency. However, potential benefits to a less frequent patrol may include:

- The collection of additional inspection details (i.e. more accurate measures of the remaining strength of poles and the condition of poles below the ground line); which would enable Hydro One Distribution to make more informed capital replacement investments.
- The maintenance treatments to increase the life span of in-service wood poles could also be considered; as a less frequent inspection cycles would permit more time per pole to administer more advanced treatment methods.

b) Hydro One has a dedicated Line Patrol program, as outlined in Exhibit C1, Tab 2, Schedule 2, pages 21-22, to satisfy the Minimum Inspection Requirements required by the Distribution System Code. Hydro One does not consider asset inspections that are incidental to other work to fulfill the requirements of a line patrol as not all assets in the vicinity are inspected during such work.

c) To date Hydro One has not considered requesting an exemption from the DSC minimum inspection requirements.

Ontario Energy Board (Board Staff) INTERROGATORY #45

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 2/p. 27

Hydro One indicates that it will replace 18,000 meters each year. What were historical levels? Please provide the number of meters replaced from 2010 to 2014 and the forecast from 2015 to 2019. What is the relationship between the smart meters replaced in the past few years and current/future replacements?

Response

Please see below table for the number of meters replaced within the Sustaining work program from 2010 to 2013 and the forecast number of replacements planned for 2014 through 2019.

	Actual				Forecast					
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Meter Replacements	29,349	23,256	17,751	12,850	21,228	18,000	18,000	18,000	18,000	18,000

Hydro One's Smart Meter system was setup as a dedicated project in line with the Government of Ontario's Smart Meter Initiative. The transition of the Smart Meter system from project to sustainment phase will be completed in 2014; as such any smart meter replacements in the past few years were captured under the Smart Meter project.

Future smart meter replacements have been included in the 2015 to 2019 forecasts, and as outlined in the table above, the replacements are estimated to stabilize at 18,000 units per year as the new technology matures

Ontario Energy Board (Board Staff) INTERROGATORY #46

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: ExhibitC1/Tab2/Schedule 4/p. 7

The Table on page 7 indicates a steady increase in costs over the course of the plan for Operations. There does not appear to be an indication of cost efficiency improvements (i.e., reduced or moderated costs). Do Smart Grid investments not work to increase cost efficiencies? If not, why? If so, when will such cost efficiencies be evident/achieved?

Response

The new Smart Grid business capabilities enable the control centre to proactively monitor and control the distribution system. In the past the control centre reacted to customer calls about power outages and dispatched field crews to investigate. As new remotely controllable devices get installed in the field and with the Distribution Management System in the control centre, the controllers will have the ability to monitor increasing parts of the distribution system in real time and proactively restore power. While this increases the amount of work in the control centre, it provides benefits in the form of improved reliability for customers and decreased risk associated with distributed generation.

Smart Grid investments also establish new control systems and information technology systems. As additional systems are commissioned, additional sustainment costs are required. The Distribution Management System is a third control system at the Ontario Grid Control Centre (along with the Outage Response Management System and the Network Management System) that creates a step-change increase in sustainment costs.
As Smart Grid investments are deployed in the field over the course of the DSP, there will be sustainment costs associated with this growing set of assets. Since many smart grid assets have communications and computer based components, there will be a higher than normal requirement for sustainment in the form of firmware upgrades and security patches as well as communications/computer refreshes. The Smart Grid assets to be deployed require communications to be established and sustained. The cost of providing communications to these assets will grow along with the number of assets being deployed.

For additional information, please see response to Exhibit I, Tab 3.2, Schedule 1 Staff 52 part c), bullet v.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #22

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit C1, Tab 2, Schedule 5, Page 11 of 19**

a) How has the $1.2 million designated for LEAP been calculated? Please confirm that this represents 0.12% of HONI's Service Revenue Requirement, as required by the OEB's LEAP directives.
b) Given that HONI's service revenue requirement is forecast to rise over the 2015 to 2019 period, does HONI intend to proportionally increase its annual LEAP contribution over this same period? If not, why not?

Response

a) The $1.2 million was calculated based on the prescribed OEB formula of 0.12% of HONI's Service Revenue Requirement.

b) Yes, HONI intends to proportionally increase its annual contribution over the 2015-2019 period as directed by the OEB.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #23

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 5, Page 11 of 19

Besides LEAP, please provide some other examples of past and/or expected future projects that would be included under the Regulatory Compliance category of spending.

Response

Some past examples of projects, other than LEAP Funding, were the implementation of regulatory requirements such as OEB Code Changes, Ontario Green Energy Benefit, Seasonal Commodity and Threshold changes, Harmonized Sales Tax, Rate Changes and Riders.

Some examples of expected future projects included in this category, other than LEAP Funding, are Seasonal Commodity and Threshold changes and Conditions of Service Updates.

Any major projects of a Regulatory Compliance nature in the planning period would be funded through Information Technology Corporate Common costs as stated in Exhibit C1, Tab 2, Schedule 10, page 12, lines 12-13: “Also, starting in 2013, Customer Care work related to Regulatory Compliance and Service Enhancement moved from Customer Service Operations to IT.”

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #24

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit F1-1-3, Attachment 1, Page 4 of 6, Lines 1-5**

Please quantify the reductions to manual meter reading costs as a result of smart meter installations over the 2011 through 2013 period.

Response

Smart meter technology allowed Hydro One to begin wirelessly collecting interval meter readings in 2009 thereby reducing the volume of customers that require a manual meter read. As a result, Hydro One's manual meter reading costs have declined approximately 60% from 2008 to 2013.

Although fewer customers require a manual meter read, the remaining customers are in rural and sparsely populated areas of Hydro One's service territory. As a result, the unit cost per manual read has increased over the same time period due to the geographical dispersion.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #25

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit C1, Tab 2, Schedule 5, Page 15 of 20**

Does the OPA provide funding for any pilot projects or other similar activities under the budgets it provides to distributors?

Response

No, the OPA does not provide funding for pilot projects under the Program Administration Budget (PAB) that it provides to distributors. OPA budgets to distributors are for the delivery of Province-Wide Programs.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #26

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 5, Page 15 of 20

Please identify the regulatory authority under which HONI is requesting this specific CDM funding, and how it aligns with the guidance provided by the OEB in the CDM Code and CDM Guidelines.

Response

Hydro One is asking the Board for this specific CDM funding based on the Decision in EB-2009-0096 where OM&A funding was approved to continue support of CDM research and development and maintain a base level of capability. More recently in 2011, in the Toronto Hydro (THESL) Decision and Order in EB-2011-0011 (page 8), where THESL requested recovery of their development costs, the Board ruled that these costs and that "preparing and defending" Board-Approved CDM Program applications should be recovered through distribution rates and not through the Global Adjustment.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #27

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 5, Page 15 of 20

HONI states the part of this budget is used to "….support programs in the market". Would funding for in-market OPA programs not be the sole responsibility of the OPA?

Response

This quote may have been taken out of context. The full sentence (page 16, line 7) reads: "Hydro One is seeking funding to support programs in the market to continue research and development…" This funding focuses on the research and development component. The funding also supports capability for new program development, for industry collaboration such as participation in the CLD (Coalition of Large Distributors) and for testing of new technologies.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #28

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 2, Page 12 of 42

HONI states that it "applied for an extension, requesting that the 2014 deadline be extended to 2025". It further states that "On April 23, 2014 the regulations were amended and passed through legislation, allowing the extension of oil filled equipment with PCB contamination levels above 500 ppm to be eliminated by 2025."

a) Was the requested extension filed as specific to HONI's circumstances, or was it filed in the context of a general review of regulations?
b) Please confirm that the legislation mentioned above applies to all utilities.
c) Please provide a copy of the extension application filed by HONL
d) Please provide a copy of any note/memo outlining the amended legislation, or otherwise provide a reference to the specific legislation being referenced.

Response

a) The CEA (Canadian Electricity Association) on behalf of its member utilities requested an amendment to the "PCB Regulations" to extend the end-of-use date to December 31, 2025 for all current transformers, potential transformers, circuit breakers, reclosers and bushings that are located at an electrical generation, transmission or distribution facility and contain PCBs in a concentration of 500 mg/kg or more if that equipment was in use on September 5, 2008. This amendment was requested on behalf of all Canadian member utilities by the CEA and was strongly supported by Hydro One.

b) Yes, the regulatory amendment ("Regulations Amending the PCB Regulations and Repealing the Federal Mobile PCB Treatment and Destruction Regulations") applies to all Canadian utilities.

c) As stated in part (a), the CEA requested the amendment. Please see Appendix A to this response for the correspondence between the CEA and Environment Canada.

d) Please see below for the reference to the specific legislation.

PCB Regulations and Repealing the Federal Mobile PCB Treatment and Destruction Regulations – Regulations Amending Canadian Environmental Protection Act, 1999. SOR/2014-75, 04/04/14

Appendix A

Canadian Electricity Association | Association canadienne de l'électricité

August 15, 2013

Tim Gardiner
Director, Waste Reduction and Management Division
Department of the Environment
Gatineau, Quebec
K1A 0H3
via email: PCBProgram@ec.gc.ca

Re: Publication of the Regulations Amending the PCB Regulations and Repealing the Federal Mobile PCB Treatment and Destruction Regulations on June 22, 2013 in Canada Gazette Part I

Dear Mr. Gardiner:

On behalf of its members, The Canadian Electricity Association (CEA) is very pleased to provide the following comments on the *Regulations Amending the PCB Regulations and Repealing the Federal Mobile PCB Treatment and Destruction Regulations* (the Amendment) published in Canada Gazette Part I on June 22, 2013.

CEA members are committed to providing safe, reliable and affordable power to Canadians while striving to maintain or enhance environmental integrity. As such, CEA is very supportive of the Amendment which permits the use of "current transformers, potential transformers, circuit breakers, reclosers and bushings that are located at an electrical generation, transmission or distribution facility" until 2025. Only ~1% of the 50,000 pieces of untested equipment across the country (approximately 500 total pieces) are thought to have PCB contamination above 500 mg/kg; furthermore, all of this equipment is located in secure facilities with extremely low potential for environmental contamination. Therefore, CEA strongly believes that allowing the use of this equipment until 2025 poses no additional risk to human health or the environment and it allows a reasonable amount of time for utilities to test, identify and safely remove the 1% of equipment without compromising system reliability.

The CEA strongly supports the existing wording of the Amendment. We will be providing additional informal comments requesting clarification and additional information with respect to some areas of the Amendment. The key areas of interest are: facts and figures in the Regulatory Impact Assessment Statement (RIAS), specifics regarding the exempted equipment, clarification on reporting requirements and transition from operating under the extension permits to operating under the Amendment.

Once again, I'd like to take this opportunity to reiterate CEA's support and thank those at Environment Canada whose work enabled the successful publication of the draft Amendment. CEA eagerly anticipates finalization of the Amendment, and looks forward to continued engagement during this process. Should you have any questions or concerns, please do not hesitate to contact me at any time for any PCB related matters.

Sincerely,

M. Turner

Michelle Turner
Director, Generation and Environment

cc: Cheryl Heathwood, Manager, Waste Programs

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<u>Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #29</u>

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

<u>Interrogatory</u>

Reference: **Exhibit C1, Tab 2, Schedule 2**

How much of the PCB Equipment and Waste Management Budget between 2015 and 2019 is specifically related to work required as a result of new environmental regulations?

<u>Response</u>

Approximately 70% of the PCB Equipment and Waste Management proposed spending over the test years 2015 to 2019 is specifically related to the PCB Regulations.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #30

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 2, Page 20 of 42

Please identify the primary reason for the nearly ~50% decrease in the Line Patrol Budget (from $10.3M in 2 013 to between $5-$6M over 2014-2019).

Response

Hydro One will be initiating drive-by patrols over the course of the test years for line sections that are readily accessible along road allowances. These patrols meet the Distribution System Code minimum patrol requirements by identifying and collecting the most critical defects on the distribution system.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #31

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 2, Page 21 of 42

Is HONI able to estimate to what extent "minor defective components" contribute to decreased reliability? (e.g. of all outages caused by defective equipment, what rough percentage would be categorized as caused by "minor defective components")

Response

Hydro One does not currently track the contribution of “minor defective components” within the outage tracking.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #32

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit C1, Tab 2, Schedule 2, Page 34 of 42**

HONI identifies vegetation (tree contact?) as "the largest contributor to system outages". Please identify the percentage of outages caused by vegetation over 2011 through 2013.

Response

Total Number of Vegetation-Caused Interruptions

Year	All Interruptions			Force Majeure Events		
	Total	Tree Contribution	Tree %	Total	Tree Contribution	Tree %
2011	40,927	14,047	34%	12,654	7,934	63%
2012	35,013	9,797	28%	5,447	2,844	52%
2013	44,834	17,279	39%	17,860	11,488	64%

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #33

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit C1, Tab 2, Schedule 2, Page 34 of 42**

In HONI's analysis is, to what extent was vegetation a contributing factor in the ice storm related outages experienced in December 2013?

Response

Tree contacts contributed to 66% of the interruptions during the December 2013 ice storm. An additional 6% of the outages were related to equipment failures triggered by vegetation.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #34

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 3, Page 11/13 of 13

HONI identifies a number of industry partners with which it is cooperating on various Smart Grid initiatives, but does not include any distribution utilities on this list. However, HONI goes on to note that EV challenges are similar to those faced by other distributors. To what extent is HONI coordinating its efforts with other such distribution utilities to jointly address any potential challenges related to EV expansion?

Response

Hydro One collaborates with utilities both inside and outside of Ontario on its Smart Grid Initiatives, including electric vehicle integration. Please see the response to I-3.02-01-Staff-52.

Hydro One has undertaken various collaborative projects in partnership with Canadian utilities and major US utility companies through the Electric Power Research Institute (EPRI).

Hydro One has also collaborated with similar partners on electric vehicle studies at the Centre for Energy Advancement through Technological Innovation (CEATI) research platform which Toronto Hydro also participates in.

Hydro One's collaboration with Pollution Probe, a national non-profit organization on an Electric Mobility Adoption and Prediction project to assess various aspects of potential electric vehicle deployment in the Toronto Hydro service area has been unique in scope with direct participation by Toronto Hydro and in partnership with the Ontario Power Authority, the Ontario Ministry of Energy, Ontario Ministry of Transportation, academia and private industry.

Power Workers Union (PWU) INTERROGATORY #3

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: (a) Exh D1, Tab 2, Schedule 1, Pages 25-30. Distribution Asset Investment Overview, 2.2.2 Right of Ways.
(b) Exh D1, Tab 2, Schedule 1, Page 29. Table 7 – Total SAIDI and Vegetation Contribution

Table 7 - Total SAIDI and Vegetation Contribution

	All Interruptions (hours)			*Force Majeure Events (hours)*		
Year	**Total**	**Tree Contribution**	**Tree %**	**Total**	**Tree Contribution**	**Tree %**
2010	9.4	3.8	40%	1.9	1.4	74%
2011	22.1	11.9	54%	14.7	10.0	68%
2012	11.3	4.3	38%	3.8	2.1	55%
Total	**42.8**	**20.0**	**47%**	**20.4**	**13.5**	**66%**

a) Please provide kilometres of ROW cleared for each of the last five years.

b) Please add 2013 to Table 7 provided in Ref (b).

c) What is Hydro One's estimate of the percentage of Rights-of-Way (ROW) beyond the eight-year planning target by 2020 assuming the current rate of clearing of ROW is maintained?

Response

a) Please refer to Exhibit PD1, Slide 9 from the executive presentation on May 12, 2014 for the kilometers ROW cleared for the years 2010 to 2013. The kilometers ROW cleared in 2009 were 10,837 km for line clearing and 10,393 km for brush control.

b) Please see below for the revision of Exhibit D1, Tab 2, Schedule 1, Table 7 to include the 2013 data.

Total SAIDI and Vegetation Contribution

Year	All Interruptions (hrs)			Force Majeure Events (hrs)		
	Total	Tree Contribution	Tree %	Total	Tree Contribution	Tree %
2010	9.4	3.8	40%	1.9	1.4	74%
2011	22.1	11.9	54%	14.7	10.0	68%
2012	11.3	4.3	38%	3.8	2.1	55%
2013	27.3	14.6	53%	20.0	12.7	64%
Total	**70.1**	**34.6**	**49%**	**40.4**	**26.2**	**65%**

c) If the 2015 rate of clearing (i.e 10,200 km) was maintained through to 2020, then approximately 23% of the ROW inventory will be beyond the 8-year clearing cycle target.

Power Workers Union (PWU) INTERROGATORY #4

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: (a) Exhibit C1, Tab 2, Schedule 7, Page 2. 2.1 Scope of Work

> **2.1 Scope of Work**
>
> **The scope of work under the Current Agreement is comprised of services ("Base Services") and project services performed over a finite period to produce a project deliverable, solution or result ("Project Services"). Base Services are divided into the following six areas (individually, a "statement of work" or a "SOW"), each of which relates to a line of business within Networks: (1) information technology services; (2) customer service operations; (3) settlements; (4) source-to-pay; (5) payroll; and (6) finance and accounting services. Appendix A contains the descriptions of Base Services contracted for each SOW.**

a) Please provide descriptions of Project Services under the Current Agreement referred to in the above statement.

b) Please provide descriptions of the services to be contracted under the new agreement.

Response

a) The Project Services are defined as "Services to be performed by Supplier in accordance with any Project Order including as described in a Project Definition Response."

b) Please see Hydro One's response to Exhibit I, Tab 4.2, Schedule 10 CCC 24.

Power Workers Union (PWU) INTERROGATORY #5

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **(a) Exh C1, Tab 2, Schedule 7, Page 12, Lines 12-22. 3.2 Phase 2 – Supplier Selection & Contract Negotiations**

> **In early December 2013, the project team held individual discovery sessions to provide the pre-qualified suppliers with an opportunity to seek clarification regarding the RFP. Responses to the RFP were originally anticipated by February 18, 2014. RFP responses were deferred to April 10, 2014, pending the clarification of certain matters related to the Power Workers' Union settlement. RFP responses will be evaluated, as will the option of Networks performing any or all of the services itself. After the written responses are reviewed, pre-qualified proponents will be short-listed to give oral presentations later in April 2014. Following these presentations, the pre-qualified supplier submissions and oral presentations will be evaluated.**

a) Please provide the clarifications that Hydro One has provided to pre-qualified suppliers in respect of matters related to the Power Workers' Union Settlement.

Response

a) As a result of further discussions held with the arbitrator, no clarifications were provided.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #52

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: C1/T2/S1/pg. 3

a) Table 1 shows that Hydro One has not reduced actual OM&A costs to reflect the last two Board Approved amounts. Please explain what efforts were made to reduce costs subsequent to the Decisions. Specifically, please provide any internal memos, strategies, business plans or other documents stemming from the Board's decisions and which dealt with the issue of the need to reduce costs.

Response

Upon receiving the Board's Decision and Order, Hydro One's senior management did direct a budget update which included the results of the OM&A reductions outlined in the Decision. The Board Memo which contains the details of the revised budget can be found in Attachment 1 of this interrogatory response.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #53

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: C1/T2/S1/Table 1

a) If Table 1 does not show 2013 actuals please update the table for this data.
b) Please add a column showing 2014 actuals to date.
c) Please provide a table which shows for each OM&A for each category for the same period to date in 2012 (the purpose of which is to understand the percentage of 2014 capital budget to date spent as compared to an equivalent period in 2012.

Response

a) Table 1 in Exhibit C1, Tab 2, Schedule 1 filed on May 31, 2014 as part of the evidence update includes 2013 actuals.

b) The latest quarterly results, 2014 Q1 year-to-date results are included in table below.

Description	**Historical Years**						**March YTD**	**Bridge Year**	**Test Years**				
	2010	**2010 Approved**	**2011**	**2011 Approved**	**2012**	**2013**	**2014**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Sustaining	305.9	315.2	317.1	337.5	307.9	335.7	67.1	320.4	329.5	374.4	380.1	363.2	358.1
Development	12.3	11.7	15.8	12.0	14.7	11.1	6.1	18.4	15.4	17.7	17.0	17.4	17.8
Operations	18.5	20.2	18.1	20.9	21.0	22.0	0.5	30.4	30.2	34.4	34.8	42.2	41.0
Customer Services	114.7	117.2	113.3	113.4	116.7	148.6	44.5	133.7	117.9	116.3	114.7	113.5	115.4
Common Corporate Costs and Other OM&A	94.9	50.9*	85.5	46.5*	88.6	88.8	43.3	73.8	66.7	62.5	62.4	62.4	62.3
Property Taxes & Rights Payments	4.6	4.7	4.6	4.8	4.5	4.4	1.2	4.6	4.7	4.9	5.0	5.2	5.4
TOTAL	**550.9**	**520.0**	**554.4**	**535.0**	**553.4**	**610.6**	**162.7**	**581.3**	**564.3**	**610.2**	**614.0**	**603.9**	**600.0**

c) 2012 Q1 year-to-date results are provided in table below.

Description	**March YTD**
	2012
Sustaining	59.7
Development	5.2
Operations	1.0
Customer Services	23.6
Common Corporate Costs and Other OM&A	33.7
Property Taxes & Rights Payments	1.1
TOTAL	**124.3**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #54

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: C1/T2/S2/ - Sustaining OM&A

a) For each of the OM&A categories in Tables 2 through 10 please compare (and provide) the three year average spending from 2010 through 2012 to the average for 2015 through 2019. In a third column please calculate the percentage difference between the two averages*. Where the difference is 10% or more please provide the following:
   i. The cost-benefit analysis that was performed for the increase in that category of spending.
   ii. The target or metric that is being used to compare the pre and post annual spending outcome/metric results;
   iii. If no cost-benefit analysis was performed and no metrics developed to assess the effectiveness of the increase spending please explain why
   iv. In the alternative, if the program is being done to pursue an external regulatory requirement (e.g. Environment Canada-PCB/Measurement Canada Meters etc.) please show the analysis by which Hydro One concluded it would be unable to meet these requirements without the increase in spending.

*(For example Table 10 Category "Line Clearing" 2010-12 annual average = $82.9m vs 2015-2019 average =$108.04m = 30% increase)

Response

For the OM&A categories in Tables 2 through 10, the three year average spending in 2010 to 2012 is compared to the average 2015 to 2019 proposed spending in the table below. For the comparison, all costs were converted to 2014 constant dollars to account for inflation. A constant inflation rate of 1.7% per year is assumed.

Table	Line Item	2010-2012 Average*	2015-2019 Average*	% Increase (Decrease)
2 - Stations Sustaining OM&A	Stations Demand & Corrective Maintenance	9.0	9.6	5.9%
2 - Stations Sustaining OM&A	Planned Station Maintenance	13.1	11.8	(9.9%)
2 - Stations Sustaining OM&A	Land Assessment & Remediation	5.6	5.6	(0.9%)
3 - Planned Station Maintenance	Power Equipment Maintenance	11.5	9.4	(18.5%)
3 - Planned Station Maintenance	Grounds & Site Maintenance	1.4	1.9	**35.6%**
3 - Planned Station Maintenance	PCB Testing and Retrofilling	0.1	0.5	**237.6%**
4 - Lines Sustaining OM&A	Demand Work	97.5	90.0	(7.7%)
4 - Lines Sustaining OM&A	Line Maintenance	25.0	23.2	(7.1%)
4 - Lines Sustaining OM&A	PCB Equipment & Waste Management	4.9	16.5	**237.6%**
4 - Lines Sustaining OM&A	Other Services	10.3	14.0	**35.8%**
5 - Demand Work	Trouble Calls	69.9	64.1	(8.3%)
5 - Demand Work	Underground Cable Locates	18.0	16.2	(9.7%)
5 - Demand Work	Disconnects/Reconncets	9.6	9.6	0.3%
6 - Line Maintenance	Preventative and Corrective Maintenance	12.9	16.5	**27.4%**
6 - Line Maintenance	Line Patrols	11.1	5.7	(49.0%)
6 - Line Maintenance	Sentinel Lights	0.9	1.0	**12.7%**

Table	Line Item	2010-2012 Average*	2015-2019 Average*	% Increase (Decrease)
7 - PCB Equipment & Waste Management	PCB Lines Equipment Inspection & Testing	0.4	11.2	**3043.2%**
7 - PCB Equipment & Waste Management	Waste Management	4.5	5.2	**15.7%**
8 - Other Services	Customer Inquiries	6.0	5.5	(7.7%)
8 - Other Services	Investigations and Data Collection	1.2	2.0	**65.4%**
8 - Other Services	Miscellaneous Services	3.1	2.5	(20.2%)
8 - Other Services	Transmission Idle Line Rental	-	4.0	**Greater than 10%**
9 - Metering Sustaining OM&A	Retail Revenue Meters	18.6	12.0	(35.5%)
9 - Metering Sustaining OM&A	Wholesale Revenue Meters	1.7	2.4	**38.5%**
9 - Metering Sustaining OM&A	Telecom, Monitoring and Control	2.5	3.5	**40.4%**
10 - Vegetation Management OM&A	Landowner Notification	7.7	8.6	**11.3%**
10 - Vegetation Management OM&A	Line Clearing	87.2	102.7	**17.9%**
10 - Vegetation Management OM&A	Brush Control	35.3	36.6	3.6%
10 - Vegetation Management OM&A	Demand Vegetation Management	7.9	6.6	(15.8%)
10 - Vegetation Management OM&A	Hazard Tree Removal	0.1	0.3	**313.7%**

*Average provided in constant 2014 dollars; assumes an annual inflation rate of 1.7%

Details on the line items that had a difference of greater than 10% are provided below.

Table 3 – Planned Station & Site Maintenance

- Grounds & Site Maintenance (increased from $1.4 million to $1.9 million)
  - The increase is driven by copper thefts that require fence repair and replacement of copper. No cost benefit analysis was conducted because this is a demand investment category. Funding is allocated based on anticipated need. As a demand investment, there are no outcome measures associated with this investment.
- PCB Testing & Retro-Filling (increased from $0.1 million to $0.5 million)
  - The increase in funding for PCB testing and retrofill of Distribution station equipment is required in order to complete sampling of all oil filled equipment with unknown PCB content, and to bring the content within acceptable levels, in accordance with 2025 deadlines specified by Environment Canada.

Table 4 – Line Sustaining OM&A

- PCB Equipment & Waste Management – explained in detail under Table 7 response below
- Other Services – explained in detail under Table 8 response below

Table 6 – Line Maintenance

As noted in the above table for line item *"4 - Lines Sustaining OM&A – Line Maintenance"* the total Line Maintenance program is decreasing from $25.0 million to $23.2 million, even though there are two categories that are increasing as described below.

- Preventative and Corrective Maintenance (increased from $12.9 million to $16.5 million)
  - This program is required to increase to address the growing number of defects identified through the patrol program. The Distribution System Code requires that defects identified as part of the patrol are to be addressed within a reasonable time period. Defects are logged and accomplishments are tracked for this program to measure progress.
  - There is also a need to perform regular maintenance to ensure the continued operability of the line equipment (i.e. regulators, reclosers, multi-phase switches). An increasing population of electronically controlled equipment will require a corresponding increase in preventive maintenance to perform battery replacements during the test years.

- Sentinel Lights (increased from $0.9 million to $1.0 million)
  - No cost benefit analysis was conducted because this is a demand investment category. Funding is allocated based on anticipated need. As a demand investment, there are no outcome measures associated with this investment.

Table 7 - PCB Equipment & Waste Management

- PCB Lines Equipment Inspection & Testing (increased from $0.4 million to $11.2 million)
  - Program spending ramping up beginning 2014 to meet the mandated Federal Environment PCB Elimination Legislation to eliminate all oil filled equipment with PCB concentration greater than 50ppm by 2025. Inspecting and Testing of Overhead equipment is not a program Hydro One would undertake unless mandated by Federal PCB Regulations.
- Waste Management
  - Result of the increased PCB waste generated by the mandated Federal Environment PCB Elimination Legislation. PCB contaminated transformers removed from service under PCB Transformer Capital Replacement program will impact the Waste Management Program.

Table 8 – Other Services

- Investigations and Data Collection (increased from $1.2 million to $2.0 million)
  - No cost benefit analysis was conducted because this is a demand investment category. Funding is allocated based on anticipated need. As a demand investment, there are no outcome measures associated with this investment.
- Transmission Idle Line Rental (increased from $0 to $4 million)
  - Consistent with Hydro One Transmission's Idle Line Rental Policy, Hydro One Distribution has begun paying annual rental fees for the transmission lines it occupies to distribute power. The corporate operational policy was not published until 2013 therefore; rental payment did not start until 2013.

Table 9 – Metering Sustaining OM&A

- Wholesale Revenue Meters (increased from $1.7 million to $2.4 million)
  - Wholesale revenue meters funds the services of a wholesale "Meter Service Provider" as required by the IESO market rules. The funding increase is a result of the gradual increase in the number of wholesale revenue meters on Hydro One's distribution system due to new transformer stations being built, new wholesale meter points as a result of LDC acquisitions which Hydro One Distribution has assumed

accountability to maintain, and also Hydro One's legacy meter installations that are triggered for upgrade by Measurement Canada seal expiry.

- Telecom, Monitoring and Control (increased from $2.5 million to $3.5 million)
  - Telecom, monitoring and control provide telecommunication circuits in support of retail Advanced Metering Infrastructure (Smart Meter) and Wholesale level metering as required by the Ontario Energy Board and IESO market rules.

Table 10 – Vegetation Management OM&A

- Landowner Notification (increased from $7.7 million to $8.6 million)
- Line Clearing (increased from $87.2 million to $102.7 million)
- Hazard Tree Removal (increased from $0.1 million to $0.3 million)

Hydro One's decision to move to a shorter vegetation management cycle was informed by the benchmarking report filed as Proceeding EB-2009-0096 Exhibit A, Tab 15, Schedule 2 Attachment 1 and the factors considered in Exhibit I, Tab 3.1, Schedule 1 Staff 40. The benchmarking report concluded that "if Hydro One is successful in reducing its cycle length in a controlled manner and can sustain accomplishment levels associated with lower cycles, then the company's UVM efficiency will be improved along with system reliability". Under the proposed plan, Hydro One is increasing the number of kilometers cleared annually in order to achieve a shorter cycle and the associated benefits of a reduced unit cost once a sustainable 8 year cycle is achieved. The outcome measures for the vegetation management program can be found in Exhibit A, Tab 4, Schedule 4, Section 3.0.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #55

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: C1/T2/S3/pg. 10

a) Please provide the reason(s) for the significant increase in smart grid studies beginning in 2014 as compared to the previous 4 years.
b) Please provide a list of the studies being done in 2014; their expected cost and their expected completion date.
c) Please provide the list of studies and abstracts for the studies undertaken or planned for 2014, 2015 and 2016.

Response

a) The increase in Smart Grid Studies in 2014 is due primarily to Hydro One's upfront contribution to an energy storage demonstration project. This demonstration project is in partnership with other organizations. Through this partnership approach, Hydro One is able to leverage this investment and only makes a partial contribution to the overall project cost while gaining the full learnings from the energy storage project. Another energy storage demonstration project is planned for 2016 requiring further expenditure.

   Hydro One has an additional initiative in the 2014 to 2019 period. This includes participating in the Ontario Government's Smart Grid Fund initiative. Hydro One will collaborate with other members on Ontario based projects to identify, test, develop and bring to market the next generation of smart grid solutions to support the modernization of the grid.

b) and c)
   Please see below for the list of studies being conducted in the 2014 to 2016 period along with the expected cost and benefits. See also Exhibit I, Tab 3.02, Schedule 10 CCC 20.

SMART GRID STUDIES	SCOPE & VALUE	2014	2015	2016
RD&D Program External Service Providers	This program covers contracted research and development technical services, provided by external providers. The services provided include a wide variety of technology and application related to Hydro One's distribution grid including protection and control, distributed generation integration, power quality, and performance validation and testing. Benefits to customers include increased reliability. In addition, these studies aid Hydro One in ensuring the safe and secure distribution of electricity while integrating distributed generation.	$1.4M	$1.4M	$1.6M
Micro Grid Studies	Covers assessment, development and demonstration of technologies and integration of micro grids in collaboration with universities, industry partners and government agencies. Benefits to Hydro One are the ability to increase the utilization factor of assets through demand response and peak shaving.	$0.3M	$0.3M	$0.4M
Clean Energy Initiatives	Supports multi-year programs offered by non-profit organizations such as Pollution Probe (PP) and the Toronto Atmospheric Fund (TAF), Toronto Region Conservation Authority (TRCA) in collaboration with local distribution companies (LDCs), industry and government agencies. This collaboration enables Hydro One to leverage the investments of partners to explore and deploy new technologies to support renewable energy, energy conservation, and electric vehicle integration.	$0.1M	$0.1M	$0.1M
Energy Storage Systems	Covers identification, technology assessment, development, field demonstration of energy storage systems with potential integration to the grid. Benefits include the efficient integration of distributed generation connections and improved reliability.	$3.1M	$0.3M	$2.4M
Hydro One Applied Research Consortium (HARC)	Hydro One Applied Research Consortium (HARC) is an inter-institution initiative to harness the practical “hands-on” focus of College Applied Research and engages Ontario's four (4) community colleges (Georgian, Algonquin, Northern and Mohawk) to investigate the adoption and impacts of Electric Vehicles on distribution system. Benefits for Hydro One will be to develop practical solutions / tools for timely mitigating impacts and supporting effective asset lifecycle management and investment planning at Hydro One with substantial benefits on customer service and system reliability.	$0.2M	$0.2M	$0.2M
Smart Grid Initiatives by MOE	The Smart Grid Fund was initiated by the Ministry of Energy in July 2013 to support various advanced energy technology projects integrating smart grid solutions with Ontario’s electrical grid. Hydro One is partnering with other organizations to leverage this fund to validate new smart grid technologies.	$1.0M	$0.5M	$0.5M
TOTAL		**$6.1M**	**$2.9M**	**$5.2M**

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #56

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: C1/T2/S4/pgs. 5, 8-9/ Table 1

a) For each of the years 2014 through 2019 please provide a list of smart grid projects that are contemplated in Table 1. Please identify separately the amounts solely for the Distribution Management System (page 5) and provide the number of FTEs required to operate the three applications listed.
b) Please explain what "new system" are being contemplated as being commissioned over the test period

Response

a) b)
The list of projects that the Smart Grid Operations OM&A will support can be found in Exhibit D1, Tab 3, Schedule 5, Table 2, pages 5-7. These are the "new systems" that will be commissioned over the test period.

The amount required for the maintenance of the Distribution Management System is consistent with that previously filed in EB-2012-0136 and EB-2013-0141 and is shown in the table below.

	2014	2015	2016	2017	2018	2019
Distribution Management System Sustainment	5.8	5.0	7.0	7.0	7.0	7.0

The three specific applications listed are power system applications of the Distribution Management System. These applications would require one to two application specialists who can configure the applications, resolve issues that arise and support the control room staff.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #57

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: C1/T2/S5/pg. 9-11

a) Table 2 does not show a significant decline in meter reading costs. Please explain how this is consistent with the objective of reducing estimated bills. That is, do the strategies to reduce estimated bills include connecting more customers to the smart meter network and reducing the number of manual reads?

Response

a) The referenced meter reading costs include the costs to operate the smart meter network and the costs to manually read meters that are not part of the network. Hydro One is attempting to reduce the number of estimated bills through ongoing monitoring, maintenance and tuning of the smart meter network. For meters not under the smart meter network Hydro One is looking to optimize meter read routes and educate customers about the need to provide access to allow for collecting of manual reads.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #58

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **C1/T4/S1/pg. 14-15 Fleet Management**

a) Please explain the increase in Operations and Repairs as compared to the historical average.
b) Please provide the same with respect to Depreciation

Response

a) The increase in Operations and Repairs as compared to the historical average is due to additional costs in maintaining Hydro One's core fleet and the additional equipment acquisitions required to fulfill increasing Corporate work program requirements.

b) The increase in Depreciation as compared to the historical average is due to additional equipment acquisitions required to fulfill Corporate increasing work program requirements.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #59

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **C1**

For each year in the period 2010 through 2019 please provide the amounts separately for:

i. EDA Membership Fees
ii. MEARIE Insurance Premiums;
iii. Other Corporate memberships over $25,000 per annum

Response

Please see the table below for a breakdown of membership fees for the 2010 to 2019 period.

($000s)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
EDA	155	160	168	174	179	185	191	198	205	212
Edison Electric	38	39	39	40	43	45	46	48	50	51
Canadian Women's Foundation	100	100	100	100	-	-	-	-	-	-
North American Transmission	-	69	99	115	126	130	135	139	144	149
Canadian Electricity Association	457	251	356	388	400	400	400	400	400	400
OEA Membership	10	50	50	75	75	-	-	-	-	-

Hydro One does not pay MEARIE insurance premiums.

School Energy Coalition (SEC) INTERROGATORY #12

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference:

Please provide a table showing the OM&A Cost Drivers as set out in section 2.7.2 of the *Filing Requirements For Electricity Distribution Rate Applications.*

Response

Please refer to Exhibit C1, Tab 2, Schedule 1, Table 1, for Summary of Recoverable OM&A Expenses (Appendix 2-JA).

Please refer to Exhibit C1, Tab 2, Schedule 1, Table 1, for OM&A Cost Drivers (Appendix 2-JB); and Exhibit C1, Tab 2, Schedule 2 to 12 for details.

Please refer to response to Exhibit I, Tab 3.1, Schedule 1 Staff 38, for Recoverable OM&A Cost per Customer and per Full Time Equivalent (Appendix 2-L).

School Energy Coalition (SEC) INTERROGATORY #13

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1

Please detail how the Applicant has prepared its OM&A budgets for the five-year period. Please explain how confident the Applicant is of the accuracy of its proposed OM&A budgets, for each category, in the later years of the test period.

Response

As detailed in Exhibit A, Tab 4, Schedule 1, the OM&A budgets for the five-year period are developed through Hydro One's rigorous business planning process. Hydro One Distribution is confident in the accuracy of the proposed OM&A budgets.

<u>School Energy Coalition (SEC) INTERROGATORY #14</u>

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 2/p.18

Please provide further details about the significant increase in Preventive and Corrective Maintenance for the test period as compared to 2012-2014.

Response

The proposed funding for the 2015-2019 test years is based on the forecast of work required to meet the preventive and corrective maintenance needs of the distribution system during that time.

Distribution system patrols identify defects requiring corrective activity on an ongoing basis. The proposed level of corrective maintenance is required to address all the projected number of defects that will be discovered during the test years. Funding for this program from 2012 to 2014 was at a level that was sufficient to only address urgent issues.

Additionally, an increasing population of electronically controlled equipment will require a corresponding increase in preventive maintenance to perform battery replacements during the test years.

School Energy Coalition (SEC) INTERROGATORY #15

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 2/p.21

The Applicant states: "Hydro One Distribution initially focused on the inspection and testing of pad-mounted transformers. Testing of these transformers was completed in 2010. Beginning in 2014, pole mounted line equipment will be inspected and tested." Does this mean that no PCB inspections and testing was done between 2011-2013? If so, please explain why not. If this is not the case, please explain what PCB inspections and testing did occur in that time period.

Response

Hydro One Distribution did not have an active PCB inspection and testing program of pole-top transformers between 2011 and 2013; therefore no planned PCB inspections and testing were completed in this period. After the conclusion of the pad-mounted transformer inspection and testing program in 2010, Hydro One focused on capturing pole-top transformer nameplate data and building an overhead asset registry. These activities were necessary to facilitate the pole-top transformer PCB inspection and testing program in order to target only transformers manufactured prior to 1985; thereby minimizing the total number of inspections and testing required. The PCB inspections and testing of pole-top transformers began in 2014.

School Energy Coalition (SEC) INTERROGATORY #16

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 2/p.21

Based on the level of proposed PCB inspections and testing expenditures for the test period, does the Applicant expect that a similar amount (adjusted for inflation) will be required between 2020-2025 to comply with the 2025 PCB contamination regulations deadline?

Response

Yes, similar expenditures in the 2020 to 2025 period will be required to be compliant with Federal PCB Regulations.

School Energy Coalition (SEC) INTERROGATORY #17

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 2/p.32

With respect to the Line Clearing expenditures:

a) Please explain the significant variation in proposed expenditures between 2015-2019.
b) The Applicant states: "By 2019 program costs will be better align with historical sending and reflect the reliability and life-cycle cost benefits of maintain the system on the 8-year cycle targets." Please explain how 2019 costs of $99.9m better align with historical spending based on the actual expenditures between 2010-2013.

Response

a) Please see response to Exhibit I, Tab 3.1, Schedule 1 Staff 40 part (f).

b) The 2019 program costs of $99.9 million will address an additional 2,372 kilometers over the 2013 program level of line clearing, therefore the unit costs per kilometer for 2019 of $7,829/km does better align with the 2012 to 2013 historical spending levels which had unit pricing of $7,777/km and $7,994/km respectively.

School Energy Coalition (SEC) INTERROGATORY #18

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 4/p.7/Table 1

Please explain the increase from 2013 to 2014 in the operations category.

Response

The difference in the Operations category from 2013 to the bridge year is primarily due to attrition and delay in backfilling of positions in 2013. The 2014 plan represents full staffing compliment.

School Energy Coalition (SEC) INTERROGATORY #19

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 4/p.4

Please provide details about Smart Grid OM&A expenditures for the test period. Please explain the significant increases in proposed expenditures in 2018-2019.

Response

Please see Exhibit I, Tab 3.01, Schedule 1 Staff- 46 for details on the OM&A components.

As Distribution Operations evolves to take advantage of the smart grid assets being installed on the distribution system, additional Controllers will be required in the control room. This will require a re-organization of the control room as well as additional Controllers. This is planned for 2018 once a significant number of smart grid assets have been installed on the distribution system. In addition, the second release of the Smart Grid Pilot Project will deliver new systems that will need to start being sustained starting in 2018. As smart grid assets are installed on the distribution system, additional sustainment will be required to support the new telecommunications infrastructure required.

School Energy Coalition (SEC) INTERROGATORY #20

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 7

Please provide a copy of the agreement between the Applicant and Inergi.

Response

A copy of the redacted agreement will be filed as Attachment 1 in paper form, similar to what Hydro One filed in past proceedings.

School Energy Coalition (SEC) INTERROGATORY #21

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 7/p.4

Please provide a copy of the benchmarking review report of Inergi's fees.

Response

A paper copy of the benchmarking report will be filed in redacted form.

School Energy Coalition (SEC) INTERROGATORY #22

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 7/p.12

Please provide a copy of the RFP issued in November 2013 to pre-qualified suppliers.

Response

Hydro One respectfully declines to file a copy of the RFP. Hydro One is presently in the middle of its evaluation and selection process. Material information about the RFP and the RFP process is set out in Exhibit C1, Tab 2, Schedule 7. The RFP, itself, does not provide any information about the costs Hydro One expects to pay under the final contract, but it does contain internal sensitive, information about Hydro One. The RFP was only distributed to proponents who were screened in advance through a pre-qualification process and signed confidentiality agreements. Should the RFP become part of the public domain, those proponents would no longer be obligated to keep the information contained therein confidential.

School Energy Coalition (SEC) INTERROGATORY #23

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 7/p.12

Please provide a status update of the pre-tendering process.

Response

The oral presentations were completed in May 2014. The status remains largely the same as stated in Exhibit C1, Tab 2, Schedule 7.

School Energy Coalition (SEC) INTERROGATORY #24

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 7/Appendix C

What type of cost impact does the Applicant believe will occur because of the requirements of the Minister's shareholder directive dated October 17th 2013, in which under any new procurement for work currently being done by Inergi LP, the work must be performed in Ontario by persons employed and residing in Ontario.

Response

Based on market intelligence gathered through the RFP process for the renewal of the work being performed currently by Inergi LP and our overall understanding of the market, we had estimated that savings of up to 20% to 30% might be achievable for certain functions which utilized a global delivery model leveraging offshore delivery locations. We believe that such stretch savings might be as high as $30 million annually but these savings could only be verified through a formal procurement process, which was not undertaken. We also understand that any annual savings would be reduced by any transition costs, knowledge transfer costs, training costs, costs associated with the complexity of dealing with the utilization of offshore resources, or other costs to establish the services being performed in another location. In addition, the offshore component would require some level of onshore support and depending on the solution might be not realize all of the potential labour savings estimated. The extent of the savings realized would depend on the economies of scale, scope and labour arbitrage that a vendor might be able to realize in delivering those services.

