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Frank D'Andrea
Vice President, Regulatory Affairs & Chief Risk Officer

BY COURIER

August 21, 2019

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Walli,

EB-2019-0082 – Technical Conference Undertakings for Hydro One Networks Inc.'s 2020-2022 Transmission Custom IR Application (the "Application")

Pursuant to the Ontario Energy Board's (OEB) letter dated August 16, 2019, wherein the OEB granted Hydro One's request to file undertaking responses to the above noted Application in two tranches – on August 21, 2019 and August 28, 2019 – please find enclosed Hydro One's undertaking responses for tranche 1.

This filing has been submitted electronically using the Board's Regulatory Electronic Submission System and two (2) hard copies will be sent via courier.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Encls.
cc. EB-2019-0082 parties (electronic)

UNDERTAKING - JT 1.2

Reference:
I-01-OEB-136

Undertaking:
With reference to STAFF IR 139 (i), for each of the four named site-specific conditions - namely the relocation of existing low voltage capacitor bank, extension of the control building, increased grounding, and increased cable trench civil works; to clarify how much of the delta is attributable to each; to list any other elements that also contributed to the delta.

Response:
The table below shows the differences between the original estimates submitted in proceeding EB-2018-0098: Kapuskasing Area Reinforcement Project (Exhibit B, Tab 7, Schedule 1) (the "Original Estimate") and the updated cost of $17.3 million provided in letter to OEB in March 2019 (the "Updated Estimate").

Items	**Original Estimate**	**Updated Estimate**
10 MVar reactive support(1)	$4.0M	$6.4M
10 MVar capacitive support(1)	$2.0M	$4.4M
New site specific work and scope additions:		
- Relocation of existing low-voltage capacitor bank(2)	N/A	$1.0M
- Extension of the control building	N/A	$3.6M
- Increased grounding	N/A	$0.2M
- Increased cable trench / civil works	N/A	$1.7M
Total Station Work	**$6.0M**	**$17.3M**

(1) Costs include associated yard work and removals, station service, terminal station, and special protection scheme.
(2) Costs include voltage regulator VR2 removals

Witness: Robert Reinmuller

UNDERTAKING - JT 1.5

Reference:
I-05-CME-008 under section 2

Undertaking:
To advise whether the results of the SAP audit or the conclusion of the audit are reflected in the evidence that was identified or that's on the record.

Response:
Yes. The results of the audit of asset and maintenance data in SAP relates to Asset Analytics and the review of existing algorithms are reflected in the evidence that was identified or that's on the record.

UNDERTAKING - JT 1.6

Reference:
I-02-EnergyProbe-014

Undertaking:
To advise what happened with Clarington, to clarify how the savings were achieved; to advise how much was deferred to 2019.

Response:
The 2018 actual expenditures were lower than the forecast used for the DRO due to a combination of skywire replacement work that was completed for a lower cost than forecast, risks which did not materialize, and deferral of $2.2M into 2019 for the relocation of instrument transformers.

UNDERTAKING - JT 1.7

Reference:

I-08-PWU-003

Undertaking:

To reconcile the amount stated in PWU-03, 2020 to 2024 spending on capacity to accommodate new customers and businesses, with the figure given for system access in TSP section 3.1, page 17.

Response:

The response provided to PWU-03, Exhibit I, Tab 8, Schedule 3, part b) was incorrect. The $552 million referenced in Exhibit A, Tab 3, Schedule 1, page 3, line 12 refers to ***net*** capital expenditure over the ***three*** year period (2020 to 2022) for ***System Access and System Service investments***, as documented in the Table 1 below[1].

Table 1 - Test Period Capital Expenditure for System Access and System Service

OEB Category	Forecast (Planned $M)			
	2020	**2021**	**2022**	**Total**
System Access	24.8	11.3	11.7	47.8
System Service	204.1	148.2	151.8	504.1
Total	228.9	159.5	163.5	**551.9**

Whereas the $345 million referenced in TSP Section 3.1 page 17, lines 9 to 12 refers to the ***gross*** capital expenditure over the ***five*** year period (2020 to 2024) for ***only System Access investments***.

[1] The values shown in Table 1 are from TSP Section 3.1, Table 1

UNDERTAKING - JT 1.8

Reference:
I-08-PWU-003

Undertaking:
To advise what portion of the $552 million (reference: PWU IR No. 3, 2020 to 2024 spending on capacity to accommodate new customers and businesses) applies to the 2020 to 2022 period.

Response:
Please see response provided in Exhibit JT 1.7.

Witness: Robert Reinmuller

UNDERTAKING - JT 1.10

Reference:

I-07-SEC-006

Undertaking:

If possible, to provide full copies of audit reports 2017-14, 2017-17, 2017-24, 2018-06, 2018-16 and 2018-19.

Response:

Please refer to attachments 1 to 6, for copies of the audit reports 2017-14, 2017-17, 2017-24, 2018-06, 2018-16 and 2018-19 respectively.

Witness: Regulatory Affairs

INTERNAL AUDIT REPORT

Investment Planning Follow-up (IPF)

To:

Darlene Bradley
Vice President, Planning

Distribution:

Mayo Schmidt	President & Chief Executive Officer
Greg Kiraly	Chief Operating Officer
Chris Lopez	Senior Vice President, Finance
Bruno Jesus	Director, Strategy & Integrated Planning
Kevin Mancherjee	Manager, Investment Planning and Process
Additional Recipients	Email Distribution List

Final Report Issued: September 6, 2017
Draft Report Issued: June 30, 2017
Report Number: 2017-14

Lead Auditor: Atul A. Solanki
Audit Manager: Jeff Schaller

EXECUTIVE SUMMARY

Background:

In January 2015, we completed an audit of the Investment Planning process covering the identification of asset needs to the approval and release of investment plans to address those needs. That audit included our assessment of the controls in place to effectively identify, develop, prioritize and select investment plans in support of the Hydro One five-year business plan and the work program. Our final report concluded that the key controls concerning the Investment Planning process needed significant improvement. The final report contained 18 recommendations that resulted in actions being identified by management under 5 subject areas. At that time, management committed to action plans to address our recommendations and mitigate the risks identified within the report. Management has reported all actions as complete through the quarterly tracking of actions.

Objective and Scope:

The primary objective of this follow-up audit was to provide assurance that Hydro One has completed the committed actions and addressed all the audit recommendations and mitigated the associated risks.

Our work included a review of:

- Governance framework (roles, accountabilities and oversight for addressing audit recommendations)
- Completion of committed action items to effectively address the recommendations and risks
- Assessment of design effectiveness and implementation of any new/revised controls
- Communication of progress and completion of committed action plans (to senior management and process stakeholders)

The following table summarizes our assessment of audit action plan status and control design effectiveness.

Assessment Item	Risk (2015)	Action Item Status Assessment[1]	Control Design Assessment	Risk (2017)
1.1 Business Risk Assessment	M	Substantially Complete	Partially Effective	M
1.2 Governance Documents	H	Substantially Complete	Substantially Effective	M
1.3 Operations Group Input	M	Substantially Complete	Substantially Effective	L
1.4 Quality Assurance Program	H	Substantially Complete	Substantially Effective	M
1.5 Training and tracking	M	Complete	Effective	L
1.6 Lessons Learned	M	Substantially Complete	Substantially Effective	L
2.3 Asset Analytics Data	H	Partially Complete	Not Applicable	H
2.4 Power System Data	M	Partially Complete	Not Applicable	M
2.5 Asset Strategies	M	Substantially Complete	Substantially Effective	L[2]
3.1 Optimizable Alternatives	H	Complete	Substantially Effective	L
3.2 Risk Assessment Matrix	M	Substantially Complete	Partially Effective	M[3]
3.4 Unit Price Catalogue	M	Substantially Complete	Substantially Effective	L

[1] The Action Item Status and Control Design Assessment ratings are described in the legend at the end of this Executive Summary.

[2] Although the development of the required asset strategies are still in progress, management has introduced controls to track and monitor their development by May 31, 2018 with assigned accountabilities and periodic review cycles.

[3] Management has recently introduced a new Risk Assessment Matrix for Transmission and Common assets so the residual risk for these assets may be lower but a similar matrix for Distribution assets is planned to be introduced in 2018 so the residual risk for these assets remains at Medium.

4.2 AIP Tool Availability	M	Complete	Effective	L
4.3 AIP Manual Workarounds	L	Partially Complete	Not Applicable	L
4.4 Enterprise Engagement period	H	Complete	Effective	L
4.5 IP Change Log	M	Substantially Complete	Substantially Effective	L
4.6 Re-optimization requirement	M	Complete	Effective	L
5.1 “Projam” Investments	H	Complete	Effective	L

Success Factors:

We noted that the following success factors were in place:

- Management is now providing instructor-led training to planners for the Investment Planning Process and Risk Assessment with support from the Investment Management team providing drop-in sessions and one-on-one assistance to Planners during the Investment Planning cycle.
- Management has significantly increased access to the Asset Investment Planning (AIP) tool for planners to provide their input on the investment plans from a 4 week window to a 6-month window.
- Management has increased the Enterprise Engagement Review period to a 7-8 week timeframe to enable a line-by-line review of the investment plan by the Operations group.
- Management has developed and documented guidelines for optimization of the investment plans and conditions which must be met in order to re-optimize the plan.
- Management has established more robust oversight controls for “Station Centric” asset sustainment investments by managing them as specific projects (with specific scope, time and cost constraints) rather than on-going multi-year programs.

Summary of Key Recommendations:

We have discussed our observations with management throughout this follow-up audit. The key recommendations we made, which management has reviewed and developed action plans, are included in the following list of high and medium residual risk impact items:

High Risk:

- Continue to identify and correct issues with Asset Analytics input data and risk factor algorithms that will affect the degree to which the output results can be used to influence investment decisions.

Medium Risk:

- Develop and implement a process with accountabilities to identify emerging risks and periodically review existing business risks and related mitigating actions. Incorporate results of other targeted risk workshops into the overall business risk register.
- Review and formalize existing management direction, presently being delivered as part of Investment Planning training presentations, into governance documents (policies, processes, procedures, standards, guidelines, etc.) and decommission existing out-dated governance documents (including draft policies and process documentation).
- Establish and implement appropriate measures and targets for the Investment Planning Scorecard. Track “go to green” action plans for management to achieve the targets either for the current or future Investment Planning cycles. Document the results of quality assurance reviews performed by management and feedback given to planners.
- Review and establish appropriate funding and actual implementation plans for the enhancements identified in the Asset Management Tool Integration Roadmap.

- Assess the effectiveness of the recently implemented, simplified risk assessment approach for the transmission assets and develop a plan to implement a similar approach suitable for distribution assets.

Audit Opinion:

Management has made significant progress in addressing the control deficiencies that we identified and documented within the 2015 audit report, however further progress is needed. Based on the specific areas reviewed, **we concluded that control improvements are needed** to effectively identify, develop, prioritize and select investment plans in support of the Hydro One six-year business plan and the work program.

Management has developed action plans to mitigate the identified risks and address our recommendations, as summarized in Attachment "A" of this report. In a separate memorandum we have shared with management additional opportunities for improvement that we believe will further strengthen this function. Additional details are available upon request.

Management Response:

Bruno Jesus, Director, Strategy and Integrated Planning

Management agrees with Internal Audit's observations and recommendations and we are committed to complete our associated actions by the completion dates.

Assessment of Action Item Status and Control Design Effectiveness by Internal Audit[1]		
Assessment Type	**Assessment Level**	**Description**
Action Item Status	Complete	All committed management actions are complete and fully implemented.
	Substantially Complete	All committed management actions are complete but not yet communicated, approved or implemented.
	Partially Complete	Work is progressing on committed management actions with a clear plan to achieve implementation.
	Incomplete	No or little work progress on committed management actions with no clear plan to achieve implementation.
Control Design Effectiveness	Effective	New or revised controls introduced through management actions have mitigated all identified risks to an acceptable level.
	Substantially Effective	New or revised controls through management actions have mitigated most but not all risks to an acceptable level. Minor control enhancement is required to achieve full risk mitigation
	Partially Effective	New or revised controls through management actions have not mitigated the risk to an acceptable level. Substantial control design improvement are needed to achieve full risk mitigation
	Ineffective	No new or revised controls have been introduced through management action. Identified risks remain unmitigated.

OBSERVATIONS, RECOMMENDATIONS AND MANAGEMENT ACTIONS

Observations	Recommendations	Action Plan
1.1 Business Risk Assessment	**Risk**[4] M	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
During our audit on this subject in 2015, we noted that a recent and formal business risk assessment for the Planning business unit had not taken place. Subsequent to that audit, a business risk workshop was completed later in 2015 identifying five Investment Plan risks. Four of these risks were discussed in detail with only one risk (related to productivity underachievement) requiring mitigating actions. The fifth risk, related to erosion of customer goodwill, was not fully discussed due to time limitations of the workshop. Management informed us that the mitigating action related to developing accountabilities and plans for productivity underachievement risk was assigned to Finance which has been completed, but has not yet been fully implemented. Management further informed us that a targeted risk workshop specific to the Distribution System Plan was conducted in 2016. The risk workshop reports did not identify risk owners and no documented accountabilities or processes are currently in place to identify, monitor, control or communicate emerging or revised business risks on a periodic basis as per the Enterprise Risk Management (ERM) framework. ***Risk:*** *Lack of identified business risks and mitigating actions could result in an inability to meet the business objectives and goals.*	Develop and implement a process with accountabilities to identify emerging risks and periodically review existing business risks and related mitigating actions originally identified in the 2015 Investment Plan Risk Workshop Report. Incorporate results of other risk workshops into an overall Planning business risk register for appropriate tracking by specifying business objectives, risks, risk owners, mitigating actions, and target completion dates.	The requirement to conduct risk assessments on the annual Investment Plan will be added to the overall Investment Planning deliverables each year. Any recommendations/action items resulting from the risk assessment will be added to the Planning Division's tracker for action items (Internal Audit, AEI, etc.) **Completion:** March 31, 2018

[4] Residual Risk levels applied are described in the legend that follows this table.

Observations	Recommendations	Action Plan
1.2 Governance Documents	**Risk**[2] M	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
During our audit on this subject in 2015, we found that approved policies and directives were out-dated or not being followed while business process models documented in ARIS[5] were incomplete. Since then, a Corporate Operational Policy Development Review process has been documented and used to develop 13 new policies. The older policies are being reviewed, updated or rescinded as part of the Corporate Policy Review project. Management further informed us that a key policy document titled "Asset Investment Planning Risk Assessment Corporate Operational Policy" continues to remain in draft form since 2013 as the Investment Planning Process is currently under review. The process models documented in ARIS on this subject are now recognized as out-dated by management but they have neither been formally decommissioned nor replaced. Management's current approach is to provide required direction through investment planning process training, however this will likely not be effective as only the individuals receiving the training will become aware of management direction while other stakeholders will not be aware of the investment planning process and related requirements. ***Risk:*** *Lack of well-defined, communicated and understood governance documents could lead to inconsistent decision making and poorly defined investment plan.*	Review and formalize existing management direction, presently being delivered as part of Investment Planning training, into governance documents (policies, processes, procedures, standards, guidelines, etc.) and decommission out-dated governance documents (including draft policies and process documentation within ARIS).	Appropriate governance documents (policy, process, procedure, standard or guideline) will be established taking the existing Investment Planning training material into account. All other existing draft documentation that no longer applies will be removed (e.g. ARIS). **Completion:** June 30, 2018.

[5] **AR**chitecture of **In**tegrated information **S**ystem (ARIS) is business process modeling tool used for enterprise wide business process modeling.

Observations	Recommendations	Action Plan
1.3 Quality Assurance Program	**Risk**[2] **M**	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
Management had agreed to establish and communicate quality expectations and required metrics for the end-to-end investment planning process based on our recommendation from the audit on this subject in 2015. Subsequent to that audit, Management implemented an Investment Planning Scorecard, Manager Quality Assurance checklist, and Investment Health Report to assist in identifying potential errors and quality issues as they develop and review the investment plans. Although the Investment Planning Process Scorecard and Investment Health Report provide statistical information regarding potential quality issues, there are no realistic targets or expectations of actions required to achieve those targets. Management informed us that quality assurance review feedback is not documented but verbally provided to the planners based on issues observed during the quality reviews. Without comparing the current measures to established targets and related "go to green" plans to ensure that the targets will be met, the effectiveness of the current quality assurance program cannot be fully assessed. ***Risk:*** *Insufficient monitoring of process effectiveness and quality assurance of process outputs would lead to an increased risk of errors and degradation of output quality.*	Establish and implement appropriate measures and targets for the Investment Planning Scorecard (specifically for non-accomplishment related measures such as estimate quality, Potential Need (PN) [6] notifications that are actioned/accepted, etc.). Track "go to green" action plans for management to achieve the targets either for the current or future Investment Planning cycles. Document the results of quality assurance reviews performed by management and feedback given to planners.	Key performance indicators (KPI) for the investment planning process will be developed and incorporated into 2018 scorecards for impacted directors as per the recommendation. **Completion:** December 31, 2017

[6] Potential Need (PN) is an SAP notification that provides visibility to assets in need of replacement or refurbishment. PNs can be entered into SAP by head office or field Operations staff and are reviewed as part of the investment planning process.

Observations	Recommendations	Action Plan
1.4 Asset Analytics (AA)	**Risk**[2] H	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
Asset Analytics (AA) is a tool available to planners to assess asset needs based on asset condition data collected during routine maintenance, performance history, utilization, age and criticality. Management informed us that Asset Risk Indexes (ARI) from the AA tool are one of many inputs that feed into the development of candidate investments, and that these ARIs are not intended to be used as a replacement for the sound engineering judgment and decisions of the qualified Planning engineers, and is only one step of the broader process which is used in conjunction with physical inspections. In 2016, management held workshops with key stakeholders involved in the Investment Planning Process to review and discuss changes to ARI algorithms, input data and new risk factors. To date, management has not implemented any of the requirements identified in the AA workshops, however plans are underway to address 78 requirements related to two new risk factors and 159 requirements related to enhancements to risk factors by end of 2020. We remain concerned about the data quality from supporting systems (such as SAP) that are used as inputs to Asset Analytics. ***Risk:*** *The absence of well-understood and quality asset information increases the risk of inadequate asset need assessment which can result in diminished confidence in the process involving the AA tool and the potential for less than optimal investment decisions.*	Continue to identify and correct issues with Asset Analytics input data and risk factor algorithms that will affect the degree to which the output results can be used to influence investment decisions.	Plans related to data required for Asset Analytics will be developed and key steps and milestones to address the recommendation will be tracked in the Divisional Scorecard. **Completion:** December 31, 2017

Observations	Recommendations	Action Plan
1.5 Asset Management Tool Enhancements	**Risk**[2] M	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
Asset Analytics (AA) and Asset Investment Planning (AIP) are two key support tools used by planners for which a number of deficiencies were identified during the last audit. We had noted that the load flows, voltages, asset connectivity and statuses related power system historical data required for area supply studies in support of System development projects were unavailable in AA. We had also noted that there were manual workarounds in place to update AIP input data from SAP and other systems (such as Unit Price Catalogue, Project Forecasts, etc.). Since then, Management has developed an Asset Management Tool Integration Roadmap in 2015, identifying 24 enhancement requests and 16 integration requests with other systems. The roadmap shows that the requirement to integrate power system data from NMS & PSDB[7] systems is ranked 22nd out of 24 in priority. A firm implementation schedule for the enhancement and integration requests identified in the roadmap is unavailable. Management informed us that in the absence of further progress, same manual workarounds as those observed in 2015 remain in place. ***Risk:*** *Unavailability of required data in AA & AIP tools may result in incorrect/inconsistent decision making. Manual workarounds as a result of lack of data integration could result in delays and/or poor quality investment plans.*	Review and establish appropriate funding and actual implementation plans for the enhancements identified in the Asset Management Tool Integration Roadmap.	Management will review the tool enhancement roadmap, to determine necessary enhancements taking into account cost/benefit with decisions to keep, defer or discard items. **Completion:** June 30, 2018

[7] Network Management System (NMS) and Power System Database (PSDB) are two systems that contain power system historical data.

Observations	Recommendations	Action Plan
1.6 Risk Assessment Matrix	**Risk[2]** **M** [8]	**Executive:** Darlene Bradley, VP Planning **Accountability:** Bruno Jesus Director, Strategy & Integrated Planning
During our audit on this subject in 2015, we found that the risk assessment matrix being used to assess baseline and alternative risks for a given investment was being used inconsistently. Subsequent to that audit, management has conducted annual Risk Assessment training to provide specific guidance to planners with examples on how to perform risk assessment using the available risk matrix. A risk calibration session held in 2016 indicated a moderate success in aligning risks across all investments. As a result, management sought the services of an external consultant (McKinsey) in 2017 to review and recommend a simplified approach to consistent risk assessment for the 2017 investment planning cycle. A new simplified risk assessment is now planned for transmission investments in 2017 with plans to use a similar approach for distribution investments starting in 2018 because the Distribution investment plans are presently with the regulator and “frozen” for the current planning cycle. We note that an informal survey of 17 planners indicated that challenges remain related to risk assessments for distribution investments. ***Risk:*** *Inadequate assessment of baseline and alternative-specific risk could result in incorrect risk values being assigned.*	Assess the effectiveness of the recently implemented, simplified risk assessment approach for transmission assets and develop a plan to implement a similar approach suitable for distribution assets.	Management will assess the effectiveness of the current transmission process and develop a plan (relating to risk assessment approach) to improve the distribution process accordingly. **Completion:** June 30, 2018.

[8] A new Risk Assessment Matrix for Transmission and Common assets has been recently introduced so the residual risk for these assets may be lower but a similar matrix for Distribution assets is planned to be introduced in 2018 so the residual risk for these assets remains at Medium

LEGEND: ACTION ITEM STATUS AND CONTROL DESIGN EFFECTIVENESS RATINGS:

Assessment of Action Item Status and Control Design Effectiveness by Internal Audit[1]		
Assessment Type	**Assessment Level**	**Description**
Action Item Status	Complete	All committed management actions are complete and fully implemented.
	Substantially Complete	All committed management actions are complete but not yet communicated, approved or implemented.
	Partially Complete	Work is progressing on committed management actions with a clear plan to achieve implementation.
	Incomplete	No or little work progress on committed management actions with no clear plan to achieve implementation.
Control Design Effectiveness	Effective	New or revised controls introduced through management actions have mitigated all identified risks to an acceptable level.
	Substantially Effective	New or revised controls through management actions have mitigated most but not all risks to an acceptable level. Minor control enhancement is required to achieve full risk mitigation
	Partially Effective	New or revised controls through management actions have not mitigated the risk to an acceptable level. Substantial control design improvement are needed to achieve full risk mitigation
	Ineffective	No new or revised controls have been introduced through management action. Identified risks remain unmitigated.

LEGEND: RESIDUAL RISK CLASSIFICATION:

RESIDUAL RISK CLASSIFICATION[2]	Assessment Indication
MEDIUM: The risk will cause some elements of the objective to be delayed or not be achieved, causing potential negative impacts to the organization's strategic objectives.	M
HIGH: The risk will cause the objective to not be achieved, causing negative impacts to the organization's strategic objectives.	H

INTERNAL AUDIT REPORT

Investment Planning Support Tools

To:

Darlene Bradley
Vice President, Planning

Distribution:

Mayo Schmidt	President & Chief Executive Officer
Greg Kiraly	Chief Operating Officer
Chris Lopez	Senior Vice President, Finance
Bruno Jesus	Director, Strategy & Integrated Planning
Kevin Mancherjee	Manager, Investment Management
Additional Recipients	Email Distribution List

Final Report Issued: October 31, 2017
Draft Report Issued: August 31, 2017
Report Number: 2017-17

Lead Auditor: Atul A. Solanki
Audit Manager: Jeff Schaller

EXECUTIVE SUMMARY

Background:

The annual Investment Plan Proposal details investments and resulting work programs required to develop and sustain transmission and distribution assets and system capabilities. This plan represents a substantial portion[1] of the Hydro One's Corporate Business Plan that is approved annually by Hydro One's Board of Directors. The Planning organization uses software tools such as Asset Analytics and Asset Investment Planning to support the development of the annual Investment Plan Proposal. The Asset Analytics tool[2] is used to assess asset demographics and condition data to provide input to asset refurbishment and replacement decisions over a 30 year time frame. The Asset Investment Planning tool[3] (aka Copperleaf C55 software solution) is used to select the best investment alternative based on the timing of the investment that will maximize risk mitigation and financial benefits while satisfying pre-determined constraints and dependencies. Both of these tools have been in place for several years.

Objective & Scope:

The primary objective of this audit was to provide assurance that key controls are in place for the effective use of the Asset Analytics and Asset Investment Planning tools to support the investment planning process.

Our work included a review of:

- Governance (clarity of roles, accountabilities, process, training, communication, etc.) related to the setup and utilization of the Asset Analytics and Asset Investment Planning tools.
- Control Activities (including documented definitions of input data requirements, data processing and validation of tool outputs).
- Monitoring of consistent and effective use of both tools in support of development of the annual Investment Plan Proposal.

Excluding:

- IT related work for software tool licensing, configuration, upgrades, vendor support, etc.
- Known asset data governance issues which were addressed in a separate audit (Audit Report 2016-15 SAP Data Integrity Follow-up and Data Governance Review)

Audit Opinion:

Process improvements are currently underway for the Investment Planning process as part of the 2017 investment planning cycle and this has resulted in a rigorous use of the Asset Investment Planning tool, however the use of the Asset Analytic tool has been limited and inconsistent. Based on the specific areas reviewed, **we concluded that controls over the Asset Investment Planning tool are generally effective while control improvements are needed over the Asset Analytics tool** to ensure consistent and effective use of these tools to develop the annual Investment Plan Proposal.

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[1] The Investment Plan Proposal represented aapproximately 70% of the Corporate Business Plan in 2015.

[2] Asset Analytics (AA) tool comprises of a software solution from SpaceTime Insight Inc. and SAP Business Intelligence that has been customized for use within Hydro One.

[3] Asset Investment Planning (AIP) tool is the name of Hydro One's implementation of a commercial off the shelf software from Copperleaf Inc.'s C55 software solution for Asset Investment Planning & Management.

Success Factors:

We noted that the following success factors were in place:

Asset Analytics:
- A formal process is in place for identifying and escalating Asset Analytics tool related issues to Help One for resolution.
- Two full-time resources support the Asset Analytics tool with an annual sustainment budget of approximately $455k.
- Six Asset Risk Indexes (ARIs) are being calculated within Asset Analytics using data from nineteen different systems for the majority of transmission and distribution assets.