For onshore or near shoring of services of back office functions in Canada, which might be provided through a combination of services located in Ontario and other provinces, the stretch savings might be up to 10% to 20%. Savings in this range might translate in cost reductions of up to $15 million annually but again could only be verified in an RFP process, which was not undertaken. The potential savings obtained would be reduced by the costs to transition from Ontario to new sites outside of Ontario, relocation costs for some of the existing Inergi staff, the costs to transfer knowledge to a new work force, training costs and other costs. The scope of services which might be onshored would be additionally limited by the vendor's ability to leverage scope, economies of scale, and labour arbitrage elsewhere in Canada while maintaining the necessary staff presence in Ontario. Consistent with using offshore resources, these high level estimates are speculative and could only be verified by a formal procurement process, which was not undertaken.

Consumers Council of Canada (CCC) INTERROGATORY #18

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 1/Schedule 1/p.2

In 2010 HON spent $10 million less than the Board approved level in the category of Sustaining OM&A. In 2011 HON spent $20.4 million less than the Board approved level. In 2012, 2013 and 2014, HON's actual Sustaining OM&A was also significantly below the level embedded in rates. For each year, 2010-2014, please explain why actual Sustaining OM&A expenditures varied significantly from the Board approved/forecast level?

Response

Please see the note below Table 1 Summary of Distribution OM&A Budget in Exhibit C1, Tab 2, Schedule 1.

In its Decision in EB-2009-0096, the Board ordered an envelope reduction of $40 million of OM&A expenditure in each of 2010 and 2011. This reduction was not allocated among the different categories and shown as part of Other OM&A in Table 1. The Board approved amount in this table for Sustaining in 2010 and 2011 reflect the proposed amount in Hydro One's original application, instead of the Board approved amounts. Therefore, Hydro One did not underspend compared to the Board approved levels for Sustaining OM&A in 2010 and 2011.

Consumers Council of Canada (CCC) INTERROGATORY #19

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1/Tab 2/Schedule 2/p.33

With respect to Vegetation Management HON refers to a backlog wave. This backlog is the reason for significant increases in 2016 and 2017. Please explain why HON has a backlog, and has not, in recent years, ensured an appropriate pace for line clearing and brush control.

Response

Please see the response to Exhibit I, Tab 3.1, Schedule 1 Staff 40 parts (a) and (b).

Consumers Council of Canada (CCC) INTERROGATORY #20

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **Ex. C1/T2/S3/p. 3**

HON is planning spending over $21 million on Smart Grid Studies (Development OM&A) during the five-year term of the Custom Plan. Please provide a detailed breakdown of these expenditures. Has HON conducted a business case analysis for these studies? If not, why not? Please explain how these expenditures will bring value to HON's customers? What are the associated capital expenditures expected during the Custom Plan?

Response

A detailed breakdown of funding for each study planned is identified below for the 2015-2019 period along with the anticipated value for Hydro One customers.

Hydro One does not perform business case analyses for the studies. The objective of these studies is to understand new technologies and their potential for application on the Hydro One distribution system. Once a technology has been proven through study, then a business case analysis would prepared prior to deployment across the distribution system.

Funding for Smart Grid Studies in the 2015-19 time period is purely OM&A. No capital expenditures are required to conduct these studies.

SMART GRID STUDY	SCOPE & VALUE	2015	2016	2017	2018	2019
RD&D Program External Service Providers	This program covers contracted research and development technical services, provided by external providers. The services provided include a wide variety of technology and application related to Hydro One's distribution grid including protection and control, distributed generation integration, power quality, and performance validation and testing. Benefits to customers include increased reliability. In addition, these studies aid Hydro One in ensuring the safe and secure distribution of electricity while integrating distributed generation.	$1.4M	$1.6M	$1.8M	$1.8M	$1.8M

SMART GRID STUDY	**SCOPE & VALUE**	**2015**	**2016**	**2017**	**2018**	**2019**
Micro Grid Studies	Covers assessment, development and demonstration of technologies and integration of micro grids in collaboration with universities, industry partners and government agencies. Benefits to Hydro One are the ability to increase the utilization factor of assets through demand response and peak shaving.	$0.3M	$0.4M	$0.5M	$0.5M	$0.6M
Clean Energy Initiatives	Supports multi-year programs offered by non-profit organizations such as Pollution Probe (PP) and the Toronto Atmospheric Fund (TAF), Toronto Region Conservation Authority (TRCA) in collaboration with local distribution companies (LDCs), industry and government agencies. This collaboration enables Hydro One to leverage the investments of partners to explore and deploy new technologies to support renewable energy, energy conservation, and electric vehicle integration.	$0.1M	$0.1M	$0.1M	$0.1M	$0.1M
Energy Storage Systems	Covers identification, technology assessment, development, field demonstration of energy storage systems with potential integration to the grid. Benefits include the efficient integration of distributed generation connections and improved reliability.	$0.3M	$2.4M	$1.2M	$1.2M	$1.2M
Hydro One Applied Research Consortium (HARC)	Hydro One Applied Research Consortium (HARC) is an inter-institution initiative to harness the practical “hands-on” focus of College Applied Research and engages Ontario's four (4) community colleges (Georgian, Algonquin, Northern and Mohawk) to investigate the adoption and impacts of Electric Vehicles on distribution system. Benefits for Hydro One will be to develop practical solutions / tools for timely mitigating impacts and supporting effective asset lifecycle management and investment planning at Hydro One with substantial benefits on customer service and system reliability.	$0.2M	$0.2M	$0.2M	$0.2M	$0.2M
Smart Grid Initiatives by MOE	The Smart Grid Fund was initiated by the Ministry of Energy in July 2013 to support various advanced energy technology projects integrating smart grid solutions with Ontario’s electrical grid. Hydro One is partnering with other organizations to leverage this fund to validate new smart grid technologies.	$0.5M	$0.5M	$0.5M	$0.5M	$0.5M
TOTAL		**$2.9M**	**$5.2M**	**$4.3M**	**$4.3M**	**$4.4M**

Consumers Council of Canada (CCC) INTERROGATORY #21

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **Ex. C1/T2/S4**

With respect to Operations OM&A HON is planning on increasing Smart Grid expenditures over the test period. For each year 2014-2019 please provide a detailed breakdown of those expenditures. Please provide any associated business case analyses. What are the associated capital expenditures during those years for "Operations"?

Response

Please see below for a detailed breakdown of those expenditures.

	2014	2015	2016	2017	2018	2019
Distribution Operations	0.0	0.0	1.5	1.5	6.2	4.5
Systems Sustainment	5.8	4.7	6.5	7.0	8.6	8.7
Telecommunications Sustainment	0.3	0.6	1.1	1.1	2.0	2.0
Smart Grid Operations OM&A	**6.1**	**5.3**	**9.1**	**9.6**	**16.8**	**15.1**

The business case was filed as part of EB-2013-0141 Exhibit C, Schedule 1, Tab 1, Attachment 1.

The capital expenditures associated with this Operations OM&A are included in the Development Capital Exhibit (Exhibit D1, Tab 3, Schedule 3) and the Customer Service Capital Exhibit (Exhibit D1, Tab 3, Schedule 5). The breakout of the smart grid capital expenditures was also highlighted during the Stakeholder Sessions presented in December 2013 and filed as part of this evidence in Exhibit A, Tab 20, Schedule 1, Appendix E, Slide 40.

Consumers Council of Canada (CCC) INTERROGATORY #22

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: Ex. C/T2/S5/p. 18

HON has additional Smart Grid Pilot expenditures in the category of Customer Service OM&A. Please provide a detailed breakdown of those expenditures. How do these differ from the Smart Grid Studies referred to as Development OM&A?

Response

The projects that the Customer Service OM&A will support are listed in the Customer Services Development Capital evidence Exhibit D1, Schedule 3, Tab 5. The breakdown of the OM&A by project is found below:

Project	Forecasted Expenditures ($M) 2015 OM&A	2016 OM&A	2017 OM&A
Consumer Research	0.2	0.2	0.2
Demand Response	1.0	0.3	
Validation of Smart Grid Technologies and Processes	0.5	0.5	0.5
Infrastructure Support	2.5	2.0	
Mobile Systems		0.5	1.0
Demand Response for Operations		0.5	0.5
Other	1.5	0.9	0.6
PROJECT OM&A TOTALS	**5.7**	**4.9**	**2.8**

The Smart Grid Studies OM&A referred to in the Development OM&A is for initiatives Hydro One undertakes with universities and research institutions in collaboration with other utilities inside and outside Ontario to determine feasibility of technology for utility application. Once deemed feasible, then Hydro One would undertake a project to implement the technology under Smart Grid Capital or OM&A.

Energy Probe Research Foundation (EP) INTERROGATORY #24

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 1 - OM&A Envelope % Changes

a) Confirm the Exhibit shows the following changes for each category. (If not amend table)

	Historic 5 years	Forecast 5 years	Total 10 years
Sustaining	4.7%	11.7%	17.1%
Development	5.0%	-3.2%	44%
Operations	11.9%	34.8%	121.6%
Common	-	-15%	-
TOTAL	5.5%	3.2%	8.9%

b) Please explain what happened to Sustaining in 2016.

c) Please explain changes in common costs, including if the changes in Common Costs were driven by definitional or other changes to presentation.

d) Please provide more information on the drivers and needs for the increase in Operations OM&A envelope.

Response

a) Hydro One Distribution's OM&A expenditures vary year to year over the 10 year period from 2010 to 2019 as demonstrated in Exhibit C1, Tab 2, Schedule 1. Therefore the table below provides an average OM&A change for each category over the time periods outlined above.

Description	5 Year Average OM&A Change over Historic (2010-13) and Bridge (2014) Years	5 Year Average OM&A Change over Test Years (2015-2019)	10 Year Average OM&A Change over the 2010-2019 period
Sustaining	1.3%	2.3%	1.9%
Development	15.7%	3.9%	6.9%
Operations	14.2%	8.4%	10.0%
Customer Services	4.8%	-0.5%	0.6%

Description	5 Year Average OM&A Change over Historic (2010-13) and Bridge (2014) Years	5 Year Average OM&A Change over Test Years (2015-2019)	10 Year Average OM&A Change over the 2010-2019 period
Common Corporate Costs and Other OM&A	-5.7%	-1.7%	-4.4%
Property Taxes & Rights Payments	0.0%	3.5%	1.8%
TOTAL	1.5%	1.6%	1.1%

b) There are two significant drivers to the change in Sustaining OM&A in 2016. The first is the vegetation management backlog reduction strategy outlined in Section 6 of Exhibit C1, Tab 2, Schedule 2. The second is the ramp up of the PCB Lines Equipment Inspection and Testing program outlined in Section 4.3 of Exhibit C1, Tab 2, Schedule 2.

c) For changes in common costs, please refer to Page 2 and 3 of Exhibit C1, Tab 2, Schedule 6.

d) For the drivers and need for the increase in the Operations OM&A envelope, please refer to Page 8 and 9 of Exhibit C1, Tab 2, Schedule 4.

Energy Probe Research Foundation (EP) INTERROGATORY #25

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit C1, Tab 2, Schedule 1, Table 1 and Exhibit C1, Tab 2, Schedule 2, Page 32 ff &Table 10 Sustainment Vegetation Management**

Preamble:
Hydro One proposes over 2016-2017 to move to 8 year optimum VM cycle.

a) Confirm this has been the ideal (industry best practice) and Hydro One target cycle for 10 years.

b) Section 6.2.2 Investment Plan shows 12,750km-14,250 km. Why move to 8 year cycle over 2 years instead of longer transition?

c) What will be the mitigation if the transition occurs over 5 years? Please provide a schedule that shows costs and Revenue Requirement impacts

Response

a) Please see the response to Exhibit I, Tab 3.1, Schedule 1 Staff 40.

b) The primary driver of the 2 year increase is to address the escalating unit costs resulting from the increased workload to clear the worst backlogged maintenance rights-of way. As outlined in Exhibit I, Tab 2.01, Schedule 11 EP 10; by achieving a sustainable 8 year cycle Hydro One is able to start realizing unit cost reductions in the mid to long term.

c) If the backlog of maintenance planned over the 2 years was addressed over the 2016 to 2019 period, at an accomplishment rate of 13,500 km annually, the vegetation management program costs would increase and continue to escalate beyond the test years. This would also result in a corresponding increase in the revenue requirement.

As outlined in the table below, this scenario would cost $850 million for 64,200 units from the 2015 to 2019 period compared to the $814 million for 64,200 units in the proposed plan for the 2015 to 2019 period.

Year	Unit Target (km)	Program Cost ($M)
2015	10,200	142
2016	13,500	173
2017	13,500	176
2018	13,500	178
2019	13,500	181

Energy Probe Research Foundation (EP) INTERROGATORY #26

Issue 3.1 Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit C1, Tab 2, Schedule 4 - Operations OM&A

Preamble:
The increase in Operations expenditures from 2010 to 2011 is attributed to an organizational realignment. Customer Operation Support (COS), formerly part of the Large Customer and Generator Relations group, was moved under Operations.

a) Confirm where the offsetting OM&A cost reduction is. (See Exhibit C1Tab 2Schedule 5 Page 2 Table 1: Customer Services Costs line 1 customer operations)

b) Provide drivers for major Increase 2016-2019 related to Smart Grid (Roll Out).

c) Confirm historic SG Pilot CAPEX was kept in deferral account now being cleared to Rate Base.

d) Confirm Smart Grid Pilot is continuing 2015-2017 OM&A C1 T2 S5 Table 6. [CAPEX D1 Tab3 S5]

e) Please provide the supporting Project Level write up/evidence.

Response

a) The offsetting OM&A cost reduction can be found in Customer Service OM&A Exhibit C1-2-5, Page 5, Table 2 under Customer Business Relations. The realignment resulted in a decrease to Customer Business Relations costs allocated to Distribution of $130,000 (the majority of the Customer Operations Support costs were allocated to Transmission). The remainder of the 2011 increase in Operations OM&A relates primarily to new operators hired into the OGCC at the beginning of that year.

b) Please see the responses to 3.1 Staff 46 and 3.1 SEC 19.

c) Hydro One is seeking to include the Smart Grid capital expenditures to date in rate base. Please see Exhibit F1, Tab 1, Schedule 3, Attachment 4.

d) Hydro One is continuing its Smart Grid Pilot through 2017.

e) The project level write up for the projects is included in the Customer Service Development Capital evidence Exhibit D1, Tab 3, Schedule 5, Table 1, pages 4-6.

Energy Probe Research Foundation (EP) INTERROGATORY #27

Issue 3.1 **Are the levels of planned operation, maintenance and administration expenditures for 2015-2019 appropriate, and is the rationale for the planning choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit C1, Tab 2, Schedule 5, Table 4- CDM**

Please provide breakdown of Historic and Forecast CDM costs NOT covered in the Global Adjustment.

Response

The table below shows the breakdown of Historic and Forecast CDM costs NOT covered in the Global Adjustment.

CDM Costs										
Strategy & Conservation	**Historic**				**Bridge**	**Test**				
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Labour	**0.8**	**0.8**	**0.7**	**1.1**	**2.1**	**2.1**	**1.7**	**1.7**	**1.8**	**1.8**
Research, Development and Pilots	**0.9**	**1.2**	**0.9**	**0.7**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**
Total	**1.7**	**2.0**	**1.6**	**1.8**	**3.1**	**3.1**	**2.7**	**2.7**	**2.8**	**2.8**

Ontario Energy Board (Board Staff) INTERROGATORY #47

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **1. Exhibit A/Tab7/Schedule 1/Appendix A (OPA Letter of Comment)**
2. Exhibit A/Tab17/Schedule 8 (Regional Planning Process)
3. Exhibit A/Tab4/Schedule 3 (Adjustments Outside the Normal Course of Business)

Preamble:
The cited references show the extent of Regional Planning and OPA involvement in Hydro One's plan. Reference 3 in particular, indicates that:

> "Hydro One Transmission and the OPA expect it will take four to five years to complete all the Regional Plans that could impact Hydro One's distribution business. If any of the Regional Plans created the need for a project in the 2015 – 2019 period that was outside the plan and met the materiality threshold, an adjustment to revenue requirement would be sought to fund the project."

Reference (2) shows that regional planning for Group 1 regions is underway. In the May 30, 2014 update, Hydro One indicates that:

> "On January 22, 2014, Hydro One filed a Section 92 application for the Supply to Essex County Transmission Reinforcement Project with the Board. As part of this project a new transmission station, Leamington TS, is proposed to address the electricity supply capacity needs for the local area. Hydro One Distribution will be required to make a capital contribution to Hydro One Transmission for the new transmission facilities as stipulated in the Transmission System Code. Further details on this project are provided in Exhibit D2/Tab 2/Schedule3, Ref # D-12."

Questions:

a) Please confirm that the OPA's letter of comment only dealt with regional planning respecting renewable generation projects. Otherwise please clarify.

b) Please clarify whether projects arising from Regional Plans will be subject to the threshold in Chapter 2 of the Filing Requirements equal to $1M or Hydro One's alternative materiality threshold of 0.5% of revenue requirement.

c) Other than the Supply to Essex County Transmission Reinforcement Project, are there any other regional plan projects (IRRP or RIP) likely to be in the pipeline in the 2015-2019 period? If so, please describe.

d) At the time of filing, expenditures arising out of regional planning are largely unknown, where in the evidence are plans or contingencies for projects arising out of the regional planning during the DSP horizon?

e) An applicant for custom IR is expected to be able to manage its business within the rates set (RRFE, p. 19) and that variance from the plan is expected. Under what circumstances would the identification of a regional planning project trigger a rate adjustment? And on what grounds should one be triggered, given that this is a risk that custom IR applicants are largely expected to bear, and given the expectation that Hydro One's specific circumstances should generally mean it is well equipped to manage such risks?

Response

a) Yes, Hydro One confirms that OPA's letter of comment only dealt with regional planning respecting renewable generation projects.

b) Hydro One proposes to use Hydro One's alternative materiality threshold of 0.5% of revenue requirement (approximately $7.5 M) for requesting an adjustment to revenue requirement to fund new projects in the 2015 – 2019 period identified by Regional Plans. The threshold for Hydro One in Chapter 2 of the Filing Requirement of $1 million would trigger adjustment more often than necessary, thus reducing regulatory process efficiencies.

c) At this time, there are no other capital expenditures towards Regional Planning projects identified by the OPA.

d) Hydro One proposes to fund any new projects arising from regional planning as outlined in Exhibit A, Tab 4, Schedule 3 – Adjustment Outside of Normal Course of Business), Section 1.3 New Investment Resulting from Regional Plans.

e) Hydro One would propose to trigger a rate adjustment to meet unforeseen regional planning needs under the following circumstances:

- The revenue requirement associated with the project is above the $7.5 million materiality threshold; and
- The project was not identified by the OPA at the time of this application.

As described in Exhibit A, Tab 4, Schedule 3, new regional planning projects identified by the OPA are unexpected event that can be materially impactive to the operation of the Company and are outside of the Company's control.

Hydro One is bearing some risks during the term of the five year Custom Application, to the extent that the required investment identified through the regional planning process is not material enough to trigger the proposed threshold discussed above.

Ontario Energy Board (Board Staff) INTERROGATORY #48

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit A/Tab17/Schedule 8 & Technical Conference #2, TR pp. 109-110**

In the Second Technical Conference, Hydro One indicated that it did not have any updates to the status of Regional Planning efforts in the Burlington to Nanticoke area and in the Greater Ottawa zone. While the evidence update included additional planning information in the Leamington area, the other two cited areas were not updated. Please provide a regional planning update for both of the cited areas.

Response

The Greater Ottawa area has been split into two sub-areas, the Ottawa Area Subregion and the Outer Ottawa Subregion. The Ottawa Area Subregion currently has an Integrated Regional Resource Plan (IRRP) under development by the OPA. A near-term need for additional connection capacity has already been identified and is being addressed by Orleans TS (details on this project have been provided in the Investment Summary Document filed at Exhibit D2/Tab 2/Schedule 3/D-07). For the Outer Ottawa area, the study is still at the information gathering stage for Needs Screening.

For the Burlington to Nanticoke area, the Needs Screening stage of this study has been finalized. This area has been split into four sub-areas for further analysis. Hydro One Distribution will now only be involved in two of these sub-areas: Burlington-Hamilton, and Caledonia-Norfolk. This study is now moving into the stage of developing potential wires solutions between Hydro One Transmission and the relevant LDCs including Hydro One Distribution, to address the issues in these sub-areas.

Ontario Energy Board (Board Staff) INTERROGATORY #49

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: 1. OEB RRFE Report, October 18, 2012
2. Exhibit A/Tab 17/Schedule 2/ Asset Management Planning Process
3. Exhibit A/Tab 17/Schedule 3/ Investment Plan Development
4. Exhibit A/Tab 17/Schedule 4/ Investment Prioritization Process
5. Exhibit A/Tab 17/Schedule 5/ Project/Program Approval and Control
6. Exhibit A/Tab 17/Schedule 7/ Asset Risk Assessment

Preamble:
The RRFE emphasizes that planning is at the foundation of rate-setting. In addressing the methods to support proposed investments, at page 36, the RRFE highlights that "filings must enable the Board to assess whether and how a distributor has sought to control costs in relation to its proposed investments through the appropriate optimization, prioritization and pacing of investment expenditures." At page 55, the RRFE envisages that good planning may ultimately lead to reduced costs for customers: "under the renewed regulatory framework a distributor will be expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services, which in turn can lead to reduced costs for customers."

At references 2 and 3, Hydro One describes its investment prioritization process and at reference 4, it also refers to its Asset Investment Planning (AIP) tool.

Questions:

a) As an overview, please provide in terms of percentage, the share/impact of each of the following factors in Hydro One's long-term strategy both for distribution and non-distribution assets: asset condition, obsolescence, system growth, municipal initiatives, and regional planning (IRRP and RIP).

b) Will the proposed plan lead to reduced monetary costs or have other non-monetary benefits for customers? If yes, please indicate what they are.

c) Is the AIP tool the Asset Analytics? If not, please indicate what the AIP is.

d) Does the Investment Plan Proposal contain an economic evaluation component indicating what the most cost effective actions are for the various areas of planning? If so, where is this reflected in the evidence?

Response

a) The share/impact of each of the identified factors on Hydro One's 2015-2019 strategy for capital expenditures is provided in Table 1 and Table 2 below.

Table 1: Distribution Assets

Factor	Impact on 2015-2019 Strategy for Distribution Asset Capital Expenditures
Asset Condition (2)	60%
Obsolescence	3%
System Growth(1)(2)	33%
Municipal Initiatives(2)	1%
Regional Planning(3)	3%

(1) "System Growth" includes both system load growth and investments to accommodate distributed generation.
(2) "Municipal Initiatives" only considers projects driven by municipal relocation requests; requests from municipal LDCs are included in "Asset Condition" and "System Growth".
(3) Regional Planning considers investments to the Transmission system to accommodate regional Distribution needs and any associated Distribution system upgrades.

Table 2: Non-distribution Assets

Factor	Impact on 2015-2019 Strategy for Total Common Corporate Cost Capital Expenditures (TX & DX)
Asset Condition	66%
Obsolescence	13%
System Growth	21%
Municipal Initiatives	N/A
Regional Planning	N/A

b) The proposed plan will have monetary and non-monetary benefits for ratepayers.

- The average ratepayer will receive current service levels at a rate increase at or below inflation, which service levels would actually erode but for the investments set out in the proposed plan. (Some customers may see an improvement in current service levels.)
- Ratepayers will receive current service levels at a cost below what it would otherwise be without the productivity initiatives described in Exhibit A, Tab 19, Schedule 1.

- Hydro One intends to improve ratepayers' customer experience with the proposed plan. Please refer to Exhibit A, Tab 5, Schedule 1.
- Ratepayers should benefit from less upward pressure on rates caused by vegetation management expenditures as the proposed vegetation management improvements will result in long-term, sustainable cost savings.
- A smarter grid and investments targeting energy and materials theft will also reduce economic losses to the benefit of the ratepayers.
- The proposed plan reflects and responds to identified customer preferences as set out in Hydro One's response to Exhibit I, Tab 2.1, Schedule 1 Staff 4.

c) The Asset Investment Planning (AIP) tool and the Asset Analytics (AA) tool are different. The AA tool is described in Exhibit A, Tab 17, Schedule 3, p.5. The AIP tool is the C55 software package acquired from Copperleaf Technologies. It uses a Mixed Integer Linear Programming optimization engine enabling it to suggest the best blend of investments, using the information entered while honoring multiple financial constraints. Senior management uses this tool when determining the best portfolio of investments that achieves the optimal balance between cost effectiveness, customer needs, and asset and business needs. The objective of this exercise is to maximize risk mitigation and savings by identifying work that mitigates the most risk per dollar within defined constraints. For more information on how investments are valued, please refer to Exhibit A, Tab 17, Schedule 4.

d) Yes. As a consideration in the planning and execution stages of work, cost is reflected in many different parts of the evidence. Here are a few examples relating specifically to the planning stage:

- Section 2.4 of Exhibit A, Tab 17, Schedule 3 for information on Hydro One's emphasis on "best value" and how potential alternative investments are reviewed for potential productivity gains and cost synergies from work-bundling;
- Table 1 of Exhibit A, Tab 17, Schedule 4 which references productivity as a business value, which forms the basis, together with the other business values (and their associated key performance indicators), for a multi-criteria analysis used to prioritize investments;
- Section 3.3 of Exhibit A, Tab 17, Schedule 6, which addresses how cost effectiveness is a factor in prioritizing investments; and
- Section 3.5.1 of Exhibit A, Tab 17, Schedule 7, which describes how "Asset Economic Risk" factors into the Asset Risk Assessment methodology used in investment planning.

Considerations of "cost effectiveness", "productivity", and "best value" together with other factors have resulted in the investment decisions reflected in the Custom Application. Hydro One believes these decisions deliver the best value to ratepayers, while still meeting policy and regulatory requirements and the fair return standard in rate-making.

Ontario Energy Board (Board Staff) INTERROGATORY #50

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference:
1. **Exhibit A/Tab 17/Schedule 3/Investment Plan Development**
2. **Exhibit A/Tab 17/Schedule 7/ Asset Risk Assessment**
3. **Exhibit D1/Tab 2/Schedule 1/ Distribution Assets Investment Overview**

Preamble:
At reference (1), Hydro One states in part:

> "The Asset Analytic solution provides a common understanding of asset risk and comparability between assets of the same type along with standardized reports and dashboards. Asset Analytics also provides:
>
> 1. A cascading information view of asset risk/priorities based on demographics, condition, economics, utilization, performance and criticality/customer;
> 2. Geo-spatial presentation to help identify potential bundling opportunities;
> 3. Integrated data to support asset decision-making and the ability to format, filter and present data;
> 4. Documented, consistent and reliable processes that support the understanding of asset needs; and
> 5. A method of institutionalizing knowledge within the system to maximize value and facilitate knowledge transfer."

Reference (2) outlines six risk categories: condition risk; demographic risk; criticality risk; performance risk; utilization risk; and economic risk.
Reference (3) provides an asset risk analysis summary and states in part that:

> "The Asset Risk Assessment provides a standardized approach to assessing the risk associated with distribution assets. This approach assists in the planning and prioritization of both the OM&A and Capital work required to maintain the safety and reliability of the distribution system. By understanding the risks associated with an asset and the ongoing operating costs, the most cost effective determination of when to replace or refurbish an asset can be made."

Keeping with a risk analysis perspective, staff assumes that the Asset Analytics not only aids in risk assessment, but also provides several solutions/alternatives for risk control, and corresponding options for funding.

Questions:

a) Is staff's assumption correct?

b) Please confirm that the Asset Risk Assessment is performed by the Asset Analytics.

c) Please confirm that the output of the Asset Analytics in the form of an assets condition review is an essential piece in optimizing investments.

d) What standardized reports of the Asset Analytics are translated into a plan?

e) Some of the variables in the composite risk index appear interdependent. How is this addressed in the planning process? Is the explanatory value of the assessment affected?

f) In light of the importance of the asset risk assessment in determining and driving investments and current planning, please provide Hydro One's risk mitigation and funding strategy for material initiatives. In particular, with respect to the company's risk mitigation and funding strategy, please describe the balancing of risk/reward between Hydro One and its customers.

g) Are any of the risks transferred to a third party, for example in the case of critical assets where an event could cause loss of operations and income?

h) Please explain how the RRFE outcomes and RRFE suggested performance metrics are embedded in the risk model and process.

i) Please file Hydro One's prioritization strategy for both non-discretionary and discretionary projects.

j) Under issue 2.4, staff asked some higher level questions related to Hydro One's planning process. In addition, please discuss scenarios that would affect Hydro One's prioritization and asset optimization strategy, for instance a more resource constrained environment, or a varying load growth environment (higher/lower than forecast). Please specify conditions under which the current DSP would be modified and which current projects would be deferred and/or abandoned? Please define qualitatively and quantitatively the impact of such investment deferrals along outcome lines.

Response

a) No. Asset Analytics is a standardized tool that can be used to assess asset risk. It does not generate alternatives or calculate funding options.

b) Investment planners use Asset Analytics among other information sources to perform asset risk assessments.

c) An asset risk assessment review is a key aspect to identifying the asset needs in order to develop investment alternatives and determine the benefits and risks associated with these alternatives. The subsequent optimization of the investment plan involves a consideration of all Hydro One business values, as described in Exhibit A, Tab 17, Schedule 4.

d) Asset Analytics does not provide reports that are translated into investment plans; however it does provide Hydro One Distribution with a unified geospatial view of multiple data sources, providing insight into the condition, demographics, performance, utilization, economics and criticality of specific assets. This view can assist investment planners in assessing asset needs and generating and evaluating potential investment alternatives, as described in Exhibit A, Tab 17, Schedule 3.

e) The composite risk index is designed to provide a high level overview of the risk associated with a given asset. However, investment planners can consider individual components of the composite risk index when assessing asset needs and generating investment alternatives. The explanatory value of the assessment is not affected when individual risk factors are considered in this manner.

f) Hydro One's risk mitigation strategy is embodied in the Investment Prioritization Process described in Exhibit A, Tab 17, Schedule 4. With respect to the balancing of risk/reward between Hydro One Distribution and its customers, several of the Business Values used to prioritize investments are "Safety", "Satisfying our Customers", and "Reliability", all of which reflect the risk/reward to Hydro One Distribution's customers and the Hydro One distribution system.

g) If there were any events affecting Hydro One's critical assets which resulted in a loss of operations and income, risk would not transfer away from Hydro One. However, it could spread to Hydro One's customers. In certain situations, service may be adversely impacted, and customer assets connected to the critical assets could also be at risk of physical damage. Furthermore, depending on the nature of the event, there may also be risk to any persons and property in the physical vicinity of the affected critical asset. Hydro One mitigates its own risk through contractual arrangements with insurers and its other vendors. Vendors' risk would also be mitigated through contractual arrangements.

h) Risk is assessed at every stage of Hydro One's investment planning process. This is reflected in Hydro One's use of the Asset Investment Planning solution (AIP), which is described in Section 2.0 of Exhibit A, Tab 17, Schedule 4 and incorporates the different steps of the investment prioritization process described on page 3 therein.

The AIP is used to assess and prioritize all investments, enterprise-wide; and incorporates the RRFE outcomes in the form of Hydro One's Business Values. Hydro One's Business Values align with the four RRFE outcomes as follows:

<table>
<tr><th>OEB Performance Outcomes</th><th>Hydro One Business Values</th></tr>
<tr><td rowspan="2">Customer Focus</td><td>Satisfying our Customers</td></tr>
<tr><td>Shareholder Value</td></tr>
<tr><td rowspan="3">Operational Effectiveness</td><td>Safety</td></tr>
<tr><td>Reliability</td></tr>
<tr><td>Productivity</td></tr>
<tr><td rowspan="2">Public Policy Responsiveness</td><td>Shareholder Value</td></tr>
<tr><td>Safety</td></tr>
<tr><td>Financial Performance</td><td>Shareholder Value</td></tr>
</table>

Please refer to Table 1 of Exhibit A, Tab 17, Schedule 4 for the performance measures/key performance indicators associated with each of these business values.

i) Hydro One employs one investment prioritization strategy for all investments, which is described in Exhibit A, Tab 17, Schedule 4.

j) Hydro One's prioritization and asset optimization strategy remains constant. Please refer to Section 2.5 of Exhibit A, Tab 17, Schedule 4 for information on how Hydro One redirects resources on an as-needed basis to deal with unanticipated situations. Given the multitude of possible variables, Hydro One respectfully submits that it cannot responsibly provide a reliable guidance on the decisions it would make in some speculative future scenarios. However, Hydro One can advise that it would likely reallocate resources from a task with a lower risk profile to resolve a situation with a higher risk profile. Note that risk profiles of programs or projects may vary depending on the stage they are in and on a variety of other factors.

Ontario Energy Board (Board Staff) INTERROGATORY #51

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference:
1. **OEB Distribution Filing Requirements, Chapter 5, 5.4.5.1 Justifying Capital Expenditures/ p. 19**
2. **Exhibit A/Tab 6/Schedule 1/Summary of Distribution Business**
3. **Exhibit D1/Tab 2/Schedule 1/Investment Overview**
4. **Exhibit C1/Tab 2/Schedule 1/ Summary of OM7A Expenses**

Preamble:

Chapter 5 at reference (1) states, in part:

> To support the overall quantum of investments included in a DS Plan by category, a distributor should include information on:
> - comparative expenditures by category over the historical period;
> - the forecast impact of system investment on system O&M costs, including on the direction and timing of expected impacts;
> - the 'drivers' of investments by category (referencing information provided in response to sections 5.3 and 5.4), including historical trend and expected evolution of each driver over the forecast period (e.g. information on the distributor's asset-related performance and performance targets relevant for each category, referencing information provided in section 5.2.3);

Questions:

To provide an expenditure picture that allows a comparative analysis, please include capital and OM&A in the **same schedule** for each asset category/sub-category (where applicable). Please distinguish, where applicable, between planned and reactive OM&A.

Please provide trends over time for all relevant capital expenditures, capital vs. OM&A (planned vs. unplanned) and capital vs. depreciation for the 10 year-period; and provide explanations of trends and outliers.

Response

Distribution ($millions)	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Sustaining										
Stations (Capital)	13.8	21.2	32.7	56.5	50.6	63.9	67.8	68.5	76.4	77.2
Stations (planned & reactive OM&A)	27.2	25.8	26.4	23.7	27.9	27.6	28.4	28.9	28.6	28.3
Lines (Capital)	170.1	181.2	183.2	234.4	203.9	227.6	246.8	267.4	282.7	295.8
Lines (planned & reactive OM&A)	124.4	137.4	130.9	161.3	134.0	141.3	149.7	152.4	154.6	157.5
Meters (Capital)	130.1	71.8	45.9	32.3	31.9	16.6	20.6	23.8	21.3	10.5
Meters (planned & reactive OM&A)	24.1	26.6	14.2	15.8	19.4	18.5	18.7	18.5	18.9	19.4
Vegetation Management (planned & reactive OM&A)	130.2	127.3	136.4	134.9	139.1	142.0	177.6	180.3	161.1	152.9
Total Sustaining	**619.9**	**591.3**	**569.7**	**658.9**	**606.8**	**637.5**	**709.6**	**739.8**	**743.6**	**741.6**
Development										
Connections, Upgrades (Capital)	92.0	95.3	107.2	92.7	105.5	108.8	112.1	115.8	119.3	122.9
System Capability Reinforcement (Capital)	49.3	45.9	56.7	70.0	61.1	81.4	71.5	83.2	62.0	74.2
Wholesale Revenue Meters (Capital)	9.3	2.4	4.0	3.9	0.4	0.0	0.0	0.0	0.0	0.0
Generation Connections (Capital)	12.4	13.5	18.0	25.5	33.2	33.1	22.7	8.7	2.1	2.0
Distribution Generation Connections (planned OM&A)	0.0	2.8	2.9	2.5	2.0	2.2	2.0	2.0	2.0	2.1
Data Collection, Engineering and Technical Studies (planned OM&A)	6.6	4.2	3.9	4.0	4.7	4.7	4.7	4.7	4.9	5.0
Standards and Technology (planned OM&A)	5.4	6.1	4.2	4.0	5.6	5.6	5.8	6.0	6.1	6.3
Smart Grid Studies (planned OM&A)	0.3	2.7	3.7	0.5	6.1	2.9	5.2	4.3	4.3	4.4
Total Development	**175.3**	**172.9**	**200.6**	**203.1**	**218.6**	**238.7**	**224**	**224.7**	**200.7**	**216.9**
Operations										
Operations (Capital)	1.2	1.3	2.7	3.6	5.1	9.4	18.8	7.0	7.0	4.2
Operations (planned OM&A)	12.3	13.0	14.8	15.7	16.7	16.9	17.1	17.1	17.4	17.6
Operations Support (planned OM&A)	4.4	4.2	4.8	4.7	5.2	5.3	5.4	5.5	5.5	5.6
Health, Safety & Environment (planned OM&A)	1.8	0.9	1.4	1.6	2.4	2.7	2.8	2.6	2.6	2.7
Smart Grid (planned OM&A)	0.0	0.0	0.0	0.0	6.1	5.3	9.1	9.6	16.8	15.1
Total Operations	**19.7**	**19.4**	**23.7**	**25.6**	**35.5**	**39.6**	**53.2**	**41.8**	**49.3**	**45.2**

Distribution ($millions)	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Customer Service										
Customer Operations (planned OM&A)	105.5	101.3	105.2	128.5	109.2	96.8	96.2	96.6	98.0	99.6
Distributed Generation (planned OM&A)	5.0	9.5	9.0	6.9	7.7	7.9	8.1	8.3	8.5	8.7
Conservation & Demand Management (planned OM&A)	1.7	2.0	1.6	1.8	3.1	3.1	2.7	2.7	2.8	2.8
Customer Experience (planned OM&A)	0.0	0.0	0.0	1.6	4.2	4.3	4.3	4.3	4.2	4.3
Smart Grid Pilot (Capital)	18.4	30.1	43.1	6.4	22.9	22.6	9.9	3.9	0.0	0.0
Smart Grid Pilot (planned OM&A)	2.5	0.4	0.8	9.8	9.5	5.7	4.9	2.8	0.0	0.0
Total Customer Service	**133.1**	**143.3**	**159.7**	**155**	**156.6**	**140.4**	**126.1**	**118.6**	**113.5**	**115.4**
Common Corporate Costs and Other Costs										
Transport and Work, and Service Equipment (Capital)	51.1	36.3	39.9	43.5	51.4	43.8	49.1	44.8	48.9	46.1
Facilities & Real Estate (Capital)	14.9	22.1	13.0	10.1	19.9	19.0	15.3	15.4	17.7	17.7
Information Technology (Capital)	18.9	26.1	19.4	13.4	29.8	22.6	20.1	22.9	17.6	18.6
Cornerstone (Capital)	8.3	49.6	67.8	47.6	8.7	0.0	0.0	0.0	0.0	0.0
Information Technology including Cornerstone (planned OM&A)	71.2	72.6	80.6	100.1	86.0	85.7	86.4	86.1	86.5	87.6
Asset Management (planned OM&A)	30.6	34.6	25.1	19.9	18.4	18.4	17.8	17.6	17.5	17.8
Common Corporate Functions & Services (planned OM&A)	69.7	68.5	71.5	76.3	79.1	77.2	76.8	76.7	78.6	79.9
Other (Capital)	0.0	-1.1	2.4	-2.9	0.0	0.0	0.0	0.0	0.0	0.0
Other (planned OM&A)	-82.0	-96.0	-107.1	-113.5	-111.7	-116.7	-120.6	-120.1	-122.4	-125.2
Cost of Sales (planned OM&A)	5.4	5.8	18.5	5.9	2.0	2.1	2.1	2.1	2.2	2.2
Total Common Corporate Costs and Other Costs	**188.1**	**218.5**	**231.1**	**200.4**	**183.6**	**152.1**	**147**	**145.5**	**146.6**	**144.7**
Property Taxes & Rights Payments (planned OM&A)	**4.6**	**4.6**	**4.5**	**4.4**	**4.6**	**4.7**	**4.9**	**5.0**	**5.2**	**5.4**
Total Distribution	**1140.7**	**1150.0**	**1189.3**	**1247.4**	**1205.7**	**1213.0**	**1264.8**	**1275.4**	**1258.9**	**1269.2**

Sustaining

Stations Capital & OM&A:

Increase in overall stations capital spending over the test years is due to increases in station refurbishment projects, transformer replacement projects and spare transformer purchases. Increases in transformer replacement projects and station refurbishment projects are needed to keep pace with the deteriorating condition and demographics of station transformers, metalclad breakers beyond expected service life, deteriorating and aging structures, site or property issues, safety concerns, environmental compliance and operational issues.

Planned OM&A expenditures in the test years are in-line with average historical expenditures, with marginal increases over the test years. Although there is a marginal net increase in OM&A expenditures, the following can be realized:

- OM&A expenditures in PCB testing and retrofill activities have increased over the test years to meet Environment Canada requirements of identifying and removing PCB contaminated equipment.
- OM&A corrective maintenance is marginally increasing over the test years in order to incorporate recent trending in the declining condition of the transformer fleet.
- OM&A planned preventive maintenance is decreasing over the test years as Hydro One shifts from a time-based maintenance strategy to condition based maintenance.
- OM&A transformer refurbishment expenditures have been reduced, to offset the increase of new transformer purchases and replacements through capital investments.

Lines and Vegetation Capital & OM&A:

Distribution lines capital spending increases over the test years to accommodate a greater number of pole replacements and lines projects which are required to mitigate risks associated with an ageing asset base. These capital activities could include replacing equipment that would otherwise require corrective maintenance, leading to slight reductions in OM&A requirements.

Distribution lines OM&A spending increases over the test years to meet Environment Canada requirements to identify and remove PCB contaminated equipment, to increase efforts in correcting identified defects, to maintain a growing number of electronically controlled equipment, and to implement an 8-year vegetation management cycle. Impacts to capital requirements are as follows:

- Increased PCB inspection and testing activities will drive increased capital requirements in replacing identified contaminated equipment.
- The increased effort to correct minor identified defects will not impact capital requirements.
- The maintenance of a growing volume of electronically controlled equipment will not impact capital requirements.

- The implementation of an 8-year vegetation management may decrease damage to the distribution system during severe storms, potentially leading to reduced capital requirements. However, due to the unpredictable nature of the storm damages, it is difficult to estimate the impact on capital.

Metering Capital & OM&A:

Historical metering capital spending was unusually high due to the installation of the smart meter network. The investment requirements during the test years are expected to stabilize as the network is fine tuned to maximize performance and maintain reliability. OM&A is also expected to stabilize as benefits from the smart meter network are realized.

Development

Capital spending under development programs varies over the test years in response to demand for new load connections, distributed generation and load growth, and declines slightly in response to the forecasted decline in Distributed Generation connections.

Operations

Investment on information technology (IT) systems, associated infrastructure and facilities is driven by asset lifecycle management to ensure vendor support and IT systems reliability and availability targets. OM&A expenditures are fixed costs which are incurred irrespective of the stage of the asset lifecycle, such as IT systems maintenance fees and field staff support. As Hydro One continues to invest in its Smart Grid, Operating OM&A expenditures will increase to fund the additional staff needed to monitor, control and support Smart Grid-related assets.

The increase in capital spending during the test years is largely attributable to two main capital sustainment projects, the ORMS Upgrade and the Backup Control Centre new facility development project.

The remaining planned capital investments in the test years are to maintain the Operations IT systems, associated infrastructure and facilities. Environmental, health and safety OM&A increases from historic to bridge and test years are due to the additional audit requirements. The other OM&A activities under Operations remain relatively steady over the test years, with the exception of Smart Grid-related OM&A as described above.

Customer Services

Hydro One's Customer capital expenditures are comprised of smart grid capital investments, which are expected to be within the same envelope as stated in EB-2009-0096. Smart grid

OM&A expenditures end in 2017 with the completion of Hydro One's smart grid pilot and comprise very little of the total Customer Service OM&A expenditures during the test years.

The smart grid pilot is area-specific and not material enough to impact Hydro One's forecasted OM&A expenditures. Furthermore, the benefits are still subject to validation. Hydro One will continue to monitor the success of the piloted technologies. On a case-by-case basis, Hydro One will make decisions on the further deployment of piloted technologies which may reduce OM&A expenditures over the longer term.

Common Corporate

IT capital spending in the test years is consistent with historical levels. Capital spending on the Cornerstone project will be complete in 2014. OM&A levels remain stable through the test years.

Spending in Facilities and Real Estate is driven by the need to properly accommodate the staff and equipment required to handle the growth in Sustaining, Development and Operations work programs over the test years. OM&A spending levels during the test years are slightly higher than historical levels due to moving costs and planned improvements in head office space and increases in fixed operating costs. The majority of facilities work program OM&A costs (such as lease fees) are fixed and rising. (See Exhibit C1, Tab 2, Schedule 8 for further details.)