Asset Investment Planning:
- Annual refresher training is provided to Planners by the Investment Planning and Process team using updated training materials as well as job aids along with one-on-one support for specific needs.
- Three members of the Investment Planning and Process team support the Asset Investment Planning tool on a part-time basis with an annual sustainment budget of approximately $160k.
- Nine measures were in place during 2016 investment planning cycle to monitor effective use of the Asset Investment Planning tool and related processes. Additional measures are planned for the 2017 investment planning cycle.
- Lessons learned related to the use of the Asset Investment Planning tool are captured as part of the overall investment planning process. Members of the Investment Planning and Process Team are part of the Copperleaf Community Advisory Board and take part in the Community Online Forum as well as industry conferences to share their knowledge and experience with peer utilities.
- A detailed process is available and used to configure Asset Investment Planning tool, perform quality assurance of data input, run optimization engine and review optimization results.

Summary of Key Recommendations:

We have discussed our observations with management throughout this audit. The key recommendations we made, which management has reviewed and developed action plans, are included in the following list of high and medium residual risk impact items:

High Risk:
- Ensure that the needs for changes to data and algorithms for asset risk index calculation, which are already identified by management, are prioritized and implemented on a timely basis.
- Ensure that appropriate mechanisms are in place for periodic monitoring, escalation for follow-up and correction of known data quality issues with the owners of the supporting data systems so that Asset Analytics input data quality continues to improve.

Medium Risk:
- Develop and implement suitable measures to periodically monitor consistent and effective use of Asset Analytics within Planning and to ensure that this tool is being used for its intended purpose.
- Develop and communicate appropriate guidelines to ensure consistent and effective use of available Asset Analytics data and tool capabilities for investment planning assessment needs.
- Review the current use of the Asset Analytics tool capabilities and features and determine which are required for on-going use. Perform a cost/benefit review of features to determine their continued use.

Provide the required training and support for capabilities that are available (such as ad-hoc BOBJ Reports[4]).

Management has developed action plans to mitigate the identified risks and address our recommendations, as summarized in Attachment "A" of this report. In a separate memorandum, we have shared with management additional opportunities for improvement, which we believe will further strengthen this function. Additional details are available upon request.

Management Response:

Bruno Jesus, Director, Strategy & Integrated Planning

Hydro One Management is in agreement with the proposed issues and recommendations and are very committed to implementing the resulting action plans for resolution.

[4] SAP Business Objects (BOBJ) is a reporting tool being used to create both ad-hoc and formal reports using the available data from the data warehouse that contains data from various source systems including SAP.

Observations	Recommendations	Action Plan
1.0 Measures related to Asset Analytics use are unavailable	**Risk**[5] M	**Executive:** Darlene Bradley, VP, Planning **Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
Currently, there are no measures in place to periodically monitor consistent and effective use of Asset Analytics (AA). Although an AA user list is available on a monthly basis, it does not adequately monitor the effective use of the AA data and tool capabilities. There are approximately 900 individuals approved to use the AA tool but it is unclear how many users are actually using AA and for its intended purpose. Five measures related to monitoring of continued acceptance of AA by users were envisioned during AA implementation. Currently none of these measures are either implemented or tracked. ***Risk:*** *A lack of monitoring for effective use of the support tool could lead to inconsistent or inappropriate use of the tool or inability to leverage available tool capabilities.*	Develop and implement suitable measures to periodically monitor consistent and effective use of AA within Planning.	We will review the existing use of AA tool capabilities and develop measures for its effective use that can be tracked as part of the Planning Scorecard. **Completion:** March 31, 2018

[5] Residual Risk levels applied are described in the legend that follows this table.

Observations	Recommendations	Action Plan
2.0 Asset Analytics Algorithms require improvement to be effective	**Risk** H	**Executive:** Darlene Bradley, VP, Planning **Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
Since the implementation of Asset Analytics in 2012 (Wave 1) and 2014 (Wave 2), Management has recognized that further improvements are needed to the existing Asset Risk Index (ARI) algorithms and data, along with new ARIs related to Obsolescence and Health, Safety and Environment. The 159 currently proposed enhancements are organized into three categories: a) Enhancements related to existing ARI algorithms and existing data, b) Enhancements related to existing ARI algorithms requiring new data, and c) Enhancements related to new ARI algorithms and new data. We were informed by Management that plans are underway to address the a) & b) enhancements by end of 2020 as per the current approved business plan and management is planning to expedite these changes to be completed by end of 2018 as per the business plan currently under development. ***Risk:*** *Untimely correction of known issues with AA algorithms can reduce the effectiveness and use of the AA tool for its intended purpose.*	Ensure that the identified needs for changes to data and algorithms for asset risk index calculation are prioritized and implemented on a timely basis.	As per our current plan, we will monitor the implementation of a) enhancements related to existing ARI algorithms and existing data and b) enhancements related to existing ARI algorithms requiring new data enhancements by end of 2018. We will look for opportunities to expedite this work along with c) Enhancements related to new ARI algorithms and new data. **Completion:** December 31, 2018

Observations	Recommendations	Action Plan
3.0 Asset Analytics input data quality remains poor	**Risk** H	**Executive:** Darlene Bradley, VP, Planning **Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
Poor quality data from source systems that are used as inputs to the Asset Analytics (AA) tool has resulted in unreliable Asset Risk Index calculations/outputs from the tool. The input data quality is determined by accuracy, completeness and timely availability of these data largely provided by other line of business groups. An SAP data dashboard is currently available to indicate completeness of SAP asset and <u>static</u> nameplate data (such as ratings, volume, etc.) used for ARI calculations, however a similar mechanism is unavailable for completeness of SAP <u>dynamic</u> data (such as counter readings, test results, condition ratings, etc.) or input data from the other 18 supporting systems into the AA tool. The AA tool has built in data quality measures for each ARI, namely, Data Completeness (DC) and Confidence Level (CL). Analysis of these measures for stations and lines asset composite ARI show that stations assets have low data completeness while lines assets have low confidence levels. A composite ARI is currently unavailable for 10 asset types. The input data from source systems used in ARI algorithms are known as Supporting Factors. An analysis of Supporting Factor availability shows that there has been only a marginal improvement between 2014 and 2017. Almost 10% of Supporting Factors for Distribution	Ensure that appropriate mechanisms are in place for periodic monitoring, escalation for follow-up and correction of known data quality issues with the owners of the supporting data systems.	We will discuss source system data quality issues with the system owners and then implement periodic monitoring and correction of identified issues by the system owners. **Completion:** June 30, 2018

Observations	Recommendations	Action Plan
Stations are either missing or using default values while 12% of Supporting Factors for Transmission Stations are either missing or using default values. There are informal mechanisms in place to identify and escalate missing/inaccurate data for correction in supporting systems once they are identified by the Planners as part of the field validation/review, however there is inadequate follow-up and monitoring to ensure that this occurs in a timely manner. Enhancements currently planned for algorithm updates (discussed in observation 2.0 of this report) are not expected to address the underlying data quality issues from support systems. ***Risk:*** *Poor quality input data and output results or timely correction of known issues would reduce the effectiveness and use of the Asset Analytics support tool for its intended purpose.*		
4.0 Asset Analytics use guidelines are unavailable	**Risk** M	**Executive:** Darlene Bradley, VP, Planning **Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
Although the use of the Asset Analytics (AA) tool is governed by the Asset Risk Index policy (SP1213) and related Directive (SP1204), there is a lack of specific documented expectations or guidelines on how the AA data and tool analytical capabilities and features	Develop and communicate appropriate guidelines to ensure consistent and effective use of available AA data and tool capabilities for investment planning assessment needs.	We will review and formalize the current Asset Risk Assessment process in our policy documents along with revision and/or development of suitable processes, procedures,

Observations	Recommendations	Action Plan
(including dashboards, charts, reports, asset survival curves, Duval Triangles[6], heat maps, etc.) are to be used for the Investment Planning process. Specific guidelines for validating ARIs and translating ARIs to Business Value Risks for investment candidate development are also unavailable. We were informed by Management that the ARIs are only one of several inputs to the Asset Risk Assessment Process (ARA). This has been communicated and described in the recent transmission and distribution rate filings with the regulator and to Planners by their respective managers. ***Risk:*** *Inconsistent or unclear direction on use of AA data and tool capabilities in support of investment planning decisions may lead to development of suboptimal investment plans.*		guidelines and training on consistent use of AA data and tool capabilities. **Completion:** December 31, 2018
5.0 Use of Asset Analytics tool is inconsistent	**Risk** M	**Executive:** Darlene Bradley, VP, Planning **Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
Asset Analytics (AA) was envisioned to deliver decision support tools and processes focused on asset risk prioritization enabling planners to make optimal asset decisions at any point in time (30+ year timeline)	Review the current use of the AA tool capabilities and determine which are required for on-going use. Perform a cost/benefit review of features to	We will initiate a review of the AA tool features and capabilities with the intent to specify and reinforce which features and capabilities are to be used

[6] Duval Triangle is a diagnostic technique used to analyze results of dissolved gases in transformer oil samples by plotting them on a special triangle chart to detect incipient internal fault condition and tracking the movement of results over time for internal condition deterioration.

Observations	Recommendations	Action Plan
leveraging existing BW framework and SAP investments[7]. Currently AA is primarily used for sustainment capital projects and not for development projects or maintenance programs. Interviews with the Planners and sample testing of "station centric" projects have confirmed that the AA tool is primarily used as a screening tool to identify high risk assets in the fleet. Further analysis of system data outside of the AA tool is needed to validate ARI scores and then use them to prioritize and justify asset investment needs. Some of AA tool features (such as geo-spatial views, "what-if" analysis, Duval Triangles, Heat Maps, etc.) are inconsistently used by the Planners because of issues with underlying data quality, ease of use and unfamiliarity with the tool capabilities. We observed that experienced Planners generate their own ad-hoc BOBJ[8] reports to analyze supporting system data compiled within AA rather than use the various asset views, dashboards, charts and graphs with drill-down capabilities provided within AA tool. We were informed by Management that formally certified and published BOBJ reports are currently unavailable for use by all Planners. ***Risk:*** *Inconsistent use of AA outputs in support of investment planning decisions may lead to suboptimal investment plans.*	determine their continued use. Provide the required training and support for capabilities that are available (such as ad-hoc BOBJ Reports).	for what purpose. We will perform a cost/benefit review of features prior to determining if any should be decommissioned. **Completion:** June 30, 2018

[7] As per presentation titled "EC Update: AA/AIP/BPC Projects", May 17th 2012.
[8] SAP Business Objects (BOBJ) is a reporting tool being used to create both ad-hoc and formal reports using the available data from the data warehouse that contains data from various source systems including SAP.

LEGEND: RESIDUAL RISK CLASSIFICATION:

RESIDUAL RISK CLASSIFICATION[2]	**Assessment Indication**
MEDIUM: The risk will cause some elements of the objective to be delayed or not be achieved, causing potential negative impacts to the organization's strategic objectives.	M
HIGH: The risk will cause the objective to not be achieved, causing negative impacts to the organization's strategic objectives.	H

INTERNAL AUDIT REPORT

Transmission Reliability Strategic Plan

To:

Darlene Bradley
Vice President, Planning

Distribution:

Mayo Schmidt	President & Chief Executive Officer
Greg Kiraly	Chief Operating Officer
Chris Lopez	Senior Vice President, Finance
Bruno Jesus	Director, Strategy & Integrated Planning
Chong Kiat Ng	Director, Transmission Asset Management
Additional Recipients	Email Distribution List

Final Report Issued: January 10, 2018
Draft Report Issued: November 13, 2017
Report Number: 2017-24

Lead Auditor: Jeff Schaller
Audit Manager: Neil Power

EXECUTIVE SUMMARY

Background:

Hydro One's transmission network is comprised of over 29,000 km of high voltage transmission lines and 292 stations representing a valuation of approximately $15 billion[1] in assets, requiring approximately $430 million[2] in annual expenditures to sustain and operate. As one of the largest transmission systems in North America, it forms the backbone of the electricity network in Ontario and enables the transport of electricity from generation to wholesale and retail customers. Our transmission system also has an impact on neighbouring transmission networks through 25 interconnections at our provincial borders. It is important for Hydro One that these efforts align with an overarching transmission reliability strategy that is consistent with corporate priorities and objectives.

Objective and Scope:

The objective of this audit was to provide assurance that controls and processes were in place to support a transmission reliability strategy that provides governance, clear accountability and direction to support a reliable transmission system.

The scope of this audit includes a review of:

- Governance (clarity of roles, accountabilities, direction, communications).
- Risks to achieving a reliable transmission system are identified and mitigated, taking into consideration external factors such as regulatory requirements.
- Key controls (processes in place to support the achievement of the strategy that address the operability, responsiveness and continuity of the power system, impact to customers, cost effectiveness).
- Monitoring (including processes to measure and report reliability).

This audit did not include a:

- Detailed review of the transmission reliability processes.
- Review and assessment of reliability measurements.
- Assessment of known asset data governance issues which were addressed in a separate internal audit (Audit Report 2016-15 SAP Data Integrity Follow-up and Data Governance Review).

The key controls for this audit were determined through discussions with management which included reference to the Global Forum on Maintenance and Asset Management[3] practices and elements of the Reliability Issues Steering Committee (RISC) 2016 report[4] as they relate to transmission reliability.

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[1] As presented to the Ontario Energy Board - EB-2016-0160 Exhibit B1-3-9 (Total Gross Value).
[2] As presented to the Ontario Energy Board - EB-2016-0160 Exhibit C1-2-1 (2016 Board-approved OM&A expenditures).
[3] The Asset Management Landscape, Second Edition, Global Forum on Maintenance and Asset Management.
[4] Reliability Issues Steering Committee (RISC) is an advisory committee to the NERC Board of Trustees providing key insights, priorities, and executive leadership for issues of strategic importance to Bulk Power System reliability.

Audit Opinion:

Based on the specific areas reviewed, **we concluded that the control environment needs improvement** to ensure adequate governance and direction to address transmission reliability. Although various independent processes are in place to address transmission reliability, there is no all-encompassing strategy and program that links these processes together and takes into consideration their interrelationships and interdependencies.

Success Factors:

We noted that the following success factors were in place:

- Management shared with us a presentation slide deck on their *Journey to Operational Excellence, COO Roadmap and Operating Model, July 2017* which identifies the vision, goals and initiatives across the Operations line of business. Reliability is established as one of the pillars to achieving Operations' 2020 vision.
- Multi-year targets have been established for the key transmission reliability metric that is utilized within the Canadian utility industry.
- Management routinely performs analyses of outage data on both single and multi-circuit systems to identify causes and factors that affect system reliability. Reliability measurement and analysis tools are in place along with equipment and delivery point outage data for more than 10 years, all of which provide Hydro One with the ability to perform detailed reliability analyses.
- We verified that there is a process in place that takes operational considerations into account for transmission plans, supported by active communications between System Operations and Planning.[5]
- A lifecycle management policy exists and is utilized within the annual investment planning process.

Summary of Key Recommendations:

We have discussed our observations with management. The key recommendations we made, which management has reviewed and developed action plans, are included in the following list of medium residual risk impact items:

- Develop and implement an overarching transmission system reliability strategy to align with corporate strategic objectives and achieve operational reliability targets. The implementation should include formally defined roles and responsibilities, including lead accountability for the overall plan, communication of the plan to the Operations line of business along with adequate change management.
- Establish reliability metrics that address all of the key functions of the transmission system in alignment with corporate risk tolerances and corporate priorities.
- Establish a standard asset maintenance methodology to support the achievement of reliability targets.
- Identify leading asset performance-based metrics that would serve as early indicators before changes to transmission reliability would be detected by the selected operational metric.

[5] This activity was included in the processes established through the recent Transmission Capital Efficiency initiative.

In a separate memorandum, we have shared with management additional opportunities for improvement, which we believe will further strengthen Hydro One's transmission reliability strategic plan. Additional details are available upon request.

Summary Management Response

Bruno Jesus, Director, Strategy & Integrated Planning

Management agrees with Internal Audit's assessment and we have established actions to address their recommendations.

Observations	Recommendations	Action Plan
1. Develop and implement an overarching transmission system reliability strategy that align with corporate strategic objectives and achieve operational reliability targets.	**Risk**[6] M	**Executive Accountability:** Darlene Bradley, VP, Planning **Action Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
There is no single strategic plan document that describes how the company will achieve its operational targets for transmission reliability, however management shared with us their *Journey to Operational Excellence, COO Roadmap and Operating Mode*[7] which identifies the vision, goals and initiatives within Operations including the initiative to develop an Asset Management Strategy. Although stand-alone policy and process documents are in place, there is an initiative underway to integrate these into an all-encompassing strategic plan. In our review, we noted that there are existing policies, directives and process documentation in place that take reliability into account. These include, for example, the Asset Risk Index Policy and Asset Strategy documents (e.g., Directive to Achieve Reliability Compliance (DARC) documents). Our interviews with key management stakeholders during the fieldwork of this audit demonstrated that there are inconsistent views as to overall accountability for transmission system reliability. Responses included Director of Network Operating, Director of Strategy and Integrated Planning, VP of Planning and combinations of positions within these Lines of Business. ***Risks:*** *Unclear governance and misalignment with corporate strategic objectives risks achievement of those objectives.*	Develop and implement an overarching transmission system reliability strategy to align with corporate strategic objectives and achieve operational reliability targets. The implementation should include formally defined roles and responsibilities, including lead accountability for the overall plan, communication of the plan to the Operations organization along with change management.	Agree. Our work to create a transmission reliability strategy is already underway and aligns with the corporate operational roadmap. We will continue this work along with the implementation of the strategy as recommended. **Completion**: June 30, 2018

[6] Residual Risk levels applied are described in the legend that follows this table.
[7] The Journey to Operational Excellence and Roadmap were presented at the Quarterly leadership team meeting in July 2017.

Observations	Recommendations	Action Plan
2. Establish reliability metrics that address all of the key functions of the transmission system in alignment with corporate risk tolerances, risk profile and corporate priorities.	**Risk** M	**Executive Accountability:** Darlene Bradley, VP, Planning **Action Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
There is a lack of clear association between the key transmission reliability metric identified in the *Journey to Operational Excellence Scorecard* and the corporate risk tolerance, risk profile and corporate priorities. Specifically, the *Journey to Operational Excellence Scorecard* identifies "TxSAIDImc[8]" as the key transmission reliability metric, whereas the metrics identified in the *Corporate Risk Tolerance Impact Table* are "Unsupplied Energy[9]" and "TxSAIDI[10]". This creates a scenario, where the impact of large events are considered at the executive level (with the Unsupplied Energy metric) but not taken into account at the Operational management level scorecard (TxSAIDImc metric). Hydro One's risk profile identifies risks associated with transmission asset condition and customer relationship, specifically: "*Deteriorating or Inadequate Transmission Asset Condition*" and "*Customer Relationship Uncertainty*". There is no clear indication of how the metric TxSAIDImc, identified in the *Operational Excellence Scorecard*, will contribute to mitigating these risks. Also, the key transmission reliability metric identified in the *Operational Excellence Scorecard* (TxSAIDImc), alone, does not fully support all of the key functions of the transmission system and Hydro One's overall strategic	Establish reliability metrics that address all of the key functions of the transmission system in alignment with corporate risk tolerances, risk profile and corporate priorities (i.e. bulk transmission capabilities, load serving to all customers, customer needs, Hydro One's presence in the North American marketplace)	Agree. Additional reliability metrics will be established to address the recommendation including the following: a) Targets will be established for TxSAIDI and TxSAIFI[13] to include both Single and Multi-circuit supplied delivery points. b) Existing reporting of events resulting in reliability and power quality disruptions at specific delivery points will be enhanced. c) Reliability assessments will be enhanced to enable benchmarking throughout North America. **Completion**: December 31, 2018

[8] Transmission System Average Interruption Duration Index specific to 635 multi-circuit supplied delivery points of the total of 896 delivery points on the system.
[9] Unsupplied Energy (expressed in MWh units) quantifies the extent to which energy is not supplied to customers as a result of power interruptions.
[10] Transmission System Average Interruption Duration Index taking all 896 delivery point on the transmission system into account.

Observations	Recommendations	Action Plan
goals and corporate priorities since this measure, • focuses only on the reinforced part of Hydro One's system (where delivery points are supplied by two or more circuits). • represents an average duration of interruptions at delivery points whereas customers generally consider frequency of interruptions as a higher impact to their operations than duration of interruptions[11]. • does not include power quality impacts, which customers identified as "*…an integral part of Reliability*".[11] • captures only unplanned interruptions (not planned interruptions). • enables comparisons exclusively with a small number of Canadian utilities (part of the CEA reliability program group). This measure excludes comparisons across all of North America. • does not take into account the extent to which Hydro One's transmission system is performing sufficiently to meet its obligations pertaining to the Regional Infrastructure Planning Process[12], namely to ensure sufficient availability of the transmission system to transport energy from generators to major load centres across the province and through interties with neighboring utilities to support the electricity market. A suite of metrics may be needed to represent performance of all of the key functions of the transmission system and provide direction and focus to drive appropriate management processes and decisions. ***Risk:*** *Lack of appropriate reliability measures with specific targets for these measures may result in not achieving the reliability objectives.*		

[13] Transmission System Average Interruption Frequency Index
[11] Hydro One Transmission Customer Engagement report, July 2017
[12] Ontario Energy Board - Transmission System Code, 2013

Observations	Recommendations	Action Plan
3. Establish a standard asset maintenance methodology.	**Risk** M	**Executive Accountability:** Darlene Bradley, VP, Planning **Action Accountability:** CK Ng, Director, Transmission Asset Management
A Maintenance Plan and Work Standard Document Review process (SP1564) document is in place. The focus of this document is on the review process and lists various "*…considerations Asset Management is to take into account...*", however it does not prescribe a maintenance strategy or approach to be applied when determining maintenance plans for equipment. Adoption of a best practice industry standard approach for asset management (including maintenance programs) would improve the effectiveness and efficiency of asset standardization, determination of asset criticality and optimization of asset maintenance including spare parts management. For example, in 2009, Hydro One performed a gap assessment against the PAS55-Asset Management Standard, a standard for optimal life cycle management of physical assets that has since been adopted as an international standard, ISO 55000. The final report from this assessment was issued in 2010, however there is no evidence that the actions were tracked to completion. Late in our audit review period, management shared with us, a presentation slide deck on the *Journey to Operational Excellence, COO Roadmap and Operating Model, July 2017* which identifies the vision, goals and initiatives across the Operations organization including the initiative to develop an Asset Management Strategy. A standard asset maintenance strategy and methodology (such as Reliability Centred Maintenance) could be developed as part of the Management Strategy, one of the initiatives identified in the Operational Roadmap. This would provide improved clarity of the method by which the asset maintenance programs will support achievement of the reliability targets. ***Risk:*** *Lack of standardization and unnecessary complexity in the system can pose*	Establish a standard asset maintenance methodology to efficiently and effectively support the achievement of reliability targets.	Agree. We will establish a standard asset maintenance methodology, in alignment with ISO 55000. **Completion**: August 31, 2018

Observations	Recommendations	Action Plan
risks to the efficient and effective operation of the transmission system.		
4. Identify leading asset performance-based metrics that would serve as early indicators before changes to transmission reliability would be detected by the selected TxSAIDI[14] metric.	**Risk** M	**Executive Accountability:** Darlene Bradley, VP, Planning **Action Accountability:** Bruno Jesus, Director, Strategy & Integrated Planning
The key reliability metric selected (TxSAIDI) is substantially a lagging metric. Availability metrics (i.e. primary power system equipment in service on the system) are widely used in the electricity industry can provide leading visibility to potential impact to the TxSAIDI metric. Also, through its work management system (SAP), Hydro One has the means to track additional parameters that can provide even more visibility to potential impact to transmission reliability; impact to the TxSAIDI measure. For example, completion of maintenance plans, equipment defects, reliability compliance (e.g. vegetation clearing requirements) are all traceable and factors that can influence system reliability. Accumulation of equipment defect backlogs can increase the probability of negative impacts to reliability. Without establishing leading metrics linked to potential impact to reliability may create the risk of the accumulation of deficiencies over time that would result in system reliability deterioration. ***Risk:*** *There is a risk that broad deterioration of asset performance may not be detected by system reliability and/or delivery-based metrics, in a timely manner.*	Identify leading asset performance-based metrics that would serve as early indicators before changes to transmission reliability would be detected by the selected TxSAIDI metric.	We will establish trending of equipment based trouble calls and deficiency reports for tracking of degradation of assets over time. This will highlight, at an early stage, any broad based deterioration of equipment performance that might affect transmission reliability over the long term. **Completion**: August 31, 2018

[14] Transmission System Average Interruption Duration Index taking all delivery points on the transmission system into account (present count incl. 896).

LEGEND: RESIDUAL RISK CLASSIFICATION:

RESIDUAL RISK	Assessment Indication
HIGH: The risk will cause significant impact that may cause the business objective not to be achieved.	H
MEDIUM: The risk will cause some elements of the business objective not to be achieved.	M

Transmission In-service Additions
(resulting from Capital Project and Program work)
Internal Audit Report

Clients:

Andrew Spencer
Vice President, Transmission & Stations

Kathleen McCorriston
Director, Portfolio Management

Executive:

Greg Kiraly
Chief Operating Officer

Business Risk Areas:
- Regulatory Uncertainty
- Work Program Accomplishment

Primary Lines of Business Affected:
- Transmission & Stations
- Finance

Lead Auditor: Atul A. Solanki
Audit Manager: Jeff Schaller

Report Number: 2018-06
Date Issued: July 6, 2018

Transmission In-Service Addition Internal Audit Report
Executive Summary

Objective and Scope

The objective of this audit was to provide assurance that appropriate oversight and controls are in place to ensure that the in-service additions are budgeted, forecasted and added to the rate base in a timely manner such that capital assets meet regulatory conditions for being included in the rate base. The scope of this review was limited to the process controls within the Transmission & Stations line of business.

Audit Opinion

Needs Significant Improvement
Needs Improvement
Needs Minor Improvement
Satisfactory

Conclusion

Based on the specific areas reviewed, we concluded that **process and control improvements are needed** to ensure the effectiveness of in-servicing of transmission capital project and program work. Management has agreed with the recommendations and established action plans that will strengthen controls within this business function.

Summary of Key Observations and Management Actions

Deviations from budgeted in-service additions and associated approvals are not documented

Management has established plans to track, document and approve rationale for deviation from budget to actual in-service additions at the specific project and program level as part of the now-established redirection process. These will assist management in explaining any significant deviation from the annual level committed to the customers and the regulator.

Decision criteria to determine costs and assets that are being declared in-service are not clearly documented

Management will clarify and monitor consistent application of rules for declaring assets in-service then capitalize relevant costs as per the existing Report of Equipment In-Service (REIS) process. Portfolio Management will continue to seek clarification from Finance to ensure that in-servicing of assets or costs are completed as per the documented capitalization policy. Extraordinary items will be appropriately discussed with clear documentation of decisions with rationale.