A decrease in Transportation & Work Equipment spending in 2015 from the bridge year reflects the stabilization in work programs for the Electro-Forestry Journey Person Program, the Forestry and Provincial Lines Apprenticeship Program and the helicopter replacement schedule. The helicopter replacement schedule causes a slight increase in spending during the test years. Service Equipment spending decreases during the test years due to a lesser requirement to replace specialized equipment and decreased costs for automated external defibrillators. OM&A levels are slightly elevated from historical levels due to (a) additional maintenance costs in maintaining core fleet, (b) additional equipment acquisitions required to fulfil the company's increasing work program requirements, and (c) an increase in depreciation expenses arising from the additional equipment acquisitions. For Transport & Work Equipment assets, Hydro One employs the declining balance method of calculating depreciation which prescribes a higher depreciation rate in the early years of the asset's life.

Ontario Energy Board (Board Staff) INTERROGATORY #52

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference:
1. **OEB Distribution Filing Requirements, Chapter 5, 5.4.5.1 Justifying Capital Expenditures/ p. 19**
2. **Exhibit D1 (Capital Exhibits)**
3. **Exhibit C1 (OM&A Exhibits)**
4. **Exhibit D2/Tab 2/Schedules 1, 2 & 3**

Preamble:

Chapter 5 at reference (1) says in part that:

> "Filings must enable the Board to assess whether and how a distributor's DS Plan delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures."

Appendices C1 and D2 contain detailed information related to planned investments for the DSP period of 2015-2019. However, there are areas that relate to the fundamentals outlined in the RRFE Report and the *Filing Requirements* that can benefit from additional information.

Questions:

a) For material projects, please distinguish between discretionary and non-discretionary projects, and provide the following project elements to establish whether the most cost-effective actions have been adopted, whether pacing of the investments is appropriate, and establish the value and rate impacts of these activities on ratepayers:

- In the project overview section, please provide:
  - The overall priority of the project; Benefits to be incurred from maintaining/upgrading or replacing the asset(s), such as lower operating costs. Where applicable, please include a discussion on value for the business and/or customers;
- In the project cost section, please provide:
  - An overview of the economics of the project (eg. assumptions, NPV calculation) and a discussion of alternatives in that context (eg. discuss in monetary terms alternatives for the TS capital contributions); and
  - Where applicable please reference or submit additional documentation, such as independent studies that support a recommended option;
- The impact of the project on rates;
- Any investment pacing considerations related to the project;

b) For programs (eg. Vegetation Management), please provide the following program elements to establish whether the most cost-effective actions have been adopted, and the value and rate impacts of these activities on ratepayers:
   - In the overview of the program, please highlight:
      - The expenditure cycle;
      - Benefits to be incurred from planned expenditures on program, such as lower operating costs, increased reliability. Where applicable, please include a discussion on value for the business and/or customers;
   - In the program cost section, please include an overview of the economics of the program and a discussion of alternatives (e.g. discuss in monetary terms the alternatives presented at exhibit D2 for the Pole Replacement program);
   - The impact of the program on rates;
   - Any investment pacing considerations related to the program and the cycle adopted; and
   - Any benchmarking (historical/internal; industry peers/external; general/best practices)

c) For the smart grid pilot projects, to determine the value of these initiatives, please provide:
   - The OM&A cost of the pilots;
   - Please discuss the value of the pilots since the time of their roll-out;
   - Please discuss any significant findings and recommendations on scaling-up during the DSP period; and
   - If applicable, please discuss plans to share findings with peers in the industry.

Response

a) Please see table below for the details on the benefits, project economics, rate impact and pacing considerations for each of the material capital projects outlined in Exhibit D2, Tab 2, Schedule 3.

Project Name		**Discretionary/ Non-Discretionary**	**Benefits of Project**	**Project Economics**	**Rate Impact***	**Pacing Considerations**
S7	Station Refurbishments	Non-Discretionary	- Address ageing and degrading condition of station assets in a cost effective manner. - Ensure the safe and reliable operation of the distribution system. - Minimize lengthy customer outages - Reduce risk of negative impacts on the environment	These projects provide an integrated solution where multiple end-of-life or deteriorated components, or other risk factors, are present at a single station. This approach results in a more efficient and cost-effective solution compared to addressing each need individually under individual component replacement programs.	0.03%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing considerations include: the rate of station assets which are approaching their expected service life and are in deteriorated condition, integration with other sustainment and development needs, and availability of resources to complete work in a cost-effective manner.
S12	Large Sustainment Initiatives	Non-Discretionary	- Prevent deterioration in supply reliability. - Minimize planned interruptions. - Ensure the safe and reliable operation of the distribution system.	These projects provide an integrated solution where multiple end-of-life or deteriorated components, or other risk factors, are present within a specific section of distribution line. This approach results in a more efficient and cost-effective solution compared to addressing each need individually under individual component replacement programs.	0.03%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing considerations include criticality of the project, and availability of resources to complete work in a cost-effective manner. Some very large projects are separated into multiple stages to allow effective use of available resources.
D2	Upgrades Driven by Load Growth	Non-Discretionary	- Provide sufficient network capacity to supply existing and forecast customer load. - Ensure acceptable delivery voltage to customers in accordance with CSA standards. - Maintain reliability of supply.	The majority of projects in this category are identified through area supply studies that consider overall customer and system needs (i.e. capacity, sustaining, and reliability). The recommended work is determined based on least-cost solution which addresses all needs based on the present value of capital expenditures and relevant O&M costs.	0.02%	Pacing is based on providing “just-in-time” capacity upgrades as determined by existing and forecast load versus available capacity. General prioritization of projects is based on: (1) ensuring acceptable delivery voltage to customers, (2) maintaining load within equipment ratings, (3) maintaining/improving supply reliability, and (4) meeting Hydro One planning guidelines.

Project Name		Discretionary/ Non-Discretionary	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
D3	Upgrades Driven by Load Growth - Distribution System Modifications	Non-Discretionary	- Ensure acceptable delivery voltage to customers in accordance with CSA standards. - Ensure equipment is adequately rated for expected load and short circuit conditions. - Ensure reliability of supply through optimal application of coordinated overcurrent protection schemes. - Contribute to loss minimization by balancing feeder loads.	These projects reflects a cost-effective balance between the need to ensure that acceptable supply conditions exist on the system and achieving efficiencies in the execution of the required work by addressing a number of cumulative changes which have occurred over time.	0.01%	Project pacing is based on a 6-year cycle which is considered optimal for this type of work and aligns with the DSC-mandated 6 year inspection cycle for distribution lines.
D4	Upgrades Driven by Load Growth - Demand Investments	Non-Discretionary	- Ensure acceptable delivery voltage to customers in accordance with CSA standards. - Ensure equipment is adequately rated for expected load and short circuit conditions. - Enable large new loads to be connected to the distribution system without compromising power quality and reliability. - Address emergent power quality issues to be addressed in a timely manner.	This work is demand driven by new load connections and customer complaints over power quality or reliability; therefore no present value calculations are performed for this type of project.	0.00%	This work is demand driven; pacing is based on external demand.
D5	Asset Lifecycle Optimization and Operational Efficiency	Discretionary	- Maintain or improve reliability by replacing assets that are at the end of their expected service life, or are performing poorly. - Optimize network configurations for operability and maintainability. - Reduce overall costs by integrating multiple needs into a common solution.	Projects in this category are usually identified through local supply studies that consider overall customer and system needs (i.e. capacity, sustaining, and reliability). The recommended work is determined based on least-cost solution which addresses all needs based on the present value of capital expenditures and relevant O&M costs.	0.01%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing considerations include addressing identified end-of-life asset needs in a cost-effective manner based on the efficient use of available resources.
D6	Reliability Improvements	Discretionary	- Improve reliability of supply in targeted areas. - Meet customer needs.	Work is demand driven by customer complaints about poor reliability; therefore no present value calculations are performed for this type of project.	0.00%	This work is demand driven; pacing is based on external demand.

Project Name		Discretionary/ Non-Discretionary	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
D7	Orleans TS Capital Contribution	Non-Discretionary	- Provide sufficient transmission connection capacity for growing customer demand in the Orleans area near Ottawa. - Improve reliability of supply for existing customers in the Orleans area.	The recommended work is the only option which will increase reliability of supply; therefore no present value calculation was performed for this project.	0.01%	Pacing is based on the need to address the existing overloading of transmission connection assets.
D8	Red Lake TS Capital Contribution	Non-Discretionary	- Meet customer requests for new load connections in the Red Lake area.	The recommended work is the most economical solution to meet forecasted load. The alternative to build a second transmission line would cost about 10 times the recommended work.	0.00%	Pacing is based on the need to address the current customer loading demand which already exceeds the available capacity.
D9	Hanmer TS Capital Contribution	Non-Discretionary	- Address aging and deteriorating transmission and distribution assets serving the east Sudbury area. - Improve reliability of supply to customers in the Valley East area. - Reduce line losses and improve operating flexibility. - Provide sufficient transmission connection capacity to meet long-term needs in the east Sudbury area.	The project was determined based on combined Transmission and Distribution costs to meet needs in the east Sudbury area. The recommended work would cost about 10% more than "like-for-like" replacement alternative, but delivers other benefits including improved reliability, and reduce line losses.	0.00%	Pacing is based on need to address end-of-life assets in a timely manner.
D10	Enfield TS Capital Contribution	Non-Discretionary	- Provide sufficient transmission connection capacity for growing customer demand in the Durham Region area east of Oshawa. - Improve reliability of supply to customers in the Bowmanville area. - Avoid rotational load-shedding for single-contingency loss of a transformer or transmission circuit during peak loading conditions.	There were two viable alternatives identified to meet the medium term needs of this area. Both alternatives are financially comparable; however the construction of Enfield TS is recommended based on the greater reliability improvements and incremental capacity it provides.	0.00%	Pacing is based on the need to integrate a solution with Regional Planning for the GTA-East area, including coordinating with Hydro One Transmission and Oshawa PUC requirements.
D11	Recloser Retrofit Project	Non-Discretionary	- Reduce the number of service interruptions to customers. - Increase customer satisfaction.	The recommended work is the only viable alternative to restore system reliability and increase customer satisfaction therefore no present value calculations are performed for this type of project.	0.00%	Pacing is based on need to address reclosers associated with the poorest performing feeders with the most customer complaints in a timely manner. A slower pace would put the distribution system at further exposure to reduced system reliability.

Project Name		Discretionary/ Non-Discretionary	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
D12	Leamington TS Capital Contribution	Non-Discretionary	- Provide sufficient transmission connection capacity for growing customer demand in the Kingsville-Leamington area. - Avoid rotational load-shedding for single-contingency loss of a transformer or transmission circuit during peak loading conditions. - Facilitate retirement of end-of-life transformers at Kingsville TS. - Enable the connection of additional renewable energy generation in the Leamington area. - Improve reliability of supply to customers in the Leamington area.	The proposed project is based on the recommendations of the OPA for the Windsor-Essex area. Construction of Leamington TS is 20% less costly than the next closest alternative which would involve maintaining supply to the area from Kingsville TS plus a new 115kV connected station.	0.00%	Pacing based on the need to integrate a solution with Regional Planning for the Windsor-Essex area, including coordinating with Hydro One Transmission and embedded LDCs.
O1	Operating Compute Refresh	Non-Discretionary	- Provide lifecycle management of common Operations IT hardware, software, system architecture and infrastructure which supports critical systems and applications. - Maintain viability of Operations applications (such as ORMS, NOMS and other critical applications) by addressing end of life database servers and workstation consoles.	The proposed project is based on industry best practices and vendor support schedules to ensure viable operation of these assets. IT asset lifecycles are typically five years and include capacity growth provisions. Failure to refresh systems could result in loss of support from the vendor, increased maintenance costs and increased probability of system failure.	0.00%	Pacing is based on industry best practice, and vendor support schedules to ensure reliability and availability of these assets and also compatibility between common assets.
O2	NOMS Refresh	Non-Discretionary	- Provide for lifecycle upgrades of software and hardware components of NOMS to maintain reliability, availability and flexibility of the system to accommodate customer requirements.	The proposed project is based on industry best practices and vendor support schedules to ensure viable operation of these assets. The system must be supported by the vendor and upgraded or replaced when support for the legacy version is withdrawn.	0.00%	Pacing is based on industry best practice, and vendor support schedules to ensure reliability and availability of these assets and also compatibility between common assets.
O3	Operating Facilities Refresh	Non-Discretionary	- Maintain the stability of Operations Information Technology infrastructure. - Provide flexibility for system modifications, system growth and future upgrades. - Provide lifecycle management of facility assets to sustain IT system operability and ensure acceptable performance.	The proposed project is based on the need to replace end of life and unsupported assets to ensure the operability of Operations IT infrastructure required to support critical Operations systems and applications and tools they support.	0.00%	Pacing is based on industry best practice, and vendor support schedules to ensure reliability and availability of these assets and also compatibility between integrated systems, tools and associated infrastructure.

Project Name		Discretionary/ Non-Discretionary	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
O4	BUCC – New Facilities Development	Non-Discretionary	- Provides for the development, design and build of a new Backup Control Centre (BUCC). - Ensure monitoring, control and Operation of the distribution system, safeguarding Hydro One customers from a loss of primary control, and any system event/contingency that may result.	Existing computer rooms at the BUCC are at design limits and as a result availability and the reliability of Operating backup facilities have been reduced. The recommended work is required to establish a new BUCC (Backup Control Centre) facility to ensure continued compliance to regulatory requirements. See Exhibit I, Tab 3.2, Schedule 3.2 EP 31 for additional details on alternatives.	0.00%	Pacing is based on need to address end-of-life assets in a timely manner. The current BUCC facility is 40 plus years old and has experienced reduced reliability due to increases in critical failures.
O5	OGCC Storage Area Network Upgrade	Non-Discretionary	- Provide a common data storage platform for Operations IT systems and application including OMRS, NOMS and other critical systems. - Provide a refresh and lifecycle management of IT data storage at the control centres.	The proposed project is based on industry best practices and vendor support schedules to ensure viable operation of these assets. IT asset lifecycles are typically five years and include capacity growth provisions. Common platforms have the effect of reducing the number of discrete components thereby reducing support costs, the need for Operations spares and decreases complexity	0.00%	Pacing is based on industry best practice, and vendor support schedules to ensure reliability and availability of these assets and also compatibility between integrated systems, tools and associated infrastructure.
O6	ORMS Refresh	Non-Discretionary	- Provide lifecycle system renewal of the current software and hardware in order to maintain vendor support as the current version is nearing end of life.	The proposed project is required in order to ensure the ongoing reliability of the critical Outage Response activities including: communications with field crews and customers, and compliance with regulatory obligations.	0.00%	Pacing is based on industry best practice, and vendor support schedules to ensure reliability and availability of these assets and also compatibility between integrated systems, tools and associated infrastructure.
IT5	Field Workforce Optimization and Mobile IT	Discretionary	- Provide the schedulers/field staff with real or near time work status update capability. - Provide better data integrity and work efficiency by presenting staff with a consolidated view of work information and a geographic scheduling tool on PC/ tablets. - Provide data validation at time of entry. - Provide a near paperless and automated work environment to reduce paper, fuel and natural resources and save on operation cost	The recommended work will replace existing manual processes and applications used to manage work within the Distribution Lines Organization. By improving and integrating the processes and applications used to schedule, dispatch and report work accomplishments in the field, improvements in timeliness and data accuracy will be made.	0.00%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing considerations included development and implementation of the full solution for multiple line of businesses roll out.

Project Name		Discretionary/ Non-Discretionary	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
IT6	Customer Experience	Discretionary	- Provide a better overall customer experience and proactive communication. - Allow the customer to be able to communicate with us how they choose to. - Increase online functionality to allow customers to be self-sufficient with the ability to manage their online usage and understand their bill better. - Decrease the time an agent needs to spend with individuals and thus speed up the average handle time of call center agents. - Improve the customer experience with Hydro One.	The recommended work will provide Hydro One the means to meet the needs to be able to communicate to customers through the eCustomer portal in new and improved ways, and include a provision self-serve capability. It will also address the existing Computer Telephony Integration (CTI) that is at end of life. The plan is to leverage the increase in technology that has occurred since implementation of the existing CTI in order to bring the customer a better, faster product with enhanced features.	0.00%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Hydro One's current CTI solution has reached its end of life. Pacing considerations includes many medium to large initiatives requiring the same resources to complete work in a cost-effective manner.
IT7	Information Rights Management	Non-Discretionary	- Allow Hydro One to remain compliant with internal and external security policies and to meet our commitments to NERC, CIP and Bill 198. - Enhance Hydro One's Records Management program and Enterprise Content Management investments by providing Hydro One with direct control over the dissemination and destruction of our records.	The recommended work is required to protect critical data within the organization, and more importantly, when it leaves the organization. Given the high level of awareness to privacy and confidentiality by businesses and customers, implementing an Information Rights Management solution was evaluated and deemed a necessity for protecting Hydro One data in a modern business environment.	0.00%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing considerations include solution roll out to all Lines of Businesses and availability of resources to complete work in a cost-effective manner.
IT8	Enterprise Analytics	Discretionary	- Provide investment planners and field staff the ability to make strategic asset lifecycle investment decisions that optimize cost and operational risks. - Provide a central system to house the critical data to improve efficiency and accuracy.	The recommended work is to replace the existing disparate systems, databases and tools. The alternative to Acquire Specialized Point Solution to Deliver AM analytics was considered and rejected as it will expand the software application landscape, which is contrary to corporate objectives. It also would require additional interfaces and integrations to be built to fully integrate data and processes. The recommended solution will leverage existing SAP solution to deliver AM analytics.	0.00%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing considerations include changing business needs and availability of resources to complete work in a cost-effective manner.

Project Name		Discretionary/ Non-Discretionary	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
IT9	Corporate Support Optimization	Discretionary	- Provide consolidation of multiple systems into one to manage data and information. - Provide a complete view of the asset demographics that drive investment decisions. - Provide the ability to better determine the cause of an incident and institute corrective actions, reduced environmental impacts, minimize risk of incurring a fine, and compliance with regulatory demands.	The recommended work will consolidate the functionality and data of the ICM and waste management solutions into SAP. It will provides improvements with information accessibility and a more simplified system landscape, resulting in improved decision making and lower costs through the leverage of Hydro One's investment in SAP. The alternative to enhance existing systems was considered and rejected as it will not fully overcome the issues related to managing across multiple systems and will add complexity to the existing landscape.	0.00%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing considerations include changing business needs and availability of resources to complete work in a cost-effective manner.
IT10	Engineering Design Transformation	Discretionary	- Savings in turnaround time and accuracy of design documents. - Allow Hydro One to be up-to-date with external engineering practices and allow for an integral external seamless workflow.	The recommended work will implement a drawing documents management system that supports 3D drawings and that supports internal and external collaborations through cloud and mobile platforms. It will also implement 3D design tools/technologies that support intelligent design, and interaction with SAP for the exchange of materials to support the building of a bill of materials.	0.00%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing considerations include modernizing multiple technologies, improving processes and availability of resources to complete work in a cost-effective manner.
IT11	Enterprise GIS	Discretionary	- Provide immediate access to more comprehensive and integrated spatial asset and connectivity data in corporate systems, contributing to consistency and timeliness in asset planning, maintenance and outage decisions. - Provide timely access to reliable, accurate and up-to-date data regarding the state of the network, which empowers work crews to work more safely.	The recommended work will enable continued investment in the GIS systems, integration between GIS and satellite systems it supports and leverage new technologies that enhance the data within GIS and leverage the GIS data to provide better information to the business.	0.00%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing considerations include expanding current platform to meet changing business needs and availability of resources to complete work in a cost-effective manner.

Project Name		Discretionary/ Non-Discretionary	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
C01	Real Estate Head Office and GTA Facilities	Non-Discretionary	- Complete necessary improvements to head office space, which will avoid inefficiencies and health and safety hazards associated with deteriorating workplace infrastructure.	The most viable alternative was adopted following detailed economical evaluation. The cost of moving to an alternate location outweighed the proposed investment. The tenant improvements are part of the negotiated lease agreement, which Hydro One is contractually committed to for eleven years commencing February 2010.	0.00%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing takes into consideration the plan determined and set forth several years ago. This project work began in year 2011 and is expected to be finished in 2015.
C02	Real Estate Field Facilities	Non-Discretionary	- Secure necessary accommodation space in the field to allow field staff to conduct their work in an efficient way to accomplish the work program requirements in a manner that complies with applicable laws.	The recommended work is determined based on least-cost solution which addresses all needs based on the present value of capital expenditures and relevant O&M costs where applicable.	0.01%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing consideration reflects need of aging facilities reaching end of life, work program needs, suitable locations market availability, and municipal approvals.

(*) The rate impact shown represents the proportionate amount of the average Distribution rate increase based on the project's contribution to total revenue requirement over the test years. It is used for illustrative purposes only.

b) Please see table below for the details on the benefits, project economics, rate impact and pacing considerations for each of the material capital programs outlined in Exhibit D2, Tab 2, Schedule 3.

Project Name		Discretionary/ Non-Discretionary	Cycle	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
CAPITAL PROGRAM							
S1	Transformer Spares and Replacements	Non-Discretionary	Annual	- Address end of life assets that are high risk of failure. - Maintain customer supply reliability. - Reduce the risk of lengthy customer outages. - Address customer noise complaints resulting from transformers.	Projects are need-driven, based on age, condition, performance, and operational issues, versus the "Do-Nothing" alternative. Present Value Calculations are not performed for this type of program.	0.01%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate-filing period. Pacing considerations include: the deteriorating condition of the transformer population, failure trends, and aging demographic profile of in-service transformers; as well as customer noise complaints are also considered.

Project Name		Discretionary/ Non-Discretionary	Cycle	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
CAPITAL PROGRAM							
S2	Mobile Unit Substations	Non-Discretionary	Annual	- Address end of life components of the existing MUS fleet. - Ensure adequate number of MUS's to support failures and other planned work - Reduce lengthy outages by providing emergency backup.	Projects are need-driven, based on age, condition, performance, and operational issues, versus the "Do-Nothing" alternative. Present Value Calculations are not performed for this type of program.	0.00%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate-filing period. Pacing considerations include: condition and demographics, requirements of the Highway Traffic Act, and the volume of station maintenance and capital work which require MUS's to offload the station.
S3	Spill Containment	Non-Discretionary	Annual	- Reduce the impact to the environment due to risk of oil releases. - Reduce costs of clean up in the event of a major oil spill. - Ensure compliance with the Environmental Protection Act.	Projects are need-driven, based on an environmental risk assessment. Present Value Calculations are not performed for this type of program.	0.00%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate-filing period. Pacing considerations are based on addressing the highest risk stations identified in the environmental assessment.
S4	Station Component Replacements	Non-Discretionary	Annual	- Address end of life and/or deteriorated station components. - Address station components that have known defects to mitigate safety concerns - Reduce the risk of lengthy customer outages. - Maintain supply reliability.	Projects are need-driven, based on age, condition, performance, and operational issues, versus the "Do-Nothing" alternative. Present Value Calculations are not performed for this type of program.	0.00%	Pacing is reflected in the year-by-year plan of component replacements throughout the rate-filing period. Pacing considerations include: condition and age of the station components, where replacement of these items cannot be bundled into larger refurbishment projects.
S5	Recloser Upgrades	Non-Discretionary	Annual	- Address ageing equipment by installing new reclosers that reduce future maintenance costs. - Maintain supply reliability. - Provide the ability for remote communications.	Projects are need-driven, based on age, condition, performance, and operational issues, versus the "Do-Nothing" alternative Present Value Calculations are not performed for this type of program.	0.00%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate-filing period. Pacing considerations include: condition and demographics, short circuit capability, technical obsolescence, and the upgrade of fuses to provide feeder protection.

Project Name		Discretionary/ Non-Discretionary	Cycle	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
CAPITAL PROGRAM							
S6	Demand Work	Non-Discretionary	Annual	- Ensure timely response to outages. - Mitigate reliability and safety risks. - Ensure compliance with regulatory requirements outlined in the DSC.	This work is demand driven by equipment failure, safety, and power quality issues; therefore no present value calculations are performed for this type of program.	0.00%	This work is demand driven; pacing is based on external demand.
S8	Trouble Call and Storm Damage Response	Non-Discretionary	Annual	- Ensure timely response to trouble calls, service interruptions, and power quality complaints. - Mitigate reliability and safety risks. - Ensure compliance with regulatory requirements outlined in the DSC.	This work is demand driven by trouble calls, storm damage, power interruptions and other situations that pose reliability or safety risks and require immediate attention; therefore no present value calculations are performed for this type of program.	0.04%	This work is demand driven; pacing is based on external demand.
S9	Joint Use and Line Relocations	Non-Discretionary	Annual	- Ensure compliance with the Third Party Agreements with Joint Use Partners - Satisfy the obligations to perform line relocation work at the request of road authorities as per Public Service Work on Highways Act.	This work is demand driven by Joint Use Partners and Municipal and Provincial Road Authorities; therefore no present value calculations are performed for this type of program.	0.02%	This work is demand driven; pacing is based on external demand.
S10	Pole Replacements	Non-Discretionary	Annual	- Mitigate end-of-life issues. - Reduce safety and reliability risks on the distribution system. - Ensure compliance with utility standards, and regulatory and legal requirements.	Projects are need-driven, based on age, condition, performance, and operational issues, versus the "Do-Nothing" alternative Present Value Calculations are not performed for this type of program.	0.07%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate-filing period. Pacing considerations include: inspection data as well as demographics, performance, and criticality. Poles are bundled for replacement where possible to prioritize poles in a row, poles with multiple circuits and poles with joint use attachments.

Project Name		Discretionary/ Non-Discretionary	Cycle	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
CAPITAL PROGRAM							
S11	PCB Lines Equipment Replacements	Non-Discretionary	Ongoing until 2025	- Ensure compliance with Federal PCB Legislation. - Mitigate health and safety risks associated with PCB contaminated equipment.	No alternatives are considered since the recommended work is based on complying with the Federal PCB Legislation to remove all transformers with PCB contamination >50 ppm therefore no present value calculations are performed for this type of program.	0.00%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate-filing period. Pacing is determined to ensure the required equipment replacements by the mandated 2025 deadline.
S13	Line Component Replacements	Non-Discretionary	Annual	- Mitigate end-of-life issues. - Reduce safety and reliability risks on the distribution system. - Ensure compliance with utility standards, and regulatory and legal requirements.	Projects are need-driven, based on age, condition, performance, and operational issues, versus the “Do-Nothing” alternative Present Value Calculations are not performed for this type of program.	0.01%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate-filing period. Pacing considerations include: inspection data as well as performance, and criticality. Equipment is bundled for replacement where possible with other line projects.
S14	Submarine Cable Replacements	Non-Discretionary	Annual	- Mitigate end-of-life issues. - Reduce public safety and reliability risks on the distribution system. - Ensure compliance with utility standards, and regulatory and legal requirements.	Projects are need-driven, based on age, condition, performance, and operational issues, versus the “Do-Nothing” alternative Present Value Calculations are not performed for this type of program.	0.00%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate-filing period. Pacing considerations include: line patrol inspection data as well as performance, and criticality.
S15	Meter Upgrades	Non-Discretionary	Annual	- Ensure compliance with regulatory requirements imposed by Measurement Canada, the Electricity & Gas Inspection Act, IESO Market Rules and OEB Distribution System Code. - Ensure accurate and timely billing that will lead to improved customer satisfaction.	No alternatives are considered since the recommended work is determined based on the least-cost solution which meets regulatory requirements. Present Value Calculations are not performed for this type of program.	0.01%	Pacing is reflected in the year-by-year plan of asset replacements throughout the rate-filing period. Pacing considerations include: technology obsolescence, meeting regulatory deadlines such as meter seal expiry. Work is bundled with other non-metering station work where possible for cost savings and to maximize resource availability.

Project Name		Discretionary/ Non-Discretionary	Cycle	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
CAPITAL PROGRAM							
S16	Meter Inventory Sustainment	Non-Discretionary	Annual	- Ensure a timely availability of metering equipment to minimize outage duration due to failed meters. - Ensure a reliable source of billing settlement data is maintainable.	No alternatives are considered since the recommended work is determined based on the least-cost solution which meets regulatory requirements and minimize outage duration. Present Value Calculations are not performed for this type of program.	0.00%	Pacing is reflected in the year-by-year plan throughout the rate-filing period. Pacing is determined primarily by historical failure rates.
D1	New Connections, Upgrades and Service Cancellations	Non-Discretionary	Annual	- Satisfy license obligations to connect customers. - Satisfy customer need for new or upgraded service.	This work is demand driven by customers. Costs are apportioned between Hydro One and connecting customers in accordance with the Distribution System Code.	0.08%	This work is demand driven; pacing is based on external demand.
IT1	Hardware/Software Refresh and Maintenance	Non-Discretionary	Annual	- Provide for the lifecycle management of IT hardware, software, system architecture and infrastructure which ensures that critical systems and applications are highly available. - Ensure that the supporting technology components including telecom are within vendor support criteria such that replacement or repair can be executed expeditiously in the event of failure	No alternatives are considered since the recommended work is determined based on industry lifecycle management best practices and vendor support schedules which ensures viable operation of these assets.	0.00%	Pacing is reflected in the year-by-year plan throughout the rate-filing period. Pacing considerations include hardware and software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives.
IT2	MFA Servers and Storage	Non-Discretionary	Annual	- Provide for the lifecycle management of IT hardware and operating systems software which ensures that critical systems and applications are highly available. - Ensure that the supporting technology components are within vendor support criteria such that repair or replacement can be executed expeditiously in the event of failure.	No alternatives are considered since the recommended work is determined based on industry lifecycle management best practices and vendor support schedules which ensures viable operation of these assets.	0.00%	Pacing is reflected in the year-by-year plan throughout the rate-filing period. Pacing considerations include industry best practices,warranties,reliability requirements and vendor schedules.

Project Name		Discretionary/ Non-Discretionary	Cycle	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
CAPITAL PROGRAM							
IT3	MFA PC and Printer Hardware	Non-Discretionary	Annual	- Ensures PC and Printer hardware assets will reliably support business needs and the performance of day-to-day work unimpeded by end-of-life computer reliability problems. Equipment refresh maintains or reduces maintenance costs.	No alternatives are considered since the recommended work is determined based on industry lifecycle management best practices and vendor support schedules which ensures viable operation of these assets.	0.00%	Pacing is reflected in the year-by-year plan throughout the rate-filing period. Pacing considerations include industry best practices,warranties,reliability requirements and vendor schedules.
IT4	MFA Telecom Infrastructure	Non-Discretionary	Annual	- Ensures a reliable and supportable voice and data network is in place to address Hydro One's communication needs and maintain hardware supported levels required by our contractual commitments with vendors and outsourcing partners.	No alternatives are considered since the recommended work is determined based on industry lifecycle management best practices and vendor support schedules which ensures viable operation of these assets.	0.00%	Pacing is reflected in the year-by-year plan throughout the rate-filing period. Pacing considerations include industry best practices,warranties,reliability requirements and vendor schedules.
C3	Transport and Work Equipment	Non-Discretionary	Annual	- Ensure compliance with all safety standards, regulatory and Ministry of Transportation requirements. - Allow Hydro One to maintain its present core fleet level. - Maximize productivity, utilization, and equipment availability. - Optimize repair time and fleet size - Maximize efficiency and life cycle benefits.	In order to comply with regulations and maintain the existing levels of reliability of the transport and work equipment fleet, the requested funding levels are required. Funding at a lower level would lead to degradation in the fleet, a decrease in utilization and an increase in downtime, maintenance and rental costs. Fleet capital replacement requirements are based on industry standards for life cycle expectancy, net book value to original capital value ratios and operating cost drivers.	0.02%	Pacing is reflected in the year-by-year plan throughout the rate-filing period. Pacing considerations reflect regulatory requirements and safety considerations.
C4	Service Equipment	Non-Discretionary	Annual	- Maintain equipment and tool fleets at the required levels to accomplish the growing levels of capital and OM&A work. - Reduce operating costs. - Increase efficiency and reliability.	Inadequate investment will result in equipment breakdowns or increased labour time. This would adversely impact job cost, outage duration and work program accomplishments. Spending is focused on the level of equipment required to accomplish the growth in overall transmission and distribution work programs, and end-of -life replacement.	0.00%	Pacing is reflected in the year-by-year plan throughout the rate-filing period. Pacing of investments reflect regulatory requirements and growth of work programs and end of life replacement.

Project Name		Discretionary/ Non-Discretionary	Cycle	Benefits of Project	Project Economics	Rate Impact*	Pacing Considerations
CAPITAL PROGRAM							
C5	Security Infrastructure Capital	Non-Discretionary	Annual	- Provide solutions to mitigate copper theft in stations. - Improve employee and public safety in stations and at fence boundaries. - Reduce interruptions caused by copper theft.	Projects are need-driven to enhance security at stations with repeated copper theft occurrences. Present Value Calculations are not performed for this type of program.	0.00%	Pacing is reflected in the year-by-year plan of projects throughout the rate-filing period. Pacing takes into consideration the plan determined and set forth several years ago as pilot program, with the intent to evaluate alternate solutions to address stations with repeated copper theft by enhancing security.

(*)The rate impact shown represents the proportionate amount of the average Distribution rate increase based on the project's contribution to total revenue requirement over the test years. It is used for illustrative purposes only.

Please see table below for the details on the benefits, project economics, rate impact and pacing considerations for the material OM&A programs outlined in Exhibit C1, Tab 2, Schedules 2 to 4.

Project Name	Discretionary / Non-Discretionary	Cycle	Benefits of Program	Program Economics	Rate Impact*	Pacing Considerations
OM&A Programs						
Stations Maintenance	Partially Discretionary	Annual ***Inspection Cycles:*** *Semi-annually for rural* *Monthly for urban* *Quarterly for Containment Systems*	- Maintain equipment to mitigate risk of unplanned failures. - Address safety and customer related issues. - Prevent lengthy outages caused by defective equipment. - Ensure compliance with distribution system code minimum inspection requirements. - Ensure compliance with Federal PCB Legislation for Inspection and Testing of oil filled equipment.	This program is a combination of demand and needs-driven activities. The cost of the work is based on planned inspection cycles and historical spending on trouble calls and corrective maintenance	0.08%	Pacing considerations include: timely response to demand and corrective maintenance activities, minimum inspection requirements outlined by the distribution system code and Federal PCB Legislation.

Project Name	Discretionary / Non-Discretionary	Cycle	Benefits of Program	Program Economics	Rate Impact*	Pacing Considerations
OM&A Programs						
Land Assessment and Remediation	Non-Discretionary	Annual	- Reduce the human and ecological risks of off-property contamination - Ensure compliance with Ministry of Environment Regulations.	This program is needs driven and is required to address sites which exceed the Ministry of Environment land-use criterion. The cost of the work is based on the complexity and volume of work needed to assess and remediate the site.	0.02%	Pacing is based on operating in an environmentally responsible manner that minimizes the risk to human health and the environment and being compliant with applicable Ministry of Environment regulation.
Lines Demand Work	Non-Discretionary	Annual	- Ensure timely response to trouble calls, service interruptions, cable locates and disconnect/reconnects. - Mitigate safety risks of damaged assets - Meet customer expectations. - Ensure compliance with the distribution system code.	This program is demand driven by trouble calls, customer requests for cable locates and disconnection /reconnection requests. The cost of the work is based on historical spending.	0.33%	This work is demand driven; pacing is based on external demand.
Lines Maintenance	Partially Discretionary	Annual ***Inspection Cycles***: *6 years for rural* *3 years for urban*	- Maintain equipment to mitigate risk of unplanned failures. - Prevent lengthy outages caused by defective equipment. - Ensure compliance with distribution system code minimum inspection requirements.	This program is a combination of demand and needs-driven activities. The cost of the work is based on meeting minimum DSC inspection requirements and a forecast of defect corrections. Equipment replacements are bundled for cost-effectiveness where possible.	0.09%	Pacing considerations include: timely response to corrective repairs, and minimum inspection requirements outlined in the Distribution System Code
PCB Equipment and Waste Management	Non-Discretionary	Annual	- Ensure compliance with Federal PCB Legislation for Inspection and Testing of oil filled equipment and other Waste Management regulations.	This program is demand driven and required to comply with the Federal PCB Legislation to remove all transformers with PCB contamination >50 ppm.	0.06%	Pacing is determined by the need to meet PCB testing and removal legislation.
Other Services	Non-Discretionary	Annual	- Meet miscellaneous requests from customers and other external parties in a timely manner. - Reduce costs by renting idle transmission lines for distribution purposes.	This program is mostly demand driven by external requests. The cost of the work is based on historical spending for external requests and rental fees for idle transmission lines. .	0.05%	Pacing is determined primarily based on historic demand for this type of work.

Project Name	Discretionary / Non-Discretionary	Cycle	Benefits of Program	Program Economics	Rate Impact*	Pacing Considerations
OM&A Programs						
Meters	Non-Discretionary	Annual ***Meter Verification Cycle:*** *6 to 10 years*	- Ensure compliance with Electricity & Gas Inspection Act, Measurement Canada standards and practices. - Maintain meter reading capability and subsequently provide accurate and timely customer bills.	This program is needs-driven and is required to meet regulatory requirements and minimize outage duration.	0.05%	Pacing is primarily determined by meeting regulatory deadlines such as meter seal expiry; as well as failure trends of sample groups.
Telecom, Monitoring and Control	Non-Discretionary	Annual	- Maintain metering telecommunication infrastructure to ensure collection of consumption data required for customer billing.	This program is needs-driven and is based mostly on 3rd party leased telecomm fees.	0.01%	Pacing is determined by system growth of the total number of meter installations in service.
Vegetation Management	Partially Discretionary	Annual ***Clearing cycle:*** *8 Years*	- Maintain an acceptable and sustainable level of reliability. - Manage safety hazards posed by trees in proximity to energized lines.	This program is based on a focus to reduce the vegetation backlog and realize unit cost benefits of a sustainable 8 year cycle.	0.57%	Pacing is reflective of achieving a sustainable 8 year clearing cycle to improve life-cycle costs and reliability within the test years.
Data Collection, Engineering and Technical Studies	Partially Discretionary	Annual *6 Year Cycle for planned feeder studies.*	- Obtain annual loading data to support system load studies and ensure customer delivery voltages within standards and equipment loading within ratings - Determine impacts of large new load connections on the distribution system - Identify opportunities to reduce line losses and improve reliability through improved automatic sectionalizing schemes. - Obtain specific information on assets to support business decisions.	This program is based on the 6-year cycle of planned feeder studies and an annual load survey of all stations and feeder; which reflects a responsible level of due diligence in managing the distribution system. Present Values are not calculated for this investment	0.02%	Pacing is determined primarily based on cycle of the studies and surveys for this type of work.

Project Name	Discretionary / Non-Discretionary	Cycle	Benefits of Program	Program Economics	Rate Impact*	Pacing Considerations
OM&A Programs						
Distribution Generation Connections	Non-Discretionary	Annual	- Connect generation facilities as per distribution license requirement - Reduce peak load demands by increasing renewable energy penetration in the distribution system. - Ensure projects move through the generator connection process efficiently and within the timelines specified by the DSC.	As regulated by the DSC, Hydro One is obligated to connect all distribution generation facilities including Micro-embedded, CAE, CAR, Net Metering and Merchant generation. The costs for distributed generation connections are determined as per the Distribution System Code and recovered consistent with Hydro One's Policy.	0.01%	Pacing for the volume of generation connection projects is determined mainly by procurement targets for the renewable energy programs offered by the OPA. The prioritization of DG connection projects is dictated by many factors such as their proposed in-service date, planned outages required to connect the generation, resourcing issues, etc.
Standards and Technology	Partially Discretionary	Annual	- Develop new standards and review/update existing standards to meet internal business requirements and compliance requirements set by regulatory authorities such as the Electrical Safety Authority.	This program is demand based. The proposed costs are based on historic spending and any known compliance requirements to be met in the test years.	0.02%	This work is demand driven; pacing is based on external demand.
Smart Grid Studies	Discretionary	Annual	- Support grid modernization activities that will result in safe and reliable integration of distributed generators, energy storage and eventually electric vehicles into the system and allow customers greater control over their energy usage.	The program is needs-driven and based on ongoing commitments for multi-party funding obligations where Hydro One benefits from the leveraging of industry group funded activities.	0.01%	Pacing is based on a relatively consistent level of funding from year-to year as this work is required annually and supports funding of multi-year activities.

Project Name	Discretionary / Non-Discretionary	Cycle	Benefits of Program	Program Economics	Rate Impact*	Pacing Considerations
OM&A Programs						
Operations Support	Non-Discretionary	Annual	- Provide for the demand based work required to sustain Network Operations. - Ensure essential Operational information accuracy for efficient and effective distribution operation (diagrams, connectivity, maps, etc) - Provide Power System IT support to ensure the facilities, system and tools at the OGCC and BUCC are fully supported and meet availability and reliability targets. - Provide for emergency preparedness to ensure all emergency backup equipment, documentation, procedures and training are up to date and functioning as intended. - Provide voice communications support to ensure critical communication facilities are maintain. These are the primary communication paths to customers.	These programs are demand based in nature. The proposed costs are based on historical spending. This is a base consideration to ensure availability and reliability of Operations systems and functions as well as ensuring employee, customer and public safety.	0.02%	Pacing is based on a consistent level of funding from year-to year as this work is required annually 24x7. Power System IT pacing is determined by the systems, tools, infrastructure and facilities they support and their respective lifecycle in terms of licensing, support (security patching), lifecycle management etc.
Environmental, Health & Safety	Non-Discretionary	Annual	- Support EH&S programs that are required to meet legal obligations. - Ensure a level of due diligence - Promote environment impact reduction, conservation through energy efficiencies and reduced emissions in fleet.	This is a combination of demand based work as well as the continuation of corporate EH&S initiative and training to ensure appropriate due diligence.	0.01%	Pacing of these programs are based on legal obligations (training), requirements of certification and registration (OHSAS 18001 & ISO14001).

Project Name	Discretionary / Non-Discretionary	Cycle	Benefits of Program	Program Economics	Rate Impact*	Pacing Considerations
OM&A Programs						
Smart Grid Sustainment	Non-Discretionary	Annual	- Improve reliability through proactive management of the distribution system from the control centre using new distribution automation. - Improve outage restoration times and efficiency by leveraging smart meters and using fault location technology. - Improve distribution asset planning capability by using increasing data set from sensors - Maintain smart grid systems in the control centre and back office - Maintain smart grid assets on the distribution system - Provide telecommunications to smart grid assets	The cost is needs-driven based on the cost to support and operate the distribution automation assets and maintain and provide communications to those assets. It also provides for the maintenance and support of computer infrastructure, software systems, and associated licensing fees.	0.03%	The pacing is based on the timing of when smart grid assets are deployed in the field and when additional systems are intended to be commissioned, to ensure adequate support and maintenance of all assets.

(*)The rate impact shown represents the proportionate amount of the average Distribution rate increase based on the project's contribution to total revenue requirement over the test years. It is used for illustrative purposes only.

C) Please see responses below for the details on the smart grid pilot project.

OM&A Cost of the Pilot

The OM&A costs for the pilots can be found in Exhibit C1, Tab 2, Schedule 5 and has been extracted below:

Table 6: Smart Grid Pilot ($ Million)

Description	Historical Years				Bridge Year	Test Years				
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Smart Grid Pilot	**2.5**	**0.4**	**0.8**	**4.0**	**9.5**	**5.7**	**4.9**	**2.8**	**0.0**	**0.0**

Value of the Pilots to Date

As the Smart Grid Pilot is limited to the small geographic area of the Owen Sound Smart Zone area, the value of the pilot to date has been the insights gained in shaping the smart grid deployment in future years as well as establishing the foundational systems and processes required to enable the new smart grid business capabilities. The findings from the Owen Sound Smart Zone pilot are summarized below.

Significant Findings & Recommendations

i. Smart Grid investments can make a significant improvement to reliability and Hydro One should proceed with programs to modernize the distribution system over the next 10-15 years. Investments should be made in adding communications and controls to existing distribution operating assets, installing new remotely controllable SCADA-enabled tie-switches and replacing hydraulic reclosers with communicating electronic reclosers. The investments will be made on M and F-class feeders as well as within distribution stations.

ii. It is not cost effective to deploy Smart Grid devices on all of Hydro One's feeders and distribution substations. Investments need to be targeted to those feeders that have the largest opportunities for improving reliability, integrating renewable energy, or have the largest customer load.

iii. Smart Grid investments should be bundled with end-of-life replacements of existing assets to make them cost effective. Many of the assets that are being replaced only require an incremental investment in connecting communications equipment to the operable device being replaced. This along with connectivity to the Distribution Management System provides many of the expected smart grid benefits at a lower incremental cost.

iv. The Distribution Management System is valuable and should be sustained. The Distribution Management System provides a platform from which Hydro One will operate the new remotely controllable assets on the distribution system. This enables the improvement in reliability as well as provides a control system to provide situational awareness to an evolving distribution system (one with highly variable renewable generation). As Hydro One did not have a Supervisory, Control and Data Acquisition (SCADA) system for its distribution system it was essential for Hydro One to establish one. The Distribution Management System does this but also provides the central control system to optimize the distribution grid through Conservation Voltage Reduction and other grid automation applications.

v. Smart Grid provides opportunities to improve operational effectiveness in many ways. The Distribution Management System can create and validate switch orders more efficiently for planned distribution maintenance; field crews will be provided the ability to update the control centre through mobile computers/tablets instead of voice calls enabling more work effort to be spent on maintenance; load transfer studies can be performed directly on the Distribution Management System in the control room; and fault location aids field crews in finding faults more quickly. This, combined with the general benefit that situational awareness of the distribution system creates, all improve operational efficiencies for Hydro One.

vi. Establishing a Distribution Management System is data intensive. In order for the Distribution Management System to provide accurate load flows, state estimation and fault location predictions it is important to establish a network model that reflects the true distribution system in the field.

vii. The use of the new IEC 61850 standard for protection and control schemes that coordinate protections between substations and feeder protective devices are not ready for broad deployment by Hydro One. The cost of implementation outweighs the marginal increase in reliability created by the quicker switching times. Alternative technologies are being investigated to provide automated system restoration schemes at lower cost.

viii. Utilizing Smart Meters and the Advanced Metering Infrastructure for distribution operations has demonstrated significant savings and should proceed. Hydro One often needs to dispatch crews where there are no actual power outages (i.e. issues are with the phone lines or with the customer side of the meter). Operational efficiencies are expected by interrogating the state of the meter prior to dispatching service personnel. In addition, confirming restoration of power after an outage by interrogating the state of the meter will allow Hydro One to detect and resolve nested outages. This will reduce outage duration for those customers and reduce restoration costs by optimizing field personnel scheduling.

ix. Utilizing more advanced demand response technologies on electric hot water heaters and smart thermostats can offer cost savings for customers. Market indication shows that smart thermostats are able to provide energy savings to the customer with less kWh being consumed for air conditioning. In addition, the use of intelligent demand response programs on electric hot water heaters that shift usage from on-peak times to off-peak times can provide customers additional costs savings.

x. Hydro One should continue its Conservation Voltage Reduction pilot that will better manage the voltage on the distribution system. Conservation Voltage Reduction allows Hydro One to lower overall voltage of the feeder, while adhering to regulated voltage limits. This reduction in voltage results in lower power consumption by the customers and hence a reduction in their electricity costs. This has been successfully employed at other utilities to reduce usage and peak demand.

Plans to Share Findings with Peers in the Industry

Hydro One continues to participate in multiple industry forums to share information with other Ontario distributors.

- Hydro One participates in the Toronto Hydro organized “E-8” group of the eight largest urban distributors in Ontario plus Hydro One.
- Hydro One is a member of the Independent Electricity System Operator organized Smart Grid Forum.
- Hydro One is actively participating in the Minister of Energy/MaRS led Green Button Initiative.
- Hydro One is involved in various provincial, national and international industry associations including the Electricity Distributors Association, SmartGrid Canada, the Canadian Electricity Association as well as the Standards Council of Canada.
- Hydro One has made a number of presentations on its Smart Zone pilot at various industry conferences both inside and outside Ontario.
- As part of the Smart Grid Pilot project, Hydro One has commissioned a Mobile Electricity Discovery Centre that it has used around the province to explain the smart grid to customers. Hydro One has shared the learning from this project with other Ontario distributors.

Ontario Energy Board (Board Staff) INTERROGATORY #53

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference:
1. Exhibit A/Tab6/Schedule 1 (Summary of Distribution Business)
2. Filing Requirements for Electricity Distribution Rate Applications **July 17, 2013, (the "Filing Requirements")/Chapter 2/ 2.5.2.2 Required Information/ p.19**
3. Exhibit A/Tab 9/Schedule 1/Compliance with OEB Filing Requirements for Electricity Distributors
4. Exhibit TC 2.1/ p. 7/ Asset Analytics Software
5. Exhibit A/Tab 7/Schedule 1/ (Distribution System Plan)
6. Exhibit D2/Tab 2/Schedule 3/Investment Summary Programs /Projects in Excess of $1M
7. Chapter 5, Consolidated Distribution System Plan Filing Requirements, p. 7

Preamble:
At Reference (1) Hydro One's evidence indicates that its distribution system consists primarily of the following five asset categories: Sub transmission feeders, distribution stations, primary distribution feeders, pole top/pad mounted transformers and secondary distribution feeders. Hydro One also states, that:

> "Individual investments are developed taking into account various factors such as asset risk assessment, historical performance data, asset criticality, availability of spare equipment and material, asset demographics, load growth and future capacity requirements using the process described in Exhibit A, Tab 17, Schedule 3. "

Reference (2) the "Filing Requirements" state in part:

> "As part of this exhibit, distributors must file a consolidated DS Plan in accordance with Chapter 5 for matters pertaining to asset management, renewable energy generation, smart grid and regional planning. The consolidated DS Plan should be filed as a stand-alone document."

At Reference (3), Hydro One states in part:

> "It is critical that Hydro One address its rapidly aging infrastructure and introduce the new technology needed to support customer choice and distribution generation. New system analytics tools and rigorous planning have given Hydro One confidence in its investment schedule. Hydro One has customized this Application to fit its specific circumstances."

Reference (4) relates to the Asset Analytics software which Hydro One addressed during the Technical Conference on April 23, 2014. Hydro One ran a demonstration and briefly commented on the underlying assumptions and variables of the model and illustrated the model's explanatory power. Hydro One also discussed the "composite risk score/index". Staff understands that the factors used to evaluate asset risk are: condition, demographics, criticality, performance, utilization and economics. How these factors are taken into account in a multivariate analysis for each asset category and how a composite risk index is obtained as highlighted during the technical conference is still unclear to Board staff. In addition, how this multivariate analysis leads to a multi-outcome investment plan is unclear. Accordingly, further explanation is needed.

At reference (5), Hydro One indicates that it has chosen to continue to use the terminology of "Sustaining", "Development", "Operations", "Customer Services" and "Common Corporate Costs" to accurately reflect the company's internal system of investment planning and to apply consistent definitions to historical expenditures and forecast expenditures. Hydro One acknowledges that this categorization does not precisely align with the categorization of investments set out in Chapter 5 of the Filing Requirements.

At reference (5), Hydro One states:

> "An important change in Hydro One Distribution's asset management process since its last rebasing application (EB-2009-0096) is the adoption of its "Asset Risk Assessment" methodology in its decision-making process. Previously, Hydro One Distribution relied upon an "Asset Condition Assessment and Analysis" methodology, which is described in its last application. Building upon that approach, Hydro One Distribution has since enhanced the quality of its asset data and process to systematically evaluate the risk associated with distribution assets in order to improve decision-making and prioritize investments. The end result is its "Asset Risk Assessment" process."

At reference (6), for certain future investments, Hydro one has provided the corresponding Chapter 5 investment categorization. Staff notes that the categorization outlined in Chapter 5 of the Filing Requirements will help comparative reviews and benchmarking of utilities in the long-run.

At reference (7), "All distributors are required to file a DS Plan as specified here when filing a cost of service application for the rebasing of their rates under the 4th Generation IR or a Custom IR application."

Questions:

a) In accordance with section 5.1.3 of Chapter 5 of the Board's filing requirements and Reference 2, please submit a stand-alone Distribution System Plan (DSP). For the purposes of the DSP, as was done at reference (6), please submit a schedule of investments that uses the Chapter 5 categories.

b) Alternatively, if available, please file the company's Asset Management Plan.

c) Please indicate whether the output of the Asset Analytics software corresponds to Hydro One's asset condition assessment review. Please explain in what manner the "new" Asset Risk Assessment differs from the "old" Asset Condition Assessment and Analysis.

d) If different from reference (1), please outline all the asset categories/sub-categories that are delineated in the Asset Analytics model.

e) Please reconcile the statement at reference (1) in which asset risk appears to be just one factor, with the fact that elsewhere in the pre-filed evidence and Technical Conference 2, asset risk is put forward as a composite index.

f) Please submit a copy of Hydro One's comprehensive asset condition assessment review by asset category, possibly subcategory (i.e. sub-transmission feeders, distribution stations, primary distribution feeders, pole top/pad mounted transformers and secondary distribution feeders) . The review should include:

   i. A comprehensive picture of the asset population health/risk distribution by asset category/subcategory, (please provide reasonable groupings, eg. <u>asset risk scale</u> very likely, likely, medium, unlikely remote or asset <u>health scale</u> very poor, poor, fair, good, very good);
   ii. The methodology for the development of a composite health/risk index, index formula and weights; and
   iii. For each asset category, findings and recommendations.

g) To determine whether the input methodology is appropriate, please indicate whether Hydro One has or will conduct an independent third party assurance review of the asset condition assessment review.

Response

a) Exhibit A, Tab 7, Schedule 1 contains Hydro One’s Distribution System Plan (DSP). This exhibit provides a mapping of the exhibits used in this application to the section headings used in Chapter 5 as per section 5.2, page 9.

> *“Distributors are encouraged to organize the required information using the section headings indicated. If a distributor’s application uses alternative section headings and/or arranges the information in a different order, the distributor shall demonstrate that these requirements are met by providing a table that clearly cross-references the headings/subheadings used in the application as filed to the section headings/subheadings indicated below.”*

Please see Appendix A for a schedule of investments that uses the Chapter 5 categories of System Access, System Renewal, System Service, and General Plant.

b) A DSP was provided in the application, which describes Hydro One’s asset management process and capital expenditure plan as per section 5.0 of Chapter 5 of the Filing Requirements.

c) The output of the Asset Analytics software utilizes some of the same factors as were used in the Asset Condition Assessment (ACA) review, however, the output of the Asset Analytics software does not correspond to the output of the ACA review.

As described in Exhibit A, Tab 17, Schedule 7, page 1, the Asset Risk Assessment methodology is more comprehensive than the Asset Condition Assessment review in that it provides additional information on non-condition risk factors, including customer and outage data.

d) The current Asset Analytics model includes two general asset categories for Hydro One Distribution: Distribution Lines and Distribution Stations. Assets included in the Distribution Lines category include poles, right-of-ways, transformers, switches, reclosers, regulators, capacitors, and submarine cables. Assets included in the Distribution Stations category include transformers, structures, breakers, reclosers, and poles.

e) The asset risk assessment feeds into the needs assessment and investment alternative development process in Exhibit A, Tab 17, Schedule 3. The asset risk assessment includes the composite risk index, which incorporates information related to asset condition, demographics, economics, performance, utilization and criticality.

f) The Asset Condition Assessment review was replaced with an Asset Risk Assessment. Results of the Asset Risk Assessment are found in Exhibit D1, Tab 2, Schedule 1.

g) Hydro One has not and does not intend to commission a third party assurance review of any asset condition assessment review because Hydro One no longer conducts these reviews given the investment made in the new asset management tools.

Appendix A

Project/Program in Exhibit D2		2015	2016	2017	2018	2019
System Access						
S09	Joint Use and Line Relocations Program	26.7	27.3	27.8	28.4	28.9
S15	Meter Upgrades	10.0	15.8	18.8	16.1	5.0
S16	Meter Inventory Sustainment	4.6	4.8	5.0	5.2	5.5
D01	New Connections, Service Upgrades and Metering	108.9	112.1	115.8	119.3	122.9
System Renewal						
S01	Transformer Spares and Replacements Program	18.0	18.4	17.9	21.2	21.6
S02	Mobile Unit Substations Program	4.6	3.6	3.7	3.6	3.7
S03	Spill Containment	1.1	1.1	1.2	1.2	0.6
S04	Station Component Replacements Program	2.1	2.2	2.2	2.2	2.3
S05	Recloser Upgrades	1.4	1.4	1.4	1.5	1.5
S06	Demand Work Program	2.1	2.1	2.1	2.2	2.2
S07	Station Refurbishments	34.6	39.0	40.0	44.5	45.2
S08	Trouble Call and Storm Damage Response Program	52.4	54.7	55.4	55.8	56.3
S10	Pole Replacements Program	88.7	95.1	105.0	115.2	125.8
S11	Lines PCB Equipment Replacements Program	1.9	5.0	10.6	10.8	11.1
S12	Lines Sustainment Initiatives	33.4	39.5	42.9	46.5	47.3
S13	Line Component Replacements Program	11.6	11.8	12.1	12.3	12.6
S14	Submarine Cable Replacements Program	7.1	7.2	7.4	7.5	7.7
D05	Asset Life Cycle Optimization and Operational Efficiency	4.05	4.85	4.45	2.1	2.25
D11	Recloser Retrofit Project	1.0	0.0	0.0	0.0	0.0
O01	Operating Compute Refresh	0.0	0.0	0.0	0.9	1.9
O02	NOMS Refresh	0.0	1.4	0.0	0.0	0.0
O03	Operating Facilities Refresh	0.0	0.0	0.7	2.1	1.4
O04	BUCC – New Facilities Development	0.5	9.4	5.2	2.9	0.0
O05	OGCC Storage Area Network Upgrade	0.0	0.0	1.2	1.2	0.9
O06	ORMS Refresh	8.0	8.0	0.0	0.0	0.0
C05	Security Infrastructure Capital	0.2	0.2	0.3	0.3	0.3

Project/Program in Exhibit D2		**2015**	**2016**	**2017**	**2018**	**2019**
System Service						
S08	Trouble Call and Storm Damage Response Program	5.8	6.1	6.2	6.2	6.3
D02	System Upgrades Driven by Load Growth	20.1	26.4	28.5	30.8	32.9
D03	Upgrades Driven by Load Growth – Distribution System Modicfications	9.0	9.2	9.4	9.1	8.8
D04	Upgrades Driven by Load Growth – Demand Investments	3.6	3.7	3.8	3.4	3.4
D05	Asset Life Cycle Optimization and Operational Efficiency	4.05	4.85	4.45	2.1	2.25
D06	Reliability Improvements	2.7	2.0	2.6	1.6	2.2
D07	Orleans TS Capital Contribution	21.0	0.0	0.0	0.0	0.0
D08	Red Lake TS Capital Contribution	1.8	0.0	0.0	0.0	0.0
D09	Hanmer TS Capital Contribution	0.0	11.5	0.0	0.0	0.0
D10	Enfield TS Capital Contribution	0.0	0.0	0.0	0.0	11.1
D12	Leamington TS Capital Contribution	0.0	0.0	22.0	0.0	0.0
General Plant						
IT01	Hardware/Software Refresh and Maintenance	12.0	11.2	10.1	10.1	10.1
IT02	MFA Servers and Storage	7.1	9.3	8.0	5.3	5.3
IT03	MFA PC and Printer Hardware	5.6	5.3	5.3	4.5	4.0
IT04	MFA Telecom Infrastructure	2.7	2.9	2.5	2.8	2.9
IT05	Field Workforce Optimization and Mobile IT	5.0	5.0	8.0	2.0	2.0
IT06	Customer Experience	5.0	1.0	4.0	1.0	3.0
IT07	Information Rights Management	0.0	0.0	0.0	2.5	2.5
IT08	Enterprise Analytics	2.0	2.0	2.0	0.0	0.0
IT09	Corporate Support Optimization	0.0	3.0	0.0	3.0	0.0
IT10	Engineering Design Transformation	0.0	0.0	0.0	4.0	3.0
IT11	Enterprise GIS	2.0	1.0	2.1	0.0	1.0
C01	Real Estate Head Office and GTA Facilities Capital	13.1	0.0	0.0	0.0	0.0
C02	Real Estate Field Facilities Capital	26.5	31.5	31.5	36.5	36.5
C03	Transport and Work Equipment	54.5	62.5	56.7	62.9	59.0
C04	Service Equipment	9.1	7.9	7.9	7.0	7.0
C05	Security Infrastructure Capital	0.8	0.8	0.8	0.8	0.8

Ontario Energy Board (Board Staff) INTERROGATORY #54

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab3/Schedule 1/p. 3 (Capital Expenditures)

Please complete the following table to analyze directly capitalized costs from indirectly capitalized costs.

		($ Millions)						
		2013	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Directly Capitalized								
Sustaining								
Development								
Operations								
Customer Service								
Corporate Common Costs								
Sub-total - Directly Capitalized								
Indirectly Capitalized from:								
Overhead	C1-5-2-pg3			85.9	81.4	80.2	82.5	85.3
Depreciation	C2-4-1-pg2	15.9	12.7	13.2	13.7	14.0	14.4	14.8
Interest - AFUDC	D1-4-1-pg2	17.4	18.0	16.6	19.6	22.9	21.9	16.2
Pension	C1-3-3-pgs2-3			45.0	44.0	44.0	45.0	46.0
OPEBs								
Other								
Sub-total - Indirectly Capitalized								
Total Capital Expenditures	D1-3-1-pg3	649.0	624.5	648.9	654.7	639.4	655.1	669.1

Response

Please see attached table below:

		2013	2014	2015	2016	2017	2018	2019
		($ Millions)						
Directly Capitalized								
Sustaining		219.5	187.8	207.0	229.5	249.5	259.5	266.5
Development		130.4	131.3	150.0	141.2	144.0	125.1	138.4
Operations		2.4	3.4	6.3	12.9	4.9	4.8	2.9
Customer Service		4.4	15.0	15.1	6.8	2.7	0.0	0.0
Corporate Common Costs & Other Capital		91.7	93.7	75.1	76.3	74.0	75.3	73.5
Sub-total - Directly Capitalized		448.4	431.2	453.7	466.7	475.1	464.7	481.2
Indirectly Capitalized from:								
Overheads	C1-5-2-pg3	77.6	84.3	85.9	81.4	80.2	82.5	85.3
Depreciation	C2-4-1-pg2	15.9	12.7	13.2	13.7	14.0	14.4	14.8
Interest – AFUDC	D1-4-1-pg2	17.4	18.0	16.6	19.6	22.9	21.9	16.2
Pension	C1-3-3-pgs2-3	42.5	42.6	45.0	44.0	44.0	45.0	46.0
OPEB		35.3	35.7	34.4	29.8	25.6	26.8	25.8
Other								
Sub-total - Indirectly Capitalized	D1-3-1-pg3	188.6	193.3	195.2	188.0	186.3	190.4	187.9
Total Capital Expenditures		637.0	624.5	648.9	654.7	661.4	655.1	669.1

<u>Ontario Energy Board (Board Staff) INTERROGATORY #55</u>

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

<u>Interrogatory</u>

Reference:
1. RRFE Report, October 18, 2012
2. Exhibit A/Tab 17/Schedule 3/p. 6 (Investment Plan Development Process)
3. Exhibit A/Tab 17/Schedule 4/pp. 3-12 (Investment Prioritization Process)

Preamble:

In the Board's RRFE Report; on page 27, the Board states that it needs "*evidence that a distributor's planning and prioritization process is sufficiently rigorous to support and justify its proposed capital budget."* At page 2 of Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, the Board states that, *"Filings must enable the Board to assess whether and how a distributor has sought deliver value to customers. One of the primary goals of DS Plans and by extension, hallmarks of good planning, is pacing and prioritizing capital investments in a manner that considers rate impacts. To facilitate the achievement of this goal, these filing requirements focus on the qualitative and quantitative information distributors can use to support their investment proposals that will best enable the Board to assess how a distributor has sought to control the costs and related rate impacts of proposed investments."*

a) Please describe how pacing investments to consider rate impacts is taken into account in the Investment Planning methodology described in these schedules. Why is the consideration of rate impacts neither a business Value ("BV") nor a Key Performance Indicator ("KPI")?

b) Please identify and explain examples from this application of sustainment projects/programs for which a vulnerable investment level has been chosen to be pursued, and specify whether this level was selected before or after consideration of "short-term constraints" in the form of "customer rate impacts" (A17/4/p.5). Please do the same for any program for which an intermediate investment level was chosen and explain the reasons for the choice.

c) If there were no sustainment projects identified in answer to (b), under what circumstances would a "Vulnerable" or "Intermediate" funding level be proposed?

d) Section 2.2 of Schedule 4 states that customer rate impacts are considered as a "short term constraint" when establishing investment alternatives. Please explain how this is performed, and what metrics or guidelines are used at this stage. Please confirm whether this is prior to or following the BV/KPI evaluation, or both. Please contrast this exercise with senior management's review of the IPP (s2.4), which takes into consideration "the associated impacts on customer rates" of the selected investment levels. What guidelines, principles or metrics does the senior management team use when considering rate impacts in the IPP?

e) To assist in the assessment of how Hydro One has sought to control costs through its investment plan development and prioritization process in relation to Sustainment investments, please provide - for each of the funding levels considered for each Sustainment investment category, quantitative information on cost and expected risk mitigation level achieved.

Response

a) Minimizing the rate increases and maximizing value to our customers are cornerstones of the investment planning process. These in addition to influencing productivity are key considerations when setting the financial guidelines for Distribution OMA and Distribution Capital. Our goal is to diminish the increase to the rates however Hydro One must balance this with the customers, assets and business needs. In addition to setting financial constraints for our work program, the optimization engine also considers the total cost of an investment. Investments are valued using risk mitigation and costs savings per dollar, so the total cost of the investment is included in the overall evaluation. The higher the cost of an investment the more risk it is expected to mitigate. It would therefore be redundant to add a KPI or Business Value for rate impacts.

b) Consideration of rate impacts is inherent in the investment planning process as discussed above in response to question a) and is the first step when setting financial constraints. Therefore level of investment is identified through the optimization process which is after the "short term constraints" are identified. There are several investments selected at the Vulnerable and Intermediate levels. For instance the Re-closer and Regulator Maintenance program was selected at the Vulnerable level and the ISD Business Improvements and Enhancements was selected at the Intermediate level of investment.

c) Answered above in b)

d) The impact to customer rates is foremost in the planners' minds throughout the investment planning process. The investment alternatives are prepared with the assets, business and customer's needs in mind but don't exceed the corporate strategy. With the customer rates in mind the investment planner may propose to replace assets over a 10 year period versus a 5 year period, which would increase the risk of failure but delay the rate of investment and ultimately smooth the rate impact to the customer. In contrast, senior management looks at the entire suite of investments when determining the best blend of investments. Hydro One may choose to slow the rate of replacement of one asset to facilitate an increased rate of investment in another that provides more value to the customer and ultimately smooth the rate of the investment. Senior Management tries to keep the customer rate impact to a level that is less than inflation.

e)

2014 - 2019 Investment Plan (Net $M)

Dx Capital	Lines	Vulnerable	$	1,363.86
		Asset Optimal	$	1,614.45
	Stations	Vulnerable	$	195.54
		Asset Optimal	$	384.56
	Meters, Telecom & Control	Vulnerable	$	124.70
		Asset Optimal	$	124.70

2014 - 2019 Investment Plan (Net $M)

Dx OMA	Lines	Vulnerable	$	889.46
		Asset Optimal	$	1,153.32
	Stations	Vulnerable	$	121.02
		Asset Optimal	$	169.88
	Meters, Telecom & Control	Vulnerable	$	113.50
		Asset Optimal	$	113.50
	Vegetation	Vulnerable	$	832.26
		Asset Optimal	$	1,162.07

The data in the table above represents investments over a six year period aligning with the information provided during the 2014-2019 Investment Planning process. In each of the Sustainment Investment categories the level of investment associated with the planned risk mitigation level has been provided. As stated in Exhibit A, Tab 17, Schedule 4, Investment Prioritization Process the “Vulnerable” investment level ensures compliance however asset performance will deteriorate over time and will expose the company to significant risk of asset failure. This level of investment cannot be continued beyond the planning period without the residual risk increasing to an unacceptable level. The compounded risk of all investments selected at this level would be insupportable. The Asset Optimal level of investment will preserve asset performance, residual risk and operational effectiveness. This level represents a balancing point where total lifecycle costs of the asset are minimized.

Ontario Energy Board (Board Staff) INTERROGATORY #56

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit D1/Tab3/Schedule 2

It appears, as shown in the Capital Expenditures exhibits, that there is a significant ramp up in spending in many areas, such as transformers, station refurbishment, and line and pole replacements.

Why were total capital expenditures in past years not made to a level that this ramp up in spending was required in the 2015 to 2019 period?

Response

Since Hydro One Distribution's last Cost of Service rate application (EB-2009-0096), Hydro One has completed an asset inventory of its key distribution assets and the data now resides in a centralized repository. With this completed data set, Hydro One now had a holistic view of asset risk which led to improved decision making and an investment plan that mitigates the risk to distribution assets.

In Hydro One's 2013 rate application (EB-2012-0136) both station assets and poles were highlighted as key areas where funding was required to be increased to mitigate the large number of assets exceeding their expected service life and in deteriorating condition. A request to start ramping up the capital funding for these assets was presented. It also indicated that this step was a first in replacement rate increases that must start now in order to avoid the backlog of assets that require replacement from becoming unmanageable. The proposed plan for 2015 to 2019 continues with the ramp up of capital spending in areas identified with large number of assets beyond their expected service life to ensure the risk associated with Hydro One's aging asset base is mitigated.

Ontario Energy Board (Board Staff) INTERROGATORY #57

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit D1/Tab3/Schedule 2/p.8**

Hydro One indicates that it intends to increase specific stations capital spending by 5% annually to 2019, about 50% over historical levels. This increased spending is needed in order to replace the existing transformer fleet with regard to demographics. Why were past capital expenditures not made to a level that this ramp up in spending was required?

Response

Please see response to Exhibit I, Tab 3.2, Schedule 1 Staff 56.

<u>Ontario Energy Board (Board Staff) INTERROGATORY #58</u>

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

<u>Interrogatory</u>

Reference: Exhibit D1/Tab3/Schedule 2/p.20

Hydro One shows that it will increase specific spending on station refurbishment by 7% annually, doubling capital spending by 2019 and also indicating that "…this represents a significant increase over historical spending levels. Hydro One Distribution has currently been refurbishing less than 1% of its distribution stations annually."

Why were past capital expenditures not made to a level that this ramp up in spending was required?

<u>Response</u>

Please see response to Exhibit I, Tab 3.2, Schedule 1 Staff 56.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #35

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit D2-2-3, Reference #: C-01**

Please provide a breakdown of the proposed $13.1 million facilities investment into its major components.

Response

The 2015 head office renovation project entails completion of the last three remaining floors:

Floor 14, North Tower	$4.8 million
Floor 12, North Tower	$4.8 million
Floor 5, South Tower	$3.5 million
Total	**$13.1 million**

The work is being undertaken in sequential order and within the timeframe that swing space remains contractually available from the landlord to facilitate completion of the work. The work is being completed within budget.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #36

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1, Tab 3, Schedule 2, Page 3 of 36, Lines 23-28

Does HONI have an overarching long term plan for capital refurbishment with a targeted sustainable end state (an average asset age that it would deem acceptable, for example), or are its Sustainable Investments driven more by short term requirements predominantly triggered by immediate asset failure risks?

Response

Hydro One Distribution has both long term and short term planning objectives. Hydro One Distribution's long term plans for capital refurbishments are driven by the Hydro One Strategic Objectives outlined in Exhibit A, Tab 6, Schedule 1. Short term asset requirements, including the replacement of assets that are at a high risk of immediate failure, are addressed through the demand capital replacement programs described in Exhibit D1, Tab 3, Schedule 2.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #37

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit F1, Tab 1, Schedule 1, Page 12 of 23

HONI states that it "... was granted an exemption until December 31, 2014 from the requirement to apply TOU pricing by a mandatory date under the Standard Supply Service Code for Electricity Distributors in respect of approximately 122,000 Regulated Price Plan (RPP) customers."

a) Given that HONI does not expect to be able to complete the conversion until "... there is improved telecommunications infrastructure or when there are advancements in telecommunications infrastructure", is HONI planning to request an extension to this exemption?
b) Please confirm that HONI does not plan to undertake any activity to convert these outstanding customers during the 2015-2019 period.

Response

a) Obtaining timely interval meter reads continues to be a challenge in rural and sparsely populated areas of Hydro One's service territory. Although Hydro One continues to refine processes and technology in order to increase the reach of the smart meter network, it is not economically feasible to move all customers to TOU. As a result, Hydro One will file for an exemption from the requirement to apply TOU pricing to all customers. The plan is to submit this application in the fall of 2014 to reflect any smart meter communications improvements that may be gained through network tuning in 2014.

b) Hydro One is completing the smart meter network tuning to maximize network reach to as many meters as possible within economic limits. The results from this effort will be available in the fall of 2014 at which time Hydro One will complete the movement of customers to/from TOU rates. This activity is expected to be completed by end of 2014. Hydro One does not expect that this activity will result in a material change in the total number of customers on TOU.

Barring any major step change in the telecommunication infrastructure reach within Hydro One's service territory Hydro One does not plan to undertake activities to convert the currently exempt group of customers to TOU in the 2015 – 2019 timeframe.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #38

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit F1, Tab 1, Schedule 1, Page 14 of 23**

Please define/explain the term "Head End" on line 24.

Response

"Head End" is defined as the "AMCC" in the Smart Meter Functional specification published by the Ministry of Energy and is defined as an Advanced Metering Control Computer that is used to retrieve meter reads from the smart meter population and temporarily store Meter Reads before they are transmitted to the MDM/R. This system is also used to monitor the health of the communication network; log and analyze maintenance and transmission faults; firmware version and security monitoring and control of network field devices and to issue reports on the overall health of the Automated Metering Infrastructure to the distributor.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #39

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit C1, Tab 2, Schedule 5, Page 10 and Exhibit F1, Tab 1, Schedule 1, Page 12**

Exhibit C1 states that "approximately 70,000 meters still require a visit by field staff to the customer premise due to limits in reach of the Smart Meter Network infrastructure". Exhibit F1 notes that " ... approximately 122,000 Regulated Price Plan (RPP) customers ..." remain to be converted to TOU rates. Please reconcile these numbers.

Response

Of the approximately 122,000 customers that remain on 2-Tier RPP, approximately 70,000 meters still require a manual read since Hydro One cannot obtain automated meter reads via the smart meter infrastructure (mainly in very rural and sparsely populated areas).

The remaining approximately 52,000 meters are read automatically via wireless signals and therefore may not require a manual meter read. However, the network reliability is inadequate to support TOU billing.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #40

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit D2-2-3, Reference #: S-10, Page 2 of 3**

a) Please clarify whether poles are replaced by small geographical groupings or on a single case by case basis? (i.e. would a crew ever be sent to replace a single pole on a planned basis?)

b) Does this program consider the replacement of average condition poles along with poor condition poles in the same area in order to achieve future efficiency savings? (i.e. of not having to revisit the same area within the near to medium term)

Response

a) Poles are identified for planned replacement by feeder and as such are replaced as a geographical grouping.

b) When replacing poles in poor condition, the risks associated with neighboring wood poles would be evaluated. Based on the results of this evaluation, these poles would be considered for replacement.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #41

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1, Tab 3, Schedule 2, Page 20 of 36

a) What percentage of HONI's lines are underground?
b) Are HONI's underground cables direct buried or placed in conduits? If both, please provide an approximate percentage breakdown.
c) Does HONI have a preferred standard, or are both methods (direct buried/conduit) employed depending on circumstances?

Response

a) Approximately 7% of Hydro One Distribution's lines are underground including submarine cable.

b) Hydro One Distribution has underground cables that are both direct buried and placed in conduit; however Hydro One does not track data on the breakdown of each type.

c) Hydro One Distribution's preferred standard for underground primary cable installation is in conduit, allowing for replacement in the event of failures. However both methods are employed depending on the installation. Secondary conductors are primarily direct buried.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #42

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit D**

In developing the spending plan for 2015-2019, please identify any capital programs that were considered but ultimately rejected. Please provide the program name, a brief description, and anticipated cost.

Response

Programs are repeatable pieces of work that utilize standardized designs that satisfy reoccurring needs at multiple locations. The extent of the work executed in any particular year, may change from year to year depending on its ranking in the prioritized programs and the overall availability of funds.

Programs are proposed with several levels of investment. There is a rigorous process to review the investment alternative proposals to ensure the alternatives are properly captured and each adds value to Hydro One and its customers. The vulnerable alternative includes non-discretionary investments required to ensure strict regulatory compliance and safety is reasonably assured. The level of funding associated with this level is relatively low or in rare cases the vulnerable level is $0 if the risks to the company are acceptable. The optimization tool, AIP, selects the best blend of alternatives.

In some cases during the executive review capital programs may be reduced to $0 in certain years to offset other risks and cost pressures. In the 2014-2019 planning process there were no capital programs that were rejected through the investment planning process.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #43

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit D**

Please produce a summary table (following the sample format provided below) listing all proposed capital programs along with the associated drivers of each program (safety, reliability, etc.). If a program is a result of more than one driver, please indicate the primary driver.

	Cost 2015	Driver 1	Driver 2	Etc…
Program 1	$	x	P	
Program 2	$	P		
Etc…	$	x	x	P

Response

Please see table below for a summary of Hydro One's proposed capital projects and programs along with the associated business value drivers. Hydro One investment plan is based on multi-criteria analysis; as such each program/project will address multiple drivers as is outlined in the table.

Project/Program in Exhibit D2		2015 Net Cost ($M)	Business Value Drivers						
			Safety	Customers	Reliability	Environment	Employees	Shareholder Value*	Productivity
S01	Transformer Spares and Replacements Program	18.0	X	X	X	X			
S02	Mobile Unit Substations Program	4.6		X	X				X
S03	Spill Containment	1.1	X			X			
S04	Station Component Replacements Program	2.1	X	X	X				
S05	Recloser Upgrades	1.4	X	X	X				X
S06	Demand Work Program	2.1	X	X	X			X	
S07	Station Refurbishments	34.6	X	X	X	X			
S08	Trouble Call and Storm Damage Response Program	58.2	X	X	X			X	
S09	Joint Use and Line Relocations Program	26.7		X				X	
S10	Pole Replacements Program	88.7	X	X	X			X	
S11	Lines PCB Equipment Replacements Program	1.9	X			X		X	
S12	Lines Sustainment Initiatives	33.4	X	X	X			X	
S13	Line Component Replacements Program	11.6	X	X	X			X	
S14	Submarine Cable Replacements Program	7.1	X	X	X			X	
S15	Meter Upgrades	10.0		P	X			X	X

Project/Program in Exhibit D2		2015 Net Cost ($M)	Business Value Drivers						
			Safety	Customers	Reliability	Environment	Employees	Shareholder Value*	Productivity
S16	Meter Inventory Sustainment	4.6		P	X			X	X
D01	New Connections, Service Upgrades and Metering	108.9		X				X	
D02	System Upgrades Driven by Load Growth	20.1		X				X	
D03	Upgrades Driven by Load Growth – Distribution System Modifications	9.0	X	X	X			X	
D04	Upgrades Driven by Load Growth – Demand Investments	3.6		X				X	
D05	Asset Life Cycle Optimization and Operational Efficiency	8.1		X	X			X	X
D06	Reliability Improvements	2.7		X	X			X	
D07	Orleans TS Capital Contribution	21.0		X	X			X	
D08	Red Lake TS Capital Contribution	1.8		X	X			X	
D09	Hanmer TS Capital Contribution	0.0		X	X			X	
D10	Enfield TS Capital Contribution	0.0		X	X			X	

Project/Program in Exhibit D2		2015 Net Cost ($M)	Business Value Drivers						
			Safety	Customers	Reliability	Environment	Employees	Shareholder Value*	Productivity
D11	Recloser Retrofit Project	1.0			X				
D12	Leamington TS Capital Contribution	0.0		X	X			X	
O01	Operating Compute Refresh	0.0			X				
O02	NOMS Refresh	0.0		X	X				
O03	Operating Facilities Refresh	0.0			X				
O04	BUCC – New Facilities Development	0.5			X			X	
O05	OGCC Storage Area Network Upgrade	0.0			X				
O06	ORMS Refresh	8.0		X	X			X	X
IT01	Hardware/Software Refresh and Maintenance	12.0		X	X			X	X
IT02	MFA Servers and Storage	7.1		X	X			X	X
IT03	MFA PC and Printer Hardware	5.6					X		X
IT04	MFA Telecom Infrastructure	2.7		X	X		X		X
IT05	Field Workforce Optimization and Mobile IT	5.0		X	X			X	X

Project/Program in Exhibit D2		**2015 Net Cost ($M)**	**Business Value Drivers**						
			Safety	**Customers**	**Reliability**	**Environment**	**Employees**	**Shareholder Value***	**Productivity**
IT06	Customer Experience	5.0		X					X
IT07	Information Rights Management	0.0			X				
IT08	Enterprise Analytics	2.0	X		X				X
IT09	Corporate Support Optimization	0.0	X			X		X	X
IT10	Engineering Design Transformation	0.0		X					X
IT11	Enterprise GIS	2.0		X					X
C01	Real Estate Head Office and GTA Facilities Capital	13.1	X	X				X	X
C02	Real Estate Field Facilities Capital	26.5	X	X	X			X	X
C03	Transport and Work Equipment	54.5	X		X				X
C04	Service Equipment	9.1	X		X				X
C05	Security Infrastructure Capital	1.0	X	X	X				

**Shareholder Value includes meeting license conditions and maintaining credibility with regulators.*

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #44

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D

Has HONI undertaken any external reviews of any of its capital programs (in terms of their need, urgency, and/or manner of implementation)? If not, why not?

Response

Hydro One does seek external assistance when developing capital programs on an as-needed basis. (Please see Hydro One's response to Exhibit I, Tab 4.2, Schedule 10 CCC 26.) However, Hydro One has made a significant investment in its rigorous planning processes, in-house expertise, and sophisticated data set and analytical tools. Retaining an external consultancy to review all of its capital programs would be an expensive redundancy that ratepayers should not have to pay for.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #45

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit D

Please map HONI's capital investments into the 4 categories specified in the OEB's Filing Requirements for Electricity Transmission and Distribution Applications (Chapter 5, page 6). Please include the forecast cost of each investment, and provide total costs for each investment category (i.e. General Plant, System Access, System Renewal. and System Service). Using best efforts, please map historical spending over 2011-2014 using the same methodology.

Response

For forecast capital expenditures in the test years, please refer to Hydro One’s response to Exhibit I, Tab 3.2, Schedule 1 Staff 53, Appendix A. Utilizing the same percentage assumptions applied in the 2015 to 2019 forecast in Staff 53, below are Hydro One’s best efforts at mapping the historical mapping into the investment categories.

Project/Program in Exhibit D2	2010	2011	2012	2013	2014
System Access					
Joint Use and Line Relocations Program	36.3	20.1	23.2	26.2	26.2
Meter Upgrades	1.0	2.4	6.0	8.3	8.6
Meter Inventory Sustainment	0.7	0.7	1.3	2.9	4.5
New Connections, Service Upgrades and Metering	92.0	95.4	107.2	92.7	105.5
System Renewal					
Transformer Spares and Replacements Program	3.9	8.7	18.1	18.4	14.6
Mobile Unit Substations Program	1.0	3.4	1.7	1.8	3.7
Spill Containment	0.3	0.6	1.3	1.9	1.1
Station Component Replacements Program	2.7	4.6	2.4	3.8	2.1
Recloser Upgrades	0.5	0.3	0.5	1.3	1.0
Demand Work Program	2.6	1.2	2.7	2.9	2.0

System Renewal					
Station Refurbishments	2.7	2.3	6.0	26.3	26.1
Trouble Call and Storm Damage Response Program	48.1	70.8	59.7	92.5	52.5
Pole Replacements Program	53.6	54.7	55.5	73.9	82.5
Lines PCB Equipment Replacements Program	1.7	0.8	1.0	1.1	0.0
Lines Projects	25.0	26.9	37.2	30.3	36.8
Operation Projects	1.2	1.3	2.7	3.6	5.1
System Service					
Trouble Call and Storm Damage Response Program	5.3	7.9	6.6	10.3	5.8
System Capability Reinforcement	49.3	45.9	56.7	70.0	61.1
General Plant					
Information Technology Projects	18.9	26.1	19.4	13.4	29.8
Cornerstone Initiative	8.3	49.6	67.8	47.6	8.7
Facilities & Real Estate & Station Security Upgrades	14.9	22.1	13.0	10.2	19.9
Transport & Work, and Service Equipment Programs	51.1	36.3	39.9	43.5	51.4

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #46

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D

Has HONI performed a resource planning analysis to ensure that it has the needed labour resources (whether internal or contractor) to complete its proposed capital plan as filed?

Response

Please see Exhibit C1, Tab 3, Schedule 1 (pp.4-9) for a discussion on the staffing strategy and Exhibit A, Tab 17, Schedule 6 (pp. 4-11) for a discussion on implementing the work execution strategy for the 2014-19 work program.

Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #47

Issue #3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Capital Planning

a) Given the significantly increased budgets in 2015-2019 over prior years and the apparent urgent nature of some of the proposed capital programs, did HONI consider making any of the investments proposed in this application prior to 2015? If not, why not?

b) Did HONI consider filing an ICM application for 2014? Please explain why HONI ultimately did not feel such an application would have been appropriate or required.

c) Did the absence of an ICM application in 2014 result in certain planned 2014 projects to be delayed into 2015? If so, please identify any affected projects.

Response

a) Please see the response to Exhibit I, Tab 3.2, Schedule 1 Staff 56.

b) Hydro One's experience with ICM applications has not been successful so Hydro One did not file an ICM in 2014 and is filing this Custom application to properly reflect adjustments to rate base for in service additions.

c) The timing of investments over the 2015 – 2019 period reflects prioritized planning and risk assessment to develop an optimal plan and is not the result of any delay in projects from 2014.

Power Workers Union (PWU) INTERROGATORY #6

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **(a) Exh D1, Tab 2, Schedule 1. Distribution Asset Investment Overview.**
(b) Exh D1, Tab 3, Schedule 2, Page 19.

Ref (b) states:

> **The strategy is to address stations that are at a high risk of failure as determined by the asset risk assessment and prioritized based on the impact of failure of key factors including customer, safety and environmental risks.**

(c) Exh D2, Tab 2, Schedule 3, Reference #: S-07. Hydro One Distribution – Investment Summary Document Sustaining Capital – Stations

a) Please provide the current demographics of Hydro One Distribution Stations.

b) Please list Hydro One Distribution Stations that were replaced/refurbished in 2010, 2011, 2012 and 2013 historical years and projected for the 2014 bridge year.

c) Please provide the rate (share in total distribution stations) of stations replaced/refurbished for 2012, 2013 historical years and 2014 bridge year.

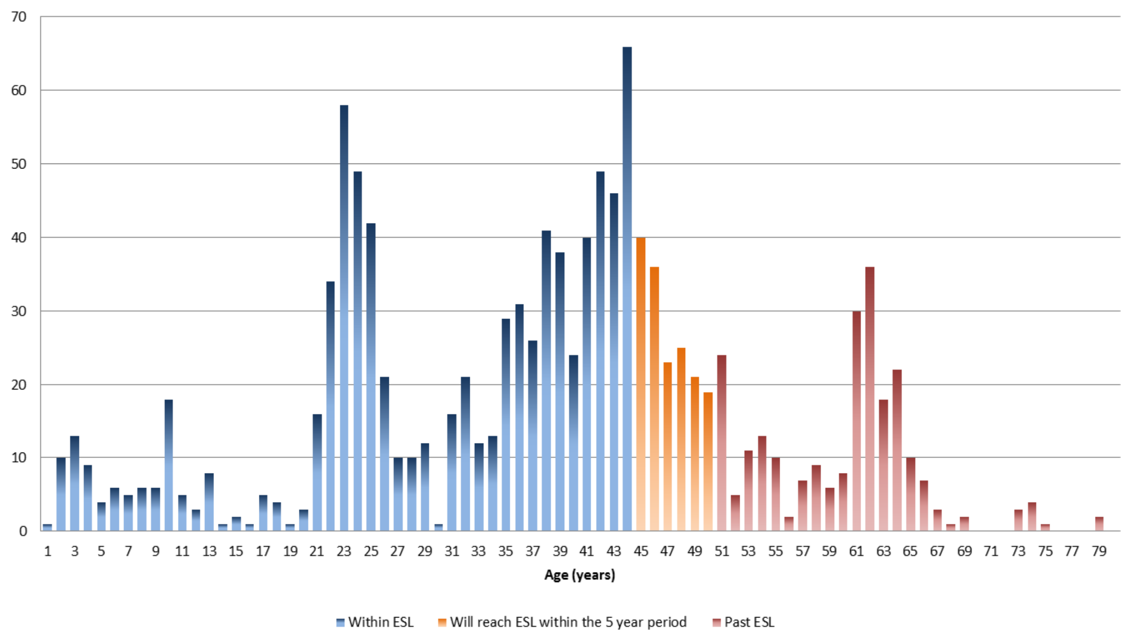
d) How many stations are currently at a high risk of failure?

e) How many stations would be at a high risk of failure by 2020 assuming Hydro One's proposed stations refurbishments over the test period 2015-2019 are accomplished?

f) How many stations would be in a high risk of failure by 2020 assuming historical replacement or refurbishment rates are maintained?