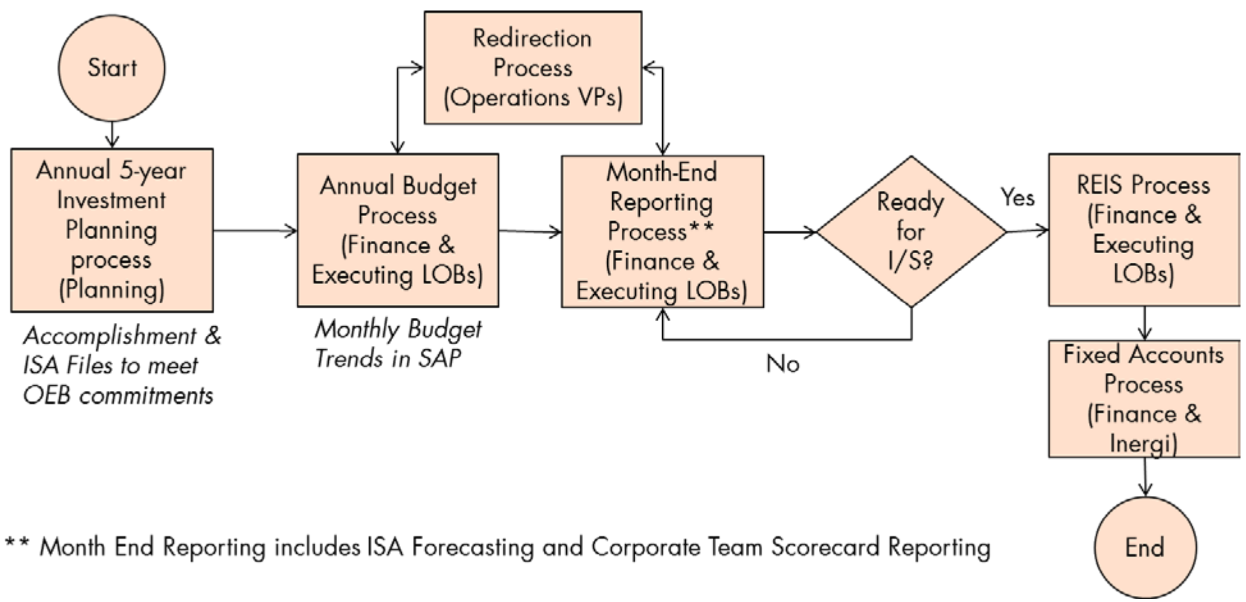
Heightened efforts in Q4 are expended to achieve the transmission in-service additions corporate year-end target

Management will initiate a review of the portfolio level metrics (such as cost and schedule adherence and milestone achievements) to complement the existing portfolio metrics around adherence to capital expenditure and in-service additions budget, to further drive best-in-class project and program-level reporting and demonstrate value to stakeholders.

In-Service Addition Process Overview

- In-service additions (ISA) represent increases to Hydro One's rate base and revenue requirements as a result of capital work being declared in-service and ready for use by our customers. Following each rate approval, Hydro One informs the regulator about expected in-service addition during future years for which the rate approval is received. As a result, both transmission and distribution in-service addition measures are included in the Corporate Team Scorecard to ensure that regulator commitments are being met.
- Appropriate budgeting, forecasting and tracking of actual in-service addition is critical to ensure that we do not over or under-collect from our rate payers. Accurate tracking of in-service additions is necessary to ensure accurate and complete internal and external financial reporting related to asset under construction accounts, depreciation, taxes and other regulatory requirements.
- In 2017, there were $872M of in-service additions for the transmission business. The Transmission & Stations LOB accounted for approximately 55% of the total in-service additions, the Distribution LOB accounted for 30%, and the other LOBs accounted for the remaining 15%.

High-level In-service Addition Process



This business overview is included for information purposes only and intended to provide readers further context into the area reviewed

Transmission In-Service Addition Internal Audit Report
Summary of Recommendations and Management Actions

Management has developed action plans to address and mitigate the identified risks. A summary of the key recommendations and action plans to address the areas of higher priority are as follows:

1. Deviations from budgeted in-service additions and associated approvals are not documented
Deviations between budget and actual transmission in-service additions were observed for which rationale at the project and program level was neither documented nor approved.

Recommendation:	Management Action:
Reinforce the month-end reporting process to keep track, document and approve deviations from budgeted in-service additions at project and program level.	Actual in-service additions may deviate from budget due to a variety of factors that are both within and beyond management control. Moving forward, we will consistently track, document and approve rationale for deviation from budget to actual in-service additions at the specific project and program level as part of the now-established redirection process. These will assist us in explaining any significant deviation from the annual level we have committed to our customers and regulator. **Accountable:** Kathleen McCorriston, *Director – Portfolio Management* **Completion Date:** December 31, 2018

2. Decision criteria to determine costs and assets being declared in-service are not clearly documented
Rules for allowing "partial in-servicing" of project work and journal transfer of related costs are unclear as per the existing Report of Equipment In-Service (REIS) process. Untimely or incorrect capitalization of assets in the current year could lead to a cascading effect on future in-service additions.

Recommendation:	Management Action:
Review the existing documentation to ensure that controls relating to "*partial in-service*" are clear so that only appropriate costs are capitalized after confirming that assets are actually being used for "*intended purpose*" from field operation.	We will clarify and monitor consistent application of rules for declaring assets in-service then capitalize relevant costs as per the existing Report of Equipment In-service (REIS) process. We will continue to seek clarification from Finance to ensure that in-servicing of assets or costs are completed as per the documented capitalization policy. Extraordinary items will be appropriately discussed with clear documentation of decisions with rationale. **Accountable:** Kathleen McCorriston, *Director – Portfolio Management* **Completion Date:** September 30, 2018

3. Heighted efforts in Q4 are expended to achieve the transmission in-service additions corporate year-end target 44% of the 2017 annual in-service additions were completed during the short working month of December resulting in incremental efforts and senior management involvement. Heightened efforts near year-end to meet in-service addition targets may lead to increased operational inefficiencies and/or operational risks.	
Recommendation: In addition to the in-service additions corporate scorecard dollar value measure, ensure that tracking of other performance factors are taken into account, including completion of budgeted work, adherence to plan (actual cost less than planned cost) and management of operational risks.	**Management Action:** We will initiate a review of the portfolio level metrics (such as cost and schedule adherence and milestone achievements) to complement the existing portfolio metrics around adherence to capital expenditure and in-service additions budget, to further drive best-in-class project and program-level reporting and demonstrate value to stakeholders. **Accountable:** Kathleen McCorriston, *Director – Portfolio Management* **Completion Date:** December 31, 2018

Transmission In-Service Addition Internal Audit Report
Legend

Audit Opinion	Definition
Needs Significant Improvement	- Pervasive or multiple control weaknesses detected may cause non-achievement of enterprise objectives.
Needs Improvement	- Numerous control weaknesses detected which may lead to non-achievement of specific key business objectives.
Needs Minor Improvement	- Partially effective control environment which may lead to a moderate risk of business objectives not being achieved.
Satisfactory	- Internal controls are appropriately designed, implemented, and are operating effectively to support related objectives.

Recommendation Priority Rating

Critical priority recommendation	Urgent action is recommended to avoid immediate negative and pervasive impacts to the business function. Oversight by the Executive Leadership Team and the Board is advised.
High priority recommendation	High priority issues that require timely management action to avoid negative impacts to the business function. Oversight by Executive Leadership is advised.
Medium priority recommendation	Major weaknesses detected that could impact business effectiveness if not remediated. Line management to oversee remediation.

Capital Project Stage Gate Review Internal Audit Report

Client:

Andrew Spencer
VP, Transmission & Stations

Kathleen McCorriston
Director, Portfolio Management

Executive:

Greg Kiraly
Chief Operating Officer

Business Risk Area:
- Work Program Accomplishment
- Cost/Productivity Uncertainty

Primary Lines of Business Affected:
- Transmission and Stations
- Planning
- Engineering

Lead Auditor: Moufid Dardas
Audit Manager: Atul A. Solanki

Report Number: 2018-16
Date Issued: September 27, 2018

Objective and Scope

The primary objective of this audit was to provide assurance that the key process and controls related to the Transmission Capital Project Stage Gate (Stage Gate) review are effective, and validate that the defined stage gates are consistently being utilized and monitored. This audit focused specifically on the recently revised Stage Gate process implemented in 2017 within Transmission and Stations for all capital projects with a cost greater than or equal to $7 Million.

Audit Opinion

Needs Significant Improvement
Needs Improvement
▶ **Needs Minor Improvement**
Satisfactory

Conclusion

The current Stage Gate process is generally effective; however, some controls **need minor improvement** to ensure effective project governance decisions are made throughout the life-cycle of a capital project. This conclusion was driven primarily by the need to further strengthen controls associated with the quality of the deliverables being used for Stage Gate Panel decision making and to ensure the timely follow-through and monitoring of resulting actions and conditions arising from the Stage Gates.

Summary of Key Observations

Inconsistent quality and timing of input being used for Stage Gate decision making

For a project to proceed past a Stage Gate, a presentation detailing current project status and progress-to-date is made to the Stage Gate Panel (Panel). This presentation allows the Panel to make an informed decision to allow the project to continue to the next Stage Gate. There is room for improvement in these presentations as:

- The quality of project deliverables (such as estimates, schedules, execution plans, etc.) being used to support the presentation is subjective;
- "Go/No Go" criteria are undefined for 2 of the 6 Stage Gates ("In-service" and "Project Closure") which are not yet fully matured; and
- Stage Gate presentations are not consistently provided to the Stage Gate Panel 3 days in advance of the meeting, as required by the process.

Inadequate tracking of actions and conditions to timely completion following a Stage Gate decision

While an Action and Condition Tracker tool is in place to track and monitor the completion of identified actions and conditions arising from the Stage Gate Panel decisions:

- Actions and conditions are not consistently entered in the tracking tool to allow for timely follow-through;
- The action and condition tracking list contained items with expired due dates (and no follow-through for a revised forecast date); and
- Expired conditions are not being consistently escalated to the Panel Chair for decision in accordance with the existing process.

Management has developed corrective action plans to address the above-noted gaps as well as to address other lower risk opportunities for improvement identified as part of this engagement.

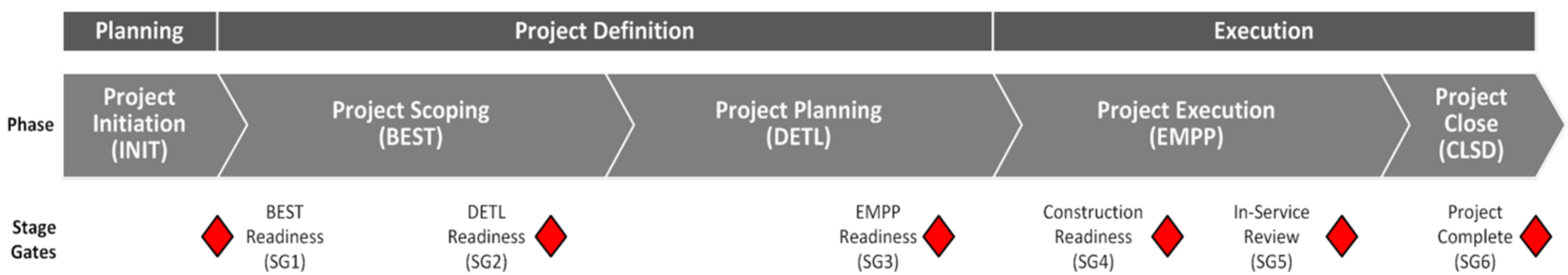
Capital Stage Gate Review
Background

A Stage Gate process is an industry best practice project management technique in which a project is divided into distinct stages or phases, separated by decision points (known as "gates") based on pre-established criteria. At each gate, continuation of a project to the next phase is approved by key stakeholders and a governance board (referred to as the Stage Gate Panel). At each Stage Gate, a decision is made by the Panel based on project progress and forecast information available at the time, including risk analysis and availability of necessary resources. The Stage Gate process ensures that safety, scope, cost, schedule and risks are effectively managed for successful project delivery. A successful Stage Gate process has clearly defined gates and deliverables, with consistent decision making criteria defined for each Stage Gate.

A substantial corporate effort was initiated to develop a revised Capital Project Stage Gate process within Transmission and Stations, to address the recommendations of the Asset Deployment Audit (conducted in 2016). This revised process was implemented as part of the Transmission Capital Efficiency initiative in 2017. This process consists of six distinct gates starting with budgetary project estimate readiness and ending with project completion. These six Stage Gates are being tracked as independent project milestones in the project schedule. At each Stage Gate, a "Pass", "Fail" or "Pass with Conditions" decision is made by the Stage Gate Panel, who independently reviews project progress and determines if the project may continue to the next Stage Gate.

The Stage Gate Panel currently comprises of the Vice Presidents of Transmission and Stations (Panel Chair), Planning, and Engineering groups. Since the process implementation in early 2017, approximately 60 projects, with a combined value of $2.4 Billion, have proceeded through various stages of the Stage Gate process. Transmission capital projects planned for execution by Transmission and Stations that would be subject to the Stage Gate process over the next 3 years are valued at approximately $3.2 Billion.

The following diagram depicts the six Stage Gates used in Transmission and Stations for capital projects:



This business overview is included for information purposes only and intended to provide the reader further context into the area reviewed.

Capital Stage Gate Review
Legend

Audit Opinion	Definition
Needs Significant Improvement	Pervasive weaknesses detected in the control environment, likely to cause non-achievement of enterprise objectives.
Needs Improvement	Numerous control weaknesses detected which may lead to non-achievement of specific key business objectives.
Needs Minor Improvement	Partially ineffective control environment which may lead to a moderate risk of business objectives not being achieved.
Satisfactory	Internal controls are appropriately designed, implemented, and are operating effectively to support related objectives.

Recommendation Priority Rating

Critical priority recommendation	Urgent action required to avoid immediate negative and pervasive impacts to the business function. Oversight by the Executive Leadership Team and the Board is advised.
High priority recommendation	High impact issues that require timely management action to avoid impacts to the business function. Oversight by Executive Leadership is advised.
Medium priority recommendation	Major weaknesses detected that could impact business effectiveness if not remediated. Oversight by Line of Business management is advised.

Transmission & Stations Program Work Cost Management & Reporting Internal Audit Report

Client:	**Andrew Spencer** Vice-President, Transmission & Stations	**Business Risk Area:**	Cost/Productivity Uncertainty
	Kathleen McCorriston Director, Work Program Management	**Primary Lines of Business Affected:**	Transmission & Stations
	Ryan Lee Director, Management Accounting	**Audit Manager:** **Audit Lead:**	Atul Solanki Adrienne Pieri
		Report Number:	2018-19
cc:	**Greg Kiraly** Chief Operating Officer **Chris Lopez** Chief Finance Officer	**Date Issued:**	April 8, 2019

Tx & Stn Program Work – Cost Management & Reporting – Internal Audit Report Executive Summary

Objective and Scope

To review program work cost management processes and controls to ensure timely, complete and accurate forecasting, cost reporting and work accomplishment tracking against the approved annual Transmission & Stations business plan. The scope included key controls related to: 1) maintenance of the Unit Price Catalogue (UPC) to support effective cost planning; 2) monitoring, reporting and forecasting of actual and future work program costs and accomplishments; and 3) timely review and approval of redirection to address observed cost and accomplishment variances.

Audit Opinion

- Needs Significant Improvement
- Needs Improvement
- ▶ **Needs Minor Improvement**
- Satisfactory

Conclusion

A cadence of monthly meetings allows management to ensure that overall program costs and accomplishments are managed. Program work cost management and reporting processes and controls would benefit from **minor improvements**, particularly relating to UPC confirmations and updates, monthly cost monitoring, forecasting and approval, and communication of redirection decisions affecting program work. Effective program work cost management and reporting processes are essential to demonstrate work program accomplishment whilst ongoing communication of realized variances enhances the accuracy of the Planning process, reducing the need for future redirections.

Summary of Key Observations and Management Actions

Establish a more consistent approach to confirm unit prices and executability of planned and budgeted work

Accurate planning and costing requires an understanding of the body of work that can be reasonably accomplished with available resources. Whilst Planning has established a process to request unit price updates and confirm executability of planned work program, a more consistent approach is needed in the execution of this process. And, although variances net out to zero for the overall approved programs budget, Management has committed to improving processes to support the accuracy of unit prices and the executability of the proposed work plan.

Enhance the quality of program cost and accomplishment monitoring and forecasting commentary

Management conducts monthly meetings to review program cost and accomplishment variance root causes and related commentary that are captured in the centralized "PP-191" report. However, the quality of variance commentary to explain the reasons for the variance and remedial actions that were taken is inconsistent. Management has committed to improving variance commentary in order to provide a more effective decision trail and to provide enhanced feedback.

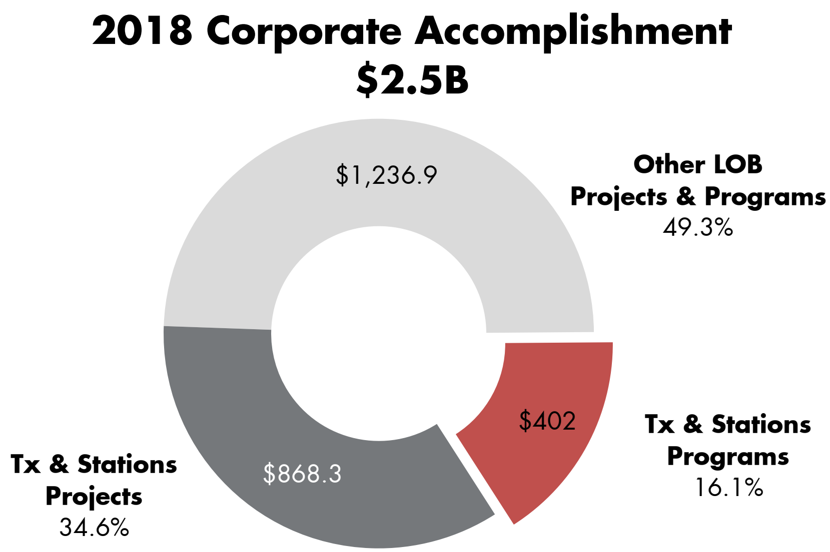
Establish a more formal approach to communicate program redirection decisions

Decisions endorsed by the Redirection Committee (est. Sept. 2017 to oversee variances from the business plan) are not consistently approved at an individual program level nor consistently communicated to the accountable Program Managers. Actions have been established to improve communications and enhance the ability of the Program Managers to effectively manage their program(s).

Tx & Stn Program Work – Cost Management & Reporting – Internal Audit Report
Background

- Hydro One's annual work program (valued at $2.5B in 2018), develops and sustains the transmission and distribution grid capabilities to deliver safe and reliable power to our customers. This work program consists of project and program work.
- *Project work* is:
  - a specific body of work that is one-time event and occurs during a specific time period (such as a new station build).
- *Program work* is:
  - generally repetitive work and recurs year-over-year (such as pole replacements, which occur annually but the required accomplishments may vary each year).
  - unit-priced and based on units to be accomplished in a given year. Unit prices for each program work are identified within the Unit Price Catalogue, which is confirmed annually based on historical costs.
- This review assessed the program work executed by Transmission & Stations, valued at $402M in 2018.
- The program work budget is approved by the Board of Directors annually as part of the Consolidated Business Plan approval.

The outcome of this review will be shared with other Lines of Business who may benefit similarly from these recommendations for improved cost management and reporting processes and controls for program work management.



This business overview is included for information purposes only and intended to provide the reader further context into the area reviewed.

Tx & Stn Program Work – Cost Management & Reporting – Internal Audit Report
Legend

Audit Opinion	Definitions
Needs Significant Improvement	Pervasive or multiple control weaknesses detected may cause non-achievement of enterprise objectives.
Needs Improvement	Numerous control weaknesses detected which may lead to non-achievement of specific key business objectives.
Needs Minor Improvement	Partially effective control environment, which may lead to a moderate risk of not achieving business objectives.
Satisfactory	Internal controls are appropriately designed, implemented, and are operating effectively to support related objectives.

Recommendation Priority Rating

Critical priority recommendation	Urgent action required to avoid immediate negative and pervasive impacts. Oversight by the Executive Leadership Team and the Board is advised.
High priority recommendation	High impact issues that require timely management action to avoid damages. Oversight by Senior Management is advised.
Medium priority recommendation	Major weaknesses detected that could impact business effectiveness if not remediated over time. Oversight by Line of Business management is advised.

UNDERTAKING - JT 1.13

Reference:
I-07-SEC-037

Undertaking:
Based upon the programs that are identified in SEC 37, to the extent that they were alternatives considered, provide the numbers of assets that would be replaced within each particular alternative.

Response:
As noted in SEC-37, alternative work volumes are typically included for line component programs such as wood pole replacements or steel tower coating. Descriptions of alternatives considered are included in:

- Wood Poles: System Renewal ISD #21
- Tower Coating: System Renewal ISD #22
- Foundation Replacement: System Renewal ISD #23
- Shieldwire Replacement: System Renewal ISD #24

Alternative replacement volumes for the test years for these investments are included in the tables below. The “As Filed” alternatives are shaded.

Wood Poles: System Renewal ISD #21

	2020	**2021**	**2022**
Alternative 1: The “Do Nothing” - Reactive Pole Replacement	0	0	0
Alternative 2: Planned Pole Replacement at the Optimal Level	1450	1450	1450
Alternative 3: Pole replacement Based on Risk Mitigation Assessments (As Filed)	800	800	800

Tower Coating: System Renewal ISD #22

	2020	**2021**	**2022**
Alternative 1: The “Do Nothing” - Reactive Replacement of Failed Structures	0	0	0
Alternative 2: Coating at the Optimal Level	1600	1600	1600
Alternative 3: Coating at Currently Planned Pacing (As Filed)	260	500	500

Witness: Bruno Jesus

Foundation Replacement: System Renewal ISD #23

	2020	**2021**	**2022**
Alternative 1: Reactive Foundation Replacement	0	0	0
Alternative 2: Planned Foundation Coating/Repair at the Optimal Level (As Filed)	820	1600	1600

Shieldwire Replacement: System Renewal ISD #24

	2020	**2021**	**2022**
Alternative 1: Reactive Replacement of Failed Shieldwire	0	0	0
Alternative 2: Proactive Replacement of Critical EOL Shieldwire and Backlog	220	220	220
Alternative 3: Proactive Replacement of All EOL Shieldwire (As Filed)	290	290	290

UNDERTAKING - JT 1.14

Reference:
I-07-SEC-046

Undertaking:
To provide the 2018 NATF transmission reliability report.

Response:
The 2018 NATF transmission reliability report becomes available in or around September 2019. Hydro One will update this undertaking with a summary of the report shortly thereafter.

UNDERTAKING - JT 1.16

Reference:

I-12-AMPCO-023

Undertaking:

To provide the refined cost and schedule metrics that Hydro One uses to track cost schedule and scope, as referred to in AMPCO 23.

Response:

Hydro One is continuously improving the reports it uses to evaluate project performance. Below is a list of metrics used on both a project and portfolio basis.

Project Level Metrics:

- On-time: Project In-Service Date Forecast versus Current Approved
- On-time: Project In-Service Date Forecast versus Original Approved
- On-budget: Gross Project Total Forecast versus Current Approved
- On-budget: Gross Project Total Forecast versus Original Approved

Portfolio Level Metrics:

- In-Service Additions: Annual Forecast versus Budget
- Capital Expenditures: Annual Forecast versus Budget
- Portfolio Risk: Number of Projects Forecasting a Major Variance (+/- 10%) to Budget
- Portfolio Risk: Value of Projects Forecasting a Major Variance (+/- 10%) to Budget
- Project Cost Performance: Number of Projects complete within AACE Estimate Class Range documented in original approval
- Project Cost Performance: Value of Projects complete within AACE Estimate Class Range documented in original approval
- Cost Variance Distribution: Portion of Project Portfolio Delivered On Budget, Over Budget, Under Budget
- Cost Variance Distribution: Standard Deviation of Project Cost Performance represented as a percentage of original Budgets
- Schedule Variance Distribution: Portion of Project Portfolio Delivered On-time, Late, Early
- Schedule Variance Distribution: Standard Deviation of Schedule Variance in Days

UNDERTAKING - JT 1.17

Reference:

I-12-AMPCO-031

Undertaking:

To clarify the calculation of failure rate in the table in AMPCO 31.

Response:

The table below provides the input variables applied to the formula below, to determine the transformer failure rate.

Formula:

Transformer Failure Rate (average):

TFR= (∑ TRf/TRs)/NY*100%

Where:

TRf: number of transformers which have failed in the given year

TRs: number of transformers which are in service in the given year

NY: number of years

Calculation:

Example: The 115kV 5 year failure rate (2009 – 2013) is determined as follows:

([(1/307) + (1/307) + (3/307) + (1/285) + (2/285)]/5) x 100% = 0.54%

	# of Transformer Failures(I-12-AMPCO-30)			# of Transformers in Service			Transformer Faiure Rate (10 year), %				Transformer Faiure Rate (5 year), %				Transformer Faiure Rate (5 year), %			
Year	115kV	230kV	500kV	115kV	230kV	500kV	115kV	230kV	500kV	All	115kV	230kV	500kV	All	115kV	230kV	500kV	All
2009	1	0	1	307	379	43	0.33	0.00	2.33	0.27	0.33	0.00	2.33	0.27				
2010	1	0	1	307	379	43	0.33	0.00	2.33	0.27	0.33	0.00	2.33	0.27				
2011	3	3	0	307	379	43	0.98	0.79	0.00	0.83	0.98	0.79	0.00	0.83				
2012	1	0	1	285	388	42	0.35	0.00	2.38	0.28	0.35	0.00	2.38	0.28				
2013	2	2	0	285	388	42	0.70	0.52	0.00	0.56	0.70	0.52	0.00	0.56				
2014	3	1	1	285	388	42	1.05	0.26	2.38	0.55					1.05	0.26	2.38	0.55
2015	1	2	1	285	388	42	0.35	0.52	2.38	0.56					0.35	0.52	2.38	0.56
2016	2	2	2	288	388	40	0.69	0.52	5.00	0.70					0.69	0.52	5.00	0.70
2017	0	1	1	279	384	41	0.00	0.26	2.44	0.28					0.00	0.26	2.44	0.28
2018	2	5	1	273	393	46	0.73	1.27	2.17	0.98					0.73	1.27	2.17	0.98
							0.55	0.41	2.14	0.53	0.54	0.26	1.41	0.44	0.57	0.56	2.87	0.61

Witness: Donna Jablonsky

UNDERTAKING - JT 1.18

Reference:
Audit 2018-16

Undertaking:
To provide an overview of quality results for projects that have passed through, with an example.

Response:
This undertaking responds to a request to provide an overview of the Stage Gate review and assessment process and associated criteria. Hydro One recently implemented a quality and completeness review of the inputs into the Project Execution Plan to ensure each project is ready to proceed to the next phase. The go-no-go criteria that are used at the Execution (EMPP) Readiness Phase to assess the quality of the deliverables include:

- Scope: Amendments to Planning Specification maintain business requirements
- Plan: Updated Project Execution Plan is consistent with project schedule and cost
- Engineering: Deliverables progress in alignment with project schedule
- Environment & Permits: EA/Permits will be submitted and on track
- Regulatory: All filings will be submitted and approved
- Real Estate: Land access requirements align with project schedule
- Community Relations: Plans are on track and consistent with ISD
- Indigenous Relations: Plans are on track and consistent with ISD
- Procurement: Long Lead Items: Identified and procured long lead items
- Outage Planning: Outage window considered and consistent with ISD
- Schedule: ISD consistent with Business Case
- Cost Estimate: Costs within adjusted Class range

More specifically, there is a quality review for key inputs such as the Schedule which evaluates thirty criteria. For example it would check to ensure a critical path is identified, corporate and project milestones are included, links between key activities exists, reference to the outage staging plan exists. By example, below is the Quality Assessment Summary for Fairbank TS.

AR 23447 - Quality Assessment

AR 23447 - Fairbank TS: T1, T2, T3, T4, PCT & LV Yard Replace

Measure	Score (%)	Assessment Summary
Estimating	**75%**	- Assumptions were required for work breakdown structure due to numerous delays and changes to scope of work and work plan. - Cost of cables based on historical average, not bid price. Toronto underground feeder cables based on internal pricing, not Toronto Hydro price.
Risk	**100%**	
Scheduling	**88%**	- Construction Progress Measurement has not been defined
PM	**100%**	- Detailed work plan has been developed with the project team and is incorporated into the Project Execution Plan with no significant outstanding assumptions - Kick-off meeting was held at site which addressed all pertinent issues - Capitalization plan with specific work breakdown structure identified
Project Total	**91%**	

UNDERTAKING - JT 1.19

Reference:
Audit 2018-19

Undertaking:
To confirm the forecast completion date for the audit entitled "work program - cost management and reporting."

Response:
The forecasted completion date for the actions associated with the Work Program – Cost Management and Reporting audit is September 30, 2019.

UNDERTAKING - JT 1.20

Reference:
I-07-SEC-035

Undertaking:
To provide a data showing a consolidated view of total transmission capital spend, showing external resources versus internal resources, showing dollars for each.

Response:
The referenced interrogatory response has been updated as follows to include dollar values, expressed in millions, in addition to percentages previously provided.

OEB Category	2015		2016		2017		2018	
System Access	61.2		66.8		101.6		94.5	
External	8.0	13%	2.2	3%	18.3	18%	17.7	19%
Internal	53.2	87%	64.5	97%	83.3	82%	76.7	81%
System Renewal	719.3		782.2		793.8		822.9	
External	47.4	7%	58.3	7%	64.0	8%	78.2	10%
Internal	671.9	93%	724.0	93%	729.9	92%	744.7	90%
System Service	193.0		146.5		100.4		88.0	
External	62.0	32%	47.7	33%	10.4	10%	5.2	6%
Internal	131.0	68%	98.8	67%	90.1	90%	82.7	94%
General Plant	88.0		94.6		78.1		89.4	
External	0.0	0%	0.0	0%	0.0	0%	0.2	0%
Internal	88.0	100%	94.6	100%	78.1	100%	89.2	100%
Total	**1,061.5**		**1,090.1**		**1,074.0**		**1,094.7**	
External	117.4	11%	108.2	10%	92.7	9%	101.3	9%
Internal	944.1	89%	981.9	90%	981.3	91%	993.4	91%

Note: Percentages are calculated based on gross capital expenditures

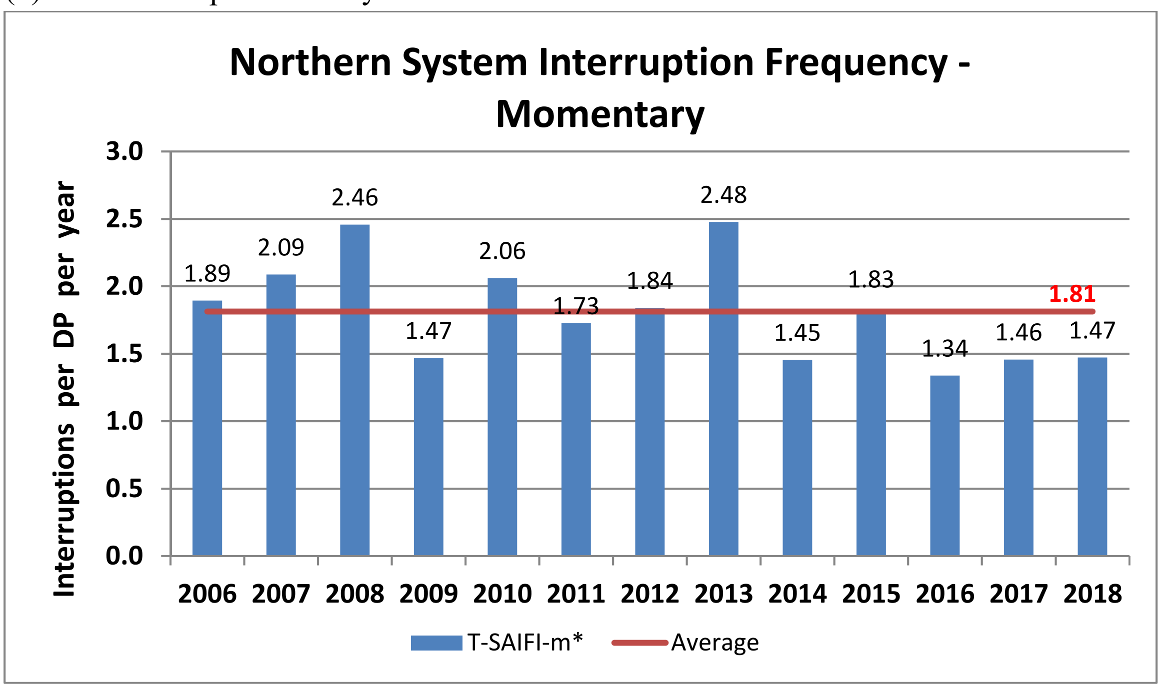
UNDERTAKING - JT 1.27

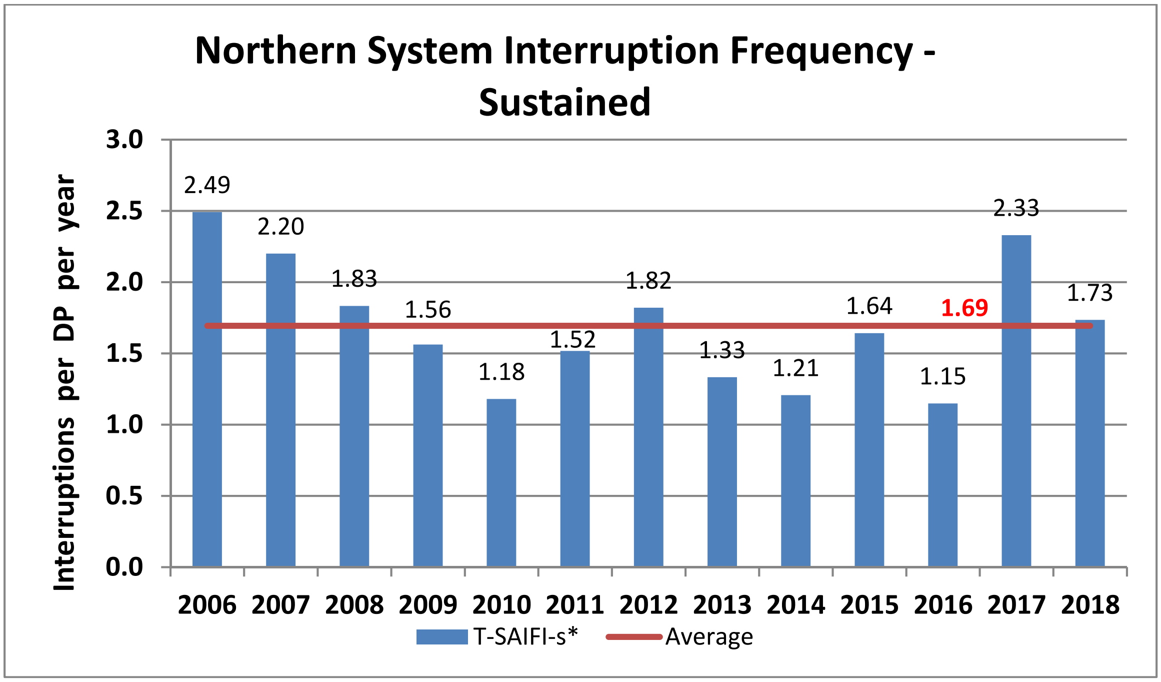
Reference:
I-09-Anwaatin-002, part b)

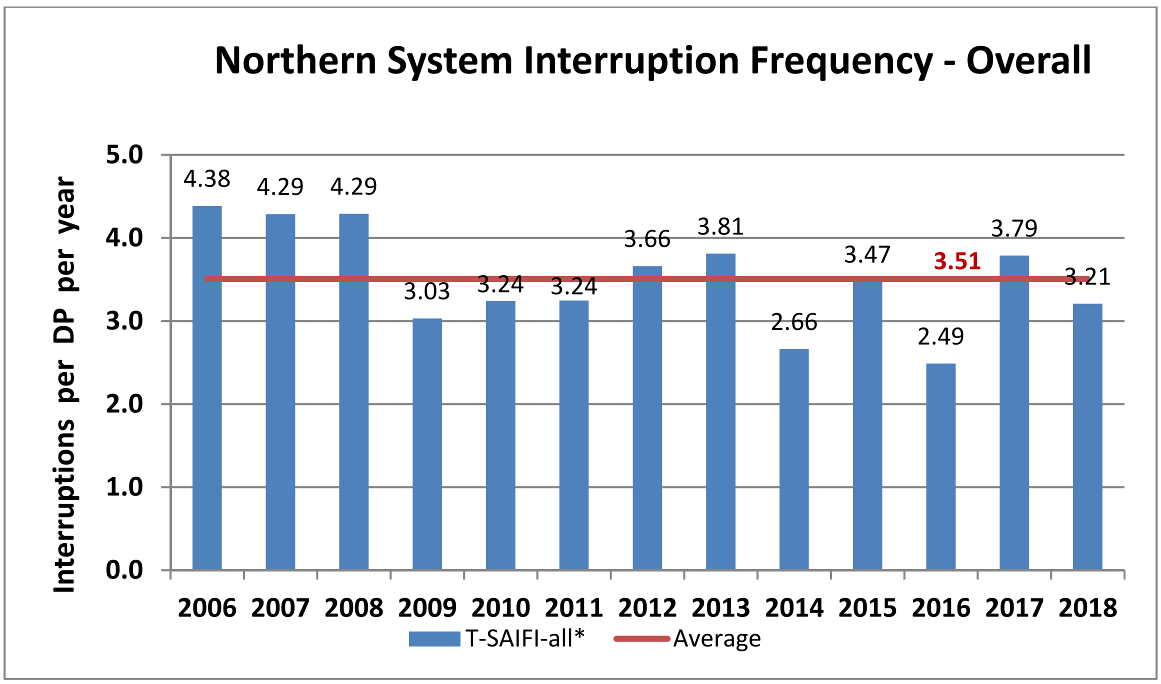
Undertaking:
To compare the figures in the bar charts in Anwaatin IR 2, page 6 to 11, to EB-2016-0160, TCJ 2.5, and confirm that the averages are calculated based on the 2006 to 2015 period; to provide updated data to include 2016 to 2018.

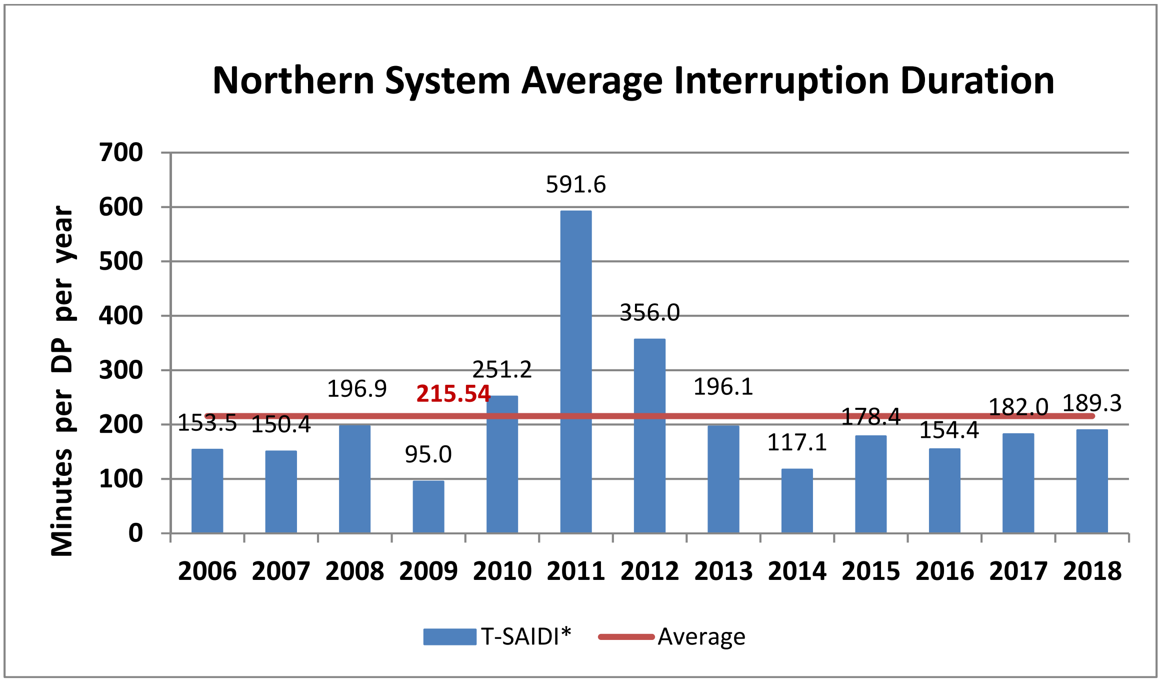
Response:
Hydro One has updated the bar charts in Anwaatin-002 to include the average from 2006 to 2018.

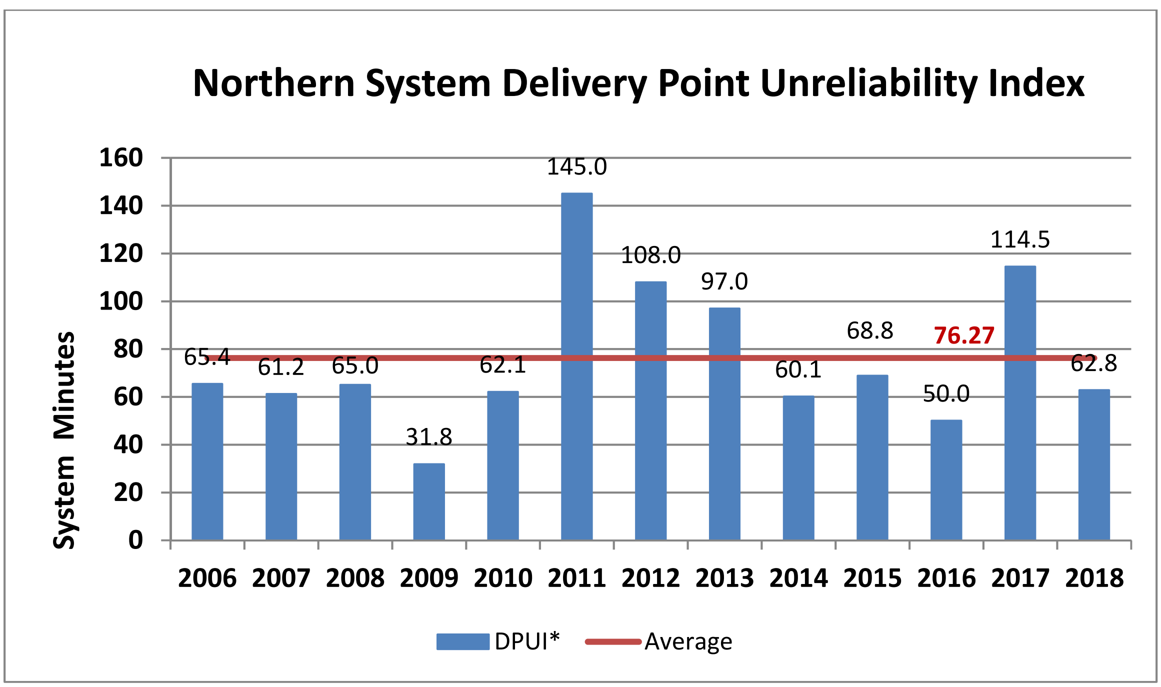
(1) "Northern" part of the system



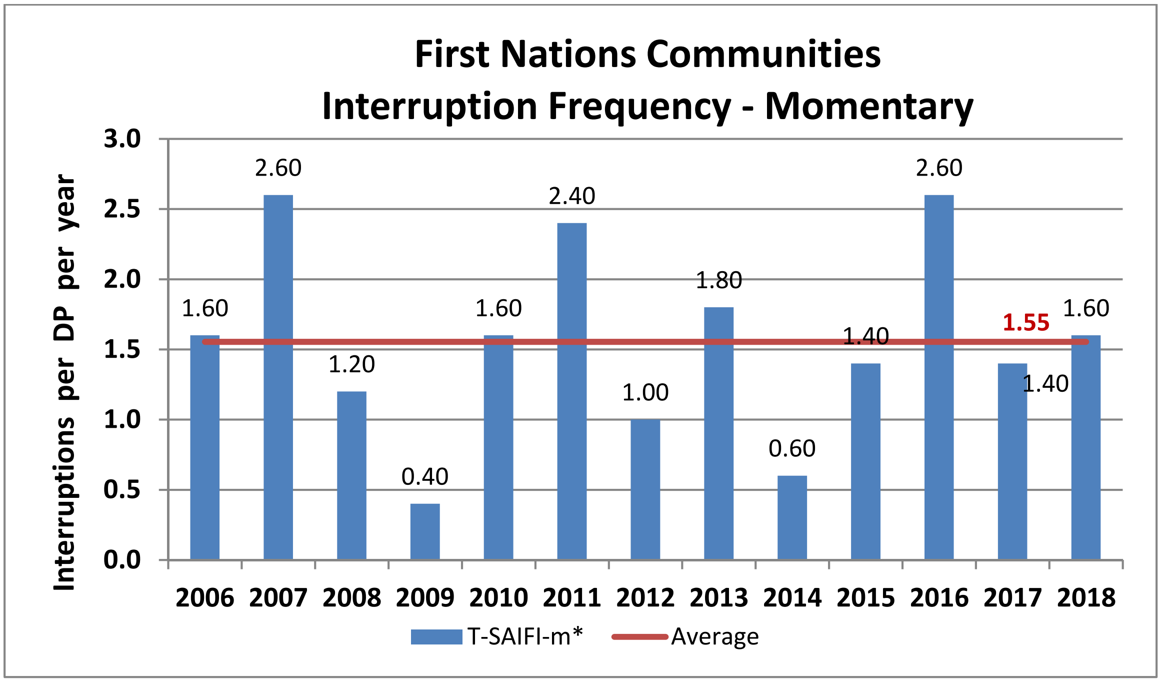

Northern System Interruption Frequency - Sustained
Interruptions per DP per year
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.49
2.20
1.83
1.56
1.18
1.52
1.82
1.33
1.21
1.64
1.69
1.15
2.33
1.73
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
T-SAIFI-s*
Average

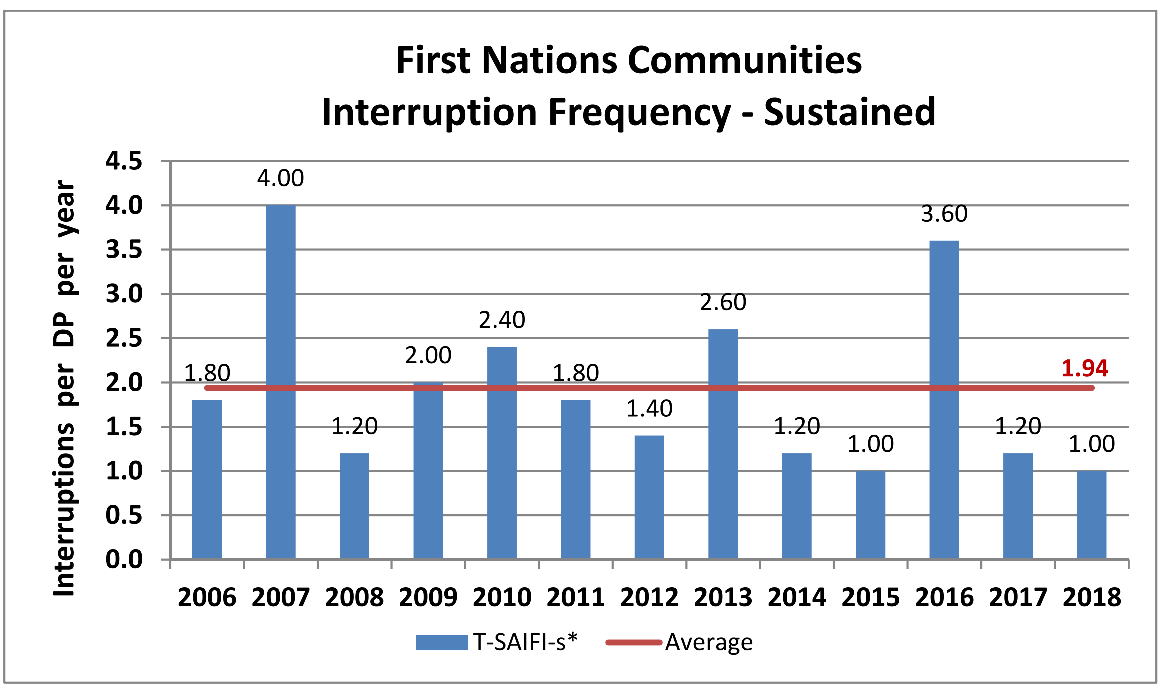

Northern System Interruption Frequency - Overall
Interruptions per DP per year
5.0
4.0
3.0
2.0
1.0
0.0
4.38
4.29
4.29
3.03
3.24
3.24
3.66
3.81
2.66
3.47
3.51
2.49
3.79
3.21
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
T-SAIFI-all*
Average

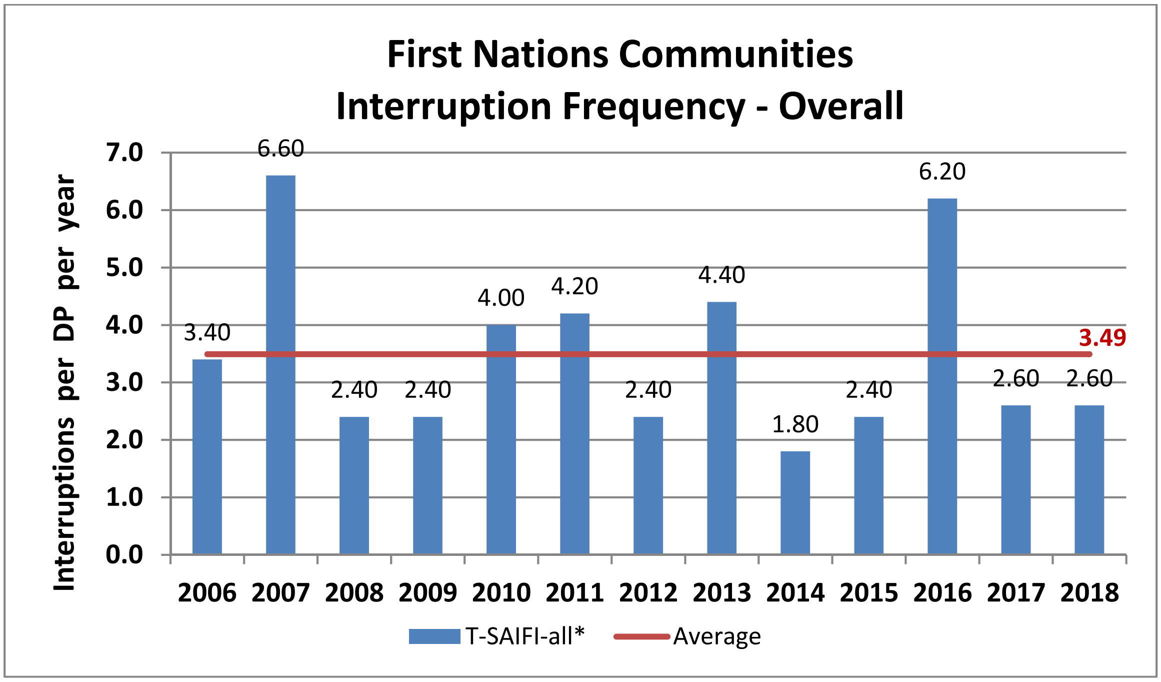

Northern System Average Interruption Duration
Minutes per DP per year
700
600
500
400
300
200
100
0
153.5
150.4
196.9
95.0
251.2
591.6
356.0
196.1
117.1
178.4
154.4
182.0
189.3
215.54
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
T-SAIDI*
Average

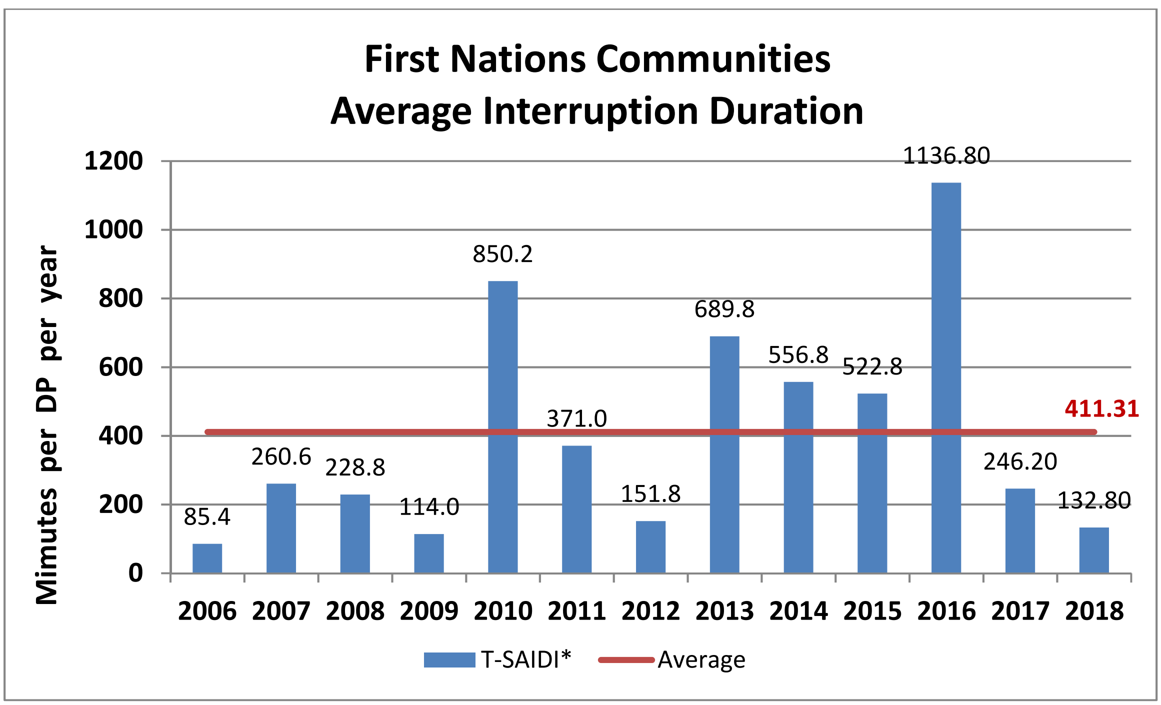

Northern System Delivery Point Unreliability Index
System Minutes
160
140
120
100
80
60
40
20
0
65.4
61.2
65.0
31.8
62.1
145.0
108.0
97.0
60.1
68.8
50.0
114.5
62.8
76.27
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
DPUI*
Average