Response

a) Hydro One's distribution stations consist of many components including but not limited to power transformers, disconnect switches, bus, insulators, fuses, support structures, reclosers, fences, grounding systems, instrument devices. Using the most critical component of a distribution station, station transformers, as a proxy for the station age below is the current demographics of Hydro One's distribution stations.



b) Please see response to Exhibit I, Tab 3.03, Schedule 1 Staff 61 for a listing of Distribution Stations that underwent major capital upgrades in the 2010 to 2013 period, as well as the distribution stations planned for completion in 2014.

c) The following table represents the rate of distribution stations (compared to the total station population) that underwent major capital upgrades in the 2010 to 2013 and the ones planned for completion in 2014.

Year	**2012**	**2013**	**2014**
Number of Station Upgrades	3	14	32
Percentage of Population	0.3%	1.4%	3.2%

d) Approximately 27% of the distribution stations are currently at high risk of failure.

e) Assuming that Hydro One's proposed station refurbishments over the test period of 2015 to 2019 are accomplished, it is expected that by 2020 the number of high risk stations will remain at approximately 27% of distribution station.

f) Assuming that historical refurbishment rate (average of 5 stations per year) are maintained over the 2015 to 2019 period, it is expected that by 2020 the number of stations that will be high risk will increase by the number of stations in the proposed plan that will not be refurbished and account for approximately 44% of the distribution station population.

Power Workers Union (PWU) INTERROGATORY #7

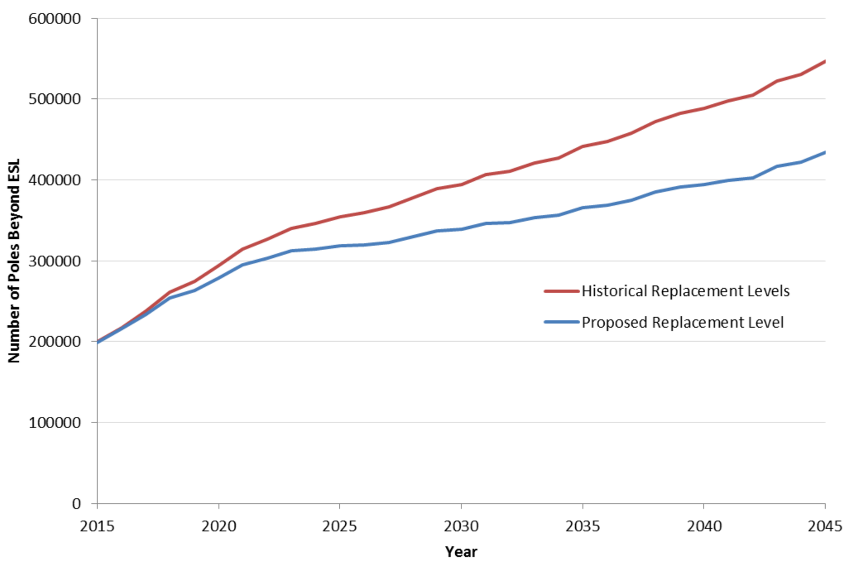
Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **(a) Exh D1, Tab 2, Schedule 1, Pages 18-25. Distribution Asset Investment Overview, 2.2.1 Poles.**

Ref (a) pages 24-25 states:

> **Trends and Impacts**
> **Hydro One Distribution proactively replaced approximately 11,000 poles in 2013 under its pole replacement program. Over the next several years, an increasing number of poles are expected to reach the end of their service life each year. In order to manage the large number of replacements that will be rapidly required, Hydro One Distribution is proposing an increase in the number of replacements to approximately 15,200 poles annually. As can be seen in Figure 15, this proposed replacement rate will assist in mitigating the increased reliability and safety risk associated with ageing distribution poles.**



Reference: **(b) EB-2012-0136, Exh B, Tab 2, Schedule 3, Pages 11-12**

1.2.1 Summary

To compare the long-term impacts of the scenarios, the numbers of EOL poles remaining in-service each year are considered. These are shown in Figure 2.

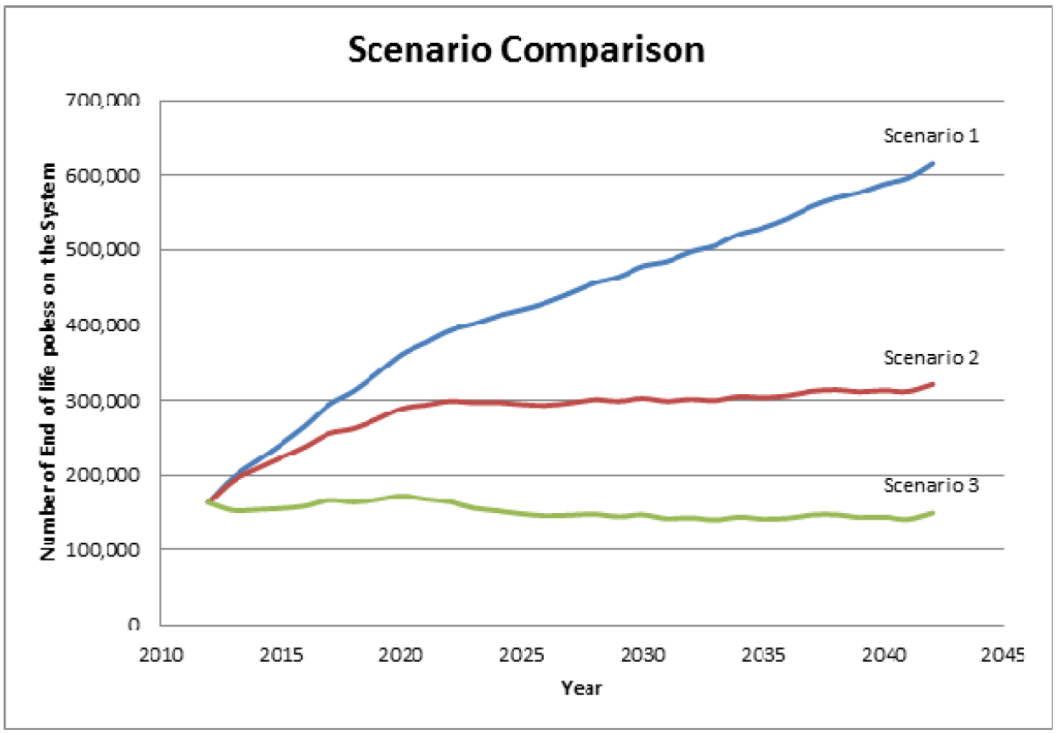


Figure 2: End-of-life wood poles existing in the distribution system over the next 30 years

Scenario 1 demonstrates what will happen if Hydro One continues to replace only 7,500 poles per year. After 10 years the number of EOL poles will be 390,000, after 20 years that number will increase to 500,000. By 2042, 30% (~620,000) of all poles remaining in the system will have exceeded their expected useful life. In Scenario 1, the number of EOL poles increases annually…

Scenario 2 shows what will happen assuming a volume of 11,000 poles in 2013 plus an incremental increase of 2,000 poles replaced annually through the Wood Pole Replacement program up to 20,000 poles annually by 2018. At the end of 10 years the volume of EOL poles will increase to 300,000. After 20 years that volume will remain the same. By 2042, about 20% (~320,000) of all poles remaining in the system will have exceeded their expected useful life…

Scenario 3 attempts to maintain the current volume of EOL poles. It assumes that 30,000 poles are replaced annually until 2023, after which the volume is reduced to 22,500 poles a year until 2026 and maintained at that rate thereafter. In this scenario, after 10 years the number of EOL poles will reach approximately 160,000 and after 20 years that number will be reduced to 140,000 poles and after 30 years the number of end of

life poles will be at 150,000. Scenario 3 generally maintains the current level of EOL poles.

a) What percentage of Hydro One 's wood poles are currently in "Fair", "Poor" and "Very Poor" condition?

b) As per Ref (b), in EB-2012-0136 Hydro One proposed Scenario 2 which assumed a volume of 11,000 in 2013 plus an increase of 2,000 poles replaced up to 20,000 poles annually by 2018 and that at the end of the next 10 years the volume of EOL poles would increase to 300,000 and remain around that level. In preparing the current Application, did Hydro One consider a scenario in which it would be able to achieve and maintain a relatively stable level of End of Life (EOL) poles subsequent to an initial period of ramp-up in pole replacement activity?

c) How many poles a year would Hydro One need to replace over the test period 2015-2019 in order to maintain the current level of poles beyond the Expected Service Life (ESL)?

d) Given that Hydro One has approximately 1.7 million wood poles, and that the average expected EOL is less than 100 years, please explain how any replacement strategy that does not replace, at a minimum, more than 17,000 poles per year can be considered to be sustainable?

Response

a) Hydro One no longer uses the terminology "Very Good", "Good", "Fair", "Poor", and "Very Poor" of the Asset Condition Assessment applied in proceeding EB-2009-0096; rather Hydro One now utilizes an Asset Risk Assessment methodology that classifies equipment condition based on level of risk relative to the asset population. Approximately 4% of Hydro One's wood pole condition assessments fall into the high risk category.

b) As part of the Planning Process described in Exhibit A, Tab 17, Hydro One's proposed plan as well as a level similar to the scenario described in the question were considered. The proposed level of funding was selected to balance asset risks, rate impact to customers, and the ability to resource the work.

c) Between 2015 and 2019 approximately 28,000 poles per year will be reaching their expected service life.

d) Please see response to Exhibit I, Tab 2.2, Schedule 11 EP 13.

<u>Power Workers Union (PWU) INTERROGATORY #8</u>

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: (a) Exh D1, Tab 3, Schedule 2, Page 29, Lines 1-2.

Ref (a) states:

> **In addition to concerns with demographics, Hydro One Distribution continues to address a subset of red pine poles that are demonstrating premature deterioration.**

a) How many defective red pine poles have been replaced each year since the problem of defective red pine poles was identified?

b) How many defective red pine poles does Hydro One expect to replace each year of the 2015-2019 test period?

Response

a) The following table summarizes the number of red pine poles replaced to date.

	2009	**2010**	**2011**	**2012**	**2013**	**2014 YTD**
Number of red pine poles replaced	121	201	374	1,180	2,139	1,173

b) Hydro One is proposing to replace on average 3,500 defective red pine poles per year over the test period.

Power Workers Union (PWU) INTERROGATORY #9

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **(a) Exh D1, Tab 2, Schedule 1, Pages 1-9. Distribution Asset Investment Overview, 2.1.1 Transformers.**

a) What percentage of station transformers are currently in "Poor" or "Very Poor" condition?

Response

Hydro One no longer uses the terminology "Very Good", "Good", "Fair", "Poor" and "Very Poor" of the Asset Condition Assessment applied in proceeding EB-2009-0096; rather Hydro One now utilizes an Asset Risk Assessment methodology that classifies equipment condition based on level of risk relative to the asset population. As mentioned in Exhibit D1, Tab 2, Schedule 1, Page 5, approximately 24% of Hydro One's distribution station transformer condition assessments fall into the high risk category.

Power Workers Union (PWU) INTERROGATORY #10

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **a) Exh D1, Tab 2, Schedule 1, Pages 18-25. Distribution Asset Investment Overview**
b) EB-2012-0136, Exhibit I, Tab 2, Schedule 6.13 PWU 14

In its response, Hydro One provided the following:

	Asset Class	Stations	Transformers	Poles
(1)	Number of Units 2012	1002	1212	1,700,000
(2)	Current Replace Rate	4	6	7,200
(3)	Proposed Replace Rate	32	36	11,000
(4)	% ESL 2012	24%	19%	10%
(5)	# ESL 2012	242	226	170,000
(6)	Ave # per year Reaching ESL 2013-2021	24	30	30,500
(7)	% ESL 2021 using (2)	42%	36%	22%
	# ESL 2021 using (2)	421	439	380,000
	% ESL 2021 using (3)	17%	14%	20%
(8)	# ESL 2021 using (3)	169	169	346,000
(9)	Ave # per year Reaching ESL 2022-2031	25	34	22,400
(10)	Backlog # ESL Reduced over 2022-2031 using (2)	Increase of 178	Increase of 193	Increase of 152,000
(11)	Backlog # ESL Reduced over 2022-2031 using (3)	Reduction of 74	Reduction of 77	Increase of 114,000
(12)	% ESL 2031 using (2)	63%	59%	31%
(13)	# ESL 2031 using (2)	628	716	532,000
(14)	% ESL 2031 using (3)	10%	12%	27%
(15)	# ESL 2031 using (3)	96	146	460,000

Notes:
(1) A constant replacement rate was assumed to complete the above table. However, this information is for illustrative purposes only and is not intended to represent future proposed levels; future replacement rates will be determined through future applications.
(2) To simplify the analysis in the table above, it was assumed the oldest station, transformer, or pole would be replaced first. However this is for illustrative purposes only, actual replacement candidates are selected based on a combination of age, condition, etc.
(3) The analysis in the above table utilized Expected Service Life (ESL) for the assets. For distribution stations and transformers the ESL assumed was 50 years, and an ESL of 62 years for distribution poles. This analysis for distribution poles replacements does not include poles that were not treated to CSA standard.

a) Please update the table below in similar fashion as the table above.

	Asset Class	Stations	Transformers	Poles
(1)	**Number of Units 2014**			
(2)	**Current ReplaceRate**			
(3)	**Proposed Replace Rate**			
(4)	**% ESL 2014**			
(5)	**# ESL 2014**			
(6)	**Ave # per year Reaching ESL 2015-2020**			
(7)	**% ESL 2020 using (2)**			
	# ESL 2020 using (2)			
(8)	**% ESL 2020 using (3)**			
	# ESL 2020 using (3)			
(9)	**Ave # per year Reaching ESL 2021-2030**			
(10)	**Backlog # ESL Reduced over 2021-2030 using (2)**			
(11)	**Backlog # ESL Reduced over 2021-2030 using (3)**			
(12)	**% ESL 2030 using (2)**			
(13)	**# ESL 2030 using (2)**			
(14)	**% ESL 2030 using (3)**			
(15)	**# ESL 2030 using (3)**			

Response

Please see below completed table for the requested analysis with respect to the number of distribution stations, transformers and poles exceeding the expected service life.

	Asset Class	Stations	Transformers	Poles
(1)	**Number of Units 2014**	1004	1214	1,600,000
(2)	**Current Replace Rate**	5	7	11,000
(3)	**Proposed Replace Rate**	2015: 36 2016: 38 2017: 38 2018: 41 2019: 41	2015: 32 2016: 33 2017: 32 2018: 37 2019: 38	2015: 11,600 2016: 12,200 2017: 13,200 2018: 14,200 2019: 15,200
(4)	**% ESL 2014**	19%	19%	11%
(5)	**# ESL 2014**	188	234	180,000
(6)	**Ave # per year Reaching ESL 2015-2020**	25	27	28,000
(7)	**% ESL 2020 using (2)**	31%	29%	18%
	# ESL 2020 using (2)	308	354	282,000
(8)	**% ESL 2020 using (3)**	11%	15%	17%
	# ESL 2020 using (3)	106	188	266,400
(9)	**Ave # per year Reaching ESL 2021-2030**	32	39	21,000
(10)	**Backlog # ESL Reduced over 2021-2030 using (2)**	Increase of 270	Increase of 320	Increase of 100,000
(11)	**Backlog # ESL Reduced over 2021-2030 using (3)**	Decrease of 60	Increase of 30	Increase of 58,000
(12)	**% ESL 2030 using (2)**	58%	56%	24%
(13)	**# ESL 2030 using (2)**	578	674	382,000
(14)	**% ESL 2030 using (3)**	5%	18%	20%
(15)	**# ESL 2030 using (3)**	46	218	324,400

<u>Notes:</u>

(1) A constant replacement rate was assumed to complete the above table. However, this information is for illustrative purposes only and is not intended to represent future proposed levels; future replacement rates will be determined through future applications.

(2) To simplify the analysis in the table above, it was assumed the oldest station, transformer, or pole would be replaced first. However this is for illustrative purposes only, actual replacement candidates are selected based on a combination of age, condition, etc.

(3) The analysis in the above table utilized Expected Service Life (ESL) for the assets. For distribution stations, transformers were used as a proxy of the station demographics and an ESL assumed was 50 years. For transformers and distribution poles the ESL assumed was 50 years and 62 years respectively. This analysis for distribution poles replacements does not include poles that were not treated to CSA standard.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #60

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015- 2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: A/T17/S3

Preamble: The proposed capital expenditure for the rate period is significantly in excess of the prior period. The purpose of this interrogatory is to understand the changes in Hydro One's business planning that led to past under investments in distribution plant.

a) When did Hydro One begin the implementation of the Asset Analytics tool?
b) Was the Asset Analytics tool the main instrument used to discover what past under investments needed to be addressed?
c) Please explain the relationship (if any) between the Asset Analytics tool and the new Asset Investment Planning (AIP) solution.

Response

a) Hydro One began implementation of the Asset Analytics tool in 2011, with the initial deployment of the tool in 2012.

b) Asset Analytics is a tool that can be used by investment planners to aid in performing asset risk assessments, as described in Exhibit A, Tab 17, Schedule 7. Asset Analytics streamlines the gathering of information, as it contains a consolidation of data that until the development of this tool largely resided in separate systems. The development of investments, however, is determined by the overall Planning Process described in Exhibit A, Tab 17, Schedule 1, not by Asset Analytics.

c) Asset Analytics can be used by investment planners to aid in the assessment of asset needs. The planners utilize this information to develop investment alternatives as part of the planning process, which the Asset Investment Planning solution evaluates to generate an optimized investment plan.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #61

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015- 2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: A/T17/S4/pg. 8 D1/T2/S1

Pre-amble: The illustrative example for prioritization of the Distribution Station Transformer Replacement programs concludes by noting that the historical replacement rate of transformers is lower than the expected life would require. This situation might have occurred for a number of reasons including: (1) Hydro One has recently changed its capital planning policy from run to failure to preemptive replacement; (2) there was previously insufficient data on asset age and condition or to make the noted assessment; (3) while the data was available insufficient effort was put into analyzing this data for planning purposes; or (4) the Utility choose to under invest in assets during prior rate periods in order to improve returns or for some other reason.

a) Hydro One is proposing significant increases in the capital program for the following areas:
   i. Transformers (other than line transformers)
   ii. Reclosers/Breakers
   iii. Station Switches/Fuse
   iv. Poles
   v. Line Projects
   vi. Line Transformers

For each these areas while Hydro One has described the reasons for accelerating its capital program it has not explained why took until 2015 to recognize the need for a change to its capital planning. Please explain what has changed since the last cost of service application to cause a departure from past spending practices. Please address the question of why the Board should not find that the Utility acted imprudently in the past by under investing in capital projects.

Response

The asset replacement rates in Hydro One Distribution's last cost of service application (EB-2009-0096) were based on evidence filed, in consideration of conditions extant and predicted at that time. As outlined in Exhibit I, Tab 3.2, Schedule 1 Staff 56, Hydro One did request to start ramping up the capital funding in its 2013 rate application (EB-2012-0136) and the current proposed plan for 2015 to 2019 continues to address the need for increased asset replacements to mitigate the large number of assets exceeding their expected service life.

Since Hydro One Distribution's last cost of service application, new tools have been developed such as Asset Analytics that have reaffirmed the need to increase the level of capital expenditure required for particular assets as noted below.

i. Station Transformers

Please see response to Exhibit I, Tab 3.2, Schedule 1 Staff 56.

ii. Reclosers/Breakers

The increase in reclosers/breakers mainly coincides with the increase in the integrated Station Refurbishments; as such please see response to Exhibit I, Tab 3.2, Schedule 1 Staff 56.

iii. Station Switches/Fuses

The increase in station switches/fuses mainly coincides with the increase in the integrated Station Refurbishments; as such please see response to Exhibit I, Tab 3.2, Schedule 1 Staff 56.

iv. Poles

Please see response to Exhibit I, Tab 3.2, Schedule 1 Staff 56.

v. Line Projects

Line projects involve the refurbishment of multiple components including poles, conductors, cross arms, and other line equipment. Investments in these projects are increasing correspondingly with overall increases in individual component replacements to address aging demographics and ensure that assets requiring replacement remain at a manageable level. As outlined in Exhibit I, Tab 3.2, Schedule 1 Staff 56, new asset information has become available that indicates increased levels of capital expenditure are required.

vi. Line Transformers

Hydro One has historically had a "run to failure" policy on distribution line transformers. The introduction of the Federal PCB legislation has required Hydro One to implement a planned line transformer replacement program to focus on transformers with >50 ppm PCB concentration. Hydro One has been focusing on data collection tools in recent years in order to allow a more focused Inspection and Testing Program which will drive the above capital replacement program.

Hydro One believes that it has planned and invested in an appropriate manner in the past and that the Board has provided prudent approval of its capital investment plans.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #62

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015- 2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: D1/T2/S1/pg. 31 & C1/T2/S2/pg. 15

With respect to Line Transformers:

a) What year legislation came into effect requiring transformers containing PCB s were required to be removed.
b) Please explain the capital budget policy prior to this year that was addressing this issue.
c) Please explain why a run to failure policy is not being continued for all transformers that do not contain PCBs (i.e. those manufactured after 1985).

Response

a) The Federal PCB Legislation was enacted in September 2008.

b) Hydro One Distribution's replacement strategy for line transformers was historically a "run to failure" policy; there was no specific program to address this issue. With the enactment of the PCB legislation, Hydro One initially focused on the inspection, testing and replacement of pad-mounted transformers over the 2009 to 2013 period. Beginning in 2014, the pole mounted lines equipment is now being addressed.

c) Hydro One continues to have a "run to failure" policy for all line transformers that do not contain PCB's, which includes all line transformers that were manufactured after 1985 and all the pre-1985 transformers that will be sampled and found to be compliant with PCB legislation.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #63

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015- 2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **D1/T2/S1/pg. 17-19 & D1/T3/S2**

a) Why does the accelerated capital program to improve transformers, breakers, switches etc., not have an impact (reduction) on the number of Mobile Unit Substations being required over the period of the rate plan?

b) For each of the last 3 years what was the deployment/use rate for the MUS (e.g. 90% in 2013 would indicate that the units were deployed and operating 90% of the time).

Response

a) The main purpose of the MUS fleet is to provide emergency power restoration, load relief, and carry the station load during equipment maintenance and capital activities, as stated in Exhibit D1, Tab 2, Schedule 1 page 15. As such as the capital projects increase so does the usage time of the MUS fleet. However MUS's cannot be deployed 100% of the time for capital activities as there must be a portion of the fleet on standby for emergency power restoration purposes to support equipment failures across the province. This has resulted in the requirement to increase the number of MUS's over the 2015 to 2019 period.

b) Hydro One does not compile deployment/usage rates for each MUS. The MUS's are tracked and scheduled for load relief and equipment maintenance and capital activities based on maintaining the required number of MUSs on standby for emergency power restoration. MUS's are also removed from service for annual overhauls, MTO inspections, refurbishments and corrective work. Therefore the fleet of MUS's could never be deployed 100% of the time due to the need to ensure the safe and reliable operation of the MUS in accordance with requirements of the Highway Traffic Act and the need for standby units readily available for dispatch to failures for emergency restoration of customer load.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #64

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015- 2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: D1/T2/S1/pg. 6

a) How does Hydro One determine that a transformer major failure was avoided when it proactively removes a transformer (i.e. prior to failure)?
b) Why reasons does Hydro One believe account for actual transformer failures decreasing since 2009?
c) Has Hydro One done a cost-benefit analysis of a run to failure vs. proactive replacement policy? If so please provide this. If not please explain why not.

Response

a) Hydro One performs oil testing on an annual basis of all transformers and tap changers to determine the condition of the transformer oil through lab analysis. These test results are then analyzed by technical personnel. If the results show signs of an imminent failure, the transformer is forced from service for further diagnostic tests to identify and repair the problem or change the transformer if necessary.

b) Improvements in diagnostic testing practices may account for this shift between major failures and major failures avoided. With equipment failures, some year over year variations is expected, as failures are not predictable by nature. Since 2009 the number of major transformer failures has declined, however the number of major failures avoided by proactively removing the transformer from service has been trending higher as outlined in Exhibit D1, Tab 2, Schedule 1 Figure 4. The overall long-term trend of failures is gradually increasing.

c) Based on the cost of a distribution station transformer and the impact a transformer failure has on customers, Hydro One does not have a run to failure policy for distribution station transformers. As such, Hydro One has not performed a cost-benefit analysis for this scenario. For details on the impact of planned transformer replacements and demand failure transformer replacements, please see response to Exhibit I, Tab 3.2, Schedule 14 AMPCO 25.

<u>Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #65</u>

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015- 2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

<u>Interrogatory</u>

Reference: D1/T3/S2/pg. 6

a) At the noted reference Hydro One makes the claim that reduction in sustaining capital would have impact on three listed areas. Please provide the cost-benefit analysis which supports that statement. That is, please provide the analysis which was undertaken to show the impact of budget dollar changes on service reliability.

b) The statement is made without qualification – that is it claims a "marked reduction" in reliability standards for any reduction in capital spending. Clearly this cannot be true as Hydro One is unlikely (except by serendipity) to have actual spending precisely equal its forecasts. Please provide the sensitivity analysis that was undertaken to show likelihood of reliability or regulatory requirement adverse effects should the budgets be underspent.

<u>Response</u>

a) A reduction in sustaining capital for distribution stations and lines assets (specifically transformers and wood poles) would have an impact on reliability. Reductions in capital spending would result in a decrease in the volume of assets replaced, subsequently increasing the number of assets beyond their expected service life. Operating the distribution system with assets beyond their expected service would increase the risk of equipment failure. As described in Exhibit D1, Tab 2, Schedule 2, pages 9 to 10, distribution station transformer failures result in lengthy outages to a large volume of customers, as all customers served by the station would be impacted. Similarly, line equipment failures result in outages that are significantly longer than planned outages as demonstrated for wood poles in Exhibit D1, Tab 2, Schedule 1, page 23. By increasing both the likelihood and the duration of outages from equipment failures, reductions in capital spending would result in decreasing reliability performance.

b) The marked reduction in equipment and customer reliability due to reductions in capital spending was specific to reductions in the area of distribution station transformers. As noted in part (a), reductions in capital spending on distribution station transformers would result in a decrease in the volume of assets addressed and a subsequent increase in the risk of equipment failure. Since a majority of the distribution stations are a single transformer arrangement; in the event of a transformer failure, the entire distribution station load would be interrupted affecting all downstream customers. Hence reductions in capital spending would result in decreasing reliability performance.

School Energy Coalition (SEC) INTERROGATORY #25

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit D1/Tab 1/Schedule 2/p.3

Please provide a table showing for each year between 2010 and 2014, actual versus Board approved/budgeted in-service capital additions.

Response

Refer to Exhibit D1, Tab 1, Schedule 2, Page 2, Table 1. Board approved in-service capital additions are only available for 2010 and 2011 in EB-2009-0096, as provided in Table 1. 2012 to 2014 were IRM years and thus the Board did not set in-service capital addition levels for those years, under the Board's 3rd Generation Incentive Regulation.

School Energy Coalition (SEC) INTERROGATORY #26

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 3/Schedule 2/p.32

Please explain the significant year over year changes in Metering capital.

Response

The primary reason for the increase is due to technological obsolescence, specifically replacement of meters and metering telecommunications equipment using CDMA cellular technology. Hydro One uses 3rd party provided cellular networks to obtain the necessary revenue metering data from retail and wholesale meters to meet the daily Time of Use reporting obligations and in the preparation of customer billing. These telecommunication providers are replacing their existing cellular technology with the next generation wireless technology; which will require Hydro One to update its associated metering telecommunication equipment. This replacement program runs from 2014 to 2018 after which the program forecasted spending will return to historical levels.

School Energy Coalition (SEC) INTERROGATORY #27

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 3/Schedule 5/p.2

Please provide copies of all reports or analysis detailing the findings of previous smart grid pilot projects.

Response

There are no reports available to file at this time. The business validation activities are still continuing for the Smart Grid Pilot to date. However, we have summarized our findings to date. Please see the response to Exhibit I, Tab 3.2, Schedule 1 Staff 52 for a summary of the findings to date from the smart grid pilots.

School Energy Coalition (SEC) INTERROGATORY #28

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit D2/Tab 2

For each of the Investment Summary Documents, why did the Applicant not do an economic cost/benefit analysis for each alternative?

Response

Before Investment Summary Documents (ISDs) are prepared the costs and risks associated with all work program areas are prioritized through the planning process described in Exhibit A, Schedule 17. Once the prioritized work program and investment plan is finalized, ISDs are prepared for all capital programs greater than $1 million in any one test year to provide a fuller description of these material work programs.

School Energy Coalition (SEC) INTERROGATORY #29

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D2/Tab 2/Schedule 3

Please detail the Investment Summary Document creation process.

Response

Please see the response to SEC IR 28 at Exhibit I, Tab 3.2, Schedule 9 SEC 28 for how ISDs are created. The Investment Summary Document (ISD) approach has been used by Hydro One in several recent cost-of-service filings for Distribution and Transmission rate proceedings. The format of the ISDs in this application has been changed to reflect the Board's new Chapter 5 filing requirements but the overall creation process and purpose of the ISDs remains the same.

Energy Probe Research Foundation (EP) INTERROGATORY #28

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit D1, Tab 1, Schedule 2, Page 2, Table 1, 2013 ICM and Exhibit D1, Tab 1, Schedule 2, Attachment 1, Page 2, Table 1 In Service Additions 2011-2014 Historic/Bridge years**

a) Please provide support for 2013 and 2014 Common and Other ISAs.

b) Provide explanation(s) for 2013 ICM, see Exhibit D1, Tab 1, Schedule-2, Attachment 1, Page 2, Table 1.

Response

a) Please see table below for Common and Other ISAs (in $ millions).

	2013	**2014**
Transport and Work, and Service Equipment	43.4	51.6
Information Technology	17.6	18.1
Cornerstone	154.1	9.6
Facilities & Real Estate	8.4	29.3
Other	-	-
Total	223.4	108.6

For the increase in TWE and Facilities & Real Estate in 2014, please refer to Exhibit D1, Tab 3, Schedule 9 and Exhibit D1, Tab 3, Schedule 8, respectively. The increase in Cornerstone ISA in 2013 is due to the implementation of the CIS system. IT ISA is relatively consistent in both years.

b) Explanations are provided on the remaining pages of Attachment 1 to Exhibit D1, Tab 1, Schedule 2.

Energy Probe Research Foundation (EP) INTERROGATORY #29

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit D, Tab 2, Schedule 10, Pole Replacement Program

a) Confirm/calculate Cost per Pole:
   i 2013 Actual;
   ii 2014 Budget;
   iii 2015 $8765;
   iv 2019 $9408.

b) Please explain why unit costs are increasing while volume increases.

c) Provide the breakdown of unit costs including:
   i. Capital (acquisition)
   ii. Removal of old pole
   iii. Installation

Response

a) The following are the net unit prices for wood pole replacements.
   i 2013 Actual $6894
   ii 2014 Budget $7503
   iii 2015 Budget $7646
   iv 2019 Budget $8276

b) The estimated unit prices for wood pole replacements are based on an historical average of actual unit prices. The only increase between the 2014 budgeted amount and the test years is the estimated inflation within the labour rates, material costs, and TWE prices.

c) The following is the unit cost breakdown:

	Percentage of Net Unit Price
Material	13%
Removals	N/A*
Installation	87%

(*) Unit prices are net of removals.

Energy Probe Research Foundation (EP) INTERROGATORY #30

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **Exhibit D1, Tab 3, Schedule 2, Page 15 and**
Exhibit D2, Tab 2, Schedule 07, Stations Refurbishment

Preamble:
Hydro One Distribution has also developed a new prefabricated integrated modular distribution station containing a transformer and switchgear mounted on a platform which forms a complete station. The introduction of the integrated Modular Distribution Station (iMDS) will provide a more cost effective solution to station refurbishments where space is limited especially in urban areas. The modular design is also more aesthetically pleasing compared to existing designs.

a) Please provide the average costs of iMDS compared to conventional.

b) Please provide the Lifetime compared to conventional.

c) Please provide a schedule that shows the Number units per year Conventional and iMDS (Approximately 40 stations refurbished per year).

d) Please provide the Annual Savings 2015-2019 due to iMDS.

Response

a) The average cost of a conventional refurbishment, where every piece of equipment is replaced, for a 44 kV distribution station is approximately $2.4 million. The average cost of a complete refurbishment, utilizing an integrated modular distribution station (iMDS) for a 44 kV distribution station based on the pilot of this technology in 2013 was $1.9 million.

b) The expected service life of the integrated modular distribution station will be the same as a conventional distribution station.

c) Hydro One is planning to install approximately six integrated modular distribution station's per year from 2015 to 2019; however this is dependent on the success of the iDMS pilot project.

d) At this point in time, it is too early in the pilot project to quantify efficiencies gained or cost savings. This pilot project is still underway and once completed, Hydro One will be in a better position to quantify cost savings. Hydro One is anticipating efficiencies with the use of the iMDS resulting from the distribution station being manufactured, assembled and tested by an external vendor, which will enable the cost of installion to be lower than a conventional refurbishment. Also the integrated modular distribution station will be utilized in small urban stations where Hydro One would have to purchase property or relocate the station in order to use a conventional refurbishment.

Energy Probe Research Foundation (EP) INTERROGATORY #31

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1, Tab 3, Schedule 4, Table 3, Operations Capital

a) Please provide the Business Case for BUCC ISD O04D2 T2 S3.

b) Please provide the need for and alternatives to the proposed facilities.

c) Please provide why the costs of the ORMS Refresh cannot be spread over the 5 year plan period.

Response

a) The BUCC no longer meets Network Operating's business or operational requirements to sustain Hydro One monitoring and control operations to required standards. There are many limiting factors and deficiencies that have been identified that may render the BUCC inoperable. The risk of reoccurring failures continues to increase and is currently beyond acceptable levels. The business case justification is therefore predicated on providing for the requirements of Network Operating and mitigating the risk of facility failure(s). Additionally, a fully functioning and reliable BUCC mitigates potential impacts to Hydro One, most notable are; regulatory compliance, financial risk, customer impacts and reputational harm.

The BUCC facility consists of the physical building which houses the backup control rooms for the Hydro One transmission and distribution systems and the associated computer rooms. The existing computer rooms are one of the most limiting factors that put the BUCC at risk. They have reached their design limits in terms of physical space, power supply and environmental controls. As a result, full redundancy of all systems is not currently available and the reliability of Operating backup facilities has been reduced. Operating has experienced an increase in critical failures, and emergency preparedness considerations have become a significant concern.

b) The current Back-up Control Centre facility is greater than 40 years of age and has served as Network Operating's BUCC since 2004. In this time, Hydro One has experienced an increase in functional requirements due to regulatory requirements, systems, applications, and tool growth, while at the same time experiencing an increase in critical failures.

Network Operating is also limited in its ability to provide backup recovery for other major distribution system tools, most notable, the Distribution Management System (DMS) and the Outage Response Management System (ORMS).

Alternatives:

Alternative	Cost	Analysis
Enhancement of existing BUCC	Varies $25M	This option fails to provide scalability and flexibility. This option cannot provide for Network Operating requirements and fails to adequately address identified risks.
Build a New BUCC	Varies $40M	This option provides a new building for Network Operating's requirements. Reliable power, communication connections, meets capacity requirements with scalability to address future growth. This is the recommended alternative.
Buy / Lease	Varies >$35M	Analysis of this option has determined that it is cost prohibitive to buy or lease an existing facility. The requirements of Operating in terms of communication, power and infrastructure would require further costs not present in the initial purchase cost.
Co-location of Computer Rooms	Varies >$40M	This option presents the shortest implementation period; however fails to meet Operating requirements without a large initial cost to retro-fit an area within a co-location facility to meet Operating needs. This option also relies heavily on third party resources. The reliability in communication, power supply and infrastructure would also need to be upgraded to meet Operating requirements and to meet regulatory requirements.

For additional information see Exhibit D2, Tab 2, Schedule 3, Reference (ISD) O04.

c) The current Outage Response Management System (ORMS) was put in service in 2007 and has been in continuous operation 24 x 7 since this time. The system is now at end of life and it is mandatory to replace it prior to the withdrawal of vendor support. This ensures that security and software patches will continue to be provided to mitigate system failure(s). The project is scheduled to be completed in 2016 and includes the replacement of the ORMS software and hardware.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #20

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 1/Schedule 1/p.3 Table 2

a) Table 2 includes a description "Less Future Use Land". Please explain.

Response

a) Future Use Land represents the acquired land or land rights/easements where there are no activities being performed to get it ready for its intended use and no active future construction plan. Since there is no benefit to rate payers, it is removed from Fixed Assets that are used for the Rate Base calculation.

<u>Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #21</u>

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

<u>Interrogatory</u>

Reference: Exhibit D1/Tab 1/Schedule 2/p.3

<u>Preamble:</u> Hydro One provides the major drivers of the in-service levels requested in 2015 through 2019 within the sustainment, development and operation work programs.

a) Please quantify the dollar and percentage amount attributable to each driver to explain the increases in 2015 to 2019.

<u>Response</u>

The table below shows the dollar amount of in-service additions attributable to each of the major drivers described above.

In-Service Additions by Driver ($M)	**2015**	**2016**	**2017**	**2018**	**2019**
New connections and upgrades	109	112	116	119	123
Troubled calls and storm damage	59	61	62	62	62
The replacement of assets at the end of their expected service lives	145	156	167	182	195
System capability reinforcements	73	59	76	88	62
Joint use and relocation capital projects	28	28	28	28	28
Ending the Smart Grid pilot project and beginning deployment of Smart Grid	46	21	28	20	20
Line improvement capital projects to ensure supply reliability to distribution customers	42	45	48	50	52
	503	481	524	550	542

The table below shows the percentage of total Distribution in-service additions attributable to each of the major drivers described above.

In-Service Additions by Driver (as a % of Total Additions)	**2015**	**2016**	**2017**	**2018**	**2019**
New connections and upgrades	17%	18%	17%	17%	19%
Troubled calls and storm damage	9%	10%	9%	9%	9%
The replacement of assets at the end of their expected service lives	22%	25%	24%	27%	30%
System capability reinforcements	11%	9%	11%	13%	9%
Joint use and relocation capital projects	4%	4%	4%	4%	4%
Ending the Smart Grid pilot project and beginning deployment of Smart Grid	7%	3%	4%	3%	3%
Line improvement capital projects to ensure supply reliability to distribution customers	6%	7%	7%	7%	8%
	77%	77%	75%	81%	82%

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #22

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 1/Schedule 2/Attachment 1/p.4

Preamble: The evidence states with respect to Fleet & Facilities Projects that an optimization of resources initiative will lead to significant savings for the project and for customers and the new integrated project is now underway and is on target to be completed in 2014.

a) Please confirm the in-service additions forecast for 2014.

Response

The GPS Telematics project described in the ICM filing has undergone a number of stages toward completion. Most recently, Senior Management has decided to delay the project in order to integrate its components with a future workflow and productivity projects expected to be launched over the next couple years. Hydro One is looking for solutions to combine these projects in order to optimize productivity and investment cost.

There have been no units placed into service to-date in 2014 and the current expectation is that there will be few if any units in-serviced prior to year end.

<u>Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #23</u>

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

<u>Interrogatory</u>

Reference: Exhibit D1/Tab 1/Schedule 3/p.2

<u>Preamble:</u> Hydro One indicates the methodology used to determine the net working cash required is based on the Navigant study that was accepted by the OEB.

a) Please identify any key differences between the past Navigant study accepted by the OEB and the Navigant study in this application.

<u>Response</u>

a) Please refer to Section VI (Findings and Conclusions) of the Working Capital Requirement Report by Navigant Exhibit D1, Tab 1, Schedule 3, Attachment 1.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #24

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 1/Schedule 4/p.3

Preamble: The evidence states "Materials and Supplies for major distribution projects are usually shipped directly to the project sites and are not included in the planned inventory levels."

a) Please confirm that these amounts are not included in Table 1 Inventory Levels at D1-1-4 Page 2.

b) Please provide the inventory levels shipped directly to project sites for the years 2010 to 2019.

Response

a) Confirmed; amounts do not include materials and supplies for major distribution projects.

b) Materials and Supplies shipped directly to project sites are not classified as inventory. They would be part of "construction in progress".

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #25

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 2/Schedule 1/p.7

Preamble: "Replacement of failed transformers takes longer to complete, is more costly, and is more impactive to customer supply when compared to replacements under planned situations."

a) Please provide the analysis to support the above statement to demonstrate the difference between the cost and interruption time to replace a transformers under planned compared to failure conditions.

Response

When transformers are replaced under planned scenarios such as Station Refurbishment or Transformer Replacement programs, no customers are interrupted. The mobile unit substation ("MUS") is connected in parallel with the in-service station, followed by removing the station from service. When transformers are replaced under failure scenarios, customers are out of power until the MUS can be installed. Based on the location of the nearest available MUS to the station, and allowing for installation time, customers can be out of power for up to 12 hours.

Under planned scenarios, all project scope development, engineering design and ordering of materials is completed prior to the installation of the MUS; therefore the required installation time of the MUS is on average 4 months. Under failure scenarios, the MUS is installed for the duration of the unplanned work which is on average 8 months. Not only does it take longer but it also reduces the availability for the MUS for other emergency or planned work.

Under planned scenarios, cost efficiencies can be achieved when transformer replacements are bundled with the replacement of other deteriorated / high risk station components. Bundled replacement of station components reduces costs in areas such as engineering, project management, project scheduling, and material order processing. Under failure scenarios, these cost efficiencies are not present.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #26

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 2/Schedule 1/p.11

Preamble: Historically, an average of 7 transformers have been replaced on a planned basis annually.

a) Please provide the average number of transformers replaced on a failure basis annually.

Response

The average number of transformers replaced on a failure basis annually is 11 units.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #27

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 2/Schedule 1/p.11

a) Please provide the number of failures for the years 2009 to 2013 for reclosers and breakers.

Response

Please see below for the number of failures for the years 2009 to 2013 for reclosers and breakers.

	2009	**2010**	**2011**	**2012**	**2013**
Recloser Failures	195	206	187	141	116
Breaker Failures	2	2	5	1	3

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #28

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 2/Schedule 1/p.12

a) Please provide the average cost for the years 2009 to 2013 to replace a recloser (with a vacuum recloser) and to replace a breaker and show the calculation.

Response

The average cost to replace one feeder (3 reclosers) with new vacuum reclosers is approximately $24,000.

The cost of replacing only a breaker is not obtainable as Hydro One does not perform "like for like" replacements for breakers, rather Hydro One replaces the existing breakers with new reclosers. This requires the station to be redesigned and refurbished to remove the breaker and accommodate the installation of the reclosers.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #29

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 2/Schedule 1/p.14

a) Please provide the average cost for the years 2009 to 2013 to replace a switch and fuse combination and show the calculation.

Response

The average cost to replace a switch and fuse combination is approximately $45,000.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #30

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit D1/Tab 2/Schedule 1/p.22

a) Please provide the number of pole failures per year for 2009 to 2014.

Response

The number of poles replaced annually due to a failure is outlined in the table below:

	2009	**2010**	**2011**	**2012**	**2013**	**2014 (YTD)**
Poles Replaced Due to a Failure (units)	987	806	1,380	1,319	2,088	374

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #31

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: Exhibit D1/Tab 2/Schedule 1/p.24

Preamble: Hydro One continues to address a subset of Red Pine wood poles that are experiencing premature degradation.

a) Please provide the quantity and cost per year related to the replacement of Red Pine wood poles for the years 2009 to 2019.

Response

Please see response to Exhibit I, Tab 3.2, Schedule 3 PWU 8 for the quantity of red pine wood poles replaced.

The unit price per red pine pole is in line with other planned wood pole replacements, the average unit price for wood pole replacements is provided on Slide 10 of Exhibit PD1 from the executive presentation on May 12, 2014.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #32

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 2/Schedule 1/p.30

a) When does Hydro One expect to return to average historical levels of 12,750 km which is required to sustain the 8 year cycle.

b) Does Hydro One plan to outsource the incremental program work. If yes explain. If no, where will Hydro One get the extra equipment to manage a temporary program surge.

c) Please provide data on the current (2014) and historical clearing rates (km/yr) for the years 2009 to 2013.

Response

a) A stable program of 12,750 km will begin in 2018, please refer to Slide 9 of Exhibit PD1 of the executive presentation on May 12, 2014.

b) The staffing strategy to address the incremental work is outlined in Exhibit C1, Tab 3, Schedule 1 pages 10 to 13 and Exhibit A, Tab 17, Schedule 6 pages 9 to 10.

c) Please see response to Exhibit I, Tab 3.1, Schedule 3 PWU 3.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #33

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 3/Schedule 1/p.4

Preamble: The evidence states "Development Capital expenditures increase in 2015 and 2016 largely due to investments in system capability reinforcement and investments to facilitate an increasing number of customer connections and upgrades."

a) In 2017, there is also an increase over historical levels. Please explain.

Response

The explanation for the increase in development capital spending in 2017 has been provided in Exhibit D1, Tab 3, Schedule 3, Page 6, Lines 1-7.

Ontario Energy Board (Board Staff) INTERROGATORY #59

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: Exhibit A/Tab 19/Schedule 1/p. 2 (Cost Efficiencies)

Preamble:
Hydro One indicates that the savings identified in Table 2 on page 4 of Exhibit A/Tab19/Schedule 1 have been incorporated in the work programs and activities previously filed and that it continues to realize material cost reductions and avoidances throughout the test years all of which are direct benefit to Hydro One customers.

a) Please provide the relevant EB numbers (and associated specific references in each EB) in which work programs and activities set out in this exhibit were previously filed. Were the total annual savings listed in Table 2 tested in the previous Board proceedings?

b) How will actual performance against the amounts in Table 2 be tracked and reported on annually? What consequences, if any, are associated with the savings being achieved or not achieved?

c) Please confirm that the amounts in Table 2 are cumulative savings accrued since 2010. Please provide a version of the table showing the actual savings achieved in years 2010 to 2013, and the projected savings to be achieved in years 2014 to 2019.

d) Please provide an OM&A and Capital breakdown of the amounts in Table 2 for each year in the table.

Response

a) Some of the work programs listed in Table 2 were included in the EB-2009-0096 filing. In Exhibit A, Tab 16, Schedule 1 of that application there is discussion of cost efficiencies/productivity savings. Costs shown in Table 1 of that exhibit for 2010 and 2011 were tested in that proceeding. EB-2009-0096 was the last cost of service filing for Hydro One Distribution. There were two IRM filings in 2012 and 2013 that did not provide evidence to be tested in this area but the cost efficiencies/productivity savings continued through that period.

b) The amounts provided in Table 2 will be reviewed and reported on a quarterly basis to ensure forecasted savings are still accurate and YTD savings are recorded. These actuals and forecasts will be presented to Hydro One senior management on a quarterly basis.

See response to Exhibit I, Tab 2.2, Schedule 1 Staff 13 (b) regarding consequences.

c) Please refer to Table 2 in Exhibit A, Tab 19, Schedule 1 that provides a full breakdown of the annual savings from 2010-2019.

Total Annual Savings - Distribution ($ Million)

	Historical				Bridge Year	Test Years					Cumulative
Description	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2014 - 2019
Back Office	1.5	4.1	6.5	18.0	23.3	26.7	26.7	26.7	26.7	26.7	156.9
Business Systems	10.8	13.2	18.6	29.9	30.6	30.8	31.0	31.1	31.3	31.5	186.3
Business Transformations	0.0	0.0	0.0	0.4	13.6	30.9	33.9	34.4	34.7	34.9	182.5
Centralized Operations	0.0	0.0	0.6	5.0	5.0	5.3	5.4	5.5	5.6	5.7	32.6
Leveraging Technology	0.0	0.0	1.9	3.4	5.7	8.1	9.3	9.5	8.7	9.3	50.5
Miscellaneous Admin	0.0	0.0	5.3	5.1	5.2	5.3	5.5	5.6	5.7	5.8	33.0
Process Improvement	0.0	0.0	0.1	0.2	0.6	2.4	2.4	2.4	2.4	2.4	12.7
Staff Flexibility	0.0	0.0	2.8	5.0	5.1	7.0	10.2	13.0	13.8	12.8	62.0
Telephony	0.0	0.0	2.1	1.0	1.5	1.9	2.1	2.2	2.3	2.3	12.3
Total	**12.3**	**17.3**	**37.9**	**68.0**	**90.7**	**118.4**	**126.5**	**130.3**	**131.3**	**131.5**	**728.8**

d) See tables below.

Dx Productivity Savings Table

Category	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Back Office	1.5	4.1	6.5	18.0	23.3	26.7	26.7	26.7	26.7	26.7
Business Systems	10.8	13.2	18.6	29.9	30.6	30.8	31.0	31.1	31.3	31.5
Business Transformations	0.0	0.0	0.0	0.4	13.6	30.9	33.9	34.4	34.7	34.9
Centralized Operations	0.0	0.0	0.6	5.0	5.0	5.3	5.4	5.5	5.6	5.7
Leveraging Technology	0.0	0.0	1.9	3.4	5.7	8.1	9.3	9.5	8.7	9.3
Miscellaneous Admin	0.0	0.0	5.3	5.1	5.2	5.3	5.5	5.6	5.7	5.8
Process Improvement	0.0	0.0	0.1	0.2	0.6	2.4	2.4	2.4	2.4	2.4
Staff Flexibility	0.0	0.0	2.8	5.0	5.1	7.0	10.2	13.0	13.8	12.8
Telephony	0.0	0.0	2.1	1.0	1.5	1.9	2.1	2.2	2.3	2.3
Total	12.3	17.3	37.9	68.0	90.7	118.4	126.5	130.3	131.3	131.5

OM&A Productivity Savings Table

Category	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Back Office	1.5	4.1	6.5	18.0	23.3	26.7	26.7	26.7	26.7	26.7
Business Systems	4.5	5.5	7.8	12.6	12.8	12.9	13.0	13.1	13.2	13.2
Business Transformations	0.0	0.0	0.0	0.4	12.2	28.7	31.6	31.9	32.2	32.4
Centralized Operations	0.0	0.0	0.6	5.0	5.0	5.3	5.4	5.5	5.6	5.7
Leveraging Technology	0.0	0.0	1.8	3.3	4.0	5.5	6.2	6.3	5.1	5.6
Miscellaneous Admin	0.0	0.0	5.3	5.1	5.2	5.3	5.5	5.6	5.7	5.8
Process Improvement	0.0	0.0	0.1	0.1	0.2	2.0	2.0	2.0	2.0	2.0
Staff Flexibility	0.0	0.0	2.8	5.0	5.1	7.0	10.2	13.0	13.8	12.8
Telephony	0.0	0.0	2.1	1.0	1.5	1.9	2.1	2.2	2.3	2.3
Total	6.0	9.6	27.0	50.4	69.4	95.3	102.7	106.3	106.6	106.6

Capital Productivity Savings Table

Category	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Back Office	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Business Systems	6.3	7.7	10.8	17.4	17.7	17.8	18.0	18.1	18.2	18.3
Business Transformations	0.0	0.0	0.0	0.0	1.5	2.2	2.3	2.4	2.5	2.5
Centralized Operations	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Leveraging Technology	0.0	0.0	0.1	0.1	1.6	2.6	3.1	3.1	3.6	3.6
Miscellaneous Admin	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Process Improvement	0.0	0.0	0.1	0.1	0.4	0.4	0.4	0.4	0.4	0.4
Staff Flexibility	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Telephony	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total	6.3	7.7	10.9	17.6	21.3	23.1	23.8	24.0	24.8	24.9

Ontario Energy Board (Board Staff) INTERROGATORY #60

Issue 3.3 **Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?**

Interrogatory

Reference: **1. RRFE Report, October 18, 2012**
2. Exhibit A/Tab 19 (Productivity Growth)

Preamble:

On page 20 of the RRFE Report, the Board states that expected inflation and productivity gains will be built into the rate adjustment over the term.

The Board calibrates the productivity factor used in its Price Cap IR and Annual Index rate setting methods using a measure of industry total factor productivity ("TFP") growth. An individual distributor's TFP growth can also be calculated. A TFP index is the ratio of an output quantity index to an input quantity index. The growth trend in a TFP trend index is the difference between the trends in the component output quantity and input quantity indexes. TFP is explained further in Section 2.2 of an EB-2010-0379 report prepared by, Dr. Lawrence Kaufmann and his team at Pacific Economics Group Research, LLC, entitled "Empirical Research in Support of Incentive Rate-Setting: Final Report to the Ontario Energy Board."[1]

Using PEG's Excel file that is posted on the Board's web site and which contains all the data used in PEG's productivity and benchmarking research in support of incentive rate setting in Ontario (i.e., the results of PEG's index-based input price and productivity computations, and related workpapers), Board staff isolated the output quantity, input quantity and productivity indexes for Hydro One Networks, Inc. Staff made no changes to the data or to the calculations in the worksheets. To be able to isolate Hydro One's data in the TFP calculations, staff used the existing "Observation Used in TFP Work" flag column in each of the following sheets: 2. BM Database, 3. TFP Database, and 5. Capital Calculations for TFP. Staff set the value in these columns to "1" for Hydro One and to "0" for all other distributors. The resultant productivity trends for Hydro One, based on PEG's worksheet are provided in **Attachment to 3.3-Staff-60.pdf.**

[1] Pacific Economics Group Research, LLC. Empirical Research in Support Of Incentive Rate Setting in Ontario. November, 2013. (http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379_Final_PEG_Report_20131111.pdf)

Using Hydro One's forecasts in this application and the PEG documentation and worksheets that are posted on the Board's web site (links entitled "Part I – Documentation for Working Papers" and "Part II - TFP and BM database calculation" are provided below) or Hydro One's comparable analyses please provide Hydro One's forecasted total factor productivity trends for the period 2013 through to 2019.

Nov 21-13
 	
Updated Dec 20-13 and Jan 24-14
	The Board has released a report prepared by Board staff's expert consultant, Dr. Lawrence Kaufmann and his team at Pacific Economics Group Research, LLC, entitled "*Empirical Research in Support of Incentive Rate-Setting: Final Report to the Ontario Energy Board*."
	
	• Cover Letter
	• Final PEG Report (as corrected on Dec 19, 2013 and Jan 24, 2014)
	    o Tables in Final PEG Report (.xlsx, 3 MB) (as corrected on Dec 19, 2013 and Jan 24, 2014)
	• PEG's Working Papers
	    o Part I – Documentation for Working Papers
	    o Part II - TFP and BM database calculation (.xlsx, 8 MB) (as corrected on Dec 19, 2013 and Jan 24, 2014)
	• Price Cap IR Benchmarking Algorithm (.xlsx, 2 MB) (as corrected on Dec 19, 2013 and Jan 24, 2014)

Response

Hydro One has endeavored to complete PEG's worksheets as requested by Board Staff. However according to Dr. Larry Kaufmann, Hydro One has no peer which makes the relevance of the worksheet questionable. Dr. Larry Kaufmann stated in his slide presentation delivered on January 10, 2013, slide 23: "Unit cost benchmarking to be based on a comparison of each distributor's unit cost (*i.e.* its total distribution cost divided by an index of output quantity) and the average unit cost of distributors in its designated peer group. Currently there are eleven peer groups, plus Hydro One (which has no Ontario peers)." Further the PEG slide presentation delivered on May 16, 2013, slide 20, states, "Toronto Hydro and Hydro One excluded because statistical tests show they are significantly and materially impacting the industry TFP trend …. In incentive regulation, industry TFP trend should not be materially impacted by one or two utilities in the industry".

Hydro One has attempted to make the same adjustments to the data as Dr. Kaufmann used in his worksheet. These include:

- For the input cost factors for OM&A and Capital, Hydro One has adjusted the plan numbers using the arbitrary adjustment factors in the PEG model worksheet.
- PEG has made significant changes between cost elements of the worksheet and input quantity data which Hydro One copied.

These adjustments which in theory improve consistency with other LDCs were carried forward by Hydro One.

Best efforts were made to complete the worksheets using information consistent with our pre-filed evidence. This information does not look continuous with the OEB spreadsheet historical data. We suspect there may be a difference in the definition of specific line items and in the tracking/grouping of data (i.e. planned spend, depreciation, etc.). Therefore numbers are representative in nature only.

For worksheet results see Attachment 1.

CALCULATION OF OUTPUT QUANTITY, INPUT QUANTITY AND PRODUCTIVITY INDEXES

	Output Quantity Measures											
	Total Customers	Growth	Average 2002-2012	Total Deliveries	Growth	Average 2002-2012	System Capacity Proxy	Growth	Average 2002-2012	Output Index	Growth	Average 2002-2012
Econometric Weight	0.4077	60.57%		0.0712	10.58%		0.1942	28.85%		100.00%	0.6732	
2012	1,221,411			35,754,000			12,044,325			100.00		
2013	1,232,134	0.9%		34,928,000	-2.3%		12,044,325	0.0%		100.28	0.3%	
2014	1,242,842	0.9%		34,694,000	-0.7%		12,044,325	0.0%		100.74	0.5%	
2015	1,254,571	0.9%		34,544,000	-0.4%		12,044,325	0.0%		101.27	0.5%	
2016	1,267,084	1.0%		34,528,000	0.0%		12,044,325	0.0%		101.87	0.6%	
2017	1,279,496	1.0%		34,435,000	-0.3%		12,044,325	0.0%		102.45	0.6%	
2018	1,291,563	0.9%		34,181,000	-0.7%		12,044,325	0.0%		102.95	0.5%	
2019	1,303,224	0.9%		34,095,000	-0.3%		12,044,325	0.0%		103.48	0.5%	

	Cost									Shares of Total Cost		
	Capital	Growth	Average 2002-2012	OM&A	Growth	Average 2002-2012	Total	Growth	Average 2002-2012	Capital	OM&A	Total
				510,526,813								
2012	705,896,473			553,400,000			1,259,296,473			56.1%	43.9%	100.0%
2013	726,204,955	2.8%		610,600,000	9.8%		1,336,804,955	6.0%		54.3%	45.7%	100.0%
2014	738,920,396	1.7%		581,300,000	-4.9%		1,320,220,396	-1.2%		56.0%	44.0%	100.0%
2015	822,622,745	10.7%		564,300,000	-3.0%		1,386,922,745	4.9%		59.3%	40.7%	100.0%
2016	847,449,100	3.0%		610,200,000	7.8%		1,457,649,100	5.0%		58.1%	41.9%	100.0%
2017	880,650,284	3.8%		614,000,000	0.6%		1,494,650,284	2.5%		58.9%	41.1%	100.0%
2018	903,846,475	2.6%		603,900,000	-1.7%		1,507,746,475	0.9%		59.9%	40.1%	100.0%
2019	930,430,546	2.9%		600,000,000	-0.6%		1,530,430,546	1.5%		60.8%	39.2%	100.0%

	Input Quantity								
	Capital	Growth	Average 2002-2012	OM&A	Average 2002-2012	Average	Index	Index Growth	Average 2002-2012
2012	40,561,210			4,403,147.76			100.00		
2013	42,276,030	4.1%		4,807,874.02	8.8%		106.42	6.2%	
2014	43,395,707	2.6%		4,471,538.46	-7.3%		104.51	-1.8%	
2015	48,061,062	10.2%		4,242,857.14	-5.2%		108.41	3.7%	
2016	48,999,659	1.9%		4,486,764.71	5.6%		112.21	3.4%	
2017	50,436,139	2.9%		4,417,266.19	-1.6%		113.39	1.0%	
2018	51,374,179	1.8%		4,252,816.90	-3.8%		112.88	-0.4%	
2019	51,857,683	0.9%		4,137,931.03	-2.7%		112.30	-0.5%	

	Productivity Trends								
	Capital	Growth	Average 2002-2012	OM&A	Growth	Average 2002-2012	Total	Index Growth	Average 2002-2012
2012	100.00			100.00			100.00		
2013	96.21	-3.86%		91.84	-8.51%		94.23	-5.94%	
2014	94.16	-2.16%		99.20	7.71%		96.39	2.26%	
2015	85.46	-9.69%		105.09	5.77%		93.41	-3.14%	
2016	84.33	-1.34%		99.97	-4.99%		90.79	-2.85%	
2017	82.39	-2.33%		102.12	2.12%		90.35	-0.48%	
2018	81.28	-1.35%		106.59	4.28%		91.20	0.93%	
2019	80.94	-0.42%	-3.0%	110.12	3.26%	1.4%	92.15	1.04%	-1.2%

Ontario Energy Board (Board Staff) INTERROGATORY #61

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: Exhibit D1/Tab3/Schedule 2/p.19

Hydro One indicates that it will utilise a new prefabricated integrated modular station that is more cost effective.

a) How much more cost effective is this method compared to earlier methods of station refurbishment? What are the efficiency gains with this method?
b) Please file any information Hydro One used to determine that the prefabricated modular station is more efficient than previous practices.
c) Did Hydro One benchmark its costs against other distributors to ensure best practices were being followed?
d) Please file a capital cost per station table from 2010 to 2019.

Response

a) It is too early in the pilot project to quantify efficiencies gained. This pilot project is still underway and Hydro One is in the process of determining lessons learned and the strategy going forward.

b) As outline in Exhibit D1, Tab 3, Schedule 2, the prefabricated modular station is more cost effective in urban areas where space is limited. The cost efficiency Hydro One is referring to is the efficiencies resulting from the small footprint of the iMDS design compared to the traditional distribution layout which would result in having to relocate distribution stations or purchase additional land to enlarge the station.

Further efficiencies Hydro One expects to gain are related to prefabrication of the iMDS by an external vendor. The external vendor will purchase, assemble and commission station equipment which translates to shorter in-service time.

c) No.

d) The following table provides the actual cost of station refurbishment completed over the 2010 to 2013 period.

Year	Stations	Actual Cost
2010	Metcalfe DS	$0.2M
	North Shore DS	$2.2M
2011	Smooth Rock Falls DS	$1.1M
	Thorold South DS	$0.6M
2012	Calabogie DS	$0.5M
	Lindsay Durham West DS	$3.0M
	Sioux Narrows DS	$2.9M
2013	Bobcaygeon Boyd DS	$1.0M
	Chesley Hawkins DS	$0.5M
	Currie DS	$1.8M
	Dundalk Victoria DS	$1.0M
	Elginfield RS	$0.4M
	Espanola DS	$0.6M
	Havelock Industrial DS	$1.7M
	Huntsville RS	$2.0M
	Iroquois Dam DS	$2.7M
	Madawaska DS	$0.8M
	Matachewan DS	$1.4M
	Meaford DS #2	$2.5M
	Noelville DS	$1.7M

The following table provides the station refurbishments planned for the 2014 to 2019 period along with the corresponding forecast cost for each station refurbishment period. The average forecast cost for each station is approximately $1 million.

Year	Stations			Forecast Cost
2014	Abitibi Canyon DS	Highgate DS	Pelee Island DS	**$26.1M**
	Aguasabon DS	Kemble DS	Post Creek DS	
	Appin DS	Kenogami DS	Red Lake DS	
	Barwick DS	Kirkland Lake Woods DS	Shining Tree DS	
	Bobcaygeon Duke DS	Larder Lake DS	St. Williams DS	
	Brockville Parkdale DS	Longlac West DS	Tilbury Peltier DS	
	Cache Bay DS	Lucan Market DS	Trenton Bay DS	
	Campbellford Industrial DS	Madsen DS	Trenton Frankford DS	
	Crow River DS	Maxville George DS	Welland Effingham DS	
	Emsdale DS	Nestor Falls DS	Wilsonville DS	
	Essex DS	Oxley DS		

Year	Stations			Forecast Cost
2015	Abbey DS	Dorchester DS	Perrault Falls DS	$34.6M
	Alexander Kenyon West DS	Exeter DS#2	Plattsville DS	
	Berwick DS	Forest Jefferson DS	Princeton DS	
	Blenheim DS	Geraldton South DS	Russell DS	
	Bolsover DS	Haliburton DS	St. Thomas DS	
	Brigden DS	Kemptville Van Buren DS	Stouffville 10th Line DS	
	Brockville Park DS	Kingsville Pulford DS	Tara DS	
	Brockville Water DS	Kirkland Lake Goodfish	Tralee DS	
	Carleton Place	Lindsay Eglinton DS	Trenton McAuley DS	
	Chatham Raleigh DS	Little Current DS	Wainfleet DS	
	Corbeil DS	Marathon DS	Warkworth DS	
	Deep River DS	Merlin DS	Wyoming Churchill DS	
2016	Adams Point DS	Fenelon Falls Elliot DS	Newport DS	$39.0M
	Bismark DS	Gorrie DS	Nipigon DS	
	Bobcaygeon Ann DS	Gravenhurst DS	Pointe Au Baril DS	
	Carp DS	Guthrie DS	Port Lambton DS	
	Consecon DS	Holland Landing DS	Precious Corners DS	
	Craigleith DS	Horsey Bay DS	Shannonville DS	
	Crozier DS	Kirkland Lake DS #1	Sutton Base Line #1 DS	
	Devlin DS	Longlac East DS	Thorold Turner DS	
	Dover Centre DS	McGregor DS	Vanastra DS	
	Dundas Sydenham DS	Meaford Louisa DS	Wallaceburg DS	
	Elk Lake DS	Meaford Thompson DS	Waupoos DS	
	Elliot Lake DS	Mountain Chute DS	Wingham DS	
	Elora Union DS	New Liskard Halibton DS		
2017	Arnprior Airport DS	Deseronto DS	Perth DS	$40.0M
	Arnprior Elgin DS	Drumbo DS	Perth North DS	
	Arnprior McLachlin DS	Firth Corners DS	Pinelands DS	
	Aspdin DS	Galetta DS	Rockland DS	
	Athens DS	Hawley DS	Smithfield DS	
	Black Corners DS	Kemptville West DS	Sturgeon Falls DS	
	Brockville Cedar DS	Killaloe DS	Thamesville North DS	
	Brockville Schofield DS	Manitouwadge DS #1	Trenton McNichol DS	
	Cameron DS	Marthaville DS	Wartburg DS	
	Clarence DS	Meaford Vincent DS	Welcome DS	
	Collins Bay DS	Milford DS	Whitney DS	
	Corunna DS	Monkton DS	Yarmouth Centre DS	
	Cumberland DS	Owen Sound 12 St E DS		

Year	Stations			Forecast Cost
2018	Alexander DS	Forest Jura DS	Owen Sound 2 Ave E DS	$44.5M
	Battersea DS	Glengarry DS	Pleasant Point DS	
	Beaumaris DS	Haycroft DS	Red Rock DS	
	Bolton Hardwick DS	Horningmill DS	Ridgetown Palmer DS	
	Cedar Mills DS	Jones Road DS	Ripley DS	
	Clayton DS	Joyceville DS	Rock Mills DS	
	Creemore DS	Kennisis Lake DS	Roseville DS	
	Dack DS	Kleinburg DS	Rylston DS	
	Deleware DS	Lagoon City DS	Sam Lake DS	
	DorcasBay DS	Madoc Madawaska DS	Shedden DS	
	Dunchurch DS	McCrimmon DS	Shelburne Andrew DS	
	Erin DS	Merrikville DS	Snelgrove DS	
	Fenelon Falls DS	Mindemoya DS	Wiarton Claude DS	
	Flynn Corners DS	Owen Sound 12 St W DS		
2019	Aberfoyle DS	Golden Valley DS	Punkidoodles Corners DS	$45.2M
	Addison DS	Huntsville DS	Ruthven DS	
	Alexandria Margaret DS	Kerwood DS	Sharon DS	
	Blythswood DS	Keswick DS	Sleeman DS	
	Bondhead DS	Lanark DS	Smith Falls DS	
	Buckhorn DS	North Brook DS	Taylor Kidd DS	
	Carleton Place Francis DS	Omemee DS	Thedford DS	
	Chatham Raleigh RS	Osgood DS	Vankleek Terry Fox DS	
	Chesterville Bran DS	Ospringe DS	Vienna DS	
	Cobalt DS	Oxford Mill DS	Virginiatown DS	
	Dunedin DS	Park Road DS	Wanup DS	
	Emo DS	Picton Barker DS	Wellington Wharf DS	
	Farlain Lake DS	Pinegrove DS	Wooler DS	
	Fonthill RS	Prospect DS		

<u>Sustainable Infrastructure Alliance of Ontario (SIA) INTERROGATORY #48</u>

Issue 3.3 **Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?**

<u>Interrogatory</u>

Reference: Exhibit A/Tab 14/Schedule 1/p.1

HONI's April 10, 2014 DBRS rating report states that "DBRS views the parameters of the Custom Incentive Rate-setting option under the Renewed Regulatory Framework as modestly positive for Hydro One's distribution business (35% of EBIT) as it provides greater clarity for recovery and pass through of capital costs to ratepayers, and it <u>reduces pressure on utilities to meet operating efficiency targets</u>." (Emphasis added)

a) Does HONI agree with DBRS that the pressure on it to meet operating efficiency targets is reduced under CIR?

b) Please explain how efficiency incentives will continue to be present throughout the 5 year term without benchmarking or an IRM-like limitation on costs.

<u>Response</u>

a) As a matter of practice, Hydro One does not comment on third party credit rating agency reports which provide an independent credit opinion of Hydro One to debt investors. However, Hydro One does not believe that the pressure on it to meet operating efficiency targets is reduced under Custom Application approach.

b) For Hydro One's Benchmarking initiatives, please refer to the response to Staff interrogatory in Exhibit I, Tab 2.6, Schedule 1 Staff 33. For how Hydro One believes that its Custom Application adequately incorporates operational effectiveness, please refer to the response to SEC's interrogatory in Exhibit I, Tab 2.3, Schedule 9 SEC 5.

Power Workers Union (PWU) INTERROGATORY #11

Issue 3.3 **Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?**

Interrogatory

Reference: **(a) Exh A, Tab 19, Schedule 1, Table 1: Impact to Revenue Requirement Inclusive and Exclusive of Productivity Savings**

Table 1:

Impact to Revenue Requirement Inclusive and Exclusive of Productivity Savings

	2013 Actual	2014 Bridge	2015 Test	2016 Test	2017 Test	2018 Test	2019 Test
OM&A per application	610,622,850	581,316,339	564,304,626	610,181,582	613,969,206	603,863,604	600,001,194
YoY growth		-4.8%	-2.9%	8.1%	0.6%	-1.6%	-0.6%
Add: Productivity Savings	50,378,620	69,418,195	95,332,361	102,698,023	106,293,228	106,581,261	106,632,090
OM&A without Productivity	661,001,470	650,734,534	659,636,986	712,879,605	720,262,434	710,444,865	706,633,284
YoY growth		-1.6%	1.4%	8.1%	1.0%	-1.4%	-0.5%

Reference: **(b) Exh A, Tab 19, Schedule 1, Table 2: Total Annual Savings – Distribution ($Million)**

Table 2:

Total Annual Savings - Distribution ($ Million)

	Historical				Bridge Year	Test Years					Cumulative
Description	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2014 - 2019
Back Office	1.5	4.1	6.5	18.0	23.3	26.7	26.7	26.7	26.7	26.7	156.9
Business Systems	10.8	13.2	18.6	29.9	30.6	30.8	31.0	31.1	31.3	31.5	186.3
Business Transformations	0.0	0.0	0.0	0.4	13.6	30.9	33.9	34.4	34.7	34.9	182.5
Centralized Operations	0.0	0.0	0.6	5.0	5.0	5.3	5.4	5.5	5.6	5.7	32.6
Leveraging Technology	0.0	0.0	1.9	3.4	5.7	8.1	9.3	9.5	8.7	9.3	50.5
Miscellaneous Admin	0.0	0.0	5.3	5.1	5.2	5.3	5.5	5.6	5.7	5.8	33.0
Process Improvement	0.0	0.0	0.1	0.2	0.6	2.4	2.4	2.4	2.4	2.4	12.7
Staff Flexibility	0.0	0.0	2.8	5.0	5.1	7.0	10.2	13.0	13.8	12.8	62.0
Telephony	0.0	0.0	2.1	1.0	1.5	1.9	2.1	2.2	2.3	2.3	12.3
Total	**12.3**	**17.3**	**37.9**	**68.0**	**90.7**	**118.4**	**126.5**	**130.3**	**131.3**	**131.5**	**728.8**

a) Please confirm if the productivity savings in Table 1 are the same as the OM&A component of total annual savings provided in Table 2.

Response

Yes the productivity savings in Table 1 are the same as the OM&A component of the total annual savings provided in Table 2.

Vulnerable Energy Consumers Coalition (VECC) INTERROGATORY #66

Issue 3.3 **Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?**

Interrogatory

Reference: A/T17/S4/pg. 4

a) With few exceptions the Measure/Key Performance Indicators shown in Table 1 are vague. For example, the business value of Reliability has as a measure "reliable delivery of electricity" but no actual target or measure. Please provide the specific measure that are associated with each Measure/Key Performance Indicator. If none is available please explain what steps are being taken to develop specific measures.

Response

Please find the specific measures that are associated with each Business Value in the table below.

Business Value	**Metric**
Safety	risk of failure to meet targeted reduction in OHSA Recordable injuries
	risk of injuries with Hydro One at fault
Satisfying our Customers	risk of failure to meet SQI indices
	risk of increase in customer complaints/lawsuits
	risk of decrease in customer satisfaction scores
	risk of media attention/letters to senior government officials
Reliability	impact to SADI and SAFI targets
Environment	risk of material spilled (L)
Employee	employee engagement survey results
Shareholder Value	risk of media attention/letters to senior government officials
	risk of regulatory order/fine
	risk of missing our net income targets
	risk of changes to our credit rating
Productivity	risk of meeting planned unit costs
	risk of meeting planned unit costs and accomplishments

School Energy Coalition (SEC) INTERROGATORY #30

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference:

Please provide a copy of the Oliver Wyman productivity study undertaken by the Applicant in 2011. Please explain how that study was utilized.

Response

The Oliver Wyman Study can be found in Attachment 1 of this interrogatory. It was previously filed as Exhibit A, Tab 17, Schedule 2, Attachment 1 of proceeding EB-2012-0031.

At the conclusion of the Hydro One Transmission filing (EB-2010-0002) the Board noted that Hydro One must be in a position to provide more robust evidence that compensation increases are matched with demonstrated productivity gains. Hydro One selected Oliver Wyman to study current market standards for measuring productivity and to suggest potential internal metrics for measuring productivity at Hydro One.

Oliver Wyman conducted a broad market survey of U.S. and Canadian utilities. The final report showed:

- most utilities looked at productivity metrics as part of a balanced scorecard to support the understanding of trends of service quality and total cost metrics;
- none of the participants tracked productivity across all business functions, relying instead on a sampling of different sections of work;
- no regulatory commission was found to routinely request measures of productivity from utilities under their jurisdiction, but instead focused on outcome metrics of overall service quality and total costs; and
- there was a wide disparity in internal performance measurement with each utility defining productivity, service quality and cost metrics differently.

Hydro One used this information to develop its own productivity metrics in the context of a balanced scorecard to measure productivity, reliability, customer satisfaction, safety and shareholder value.

December 15, 2011

Measuring Productivity at Hydro One

OLIVER WYMAN

Contents

1

Executive Summary

Oliver Wyman was engaged to report current market standards for measuring productivity and suggest potential metrics for measuring productivity at Hydro One.

As part of this effort, Oliver Wyman conducted a broad market survey of US and Canadian utilities and contacted many regulators directly to assess how productivity measures were used. Across Canada and the US, Oliver Wyman contacted 30 utilities and 17 commissions via over 350 documented emails, phone calls and requests for information.

No regulatory commission was found to routinely request measures of productivity from utilities under their jurisdiction. Instead commissions focused on 'outcome' metrics of overall service quality metrics (SQM) and total costs. In many cases, the commissions directed Oliver Wyman to contact utilities directly as the management of productivity was considered the utilities responsibility.

Most utilities did look at productivity metrics internally as part of a balanced scorecard to support the understanding of trends of the service quality and total cost metrics. The productivity metrics found suggest that none of the participants track productivity across all business functions, relying instead on a sampling of different sections of work.

Survey Findings - Metric Collected Per Utility				
Category	**Median**	**Max**	**Min**	**Total**
Cost	6	89	1	213
Productivity	4	59	0	114
Service Quality	25	176	4	478

After analyzing Hydro One's major costs and interviewing many of their staff, 25 metrics have been suggested as candidates to measure productivity, which account for 22% of total O&M and Capex labor related costs. However, as with any measurement, the development of these metrics should be evaluated in the light of the cost to measure them, any potential negative effects they may create (e.g., adverse incentives for employees), and the ability to roll up these up to corporate scorecard measures.

#	Metric	Cost Coverage	% of total costs
1	Cost of brush control per km of line	$98M	4.6%
2	Cost per meter install	$82M	3.9%
3	Cost per pole set	$78M	3.7%
4	Cost per new service installed	$11M - $34M	1.1%
5	Cost per tower constructed	$13M - $26M	0.9%
6	Cost per tower foundation	$13M - $26M	0.9%
7	Cost per km of Tx line cleared (Capital)	$13M - $26M	0.9%
8	Cost per meter read	$22M	1.0%
9	Cost per upgrade	$14M	0.7%
10	Cost per km of transmission line refurbished	$14M	0.6%
11	Cost per insulator replaced	$8M - $13M	0.5%
12	Cost per cable locate	$12M	0.6%
13	Cost per km for line patrol	$6M - $10M	0.4%
14	Cost per breaker	$8M - $10M	0.4%
15	Cost per transformer	$9M	0.4%
16	Cost per RTU	$7M - $9M	0.4%
17	Cost per bill	$1M - $8M	0.2%
18	Cost per km of Tx line cleared (OM&A)	$7M	0.3%
19	Cost per protective device replacement	$2M - $5M	0.2%
20	Cost per Transformer Refurbishment	$4M	0.2%
21	Cost per service cancellation	$4M	0.2%
22	Cost per insulator inspection	$1M - $4M	0.1%
23	Cost per disconnect	$3M	0.2%
24	Cost per reconnect	$3M	0.2%
25	Cost per line inspection	$1M - $3M	0.1%
	Total	~$480M	~22%

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Background

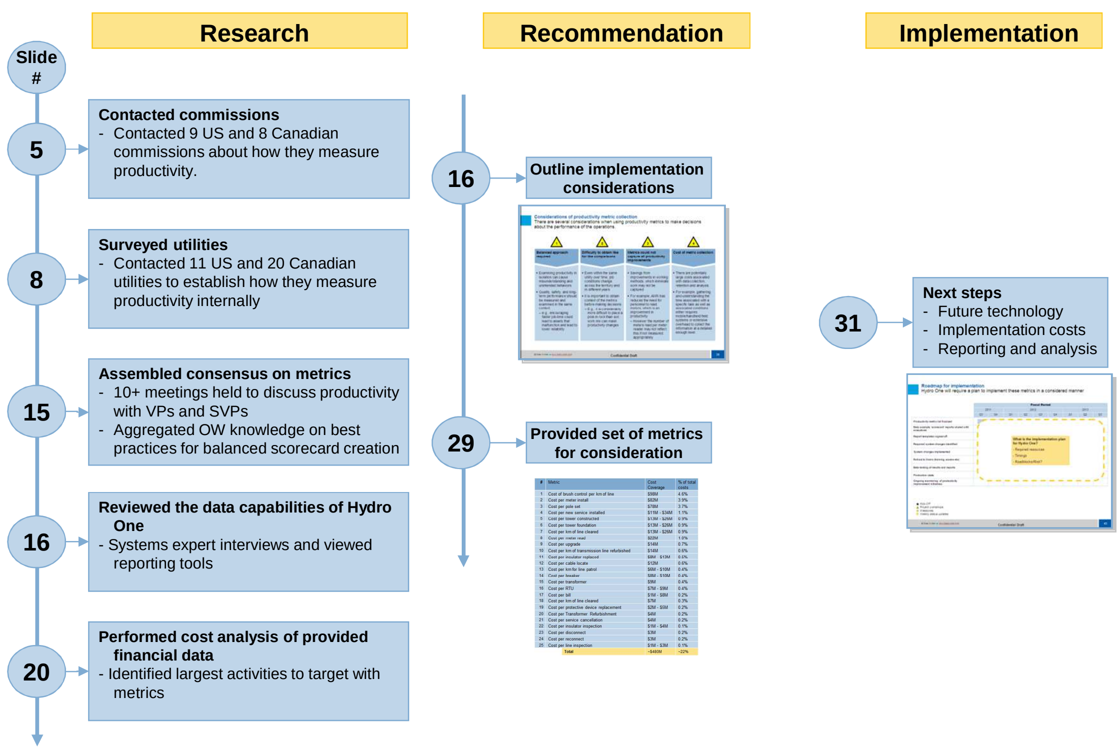
> “In its December 23, 2010 Decision approving Transmission Revenue Requirements for 2011 and 2012, the Ontario Energy Board provided direction and other expectations for further information on compensation and efficiency comparisons.
>
> The Board directed “Hydro One to revisit its compensation cost benchmarking study [the Mercer study] in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America.”
>
> Toward that end, the Board directed "Hydro One to consult with stakeholders about how the Mercer study should be updated and expanded to produce such analyses”.
>
> The Board went on to describe its expectation that Hydro One “be in a position to provide more robust evidence on initiatives to achieve a level of cost per employee closer to market value at its next transmission rate case. The Board will expect compensation increase to be matched with demonstrated productivity gains”.
>
> **Extract from Hydro One RFP # SCO-1000152789, March 2nd 2011**

To satisfy all aspects of the Ontario Energy Boards requests, Oliver Wyman was engaged alongside Mercer. Mercer was responsible for updating the compensation benchmarking study with 2011 data and separately reported changes in relative compensation levels. Oliver Wyman was to provide perspectives on industry best practices for productivity measurement.

3

Report Roadmap

The figure below represents the shape of the report, consisting of three sections; research, recommendations and implementation. The research section contains the findings from utilities and commission research and an analysis of Hydro One's cost. Using the findings from research, a list of the challenges of metric collection was created to coincide with the recommended set of metrics. To implement the data collection and reporting process steps were recommended to ensure that the recommended metrics would provide useful and accurate information.



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Findings from Regulatory Commissions

17 Regulators across the US and Canada were requested to provide which methodologies they had for measuring performance. Nine commissions were in the US and eight commissions were in Canada.

United States commissions

Canadian commissions

In addition to direct contact via a combination of calls, e-mails and requests for information, a review was performed of publicly filed documents such as rate cases, studies and other regulatory dockets.

The findings were fairly consistent across the different regulators. 15 regulators collected 134 different service quality metrics between them during regular filing processes. 12 of the commissions had annual filing requirements for service quality; these were Alberta, Ontario, Quebec, Massachusetts, New York, Pennsylvania, Michigan, Ohio, Illinois, Connecticut, New Jersey and California.

Service quality metrics were the most standardized of metrics across the regulators. Reliability metrics such as system average interruption frequency index (SAIFI), customer average interruption duration index (CAIDI), and system average interruption duration index (SAIDI) are being collected by the majority of regulators on a regular basis. Customer call center metrics such as % of calls abandoned, and % of calls answered in under 30 seconds were also collected by many regulators.

It was standard practice to collect cost metrics with seven commissions collecting 67 cost metrics. All regulators require financial information to be filed during a rate case, generally as part of the utilities cost of service which include various financial statements.

No commission was found to regularly collect any productivity metrics. Both the Manitoba Public Utilities Board (MPUB) and Nova Scotia Utilities and Review Board (NSUARB) had collected productivity metrics, but not on a regular basis. The MPUB collected “average time per call” and the NSUARB commissioned an ad hoc study containing “calls handled per agent per day.”

The summary results from each commission are found in the tables in the appendix. For a detailed review of each commission’s metric collection practices please see the appendix.

Rank	Metric Type	Common Metrics	# Found
1	SQM	System Average Interruption Frequency Index	14
2	SQM	Customer Average Interruption Duration Index	13
3	SQM	System Average Interruption Duration Index	11
4	SQM	% of Calls Abandoned	7
5	SQM	% of Calls answered in under 30 seconds	5
6	SQM	Average speed of answer	5
7	SQM	% of In-service appointments met	5
8	SQM	Momentary Average Interruption Frequency Index	3

Further studies identified

There were several other studies identified in the course of research that have related topics and provide additional summary information about the state of metric collection.

CAMPUT

The Canadian Association of Members of Public Utility Tribunals (CAMPUT) commissioned a study in 2009 to review the use of benchmarking as a regulatory tool for public utilities in Canada.

The study reviewed current practices of regulators to determine the information which regulators currently collect from utilities, finding that only service quality and cost data was being collected. The extent to which service quality and cost were being collected varied across each commission.

The study looked at the perspectives on benchmarking from the sides of both the regulators and the utilities. It was determined that utilities focused on performance assessment, target setting, performance improvement and reliability support. Whereas regulators would like to use benchmarking for ratemaking, compliance, audit monitoring and reducing information risk.

Various factors inhibiting the use of benchmarking were found, including the difference in demographics and geography in which utilities operate. The methods of data collection between utilities could pose problem unless strict definitions and processes are created for each metric under consideration. CAMPUT suggested using normalizers, a comparable peer panel and good metric choice in order to mitigate each of these hazards.

The list of metrics which CAMPUT recommended for benchmarking were: call center performance, billing accuracy, customer complaints, system average interruption frequency index, system average interruption duration index, customer average interruption duration index, asset replacement rates for distribution, transmission and substation assets, customer care, bad debt, O&M costs, corporate services costs, safety indices, line losses indices, and conservation indices

CAMPUT suggested starting with stakeholder discussions to determine the metric definition and data collection processes. The next step was identified to start a pilot project to test the feasibility of benchmarking these metrics. The pilot project would start in jurisdictions where the data is already being collected. The pilot project would test the current processes, identifying solutions to the problems as they become apparent.

Hydro One is currently participating in the first pilot of this initiative and is providing mostly reliability (CAIDI, SAIFI, etc.) and some call center information (ASA, Service Level)

Ad hoc studies

Multiple studies were found which were commissioned by regulators during a rate case. These studies either reviewed or benchmarked different aspects of the utility.

The Nova Scotia Utilities and Review Board (NSUARB) commissioned Accenture Inc. to perform a review of Nova Scotia Power’s (NSPI) corporate services due to its recent restructuring. Accenture Inc. benchmarked the corporate services function across a similar peer panel and found that NSPI was an “average to good” performer.

The NSUARB commissioned an operational review of NSPI, which was done by Kaiser Associates. As part of Kaiser Associate’s review, a benchmarking study was administered on operating, maintenance and general expenses (OM&G). The study showed that NSPI operates at a lower normalized OM&G cost than its competitors. The Kaiser study benchmarked one productivity metric; calls handled per agent per day.

5

Findings from Utility Survey

Oliver Wyman conducted a survey to determine how different utilities measure their performance internally through cost, service quality and productivity metrics to establish best practices in the industry.

Respondents

13 utilities across North America were included in the survey panel; the utilities included those in transmission, distribution and generation.

The survey consisted of two parts: the first part was to collect the performance metrics (cost, productivity and service quality), the second part was to determine the automation level of the data collection, the percentage of total cost covered by the performance metrics and what function was responsible for the data collection. For the purposes of this report and the survey, productivity was considered to be an activity-level metric such as "cost per pole" while service quality and cost were higher level metrics.

There was a wide disparity in internal performance measurement with each utility defining productivity, service quality and cost metrics differently. The reason for the disparity may have been because each utility was choosing metrics to track the success of different corporate goals.

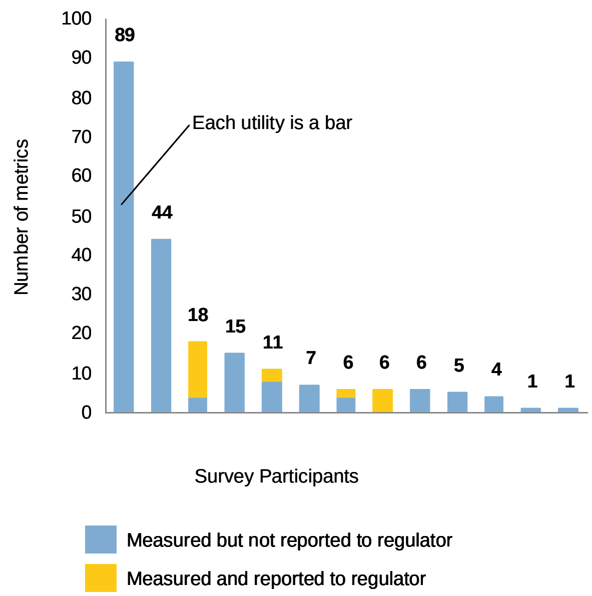
Survey Findings - Metric Collected Per Utility				
Category	**Median**	**Max**	**Min**	**Total**
Cost	6	89	1	213
Productivity	4	59	0	114
Service Quality	25	176	4	478

Cost

The cost metrics collected by utilities detail overall spend in business categories, with metrics such as "distribution spend per customer."