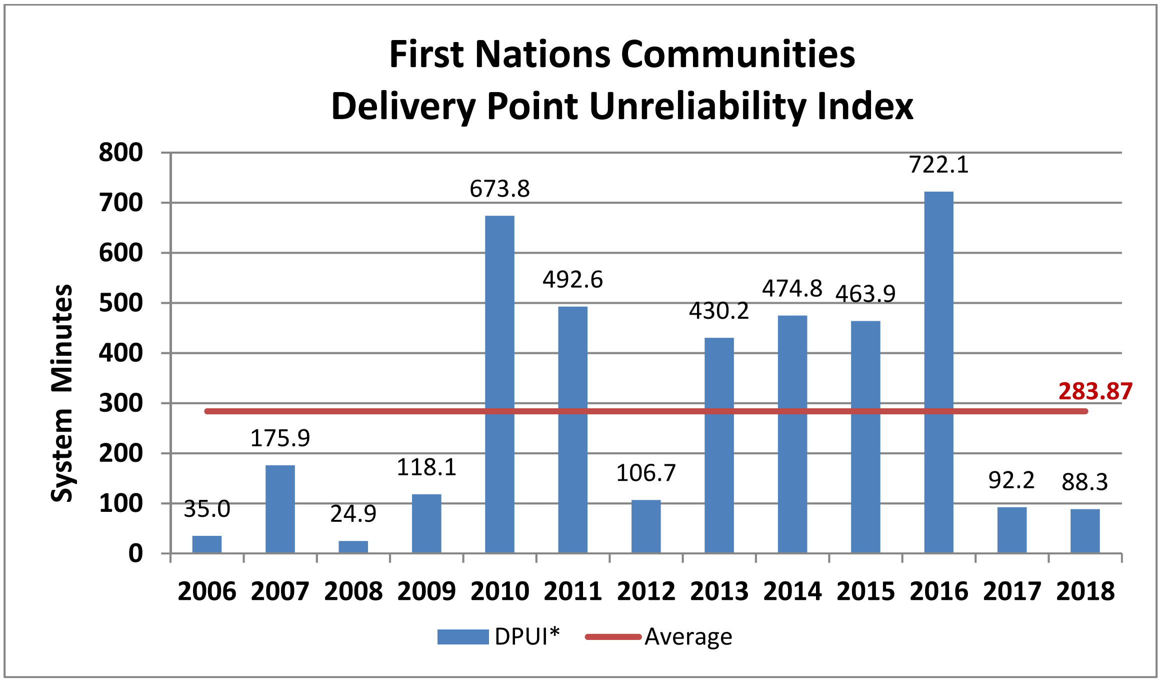
(2) The transmission system supplying certain First Nation communities (Beardmore DS #2, Long Lac TS, Moosonee DS, Nipigon DC, Red Rock DS)






First Nations Communities
Interruption Frequency - Overall
Interruptions per DP per year
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
3.40
6.60
2.40
2.40
4.00
4.20
2.40
4.40
1.80
2.40
6.20
2.60
2.60
3.49
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
T-SAIFI-all*
Average


First Nations Communities
Average Interruption Duration
Mimutes per DP per year
1200
1000
800
600
400
200
0
85.4
260.6
228.8
114.0
850.2
371.0
151.8
689.8
556.8
522.8
1136.80
246.20
132.80
411.31
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
T-SAIDI*
Average

1 
First Nations Communities
Delivery Point Unreliability Index
System Minutes
800
700
600
500
400
300
200
100
0
35.0
175.9
24.9
118.1
673.8
492.6
106.7
430.2
474.8
463.9
722.1
92.2
88.3
283.87
2006 2007 2008 2009 2010 2011 2012 2013 2014 2015 2016 2017 2018
DPUI*
Average

UNDERTAKING - JT 1.28

Reference:

I-09-Anwaatin-002

Undertaking:

With reference to Anwaatin IR 2, pages 9 to 11, to explain the disparity between First Nations communities' reliability data versus the general northern region reliability data; to explain the cause for the 2016, 2017, and 2018 numbers to be higher than in previous years; to explain the poor reliability in 2016.

Response:

The increased duration of interruptions in 2016 reflected in the graph on page 10 (First Nation Communities Average Interruption Duration) serving the five delivery points, Beardmore DS #2, Long Lac TS, Moosonee DS, Nipigon DC, Red Rock DS, was primarily driven by issues on circuit A4L impacting Longlac TS and Beardmore DS #2. The duration in 2016 was primarily impacted by two different insulator failure events on circuit A4L and a tree contact on circuit A4L during a snow storm. These two events contributed to 1074.8 minutes (94.5 %) of the total 1136.8 minutes in 2016.

The increased frequency in 2016 was driven primarily by multiple trips of the M3K on August 20 impacting Moosonee DS which was attributed to a faulty CPU card in the protections. This event, plus the aforementioned events on A4L, contributed to 1.8 interruptions (~30 %) of the total 6.2 interruptions in 2016. The other 4.4 interruptions (70%) are attributable to weather and momentary outages.

Witness: Bruno Jesus

UNDERTAKING - JT 1.29

Reference:
I-04-LPMA-009

Undertaking:
To advise whether the CEA does not include GTA flooding.

Response:
The GTA Flooding is excluded from the CEA, in all graphs.

Witness: Bruno Jesus

UNDERTAKING - JT 1.30

Reference:
I-06-EnvironmentalDefence-013

Undertaking:
To file an example of an analysis that assesses transmission losses and the benefits of mitigating those losses among the other aspects of HONI's purchase decisions.

Response:
As noted in Environmental Defence-07, Hydro One’s selection process for the purchase of new transformers and other equipment is based on comparing the effective equipment cost over its life cycle. These costs are calculated as follows:

Effective Equipment Cost = Initial Equipment Cost + Lifetime Cost of Losses

For example, in the purchasing process for transformers Hydro One requires the manufacturer to provide the equipment cost as well as both the guaranteed no-load loss (kW) at the rated voltage and the guaranteed load loss (kW) at base load rating for each transformer. For the purposes of the evaluation, Hydro One then is able to calculate the lifetime cost of losses by applying the dollar value per kW assigned to the losses as noted in the Exhibit J5.1 Attachment 1 (from EB-2016-0160) which is referenced in Environmental Defence-05. Thus the lifetime cost of losses is calculated as follows:

Lifetime Cost of Losses = {No-Load Loss (kW) x Cost ($/kW) of No-Load Loss}
+ {Load Loss (kW) x Cost ($/kW) of Load Loss}

This methodology ensures that the equipment with the lowest lifecycle cost is considered among the other aspects of Hydro One’s evaluation criteria of manufacturer submissions.

Below is an illustrative example based on a typical 75/125MVA, 230/44kV step down transformer to demonstrate the calculation above.

Transformer	Initial Equipment Cost*	No Load Losses	Cost of No Load Losses	Load Losses	Cost of Load Losses	Lifetime Cost of Losses	Effective Unit Cost
	A	B	C	D	E	F = (B x C) + (D x E)	=A + F
Unit #1	$2.0M	141.1 kW	$13,800/kW	42.5 kW	$5,200/kW	$2.2M	$4.2M
Unit #2	$1.8M	232.7 kW	$13,800/kW	72.2 kW	$5,200/kW	$3.6M	$5.4M
Unit #3	$2.2M	139.2 kW	$13,800/kW	38.0 kW	$5,200/kW	$2.1M	$4.3M

**Costs are for illustrative purposes only.*

Here Hydro One would select Unit #1 for purchase; assuming that the transformer manufacturer meets all technical requirements and all other aspects of the evaluation criteria. Unit # 2 with lower initial equipment cost and Unit #3 with lower lifetime cost of losses are not selected because of higher effective equipment cost over the life cycle.

UNDERTAKING - JT 1.31

Reference:
I-06-EnvironmentalDefence-005

Undertaking:
To explain the calculation of the lifetime cost of losses for new transformers in ED IR 7.

Response:
Please refer to Exhibit JT 1.30 for an explanation of the lifetime cost of losses calculation for new transformers as well as an illustrative example.

UNDERTAKING - JT 1.32

Reference:
N/A

Undertaking:
To provide two actual examples of the calculation of lifetime cost of losses, one example for transformers and another example for other equipment.

Response:
Please refer to Exhibit JT 1.30 for an explanation of the lifetime cost of losses calculation for transformers as well as an illustrative example.

Another example of equipment where lifetime cost of losses are used in making purchase decisions are shunt reactors; which are employed at Hydro One's transformer stations to maintain voltages within IESO specified limits. The shunt reactor does not carry load current so there are no load losses; otherwise the calculation is similar to transformers as noted above. Below is an illustrative example based on a 150MVAR, 500kV shunt reactor to demonstrate the calculation.

Shunt Reactor	Initial Equipment Cost*	No Load Losses	Cost of No Load Losses	Lifetime Cost of Losses	Effective Unit Cost
	A	B	C	F = (B x C)	=A + F
Unit #1	$2.5M	29.3 kW	$13,800/kW	$0.4M	$2.9M

**Costs are for illustrative purposes only.*

UNDERTAKING - JT 1.33

Reference:

N/A

Undertaking:

To make best efforts to provide three examples of evaluating the additional cost of increasing the conductor size versus the expected savings from transmission loss mitigation.

Response:

Table 5-6 of the EPRI report (Exhibit B-1-1, TSP Section 1.8, Attachment 1) provides loss mitigation potential information on a sample of nine transmission lines on Hydro One's system. The information outlines the In-Service Annual Losses in MWh (i.e. the estimated losses on the asset based on a year of typical loading), and the Efficient Annual Losses in MWh (i.e. the estimated losses of the same circuit under the same loading conditions with a more efficient conductor). Therefore the delta between the In-Service Annual Losses and Efficient Annual Losses represents the approximate Annual Loss Reduction in MWh. The potential annual savings can then be calculated by multiplying the Annual Loss Reduction by the energy price.

Below is an illustrative example based on three of the transmission lines taken from data in Table 5-6 assuming an annual average Hourly Ontario Energy Price ("HOEP") of $22.43 per MWh as published by the IESO[1].

Excerpt of Table5-6					**Annual Loss Reduction (MWh)**	**2018 Energy Price ($/MWh)**	**Potential Annual Savings**	**Cost* to Replace with Efficient Conductor**
Asset #	**Voltage (kV)**	**Line Length (km)**	**In-service Approx. Annual Losses (MWh)**	**Efficient Approx. Annual Losses (MWh)**				
			A	B	C = A-B	D	E = CxD	
2	500	208.7	63,185	48,772	14,413	22.43	$323.3K	$188M
4	115	40.0	3,000	2,617	383	22.43	$8.6K	$12M
8	230	116.8	14,442	13,752	690	22.43	$15.5K	$47M

**Costs are for illustrative purposes only.*

[1] http://reports.ieso.ca/public/PriceHOEPAverage/PUB_PriceHOEPAverage_2018_v1.xml

As illustrated, the potential annual savings are minimal in comparison with the cost of replacing the existing conductor with a more efficient conductor; and hence the conclusion by EPRI that no utility is pursuing loss mitigation projects solely based on the potential mitigated loss savings over the life cycle of the asset.

UNDERTAKING - JT 1.34

Reference:
I-06-EnvironmentalDefence-018
I-06-EnvironmentalDefence-019

Undertaking:
Re: IR18 and 19, to ask EPRI why they responded that they thought the questions were out of scope, and in particular question 18(b) and question 19 in its entirety.

Response:
Hydro One received the following response from EPRI:

> *"EPRI limits its role to conducting independent, objective scientific research and does not generally act in an advisory capacity. Therefore, we must decline to provide an opinion on what any person or organization should do in a given situation. We provide the underlying facts that may drive those decisions, but leave the policy judgment to those better suited to make it."*

UNDERTAKING - JT 1.35

Reference:

I-06-EnvironmentalDefence-025

Undertaking:

a) To consider the feasibility of the reporting requirements: to the extent it was feasible, explain why it is; if it's not feasible, then be clear as to why it could not be done,

b) To explain the potential benefits or lack thereof.

Response:

a) This question is in regards to Transmission Loss Reporting undertaken by National Grid in the UK[1] and the feasibility of Hydro One providing the same reporting. There are two parts to the reporting requirements identified in this report which are discussed herein.

Firstly, National Grid reports the Transmission Loss on the network by measuring the difference between the electric energy entering and leaving the transmission system. This reporting requirement is not feasible for Hydro One. As noted in Exhibit I, Tab 2, Schedule EnergyProbe-11 part (a), Hydro One does not track losses on the transmission system; and therefore does not have historical or forecast information. The losses are tracked by the Independent Electricity System Operator ("IESO"). The transmission losses for the Ontario Transmission System were about 1.82% for 2018 as provided by the IESO in EB-2019-0002 Exhibit C-5-1.

Secondly, National Grid's report identified projects that resulted in loss reduction. Identifying the loss reduction as a result of capital projects is feasible and Hydro One has provided the line loss reduction benefits resulting from its capital projects in Table 2 of Exhibit B-1-1, TSP Section 1.8. Furthermore, as noted in Exhibit I, Tab 6, Schedule EnvironmentalDefence-28, Hydro One has already committed to continue to document Hydro One's proposed capital plans that have line loss reduction benefit as part of its next rate application.

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[1] *National Grid Electricity Plc Special Condition 2K.4 – Transmission Losses Report Reporting Period 1 April 2014 to 31 March 2015*

b) From a Hydro One perspective, Hydro One is making every effort to reduce line losses by implementing best practices for loss mitigation as noted in the EPRI report (Exhibit B-1-1 TSP Section 1.8, Attachment 1). The reporting of the overall Transmission Loss on the network does not provide any guidance as to what Hydro One needs to do. Transmission losses depend largely on the power flow of the system and these are not within Hydro One's control. IESO manages the power flow by appropriately dispatching generation to meet the load requirement and therefore the potential benefits of these reporting requirements or lack thereof would be more appropriately addressed by the IESO. To that effect, as part of Settlement Proposal approved by the OEB in its Decision and Order in EB-2018-0143, the IESO has already committed to undertake work regarding transmission losses.

UNDERTAKING - JT 1.36

Reference:

APPRO Panel 4 questions

Undertaking:

To respond to APPRO's written technical conference questions for panel 4 provided by Mr. Vellone.

Response:

APPrO submitted two written questions (I2-APPrO-TC1 and I2-APPrO-TC2) at the Technical Conference dated August 12, 2019. Please refer to Exhibit JT1.36-Q01 and Exhibit JT1.36-Q02 for responses to these questions, respectively.

Witness: Clement Li

UNDERTAKING - JT 1.36 - Q1

<u>Reference:</u>
I2-APPrO-1
I-10-VECC-55

<u>Undertaking:</u>
Preamble:
In response to I2-APPrO-1, Hydro One filed a copy of the 2015 Elenchus cost allocation model in live excel format with information that was updated to calculate the ETS Rate of $1.25/MWh.

Hydro One also provided the following table summarizing the calculation of the $1.25/MWh in response to I2-APPrO-1:

			UTR Network Revenue Requirement				
ETS Allocated Revenue Requirement ($M)	Volume (GWh)	Rate ($/MWh)	Hydro One Total ($M)	Ontario Total ($M)	Escalation Factor	Ontario ETS Revenue Requirement ($M)	Ontario ETS Rate ($/MWh)
A	B	C=A/B	D	E	F=E/D	G=A X F	H=G/B
$22.1	18,800.0	$1.17	$977.6	$1,041.9	106.6%	$23.5	$1.25

Note: All revenue requirement amounts are based on Hydro One's proposed 2020 revenue requirement, as shown in Exhibit I2, Tab 4, Schedule 1, Table 1.

In response to I-10-VECC-55, Hydro One explained that:

> **<u>Response:</u>**
>
> a) The export volumes for 2020 to 2022 were calculated based on a three year rolling average of the prior year's amounts. The table below provides the export volumes for 2020 to 2022 period as used in the initial Application:

2015 Actual	2016 Actual	2017 Actual	2018 (2015 - 2017 Avg)	2019 (2016 - 2018 Avg)	2020 (2017- 2019 Avg)	2021 (2018- 2020 Avg)	2022 (2019- 2021 Avg)
23,138,052	22,157,981	19,346,599	21,547,544	21,017,374	20,637,172	21,067,364	20,907,304

> b) The same calculation as in part (a) was used for the Updated Application; however the data for 2018 was updated to reflect actual volumes. The table below provides the export volumes for 2020 to 2022 period as used in the Updated Application:

2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 (2016 - 2018 Avg)	2020 (2017- 2019 Avg)	2021 (2018- 2020 Avg)	2022 (2019- 2021 Avg)
23,138,052	22,157,981	19,346,599	18,771,464	20,092,015	19,403,359	19,422,279	19,639,218

a) In respect of I10-VECC-55, please explain the benefits of using a three-year rolling average to forecast export volumes.

b) Please confirm that Hydro One is forecasting 2020 export volumes in the Updated Application of 19,403,359 MWh, however Hydro One's calculation of the ETS Rate of $1.25/MWh assumes the allocated 2020 export revenue requirement of $22,080,665 is collected from an export volume of 18,800 GWh.

c) Please update the calculation of the ETS Rate assuming Hydro One's proposed 2020 export revenue requirement is collected from Hydro One's forecasted 2020 export volumes of 19,403,359 MWh. In connection with this update, please provide:

   a. the resulting ETS Rate,
   b. an update to the summary table that was provided in I2-APPrO-1 showing the values used for this scenario, and
   c. a revised version of the live excel version of the Elenchus cost allocation model updated to reflect this scenario.

d) Please update Hydro One's forecast of export volumes using a four-year rolling average methodology (rather than a three-year rolling average), and provide updated forecasts of export volumes for 2019, 2020, 2021, and 2022.

e) Please update the calculation of the ETS Rate assuming Hydro One's proposed 2020 export revenue requirement is collected from the forecast of 2020 export volumes calculated in response to part (d) above. In connection with this update, please provide:

   a. the resulting ETS Rate,
   b. an update to the summary table that was provided in I2-APPrO-1 showing the values used for this scenario, and
   c. a revised version of the live excel version of the Elenchus cost allocation model updated to reflect this scenario.

<u>Response:</u>

a) Normally, a three-year rolling average has the benefit that it captures the up and down fluctuations of prior years for a value being forecast. However, as shown in the response to Exhibit I, Tab 10, Schedule VECC-55 part (b), export volumes have been on a clear downward trend since 2015 and therefore the three-year average does not provide the best estimate of what the forecast exports will be in 2020.

b) Confirmed. For the purpose of cost allocation and rate design, Hydro One believes that an export volume of 18,800 GWh is the best estimate of export volumes in 2020.

c) The resulting ETS Rate assuming Hydro One's proposed 2020 export revenue requirement is collected from the forecasted 2020 export volumes using three-year rolling average of 19,403,359 MWh is $1.21/MWh.

Below is the updated table as requested:

			UTR Network Revenue Requirement				
ETS Allocated Revenue Requirement ($M)	**Volume (GWh)**	**Rate ($/MWh)**	**Hydro One Total ($M)**	**Ontario Total ($M)**	**Escalation Factor**	**Ontario ETS Revenue Requirement ($M)**	**Ontario ETS Rate ($/MWh)**
A	B	C=A/B	D	E	F=E/D	G=A X F	H=G/B
$22.1	19,403.4	$1.14	$977.6	$1,041.9	106.6%	$23.5	$1.21

A revised version of the live excel version of the Elenchus cost allocation model updated to reflect this scenario is provided as Attachment 1 to this undertaking.

d) The table below provides the requested information:

Export Volume Forecast using 4-year Rolling Average			
2019 Export MWh Forecast (2015 - 2018 Avg)	**2020 Export MWh Forecast (2016- 2019 Avg)**	**2021 Export MWh Forecast (2017- 2020 Avg)**	**2022 Export MWh Forecast (2018- 2021 Avg)**
20,853,524	20,282,392	19,813,495	19,930,219

e) The resulting ETS Rate assuming Hydro One's proposed 2020 export revenue requirement is collected from the forecasted 2020 export volumes using four-year rolling average of 20,282,392 MWh is $1.16/MWh.

Below is the updated table as requested:

			UTR Network Revenue Requirement				
ETS Allocated Revenue Requirement ($M)	**Volume (GWh)**	**Rate ($/MWh)**	**Hydro One Total ($M)**	**Ontario Total ($M)**	**Escalation Factor**	**Ontario ETS Revenue Requirement ($M)**	**Ontario ETS Rate ($/MWh)**
A	B	C=A/B	D	E	F=E/D	G=A X F	H=G/B
$22.1	20,282.4	$1.09	$977.6	$1,041.9	106.6%	$23.5	$1.16

A revised version of the live excel version of the Elenchus cost allocation model updated to reflect this scenario is provided as Attachment 2 to this undertaking.

UNDERTAKING - JT 1.36 - Q2

<u>Reference:</u>
I2-APPrO-1
Section 4.3.1 of the Elenchus Cost Allocation Methodology Report for the Export Transmission Service Rate (filed in EB-2014-0140, Exhibit H1-5-1 at Attachment 1) (the "Elenchus Report")

<u>Undertaking:</u>
Preamble:
In response to I2-APPrO-1, Hydro One filed a copy of the 2015 Elenchus cost allocation model in live excel formation with information that was updated to calculate the ETS Rate of $1.25/MWh.

In response to part (c) of I2-APPrO-1, Hydro One confirmed that:

> c) The 2015 Elenchus cost allocation model was updated using the latest available data, which consists of:
> - Fixed Assets dedicated to Exports (interconnections) as of 2017 year-end;
> - 12 CP Allocator based on the total of the 2018 monthly IESO domestic and export peak data;
> - Hydro One's actual 2018 export volume (MWh); and
> - IESO's average domestic volume (MWh) from 2016-2018 (inclusive).

a) Please confirm that in Section 4.3.1 of the Elenchus Report, Elenchus explored using both the 1 CP and 12 CP Allocator for cost allocation to exporters.

b) Please provide updates to Tables 1 and 2 shown in Section 4.3.1 of the Elenchus Report to demonstrate the difference in coincident peak values for 1 CP and 12 CP, as split between export, domestic, and total, for the three-year period 2016- 2018, as well as the three-year average over that period.

c) Please update the calculation of the ETS Rate by allocating Hydro One's proposed 2020 revenue requirement using the 1 CP Allocator, rather than the 12 CP Allocator. In connection with this update, please provide:
   a. the resulting ETS Rate,
   b. an update to the summary table that was provided in I2-APPrO-1 showing the values used for this scenario, and
   c. a revised version of the live excel version of the Elenchus cost allocation model updated to reflect this scenario.

d) Please update the calculation of the ETS Rate by combining the changes requested in I2-APPrO-TC1(c) and I2-APPrO-TC2(c) together in a single update. In connection with this update, please provide:
   a. the resulting ETS Rate,
   b. an update to the summary table that was provided in I2-APPrO-1 showing the values used for this scenario, and
   c. a revised version of the live excel version of the Elenchus cost allocation model updated to reflect this scenario.

e) Please update the calculation of the ETS Rate by combining the changes requested in I2-APPrO-TC1(e) and I2-APPrO-TC2(c) together in a single update. In connection with this update, please provide:
   a. the resulting ETS Rate,
   b. an update to the summary table that was provided in I2-APPrO-1 showing the values used for this scenario, and
   c. a revised version of the live excel version of the Elenchus cost allocation model updated to reflect this scenario.

f) Finally, please confirm that Hydro One is not using the 12 CP Allocator to allocate costs elsewhere in this Application to any other customers (i.e. other than in connection with the calculation of the ETS Rate). If not confirmed, please specify exactly where the 12 CP Allocator is being use and for what purpose.

g) For completeness of the evidentiary record, please file a copy of the Elenchus Report on the evidentiary record in this proceeding.

<u>Response:</u>

a) Confirmed.

b) The export and domestic 1CP and 12 CP in 2016, 2017 and 2018 are provided in the table below:

Table 1: Coincident peak 2016 to 2018

Coincident Peak	2016			2017			2018			Average		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
1CP	1,905	23,213	25,118	3,729	19,829	23,558	4,121	20,429	24,550	3,252	21,157	24,409
12CP	30,004	244,498	274,502	27,922	231,663	259,585	25,336	241,536	266,872	27,754	239,232	266,986

The 1 CP and 12 CP percentage allocators using 2016 to 2018 data are shown in the table below:

Table 2: Coincident peak %

	2018 Data			Average 2016-2018 Data		
Coincident Peak	**Total**	**Domestic**	**Export**	**Total**	**Domestic**	**Export**
1 CP	100	83.21	16.79	100	86.68	13.32
12 CP	100	90.51	9.49	100	89.60	10.40

c) Below is the requested information updated to reflect this scenario.

a. The resulting ETS Rate using the 1 CP Allocator, rather than the 12 CP Allocator to allocate Hydro One’s proposed 2020 revenue requirement is $1.71/MWh.

b. Below is the updated table as requested:

			UTR Network Revenue Requirement				
ETS Allocated Revenue Requirement ($M)	**Volume (GWh)**	**Rate ($/MWh)**	**Hydro One Total ($M)**	**Ontario Total ($M)**	**Escalation Factor**	**Ontario ETS Revenue Requirement ($M)**	**Ontario ETS Rate ($/MWh)**
A	B	C=A/B	D	E	F=E/D	G=A X F	H=G/B
$30.2	18,800.0	$1.61	$977.6	$1,041.9	106.6%	$32.2	$1.71

c. A revised version of the live excel version of the Elenchus cost allocation model updated to reflect this scenario is provided as Attachment 1 to this undertaking.

d) Below is the requested information updated to reflect this scenario.

a. The resulting ETS Rate using forecasted 2020 export volume based on a three-year rolling average and using 1CP Allocator together in a single update is $1.66/MWh.

b. Below is the updated table as requested:

			UTR Network Revenue Requirement				
ETS Allocated Revenue Requirement ($M)	**Volume (GWh)**	**Rate ($/MWh)**	**Hydro One Total ($M)**	**Ontario Total ($M)**	**Escalation Factor**	**Ontario ETS Revenue Requirement ($M)**	**Ontario ETS Rate ($/MWh)**
A	B	C=A/B	D	E	F=E/D	G=A X F	H=G/B
$30.2	19,403.4	$1.56	$977.6	$1,041.9	106.6%	$ 32.2	$1.66

c. A revised version of the live excel version of the Elenchus cost allocation model updated to reflect this scenario is provided as Attachment 2 to this undertaking.

e) Below is the requested information updated to reflect this scenario.

a. The resulting ETS Rate using forecasted 2020 export volume based on a four-year rolling average and using 1CP Allocator together in a single update is $1.59/MWh.

b. Below is the updated table as requested:

			UTR Network Revenue Requirement				
ETS Allocated Revenue Requirement ($M)	**Volume (GWh)**	**Rate ($/MWh)**	**Hydro One Total ($M)**	**Ontario Total ($M)**	**Escalation Factor**	**Ontario ETS Revenue Requirement ($M)**	**Ontario ETS Rate ($/MWh)**
A	B	C=A/B	D	E	F=E/D	G=A X F	H=G/B
$ 30.2	20,282.4	$1.49	$977.6	$1,041.9	106.6%	$32.2	$1.59

c. A revised version of the live excel version of the Elenchus cost allocation model updated to reflect this scenario is provided as Attachment 3 to this undertaking.

f) Hydro One does not explicitly use either 1 CP or 12 CP allocators as part of the cost allocation process, but as noted in Exhibit I1, Tab 1, Schedule 2 pages 6 and 9, Hydro One does use (i) customers' average monthly CP for splitting the cost of Dual Function Lines, and (ii) customers' annual non-coincident peak demand for splitting the cost of line and transformation connection assets to which generation is connected.

g) The Elenchus Report was put on record in EB-2014-0140 as Attachment 1 to Exhibit H1, Tab 5, Schedule 1 and a copy is provided as Attachment 4 to this undertaking as requested.