Of all the cost metrics reported internally, 12% are reported to regulators, and 22% are part of a benchmarking effort but not necessarily reported to regulators.

Cost metrics collected in survey



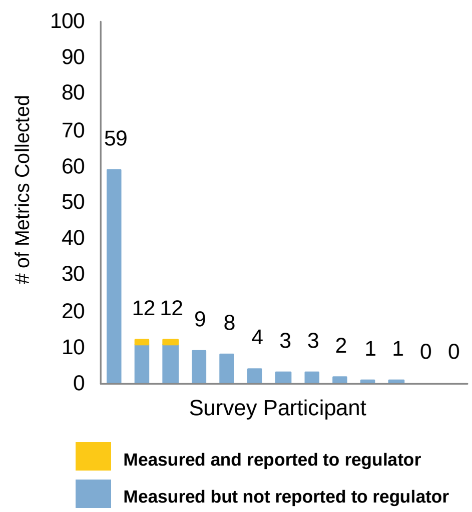
Productivity

12 of 13 utilities collected at least one productivity metric. Productivity is measured at an activity-level; with a median of six metrics per utility, it is likely that most utilities are not measuring productivity across a large portion of their activities and total costs.

The productivity metrics collected are generally not benchmarked, and none are regularly reported as to regulators.

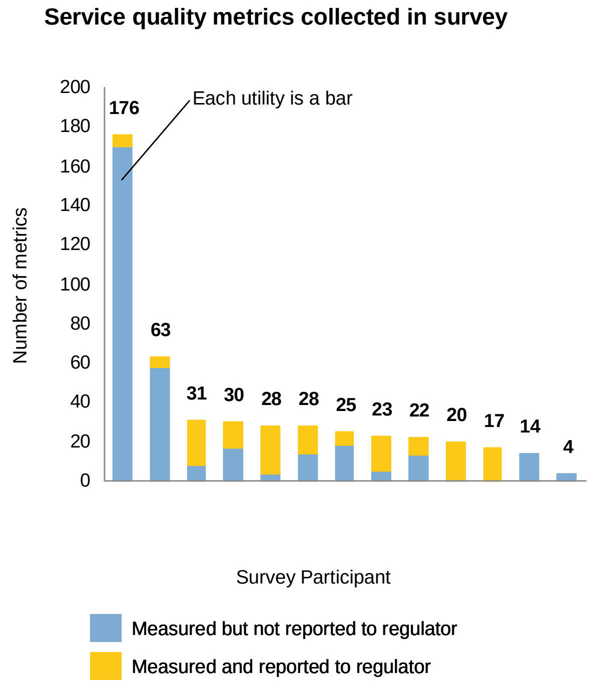
Four strategies were identified for measuring productivity: cost per unit (e.g. cost per pole), units per FTE (e.g. bills processed per FTE), reducing nonproductive time (e.g. average travel time), and time taken per activity (e.g. average time per call).

Productivity metrics collected in survey



Service Quality

The utilities surveyed place a strong emphasis on measuring service quality as these are often the primary concern of regulators, shown by the number of metrics that were reported to regulators.



The metrics collected can be grouped into five categories: system reliability (e.g. system average interruption duration index), safety, customer call center performance (e.g. % of calls answered within 30s), customer facing operations (e.g. % meters read), customer satisfaction.

System reliability metrics were standard across utilities with a majority of the utilities collecting; system average interruption duration index (SAIDI), system average interruption frequency index (SAIFI), customer average interruption duration index (CAIDI).

Common Metrics

It was difficult find metrics that were universal across utilities as each utility measured differently. The metrics below are those that were tracked by at least 2 utilities in the survey.

Cost

- Net income
- Net income from operations
- Operations Maintenance & Administration (OM&A) costs per customer

Productivity

- Turnover
- Cost per call
- Meter reads per FTE
- Lost time accident rate
- First call resolution rate
- Average time per call

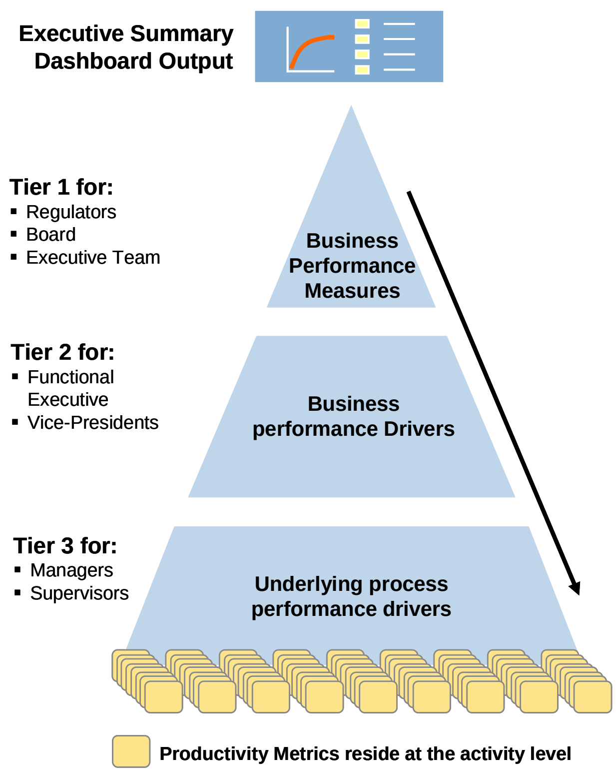
Service Quality

- System avg. interruption frequency index (SAIFI)
- Customer avg. interruption disruption index (CAIDI)
- % of Calls answered in 30s or less
- System avg. interruption duration index (SAIDI)
- % of Calls abandoned
- % of Meters read
- % In-service appointments met
- Customers experiencing multiple interruptions (CEMI)
- Bill accuracy rate
- Average speed of answer
- Occupational Safety and Health Administration Incidence Rate
- Momentary avg. interruption frequency index (MAIFI)
- Emergency response time
- SAIFI – Distribution Only
- # of Off-cycle meter reads/month
- SAIDI – Distribution Only
- Occupational Safety and Health Administration Severity Rate
- # of Post-final adjustment mechanism processed per month
- New service installation factor
- # of Sites billed/month
- # of Sites not billed/month
- Regulatory commission cases per 1000 customers
- Damages per 1000 elect. Locate requests
- Customer satisfaction – overall
- Customer experience long interruption duration (CELID)
- CAIDI – Distribution Only
- CAIDI – Storm
- Average number of energizations per month
- Average number of de-energizations/month
- Average System Availability Index (ASAI)
- % of Meters not read within 6 months
- % of Completed off-cycle meter reads >5 days
- % of Calls answered in under 20 seconds
- Vehicle accident frequency rate

6

Perspectives on Productivity Measurement

Performance measures should "cascade" in various tiers, with productivity metrics normally measuring activity-level performance in the bottom tier. There are three main tiers when measuring performance; business performance measures, business performance drivers, and underlying process performance drivers.



Business performance measures are used for strategic decision making and to align an organization to the company's strategy and vision (e.g. reliability, customer satisfaction, and overall cost to serve). These measures are often reviewed by regulators, the board of directors and the executive team, typically as part of a balanced scorecard.

Business performance drivers are measures that directly impact business performance measures. These metrics can be used to identify opportunities for different business units or operational groups as well for ongoing management education (e.g. customer service cost per customer, inventory turns, or # of outages longer than 4 hours). Business performance drivers are utilized by functional executives and vice-presidents.

Underlying process performance drivers are measures that impact business performance drivers. These drivers enable the identification of specific process improvements and provide ongoing employee education (e.g. cost per call, cost per meter read, or cost per locate). The diversity of work in a utility at this tier would require thousands of metrics to capture productivity covering the entire workforce; therefore it is important to select a representative portfolio of metrics which account for the diversity of work.

Most utilities select the portfolio of metrics using criteria that best fits their business needs. A metric may need to be used in conjunction with other metrics to meet the criteria stated below.

	Metric Criteria	Description	Details for Hydro One
1	**Targets principal labor cost areas**	Build an understanding of labor costs and target the biggest activities first. Choose enough metrics to measure a large proportion of total costs	Major activity costs should be assessed by productivity metrics. Hydro One has several repetitive large costing activities such as locates, pole replacement, tree trimming, etc.
2	**Covers a wide cross section of work**	Choose metrics which measure the major functions of the business.	Categorizing costs into T&D and O&M v Capex allows selection of a stratified sample of the major cost areas. This ensures a balanced wide range of productivity metrics from different areas of the business.
3	**Based on Data Capabilities**	Only use metrics from data that have high confidence levels.	For example do not measure pole replacement costs by location ground type, if ground type is not consistently recorded at Hydro One.
4	**Allows consistent measurement over time**	Metrics should be precisely defined, so year on year comparisons are meaningful	With the introduction of SAP and increases in the resolution of base data, it is important that changes in metric calculations are understood.
5	**Appropriate measurement costs**	Metrics should balance usefulness and costs to measure.	At Hydro One, in order to perform the exact tracking of various field resources, mobile handheld tracking systems, would have to be implemented which are very expensive as it is a new set of hardware, new tracking system and field process restructuring and training
6	**Applicable over long time frame**	Corporate metrics should not be specific to a particular project, but rather valid for multiple years	Project specific metrics are not suitable for long term productivity tracking. This should not prevent larger projects (e.g. Bruce to Milton) to have additional tracking and metrics or be tracked via Earned Value methodologies.
7	**Focus on key areas of customer interest**	Metrics should primarily focus on areas of high concern and/or are important to its customers.	Hydro One has many customer facing activities, which have a large effect on their customer satisfaction. For example average days to complete a locate or percentage of calls answered within 30 seconds

Considerations of productivity metric collection

There are several considerations when using metrics to make decisions about the performance of operations which are; using a balanced approach, the difficulty of obtaining like for like comparison, metrics not capturing all productivity improvements and the cost of metric collection. These considerations detail the various risks associated with data collection, measurement, and use.

Using a balanced approach

A balanced approach to metric reporting considers all factors of safety, quality and long-term concerns when choosing which metrics to include. A balanced approach is required because efforts to increase productivity could lead to a reduction in safety or quality standards as people try to game the system. This is especially a danger if promotions or bonuses are related to metric performance.

Example: A supervisor knows that their bonus will be determined by the metric ‘Cost per km of line cleared’. To increase their bonus, they schedule cheaper vegetation clearance jobs with sparse vegetation that were not critical for another year and push back some difficult line clearance with more impact. The metric improves in the short term, but costs rise later in the year when the uncut vegetation causes an outage in the more critical area.

This problem can be mitigated by building a clear division of labor between work planners and executioners, and not providing an incentive for the planners to affect the metric in either direction. It is necessary to be careful when setting up management and compensation structures to avoid any conflict of interest. In-depth safety training will educate workers about the risks of forgoing service quality and safety standards to expedite the completion of a job. Tracking safety standards within the portfolio of metrics will ensure that the level of safety and service quality does not erode as efforts to increase productivity continue. Measuring a balanced set of metrics prevents undue focus on any one metric.

Like for like comparison

Not all work units are of similar difficulty level, so productivity improvements could be hidden by changes in average job difficulty. Even seemingly homogenous work activities will have their own unique challenges. Each job has its own required travel time, soil type, ease of access, conditions etc. which change the overall cost of the job, these changes have the capacity to dilute increases in productivity.

Example: One year the percentage of pole replacement jobs done in rock increases from 15% to 20%. Since replacing a pole in rock rather than soil is much harder to perform, the cost per pole replacement increases. This effect masks any productivity gains.

Activities should be defined so the differences inherent in each job are not significant. In the pole example replacing a pole in rock, versus earth, could be tracked as two separate activities. This could be done through additional data collection or by defining the metric by zones. Otherwise it is possible to use comparisons across longer time frames to allow for averages to become a better indicator of true performance. This also eliminates any seasonal effects.

Breaking apart activities into similar groups in this manner allows for better like for like comparisons. However, sometimes obtaining the base data to accomplish this is prohibitively expensive, therefore, longer comparison periods should be used instead to normalize the effects of the differences.

Capturing all productivity increases

System productivity enhancements might not be captured by direct consideration of metrics. Initiatives to improve productivity often eliminate manual work streams, in favor of cheaper automated systems. These process changes can cause ‘per work unit’ metrics to deteriorate, while still being an overall productivity improvement. When considering how successful Hydro One has been at increasing productivity all of these savings should be included.

Example: Increased automated monitoring of system availability gives responders the ability to respond faster to outages. However, automated monitoring routinely detects smaller outages, negatively affecting system reliability metrics such as SAIFI.

Savings from new technology programs should be tracked through dedicated programs. It is necessary to compare the total system setup and maintenance costs with the realized savings in order to track how the system influenced productivity. During the transition period to automated meter reading, the cost of meter reads can be divided by the total number of automated reads plus number of manual reads. Similarly for the SAIFI example, during a transition period the metric can be calculated via the old and new methods. When a new baseline for the automated monitoring system is established, the older calculation method can be stopped.

Cost of metric collection

Measuring any metric requires an investment in all of the following areas: setup, data collection, data storage, and reporting and analysis. The benefits of the increased knowledge and understanding from reporting and analysis must outweigh the costs of measurement.

Example 1: Mobile time trackers can be given to all field engineers, recording exact locations and the type of work being performed at any given time. They are expensive to roll out, but allow for much more detailed time studies.

Example 2: Pole replacement costs increase by 30% in a reporting period. After two days of investigation it is found that this is because zone 6 incorrectly reported the number of poles replaced. Two days of overhead costs incurred for no gain in understanding.

In example 1, a detailed cost benefit analysis would be required - a large upfront cost would provide an ongoing wealth of interesting information. In example 2, there is a more straightforward answer; the system should be redesigned to highlight missing input data to prevent losing two days for a simple tear down analysis. Normally reports are setup once and can then be run on an automated schedule, with little to no manual effort. The total costs of measurement and reporting should be understood upfront and compared to benefits in order to decide on its implementation.

Overview of productivity metrics at utilities

Many utilities do measure productivity metrics, as they consider the benefits of understanding their business outweigh the costs and challenges of measurements. The considerations of productivity measurement show that measuring genuine productivity changes is a difficult and sometimes inexact science. There is no automated or fool proof mechanism for capturing all the contextual knowledge required to understand trends and changes in a metric over time. Similarly there is no ‘silver bullet’ metric that does not have any challenges or limitations.

Despite these caveats, productivity metrics are an integral part of the management of a utility. Tracking productivity assists utilities in understanding and explaining the drivers behind changing costs, for use internally and in explanation to regulators. Productivity metrics can assist in targeting corporate initiatives at poorly performing areas and to assess the success of corporate initiatives and of managers.

Most utilities use a balanced set of metrics to obtain the clearest picture of performance. The set of metrics ensure no significant costs of the business are untracked and that productivity is not degrading safety or service quality. Utilities have analysis teams which place results into the context of business cycles and external influences (e.g. weather). The trends in headline metrics are explained by the underlying supporting metrics which is illustrated in the cascade of performance metrics.

Utilities leverage advanced IT systems such as mobile tracking devices to produce detailed productivity metrics without creating large indirect costs. Field workers activities are tracked at a granular level, allowing for a clearer view on productivity without requiring labor intensive and inaccurate detailed timesheets. Activity-level information can be captured on the job site, which helps to further segment activities for like to like comparisons. Utilities that do not have a mobile data collection system to capture every minute of a crew's day, relying on manual entry of time at the end of a day may sometimes result in incorrect data input or inadequate time breakdown which can generate misleading metrics.

7

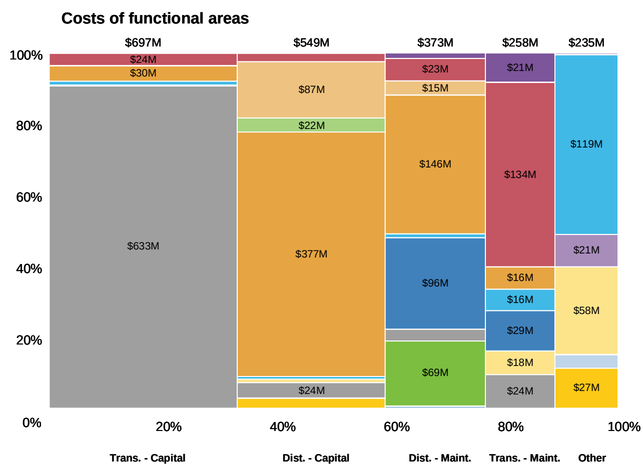
Targeted Cost Analysis

Overview of methodology

Oliver Wyman evaluated Hydro One's project-level data in a four step analysis to better understand how a suite of productivity metrics could be developed.

Step 1: Build overall cost map by functional areas

Projects were grouped into functional areas to ensure that metrics capture major sections of the business.

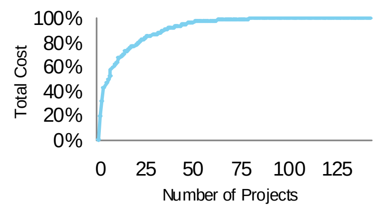


Step 2: Filter cost groups

The four major functional areas were targeted; transmission capital, transmission OM&A, distribution capital, and distribution OM&A. The 'Other' category was not targeted because it includes projects which do not relate to labor productivity. Some of the projects include real estate maintenance as well as IT projects such as SAP. Targeting the major areas allows for a sufficient proportion of the total cost to be tracked. In each of the four functional areas the irrelevant and uncontrollable costs were removed. These are costs that would fluctuate and obscure the productivity gains that are being tracked. In this initial analysis, material costs were removed, which are mainly driven by base commodity prices. Further filters could also target contracts and interest, as these costs do not directly correlate to labor productivity. Interest expense is based on market rates and does not change based on productivity. A productivity metric which includes the cost of contracts might look better if a contract is negotiated with a lower price, or it may be more expensive if internal skilled labor is more efficient. While ‘cost productivity’ may change, these scenarios may not necessarily represent a ‘workforce productivity’ change.

Step 3: Concentration of cost in major projects

It is necessary to understand how dispersed or concentrated projects are within each functional area in order to effectively track performance. Multiple large projects were selected in order to get a large proportion of the costs associated with each functional area. Within these projects understanding which activities meet the metric criteria and represent the largest proportion of cost is mandatory as these are the activities which will be tracked with metrics.



Step 4: Identify suitable metrics for activities

Using the criteria for metric selection, specific metrics within each project and their cost coverage were identified. Some projects were not covered by metrics because the activities which represent the project are not objectively measurable; they either have a short time frame or non-repetitive activities. Short term projects do not allow for long term comparison of the metrics covering these activities, without the comparison tracking the metric becomes a nonproductive effort. Projects may be composed of non-repetitive activities; these activities cannot be measured using productivity metrics as there would be no comparisons available, and tracking it would provide no relevant information.

During the stakeholder session held on October 19, 2011, a point was raised that even if activities are not consistent from activity to activity, a larger group of them should have the same profile if examined over a long period of time. The example discussed was ‘Trouble Response’. While it was agreed that no Trouble Event could be compared to the next because they are very different in nature, over a long period of time a metric looking at the large group of them should be possible. With respect to Trouble Events, it was discussed that even over an annual cycle, the ‘portfolio’ of events would vary because weather patterns change from year to year affecting the frequency and character of trouble events. So, a longer period of time (e.g., 3 years) would have to be examined.

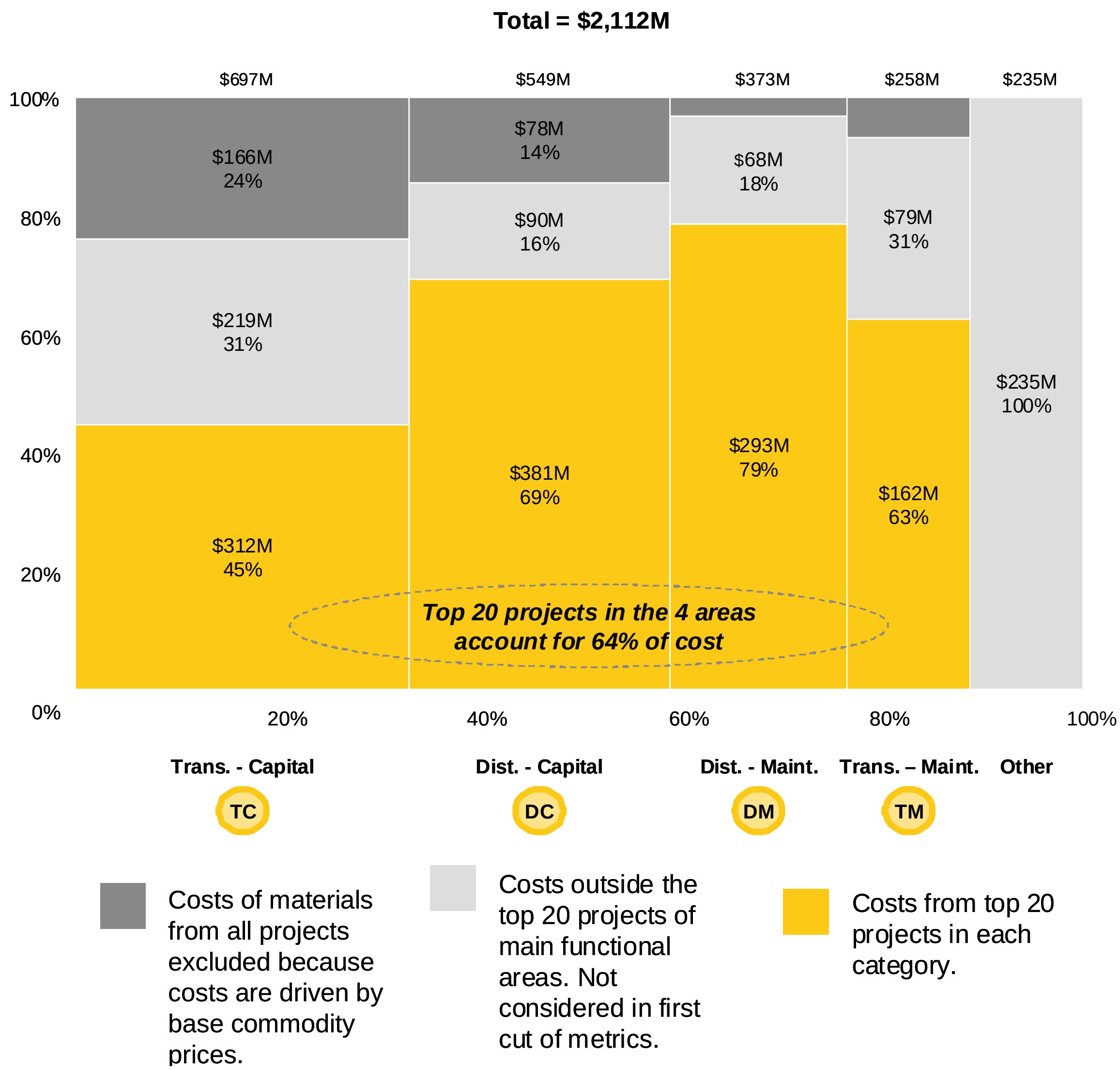
In this report we identify those activities that have potential to be measured over a long period of time. However, we believe that the long duration over which they must be examined prevents them from being used as a management tool to drive improvements in productivity. Management cannot use them on a regular basis to identify and drive improvements. Therefore, while we identify them in their respective sections, we do not recommend pursuing them at this time to drive productivity improvements.

Principal cost driver analysis

Productivity metrics should span all business areas in order to best represent the productivity for Hydro One as a whole. Understanding the cost drivers for each of the main projects in the functional areas will allow for tracking productivity across a large proportion of total cost.

Cost map of the 80 projects in focus from the four functional areas

To arrive at a list of activities (projects) that may be measured for productivity, the largest activities (measured by cost) were examined. Material costs are excluded from the analysis as they do not represent workforce productivity and can fluctuate with many uncontrollable factors. Targeting the major cost areas (projects) allows for a large proportion of total cost to be covered, by a smaller number of metrics the top 80 projects (20 from each major cost area, T OM&A, T Capital, D OM&A, D Capital) cover 64% of the total cost.

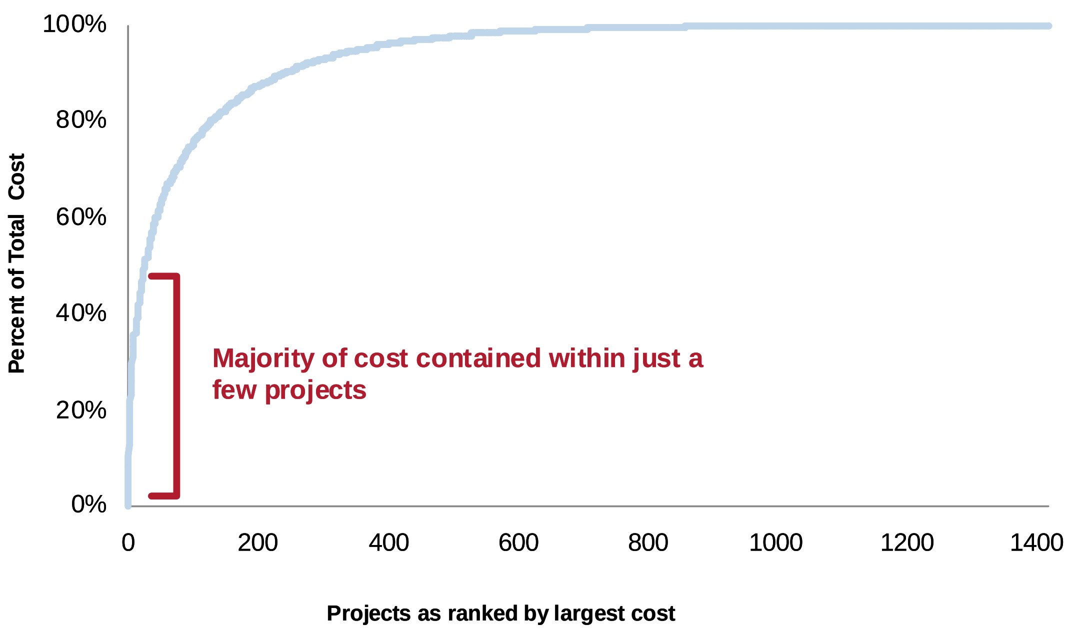


Note: All costs are approximate and have been annualized from May 2011.

Trends in project costs

Another representation of the concentration of costs is to examine what each incremental activity (project grouping) adds to the total cost of the total. Each major cost area reveals that a large proportion of total cost is covered in a small number of projects. A few metrics targeting these projects cover a large percentage of cost and work. The cumulative cost of activities shows that 80% of costs are from the 126 largest projects, 75% from 96 projects, 50% from 29 projects, and 24% from 6 projects.

Cumulative cost of projects
Excludes materials



**Note: Costs are approximate values and have been annualized from May 2011. Costs do not include projects with negative or zero costs.*

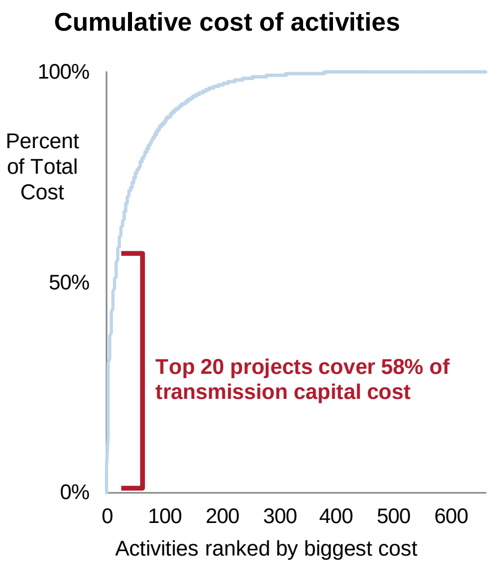
For each major cost area on the following pages we outline the concentration of costs into the largest activities (projects) and illustrate what metrics could be used to measure each.

As stated in the methodology section metrics are identified that have the most promise for measuring productivity based on the criteria outlined. In addition we identify additional metrics that could be compared over longer time frames (e.g., annual or greater), however we do not recommend pursuing these for purposes of improving productivity because they do not provide the regular view into performance required for managers to make useful changes.

Transmission capital project metrics

The top 20 largest Transmission Capital projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 58% of the total relevant transmission capital spend. However, because these projects are generally one-time in nature and do not endure over time, only nine of the twenty largest transmission capital projects have suitable metrics.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time. For example the "Burlington Switchyard Reconstruction" has many activities that are likely unique because of the project nature of the work.



#	Activity	Metric	Activity Cost	% Cumulative cost*
1	Bruce to Milton double circuit line	▪ Cost per km of line cleared ▪ Cost per foundation ▪ Cost per tower constructed (*metrics do not cover all costs)	$129M	24%
2	PC&T systems	▪ Inconsistent over time	$17M	27%
3	Wood pole replacement program	▪ Cost per pole	$14M	29%
4	Burlington switchyard reconstruction	▪ Project based	$13M	32%
5	WATR	▪ Inconsistent over time	$11M	34%
6	Kirkland Lake Reconnect Idle Line	▪ Project based	$11M	36%
7	Wood pole replacement program	▪ Cost per pole	$11M	38%
8	Mitigate reliability problems of Shunt capacity	▪ Inconsistent over time	$11M	40%
9	Build New Duart TS	▪ Project based	$10M	42%
10	SF6 Breaker Replacement Program	▪ Cost per breaker	$10M	44%
11	Detweiler: Add 230 kV, 350 MVAr SVC	▪ Project based	$9.1M	45%
12	Replace 2010 Richview Transformers	▪ Cost per transformer	$9.0M	47%
13	RTU Replacement Program	▪ Cost per RTU	$8.7M	49%
14	Nanticoke: 500 kV, 350 MVAr SVC	▪ Project based	$8.0M	50%
15	Kirkland Lake TS - Install SVC	▪ Project based	$7.4M	51%
16	Protection Replacement Program	▪ Cost per protective device replacement	$7.3M	53%
17	BSPS Mods for Bruce for 2009	▪ Project based	$7.1M	54%
18	Line Refurbishment Program ('10-'12)	▪ Cost per km of transmission line refurbished	$6.9M	55%
19	Line Refurbishment Program ('09-'10)	▪ Cost per km of transmission line refurbished	$6.8M	57%
20	Demand Capital - Equipment Failure	▪ Inconsistent over time	$5.3M	58%
	Legend	Totals	$312M	58%

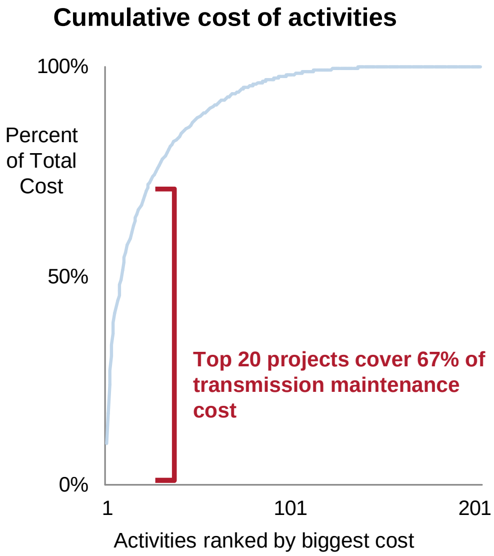
Relevant Metric | Potential metric examined over long time periods | Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.
**Metrics listed do not necessarily cover all costs in the category*

Transmission OM&A project metrics

The top 20 largest Transmission OM&A projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 67% of the total relevant transmission OM&A spend. However, because these activities (projects) do not contain discrete work activities that are consistent over time, only 8 of the areas have suitable metrics. For example, “Corrective Maintenance” contains many activities that are not consistently repeated and therefore, cannot be measured as easily.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time.



#	Activity	Metric	Activity Cost	% Cumulative cost*
1	Preventive Maintenance - Planned (PMO)	▪Cost per km for line patrol ▪Cost per insulator inspection	$24M	10%
2	Transmission Site Maintenance	▪Inconsistent over time	$18M	17%
3	Tx Lines - RoW Brush Control	▪Cost of brush control per km of line	$16M	24%
4	Corrective Maintenance - Demand	▪Inconsistent over time	$16M	31%
5	Corrective Maintenance - Planned	▪Inconsistent over time	$13M	36%
6	Operating Facilities Support & Mtce - OGCC IT	▪Inconsistent over time	$12M	41%
7	Tx Lines - RoW Line Clearing	▪Cost per km of line cleared	$7.2M	44%
8	P&C NOEA / PQ / Spares / Database / Info. Mgnt	▪Inadequate time frame	$6.3M	47%
9	PSTS Leased Circuits	▪Inadequate time frame	$5.9M	49%
10	2011 Tx ECS Stds Development	▪Inadequate time frame	$5.3M	51%
11	Field Switching - Stations	▪Inconsistent over time	$5.2M	53%
12	P&C Preventative Maintenance / Inspections	▪Cost per inspection	$4.8M	55%
13	Overhead Tx Lines - Preventative Maint. - PL	▪Inconsistent over time	$4.7M	57%
14	P&C EMERG Corrective Maint. and Trouble Call	▪Cost per call out	$3.9M	59%
15	Environmental Mgt- Demand Corrective Mtc	▪Inconsistent over time	$3.7M	60%
16	Transformer Midlife Refurbishment Program	▪Cost per Transformer Refurbishment	$3.7M	62%
17	Overhead Tx Lines - Condition Assessment - PL	▪Cost per km for line patrol	$3.2M	63%
18	Overhead Tx Lines - Demand Work - PL	▪Cost per KM of line	$3.1M	65%
19	Transformer Oil Leak Reduction Program	▪Inconsistent over time	$3.1M	66%
20	2011 Cyber Sustainment	▪Inconsistent over time	$2.8M	67%
		Totals	$162M	67%

Legend

Relevant Metric	Potential metric examined over long periods	Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.
**Metrics listed do not necessarily cover all costs in the category*

Distribution capital project metrics

The top 20 largest Distribution Capital projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 80% of the total relevant Distribution capital spend. Only 5 of the areas have suitable metrics, however because many of the activities are not repeated consistently over time. For example, "Storm Damage" contains many activities that are not consistently repeated and therefore, cannot be measured as easily.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time.

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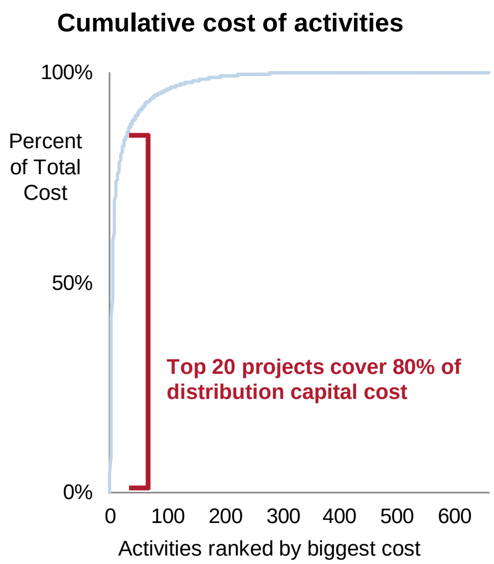


#	Activity	Metric	Activity Cost	% Cumulative cost*
1	Smart Metering - Capital	▪Cost per meter install	$82M	17%
2	End of Life Replacement of Wood Poles	▪Cost per pole	$53M	28%
3	Residential, Subdivision, Expansion	▪Cost per new service	$45M	38%
4	Dx Capital Storm Damage	▪Inconsistent over time	$38M	46%
5	Joint Use and Relocations (Yearly)	▪Cost per relocation	$37M	54%
6	ADS Project - Phase 1 - Dx Capital	▪Project based	$21M	58%
7	Dx Capital Trouble Call Poles & Equipment	▪Inconsistent over time, materials	$17M	62%
8	Cornerstone Phase 4 - CIS - Capital	▪Project based	$17M	65%
9	Customer Upgrade	▪Cost per upgrade	$14M	68%
10	Other, EI, Data Collection	▪Inconsistent over time	$11M	71%
11	2010 Connection of Micro-Generation Facilities Und	▪Cost per connection	$9.3M	73%
12	Upgrade - Other	▪Inconsistent over time	$4.8M	74%
13	Dx Capital Trouble Call Damage Claims	▪Inconsistent over time	$4.5M	75%
14	2009 Joint Use and Relocations	▪Inconsistent over time	$4.4M	76%
15	Large Project	▪Project based	$4.3M	77%
16	2011+ Distribution System Modifications	▪Project based	$4.2M	77%
17	Dx Capital Post Trouble Call & Power Quality	▪Inconsistent over time	$3.7M	78%
18	Service Cancellations	▪Cost per service cancellation	$3.6M	79%
19	Facilities Improvements DX (segment alignment)	▪Inconsistent over time	$3.5M	80%
20	Dx Capital Trouble Sub and UG Cable	▪Cost per event	$3.4M	80%
		Totals	$381M	80%

Legend

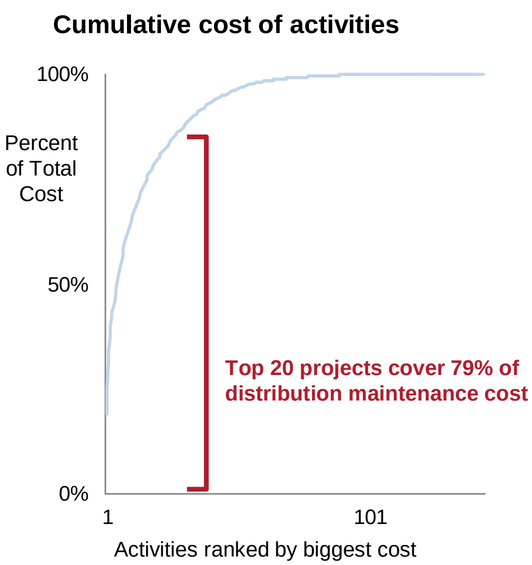
Relevant Metric	Potential metric examined over long periods	Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects
**Metrics listed do not necessarily cover all costs in the category*

Distribution OM&A project metrics

The top 20 largest Distribution OM&A projects were examined to determine which could have associated productivity measures that would fit the criteria outlined above for appropriate productivity metrics. The top 20 projects account for 79% of the total relevant Distribution OM&A spend. 8 of the areas have suitable metrics because many of the activities are not repeated consistently over time. For example, “Trouble calls” contains many activities that are not consistently repeated and therefore, cannot be measured as easily.

The illustration of the concentration of these costs and the productivity metrics associated with them are illustrated below. Where no metrics are appropriate for a given project (activity) the reason is noted. These are primarily due to the inconsistency of the cost over time.



#	Activity	Metric	Activity Cost	% Cumulative cost*
1	Dx RofW Vegetation Management - Line Clearing	▪Cost of brush control per km of line	$70M	19%
2	Dx O&M Trouble Call	▪Cost per trouble event	$46M	31%
3	CSO Sustainment	▪Outsourced	$40M	42%
4	OH Defect Correction & Insulator Replacement	▪Cost per insulator replaced	$14M	46%
5	Smart Metering - OM&A	▪Cost per meter read	$14M	50%
6	Dx Overtime and Forestry Storm Costs	▪Cost per storm (OT and forestry)	$14M	53%
7	Dx RofW Vegetation Management - Brush Control	▪Cost of brush control per km of line	$12M	57%
8	Dx Cable Locates	▪Cost per cable locate	$12M	60%
9	Dx Vegetation Management - Job Plan & Notify	▪Inconsistent over time	$8.3M	62%
10	CSO Service Support - 3rd Party - MR & Billing	▪Cost per bill	$8.0M	**64%**
11	Meter Reading - Prov. Lines	▪Cost per meter read	$7.8M	67%
12	CSO Regulatory Compliance - MR & Billing	▪Inconsistent over time	$7.4M	69%
13	Dx Disconnects / Reconnects	▪Cost per disconnect ▪Cost per reconnect	$6.5M	70%
14	CSO Service Enhancements - MR & Billing	▪Inconsistent over time	$5.8M	72%
15	Small External Demand (Yearly)	▪Inadequate frame	$5.6M	73%
16	OPA Programs	▪Inconsistent over time	$5.5M	75%
17	DS Stations O&M	▪Inconsistent over time	$5.2M	76%
18	PCB and Other Waste Management	▪Inconsistent over time	$3.9M	77%
19	Field Special Investigations	▪Cost per field investigation	$3.7M	78%
20	CSO Regulatory Compliance - Collections	▪Inconsistent over time	$3.5M	79%
		Totals	**$293M**	**79%**

Legend

Relevant Metric	Potential metric examined over long periods	Not measurable

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects
**Metrics listed do not necessarily cover all costs in the category*

Summary of recommended metrics

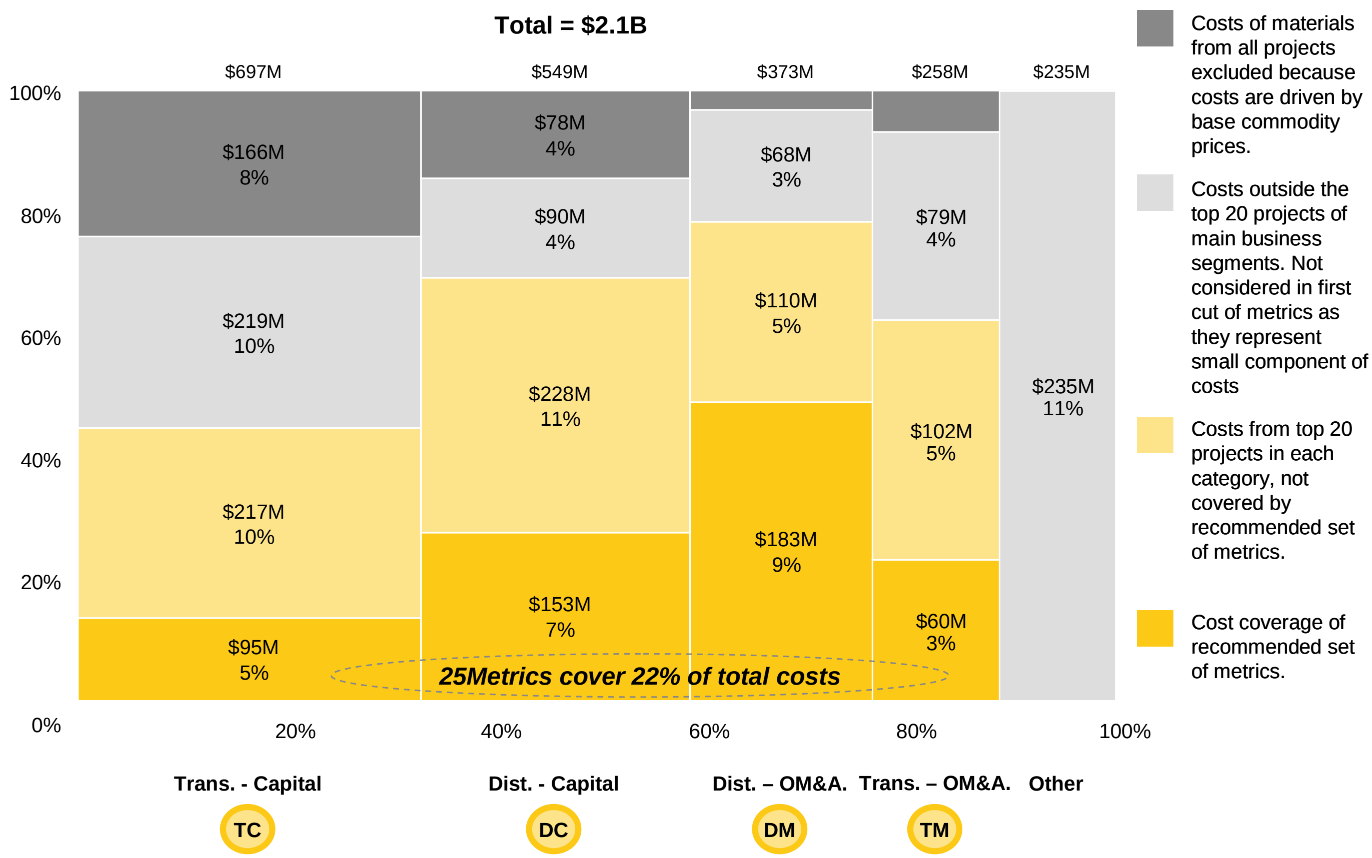
Aggregating the metric choices from the four main functional areas represents a good coverage of total cost; twenty five selected metrics account for approximately twenty two percent of total cost. Some metrics cover multiple activities across different functional areas (e.g. cost per pole). Further subdivision of these metrics may be required to allow better comparisons (e.g. cost per pole could be sub divided into cost per pole per ground type). Estimations of cost coverage were based on project titles, further validation with the business would be required to confirm the assumptions made. A large number of projects could not be understood from titles well enough to suggest metrics.

#	Metric	Cost Coverage	% of total costs
1	Cost of brush control per km of line	$98M	4.6%
2	Cost per meter install	$82M	3.9%
3	Cost per pole set	$78M	3.7%
4	Cost per new service installed	$11M - $34M	1.1%
5	Cost per tower constructed	$13M - $26M	0.9%
6	Cost per tower foundation	$13M - $26M	0.9%
7	Cost per km of Tx line cleared (Capital)	$13M - $26M	0.9%
8	Cost per meter read	$22M	1.0%
9	Cost per upgrade	$14M	0.7%
10	Cost per km of transmission line refurbished	$14M	0.6%
11	Cost per insulator replaced	$8M - $13M	0.5%
12	Cost per cable locate	$12M	0.6%
13	Cost per km for line patrol	$6M - $10M	0.4%
14	Cost per breaker	$8M - $10M	0.4%
15	Cost per transformer	$9M	0.4%
16	Cost per RTU	$7M - $9M	0.4%
17	Cost per bill	$1M - $8M	0.2%
18	Cost per km of Tx line cleared (OM&A)	$7M	0.3%
19	Cost per protective device replacement	$2M - $5M	0.2%
20	Cost per Transformer Refurbishment	$4M	0.2%
21	Cost per service cancellation	$4M	0.2%
22	Cost per insulator inspection	$1M - $4M	0.1%
23	Cost per disconnect	$3M	0.2%
24	Cost per reconnect	$3M	0.2%
25	Cost per line inspection	$1M - $3M	0.1%
	Total	~$480M	~22%

Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.

Cost coverage of selected metrics

The aggregated metrics are shown in the overall cost map below. Distribution OM&A has the largest coverage due to having more repetitive activities, suitable for metric collection. Transmission capital has mostly "one-off" project work and a higher percentage of unique, non-repetitive projects.



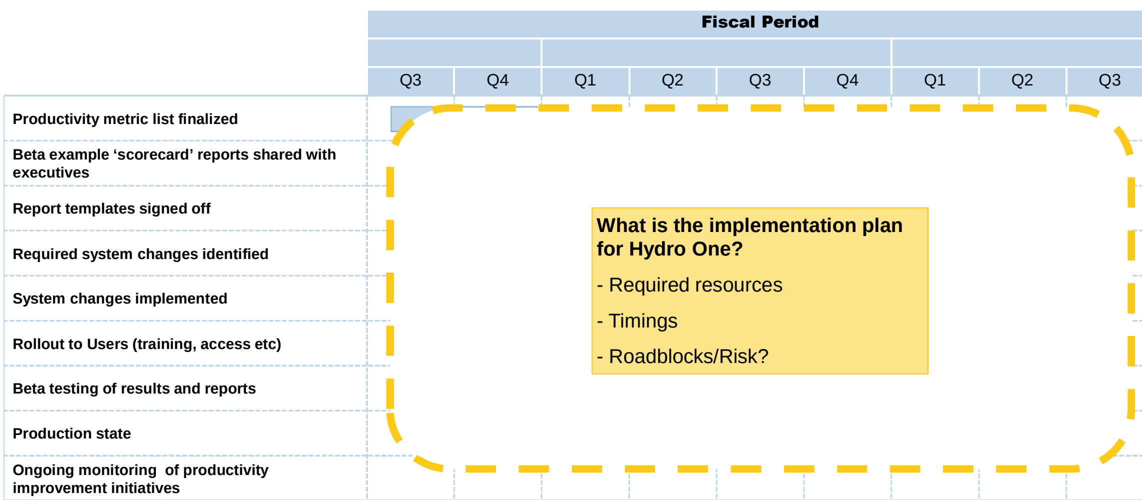
Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects.

8

Next Steps

Roadmap for implementation

Hydro One will require a plan to implement and of these recommended metrics, and their associated costs, within a timeline. The plan will need to consider what resources will be required for implementation as well as what risks they foresee during implementation.



Potential challenges for utilities in measuring productivity

Initial data collection efforts and interviews highlighted a number of areas of potential challenges for utilities in reporting productivity metrics. These challenges include: data validation, activity segmentation, partial completions, granularity, mobile data collection, indirect costs and their ability to roll up to corporate scorecard measures.

Data validation

In order to ensure useful productivity measurement, the data must be inputted into an enterprise system accurately and consistently. The total number of unit activities needs to be correct to get a valid "cost per unit" measurement. The users of the enterprise system will need to be trained to ensure that the data collected is reliable. Monitoring and auditing compliance should be added to the management review process to ensure the data in the system can be used with a high degree of confidence.

Activity segmentation

Certain activities have widely disparate costs depending on location, ground type, weather etc. and require further segmentation to provide useful measurement (e.g. type of ground for pole replacements). It will be necessary to determine how to segment these activities to ensure that like for like comparisons can be made.

Partial completions

The system should capture 'partial completions' for larger activities or activities with multiple steps. Collecting these partial completions will ensure that a metric does not look poor until the activity is fully completed but rather show a steady result through the duration of the activity.

Granularity

The system data warehouse should capture costs at a granular level. Otherwise there are concerns regarding whether the granular buckets are being used appropriately and if the data is accurate at that level. Effective measurement at an activity level requires high confidence in the data at the most granular levels. The highest level of data confidence is generally achieved through utilities using mobile/handheld equipment.

Mobile data collection

Mobile data collection allows for full tracking of field workers activities and the time taken to complete those activities. The completeness of data that arises from the use of mobile tracking devices allows for highly accurate analysis and better activity segmentation. Using timesheets to track activity level data, which are filled out at the end of the day by the field workers is a labour intensive process. This manual data collection can lead to misleading results as the field worker may be required to estimate the time he spent on each activity throughout the day.

Indirect costs

Are indirect costs traced carefully using an activity based costing model or similar? It is necessary to ensure that certain activities are weighted with appropriate indirect costs. A regular review of how the indirect costs are weighted among each activity will ensure that it is accurate each year.

Generally, each of these challenges can be addressed; they just require additional expense and/or additional time. It is necessary and appropriate for utilities to make deliberate decisions about how to spend their time and money to generate the productivity metrics that add value to the organization. There are costs of implementation to consider, as well as the costs of ongoing maintenance of any system/process put in place to generate the appropriate measurements.

Performance management design criteria

Performance management needs to focus on the following four key building blocks; measures, measurement, goals/targets and action plans and the iterative process.

Measures

The measurement process should not be an overwhelming task; a select portfolio of metrics meeting the criteria and measuring a large portion of business activities and costs should be used. The measures should include the three tiers of performance measurement to allow for strong analysis for those utilizing the metrics at each level. A mix of leading vs. lagging measures will allow for accurate forecasting as well as strong cause and effect analysis.

Measurement

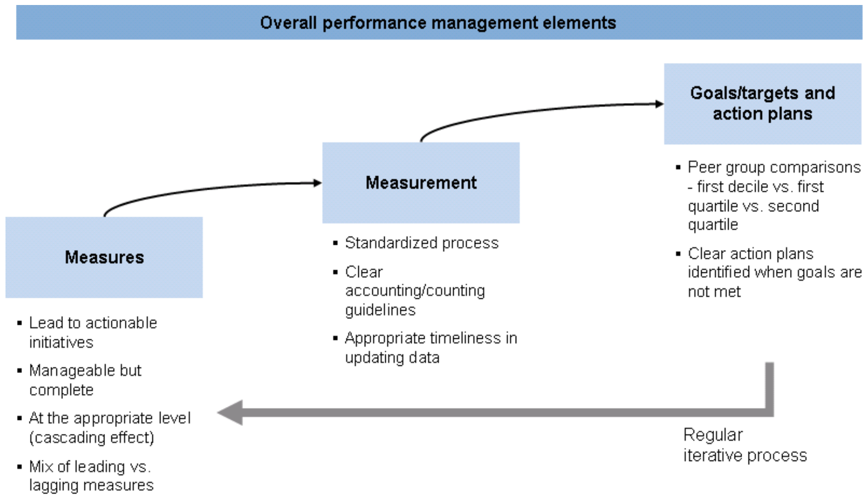
To reduce the burden of measurement, a standardized process would decrease the time and costs necessary to report on the data collected. The process should include clear accounting principles to be strictly followed to ensure data validity at all levels. Regular reporting timelines should be included as part of the process so the data is updated when it needs to be used.

Goals/Targets and action plans

Metrics can be used to track the success of meeting a target, as well as be used to create new targets. These metrics can be used to benchmark against peers and determine areas of opportunity.

Regular iterative process

Each iterative process will re-examine the usefulness of each metric being measured. Some metrics will be removed while others will be added to fit the needs of the current corporate strategy and goals.



Addressing the main drivers of productivity

There are three main drivers of productivity; reducing unproductive time, increasing efficiency of productive time and reducing unnecessary activities.

These levers should be addressed for direct as well as indirect labor (support and admin). When creating the metrics using a 'fully burdened' cost will help to ensure that improvements in the indirect portion of an activity are seen in the metric over time.

Reducing unproductive time

Targeting unnecessary meetings and trainings which are not beneficial will free the time in which the meeting or training participants are not being productive. Training times can be reduced by consolidating training sessions. Unproductive standard meetings can be removed.

Improving scheduling to reduce dead times. These dead times include the time in between jobs and the time at the end-of-day. Improving vacation scheduling to incentivize taking vacations during non-peak work times will create a larger available workforce during peak times.

Building better work planning tools to reduce travel times. These tools could reduce travel time by scheduling more jobs in similar areas together, dispatching the workforce from home instead of coming to yard and having real time traffic information to reduce time spent on the road.

Negotiating for lower minimum bill times will reduce the time that labor is unproductive but still being paid for the job.

Increasing efficiency of productive time

Improving the tools and processes in use during productive time will create an overall increase in productivity. Using more prefabricated construction offsite will allow for faster construction on site when expensive labor needs to be utilized. Technology can be used in planning to allow for more efficient job scheduling. Increasing the use of standardized components would require less training, cheaper procurement and inventory management. Another way of using tools to increase efficiency would be to preload asset location and details onto GPS systems in fleet.

Optimizing working team skill blend reduces the labor cost necessary to complete an activity. Team skill blend can be altered by using mixing more experienced hires with more junior team members (e.g. the apprentice model). Using hiring hall where possible will optimize skill blend because hiring hall is cheaper to use than experienced, often expensive full time staff.

Implement peak shaving through using contractors where applicable to reduce total staff on books required to cover peak work loads.

Align compensation and performance to ensure good audited data and encourage ‘bottom up’ initiatives.

Reducing unnecessary activities

These activities can be reduced by eliminating unnecessary work processes most importantly for indirect costs. Another strategy is to build a strategic contacting strategy by performing activity level benchmarking to determine where activities are under performing a similar panel.

Report Appendix:

- Findings from regulatory bodies
- Additional analysis of costs

Summary of results from Canadian commissions

Comm-issions	Key Findings	Metrics filed regularly		
		Produc-tivity*	**Cost****	**SQM**
British Columbia Utilities Commission	▪ The revenue requirement applications include reliability metrics (SAIDI, SAIFI, CAIDI), factor productivity (# Customers/Network Length), and cost (T+D Capex/T+D line km) ▪ BC Hydro benchmarks reliability through the CEA ▪ Fortis submits an annual review including SQM metrics and general cost of service information	✘	13	29
Alberta Utilities Commission	▪ The general tariff applications include reliability metrics (SAIDI, SAIFI, AIIFR), and cost metrics (O+M spend/gross plant assets) ▪ Rule 002 and Rule 003 detail the service quality filing requirements for annual report	✘	3	24
Saskatchewan Rate Review Panel	▪ SaskPower rate case did not contain metrics ▪ A RFI stated performance metrics would be measured internally by SaskPower but were not collected by SRRP.	✘	✓	✘
Manitoba Public Utilities Board	▪ The *Public Utilities Board Act* has no minimum filing requirements. ▪ The PUB requested independent benchmarking for MH, study is delayed until late 2011 ▪ Manitoba Hydro files an *Electric Board Annual Report* with safety and cost metrics	✘	2	7
Ontario Energy Board	▪ The rate cases contain system reliability metrics, and veg. mgmt. benchmarking study ▪ The *OEB Year Book* and *Electricity Reporting and Record Keeping Requirements* contain service quality metrics and cost metrics filed annually	✘	6	17
Quebec Energy Board	▪ The rate cases contain cost (cost per customer) and service quality metrics (SAIDI, telephone answer rate, telephone abandon rate) ▪ The annual filing requirements include cost, and service quality metrics (safety, reliability)	✘	38	20
Nova Scotia Utilities and Review Board	▪ The rate cases contain cost metrics (OM&G/Customer) and reliability metrics (SAIFI*SAIDI) ▪ A NSPI Rate case contained an operational review called the Kaiser study containing some metrics relating to cost, SQ and productivity (calls handled per agent per day) ▪ An ad hoc independent operational review contained one productivity metric: Calls handled per agent per day	✘	4	6
New Brusnwick Energy and Utilities Board	▪ The rate applications (DISCO, NBSO, NBP) do not contain performance metrics, but do include financial information ▪ The *Electricity Act* does not mandate metrics to be filed	✘	✓	✘

* An x in the productivity column states that there are no regularly filed productivity metrics.
** A checkmark in the cost column represents a commission which collects some financial information but not cost metrics.

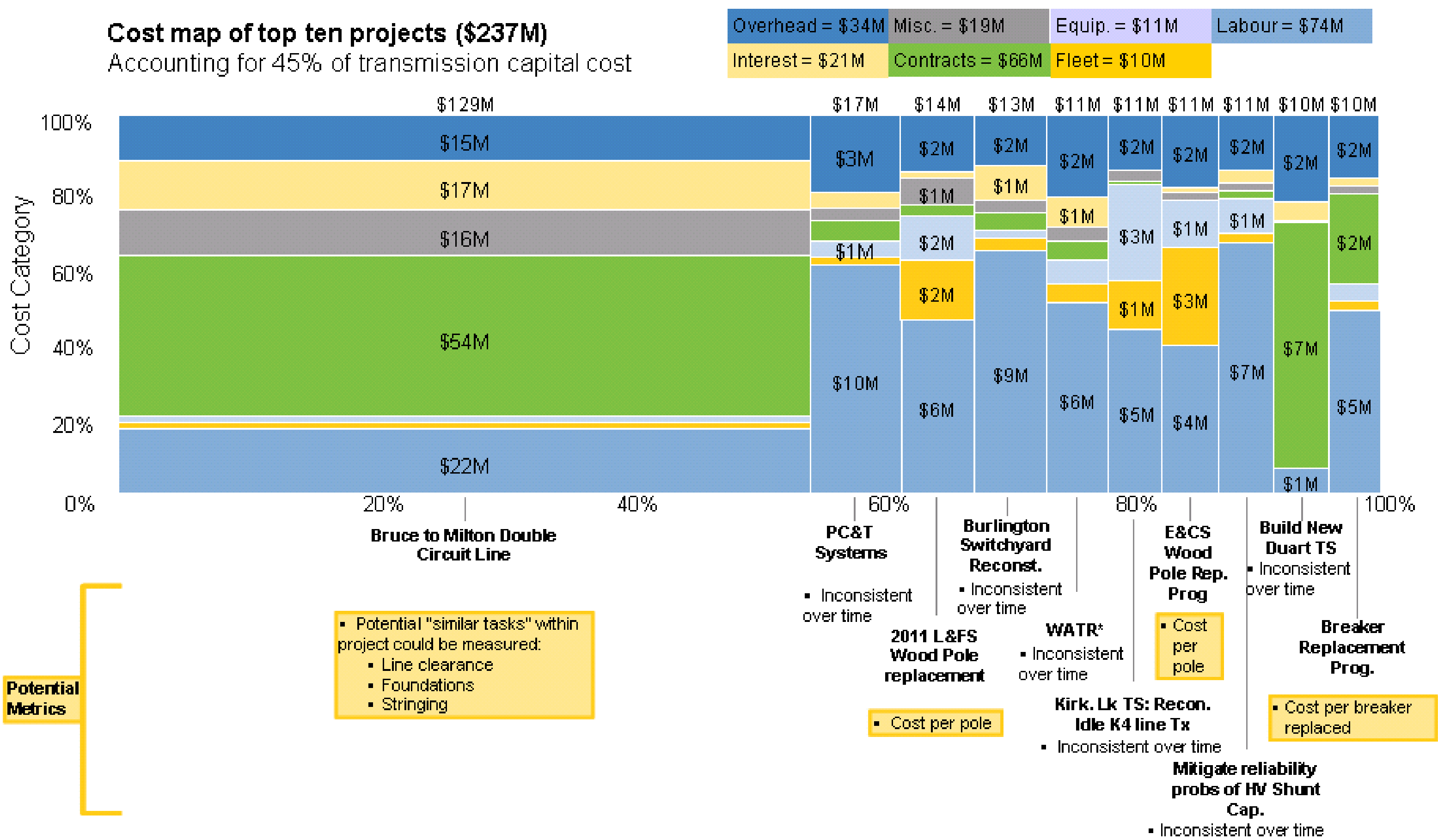
Summary of results from US commissions

Comm-issions	Key Findings	Metrics		
		Produc-tivity*	Cost**	SQM
Massachusetts Department of Public Utilities	▪ *Order 04-116* states annual minimum reporting requirements (CKAIDI, CKAIFI, SAIDI, SAIFI, % Billing Adjustments, and Customer Services guarantees) ▪ Electric and gas utilities in MA are required to file annual service quality reports	✗	✓	19
New York Public Services Commission	▪ The rate cases contain reliability metrics ▪ *NYCRR S. 61* details minimum financial filing requirements for rate cases ▪ Customer service and reliability reports are filed annually with the PSC	✗	✓	13
Pennsylvania Public Utilities Commission	▪ The Pennsylvania Public Utility Code required annual filing of reliability standards ▪ Electric service reliability and quality of service reports are filed each year	✗	✓	16
Michigan Public Services Commission	▪ System performance and power quality reports are filed annually containing service quality metrics (reliability, customer service, % meter reads etc) ▪ The rate cases does not contain performance metrics	✗	✓	13
Public Utilities Commission of Ohio	▪ The minimum filing requirements did not state performance metrics had to be filed ▪ Annual reliability reports are filed annually (SAIDI, SAIFI, CAIDI)	✗	✓	7
Illinois Commerce Commission	▪ No productivity or cost metrics required to be filed ▪ The *Public Utilities Act* and *Electric Supplier Act* detailed filing requirements (SAIFI, CAIFI, CAIDI, customer service survey)	✗	1	8
Connecticut Public Utilities Regulatory Authority	▪ The rate cases contained orders containing call center metrics ▪ Reliability information is required to be filed annually as per the *Connecticut Code*	✗	✓	9
California Public Utilities Commission	▪ The *New Jersey Administration Code* states filing requirements for reliability ▪ The rate cases have customer service metrics	✗	✓	9

* An x in the productivity column states that there are no regularly filed productivity metrics.
** A checkmark in the cost column represents a commission which collects some financial information but not cost metrics.

Transmission capital: Cost map of top ten projects

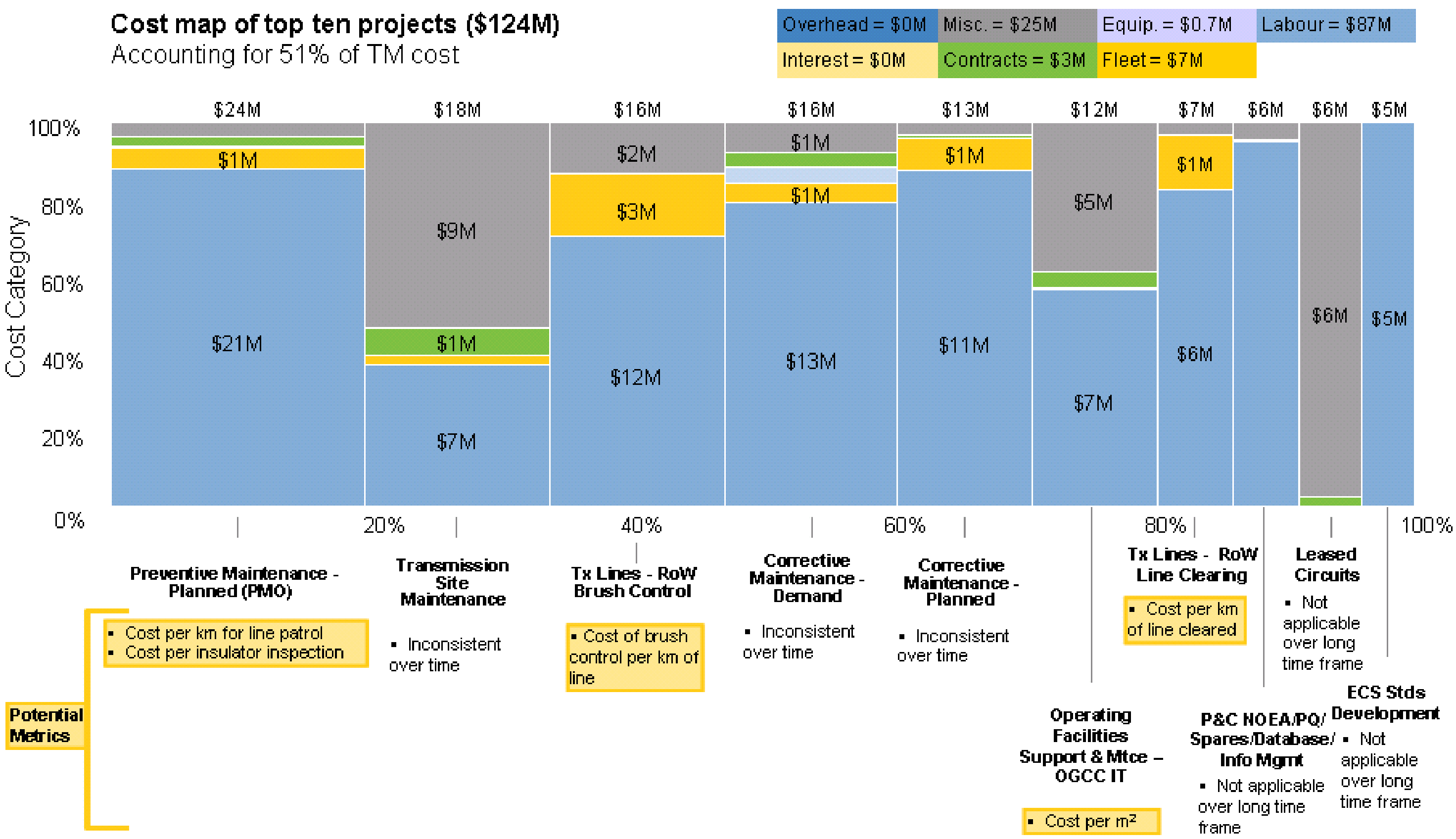
As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. Costs are concentrated in a few very large projects. Though these major projects cannot be measured with a single metric, several activities within the project could be potentially measured.



Note: Costs are approximate values, annualized from May 2011. This chart excludes material costs. Total transmission capital cost includes negative and zero cost projects.

Transmission OM&A: Cost map of top ten projects

As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. Transmission OM&A is more evenly distributed across the biggest projects than transmission capital, but each project still contains a diverse set of activities.



Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects. Total transmission maintenance cost includes negative and zero cost projects.

Distribution capital: Cost map of top ten projects

As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. For Distribution Capital costs, many are large project related and therefore not measureable over time making them less suitable for tracking.

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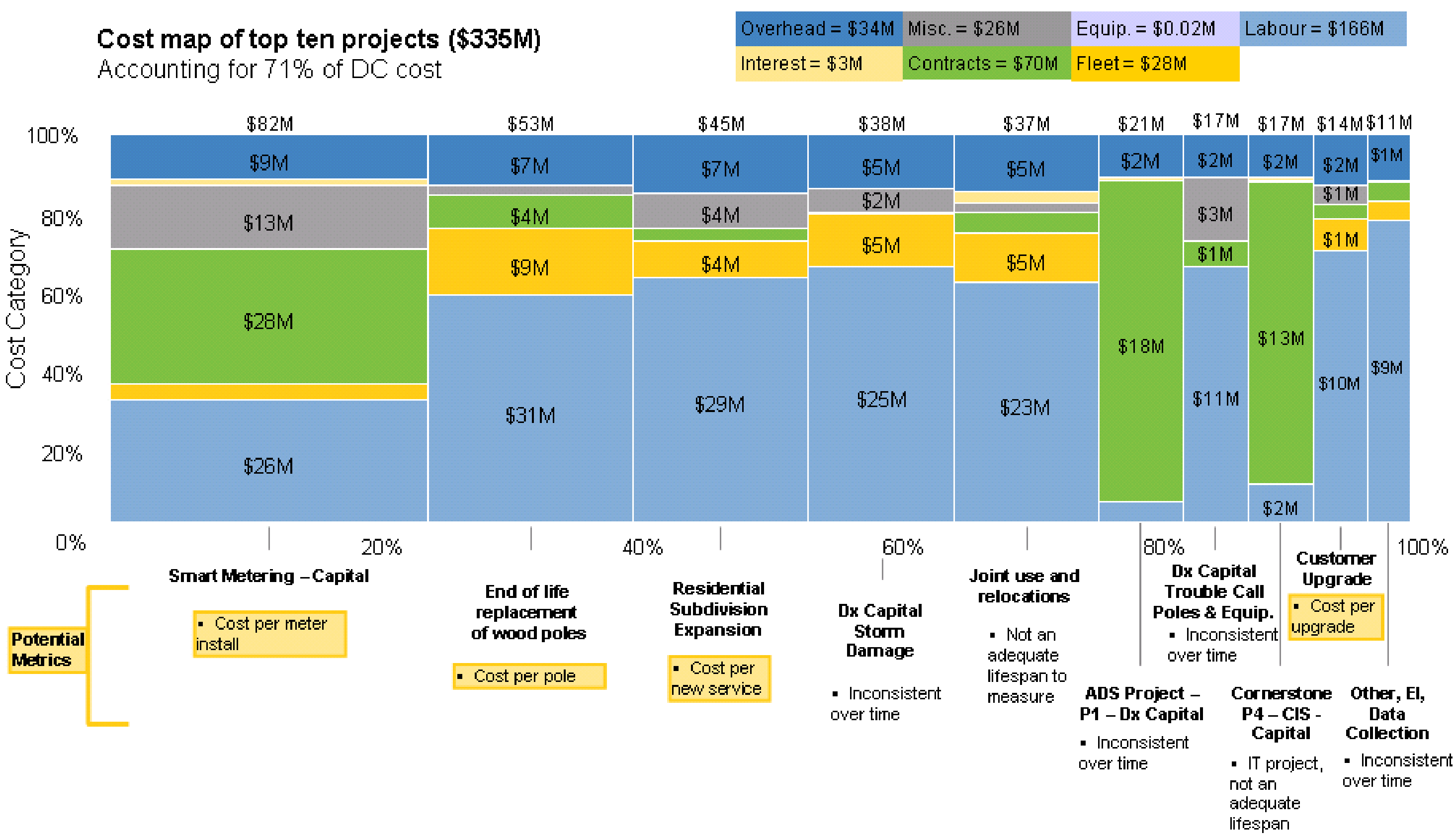
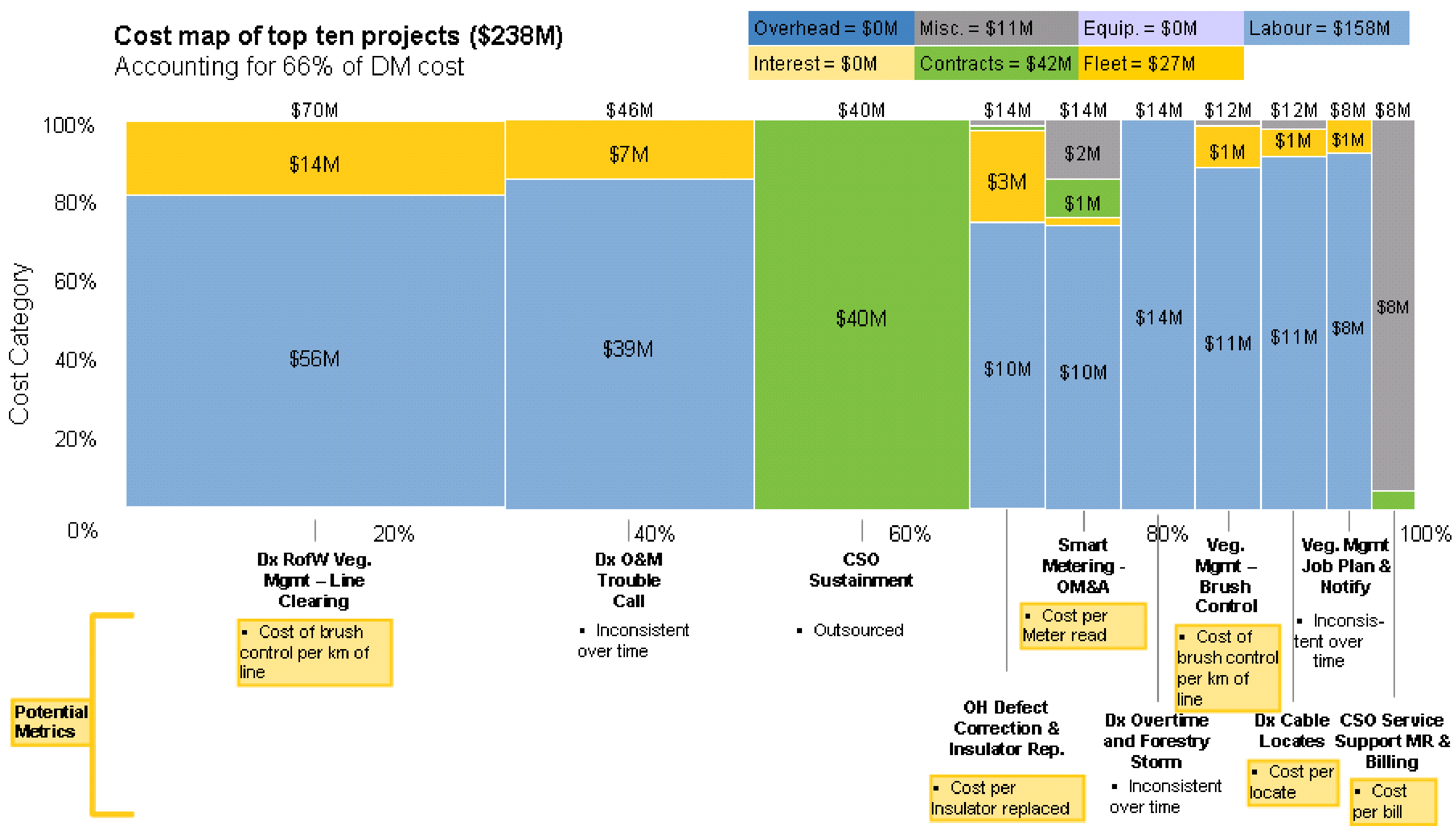


Note: Costs are approximate values, annualized from May 2011. Costs exclude materials and zero value or negative cost projects. Total distribution capital cost includes negative and zero cost projects.

Distribution OM&A: Cost map of top 10 projects

As an illustration of the major components of costs, cost maps were created for each major cost area. The maps of the top 10 largest projects are shown below to illustrate the concentration of costs. Distribution OM&A has the largest amount of repeatable activities suitable for metrics.



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School Energy Coalition (SEC) INTERROGATORY #31

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: EB-2013-0321, Interrogatory Response 6.8-SEC-116

KMPG's *Assessment of Organizational and Structural Opportunities at OPG* at p.2] Does the Applicant have in its possession a copy of a report by KPMG engaged on behalf of the Ministry of Energy in 2012, assessing Hydro One's existing benchmarking studies and to identify organizational and structural opportunities for cost savings. If so, please provide a copy of the report.

Response

As the report in question was not commissioned by Hydro One, it is not within Hydro One's jurisdiction to release the report.

Consumers Council of Canada (CCC) INTERROGATORY #23

Issue 3.3 Has HON proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: Ex. A/T19/S1/p. 2

HON has set out in Table 1 expected annual savings resulting from "productivity and cost-effectiveness improvements." For each category, for the years 2014-2015, please explain how each of those numbers were calculated. Please include all assumptions. For example, do they relate to OM&A, Capital etc.? How do they impact the revenue requirement in each of those years?

Response

Please see response to question 2.03-VECC-42 for the breakdown of the productivity savings, including the OM&A and Capital split.

Assumptions for calculations include:

i. When labour hours are saved through efficiencies, the internal labour rate is used to calculate savings. If head count is reduced then the fully burdened cost of the employee (including wages, benefits and government obligations) is used. Expected cost of labour is inflated by 2% per year.

ii. Productivity initiatives are tracked by investment drivers and costs are allocated between Transmission and Distribution based on which business segment the investment driver belongs to. For initiatives that have costs that are common to both Transmission and Distribution, the common cost allocation provided in the Black & Veatch studies is used to determine the percentage allocation between Transmission and Distribution.

iii. Administrative expense savings are recorded as the value that was saved in that year.

The revenue requirement is reduced by the value of the forecasted productivity in each of the years as demonstrated in Table 1 (showing OM&A).

Initiatives	LOB	Category	Initiative Name	OMA	CAP	Sus	Dev	Oper	Cus	Com	2013 Actual	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
LT.1	Stations Services	Leveraging Technology	Work Program Optimization (TSOGs)	100%	0%	96%	1%	3%	0%		-	973,966	965,499	1,433,654	1,358,413	1,387,167	1,691,823
SF.12	Stations Services	Staff Flexibility	TWHQ - Stations	100%	0%	95%	0%	4%	0%		952,840	177,600	181,152	184,775	188,471	192,240	196,085
LT.44	Stations Services	Leveraging Technology	IMDS	0%	100%	95%	0%	4%	0%		-	1,500,000	2,500,000	3,000,000	3,000,000	3,500,000	3,500,000

Society of Energy Professionals (SEP) INTERROGATORY #1

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: Exhibit A/Tab 17/Schedule 6/p. 4/ lns 7-13

"Work Execution Strategy", page 4 lns 7-13, in reference to "External Work Capacity" it is concluded that

All categories of external resources and services are becoming harder to contract as the North American demand increasingly exceeds available supply.

A basic premise of economics, which is widely understood and accepted, is that when demand exceeds supply the market price of supply increases.

a) Please explain how under these conditions Hydro One finds it fiscally prudent to engage external resources and services at ever increasing prices.
b) Would it not be economically prudent to build up internal resources to complete this expanding volume of work, as outlined in sections 2.1, 2.2 and 2.3 of this schedule, and which indications are will not plateau for a number of years?
c) Would using internal resources rather than external resources and services mitigate the risk that large numbers of external resources will not be available to perform necessary work when required?

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Response

a) There are a number of conditions that would make outsourcing a viable option, such as:
   - Where the work is not core to Hydro One's business
   - Where the skills and /or experience required do not exist internally
   - Where building internal capability is cost prohibitive
   - If the work/project is not ongoing work
   - Whereby doing the work internally may nullify warranties
   - Where the long term costs of using internal resources exceed outsourcing

b) For the reasons described above, it may not always be prudent to build up internal resources.
c) The work execution strategy as described in Exhibit A Tab 17 Schedule 6 is a multi-faceted approach to deal with the risks associated with completing the work. The use of skilled and talented internal resources is one component of the overall plan.

Society of Energy Professionals (SEP) INTERROGATORY #2

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: Exhibit A/Tab 17/ Schedule 6/ p.7/lns 23-25

Strategic sourcing which includes "bulk purchasing" is a significant contributor to Hydro One's cost savings initiatives and the Company's ability to complete the work programs. Bulk purchasing has been more broadly facilitated by the use of standardized designs.

a) In the context of the material increase in work program spend through this period, please provide the annual cost savings from 2010 until 2019 due to bulk purchasing.
b) If these savings do not increase materially through this period, please explain why not.
c) Where are these savings included in Exhibit A, Tab 19, Schedule 1 "Cost Efficiencies/ Productivity"?

Response

a) The actual savings from 2010 to 2013 from bulk purchasing are provided in the attached summary for Dx savings only. Forecasted Dx savings from 2014-2019 are also included in the table.
b) Savings are not forecasted to increase materially over the forecast period as optimal usage of the bulk buying program is being reached. The savings are also very dependent on the market conditions as they are a contributing factor to how much savings are available by buying in bulk. This makes forecasting savings in future years difficult as savings could be significantly less if market conditions change. As a result the best estimate for the future is that savings will be consistent with the previous year.
c) The savings for the strategic sourcing are included in the Business Systems category. The Business Systems category is related solely to phase 1 and 2 of the Cornerstone project.

Savings as a Result of the Initiative										
	2010 Actual	**2011 Actual**	**2012 Actual**	**2013 Actual**	**2014 Forecast**	**2015 Forecast**	**2016 Forecast**	**2017 Forecast**	**2018 Forecast**	**2019 Forecast**
Strategic Sourcing	11.1	12.9	27.0	36.6	36.6	36.6	36.6	36.6	36.6	36.6

Society of Energy Professionals (SEP) INTERROGATORY #3

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: Exhibit A/Tab 17/Schedule 6/ p.8/lns 24-25

An increased use of standardized and modular designs are being used to streamline the design process, allowing faster, more consistent, and lower cost work execution.

a) In the context of the material increase in work program spend through this period, please provide the annual cost savings from 2010 until 2019 due to standardized and modular designs.
b) If these savings do not increase materially through this period, please explain why not.
c) Where are these savings included in Exhibit A, Tab 19, Schedule 1 "Cost Efficiencies/ Productivity"?

Response

a) Standardized and modular designs have allowed Hydro One to reduce the number of specialized or unique parts that are required for its operations. This rationalization of the number of different parts has allowed Hydro One to benefit from economies of scale and to be able to negotiate better contracts with vendors. The savings from these standardized designs are recognized as a part of the bulk purchasing and strategic sourcing initiative. This initiative would not be possible were it not for this standardization.

b) Savings are not forecasted to increase materially over the forecast period as optimal usage of the bulk buying program is being reached. The savings are also very dependent on the market conditions as they are a contributing factor to how much savings are available by buying in bulk. This makes forecasting savings in future years difficult as savings could be significantly less if market conditions change. As a result the best estimate for the future is that savings will be consistent with the previous year.

c) The savings from these standardized designs are recognized as a part of the bulk purchasing and strategic sourcing initiative.

Society of Energy Professionals (SEP) INTERROGATORY #4

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: Exhibit A/Tab 19/Schedule 1/p.3/Table 1

"Cost Efficiencies/ Productivity", page 3, Table 1 "Impact to Revenue Requirement Inclusive and Exclusive of Productivity Savings":

a) What are the Total OM&A productivity savings for 2015 to 2019?
b) What is the average annual Total OM&A productivity savings for 2015 to 2019?
c) What is the annual average percentage productivity savings of OM&A expenditure for 2015 to 2019?
d) Using the data provided in Exhibit E1, Tab 1, Schedule 1, page 1 Table 1, what is Hydro One's average annual Revenue Requirement less External Revenue for the period 2015 to 2019?
e) What percentage is the average annual Total OM&A productivity savings for 2015 to 2019 of Hydro One's average annual Revenue Requirement less External Revenue for the period 2015 to 2019 [ie the value provided in b) above expressed as a percentage of the value provided in d) above]? How does this figure compare to the OEB's productivity analyses?
f) Please calculate the figures provided in a) and b) above for the Total Capital Expenditures productivity savings.
g) A general rule of thumb of is that Revenue Requirement increases by roughly 10% of capital expenditures placed into service in the prior year. Accepting that this rule of thumb is correct, recalculate the percentage calculated in e) above to include 10% of the average annual Total Capital Expenditures productivity savings for 2015 to 2019. How does this figure compare to the OEB's productivity analyses?

Response

a) Total OM&A productivity savings are provided in Table 1, from 2015-2019 forecasted savings for all five years is expected to be $518M.
b) The average total OM&A productivity savings from 2015-2019 is $104M.
c) The average percentage productivity savings of OM&A from 2015-2019 is 17% per year.
d) Hydro One's average annual Revenue Requirement less External Revenue for the period 2015 to 2019 is $1,509M.

e) The percentage of average OM&A productivity savings divided by average annual Revenue Requirement less External Revenue for the period 2015 to 2019 is 6.9%.

f) The total Capital productivity savings from 2015-2019 is $121M. The average Capital productivity savings from 2015-2019 is $24M.

g) The percentage of average OM&A and Capital productivity savings (applying the rule of thumb described for Capital) divided by average annual Revenue Requirement less External Revenue for the period 2015 to 2019 is 7.1%.

Society of Energy Professionals (SEP) INTERROGATORY #5

Issue #3.3 **Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?**

Interrogatory

Reference: Exhibit A/Tab 19/Schedule 1/p.4/Table 2

"Cost Efficiencies/ Productivity", page 4, Table 2 "Total Annual Savings – Distribution" and the savings from Telephony:

a) Why do the savings from Telephony decline from $2.1M in 2012 to $1.0M in 2013?

Response

Originally HONI had an individual contract with Rogers and Bell for our Telephony needs, which was not leveraging the bulk government service discounts. In 2012 we signed a new contract with Rogers and Bell leveraging the Ministry of Government Services contract (MGS) which constituted the initial $2.1M in savings. In the original contract there was a step reduction in rate plan cost between contract years 2012 to 2013, therefore the reduction is savings is reflected as shown in Table 2.

Society of Energy Professionals (SEP) INTERROGATORY #6

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: Exhibit A/Tab 19/Schedule 1/p.13,14/Section 2.6

With reference to Exhibit A, Tab 19, Schedule 1 "Cost Efficiencies/ Productivity", pages 13, 14 section 2.6 "Process Improvement". The annual savings for Process Improvement do not appear to change between 2015 and 2019, however overall OM&A and capital expenditures change significantly over this period. Under these circumstances, one would expect that the level of savings from reduced potential design changes or rework would change from year to year over this timeframe. For example, in Exhibit D2, Tab 2, Schedule 3, ISD #S7 shows that between 2015 and 2018, Distribution Station Refurbishments increase from 36 to 41 stations and total spend increases from $34.6M to $44.5M. However there does not appear to be materially increased savings in prefabricated, integrated modular distribution station design.

a) Have any Process Improvements savings been inadvertently omitted or understated?

Response

a) The funding levels requested are to maintain current reliability and to keep bill impacts to a minimum in accordance with customer preferences. The forecasted productivity savings contain all initiatives and their projected savings that are being developed and implemented for the test years.

Society of Energy Professionals (SEP) INTERROGATORY #7

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: Exhibit A/Tab 19/Schedule 1/p.18,19

Section 3.0 “Utility Transformation”:

a) Have any annual savings for Utility Transformation been inadvertently omitted?

Response

a) The Hydro One productivity reporting department has gone to great lengths to ensure that all productivity savings are properly accounted for. Often cost savings are found in budget reductions or through the cost conscious efforts of our employees, however these savings that arise through cultural efforts to reduce costs cannot be accounted for with the required degree of accuracy. However these savings are all properly accounted for during business planning and have been by default included in all budgets and the business plan from 2015-2019.

Society of Energy Professionals (SEP) INTERROGATORY #8

Issue 3.3 **Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?**

Interrogatory

Reference: Exhibit A/Tab 19/Schedule 1/p.19/lns 21-22

a) Please explain what ESA regulations are.

Response

a) The ESA is the Electrical Safety Authority, a provincial administrative authority that was established in 1999 with the mandate to enhance public electrical safety in Ontario. It administers and regulates the Ontario Electrical Safety Code, Licensing of Electrical Contractors and Master Electricians, Electricity Distribution System Safety and Electrical Product Safety. Hydro One is in compliance with the ESA's regulations.

Society of Energy Professionals (SEP) INTERROGATORY #9

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: Exhibit A/Tab 19/Schedule 1

"Cost Efficiencies/ Productivity". Recently, Hydro One has shifted the administration of its employee benefits program from Great West Life to Green Shield Canada.

a) Are there any cost savings projected from this change?
b) If there are cost savings where are they included in the filed evidence?

Response

a) Hydro One anticipates some projected savings on administrative services to be provided by the new benefits provider. The savings cannot be quantified at this time since we have not had enough experience with the new provider.

b) The potential savings are not included in this plan since the contract with the new service provider was negotiated after the business plan supporting this filing was finalized.