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Export Transmission Service Rate

Cost Allocation Methodology

Report Prepared by
Michael Roger
Elenchus Research Associates Inc.

On Behalf of HONI

May 7, 2014

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EXECUTIVE SUMMARY

This report presents Elenchus' recommendation on the cost allocation methodology that should be used to determine a cost-based Export Transmission Service rate in Ontario.

The recommended methodology should be based on:

- Using prior year actual hourly data for domestic and export customers,
- 12 CP should be the allocator used in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared OM&A expenses,
- Only dedicated assets used to serve export customers and the related costs should be allocated to the export customer class,
- OM&A expenses related to the use of shared assets should be allocated to export customers using composite assets as allocator,
- No external revenues should be allocated to the export customer class,
- The ETS rate should be based on HONI's OEB approved Network revenue requirement, as used in determining the Uniform Transmission Rates, marked-up to include other transmitters' approved revenue requirement as reflected in the Uniform Transmission Rates.

The proposed cost allocation methodology determines the ETS rate based on cost causality principles. Given the range of values calculated using 2013, 2015, 2016 data in the proposed methodology and the related scenario sensitivity results, a value between \$1.7/MWh and \$1.8/MWh for the ETS rate can be considered to be cost-based.

Based on the proposed 2015 and 2016 HONI financial data, Elenchus recommends an ETS rate of \$1.7 MWh be implemented for 2015 and that the ETS rate be maintained for at least 2 years to provide stability in determining the rate.

1 INTRODUCTION

Hydro One Networks Inc. ("HONI") retained Michael Roger of Elenchus Research Associates Inc. in order to develop a cost-based methodology to establish the Export Transmission Service ("ETS") rate.

In its Decision with Reasons dated June 6, 2013 on 2013 Export Transmission Service rates, (EB-2012-0031, Decision and Order, page 10), the Ontario Energy Board ("OEB") directed HONI to include a proposal of the appropriate cost-based ETS rate, with supporting rationale, to the OEB at its next transmission rates application.

More specifically the OEB stated on page 9 of its Decision with Reasons in Proceeding EB-2012-0031 that:

> *"The Board will require Hydro One to perform a cost allocation study to establish a cost basis for the ETS rate. Some parties have suggested that such a study would be prohibitively costly. However, the Board accepts the Elenchus testimony that a study could be properly scaled to address the magnitude of the issue and could be completed for a reasonable cost. The Board expects that this study will be completed in time for Hydro One's next cost of service transmission rate application. While Hydro One has the responsibility for completing this study, the Board expects that the IESO will assist Hydro One as required to fully address the ETS rate issue."*

This report presents the results of the cost-based methodology developed by Elenchus to establish the ETS rate.

This report is divided into 5 main sections. Section 2 provides a background on the evolution of the ETS rate from market opening in 2002 until now, section 3 presents the principles of cost allocation methodology, section 4 describes the proposed cost allocation methodology to determine the ETS rate, section 5 presents the results of applying the recommended methodology using 2013 proposed data and 2015 and 2016 proposed data and section 6 presents conclusions and recommendations to the OEB on the proposed cost allocation methodology and the ETS rate. Appendix A contains the CV for Michael Roger.

Michael Roger has been an expert dealing with cost allocation, rate design and rate regulation issues for over 35 years. Michael worked for over 32 years at Ontario Hydro, Ontario Power Generation and Hydro One and spent most of his career dealing with Cost Allocation and Rate Design issues for wholesale and retail electricity customers in Ontario. He has also testified on numerous occasions at OEB proceedings on behalf of utilities and other stakeholders and also has provided expert advice to the OEB in various task forces dealing with cost allocation and rate design issues. Michael's vast experience with Cost Allocation issues was applied in developing the cost-based cost allocation methodology to develop the ETS rate and forms the basis for Elenchus recommended methodology to the OEB.

2 BACKGROUND

In Proceeding RP-1999-0044 the OEB reviewed the issue of establishing an ETS rate to be implemented at market opening.

In its Decision with Reasons dated May 26, 2000, the OEB summarized the various arguments presented by stakeholders in this proceeding on what the ETS rate should be. The OEB decided that as an interim measure, the ETS rate should be fixed at $1/MWh. This was seen as a reasonable compromise between the competing interests and proposals presented by stakeholders in the proceeding on what was described as a complex and contentious issue. Among other things, the contention emerged from what stakeholders believed should be the basis of, or purpose of, the tariff design and what ought to be an appropriate charge level to help defray the costs to domestic customers for the use of the network transmission facilities to facilitate export and wheel-through transactions.

The OEB directed that HONI monitor and report at its next main rate submission how the export market was functioning and the developments in interconnected jurisdictions and whether the ETS rate should be reviewed.

HONI retained R. J. Rudden to do a "Jurisdictional Survey of Export and Wheel-through Service Rates". The survey was filed with the OEB on June 26, 2006 and was reviewed in proceeding EB-2006-0501.

As part of EB-2006-0501, the OEB approved a stakeholder settlement agreement which maintained the ETS rate of $1/MWh. In the agreement, the Independent Electricity System Operator ("IESO") was identified as the entity responsible for undertaking a study on the appropriate ETS rate. The settlement agreement stated that:

> *"...the IESO should now be identified as entity responsible to pursue and negotiate, with neighbouring jurisdictions, acceptable reciprocal arrangements with the intention to eliminate the ETS tariff, and study the appropriate ETS tariff, including those options identified in H1/T5/S1. The IESO will seek input from market participants and interested intervenors in this proceeding and keep the parties informed of the progress of negotiations and the study. It is agreed that the IESO will make its report available to the Board upon completion which will be no later than June 1, 2009 with the results of reciprocal arrangement negotiations and the study including recommendations for an appropriate ETS tariff. Hydro One Networks Inc. remains responsible for seeking changes to its approved transmission revenues and rates and will do so as part of the 2010 transmission rate-resetting process period, following the publishing of the study."*[1]

The IESO retained Charles River Associates ("CRA") to do a quantitative analysis of the future effect of several export rate scenarios, with respect to exports and wheel-through volumes, ETS tariff revenue, and the Hourly Ontario Energy Price. The IESO's ETS study and recommendation was filed with the OEB on August 28, 2009 and was reviewed in proceeding EB-2010-0002. The IESO study reviewed four alternatives for setting the ETS rate:

1. Status Quo;
2. Equivalent average network charge;
3. Reciprocal treatment, and
4. Elimination.

[1] EB-2006-0501, Exhibit M, Tab I, Schedule 1, page 17, April 3, 2007

The IESO recommended the status quo alternative to the OEB.

In the Decision with Reasons in proceeding EB-2010-0002, page 75, the OEB concluded that an additional study was required. The OEB stated that:

> *"The Board concludes therefore that the most pressing requirement is that a genuinely comprehensive study be undertaken to identify a range of proposed rates and the pros and cons associated with each proposed rate in time for the next transmission rate application. In the Board's view, the most appropriate party to undertake this study is the IESO. In procuring the study, the IESO should circulate the terms of reference to the Applicant and the intervenors of record in this case with a view to ensuring that the resulting study will provide detailed analysis on the issues.*
>
> *This review of the terms of reference is not intended to be a strategic negotiation, but rather a technical exercise to ensure that the scope of the project is sufficiently broad and well-defined to ensure a useful and appropriate outcome. Work on this study should begin soon, to ensure completion well in advance of the time for the filing of the next transmission rates application by Hydro One."*

The OEB in the same proceeding increased the ETS rate to $2/MWh, providing the following rationale:

> *"Accordingly, the Board will direct that a change be made to the ETS rate for 2011 and 2012, increasing the rate to two dollars per MWh. In making this change the Board seeks to recognize the directional preference of the CRA study, and the absence of any particular analytical underpinning for the current rate. Subsequent panels assessing the level of this rate should not, however regard this new rate as having any particular precedential value. It is the Board's view that the new rate has more analytical support than the status quo, but that in order to arrive at a genuinely robust and valid rate, more study is required."*

In response to the OEB directive, the IESO engaged CRA to conduct a further review of the ETS rate. CRA reviewed the tariff and structures in neighbouring markets and assessed five proposed rate options against generally accepted rate making principles (consistency, simplicity, fairness and efficiency). The rate options considered were:

1. Status Quo
2. Elimination

3. Equivalent average network charge
4. Tiered rates (two alternatives)

The CRA study was filed and reviewed in proceeding EB-2012-0031.

In the IESO's submission to the OEB, the IESO indicated that none of the ETS tariff options materially impact reliability, but elimination of the tariff would best promote efficient operation of the wholesale electricity market.

As stated in the introduction in this report, the OEB directed HONI in proceeding EB-2012-0031 to develop a cost-based methodology to determine the ETS rate.

3 PRINCIPLES OF COST ALLOCATION

In order to determine cost-based rates, a cost allocation study is performed by a utility to fairly allocate shared assets and expenses to the customer groups served by the utility.

The cost allocation study is based on actual historical or forward looking test year data and reflects the operating circumstances of the utility at a particular point in time, either the last year for which actual historical information is available, or for the future test year for which rates are being established.

Traditionally three steps are followed in a cost allocation study: Functionalization, Categorization or Classification, and Allocation.

Assets and expenses that are identified with a particular customer class and that are not shared with other customer classes are "Directly" allocated to that particular customer class.

Functionalization of assets and expenses is the process of grouping assets and expenses of a similar nature, for example, generation, high voltage transmission, customer service, meter reading, etc. Hence, as a first step in a cost allocation study, the function(s) served by the assets or expenses of the utility are identified so that costs can be attributed appropriately to the identified functions.

Categorization or Classification is the process by which the functionalized assets and expenses are classified as energy, demand and/or customer related. Hence, the costs associated with each function are attributed to these categories based on the principle that the quantum of costs is reflective of the quantum of volume, system demand, or number of customers.

Allocation, which is the final step, is the process of attributing the energy, demand, and customer related assets and expenses to the customer classes being served by the utility. This allocation is accomplished by identifying allocators related to energy, demand, or customer counts that are reflective of the relationship between different measures of these cost drivers and the costs that are deemed to be caused by each customer class.

It is in this Allocation step that customers are grouped based on common characteristics, or utility asset utilization reflecting cost causality.

4 PROPOSED COST ALLOCATION METHODOLOGY

Elenchus proposes a cost allocation methodology to determine the ETS rate that is based on cost causality, is simple and follows the traditional three steps of a cost allocation methodology.

Elenchus looked at how transmission assets are being used to sell electricity, either to domestic customers of to neighbouring jurisdictions by exporters.

In Ontario generators do not pay for the use of the transmission system when they inject power into the grid in order to supply domestic electricity needs. Elenchus applied this same principle when evaluating the interconnected assets with neighbouring jurisdictions used by exporters. The interconnected assets are used to both export and import power and since generators in Ontario do not pay for the use of the transmission assets and the ETS rate is not applied to power imported into Ontario, Elenchus assumed that importers would also continue to not be charged for the use of the transmission system.

The proposed methodology considered the sale of electricity to domestic customers and neighbouring jurisdictions, not how the electricity was sourced and made available to satisfy sales.

HONI's 2013 transmission assets and revenue requirements were used in developing the recommended approach.

The proposed cost allocation methodology to determine the ETS rate reflects the interruptible nature of exports. The basis for treating exports as interruptible loads is found in the OEB's Decision with Reason in proceeding EB-2012-0031 that on page 5 states that:

> *"First, whether curtailments originate from generation issues or transmission issues, the Board agrees that export service does not receive the same priority access as domestic service. The Board accepts that the market rules treat exporters more as an interruptible load. This difference in treatment related to generation capacity has consequences for the overall service, even if export transmissions rights are technically as firm as domestic transmission rights. As a result, the Board finds that it may be appropriate for the export service to be* viewed as a separate class."

This has implications for how costs are allocated, as discussed in Section 4.3.

4.1 FUNCTIONALIZATION

In consultation with HONI, Elenchus determined that the assets and expenses associated with export activities can be found in the following HONI's transmission functions:

- Network (500 kV, 230 kV, and 115 kV lines)
- Dual Function lines (Network portion)
- Generation Line Connection
- Generation Transformation Connection
- Common (telecommunication equipment, control centre)
- Other (facilities not allocated to other functions under normal operating conditions)

These functions include dedicated and shared assets, and related expenses used by domestic and export customers.

The remaining functions used by Hydro One Transmission in determining its revenue requirement (e.g. transformation, line connection, line connection portion of dual function lines) are considered to be used only by domestic customers.

External revenues were also considered in the development of the cost allocation methodology. These revenues result mainly from secondary land use in right of ways and from providing maintenance services to other entities. These revenues are the result of using HONI's assets which have been designed to serve domestic customers only, therefore, no external revenues are proposed to be allocated to export customers.

4.2 CLASSIFICATION

Generally in costs allocation, transmission assets and expenses are classified as demand related. Transmission assets are designed to meet the maximum demand imposed by users of the system. Based on the functions evaluated, it was determined that the assets and expenses considered in the development of the ETS rate methodology are all demand related. There are no energy related or customer related assets and expenses.

4.3 ALLOCATION

In the cost allocation methodology developed to determine the ETS rate two customer groups are considered: domestic and export.

Assets dedicated to domestic customers are assets that only serve to connect Hydro One customer's load to the network.

Assets dedicated to interconnect (export) are assets that only serve to connect to another transmission utility.

Shared assets are those that serve both domestic and export customers, including assets associated with generation connection.

As export is considered to be interruptible service, no asset related costs associated with shared assets are proposed to be allocated to the export customer class.

This is considered appropriate because, as confirmed by Hydro One staff, HONI's planning of the Network transmission system does not take into consideration the capacity needed to supply export customers, transmission planning is only based on the capacity needs of domestic customers.

The assets dedicated to serve export customers have been directly allocated to the export customer class as well as the related expenses.

The OM&A expenses related to the use of shared assets have been allocated between domestic and export customers using the allocators described below.

4.3.1 Coincident Peak Allocator

In cost allocation, the allocation of demand related assets that are closest to the customer are allocated based on the non-coincident demand of the customer. The required assets are sized reflecting the maximum customer electricity demand.

Further away from the customer and closer to the generation system, it is the aggregate electricity demand of all customers, and not the sum of the individual customer demands, that determines the size of the facilities required to satisfy customers' electricity needs. In cost allocation, when apportioning assets and expenses further away from the customer (e.g. generation, transmission) and closer to the generation of electricity, it is the coincident demand that is used as an allocator, reflecting the criteria used to size the required assets.

Using 2010, 2011 and 2012 actual hourly load data for domestic and export customers from the IESO, coincident peak ("CP") allocators were developed.

Coincident peak is the hourly demand of domestic and export customers at the hour of maximum demand in the Ontario electricity system.

1 CP is the demand for each customer class at the hour of maximum system demand in a year. 12 CP is the average of the demand for each customer class at the hour of each month's maximum system demand.

1 CP or 12 CP are used by utilities in cost allocation studies to apportion generation and transmission costs amongst customer groups.

The following table includes the values developed for coincident peak.

Table 1

Coincident peak 2010 to 2012

	2010			2011			2012			Average		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
1CP	2,687	25,048	27,735	2,549	25,450	27,999	2,179	24,636	26,815	2,472	25,045	27,516
12CP	30,897	255,485	286,382	31,343	250,819	282,161	28,164	251,842	280,006	30,134	252,715	282,850

The 1 CP and 12 CP percentage allocators using 2010 to 2012 data are show in the table below

Table 2

Coincident peak %

	2012 Data			Average 2010 – 2012 Data		
Coincident Peak	Total	Domestic	Export	Total	Domestic	Export
1 cp	100.00	91.87	8.13	100.00	91.02	8.98
12 cp	100.00	89.94	10.06	100.00	89.35	10.65

The 1 CP and 12 CP values for the period 2011 to 2013 using actual hourly data are shown in the table below.

Table 3

Coincident peak 2011 to 2013

	2,011			2,012			2,013			Average		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
1CP	2,549	25,450	27,999	2,179	24,636	26,815	1,952	24,927	26,879	2,227	25,004	27,231
12CP	31,343	250,819	282,161	28,164	251,842	280,006	30,240	255,417	285,657	29,916	252,692	282,608

The 1 CP and 12 CP percentage allocators using 2011 to 2013 data are show in the table below

Table 4

Coincident peak %

	2013 Data			Average 2011 – 2013 Data		
Coincident Peak	Total	Domestic	Export	Total	Domestic	Export
1 cp	100.00	92.74	7.26	100.00	91.82	8.18
12 cp	100.00	89.41	10.59	100.00	89.41	10.59

Elenchus recommends that 12 CP should be used to allocate shared assets between domestic and export customers using the last year for which information is available.

When system loads are relatively flat and do not show a pronounced yearly peak, 12 CP is usually used by utilities to allocate demand related assets and expenses. In instances where there is a significant yearly peak compared to other peaks in the year, that is a very peaky load profile with low load factor, then 1 CP would be used to allocate demand related assets and expenses.

In Proceeding RP-1999-0044, the OEB reviewed allocators that could be used to recover Network assets and expenses and recommended against the use of non-coincident peak and settled on the use of coincident peak. With respect to using 1 CP, in paragraph 3.4.27 of the OEB Decision it states that:

> *"A rate design aimed at customer demand reduction during the system's coincident peak hours would meet the test of economic efficiency, but only if the network transmission system is generally capacity-constrained. This is not the case for the OHNC [Hydro One] network transmission system either today or in the foreseeable future."*

12 CP is used by HONI in apportioning assets and expenses when allocating Dual Function Line assets, (Proceeding EB-2012-0031, Exhibit G1, Tab 2, Schedule 1, pages 110-111).

4.3.2 COMPOSITE ALLOCATORS

The asset functions identified in section 4.1 were apportioned between domestic and export customers using the 12 CP allocator based on 2012 actual hourly data in order to develop composite allocators used to allocate shared OM&A expenses to domestic and export customer classes.

The OM&A expenses related to the identified shared functions were allocated in the cost allocation methodology to domestic and export customers using Net Shared Assets as composite allocators. Table 5 includes the percentage allocation of the composite allocators to the two customer classes based on 12 CP.

Table 5

Composite Allocators using 2012 actual hourly data

	Total	Domestic	Export
Net Shared Assets	**100.00%**	**92.89%**	**7.11%**
Dedicated to Domestic	**100.00%**	**100.00%**	**0.00%**
Dedicated to Interconnect	**100.00%**	**0.00%**	**100.00%**

Using 2013 actual domestic and export hourly data, the composite allocators are included in the following tables based on 12 CP and the 2015 and 2016 financial data.

Table 6

Composite Allocators using 2013 actual hourly data for 2015

	Total	Domestic	Export
Net Shared Assets	100.00%	92.74%	7.26%
Dedicated to Domestic	100.00%	100.00%	0.00%
Dedicated to Interconnect	100.00%	0.00%	100.00%

Table 7

Composite Allocators using 2013 actual hourly data for 2016

	Total	Domestic	Export
Net Shared Assets	100.00%	92.79%	7.21%
Dedicated to Domestic	100.00%	100.00%	0.00%
Dedicated to Interconnect	100.00%	0.00%	100.00%

5 ETS RATE RESULTS

The results of applying the proposed cost allocation methodology to develop a cost-based ETS rate are shown below.

The proposed cost allocation methodology was developed using 2012 actual hourly load data and 2013 proposed HONI financial data as submitted in proceeding EB-2012-0031.

The model was run again with 2013 actual hourly load data and the proposed 2015 and 2016 financial data being submitted by HONI at its rate submission.

5.1 USING 2012 LOAD DATA AND 2013 HONI PROPOSED FINANCIAL DATA

5.1.1 BASE CASE ETS RATE

The base case result for developing the ETS rate using the proposed cost allocation methodology is based on the following assumptions:

- Shared Assets are apportioned using 2012 actual hourly data between domestic and export customers using the 12 Coincident Peak method in order to develop the composite allocators to be used to allocate shared expenses
- Only dedicated assets used to serve export customers and related expenses are being allocated to export customers
- No asset related costs associated with shared assets are allocated to export customers
- Shared OM&A expenses are allocated between domestic and export customers based on composite allocator of Net Shared Assets
- No External revenue credit is allocated to export customers
- HONI's proposed 2013 data, (Assets and Expenses), as submitted in proceeding EB-2012-0031 were used to develop the ETS rate based on the proposed cost allocation model.

Using HONI's export sales forecast for 2013, the resulting ETS rate is $1.77/MWh.

5.1.2 ETS RATE INCLUDING OTHER TRANSMITTERS' REVENUE REQUIREMENT

The hourly data used from the IESO reflect all transmission electricity sales in Ontario, not just Hydro One's, while the financial assets and expense data used in developing the cost allocation methodology reflects only Hydro One's data. Marking-up the calculated ETS rate to reflect other transmitters approved Network revenue requirement would result in consistency between the sales data and the financial data, both of which would reflect all transmitters in Ontario.

As seen in the 2014 Uniform Transmission Rates, HONI's Network function revenue requirement is $882.9 million. The revenue requirement for all Ontario transmitters is $912.8 million, or 3.4% higher than HONI's revenue requirement.

Increasing the ETS rate of $1.77/MWh by 3.4%, results in an ETS rate of $1.83/MWh. This higher ETS rate would take into account the revenue requirement of all transmitters in Ontario.

5.1.3 SCENARIOS

The following scenarios were run in order to determine the results sensitivity of the proposed cost allocation methodology to various assumptions.

Table 8 Scenarios (2012 load data)

Scenario	Description	ETS rate ($/MWh)[2]
1	Same as Base case, but using 12 CP average of 3 years (2010 to 2012)	1.82
2	Same as Base case, but using 1 CP (2012)	1.59
3	Same as Base case, but using 1 CP average of 3 years (2010 to 2012)	1.67
4	Same as Base case, but allocation $0.16M External Revenue credit to Export customers	1.76
5	Allocating only shared OM&A costs to Export customers, no dedicated export assets allocated to Export[3]	1.22
6	Allocating to Export customers same Network function assets and expenses as Domestic customers, $1.43M External Revenue credit, using 12 CP (2012)[4]	4.73

5.2 USING 2013 LOAD DATA AND 2015 AND 2016 HONI PROPOSED FINANCIAL DATA

5.2.1 BASE CASE ETS RATE

The same assumptions described in section 5.1.2 are used in developing the ETS rate:

- Shared Assets are apportioned using 2013 actual hourly data between domestic and export customers using the 12 Coincident Peak method in order to develop

[2] Using HONI 2013 export sales forecast
[3] Assuming exporters do not pay for dedicated assets and related expenses
[4] Assuming export is treated as firm load, similar to domestic load

the composite allocators to be used to allocate shared expenses to domestic and export customer classes

- Only dedicated assets used to serve export customers and related expenses are being allocated to export customers
- No asset related costs associated with shared assets are allocated to export customers
- Shared OM&A expenses are allocated between domestic and export customers based on composite allocator of Net Shared Assets
- No External revenue credit is allocated to export customers
- HONI's proposed 2015 and 2016 data, (Assets and Expenses), as submitted in this proceeding are used to develop the ETS rate based on the proposed cost allocation model.

Using HONI's 2015 and 2016 export sales forecast, the resulting ETS rate is $1.63/MWh for 2015 and $1.62/MWh for 2016.

5.2.2 ETS Rate Including Other Transmitters' Revenue Requirement

In HONI's proposed 2015 and 2016 Uniform Transmission Rates, HONI's Network function revenue requirements are $933.6 million and $972.0 million respectively. The revenue requirements for all Ontario transmitters are $963.0 million, and $1,001.3 million for 2015 and 2016, or 3.2% and 3.0% higher than HONI's proposed revenue requirements.

Increasing the 2015 ETS rate of $1.63/MWh by 3.2%, and the 2016 ETS rate of $1.62/MWh by 3.0% results in ETS rate of $1.68/MWh for 2015 and $1.67/MWh for 2016. This higher ETS rates would take into account the revenue requirements of all transmitters in Ontario.

5.2.3 Scenarios

The following scenarios were run in order to determine the results sensitivity of the proposed cost allocation methodology to various assumptions.

Table 9 Scenarios (2013 load data)

Scenario	Description	ETS rate 2015 ($/MWh)[5]	ETS rate 2016 ($/MWh)[6]
1	Same as Base case, but using 12 CP average of 3 years (2011 to 2013)	1.63	1.62
2	Same as Base case, but using 1 CP (2013)	1.34	1.33
3	Same as Base case, but using 1 CP average of 3 years (2011 to 2013)	1.42	1.41
4	Same as Base case, but allocation $0.12M External Revenue credit to Export customers	1.62	1.61
5	Allocating only shared OM&A costs to Export customers, no dedicated assets allocated to Export [7]	1.15	1.13
6	Allocating to Export customers same Network function assets and expenses as Domestic customers, $1.3M External Revenue credit, using 12 CP (2013)[8]	4.84	4.88

6 CONCLUSIONS AND RECOMMENDED METHODOLOGY

The results of the proposed cost allocation methodology to develop a cost-based ETS rate and the sensitivity scenarios run using 2010 to 2012 load data show a Base Case result of $1.77/MWh and a range for the ETS rate between $1.22/MWh to $1.82/MWh

[5] Using HONI 2015 export sales forecast
[6] Using HONI 2016 export sales forecast
[7] Assuming exporters do not pay for dedicated assets and related expenses
[8] Assuming export is treated as firm load, similar to domestic load

for scenarios 1 to 5. The financial data is based on HONI's 2013 proposed data and excludes other transmitter's revenue requirement.

Using hourly load data for the period 2011 to 2013 and financial data for HONI as proposed for 2015 and 2016, the Base Case result for the ETS rate for 2015 is $1.63/MWh and for 2016 is $1.62/MWh. The range for the ETS rate is between $1.13/MWh to $1.63/MWh for scenarios1 to 5. The financial data excludes other transmitter's revenue requirement.

It is Elenchus' recommendation that the cost allocation methodology to be used to develop the ETS rate should be based on:

- Using the last year of actual hourly data for domestic and export customers. Forecast domestic and export hourly data is not available either from HONI or IESO,
- 12 CP should be the allocator used in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared expenses.
- Only dedicated assets used to serve export customers and related expenses should be allocated to the export customer class,
- No asset related costs associated with shared assets should be allocated to export customers
- Expenses related to the use of shared assets should be allocated to export customers using composite assets as allocator,
- No External revenues should be allocated to the export customer class, and
- The ETS rate should be based on HONI's OEB approved Network revenue requirement, as used in determining the Uniform Transmission rate, marked up to include other transmitters' approved revenue requirement as reflected in the Uniform Transmission Rates.

The proposed cost allocation methodology provides a supporting basis for determining the ETS rate based on cost causality principles. Given the range of values calculated using 2013, 2015, 2016 data and the related scenario sensitivity results, a value between $1.7/MWh and $1.8/MWh for the ETS rate can be considered to be cost-based.

Based on the proposed 2015 and 2016 HONI financial data, Elenchus recommends an ETS rate of $1.7 MWh be implemented for 2015 and that the ETS rate be maintained for at least 2 years to provide stability in determining the rate.

APPENDIX A - CV MICHAEL ROGER

MICHAEL J. ROGER

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ASSOCIATE, RATES AND REGULATION

Michael has over 35 years of experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**
Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors, with particular emphasis in electricity rates in Ontario and the regulatory review and approval process for cost allocation and rate design. Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, Veridian, APPrO and Hydro 2000.

Hydro One Networks Inc. **2002 - 2010**
Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system. Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB). Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design. Keep up to date on Cost Allocation and Rate Design issues in the industry. Ensure deliverables are of high quality, defensible and meet all deadlines.

Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. 1999 - 2002

Manager, Management Reporting and Decision Support, Corporate Finance

- In charge of producing weekly, monthly, quarterly and annual internal financial reporting products. Input to and coordination of senior management reporting and performance assessment activities. Expert line of business knowledge in support of financial and business planning processes. Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature. Provide support to other units as necessary. Work as a team member of the Corporate Finance function.

Ontario Hydro 1998 - 1999

Acting Director, Financial Planning and Reporting, Corporate Finance

- In charge of the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company. Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting , Corporate Finance 1997

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy. Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company. Supervise professional staff supporting the function. Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing 1986 - 1997

- In charge of pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.

- The section was also responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head, (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers. Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro. Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates. Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant. Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity. Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System. Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board. Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecasting Analyst, Financial Forecasts **1980 - 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.

- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget. Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation¬.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 - 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.

UNDERTAKING - JT 1.37

Reference:
N/A

Undertaking:
To provide the number of unplanned outage hours due to equipment failure system-wide, for 2016, 2017, and 2018.

Response:
The number of unplanned outages hours due to equipment failure system-wide for 2016, 2017 and 2018 is as follows:

Year	Hours
2016	262,777
2017	255,116
2018	289,532

Witness: Bruno Jesus

UNDERTAKING - JT 2.1

Reference:
I-01-0EB-202, part b)
I-07-SEC-058

Undertaking:
The table provided in staff IR 202 that compares pension costs on a cash and accrual basis, why don't those numbers tie to the 2014 to '22 compensation table that was provided in sec staff IR 58. If they are not supposed to tie out, please explain why that is the case.

Response:
The table provided in Staff-202, part b) reflects pension costs included or requested in rates for pre-2013 and 2013-2020 years.

The compensation table in SEC-058 reflects actual incurred pension expense from 2014-2018.

Therefore, the figures will not match.

Witness: Sabrin Lila, Samir Chhelavda

UNDERTAKING - JT 2.2

Reference:
I-01-OEB-203, part b)

Undertaking:
To show the calculation of the $78 million in pensions and tie it to the report provided with staff IR 205, part a, attachment 1.

Response:
The $78 million employer pension contributions can be found in the Hydro One Inc. (“Hydro One”) Projected 2018-2023 Benefit Cost Under FASB ASC 715-20-50 forecast which was provided in OEB-205 Attachment 1- Appendix A.1 on page 14 of 21.

2020 Projections year column, section B – Change in Plan Assets, line Employer contributions of $77,733 (figures in $000s).

The table below presents the relevant section from the referenced attachment 1 of staff IR 205:

Hydro One Pension Plan **APPENDIX A.1**

Projected 2017 to 2023 Accounting Under US GAAP

Figures in $000s

	Projections						
	2017	2018	2019	2020	2021	2022	2023
A Change in Projected Benefit Obligation							
PBO at prior fiscal year end	7,774,406	8,213,084	8,394,273	8,580,528	8,770,446	8,962,687	9,156,596
Employer service cost (BOY)	146,693	172,035	177,593	181,720	184,595	186,993	191,265
Interest cost	303,616	281,384	287,646	294,016	300,467	306,972	313,618
Actuarial(gains)/losses	280,032	-	-	-	-	-	-
Plan Participants' contributions	46,587	53,977	55,588	56,410	57,242	57,894	58,978
Benefits Paid	(338,250)	(326,207)	(334,572)	(342,228)	(350,063)	(357,950)	(365,545)
Transfer from (to) other plans	-	-	-	-	-	-	-
Curtailments	-	-	-	-	-	-	-
Settlements	-	-	-	-	-	-	-
Special/contractual termination benefits	-	-	-	-	-	-	-
PBO at current fiscal year end	8,213,084	8,394,273	8,580,528	8,770,446	8,962,687	9,156,596	9,354,912
B Change in Plan Assets							
Fair value of assets at prior year end	6,874,425	7,358,364	7,631,813	7,918,180	8,218,014	8,531,202	8,858,138
Expected return on plan assets	441,393	471,846	489,467	507,919	527,215	547,364	568,469
Actual gains/(losses) on assets	261,414	-	-	-	-	-	-
Employer contributions	72,795	73,833	75,884	77,733	78,794	79,628	81,655
Plan Participants' contributions	46,587	53,977	55,588	56,410	57,242	57,894	58,978
Benefits paid	(338,250)	(326,207)	(334,572)	(342,228)	(350,063)	(357,950)	(365,545)
Transfer from (to) other plans	-	-	-	-	-	-	-
Settlements	-	-	-	-	-	-	-
Special/contractual termination benefits	-	-	-	-	-	-	-
Fair value of assets at current fiscal year end	7,358,364	7,631,813	7,918,180	8,218,014	8,531,202	8,858,138	9,201,695

Witness: Samir Chhelavda

UNDERTAKING - JT 2.3

Reference:
I-01-OEB-205
I-01-OEB-221, part b)

Undertaking:
To provide an OPEB amount sought for 2020 using the table and data in the application.

Response:
Below please find the reconciliation between the OPEB amounts included in rates for 2020 as provided in Exhibit F, Tab 5, Schedule 1 Table 3 titled "OPEB Costs Included in Rates" and the Willis Towers Watson report dated December 13, 2017 detailing the projected benefit cost for 2020 (filed as Attachment 1 in the response to Staff-205):

OPEBs: $M	Transmission	Other	2020
Amounts included in rates:			
OM&A	16	26	42
Capital (Service Cost)	18	13	31
OPEB Deferral Account (non-service cost)	21	15	36
Capital + OPEB Deferral Account	39	28	67
Total OPEB	**55**	**54**	**109**
Willis Towers Watson forecast 2020:	**$K**		**$M**
Appendix A.2: Supplemental Plan **D:** Disclosed Benefit Cost	7,532		8
Appendix B.3: Non-Pension Post Retirement Benefit **D:** Disclosed Benefit Cost	92,032		92
Appendix B.4: Post Employment Benefits **D:** Disclosed Benefit Cost	9,289		9
Total OPEB for 2020	**108,853**		**109**

UNDERTAKING - JT 2.12

Reference:

I-01-OEB-196
I-07-SEC-055
KT2.1

Undertaking:

To reconcile the difference in the FTES.

Response:

The reference to 99% in Exhibit I-01-OEB-196 part a) should state that the table accounts for 90% of the FTE changes. The remaining 10% reflect fluctuations in FTE levels amongst the various business units.

UNDERTAKING - JT 2.13

Reference:
I-07-SEC-047

Undertaking:
To provide the Q2 number; to break down the number by categories.

Response:
The total year-to-date OM&A for Hydro One Limited's Transmission (Tx) segment as at June 30, 2019 is $200 million. Hydro One Limited's Tx segment includes Hydro One Networks Tx, Hydro One Sault Ste. Marie LP and Hydro One Limited's interest in Bruce-to-Milton LP. Hydro One is unable to provide any further detailed disclosure on year-to-date OM&A due to securities legislation relating to selective disclosure.

UNDERTAKING - JT 2.19

Reference:
I-12-AMPO-035

Undertaking:
To explain the calculation of the vehicle utilization rate, giving an example.

Response:
The details of how Utilization Rate is calculated are indicated in the table below.

in $ millions, u.o.s.	**2015**	**2016**	**2017**	**2018**	
Operating Cost	133.1	133.2	133.7	135.7	Ⓐ
Utilization, *in millions of hours*	6.2	6.2	5.8	5.7	Ⓑ
Utilization Rate	**21.4**	**21.3**	**23.0**	**24.0**	Ⓐ÷Ⓑ

Witness: Robert Berardi

UNDERTAKING - JT 2.20

Reference:
I-07-SEC-006

Undertaking:
To provide the telematics information utilization.

Response:
Telematics provides utilization related information which is available for varying time periods and durations. A weekly summary is used to assess utilization performance of different asset classes and how vehicles are being utilized across Hydro One.

Reports identify individual transport and work equipment details and their respective utilization related information such as:

- Run Time - Over the time period, the total number of hours, minutes, and seconds the engine was operating
- Idle Time - During the period, the total number of hours, minutes, and seconds the engine was idling (where each idling event must be at least five consecutive minutes)
- PTO Time - Total time the vehicle's PTO (power take-off) components were engaged over the time period
- Distance - Total distance travelled by the vehicle over the time period, in kilometers
- Odometer - The vehicle's current odometer reading at the end of the period
- Engine Hours - The total lifetime engine hours of the vehicle, as of the end of the time period

Telematics data is then analyzed and shared with managers. Fleet would identify under-utilized assets and reallocate them to areas of need to improve utilization, and to ensure we are operating efficiently and maintaining optimal level of fleet complement.

Additionally, telematics information is used to close gaps identified in financial controls through exception reporting and spot checking of items billed to Hydro One. For example, telematics data is used to validate highway 407 ETR transponder usage and fuel transaction verification by cross referencing transaction place and time against telematics location of the asset at the same time.

Witness: Robert Berardi

UNDERTAKING - JT 2.21

Reference:
I-12-AMPCO-058

Undertaking:
To describe the 2020 budget impacts of revisions to functional requirement standards, engineering design and construction standards, and implementing them in the field.

Response:
Hydro One does not track the incremental impact on budget resulting from revisions to functional requirement standards, engineering design and construction standards. However, Hydro One does not expect revisions to these standards in 2020 to have a material impact on the implementation of the 2020 capital work program.

UNDERTAKING - JT 2.22

Reference:

I-12-AMPCO-067

C-09-02, Table 1

Undertaking:

To provide the billable ratio and its derivation.

Response:

The actual billable hours ratios for Transmission and Stations organization which is indicative of the majority of the transmission work of variable staff, including both regular and non-regular employees for 2015-2018 are provided below:

(%)	2015	2016	2017	2018
Billable Hours Ratio	84	84	84	83
Non-Billable Hours Ratio	16	16	16	17
Total Hours	**100**	**100**	**100**	**100**

The description of the billable hours ratio components are outlined below:

- **Billable Hours –** represents the view of the timesheet hours that were charged to work program or other recoverable work (capital, OMA, external)

- **Non Billable Hours –** represents the hours that do not directly impact the work program. The hours include vacation, sickness, training, etc.

Billable Hours Ratio = Billable Hours / Total Hours

Witness: Robert Berardi, Joel Jodoin

UNDERTAKING - JT 2.26

Reference:
I-07-SEC-026

Undertaking:
To give an explanation of the allocation.

Response:
The majority of the initiatives presented in SEC-26 are directly assigned to the transmission work program when these productivity initiatives are validated and included in the business plan. As these initiatives directly impact transmission work program an allocation to transmission and distribution is not required. The only initiatives which are subject to an allocation methodology between transmission and distribution and other are presented below:

Initiative Grouping	Allocation Methodology
Fleet Telematics and Rightsizing	2020 - Tx: 33%, Dx 67% Black and Veatch Shared Asset Study – The productivity allocation follows the same allocation as the Fleet Capital spend (consistent with plan allocation)
Procurement	2020 – Tx 65%, Dx 35% Historical Actuals and Planning Assumptions – The productivity allocation is estimated by analyzing historical and expected spending categories by each line of business. Categories are mapped to the lines of business based historical actuals and estimated spend in each category. Direct allocations between the Transmission and Distribution business can be assigned based on this analysis.
Information Technology – Contract Reductions	2020 – Tx 38%, Dx 62% Black and Veatch Shared Asset Study - The productivity allocation follows the same allocation as the affected IT sustainment spend drivers (consistent with plan allocation).
Corporate Initiatives	2020 – Tx 46%, Dx 43%, Other 11% Black and Veatch Corporate Cost Allocation methodology – The productivity allocation follows the same allocation as affected cost centres (consistent with plan allocation).

Witness: Joel Jodoin, Robert Berardi

UNDERTAKING - JT 2.29

Reference:
KT2.2

Undertaking:
To consider the calculations on line 39 on Exhibit KT2.2 and advise whether Hydro One takes issue with it or not.

Response:
Confirmed, line 39 on Exhibit KT2.2 reflects the average compensation costs per Society Represented Transmission FTE.

UNDERTAKING - JT 2.33

Reference:
I-04-LPMA-007

Undertaking:
Re: Exhibit E, Tab 2, Schedule 1, Table 2, to confirm whether bad debt is included, or is it included in the OM&A forecast; to describe how, if at all, the bad debt write-off associated with other external revenues is reflected in the variance accounts for other external revenues.

Response:
Bad debt expense is not included in the revenue items listed in Exhibit E, Tab 2, Schedule 1, Table 2. Additionally, bad debt expense is not included in the transmission OM&A forecast in the current Application.

The bad debt expense relating to other external revenues is not reflected in the variance account for other external revenues.

Witness: Samir Chhelavda

UNDERTAKING - JT 2.34 - Q1

Reference:

Exhibit E/Tab 3/Schedule 1, Tables 2 and 3

Undertaking:

a) Are the CDM savings reported in the two tables different (e.g. for 2020 the values are 3,197 MW and 2,552 MW respectively) because the first is based on generation savings while the second is based on end-use savings?

Response:

a) Both Tables 2 and 3 refer to generator level savings. The difference is that Table 3 shows the CDM impact on the 12-month average peak demand used for load forecasting purposes (as noted in the sub-title of Table 3) , while Table 2 shows both the CDM impact on the annual peak demand and the corresponding 12-month average values. For example, for the year 2020, the CDM figure of 2,552 MW represents the 12-month average CDM value, which is identical to CDM value in the last column of Table 2 for the year 2020.

UNDERTAKING - JT 2.34 - Q2

Reference:

Exhibit I/Tab 10/Schedule 24 d), Attachment 1
(VECC-24 d)-Attachment 1)
Exhibit E/Tab 3/Schedule 1, Tables 2 and 3

Undertaking:

a) Columns BQ, BR and BS of the Excel file report Net Energy Savings for 2015-2017. Similarly, Columns FG, FH and FI of the Excel file report the Net Demand savings for 2015-2017. However, in both instances, all of the values are not numerical (e.g. cell FI749) and totals by category (e.g., ICI) or for the columns overall cannot be calculated. Please provide a revised file containing the numerical values for the net energy and net demand savings for each program and the totals for these years.

b) Based on the Excel file showing IESO reported savings for 2006 to 2014 (i.e., VECC 24 d) - Attachment 1), please provide a schedule that sets out the actual net demand savings in 2014 through 2017 broken down into the following categories: DR, ICI, Dispatched Load and EE.

c) Do the 2017 CDM savings in Exhibit E/Tab 3/Schedule 1, Table 3 match the Net Demand savings attributable to EE programs for the 2017 as reported in Attachment 1 of VECC 24 d)? If not, please explain why.

Response:

a) The revised file containing the numerical values is provided in the attachment.

b) The data reported by the IESO in VECC 24 d) Attachment 1 does not provide the savings in the four categories referenced. The categories in the table provided by the IESO, and the net peak saving (MW) at the end use level are provided below:

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
EE	270	709	796	868	1,009	1,188	1,220	1,387	1,574	1,818	1,807	1,766
C&S	-	17	37	62	100	265	273	308	498	609	706	831
DR	298	662	632	598	509	509	845	1,371	1,483	1,746	2,018	2,116
CBG (customer based gene	-	2	11	11	11	11	11	11	11	11	11	11
Total	568	1,390	1,477	1,540	1,629	1,974	2,350	3,078	3,567	4,185	4,542	4,726

c) No, the values shown in VECC 24 d) Attachment 1 are annual peak values at the end-use level, while the values in Table 3 are 12-month average amounts at the generator level. The values shown in VECC 24d) Attachment 1 were only used for the variance account calculations. For the purpose of load forecasting (i.e., Table 3 values) Hydro One uses total forecast EE and C&S CDM peak savings per the 2013 LTEP in order to have a consistent data set across historical and forecast years, consistent with the load forecasting methodology previously approved by the OEB for Hydro One.

UNDERTAKING - JT 2.34 - Q3

Reference:
Exhibit I/Tab 10/Schedule 24 b); d) and h) i)
(VECC-24 b); d) & h) i))
Exhibit E/Tab 3/Schedule 1, Table 3

Undertaking:
Preamble: The response to VECC 24 b) contains the following data with respect to energy savings from CDM:

Table 3: Comparison of the LTEP and OPO Energy Savings

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
LTEP 2013 total energy savings (2006-2012 actual)	1.6	3.5	4.0	4.9	5.4	6.5	7.6	8.6	10.1	10.9	11.3	11.4	13.0	15.1	16.7	17.8	19.0
OPO 2016 Total energy savings TWh (2006-2015 actual)	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	12.8	14.3	15.9	17.8	19.5	20.7	20.9	21.1

Reference 6 from VECC 24 d) contains the following data with respect to historic energy savings from CDM which differs from that in VECC 24 b) in 2015 and after:

Conservation Achievements												
TWh	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Codes and Standards	0.0	0.1	0.2	0.3	0.5	1.0	1.6	1.8	3.1	4.2	5.2	6.3
Conservation Program	1.6	3.4	3.9	4.6	5.0	5.7	6.3	7.1	8.1	9.7	9.4	10.0

Finally Reference 7 from VECC 24 d) contains historic data with respect to net energy savings from EE programs.

a) Please confirm that the 2006-2017 energy savings reported in References 6 and 7 of VECC 24 d) are not the same and that both differ from the savings reported in the 2013 LTEP for the same period.

b) Which of the references in VECC 24 d) (#6 or #7) contain the most recently issued values from the IESO regarding historic 2006-2017 CDM energy savings?

c) Which historical series of energy savings did HON use for purposes of developing its forecasting models?

Witness: Clement Li, Bijan Alagheband

d) If the most recent data from the IESO (per part (b)) was not used please explain why.

e) If the most recent data from the IESO regarding the historic and forecast energy savings differs from that in the 2013 LTEP, please explain how the demand savings history/forecast from the 2013 LTEP can still be valid – as claimed in the response to VECC 24 h) i).

f) The materials provided by the IESO for the Technical Planning Conference in September 2018 included the following forecast for new Conservation Program Savings in 2018 and after (VECC 24 d), Reference 6, Slide 20):

Long Term Conservation Forecast					
	2018	2019	2020	2021	2022
New Conservation Program Savings (TWh)	1.99	3.37	4.50	4.90	5.30
New Conservation Program Savings (MW)	317	537	710	773	831

Is the CDM forecast in Exhibit E/Tab 3/Schedule 1, Table 3 consistent with this forecast?

Response:

a) Confirmed.

b) The information in reference #6 was released in October 2018 and the information in #7 was shared by the IESO with Hydro One in January 2019.

c) The energy savings in the 2016 OPO was used for the purpose of developing the load forecast.

d) Hydro one has considered all the available CDM information to be assured that the assumptions used for the load forecast are reasonable. The comparison of the energy savings in the 2016 OPO and 2018 Technical conference is as follows:

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
2016 OPO	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	12.8	14.3	15.9
IESO’s Technical Planning Conference in September 2018	1.6	3.5	4.0	4.9	5.4	6.7	7.9	8.9	11.3	13.9	14.6	16.3

The difference between the two data sources is minimal and Hydro One uses the 2016 OPO information for developing the load forecast as it provides a consistent data set with a breakdown by categories as required for load forecasting purposes.

e) The most recent data from the IESO only provides the energy savings outlook but not the peak savings. Only the 2013 LTEP provides a consistent data set of historical/forecast EE and C&S peak savings for Ontario necessary to develop Hydro One's load forecast.

f) As shown in the tables below, the CDM savings for 2018-2022 in the IESO 2018 technical planning conference were not used to update the load forecast since the differences were small and Hydro One's assumptions were more conservative (i.e. less CDM). Hydro One has used the peak savings in 2013 LTEP and energy savings in 2016 OPO in order to have consistent categories and persistence for 2006-2020 period.

Comparison the energy savings in load forecasting and technical conference:

	2018	2019	2020	2021	2022
Assumption on LF (2016 OPO)	17.8	19.5	20.7	20.9	21.1
technical confrence 201809	18.4	19.9	21.0	21.1	21.6

Comparison of the peak savings in load forecasting and technical conference:

	MW at generator level	2017	2018	2019	2020	2021	2022
(1)	EE and C&S (load forecasting)	2,099	2,391	2,799	3,197	3,341	3,509
(2)	IESO 201901 result	2,784					
(3)	IESO 201809 technical conference *		317	537	710	773	831
(4)=(1)+(3)	combine of (2) and (3)	2,784	3,101	3,321	3,494	3,557	3,615

** savings for EE initiatives only*

UNDERTAKING - JT 2.34 - Q4

Reference:

Exhibit I/Tab 10/Schedule 26 a) & b)
(VECC-26 a) & b)) & Exhibit I/Tab 10/Schedule 27 a)
(VECC-27 a))

Undertaking:

a) VECC 27 a) indicates that none of the forecast models used provide a forecast of the 12 monthly peaks. Rather, the monthly peaks are forecast by applying the growth rates from the models to a base year's peak values. However, VECC 26 indicates that the actual 2018 monthly peak values were not known when the forecast was determined (part a)) but also indicates that the growth rates were applied to forecast values for the 2018 billing determinants. How were these forecast 2018 billing determinants established (given the models do not forecast monthly peaks)?

Response:

a) The forecast values of the 2018 billing determinants were established by applying the forecast growth rates for 2018 to the 12-month average value of billing determinants in the year 2017.

UNDERTAKING - JT 2.34 - Q5

Reference:

Exhibit I/Tab 10/Schedule 27 b) & c) & (VECC-27 b) & c))

Undertaking:

a) In VECC 27 c) the response explains that the actual growth rates applied were higher than those from the models as they included the load impact of developments in the Leamington and surrounding areas. Please explain what these developments are and how the adjustment to the growth rates produced by the models was established.

Response:

a) These developments relate to expansion of greenhouses in the Leamington and surrounding areas. The adjustment to the growth rates reflect an additional 325MW in peak demand by the year 2020, based on consultation with Hydro One's Asset Management group regarding investment plans for the area.

UNDERTAKING - JT 2.34 - Q6

Reference:

Exhibit I/Tab 10/Schedule 31 b) (VECC-31 b))

Undertaking:

a) The last sentence in the response to part (b) states: "In practice, extreme weather may occur on any day of the month, and Hydro One must take this fact into account in calculating monthly peak in order to accurately forecast the monthly peaks that drive the collection of transmission revenue". This suggests that Hydro One's load forecast takes into account extreme weather. As requested in the original question - please reconcile this statement with the fact that the load forecast is meant to be weather normalized based on 31 years.

Response:

a) In order to accurately forecast weather-normal monthly peak demands, it is necessary to account for the normal weather fluctuations that can occur in the month based on 31-years of weather data (i.e. "normalized extreme weather impacts").

   As discussed in response to Exhibit I/Tab 10/Schedule 31 b) (VECC-31 b)), for reliability purposes, the IESO accounts for "normalized extreme weather" for a given month by adding the 31-year average extreme weather effect to the non-weather related load during a Wednesday of that month, when the non-weather related load is highest compared to other weekdays. For the purpose of its load forecast, Hydro One adds the "normalized extreme weather impact" to non-weather related load in every day of the week with equal probability and calculates the monthly peak in each scenario. The average of such monthly peak values represent weather-normal peak for that month. Thus, neither IESO nor Hydro One adds actual extreme weather to non-weather related load.

UNDERTAKING - JT 2.34 - Q9

Reference:

Exhibit I/Tab 01/Schedule 149 b) (OEB Staff-149 b))
Exhibit I/Tab 10/Schedule 16 (VECC-16)

Undertaking:

a) Please provide the actual MSP Revenues for each of the years 2016, 2017 and 2018.

b) Please provide the actual Low Voltage Switch Gear provided for each of the years 2016, 2017 and 2018.

Response:

a) The actual MSP Revenues in 2016, 2017 and 2018 are $0.6 million, $0.4 million and $0.5 million, respectively.

b) The actual Low Voltage Switch Gear provided in 2016, 2017 and 2018 are $13.0 million, $13.4 million and $14.1 million, respectively.

UNDERTAKING - JT 2.34 - Q10

Reference:

Exhibit I/Tab 10/Schedule 45 a) i) (VECC-45 a) i))
Exhibit I/Tab 10/Schedule 24 d), Attachment 1
(VECC-24 d) – Attached Excel File: IESO 2006-2017 Saving & Persistence Table)
Updated Exhibit H/Tab 1/Schedule 2, Attachment 11, Table 2

Undertaking:

a) With reference to the functional/working Excel file requested in VECC TCQ-3 for the IESO 2006-2017 Savings and Persistence Table, for each of 2016 and 2017 please indicate which rows in the Excel file contribute to each of the following categories of CDM: ICI, Dispatched Load, DR and EE and demonstrate that the totals for the respective rows reconcile with the values reported in Updated Exhibit H/Tab 1/Schedule 2, Attachment 11, Table 2 for each category.

Response:

a) The EE and C&S amounts used in the variance calculations are based on the IESO 2006-2017 Savings Table as provided in the Excel file attachment to JT 2.34-Q2 a). The reconciliation of these amounts to the values provided in Attachment 11, Table 2 is provide in the response to JT 2.34 – Q12 d).The data sources and methodologies for the ICI, dispatched load and DR variance calculations are provided in Exhibit H/Tab1/Schedule 2, Attachment 11.

Witness: Clement Li, Bijan Alagheband

UNDERTAKING - JT 2.34 - Q11

Reference:

Exhibit I/Tab 10/Schedule 45 a) ii), Attachment 1
(VECC-45 a) ii), Attachment 1)
Exhibit H/Tab1/Schedule 2, Attachment 11, page 2

Undertaking:

Preamble: The Attachment contains the following data:

Peak Demand Saving (MW)

	2016	2017
EE	1662	1575
Codes and Standards	505	525
Total	2167	2099

Generator level	2016	2017
ind-TX	115	147
ALL LDCs	2,052	1,952
Total	2,167	2,099

OPA Loss Factor Assumption

	2016	2017
distribution	0.065	0.065
transmission	0.025	0.025
Total	0.09	0.09

Generator level MW	2016	2017
ind-TX	112	144
ALL LDCs	1,927	1,833
Total	2,039	1,976

a) Is the fourth set of data meant to represent Peak Demand Savings at the Generator level (as indicated) or at the End Use level (as suggested subsequently in the Attachment where the values 2,039 and 1,976 match those attributed to the savings assumptions used for 2016 and 2017at the end-use level)?

b) If at the Generator level, please explain why these values differ from those in the second set of data – which is also at the Generator level.

c) If at the End Use level, please indicate how the values were calculated using the Loss Factor Assumptions.

Response:

a) The fourth data set was mislabeled. The values 2,039 and 1,976 are at the end-use level.

b) N/A.

c) The calculation details are shown below:

	Generator Level		Loss factor	End use level	
	2016	2017		2016	2017
	(1)	(2)	(3)	(4)=(1)/(1+(3))	(5)=(2)/(1+(3))
TX Ind	115	147	0.0250	112	143
All LDC	2,052	1,952	0.0650	1,927	1,833
Total peak saving	2,167	2,099		2,039	1,976

UNDERTAKING - JT 2.34 - Q12

Reference:

Exhibit I/Tab 10/Schedule 45 a) ii), Attachment 1
(VECC-45 a) ii), Attachment 1)
Exhibit H/Tab1/Schedule 2, Attachment 11, pages 2-4

Undertaking:

Preamble: The Attachment contains the following data:

I-10-VECC-45 a(ii)

variance in KW

Month	LF assumption at the end use level (KW)			EE monthly profile used in LF		IESO EE saving EMV resutls (KW)			variance in KW (Dif of dif)
	2016	2017	dif (2017 vs 2016)	2016	2017	2016	2017	dif (2017 vs 2016)	2017
	A	B	C= B-A			D	E	F= E-D	F-C
1	1,433,588	1,447,218	13,630	0.703098233	0.732290385	1,766,438	1,902,247	135,809	122,179
2	1,419,005	1,431,228	12,223	0.6959462	0.724199799	1,748,469	1,881,230	132,761	120,537
3	1,312,901	1,325,258	12,357	0.643908009	0.670578944	1,617,730	1,741,941	124,211	111,854
4	1,342,374	1,343,303	929	0.658362855	0.679709696	1,654,046	1,765,660	111,613	110,684
5	1,417,979	1,418,906	927	0.695442939	0.717964835	1,747,205	1,865,034	117,829	116,901
6	1,874,071	1,876,242	2,171	0.919131829	0.949376204	2,309,192	2,466,163	156,971	154,800
7	2,038,958	1,976,289	(62,669)	1	1	2,512,363	2,597,667	85,305	147,973
8	1,855,321	1,860,329	5,009	0.909935719	0.941324401	2,286,088	2,445,247	159,159	154,150
9	1,681,441	1,684,207	2,766	0.824657241	0.852206779	2,071,838	2,213,750	141,912	139,146
10	1,326,777	1,331,972	5,196	0.650713035	0.67397638	1,634,827	1,750,766	115,939	110,743
11	1,353,137	1,361,789	8,652	0.663641321	0.689063398	1,667,308	1,789,957	122,650	113,998
12	1,439,403	1,451,722	12,319	0.705950388	0.734569584	1,773,603	1,908,167	134,564	122,245

a) Please confirm that, in the above data, the values 2,039 MW and 1,976 MW are meant to represent the EE savings assumptions included in the load forecast for those years. If not confirmed what do the values represent and why at they use in the calculation?

b) If confirmed, please provide a reference to the EB-2016-0160 Application that demonstrates these were the assumed values used in the load forecast for the impact of CDM at the end use level.

c) Exhibit H/Tab1/Schedule 2, Attachment 11, page 2 states that "Hydro One's 2017 load forecast approved by the OEB included the same total CDM peak savings amount assumed for 2016 (i.e., 1,638 MW)". Please explain why, in VECC-45 a) ii), Attachment 1, the savings assumptions for 2016 and 2017 are different (2,039 MW and 1,976 MW respectively) and reconcile the differences.

d) What is the difference between the actual peak EE savings achieved for 2016 and 2017 as set out in: i) Exhibit H/Tab1/Schedule 2, Attachment 11, Table 2 and ii) that provided in Exhibit I/Tab 10/Schedule 45 a) ii), Attachment 1 per the above Preamble.

e) The calculations set out in: i) Exhibit H/Tab1/Schedule 2, Attachment 11, Table 2 and ii) in Exhibit I/Tab 10/Schedule 45 a) ii), Attachment 1 per the above Preamble are fundamentally different but yield the same monthly variance for peak EE savings. Please explain why.

<u>Response:</u>

a) The amounts shown are EE plus C&S amounts included in the load forecast for those years.

b) Table 2 on page 8 of EB-2016-0160 Exhibit E1/Tab3/Schedule 1shows the 2,167 MW (in 2016) and 2,099 MW (in 2017) values at the generator level used in the EB-2016-0160 approved forecast. The response to JT 2.34–Q11 shows how the equivalent end-use level amounts of 2,039MW (in 2016) and 1,967MW (in 2017) are calculated.

c) The monthly profile across Tx and Dx in 2016 and 2017 are different resulting in an overall less savings in 2017 summer and more in 2017 winter compared to 2016. This is consistent with the figures in Exhibit E/Tab3/Schedule 1, where maximum (July) peak reduces from 2,167 MW in 2016 to 2,099 MW in 2017, while the 12-month average remains near 1,638 MW in both years (1,638.033MW in 2016 and 1,638.14 MW in 2017), at generation level. Using Tx and Dx loss factors, the peak figures net of losses are 2,039 MW in 2016 and 1,976 MW in 2017, as detailed in response to JT 2.34–Q11.

d) There is no difference in the EE savings assumptions included in the two references provided. The difference is in how the information is displayed in the two sources. The following table shows the reconciliation of the EE amounts shown in the two references.

	2016			2017			
Month	LF sssumption at he end use level (MW) (1)	IESO EE savings EMV results (MW) (2)	Difference (3)=(2)-(1)	LF assumption at he end use level (MW) (4)	IESO EE savings EMV results (MW) (5)	Difference (6)=(5)-(4)	variance in KW (Dif of dif)=(6)-(3)
1	1,434	1,766	333	1,447	1,902	455	122
2	1,419	1,748	329	1,431	1,881	450	121
3	1,313	1,618	305	1,325	1,742	417	112
4	1,342	1,654	312	1,343	1,766	422	111
5	1,418	1,747	329	1,419	1,865	446	117
6	1,874	2,309	435	1,876	2,466	590	155
7	2,039	2,512	473	1,976	2,598	621	148
8	1,855	2,286	431	1,860	2,445	585	154
9	1,681	2,072	390	1,684	2,214	530	139
10	1,327	1,635	308	1,332	1,751	419	111
11	1,353	1,667	314	1,362	1,790	428	114
12	1,439	1,774	334	1,452	1,908	456	122

e) See answer to part d).

UNDERTAKING - JT 2.34 - Q13

Reference:

Exhibit I/Tab 10/Schedule 45 a) ii), Attachment 1
(VECC-45 a) ii), Attachment 1)
Exhibit H/Tab1/Schedule 2, Attachment 11, pages 2-4
Exhibit I/Tab 10/Schedule 29 d) (VECC-29 d))

Undertaking:

a) Please confirm that in Exhibit H/Tab1/Schedule 2, Attachment 11, Table 2 the peak savings reported for DR, Dispatched Load and ICI are savings at the time of the system peak. If not confirmed, what do they represent?

b) VECC 29 d) indicates that DR is a peak shifting program. Are Dispatched Load and ICI also peak shifting programs (i.e., meant to shift load away from the system peak)?

c) Since the billings demands for Network Service, Line Connection Service and Transformation Connection Service are not based on a transmission customer's peak at the time of the system peak, why is it appropriate to use the impact of these programs on system peak demand for purpose of calculating the variance account amounts?

d) To the extent these are peak shifting programs could they not actually shift load from the system peak in a manner that increased the customer's non-coincident peak demand?

Response:

a) Confirmed.

b) Yes.

c) Hydro One does not have access to all individual customer accounts (e.g., Class A customers) across Ontario. Consequently, it is impossible to determine the magnitude and timing of individual customer's peak savings. However, since customers do not know in advance when the coincident peak day and time will occur, it is reasonable to assume that the savings could happen at any time. As a result, for calculating the 2017 variance account amounts, Hydro One has assumed that the peak savings could occur at the time of the customer's monthly non-coincident peak demand which is the same methodology approved by the Board for calculating the 2013 and 2014 CDM variance account amounts previously disposed of in EB-2016-0160.

d) No. Customers participating in peak shifting programs are likely to have a sophisticated understanding of their electricity bill and therefore it is reasonable to assume that they would not shift their demand to a time when their peak is already high; otherwise they could increase their non-coincident peak demand which would result in a higher electricity bill.

UNDERTAKING - JT 2.34 - Q14

Reference:
Exhibit I/Tab 10/Schedule 45 b) & d)
(VECC-45 b) & d))
Exhibit I/Tab 10/Schedule 31 c) (VECC-31 c))

Undertaking:
Preamble: VECC 45 b) confirms that 2014 was the last year for which actual data regarding CDM was used in preparing the load forecast for EB-2016-0160.

VECC 31 c) indicates that the weather corrected actual load data includes the impact of DR.

VECC 45 d) requested that the analysis in Table 2 (Attachment 11) be redone using the incremental savings per IESO from the last year for which actual data was used in EB-2016-0160 (which was 2014) up to 2017 for each category of CDM set out in Table 2. The response refers back to the original Table 2 which calculates savings in reference to 2016 – not 2014.

a) Please provide a schedule that, for each of the CDM categories used in Table 2, sets out:
   i. the actual CDM savings incorporated in the 2014 data used for EB-2016-0160,
   ii. the assumed savings incorporated in the 2017 load forecast per EB-2016-0160;
   iii. the actual savings for 2017.

b) If the incremental DR savings after 2014 assumed in the load forecast are not zero, as indicated in the response to VECC 31 c), please explain why.

c) If the cumulative EE assumed for 2017 load forecast do not equal 1,638 MW, as indicated in Exhibit H/Tab1/Schedule 2, Attachment 11, page 2, please explain why.

d) If the actual 2014 and 2017 EE and DR savings by category do not match those set out in the Excel file provided in VECC 24 d) please explain why.

Response:

a)

i. HONI assumed the 2014 actual CDM savings from EE and C&S was 1820 MW (generator level) which was consistent with the 2013 LTEP for the EB-2016-0160.

ii. The assumed savings in 2017 was 2099 MW at generator level and 1976 MW at the end use level.

iii. Per the information provided to Hydro One in confidence by the IESO in January 2019, the EE and C&S peak savings for 2017 was 2598 MW.

b) The response to Exhibit I/Tab 10/Schedule 31 c) (VECC-31 c)) does not state that the incremental DR assumed in the load forecast is not zero. Hydro One's evidence is that the incremental DR over the forecast period is zero.

c) The cumulative EE and C&S assumed for the 2017 load forecast equals 1638 MW which is the 12 month average value.

d) The actual 2014 savings for all EE and C&S programs was not available at the time of the EB-2016-0160 proceeding. Hydro One only tracked the variance for the 2011-2014 target programs as per the approved Settlement Agreement in EB-2016-0160. The actual 2017 EE savings used for the 2017 variance calculation is consistent with table provided in the VECC24d) Attachment 1. Hydro One has also tracked the variance for the ICI, dispatchable load and DR auction programs consistent with the methodology approved by the OEB for calculating the 2013 and 2014 CDM variance account amounts.

UNDERTAKING - JT 2.34 - Q15

Reference:

Exhibit I/Tab 10/Schedule 48 b) (VECC-48 b))
Exhibit I/Tab 10/Schedule 49 b) (VECC-49 b))

Undertaking:

Preamble: With respect to the response to VECC 48 b), it is noted that for a number of the Transmission Lines the explanation for the change in functional category (from that in EB-2016-0160) is due to "Application of OEB Decision in Proceeding EB-2011-0043".

Similarly, in VECC 49 b), it is noted that for a number of the Transmission Stations the explanation for the change in functional category (from that in EB-2016-0160) is due to "Application of OEB Decision in Proceeding EB-2011-0043".

a) Please explain how the Board's Decision in EB-2011-0043 specifically affected the functionalization of lines and stations related to Project D5 (Guelph Area Transmission Reinforcement), Project D09 (Brant TS); Project D19 (Runnymede TS) and Project SS02 (Wataynikaneyap Line to Pickle Lake Connection)

b) Since the Decision is from EB-2011-0043, please explain why it was not implemented for the EB-2016-0160 proceeding.

c) What was the impact on the rates approved in EB-2016-0160 of not correctly reflecting the Board's Decision from EB-2011-0043 in the functionalization of costs and the determination of the rates?

Response:

a) As mentioned in the pre-filed evidence (Exhibit I1, Tab 1, Schedule 2), the Transmission System Code (TSC) amendment resulting from the Board's Decision in EB-2011-0043 expanded the definition of Network assets to also include certain assets captured under the previous definition of a Line Connection asset, and/or portions thereof, that provide other functions beyond supplying load.[1]

For the cost allocation proposed in this application, Hydro One looked at the projects that are expected to be in-service by 2020 (the year that cost allocation is based on) and reassigned the assets to the proper rate pools to comply with the TSC amendment discussed above. As can be seen in response to VECC-48(b) and VECC-49(b), all changes in asset functional categories as a result of "Application of OEB Decision in Proceeding EB-2011-0043" are essentially adding a Network component to the assets (impacted by the projects mentioned in the question) currently assigned as Line Connections, Transformation Connections, and/or Other.

b) The TSC amendment resulting from EB-2011-0043 was considered in the EB-2016-0160 proceeding. As per the evidence in EB-2016-0160 (Exhibit B1, Tab 3, Schedule 11, Reference #s D09 and D19), the expected in-service dates for Brant TS and Runnymede TS projects were beyond the test years in that proceeding (2017 and 2018). Similarly, Wataynikaneyap Line Connection to Pickle Lake project was not part of the system plan in EB-2016-0160. For this reason, the proposed changes in functional categories associated with these three projects were not implemented in EB-2016-0160.

The majority of the Guelph Area Transmission Reinforcement (GATR) project changes in functional categories due to "Application of OEB Decision in Proceeding EB-2011-0043" were incorporated in EB-2016-0160. Minor changes in system configuration that materialized only once the final stage of the GATR project was put in service in 2016 resulted in two additional line sections to be reclassified in this Application.

c) As explained in part a) and b) above, Hydro One did correctly reflect the Board's Decision from EB-2011-0043 in EB-2016-0160.

[1] This revision is only applicable where a line or station commences to be constructed on or after August 26, 2013, or where an existing line or station is expanded or reinforced for the purposes of increasing its capacity and the expansion or reinforcement commences to be constructed on or after August 26, 2013, regardless of when the line or station was originally placed into service.

UNDERTAKING - JT 2.34 - Q16

Reference:

Exhibit I/Tab 10/Schedule 48 b) (VECC-50 b))
Exhibit I/Tab 10/Schedule 49 b) (VECC-51 b))

Undertaking:

Preamble: The response to VECC 50 b) indicates that for Dual Function Lines the allocation factors used to split the asset value between Network and Line Connection functions are derived using the average forecast monthly coincident peak demand of customer load connected to the DFL and the minimum of the average of summer and winter transmission capacity of the DFL and that the allocation might differ from one year to another due to any change in customer load forecast or due to addition of new DFL lines.

Similarly, VECC 51 b) indicates that the allocation of asset value for Generator Line Connections between "Generators" and "Load" depends on the sum of the maximum annual non-coincident peak demand of all delivery points connected to the connection facility and the maximum installed capacity of generation connected to that facility and can differ from one year to another if there was a change in the annual non-coincident peak demand or due to connection/disconnection of a generator.

a) With respect to VECC 50 b), how much can the allocation vary from year to year strictly due to changes in customer load forecast (i.e., no addition of new DFL lines)?

b) In such instances, would it be more appropriate to use an average annual value (e.g., a three or four year average)? If not, why not?

c) With respect to VECC 51 b), how much can the allocation vary from year to year based strictly on changes in the annual non-coincident peak demand (i.e., no connection of new or disconnection of existing generators)?

d) In such instances, would it be more appropriate to use an average annual value (e.g., a three or four year average)? If not, why not?

Response:

a) Hydro One would like to clarify that the variation in the allocation of DFL circuits, as discussed in VECC-50(b), is between test years covered by two different applications (i.e. 2017 (EB-2016-0160) vs 2020 (EB-2019-0082)) and not year over year as indicated by VECC. Load forecast between two applications could be materially different due to updated assumptions, and hence, some variation in the allocation factors is expected based solely on changes in customer load forecast. In the current application, this variation was limited to less than 10%.

b) Dual Function Line (DFL) assets are allocated among Network and Line Connection rate pools using customers' forecasted average monthly coincident peak (CP) demand for 2020, which incorporates the trend in historical demand and anticipated economic growth, and therefore is the best available information on customer load in the forecast year. As such, Hydro One does not believe that it would be more appropriate to allocate costs based on a three or four year average value. The current methodology has been reviewed and approved by the OEB in Hydro One's previous transmission revenue requirement applications (e.g. EB-2012-0031, EB-2014-0140, EB-2016-0160 etc.).

c) Hydro One would like to clarify that the variation in the allocation of assets serving generators as well as load customers, as discussed in VECC-51(b), is between test years covered by two different applications (i.e. 2017 (EB-2016-0160) vs 2020 (EB-2019-0082)) and not year over year as indicated by VECC. The load forecast between two applications could be materially different due to updated assumptions, and hence, some variation in the allocation factors is expected based solely on changes in customer load forecast. In the current application, this variation was limited to less than 10%.

d) Assets serving both generators and load customers are allocated to appropriate rate pools using the load customers' forecasted maximum annual non-coincident peak (NCP) demand for 2020, which already reflects changes in historical demand and anticipated economic growth, and therefore is the best available information on customer load in the forecast year. As such, Hydro One does not believe that it would be more appropriate to allocate costs based on a three or four year average value. The current methodology has been reviewed and approved by the OEB in a Hydro One's previous transmission revenue requirement applications (e.g. EB-2012-0031, EB-2014-0140, EB-2016-0160 etc.).

UNDERTAKING - JT 2.34 - Q17

Reference:

Exhibit I/Tab 10/Schedule 55 b) (VECC-55 b))

Undertaking:

a) Please provide the actual export volumes for the first six months of 2019. In the same schedule please include the actual export volumes for the first six months of 2017 and 2018.

b) VECC 55 b) indicates that the annual export volumes have been decreasing over last four years (2015-2018). Can Hydro One offer any insight as to why this is the case?

Response:

a) Table below provides requested information.

	Actual Export Volume (MWh)		
	2017	**2018**	**2019**
January-June	10,052,357	10,041,806	10,158,619

b) Hydro One is not involved in the coordination of export transactions and has no insight to offer into the decreasing export volumes in the last four years.

Witness: Clement Li

UNDERTAKING - JT 2.34 - Q18

Reference:

Exhibit I/Tab 01/Schedule 225 b) (OEB Staff-225 b))
Exhibit I2/Tab 6/Schedule 1, Attachment 1, page 3

Undertaking:

Preamble: The response to OEB Staff 225 b) states: "It is Hydro One's interpretation and practice to include customers with energy storage facilities and/or solar generators (the individual inverter with capacity is 1 MW or higher) in the data provided to the IESO for billing Line Connection and Transformation Connection customers on a gross load basis as per the approved UTR tariff".

It is noted that in the currently approved 2019 Uniform Transmission rates, renewable embedded generation only attracts Line and Transformation Connection charges if the generator unit rating is 2 MW or greater and the 1 MW cut-off applies to non-renewable generators.

a) Please explain why the cut-off for energy storage and solar generators is 1 MW and not 2 MW, particularly in the case of solar generators.

Response:

a) Energy storage is not considered renewable generation and therefore the cut-off is 1 MW.

   Hydro One's experience is that solar inverter unit capacity is typically small (i.e. under 0.5 MW) and therefore the 1 MW limit is irrelevant. In any case, currently no Hydro One transmission customers with embedded solar generation are billed on a gross load basis and therefore this condition is not applied.

   Hydro One agrees that solar generators are renewable generation and therefore the cut-off should be 2 MW. As such, Hydro One proposes to remove the words "or solar generators" from the following exhibits:

   - Exhibit I2, Tab 2, Schedule 1, page 4, lines 13 and 18;
   - Exhibit I2, Tab 2, Schedule 1, page 5, lines 15 and 20;
   - Exhibit I2, Tab 6, Schedule 2, Attachment 1, page 3 Terms and Conditions (G); and

- Exhibit I2, Tab 6, Schedule 2, Attachment 1, page 5 Notes 3.

UNDERTAKING - JT 2.34 - Q19

Reference:

Exhibit I/Tab 3/Schedule 1 c) (APPRO-1 c))

Undertaking:

Preamble: The response notes that the updated Elenchus Study used “Fixed Assets dedicated to Exports (interconnections) as of 2017 year-end”.

a) Please confirm that the updated Elenchus Study used the proposed 2020 Transmission Revenue Requirement.

b) Were there any additional assets placed in service or forecast to be placed in-service in the period 2018-2020 that could be designated as “Fixed Assets Dedicated to Exports”. If yes, what are they and what is their gross book value as of year-end 2020?

Response:

a) Confirmed.

b) No.

UNDERTAKING - JT 2.34 - Q20

Reference:

Exhibit I/Tab 3/Schedule 1 a) (APPRO-1 a))
EB-2014-0140, HON 2015-2016 Revenue Requirement Application, Exhibit TCJ2.01

Undertaking:

Preamble: The response to APPRO 1 a) provides a copy of the 2015 Elenchus cost allocation model updated using the latest available information.

In several of the responses to questions posed in EB-2014-0140 (e.g., TCJ2.01) it was stated that “The Elenchus model is a simple cost based model” and it was acknowledged that refinements could be made.

a) Were any refinements or changes made to the original Elenchus cost allocation methodology for purposes of preparing the model filed in response to APPRO 1 a)?

b) If yes, please outline in detail what the refinements/changes were and the impacts each have on the results.

Response:

a) No.

b) Does not apply.

UNDERTAKING - JT 2.37

Reference:
I-01-OEB-153

Undertaking:
To provide the 2015-2016 errors individually.

Response:
Please see below the requested information.

Measurement	2016 Model	2018 Model
RMSE (GWh)		
2015	1,922	864
2016	6,549	710
%RMSE		
2015	1.40%	0.63%
2016	4.92%	0.53%

Witness: Bijan Alagheband

UNDERTAKING - JT 2.38

Reference:
I-01-OEB-153

Undertaking:
To go back to 2013, 2014 using the 2012 model to see if the model actually works for, say, three-year time frame versus five-year time frame.

Response:
This undertaking would require estimating the 2016 and 2018 models using actual data up to and including 2012 (i.e. data used in EB-2014-140), similar to the method used in response to OEB Staff interrogatory I-01-153 for examining the forecast errors based on data for the years 2015 and 2016.

Hydro One has determined that it is not possible to complete the requested undertaking for the following reason. In the 2018 model, there is a dummy variable D13 (in the industrial sector) that was used to capture a transitory change in load in the year 2013, which equals 1 in that year and zero elsewhere as discussed in Exhibit E, Tab 3, Schedule 1, p. 35. Consequently, the value of this variable is 0 for all the years prior to 2013. This makes it impossible to estimate the 2018 model using information up to and including 2012 because the model estimation process breaks down due to an explanatory variable being 0 during the estimation period. By implication, the coefficient related to this variable also remains undetermined.

Hydro One submits that the 2018 model, which accounts for the most up-to-date information using standard regression criteria as discussed in response to OEB Staff interrogatory I-01-152 is preferred to the outdated 2016 model. In addition, the response to I-01-153 demonstrates that the 2018 model is more accurate than the 2016 model using data back to 2015, and there is no reason to expect that this result would change using data back to 2012.

UNDERTAKING - JT 2.39

Reference:

I-10-VECC-048
I-10-VECC-049

Undertaking:

To provide a high-level description of the change in network assets in this application compared to the last application; if possible, broken down between transmission lines and stations.

Response:

A high-level description of the changes in Network asset classifications relative to the last application is provided in the referenced interrogatories.

Estimating the pool revenue requirement implications of changes in the classification of Network, Line Connection and Transformation Connection assets resulting from implementing EB-2011-0043 would require significant time and effort.

As discussed in Exhibit I1, Tab 1, Schedule 2, section 3.1, expanding the definition of Network asset (which results in the reclassification of some assets) is mandatory as per the OEB's Transmission System Code Amendment resulting from EB-2011-0043. Therefore, identifying the pool revenue requirement implications of implementing the approved Transmission System Code Amendment, which was the subject of a separate proceeding at which intervenors had the opportunity to participate and ask this type of question, would not assist the OEB in addressing any of the issues to be decided in this proceeding.

UNDERTAKING - JT 2.40

Reference:
I-10-VECC-048
I-10-VECC-049

Undertaking:
To advise whether, when you change function from a connection line to a network line, whether that impacts capital contributions; if it does, how; how the change is treated.

Response:
In accordance with EB-2011-0043 Section 2, when the functional category of an asset changes (e.g. from line connection to dual function line), the Gross Book Value (GBV) and accumulated depreciation of the asset are re-assigned from the existing functional category to the new functional category. For cost allocation purposes, this re-assignment does not impact capital contributions as the GBV and accumulated depreciation being re-assigned are already net of customer capital contributions.

UNDERTAKING - JT 2.41

Reference:
A-04-01-01

Undertaking:
To consult with engineers and advise whether there are other asset classes that either work the same way or differently.

Response:
As it relates to transmission systems, the engineering analysis performed for developing the subject variable was designed solely for overhead line assets. The variable does not apply to other assets such as station or generation assets. While there are other transmission assets (e.g. substations) that will have standards that may vary by region, transmission overhead line assets are the most impacted by climatic variations and are the key asset group in determining cost variations due to minimum standard requirements stemming from climatic condition variations.